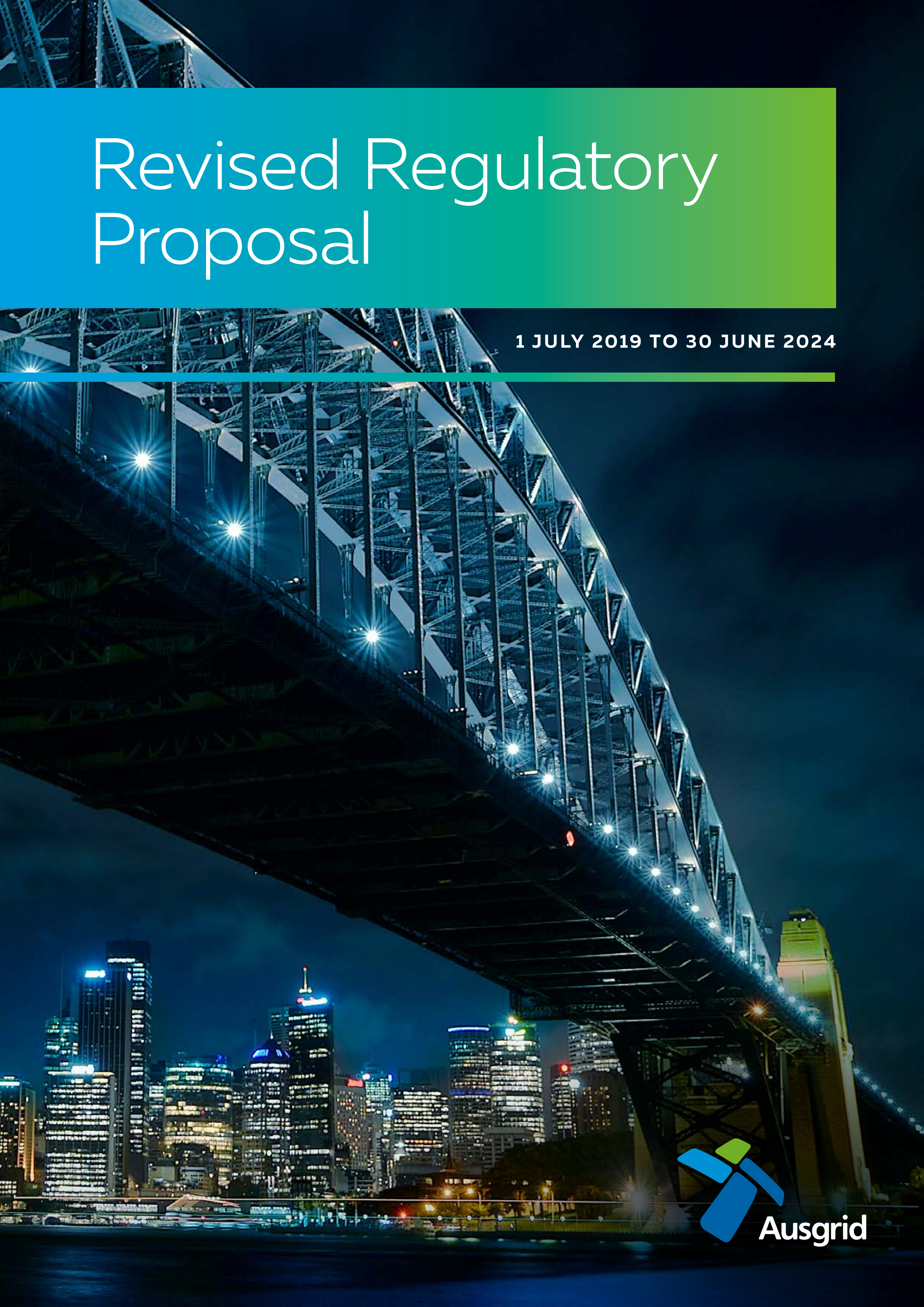
Revised Regulatory Proposal

1 JULY 2019 TO 30 JUNE 2024



Ausgrid

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CEO Foreword

Since submitting our Regulatory Proposal in April 2018 (Initial Proposal), we have continued to engage with customers while the Australian Energy Regulator (AER) conducted a detailed review of our expenditure plans.

Over recent months we have worked collaboratively with customer advocates to develop a Revised Regulatory Proposal (Revised Proposal) which better reflects customer expectations, whilst ensuring Ausgrid has the resources it needs to continue to provide safe and reliable services. We believe this Revised Proposal strikes the right balance. It meets customer expectations, continues to drive our ongoing transformation and allows the safe and sustainable operation of the network. Our Revised Proposal, if accepted by the AER, will reduce annual network charges by $71 for the average residential customer from 1 July 2019.

Customer engagement is critical for Ausgrid as our network evolves to meet changing customer needs. We are improving how we listen to, and respond to, customer feedback. This feedback has informed our investment priorities which are targeted at providing more value for customers.

We have comprehensively reviewed our capital expenditure plans in response to stakeholder feedback and the AER's Draft Decision. We concluded that although our Initial Proposal was consistent with our network risk profile, some reductions in our future investment levels are possible in the coming period.

Given the rate of technological change in our sector, we agree with customers that it may be possible to defer some capital expenditure that would be required under traditional cost benefit analysis. We are challenging ourselves to achieve more with less. Our Revised Proposal capital expenditure forecast is 13% lower than our Initial Proposal. This reflects a balance between cost efficiency, the need to transform the network and our ongoing responsibility to manage network reliability and risk.

In our Revised Proposal we are adopting the AER's 2018 Rate of Return Instrument and incorporating productivity improvements in our operating expenditure forecast from 1 July 2020. We will also work with the AER to implement the changes required to give effect to the 2018 Tax Review Final Report.

The projected cost savings resulting from these decisions build on the considerable efficiencies we have already achieved, which are also incorporated in our forecasts. We accept that our customers want us to work harder to deliver more efficiencies – and we have accepted that challenge. Our operating expenditure forecast is $20 million lower than the AER's Draft Decision and $119 million lower than our Initial Proposal.

Through our customer engagement, we also heard that our pricing plans could be improved. As a result, we have collaborated with our Pricing Working Group to develop a pricing strategy that reflects customer preferences, while delivering on the long-term need to transition to a lower cost energy system.

To further embed customers in our day-to-day operations we propose the establishment of new advisory committees, through which customers will remain at the centre of our future network plans. For example, we are establishing a Network Innovation Advisory Committee to drive our innovation program and the future direction of our network. Customer engagement will not stop at the conclusion of the AER's review – it is now an ongoing feature of our business processes.

The submission of this Revised Proposal is a significant step in Ausgrid's commitment to work closely with our customers. I would like to thank each of our customer advocate groups for their contribution to our 2019-24 Revised Proposal, which I believe reflects an appropriate balance for all stakeholders.

We welcome feedback on this Revised Proposal from customers and our wider community.

Yours sincerely,

Richard Gross

Chief Executive Officer
Ausgrid

Ausgrid's Revised Proposal at a glance

How our Revised Proposal responds to customer feedback

AFFORDABLE

Lower revenues

↓16%

in annual network revenue from 1 July 2019

Fairer pricing structures
in our tariff structure statement

We are proposing additional
Opex productivity improvements
from 1 July 2020

RELIABLE

Replacing ageing assets

$280m pa

Keeping the grid safe and reliable for the long term

Maintaining current levels of reliability

Investing in technology

$44m pa

including cyber security

SUSTAINABLE

We are investing in an
Advanced Distribution Management System
to create a more flexible grid

A new
Network Innovation Advisory Committee
to collaborate with customers to deliver the future grid sooner

Supporting distributed energy resources and demand management

Our Revised Proposal at a glance

We recognise that affordability is our customers' number one concern.

	Initial Proposal	AER Draft Decision	Revised Proposal
Our Revised Proposal will reduce annual network charges by $71 in nominal terms (or $85 in real terms) for the average residential customer from 1 July 2019. Annual revenue will reduce by 16% from 1 July 2019.	**TOTAL** $8,930m	**TOTAL** $7,983m	**TOTAL** $8,023m[1]
Our operating expenditure forecast reflects our commitment to increasing efficiency over the 2019-24 period, including an additional productivity forecast from 2020/21. This productivity improvement lowers our opex by $52 million over the period.	**OPEX** $2,402m	**OPEX** $2,305m	**OPEX** $2,285m
Our capital expenditure forecast balances our customers' affordability concerns with the need for our network to adapt to a changing energy world.	**CAPEX** $3,084m	**CAPEX** $2,327m	**CAPEX** $2,690m

1 Revenue forecast does not include the impact of changes to the AER's tax approach.

01

About this Revised Proposal

01

About this Revised Proposal

1.1 Overview

Ausgrid is the caretaker of an asset which has connected communities and empowered the lives of its customers for over a century. Today, our grid is shared by 4 million Australians living and working in 1.7 million homes and businesses. This shared asset stretches from the heavily populated Sydney CBD to the sparse Upper Hunter. Our network is the engine room of the NSW and Australian economy, supporting 20% of the national gross domestic product.

Energy markets are changing rapidly, and customers want more control over how they buy, sell and consume energy. Renewable energy resources and other emerging technologies are transforming the electricity sector. Our historically centralised electricity system is becoming more decentralised, automated and interconnected.

Our customers have made it clear that they expect us to provide active leadership in the transition to cleaner energy sources while delivering on their key priorities: affordability, reliability and sustainability. We believe that Ausgrid has a critical role to play in leading and delivering this transition.

Customer engagement is critical for Ausgrid as we transform our network to meet the changing needs of customers. We are improving how we listen to, and respond to, customers. We recognise that affordability is our customers' number one concern. Our conversations with customers have informed our Revised Proposal and the way we will prioritise investment over the 2019-24 regulatory period and beyond.

This 2019-24 Revised Proposal is prepared for the AER. Our Revised Proposal outlines how we will deliver for our customers for the five years from 1 July 2019 to 30 June 2024. It sets out how much we need to invest so we can deliver affordable, reliable and sustainable electricity supply – safely – now and into the future.

In our role as a Distribution Network Service Provider (DNSP) we provide customers with a range of electricity distribution services which are regulated by the AER under the National Electricity Rules (NER or the Rules). The objective of this regulatory framework is to promote the efficient operation and use of electricity services for the long-term interests of consumers of electricity with respect to:

- Price, quality, safety, reliability and security of electricity supply
- Reliability, safety and security of the national electricity system.

This Revised Proposal and the supporting attachments outline how we will deliver for customers and meet all our regulatory obligations.

> Our vision is to become a leading energy solutions provider, recognised both locally and globally

1.2 Why are we submitting a Revised Proposal?

Every five years, Ausgrid submits a revenue proposal to the AER. Our current 2014-19 regulatory period ends on 30 June 2019.

On 30 April 2018 we submitted our Initial Proposal. Our Initial Proposal set out our proposed capital investment and operating expenditure plans for the next five years, as well as our total revenue requirements.

Following a detailed review of our plans, the AER published its Draft Decision on 1 November 2018. In response to the AER's Draft Decision, we now must submit a Revised Proposal that responds to issues raised in the Draft Decision.

In formulating our capital expenditure (capex) and operating expenditure (opex) plans for our Revised Proposal, we need to balance expenditure to maintain and modernise the grid with the need to drive efficiencies in order to deliver electricity at the lowest possible cost. This task is made ever more challenging given the transformation that is taking place in the electricity sector across Australia.

Our Revised Proposal sets out:

- how we have responded to customer feedback on our Initial Proposal, particularly in relation to concerns around affordability
- how we propose to meet our safety, reliability and other obligations
- how we propose to modernise our grid to meet sustainability expectations into the future
- how we have considered and responded to what the AER said in its Draft Decision.

Where we agree with the AER's Draft Decision, we have said so. Where we believe a better outcome for customers can be achieved, we have explained why and provided evidence to support our revised approach.

1.3 Context for our Revised Proposal

We are in the midst of a significant reform program to reduce our costs to deliver more affordable network services.

Our reform program has been successful in reducing network charges for our customers, without compromising safety or reliability. We have reduced our workforce significantly in order to deliver lower operating expenditure, which is now $100 million lower, per annum, compared to 2014.

We developed our Initial Proposal with the intent of it being viewed by the AER and customers as capable of acceptance. Over recent months, through working closely with customer advocates and the AER, we have revised our capex, opex and pricing plans for 2019-24 that better reflect customer expectations while providing us with sufficient resources to safely operate our network.

When looked at as a whole, we believe this Revised Proposal is capable of acceptance. We value the support customers have provided in reaching this point and we look forward to their feedback.

1.4 Our transformation is continuing

We are continuing to transform our business to provide more cost-effective network services and deliver greater value for customers. This transformation involves structural, financial and cultural change, which has led to:

- New processes, systems, and internal structures
- A lower cost base and new capital governance processes
- A new focus on our future role as we transition to a new energy eco-system
- Better and more productive relationships with our customers.

Change is rarely an easy journey but we are optimistic that we can find the right balance for our customers, shareholders and employees:

- Our customers know we have improved, but also believe we can do better. We are working with customer representatives to embed changes so that we can become the business our customers want us to be: low cost, customer focused and planning for the future
- Our shareholders understand that this transformation will be difficult and that the business will need to work harder to deliver on their expectations
- Our employees have worked hard through a difficult period of transformation and our total workforce has reduced by 3000 staff.

We have heard that our customers want us to be focused on continuing to reduce our cost base, and so we make the commitment that our transformation won't stop here.

1.5 Energy markets are changing rapidly

The electricity industry is undergoing a significant transformation. For over a hundred years energy flows have been predominantly one directional, with energy moving from large thermal generators to households and businesses along high voltage transmission lines and lower voltage distribution lines.

This old paradigm is rapidly changing. Households, communities and businesses now have choices, with new technology increasingly enabling them to generate, consume, and store their own electricity, and sell excess back into the grid. The grid must evolve to enable this distributed 'two way' energy flow.

We are committed to working with customers and stakeholders to unlock greater customer choice and control, and deliver a low carbon future at the lowest possible cost. In this time of rapid technological change and increasing customer choice, we recognise that we must earn the right to continue delivering valued services to our customers.

The grid has a pivotal role in managing a growing mix of renewable and distributed energy resources and supporting customers to realise the full value of the energy investments they make.

1.6 We are transforming the way we engage with customers

We are continuing to improve the way we engage and collaborate with customers. While there is more work to be done, strengthening our relationships with customers and their advocates is improving the decisions we make.

Building on the engagement principles we developed for the Initial Proposal, we refined these further to continue our efforts on building trust and reflecting the principles in the AER's Consumer Engagement Guideline. Our engagement principles (discussed in more detail in Chapter 2) aim to enhance customer trust in our business, facilitate more effective engagement and make our plans more customer focused.

Ongoing collaboration with customer advocates has been a key driver of changes to our approach, which will ensure we deliver better long term outcomes for customers. At the heart of these changes is a desire to involve customers in implementing our business strategy and driving the future direction of our network. This will be achieved by collaborating with customers on our innovation program and talking with customer advocates about our internal processes for forecasting investment requirements, cost benefit analysis, and how we are making better use of our existing assets.

Delivering on these improvements will ensure when the next regulatory reset process commences, customers will have an improved understanding of how we operate our network and be in a much better position to engage and influence both the substance and direction of our plans.

Our customer engagement plans are designed to achieve the following goals:

- **Identify opportunities to drive policy change –** Customers have told us that they want Ausgrid to play a role in identifying and driving policy changes where improvements can be made to the regulatory framework. Working together with customers, Ausgrid has the potential to become a thought leader and recommend changes that are in the long-term interests of customers.
- **Drive the direction of our innovation and demand management investment –** Our customers, shareholders and employees all agree that Ausgrid must do more to lead innovation and technology development as the energy system transition continues. We propose the establishment of a Network Innovation Advisory Committee to set our direction and review our innovation projects and pilots before we proceed. This will ensure we get the most effective spend for every customer dollar.
- **Implement pricing reforms –** Our Pricing Working Group has worked collaboratively to produce our new pricing strategy in a short period of time, a fantastic effort from both customers and Ausgrid. This forum will continue to help us develop the right information to enable our broader customer base to take the right decisions in order for them to get the best value out their network services.
- **Review ongoing technological expenditure –** Feedback from customer groups has indicated that they would like greater visibility of expenditure on IT, cyber security and related expenditure. We will establish a specialist group that will work with customers and the AER to explore these issues.

Ausgrid is committed to expanding and building on our customer collaboration through a number of initiatives, which are discussed in further detail in Chapter 2 of this Revised Proposal.

1.7 How to provide feedback

We welcome your feedback on the Revised Proposal. You can send us feedback directly by emailing us at: yoursay@ausgrid.com.au.

You can also provide comments directly to the AER at:

https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2019-24

02 Customer engagement

2.1 Customer engagement overview

Ausgrid has been working to improve customer engagement and embed a customer focused approach across our entire business. This chapter discusses the way we have been engaging over the past months and the changes we are making in engaging with our 1.7 million customers and their advocates. We are grateful for the time both customer advocates and the AER have invested with us to contribute to the development of this Revised Proposal.

We believe the grid holds the key to unlocking greater competition in the energy sector. Our network can be a shared, open platform that will support an ecosystem of new technologies and services. Services that will unlock value and empower customers with greater choice and control. However, we cannot achieve this change without our customers' support and trust. To that end, we want to involve customers and their advocates in driving the future direction of our network. In doing so, we will improve our decision making and earn the right to deliver valued services to our customers.

Customer engagement at Ausgrid means deep and transparent conversations with stakeholders and providing opportunities to influence our strategic priorities. Responsibility for this engagement crosses the entire business. It encompasses core business such as customer connections and responding to outages. It also encompasses the engagement required for the development of our Revised Proposal.

In line with suggestions from customer advocates and the AER in its Draft Decision, we are evolving our approach to engagement, to better integrate customer preferences into our strategy and business decisions. We believe that being more transparent and inclusive will improve our decision making and improve outcomes for customers.

The AER's Draft Decision indicated that "further work was needed by the senior management team in Ausgrid to develop a culture which supports authentic engagement over time". The AER also suggested that Ausgrid "commit to a culture of compromise" and that we extend our collaborative approach to developing our Tariff Structure Statement (TSS). This chapter outlines the actions we have taken to engage at a deeper level with customers. Our CEO, executive and technical staff have been engaging regularly with customers over recent months, demonstrating our commitment to ongoing cultural change.

Central to our approach to customer advocate engagement is our willingness to listen to customers' views and be prepared to make changes. Our engagement goal was twofold;

- Improve our proposal so that it was capable of acceptance
- Lay the foundation for ongoing engagement with our customers.

We look forward to feedback from the AER and customers on the progress we are making.

2.2 Engagement Principles

After we lodged our Initial Proposal we evolved our approach to customer engagement with the development of focused Engagement Principles. These principles aim to build customers' trust and improve our decision making. They will assist us with our cultural change and our efforts to be more open and transparent.

Our Engagement Principles

The following principles aim to build customers' trust and improve decision making:

Be collaborative: Don't be defensive and remain open to possibilities

Be quantitative: Provide data from the customer's perspective

Be accountable: Agree a timeframe and deliver

Be transparent: Encourage and support our stakeholders in holding us to account on progress, agree timeframes and deliver

Be adaptable: Be prepared to change based on feedback from stakeholders

2.3 Our approach to engagement

Over recent months we have been working with customers and the AER to improve our plans so this Revised Proposal is supported by our customers. We strongly believe that, to become the business we are working hard to be, our customers need to support our plans and trust us to make decisions in their long term interests.

We developed our Initial Proposal with the intent of it being viewed by the AER and customers as capable of acceptance. Over recent months through working closely with customer advocates and the AER, we have revised our capital expenditure (capex), operating expenditure (opex) and pricing plans for the 2019-24 regulatory period to better reflect customer expectations, while providing us with sufficient resources to safely operate our network. Ausgrid staff and consumer advocates have engaged in regular and meaningful discussions to define what a Revised Proposal that could be supported by customers would look like. Together we agreed it must include:

- Capital expenditure consistent with the requirements of the National Electricity Rules and viewed by customers as prudent, in a changing environment – **we have worked hard with both customers and the AER to meet this expectation**
- An operating expenditure allowance which challenges the business to deliver more productivity improvements for customers – **we have included additional productivity forecast in our revised opex forecast**
- Acceptance of the AER's 2018 Final Rate of Return Instrument – **we have applied the 2018 Final Rate of Return Instrument**
- Positive engagement with the AER on its 2018 Tax review – **Ausgrid will work with the AER through January to March 2019 to make the modelling changes required to give effect to the 2018 Tax Review Final Decision**
- A revised TSS reflecting customer preferences – **our Pricing Working Group (PWG), a collaboration between Ausgrid and consumer advocates, co-designed this Revised Poposal in response to the AER's Draft Decision and aligned with ACCC recommendations**.

Together with customer advocates we have developed a Revised Proposal that will:

- deliver on all those elements
- make further commitments to help us become a better business for customers,and
- enable customers to contribute to our strategic and operational planning.

We believe this Revised Proposal is in the long-term interests of our customers. Not only does it deliver significant, ongoing savings for our customers, it also continues a process of embedding customer thinking into the heart of our business.

The Consumer Challenge Panel (CCP10) advised that it is "increasingly confident that Ausgrid is becoming pivoted to improved consumer outcomes with a focus on optimising capex spend and achieving better productivity including through cost effective technology platforms. This confidence, if underpinned by transparent dealings, means consumers can pivot their focus to innovation and transformation with Ausgrid".

2.4 Our commitments to customers

In our discussions with customer advocates we identified a series of commitments that represent how we will go about improving customer outcomes. Customers have told us that our engagement must not be solely about meeting a pre-requisite for regulatory proposals to the AER; it needs to be regular and meaningful. This sort of engagement will ensure that we earn the right to continue delivering valued service to our customers.

We believe we will make better decisions about uncertain issues if we work together with our customers.

The commitments set out below aim to: develop our business and shared understanding, drive industry development and deliver better outcomes for our customers. These commitments outline how we will work to address the concerns of our customers and work towards being the best distributor in the National Electricity Market.

DEVELOP

Our business & shared understanding

- Develop a Revised Proposal that is capable of acceptance.
- Sharing and improving internal forecasting approach and cost benefit analysis.
- Explore option analysis to make long term asset decisions in an uncertain environment.
- Share further granularity of customer benefits derived from IT expenditure.
- Support an industry wide review into IT forecasting to improve expenditure assessment.
- Engage with customer representatives on our cyber expenditure and maturity levels.

DRIVE

Industry Development

- Pricing Working Group - co-design tariffs, information and complementary measures.
- Jointly develop policy and regulatory framework submissions.
- Collaboration with AER to improve repex model and drive greater confidence in tool.

DELIVER

Better outcomes

- Sign up to the Energy Charter.
- Propose productivity in period from FY21 and long term commitment to achieving and sharing future productivity gains with customers.
- Deeper engagement in customer strategy and business planning not just regulatory planning.
- Network Innovation Advisory Committee to drive direction of innovation program.
- Capital Expenditure Sharing Scheme exclusions – Innovation program, cyber and Advanced Distribution Management System expenditure.
- Greater focus on non-network solutions, including demand management and work with customers on demand response rule change.
- Deliver improvements in every area of our business with our customers help.

2.5 What customers said about our Initial Proposal

The following themes reflect the key concerns raised across submissions to our Initial Proposal.

Prudent and efficient	• The prudence and efficiency of Ausgrid's capex proposal, including both growth projects and the replacement program, needs better justification. Further cost-benefit analysis is also required on the Advanced Distribution Management System (ADMS).
Non-network expenditure	• Further explaination is required to show the customer benefits of investment in ICT, fleet and property.
Forecasts	• Continued focus is needed on accurate growth forecasts to take into account growth in distributed energy resources and price signals.
Capital support costs	• Customers recognised that capital overheads have reduced, but would like to see steps to deliver further savings.
Benefits on past investments	• Stakeholders want to better understand how past investments have delivered benefits to customers.
Demand management	• Improvements in demand management and the use of new technology are needed.
Opex productivity	• Customers expect us to include a productivity improvement in our opex forecasts.
Demand tariffs	• Our TSS was not supported, with a number of submissions asking for immediate introduction of demand tariffs.

2.6 What the AER said about our Initial Proposal

The following themes reflect the key areas raised by the AER to our Initial Proposal.

Capital review processes	• The AER and its technical consultant raised concerns about our capex review and challenge processes.
Cost-benefit analysis	• More evidence of project need is required, accompanied by quantitative cost benefit analysis of our capex program.
Rate of Return	• The AER applied its 2018 Final Rate of Return Instrument in its Draft Decision, rather than adopting the rate we proposed.
Network innovation	• Our proposed monitoring system upgrades and network innovation projects are likely to have economic benefits which will be further scrutinised after submission of the Revised Proposal.
Demand tariffs	• The AER did not support our delayed introduction of demand tariffs and elements of our tariff assignment policy in our TSS.

2.7 How we responded to feedback

Prudent and efficient	• Subjected a large proportion of our capex proposal to quantitative risk assessment and cost benefit analysis in order to ensure that our total capex forecast is prudent and efficient. • Better explained the benefits and costs of our ADMS project.
Capital expenditure	• We have looked for additional ways to defer or adopt non-network solutions, where these savings can be achieved without compromising customer outcomes. • We have included productivity improvements in our network capex forecasts, in response to our customers' feedback that we should commit to driving future efficiency. improvements. • As a result of this further analysis, reprioritisations and updated input assumptions, we have identified savings compared to our Initial Proposal.
Capital review processes	• We have made immediate changes and continue to improve the internal review and challenge of our capex program. We are committed to making further improvements which are discussed further in Chapter 5.
Captial support costs	• We have reduced our capital support costs from $621 million in our Initial Proposal to $590 million. Benchmarking was also undertaken, which revealed that Ausgrid has among the lowest overhead costs per customer in the NEM
Opex	• We have accepted the AER's decision to disallow additional expenditure to support pricing reform and have not included this opex step change in our Revised Proposal. • We have provided further information in relation to emergency recoverable works and reviewed our proposed demand management programs. • We have included a productivity forecast in our Revised Proposal from FY21.
Demand tariffs	• We have included a set of demand tariffs for residential and small business customers in our revised TSS. • We are working collaboratively with customers, retailers and other stakeholders to introduce new tariffs. This includes: co-design of research on the impact of more cost reflective tariffs, the development of complementary measures and communications materials.
Continued consumer engagement	• We engaged intensively with customers prior to lodging our Revised Proposal and will engage with customers on an ongoing basis.

2.8 How we engaged

Customers and stakeholders lodged 21 submissions to the AER on our Initial Proposal. Submissions outlined aspects of our plans stakeholders supported and the areas where our plans could better meet customer needs.

With input from submissions and from the extended consultation, we undertook informal and formal engagement with customer advocates prioritising and addressing outstanding concerns. We engaged via our Consumer Consultative Committee and the PWG (see membership below). We also engaged bilaterally with the:

- AER Consumer Challenge Panel (CCP10)
- Energy Consumers Australia (ECA) and its engineering consultant
- Public Interest Advocate Centre (PIAC)
- Total Environment Centre (TEC)
- St Vincent de Paul Society
- Energy Users Australia Association (EUAA).

Positions in our Revised Proposal were consulted on and progressively refined through ongoing open, transparent and productive discussions with consumer advocates.

Summary of our engagement activities:

- Ongoing regular engagement with the AER
- Consumer Consultative Committee (CCC) meetings on 7 August 2018 and 11 December 2018
- Revised Proposal Working Group meetings on 31 October 2018 and 30 November 2018
- PWG meetings on 7, 15, 22 May 2018, 19 September 2018, 18 October 2018, 15 November and 17 December 2018
- Network of the Future Forum on 23 November 2018 with customer advocates and external experts
- 2014-19 Remittal engagement
- Meetings with ECA and its engineering consultant
- Direct discussions with customer advocates including; PIAC, EUAA, St Vincent de Paul Society, ECA and CCP10.

2.8.1 Engaging with the AER

Over the past 18 months we have engaged with the AER on a number of projects, including our 2019-24 revenue determination and the remaking of our 2014-19 determination. This engagement has been productive and transparent, and has helped build trust between the two organisations.

The AER Determination Forum on 3 July 2018 provided firm guidance on key elements of our Initial Proposal that could be improved. It was pleasing to hear feedback at the AER Draft Determination Forum on 5 November 2018 that our ongoing engagement was heading in the right direction, but that we still had more to do.

In addition to ongoing meetings to discuss various aspects of our Revised Proposal, we also received information requests from the AER and its consultant, EMCa. In total, we received over 50 information requests containing over 400 questions, some of which were complex. In response we provided the AER and its consultant with over 300 documents and 4000 pages of material.

2.8.2 Customer Consultative Committee

Customer Consultative Committee Membership

- AER Consumer Challenge Panel (CCP10)
- Council on the Ageing NSW (COTA)
- Energy Consumers Australia (ECA)
- Energy Users Association Australia (EUAA)
- Energy & Water Ombudsman NSW (EWON)
- Public Interest Advocacy Centre (PIAC)
- Urban Development Institute of Australia (UDIA)
- St Vincent de Paul Society
- Total Environment Centre (TEC)

Two Customer Consultative Committee meetings and two meetings of the Revised Regulatory Proposal Working Group were held following the submission of the Initial Proposal. The final Customer Consultative Committee meeting on 11 December 2018, chaired by Ausgrid CEO Richard Gross, provided a formal opportunity to discuss with customer advocates the progress we had made on key elements of the Revised Proposal. The feedback we received on our draft Customer Strategy, our Commitments and our approach to ongoing engagement are reflected in this document.

Feedback from these meetings has contributed substantially to the development of our Revised Proposal.

2.8.3 Pricing Working Group

Pricing Working Group Membership
- AER Consumer Challenge Panel (CCP10)
- Energy Consumers Australia (ECA)
- Energy Users Association Australia (EUAA)
- Public Interest Advocacy Centre (PIAC)
- St Vincent de Paul Society
- Total Environment Centre (TEC)

We established the PWG following the submission of the Initial Proposal. Close collaboration between Ausgrid and customers through the PWG has generated our new pricing strategy. Discussions during May focused on developing a shared understanding of the agreed Pricing Directions. Multiple working sessions in September, October and November started with Ausgrid accepting the need to accelerate the introduction of demand tariffs and progressed to co-designing new tariff structures with customer advocates.

Comprehensive input was received on the tariff options, assignment rules and importantly, transition pathways. The PWG will continue to meet and guide the transition to new tariff structures. This will include: co designing of research on the impact of the cost reflective TSS, developing a communications campaign and complementary measures to support customers transitioning to new tariffs.

Further detail on pricing reform and the benefits to customers is covered in Chapter 10 of this Revised Proposal.

2.8.4 Network of the Future Forum

On 23 November 2018, we hosted the Network of the Future Forum, with a broad range of customer representatives, industry experts, academics and Ausgrid staff. Industry experts included representatives from the solar sector, Solgen Energy Group and from the Electrical Network Operation Envelope Platform (ENOPEN) project which aims to develop and demonstrate technologies for co-ordinating distributed energy resources. Endeavour Energy and Essential Energy were also represented.

The primary objective of the forum was to work collectively to envisage what customer expectations of the grid will be in the future and how the grid will need to adapt to meet those expectations. Together we worked to identify what the grid needs to provide to meet customer's future needs and discuss what a set of principles could look like to assist in prioritisation of network innovation investment.

Customer experience 2030

Each participant at the forum took the perspective of one customer segment and shared their thoughts on what services and experiences the segment will expect from the network in 2030. To provide a breadth of needs and views seven customer segments were covered, these were: highly engaged and proactive home owners, vulnerable apartment renters, passive and disengaged households, small businesses, DER installers, aggregators, and large users. Participants identified nine 2030 customer experience themes, three of which were the top priority for at least one customer segment:

1. competition, choice & control,
2. value, and
3. ease.

To meet 2030 customer expectations Ausgrid will need to provide an easy, transparent and value for money platform for service providers to enable effective competition to flourish. Below are some of the key customer experience takeaways which highlight what Ausgrid and the wider energy sector will need to deliver to meet the themes in practice.

Following feedback we received at the forum, we established a customer vision, which is that by 2030 our customers have:

- The ability to "plug and play" – both to connect their DER and other technology and to access additional value streams via markets and aggregators.
- Stable and predictable tariffs (that have evolved from where they are today).

- Easy to access, transparent and comprehensive data, including transparency of where to connect to the grid at the lowest cost.
- The ability to "set and forget" – with ready access to service providers which make getting and staying on competitive deals easy.
- Easy and cost effective access (i.e. a level playing field) to community energy resources (solar, storage).
- Network charges that are not inflated due to stranded assets or unwarranted innovation investments made during the transition to a low carbon economy.
- Access to sustainable energy supply choices which are easy to understand.
- The opportunity and flexibility to choose, use and benefit from new renewable technologies regardless of whether or not individual customers can DER.
- A plethora of new market entrants to engage with (reduced barriers to entry).

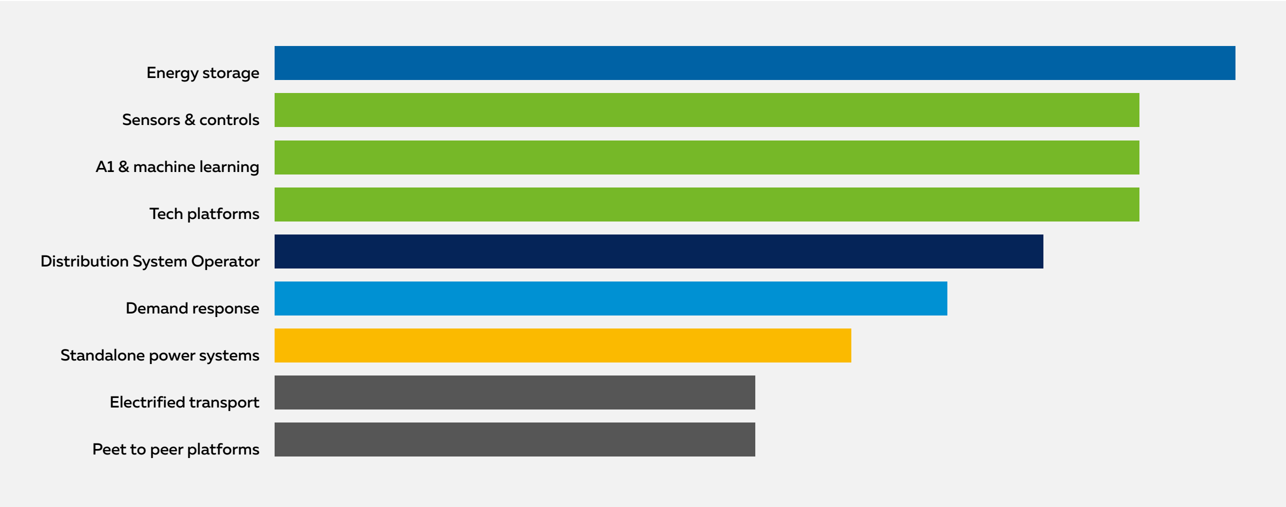
Guiding principles for customer funded innovation investment

A set of guiding principles for prioritising and assessing innovation investments was co-created by forum attendees. Principles were supported by three hurdles which any initiative must pass in order to be considered. Both guiding principles and hurdles are developed in more detail in Chapter 3.

Priority focus areas for customer funded innovation

The group also considered and prioritised where across a range of technologies customer funded innovation should be focused, noting that prioritisation was in the absence of cost benefit analysis and no project should proceed without a robust business case clearly demonstrating customer benefits.

In order of importance, the following technologies were prioritised:



Stakeholder comments on prioritisation:

- Energy storage – funding should be focused on community solutions and providing access to all
- Sensors & controls, artificial intelligence & machine learning, technology platforms and distribution system operator (DSO) – investment should follow a data pathway from data acquisition via sensors, through technology platforms to aggregate data, AI to make optimised data based decisions and DSO to put decisions into action
- Demand response – focus on long term measures to reduce peak demand and tariff reform including peak time rebates trials
- Smart meters, rooftop solar PV and home energy management systems – were not prioritised on the basis that Ausgrid should not invest in specific customer technologies, but in unlocking the network for others.

Key messages and takeaways from stakeholder input at the Forum were:

- The challenges and questions identified in the Network of the Future Forum are likely challenges for the sector as a whole. Customers expect Ausgrid to tackle these challenges collaboratively with the broader industry, taking steps to share the knowledge gained
- Insights and principles from the forum apply more broadly than innovation – Ausgrid should be seeking to find practical ways to apply them to BAU grid planning
- Customers expect Ausgrid to provide an easy, transparent and value for money platform for service providers to enable effective competition to flourish

- Proposed and implemented government subsidies pose a risk to delivery of the lowest cost energy system, and the cost effective decarbonisation of our economy (including game changing opportunities like community batteries) – Ausgrid has an obligation to educate policy makers as to the cost impact on the grid of potential policies
- Ausgrid and the wider energy sector need to create opportunities for all customers to participate and have access to DER
- Ausgrid should consider taking a policy position that any electricity subsidies should be provided from outside the energy system rather than as cross-subsidies between electricity customers.

The group agreed to continue the discussion with stakeholders on setting the framework for the Network Innovation Advisory Committee (NIAC).

2.8.5 2014–19 Remittal engagement

Since lodging our Initial Proposal we worked closely with customer advocates to finalise the 2014-19 Remittal, which was submitted with customer advocate supporting letters. Working with advocates on the 2014-19 Remittal was an important step toward deeper engagement with customers for our Revised Proposal.

We developed our final 2014-19 Remittal position in close collaboration with key customer advocates from the CCP10, ECA, PIAC and EUAA. Importantly, we had their support when we submitted our Remittal proposal to the AER.

On 22 November 2018 the AER published a draft decision on our 2014-19 Remittal Proposal. The AER accepted our Remittal Proposal in its Draft Decision. A final decision is expected in early 2019.

For our customers our Remittal Proposal will:

- deliver a 3.2% reduction in Ausgrid's component of prices from 1 July 2019 ($20)
- allow Ausgrid to continue to transform in order to reduce costs and provide more affordable network services for our customers.

Further, we recognise that the 2014-19 regulatory determination has a long legal history. We believe our Remittal Proposal is in the long-term interests of customers and aligned to the AER's Draft Decision. It provided an opportunity for Ausgrid and its new management to reset the relationship with the AER, our stakeholders and our customers.

2.9 Future customer engagement

Collaboration with customers, customer advocates and stakeholders is critical for Ausgrid as our network evolves to meet changing customer needs. Our engagement focus is not only on the next five year period but the longer term. We are building on the existing CCC framework and Charter to develop an expanded approach to engagement which maintains existing working groups and establishes new committees.

Our goal is to provide evidence that we have embedded customer choices in our business decisions on an ongoing basis and include customers in our thinking about strategy and operations. This will enable customers to better inform our positions in general or even champion them when revenue determinations come around.

Above all we have heard that our customers want us to be focused on continuing to reduce our cost base. We have made a commitment that our transformation won't stop there. Ausgrid's goal is to be the leading distribution business in National Electricity Market in terms of efficiency and we know we will only achieve this with the support of our customers

2.9.1 Customer Consultative Committee and Sub-Committees

The CCC will continue to be the key body for broad customer advocate input to our business planning. The approach to our CCC will be better focused on customer and business strategy development and implementation. A number of the commitments outlined in section 2.4 will be implemented with the support of and tracked by the CCC.

In this forum we will provide greater exposure to execution of customer strategy, internal governance processes and forecasting investment requirements. Specific attention will be paid to how to better include customer considerations into cost benefit analysis and risk based assessments, to give customers a meaningful role in developing our spending plans.

We are proposing four CCC meetings per year with time allocated to a customer strategy update, business review and progress reports on customer advocate led initiatives, and updates from the sub-committees. The final meeting of each year will provide a review of delivery against our commitments.

The following groups will be invited to join the CCC:

- Consumer Challenge Panel (CCP10)
- Council on the Ageing NSW (COTA)
- Energy Consumers Australia (ECA)
- Energy Users Association Australia (EUAA)
- Energy & Water Ombudsman NSW (EWON)
- NSW Council of Social Services (NCOSS)
- Public Interest Advocacy Centre (PIAC)
- Urban Development Institute of Australia (UDIA)
- Total Environment Centre (TEC)
- St Vincent de Paul Society
- Council Representatives

The CCC will be complemented by three key further committees:

Pricing Working Group

Purpose: Develop better tariff approaches to deliver a lower overall system cost.

We established the PWG following the submission of the Initial Proposal. This group has co-designed our new tariffs and pricing proposal, it will continue to meet in order to support the smooth implementation of the new demand tariffs and the development and implementation of complementary measures to support customers to transition to new tariffs.

Customer advocates will help us develop the right information to help our broader customer base take the right decisions to minimise their network costs and get the best value out of their network services.

Network Innovation Advisory Committee (NIAC)

Purpose: Collaboratively drive our innovation program to help our grid evolve.

Customers have told us they want a greater role in driving the direction of innovation in electricity networks. Together with customers, Ausgrid aims to take a lead role in the industry for the integration of distributed energy resources and management of new technologies, in order to achieve long-term benefits for customers. This will be guided by the innovation principles developed with customers.

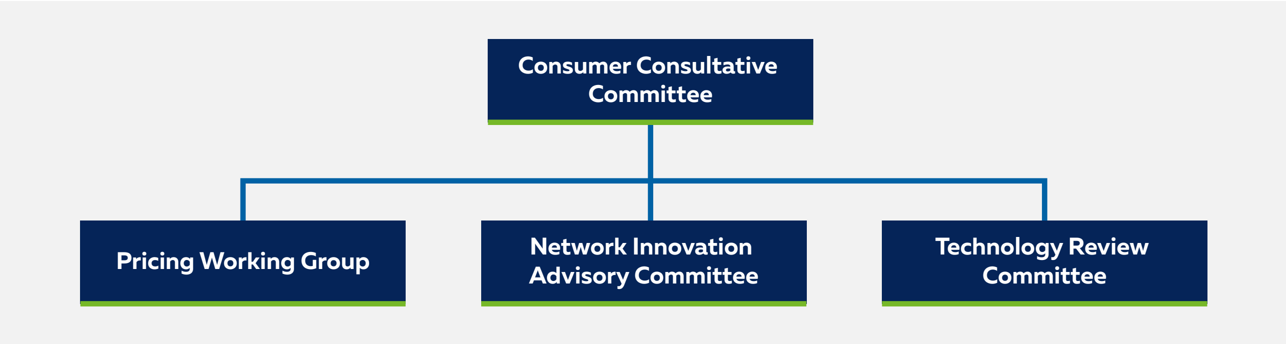
The NIAC will drive the direction of Ausgrid's network innovation program. The $42 million network innovation program has cost benefit analysis showing the projects are justified, however due to the rate of technological change the committee will oversee the implementation of our innovation projects, asking; "is the project still right?" If the answer is no, the committee will ask, "what is the right project?"

In addition the NIAC will advise on phase 3 of the ADMS program. The terms of reference and guiding principles for the NIAC are discussed in Chapter 3 of this Revised Proposal.

Technology Review Committee (TRC)

Purpose: Improve transparency of IT and cyber investments

We will work with customer advocates and the AER to ensure there is the appropriate level of oversight of our expenditure on information technology and cyber protection mechanisms. The TRC will contribute to any AER review into forecasting and assessment methods for IT expenditure.



Customers have told us that they want Ausgrid to play a role in identifying and driving policy changes where improvements can be made to the regulatory framework. Each of the working groups will also be responsible for driving policy changes where improvements can be made, by combining technical know-how and analysis with customer insights to co-develop better outcomes.

2.9.2 Engaging with councils

We work with 33 councils in our network area across parts of Sydney, the Central Coast, and the Hunter. Councils are key stakeholders. We cooperate with councils on a wide range of matters including public street lighting, maintenance, construction and vegetation management, to name but a few.

Currently, we are working with a number of councils on a LED Streetlight Replacement program, where we are replacing around 100,000 older streetlights across our network. This is anticipated to be delivered over a two-year time frame with completion planned for all Ausgrid Local Government Areas by mid-2020.

The Ausgrid lighting specialist team is visiting each of our public lighting customers with the intent to customise our services and manage any outstanding issues to meet their needs, such as, product selection and pricing options. We are about a quarter of the way there and expect to have these briefings to be completed by April 2019.

We will implement a sustainable engagement policy, where we consult with councils as our products and services evolve over time, follow through on these initiatives and also measure satisfaction on an ongoing basis. Ultimately we intend to adhere to our Engagement Principles which are designed to embed strong relationships and build trust.

2.10 The Energy Charter

CEOs from electricity and gas businesses have committed to the Energy Charter to deliver energy services in line with community expectations. More robust engagement will address the key intent of the Energy Charter, to ensure that customer preferences are reflected in business decisions. Ausgrid has committed to the Charter, which requires the release of an annual report in September each year, the first of which will be released in 2019. The CCC will review this report prior to its public release.

About the Energy Charter

The Energy Charter focuses on delivering tangible customer benefits by embedding a consumer-minded culture throughout the energy supply chain. Change is driven through the charter's five principles each underpinned by actions.

Five Principles

The Energy Charter sets out five principles to advance the industry vision. The principles are:

1. We will put customers at the centre of our business and the energy system
2. We will improve energy affordability for customers
3. We will provide energy reliably, safely and sustainably
4. We will improve the customer experience
5. We will support customers in vulnerable circumstances.

Principles in Action

Under each principle, the Energy Charter sets out a list of principles in action, which describe how the principle can be translated and measured by each part of the supply chain. They represent the practical initiatives that are intended to have a material and positive impact on the delivery or progression of that principle when implemented. They also provide the basis on which each participating energy company will report on its progress against the Energy Charter.

Our commitment

We have pledged our commitment to the Energy Charter, joining over 15 other energy supply chain CEOs. In doing so we commit to:

- Self-assessment against the Charter's *maturity model*, including where we are now, our ambitions for the future, and our action plan to get us there. We will measure and disclose our progress annually.
- *Annual reporting* on how we are delivering against the Charter principles starting with the January to June 2019 period and then every financial year thereafter.
- Evaluation by an independent accountability panel to review our performance against the Energy Charter principles. The first Evaluation Report is due in November 2019.

2.11 Customer strategy

As outlined in this chapter our customers have made it clear that they expect us to provide active leadership in the transition to cleaner energy sources.

If we are to deliver the best long term outcome for our customers we must navigate the transition to a lower carbon energy system together with our customers.

Our customers have seven clear objectives which guide our strategy and customer value proposition. To form these objectives we have undertaken:

- detailed customer needs analysis leveraging our own data
- analysed research outcomes from our "Customers at the Centre" initiative 2017
- a review of our bi-annual Customer Satisfaction Index which is compiled through in-depth monthly telephone surveys with our customers.

These seven customer objectives were provided to the CCC meeting on 11 December 2018 and representatives provided feedback which has been incorporated. These strategy materials are still being developed with further input from the business and our customers.

Protect our customers and the communities in which they live from danger and disruption, by keeping the public, our employees and contractors safe from physical harm, and taking a conscientious and community minded approach to planning and delivering works.

Ensure we are the best value form of energy supply available, by relentlessly pushing down network prices by delivering cost efficiencies, and continue to provide a service that can be relied upon 24/7, 365 days a year.

Ensure our tariffs are fair and encourage least cost decarbonisation, by introducing fairer tariffs, unwinding inequitable outcomes, and enabling price signals that promote decarbonisation and reward behaviour that reduces costs for all.

Empower customers to make choices by making our network able to deliver the services our customers expect from it, opening up access to markets and valued services that allows them to make the most from their energy investments.

Make every interaction with our customers a seamless experience, by making connecting to our network, reporting an issue, or connecting DER a simple and hassle free experience, providing informative and timely information to help our customers stay informed throughout.

Provide access to sustainable energy by partnering and investing to give customers access to green energy, regardless of their choice or ability to invest in their own energy resources, while actively encouraging the decarbonisation of the energy we supply via our grid.

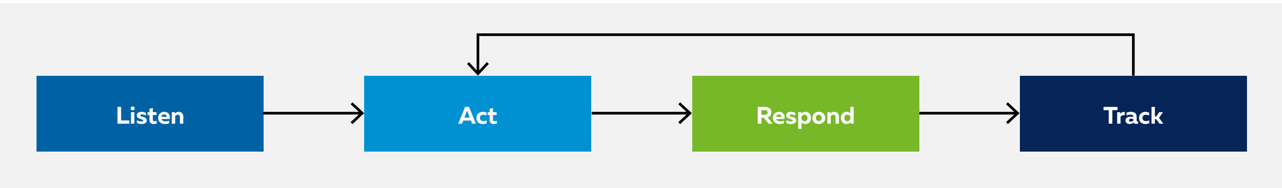
Provide access to a continuous reliable energy supply, designing and operating our network to meet our customers expectations, keeping customers informed in a timely manner when unavoidable outages do occur, and strengthening our cyber security to ensure customer data and control of our infrastructure cannot fall into the wrong hands.

2.11.1 Earning the right to get closer to our customers and provide new value

Our strategy is guided by the tenet that meeting our customers' objectives and expectations drives long-term shareholder value. For Ausgrid to maintain relevance in the long-term we must earn the right to get closer to our customers, understand their needs and deliver valued services. The figure below provides and overview of how we will do this.

2.11.2 Voice of the Customer program

Key to getting close to customers is better understanding them. Ausgrid's Voice of the Customer (VoC) program has been established to systematically provide us with an in-depth understanding of our customers and to embed customer feedback into decisions and service delivery. In order to accomplish this our VoC program consists of four main pillars. Together these provide an effective framework for assessing and improving customer experience.



Listen
- Transactional Net Promoter Score
- Customer Satisfaction Research
- Pulse Check – B2B Customers & Councils
- Touch-point assessment
- Complaints Management Assessment

Act
- Quality improvement initiatives

Respond
- Close the loop with customers

Track
- Quality improvement tracking
- Embed reporting

Listen

Customer Transactional Net Promotor Score (NPS): we launched a Customer Transactional NPS program in September 2018 to measure customer sentiment and to get an understanding of factors that may be driving satisfaction or dissatisfaction amongst our customers. This research is conducted by sending a short survey via SMS to customers who have recently interacted with us. Results are closely monitored, analyszed and reported to our executive leadership team on a monthly basis.

Customer Satisfaction Research: we conduct detailed research that measures customer satisfaction with the services we offer. This research is conducted throughout the year by a research agency and results are analysed on a quarterly basis to evaluate customer satisfaction.

Pulse Check B2B (Business to Business) Customers and Councils: we have initiated research to develop an understanding of our performance with our B2B customers (Major Connections and Accredited Service Providers) and councils. This research will be run on a biannual basis and the insights generated will be used to improve customer experience.

Touch-point Assessment: our two major touch-points with our customers are our website and our contact centre. We are currently in the process of assessing and benchmarking our website performance and plan to conduct annual research studies to assess and benchmark the performance of both these touchpoints with performance leaders in our industry. This research will provide crucial insights to help us deliver seamless interactions with our customers.

Complaints Management Assessment: we are in the process of implementing a research program to measure satisfaction amongst customers that have lodged complaints with us. This program will provide crucial insights to management on ways to improve our handling of customer complaints.

Act

Quality Improvement Initiatives: all insights gathered through our research are being utilized to engage our business into knowledge-based-action, to improve our operations to be more in-line with customer expectations and to remove sources of dissatisfaction and friction. We are beginning to work with all parts of the business on Quality Improvement Initiatives that will deliver tangible customer benefits over the next few years.

Respond

Close the Loop: A key component of our VoC program is to engage our customers with key insights gathered through their feedback and to inform them of the actions we will be taking to address their pain-points.

Track

Quality Improvement Tracking: we will track the performance of our Quality Improvement Initiatives to ensure that we are delivering tangible improvements in customer experience. Regular reports on progress will be shared with the Ausgrid executive leadership team and the wider business.

Embed Reporting: key customer metrics such as Transactional NPS are being reported on a monthly basis. Going forward, we plan to increase the breadth and depth of reporting on customer metrics as we roll out our VoC program. We also plan on introducing live dashboards that display key customer metrics in our offices. Customer metrics reporting will be embedded deep within our operations and will be a key component of maintaining our customer centric culture.

Drivers for Ausgrid's reputation with customers

We undertook analysis to identify the relative importance of a range of specific factors in driving Ausgrid's reputation.

Results indicate that being "open, honest and transparent" is the strongest driver of our reputation. This even ranks above "providing good value for its services", which is clearly next most important. It is also consistent with the Stakeholder Perceptions Survey where "open and transparent" was also the number one reputational driver.

Other important reputational drivers included:

- Providing information that is clear and easy to understand
- Operating as efficiently as possible to keep costs down
- Doing a good job of providing information to customers about electricity interruptions
- Acting in the long-term interests of customers
- Being customer-focussed in its delivery of services
- Helping customers make good decisions about electricity use.

September 2017 – Newgate research "Customers at the Centre"

03

Network evolution

03

NETWORK EVOLUTION

Innovating to accommodate changing customer expectations

Our Revised Proposal

Our Revised Proposal reflects how our grid needs to adapt to accommodate changing technologies and customer expectations, whilst continuing to deliver the most cost-effective energy supply solutions for our customers as the energy transformation unfolds.

We propose demand management projects that will reduce the need to build more network infrastructure in the future. We also propose investment in an Advanced Distribution Management System (ADMS) and a number of innovative projects, that will help the transition to a future energy sharing platform.

To more effectively drive the evolution of our network through a period of uncertainty, we will establish a Network Innovation Advisory Committee (NIAC). The NIAC will include customer advocates as well as technical experts and will provide input into our planning processes, informing Ausgrid's network innovation program and providing advice on the projects that are undertaken.

How our Revised Proposal responds to customers

Our Revised Proposal reflects customers' desire for greater choice and control over their energy. Many customers expect to connect distributed energy resources (DER) to our shared network, in order to realise the full value of their investment, while others simply want reliable access to energy.

Customers also expect us to demonstrate a clear focus on innovative demand management and other non-network solutions, which drive down energy system costs for all by reducing the need for investment in grid or generation infrastructure.

Our Revised Proposal reflects our plans to implement new technologies that will allow our network to accommodate greater levels of DER, and give customers greater choice and control over their energy. We also have a clear focus on demand management and initiatives to help our grid evolve and meet our customers' changing expectations.

How our Revised Proposal responds to the AER

In its Draft Decision, the AER indicated that we need to better justify the need for our ADMS and Network Innovation Program. Our Revised Proposal updates and refines the cost benefit analysis of both, better verifying the benefits for customers.

Importantly, given the speed of technological change across the energy industry, the NIAC will oversee any changes to priorities within these critical innovation programs that may be required during the five-year regulatory period.

3.1 The technology landscape is changing

The electricity industry is going through a process of significant change. Like other parts of the energy system, our network needs to adapt to this new landscape and manage a growing mix of renewable and DER across the grid.

While adoption of DER has been slower on our network than in other parts of Australia, mainly due to the high proportion of apartments and rental properties, we are already seeing a material uptake of rooftop PV and storage systems by our customers. Stakeholders have indicated there is strong interest in unlocking the potential of community solar and storage solutions, particularly for those without the space or ability to install their own systems. Stakeholders understand how cost effective such initiatives can be in managing the transition to a low carbon future and the critical role networks can play in giving customers access to these types of solutions.

3.2 The way we manage the network is changing

Ausgrid is transforming itself to be more proactive in delivering the services customers want at an affordable price. In this context, we are looking to take advantage of new technologies that may offer more cost-effective solutions than traditional network investments.

Energy Networks Australia (ENA) and the CSIRO published the Electricity Network Transformation Roadmap (the Roadmap) in 2017 to outline how networks need to adapt to cater for the changing market conditions. Ausgrid participated in the development of the Roadmap, which was supported by expert reports and analysis.

The Roadmap explains that Australia's electricity network can help lower emissions, keep the lights on and lower costs, through the efficient use of the shared network. However, the Roadmap also noted that there is a limited window of opportunity to reposition Australia's electricity system to deliver efficient outcomes for customers.

Importantly, the Roadmap identified the critical role of the grid in the adoption of new technologies. Customers can only realise the full value of their distributed energy resources in a connected environment that enables multi-directional exchanges of energy, information and value.[1] The optimal use of these distributed energy resources will allow future investment in network infrastructure and wholesale generation to be lower than otherwise needed. The Roadmap also noted that with the right incentives in place we can ensure that an optimal level of generation is installed, reducing overall costs for everyone.

Following publication of the Roadmap, the ENA and the Australian Energy Market Operator (AEMO) have commenced the Open Energy Networks project. The aim of the project is to consult on how best to transition to a two-way grid that allows better integration of DER for all customers.

1 ENA/CSIRO, *Energy Networks Transformation Roadmap* 2017, p10.

3.3 Proposed capex to support the evolution of our network

As highlighted by the ENA and CSIRO, timely action is required to ensure customers can continue to connect their lower carbon resources to the network. This will result in fairer, and more reliable, outcomes for all customers. There is a risk that if our network's hosting capacity is not sufficient, then DER may be curtailed and customers will not realise the full value of their investments.

Consistent with the Roadmap, our Initial Proposal contained an innovation portfolio targeting several areas that require proactive attention by distributors before 2024. Our innovation portfolio will enable us to improve our network monitoring capability, implement new technologies and demand management options. All these projects have the goal of reducing capital and maintenance expenditure on traditional poles and wires solutions, or increasing customer choice and control, thereby placing downward pressure on the whole of system costs for customers.

In response to the AER's Draft Decision, our Revised Proposal includes improved quantification of customer benefits for each of these programs:

- **Advanced Distribution Management System (ADMS)** – the initial investment in an ADMS and establishing the foundational capabilities required by the grid operator to enable distribution service operator (DSO) services to emerge and increase the DER hosting capacity of the grid.
- **Network Innovation Program** – eleven initiatives focused on the progressive implementation of new grid technologies that improve customer outcomes. The program encompasses community storage, microgrids, stand-alone power systems, EV charging and other enabling technologies, and will lay the foundations for the broader scale adoption of these technologies in the future.
- **Demand Management Innovation Program** – eight initiatives to improve our understanding of, and ability to deploy, demand management solutions, funded under the Demand Management Innovation Allowance (DMIA).
- **Planning and Technology Data Usage** – initiatives enabling greater use of network data by customers, third parties and the network to drive increased innovation and to reduce prices in the long term.

Further discussion and justification for each of these programs can be found in Chapter 5 – Capital Expenditure. In our Revised Proposal, we have not included the Accelerated Price Reform program that was contained in our Initial Proposal. We have accepted the AER's Draft Decision on this initiative and will implement our price reform within our total opex allowance.

3.4 Consumers want a greater role in driving the network transformation

During stakeholder consultation prior to lodging our Initial Proposal, consumers told us that they want to see more use of innovation and demand management options. While demand management has traditionally been used to reduce the need to build additional capacity, consumers want to see how it can be used to defer or avoid replacing aged assets, which drives the bulk of our replacement capital expenditure program.

Stakeholders also said that they want a greater role in driving the direction of innovation in electricity networks. In its submission to our Initial Proposal, the Consumer Challenge Panel (CCP10) stated:

> *CCP10 expects distributors to demonstrate active engagement with developers, technology providers, retailers and consumers with a clear commitment to not only carry out trials but reflect a genuine and intentional focus on demand management, new technologies, customer engagement and non-wires solutions in their planning for growth and asset replacement.*

The ENA and CSIRO Roadmap (the Roadmap) came to similar conclusions about the importance of customer engagement. One of the Roadmap's key findings was that networks need to enhance their relationships with customers by building on improved data analytics and a deeper understanding of customer needs. The Roadmap also recognised that networks will play a key role in the delivery and connection of an expanding range of innovative products and services to customers.[2]

3.5 Network Innovation Advisory Committee

In our Initial Proposal, we proposed $42 million of network innovation capex for innovative projects and pilots. This program was informed by stakeholder feedback early in 2018. As explained in section 3.3 above, our Network Innovation Program contained eleven initiatives focused on the progressive expansion of new grid technologies that improve customer outcomes.

In stakeholder engagement sessions over the past few months, consumer groups have expressed support for Ausgrid's ambition in this space and for customers having a role in driving Ausgrid's Network Innovation Program. To this end, we propose the establishment of a NIAC to help inform Ausgrid's innovation portfolio and provide advice on the projects that are undertaken.

The NIAC will be formally established and supported by a detailed Terms of Reference. The draft Terms of Reference (see Attachment 3.02) outlines matters such as the purpose of the committee, membership arrangements, and the roles and responsibilities of members.

Importantly, any capex approved for Network Innovation and overseen by the NIAC will not be subject to the Capital Expenditure Sharing Scheme (CESS). This will ensure that Ausgrid does not receive a CESS reward for any innovation funding not spent within the 2019-24 regulatory period.

2 ENA/CSIRO, *Energy Networks Transformation Roadmap* 2017, p16.

3.6 Barriers to innovation in the regulatory environment

Australia's current regulatory framework was developed during a time of relatively slow technological change. A number of recent reviews have looked at whether the current regulatory framework provides the necessary incentives for networks to innovate in new technologies.

A common theme amongst those reviews (e.g. CEPA 2016,[3] ENA 2017,[4] KPMG 2018,[5] Finkel 2018,[6] AEMC 2018[7]) is that the current economic framework may not be conducive to innovation. CEPA, in particular, noted that:

> *Questions have been raised as to whether current incentive rates, combined with the removal of benefits from efficiency gains after five years, are sufficient to balance incentives between traditional and innovative solutions, considering the relatively higher risks associated with the latter.*
>
> *We note other aspects of the network revenue setting process that may not be conducive to incentivising innovation, in particular: perceived reluctance of the regulator to accept initiatives proposed by network businesses; initial costs of introducing innovative solutions (or costs from trialling solutions) may not be appropriately taken account of in high-level benchmarking; and a lack of incentives for large-scale innovation until reflected in superior efficiencies.*

In relation to flexibility and innovation, KPMG commented that:

> *Lack of incentive to innovate – While NSPs are using existing sources of funding to conduct small scale trials and pilots, it is not clear how the regulatory framework will support the large scale roll-out of some of these options. The key test for the current regulatory framework is to be able to effectively move from the current trials and pilots stage to wide-spread deployment of new technologies.*

In its 2019 review of the Electricity Networks Economic Regulatory Framework, the AEMC will investigate whether the regulatory framework is sufficiently robust and flexible in a future environment of increased DER. We support the AEMC considering whether network businesses are sufficiently incentivised to innovate as part of its review. We will continue to work with the AEMC, AER and consumer advocates to ensure that the regulatory framework develops in a way that promotes the long term interests of consumers.

3 CEPA, *Future regulatory options for electricity networks*, Final Report, 3 August 2016.

4 Energy Networks Australia, *Network Innovation discussion paper*, July 2017.

5 KPMG, *Optimising network incentives: Alternative approaches to promoting efficient network investment*, A report for the Energy Market Transformation Project Team, January 2018.

6 Finkel, *Independent Review into the Future Security of the National Electricity Market*, June 2017.

7 AEMC, *Economic regulatory framework review*, July 2018.

04

Annual revenue requirement


Ausgrid

04

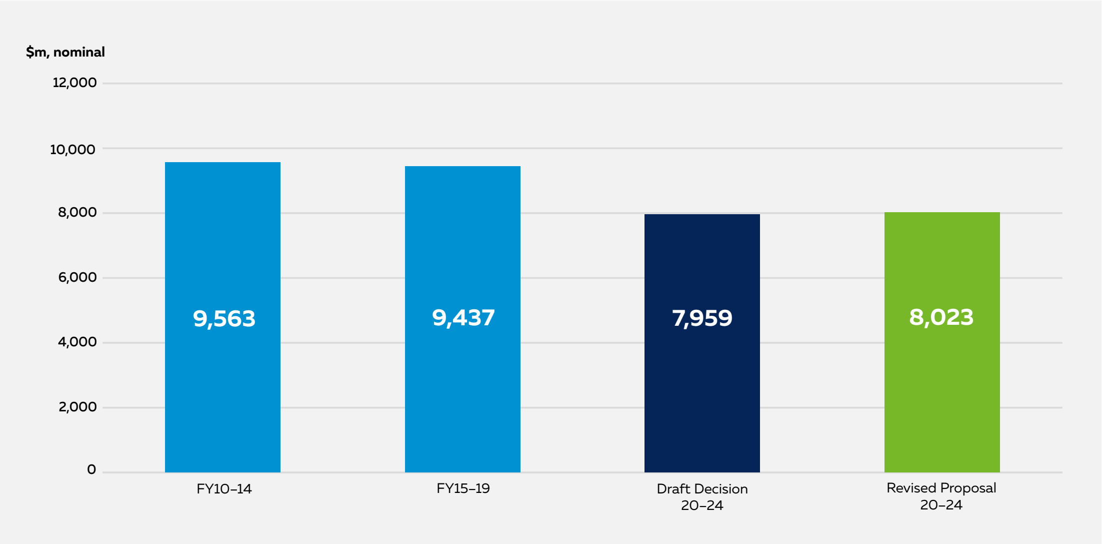
ANNUAL REVENUE REQUIREMENT

Lower revenues, lower prices for customers

Our Revised Proposal

Our revenues have significantly reduced for both of the last two regulatory periods. We are delivering better and safer network services to more customers at lower cost.

Building block revenue – historic and forecast ($million, nominal)



Our Revised Proposal includes:

- Lower capital expenditure (capex), including deferrals of some projects to ensure we are not investing ahead of technological change and to reflect customers' clear priority for affordability. Our forecast capex is $428 million lower than the amount we will spend in 2014-19.
- An annual operating expenditure (opex) cost base $100 million lower. These savings are locked in and we are committing to significant additional productivity savings.
- Adoption of the AER's 2018 Rate of Return Instrument. We will work with the AER through January to March 2019 to make the required modelling changes to give effect to the AER's 2018 Tax Review Final report.

These measures have contributed to reducing our proposed revenue requirements for the 2019-24 regulatory period from $8.9 billion to $8.0 billion.

How our Revised Proposal responds to customers

Customer feedback on our Initial Proposal highlighted the need for us to prioritise affordability and the need for increased effort to reduce network prices.

By working with customer advocates we have developed a Revised Proposal to address this concern. Our capital proposal now results in a 4.9% real reduction in the regulatory asset base (RAB) per customer over the period.

We also agreed with customers to incorporate productivity forecasts into our proposed opex allowance, challenging ourselves to do more with less. This has reduced our proposed revenue by $52 million in comparison to our Initial Proposal.

Because of the measures we've adopted, our Revised Proposal represents a 10% decrease in our revenues compared with our Initial Proposal. The outcome for customers is an average reduction of $71 in the annual network charges for the average residential customer from 1 July 2019.

How our Revised Proposal responds to the AER

On 17 December 2018, the AER published its 2018 Rate of Return Instrument. Our Revised Proposal applies the AER's 2018 Rate of Return Instrument. This reduces our revenues, which in turn flows through to customers through reduced network prices.

Additionally, the AER's Tax Review Final Decision, although not yet formalised in modelling adjustments, is estimated to reduce our regulatory tax allowance by $44 million over the 2019-24 regulatory period. This is based on the AER's decision to move to the diminishing value approach for calculating depreciation expense in our tax allowance.

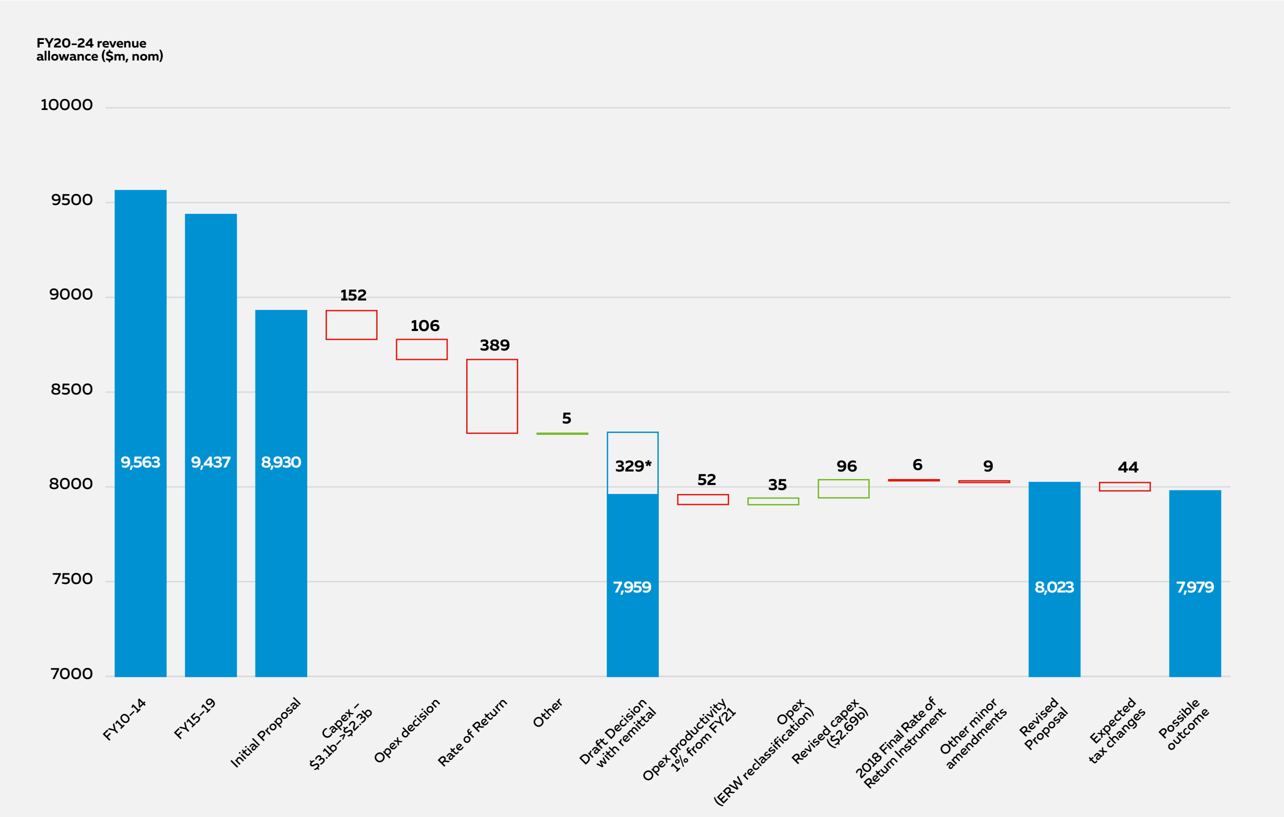
The AER sought additional information on both our operating and capex allowances. We have provided supporting information where sought, or accepted the Draft Decision where appropriate. These issues are covered in greater depth in Chapters 5 and 6.

4.1 Our Revised Revenue Proposal is 10% lower than our Initial Proposal

Our revised revenue requirement reflects changes made to opex, capex and the rate of return, based on updated analysis and in response to customer and AER feedback. We describe these building block components in later chapters of this Revised Proposal. Figure 4.1 shows the differences between our Initial Proposal and Revised Proposal in terms of total revenues, and in comparison to previous five-year regulatory periods.

Figure 4.1

Our revised Annual Revenue Requirements



* This remittal amount is the final number, not the draft number used in the AER's Draft Decision. This is why the Draft Decision revenue in this chart is different to the AER's published revenue.

Table 4.1 shows the breakdown of the revised revenue requirement.

Table 4.1

Building block components of Ausgrid's revised proposed annual revenue requirements 2019-24 ($million, nominal)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Return on and of capital						
Return on capital	940.1	953.3	959.7	959.6	958.2	4,770.9
Return of capital	104.1	135.2	164.9	194.5	194.2	792.9
Operating and tax costs						
Opex	473.6	485.5	499.1	513.2	527.5	2,498.8
Income tax	34.8	33.5	38.4	42.5	40.2	189.3
Other revenue increments or decrements						
CESS revenue	17.9	18.4	18.8	19.3	19.7	94.1
Proposed DMIA revenue	1.4	1.4	1.5	1.5	1.5	7.4
Remittal impact	-328.6	0.0	0.0	0.0	0.0	-328.6
Shared assets revenue adjustment	-1.6	0.0	0.0	0.0	0.0	-1.6
Annual revenue requirement	**1,241.6**	**1,627.2**	**1,682.5**	**1,730.5**	**1,741.3**	**8,023.2**

Note: Numbers may not sum due to rounding.

4.2 Overview of our Revised Proposal

The key differences between the AER's Draft Decision and our Revised Proposal are:

- **Opening RAB:** We have not adjusted FY16 and FY17 capex for movement in provisions. This is discussed in section 4.3.1. It affects return on capital and return of capital in the building block revenue requirement.
- **Rate of Return:** Our Revised Proposal applies the AER's 2018 Rate of Return Instrument as the basis for determining Ausgrid's allowed rate of return, and the value for imputation tax credits (gamma) for the 2019-24 regulatory period. This is discussed further in Chapter 7.
- **Total forecast capex:** We have reduced forecast capex compared to our Initial Proposal, but not to the level outlined by the AER in its Draft Decision. We address the AER's reasons and we substantiate our revised forecast capex in Chapter 5. This affects return on capital and return of capital in the building block revenue requirement.
- **Forecast opex:** We have accepted some elements of the AER's Draft Decision, but overall our revised proposed opex is $20 million lower than the AER's Draft Decision. We address the AER's Draft Decision with analysis and reasons for our revised forecast opex in Chapter 6.

4.3 Regulatory asset base

4.3.1 Opening value of regulatory asset base

The AER accepted our proposed opening RAB values subject to these revisions:

- Adjusting actual gross capex for FY16 and FY17 for movements in capitalised provisions
- Updating inputs to reflect changes resulting from the remittal for the 2014–19 regulatory period:
  - Inflation rate
  - Nominal vanilla weighted average cost of capital (WACC)
  - Depreciation.

We accept the updated inputs and have reflected these in our Revised Proposal roll-forward models (RFM). However, we have not adjusted actual gross capex for FY16 and FY17. This is because Ausgrid does not include asset related movements in provisions in gross capex reported in the annual reporting Regulatory Information Notice (RIN). Therefore, an adjustment does not need to be made to remove them. We have discussed this with the AER and proposed an alternative method of reporting movements in asset related provisions so that it is clear which amounts have been included in gross capex and which have not.

A further amendment to our proposed RAB is the addition of a finance lease asset which was brought on to the balance sheet as a finance lease liability in FY15 but was not included in the RAB. We have amended our FY17 annual reporting RIN to reflect this additional capex. To accommodate the characteristics of this type of asset we have proposed a new asset class with a standard life of 50 years.

We have also updated our actual capex for FY18 and forecast capex for FY19. Our revised estimated RAB for standard control services as at 1 July 2019 is $15,684 million ($ nominal) as shown in Table 4.2. This comprises $13,526 million attributable to distribution assets and $2,159 million attributable to dual function assets. We have calculated these amounts based on clause 6.5.1 and schedule 6.2 of the Rules and the AER's RFM. See Attachments 4.0.1 and 4.0.4 for the RFMs for distribution and transmission.

Table 4.2

Ausgrid's revised opening RAB as at 1 July 2014 and 2019 ($million, nominal)

	$M, NOMINAL
Opening RAB as at 1 July 2014	14,287.4
Add: Actual and estimated capex	2,775.2
Less: Regulatory depreciation	-1,378.3
Adjusted opening RAB as at 1 July 2019	15,684.3
Value of RAB for standard control services as at 1 July 2019	
Distribution RAB	13,525.6
Transmission RAB	2,158.6

Note: Numbers may not sum due to rounding.

4.3.2 Forecast RAB for the 2019–24 regulatory period

The AER's Draft Decision did not accept our forecast RAB for the 2014–19 regulatory period and calculated a revised forecast based on:

- Reduced opening RAB balance for 1 July 2019 (discussed above)
- Reduced forecast capex for the 2019–24 period
- Updated inflation rate
- Reduced straight line depreciation as a consequence of reduced capex.

Our position regarding the opening balance is outlined in section 4.3.1. Our proposal differs from the AER's Draft Decision with respect to capex and we have included revised forecasts that address the concerns raised by consumers and the AER. The revised forecast has a flow on effect to depreciation. We have accepted the updated inflation rate.

Table 4.3 summarises the revised amounts, values and inputs used to derive our distribution RAB value for each year of the 2019–24 regulatory period.

Table 4.3
Ausgrid's forecast RAB for standard control services 2019–24 ($ million, nominal except where stated)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Start of period RAB	15,684.3	16,237.1	16,695.9	17,059.5	17,414.6	15,684.3
Straight-line depreciation	-484.4	-528.9	-569.8	-608.1	-616.5	-2,807.7
Net capex	657.0	594.0	528.5	549.6	543.7	2,872.7
Inflation on opening RAB	380.3	393.7	404.9	413.7	422.3	2,014.9
RAB (end period)	16,237.1	16,695.9	17,059.5	17,414.6	17,764.1	17,764.1
RAB (end period) – real $ June 2019	15,853.5	15,916.2	15,878.6	15,826.2	15,762.3	15,762.3

Note: Numbers may not sum due to rounding.

In accordance with clause S6.2.1(e)(4) of the Rules and our approved cost allocation methodology, the RAB only includes actual and estimated capex properly allocated to the provision of standard control distribution services. The nominal capex in the table above excludes capital contributions.

4.4 Return on capital

The AER did not accept Ausgrid's proposed regulatory allowance for return on capital mainly because of the consequential impact of its decisions regarding Ausgrid's RAB, rate of return and proposed forecast capex for the 2019–24 regulatory period.

Since we submitted our Initial Proposal, we have undertaken extensive consultation with customers. The feedback we received is that customers considered adopting the outcomes of the 2018 Draft Rate of Return Guideline would deliver lower prices and be in line with customer priorities.

On the 17th of December 2018, the AER published its Final Decision on its Rate of Return review. The COAG Energy Council determined that the National Electricity Law should be amended to replace the existing non-binding Rate of Return Guideline with a binding rate of return instrument. The legislative amendments have been passed into law and are now legally binding. This binding rate of return instrument applies to service providers currently under review, including Ausgrid.

In light of the binding 2018 Rate of Return Instrument and consistent with the feedback we have received through our customer consultation, in our Revised Proposal we have adopted the approach set out by the AER in the Final 2018 Rate of Return Instrument (2018 RoR Instrument). In doing so, we have adopted, as a placeholder, the allowed rate of return set out by the AER in its 2018 RoR Instrument. This is shown in more detail in Table 4.4.

Table 4.4

Ausgrid's proposed rate of return

RATE OF RETURN PARAMETER	PROPOSED WACC
Overall WACC	5.99%
Return on equity	6.40%
Return on debt	5.72%
Gearing	60%
Gamma	0.585

This estimate will be updated close to the start of the 2019-24 regulatory period (for the risk-free rate and the return on debt) using the methodology set out in the 2018 RoR Instrument.

Chapter 7 of this Revised Proposal provides further information in support of our proposed rate of return.

4.5 Return of capital

The AER did not accept Ausgrid's proposed regulatory depreciation allowance, mainly because of the consequential impact of its decisions regarding Ausgrid's opening RAB, proposed forecast capex for the 2019–24 regulatory period and expected inflation. The AER did accept the proposed asset classes, the use of straight line depreciation method and standard asset lives. Except for the addition of an asset class to account for land leases noted in section 4.3.1, we have maintained these aspects of the calculation of regulatory depreciation.

Our revised regulatory depreciation has been updated based on Ausgrid's revised opening RAB and forecast capex. We have accepted the AER's placeholder forecast inflation rate of 2.42% to calculate RAB indexation. The inflation rate will be updated accordingly at the time of the AER's Final Decision.

Table 4.5 sets out our calculation of regulatory depreciation.

Table 4.5

Ausgrid's regulatory depreciation (return of capital)

	FY20	FY21	FY22	FY23	FY24	2019–24 REG PERIOD
Straight-line depreciation ($million, real FY19)	473.0	504.2	530.3	552.6	546.9	2,606.8
Straight-line depreciation ($million, nominal)	484.4	528.9	569.8	608.1	616.5	2,807.7
Inflation on the opening RAB ($million, nominal)	380.3	393.7	404.9	413.7	422.3	2,014.8
Regulatory depreciation ($million, nominal)	104.1	135.2	164.9	194.5	194.2	792.9
Forecast inflation on opening RAB (% per annum)	2.42	2.42	2.42	2.42	2.42	2.42

4.6 Regulatory tax allowance

In December 2018 the AER released its 2018 Tax Review Final Decision. We will work with the AER through January to March 2019 to make the required modelling changes to give effect to the Tax Review Final Decision. We estimate that the 2018 Tax Review Final Decision will reduce our regulatory tax allowance by $44 million over the 2019-24 regulatory period. This is based on the AER's decision to move to the Diminishing Value approach for calculating depreciation expense in our tax allowance.

The 2018 Tax Review Final Decision also indicated that the AER would move to the immediate expensing of refurbishment capex for tax purposes. The AER is yet to implement its proposed changes and has indicated that it will take into account the actual practices of individual businesses with respect to immediate expensing of capex for tax purposes.

Ausgrid does not immediately expense its refurbishment capex. We therefore do not expect that this proposed change (estimated to be $26 million) will impact our tax allowance.

4.7 Other revenue adjustments

4.7.1 Capital Expenditure Sharing Scheme

The AER amended our proposed calculated amount of the Capital Expenditure Sharing Scheme (CESS) reward due to the following updated inputs:

- Unlagged consumer price index
- More recent inflation rates
- Adjusting FY16 and FY17 capex for movement in provisions.

Ausgrid accepts the amended inflation changes. However, we have not adjusted capex in the relevant years for movement in provisions. As explained in section 4.3.1, Ausgrid does not include movement in asset related provisions in the reported capex, therefore an adjustment does not need to be made.

To calculate our revised CESS reward we have used actual FY18 capex. The revised amount is $87.6 million ($real FY19), consisting of $74.3 million for distribution and $13.3 million for transmission.

4.7.2 Proposed demand management innovation allowance

The AER has decided to apply the demand management innovation allowance without modification. Ausgrid does not propose any changes for its Revised Proposal. This is discussed in further detail in Chapter 9.

4.7.3 Shared assets revenue

The AER had accepted our Initial Proposal that there should not be a revenue decrement for shared assets. Ausgrid has re-assessed the materiality of the use of shared assets based on our revised smoothed revenue. Table 4.6 shows this assessment and demonstrates that a shared asset revenue reduction is necessary in FY20 as shared assets revenue meets the materiality threshold defined in the AER's shared asset guidelines for this year only.

Table 4.6

Materiality of shared assets ($million, nominal)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Unregulated revenue from shared assets use	16.1	12.5	12.4	12.6	12.8	66.3
Smoothed revenue (prior to shared assets reduction)	1,549.8	1,570.2	1,592.7	1,617.7	1,645.6	7,976.0
Materiality (%)	1.04%	0.80%	0.78%	0.78%	0.78%	0.83%
Adjustments for shared asset revenue	-1.6	0.0	0.0	0.0	0.0	-1.6

4.8 Annual revenue requirement

4.8.1 Unsmoothed annual revenue requirement

For the reasons discussed above and in Chapters 5, 6 and 7, Ausgrid has revised its proposed annual revenue requirements.

Table 4.7 shows the revised annual building block revenue requirement for each year of the 2019–24 regulatory period.

Table 4.7

Annual revenue requirement ($million, nominal)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Distribution	1,449.0	1,455.9	1,505.4	1,548.6	1,557.4	7,516.3
Transmission	-207.4	171.3	177.0	181.9	184.0	506.9
Annual revenue requirement	**1,241.6**	**1,627.2**	**1,682.5**	**1,730.5**	**1,741.3**	**8,023.2**

4.8.2 Smoothed revenue and X-factors

Revenue streams resulting from the building block approach can sometimes vary greatly between years within a regulatory period. In order to minimise the price volatility which arises from this, we apply revenue smoothing via a price adjustment mechanism within the AER's post-tax revenue model (PTRM). The smoothing profile prescribed in the AER's Draft Decision takes account of the outcome of the remittal for the 2014-19 regulatory period. The remittal outcome will allow Ausgrid to return a total of $321 million ($ real FY19) of revenue to customers which was recovered across the 2014-19 regulatory period above the allowed revenues set out in the 2014-19 Final Determination. This has a significant impact on the smoothing profile for the transmission network, and makes it difficult to achieve the AER's target of no greater than 3% difference between the final year building block revenue and smoothed revenue.

The smoothed revenue and X- factor profile has been calculated using the AER's PTRM and ensures that our proposed smoothed revenues are equal to required revenues in net present value terms. The smoothed revenues are shown in Table 4.8 and the X-factors in Table 4.9.

Table 4.8

Proposed "smoothed" annual revenue requirement ($million, nominal)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Distribution	1,484.0	1,492.6	1,501.3	1,510.0	1,518.8	7,506.6
Transmission	65.9	77.6	91.4	107.7	126.8	469.4
Total	**1,549.8**	**1,570.2**	**1,592.7**	**1,617.7**	**1,645.6**	**7,976.0**

Table 4.8

Proposed X-factors for distribution and transmission standard control services

X-FACTORS (%)	FY20	FY21	FY22	FY23	FY24
Distribution	2.84%	1.80%	1.80%	1.80%	1.80%
Transmission	81.94%	-15.00%	-15.00%	-15.00%	-15.00%
Weighted average	18.09%	1.09%	0.97%	0.84%	0.68%

05

Capital expenditure

05

CAPITAL EXPENDITURE

Investing to keep the network safe, reliable and affordable

Our revised capital expenditure proposal

In developing our revised capital expenditure (capex) forecast, we have responded to the matters raised by our customers and the AER. By working with customer advocates, we have developed a better understanding of customer views on the long term costs and benefits of our capex program. Our revised capex forecast now represents a different balance of the competing drivers of network investment, of which affordability is now the primary consideration.

Our revised capex has been designed to put downward pressure on costs while improving safety and maintaining reliability. We have worked with our customers to efficiently defer capex, particularly where there is uncertainty surrounding the implications of technological change. Where requested, we have also provided further information and analysis to explain and justify our proposed expenditure.

We subjected our revised capex program to a strengthened internal review and challenge process to ensure it addresses the issues raised by customers and the AER. Our internal review has also ensured that our revised capex program meets our corporate objectives of transforming to meet the customer needs and expectations of the future.

Our revised capex forecast totals $2.69 billion or, on average, $538 million per annum over the 2019–24 regulatory period. In our Initial Proposal, we proposed forecast capex of $3.08 billion or $617 million per annum. Our annual capex program is now $79 million (13%) lower than our Initial Proposal and $73 million higher than the AER's Draft Decision.

Our Revised Proposal responds to customers

Our customers told us that affordability is currently their number one concern. They legitimately want to ensure our capex plans are justified, prudent and efficient and wanted more information to understand:

- how we are getting best value out of previous investments
- what we are doing to address many customers' affordability concerns
- how we make long term investment decisions in a period of rapid technological change.

In response, we worked with our customer advocates to discuss and agree how to address these issues:

- We explained how previous investments have contributed to improved reliability and improved resilience to extreme weather events. We also outlined how this historical investment will reduce our augmentation requirements in the future and provide the level of network performance our customers expect.
- Our lower total capex forecast will contribute to reducing our regulatory asset base (RAB) by 4.9% (in real terms) per customer over the 2019–24 regulatory period. This will help to ensure we manage affordability not just in the short term but also into the future.
- We have taken steps to efficiently defer some capital investments, to provide option value if technological advances provide more cost effective alternatives in the future compared to what is available today.

Our Revised Proposal responds to the AER

We have given careful consideration to the issues raised by the AER. In response, we have enhanced our internal capex forecast review and challenge processes so that long-term forecasts are rigorously tested in addition to the testing that individual projects receive prior to obtaining approval.

In preparing our revised capex forecasts, we enhanced the level of quantitative cost-benefit analysis to provide stronger evidence of the efficiency of our proposed projects and programs to ensure that their timing coincides with the point where value is delivered to customers.

We have also addressed the AER's deliverability concerns through the deferral of some projects, where it is prudent and efficient to do so. Our Revised Proposal also uses the most up to date information available, including peak demand and customer connection forecasts.

In revising our capex program, we have addressed all of the issues raised by the AER's Draft Decision. Our revised forecast meets our expected demand and regulatory obligations and is in the long-term interests of customers. The revised forecast meets the requirements of the NER and reasonably reflects the capex objectives and criteria.

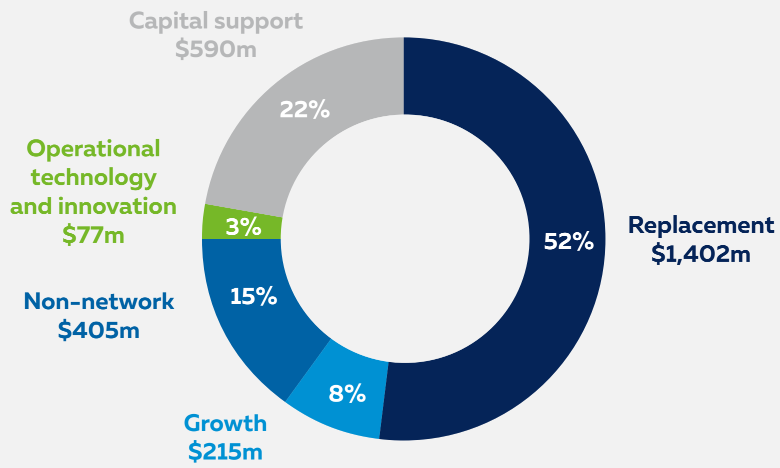
5.1 Our revised capex program prioritises affordability while still maintaining safety, reliability and sustainability

Our revised total capex forecast for the 2019–24 regulatory period is $2.69 billion or $538 million per annum, on average. This is $394 million (13%)lower than our initial capex forecast and reflects our careful consideration and response to feedback from customers and the AER's Draft Decision. The revised capex program will enable us to meet our regulatory and corporate objectives of providing safe affordable, reliable and sustainable services to our customers. The revised capex forecast meets the capex objectives and criteria, as demonstrated in the remainder of this chapter.

The breakdown of our revised capex forecasts is shown in Figure 5.1 and Table 5.1.

Figure 5.1

Components of our total capex forecast



Source: Ausgrid anaylsis

Our revised total capex forecast of $2,690 million is $394 million (13%) lower than our Initial Proposal of $3,084 million. The revised capex forecast and each of the components by year is shown in Table 5.1.

Table 5.1

Revised capex by asset driver for 2019–24 ($million, real FY19)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Replacement expenditure	346	281	257	260	258	**1,402**
Growth (Augmentation and Connection)	43	57	60	25	30	**215**
Information, Communications and Technology	50	34	20	18	21	**144**
Operational, Technology & Innovation	18	16	14	16	13	**77**
Property	18	30	42	42	20	**152**
Motor vehicles & plant	15	14	16	18	19	**87**
Minor assets	5	6	6	6	5	**23**
Capital program support	134	123	115	108	111	**590**
Total	**631**	**560**	**529**	**493**	**477**	**2,690**

Source: Ausgrid

Replacement expenditure (repex)	Refers to investment that replaces or renews network assets in major projects or planned, conditional and reactive programs. It represents the largest component of our capex plans. We propose to invest $1,402 million replacing network assets that potentially pose a risk to safety and reliability.
Growth (Augmentation and Connection) capex	Refers to investment to connect new customers and to augment network capacity to meet our forecast peak demand. We propose to invest a total of $215 million in growth related expenditure. This is $26 million (11%) lower than our initial growth forecast.
Information, Communications and Technology (ICT)	Refers to expenditure relating to ICT and is non-network expenditure that is required to support the safe and reliable delivery of network services to our customers. We propose a total revised non-network ICT capex of $144 million over the five year period, which is $13 million (9%) lower than we forecast in our Initial Proposal.
Operational Technology and Innovation (OTI)	Relates to our core system operational technology requirements as well as our innovation program, which includes a change in the way we use technology to capture our network characteristics and a number of network technology projects and pilots. We are proposing $77 million in OTI capex in our Revised Proposal. This is approximately $20 million more than our Initial Proposal as we are proposing additional expenditure for cyber security.
Property	Relates to investment in our offices, depots and specialist sites that provide essential support for the efficient delivery of network services. Our revised property forecast is $152 million over the five-year period, which is $36 million (19%) lower than our Initial Proposal.[1]
Motor vehicles and plant	Refers to expenditure for the purchase of vehicles and trucks that support our operations in the field. It also includes 'plant' equipment—such as vehicle loading cranes and pole-hole borers/erectors. Our revised fleet capex is $87 million over the five-year period, which is approximately $12 million (12%) lower than our Initial Proposal.
Minor assets	Includes tools that have an individual or group value below $1000, as well as portable testing equipment and office furniture. Our revised minor assets capex is $23 million over the five-year period. This is approximately $2 million (8%) lower than our Initial Proposal.
Capital program support (also known as capitalised overheads)	Includes the indirect costs we incur in the delivery of both our network and non-network capex programs. We propose to invest a total of $590 million in capital program support over the period, which reflects our total revised capex program and, therefore, is lower than our Initial Proposal of $621 million.

1 Our Initial Proposal was represented as $208 million when, for the reasons outlined in attachment 5.20, our Cost Allocation Model (CAM) adjusted forecast should have been represented as $188 million.

5.1.1 What our capex program means for customers

Customers have asked us to explain the benefits of our historical and proposed capex programs. The graphic below summarises why we continue to make significant investment in our network and supporting systems.

Community well-being

Keeping the power on supports the economic and social well-being of the community.

Lower costs

Labour productivity improvements of 2% per annum, reaching a 10% saving in the final year of the regulatory period, is contributing to lower costs for our customers.

Enabling the future network

More innovative uses of the electricity network to meet current and future needs, as modern technology becomes more dependable and affordable. Our network innovation program will help unlock the future energy market.

Cyber security

The risk of cyber-attack is rising. Cyber security supports reliability for our customers.

Network reliability

Having a reliable network means our customers have electricity available as and when it is needed.

Advanced Distribution Management System (ADMS)

The ADMS will replace our ageing distribution network management system with new technology that will support a high standard of outage response. The ADMS will also help enable a platform to facilitate new energy markets operating on a reliable and supported platform.

Network safety

Maintaining the current risk profile of major asset failures means a safer network for our customers, community, staff and contractors.

Bushfire mitigation

Maintaining the current bushfire risk profile by undertaking targeted programs, such as replacing steel mains and bare service lines in high risk areas and continuing to deliver our compliance programs.

Environmental care

We are committed to a sustainable environment and developing innovative ways to reduce resources and meet our environmental commitments. Our project work is always accompanied by detailed environmental analysis so that the network is built with due care for the environment we all share.

Lower growth capex and better network utilisation

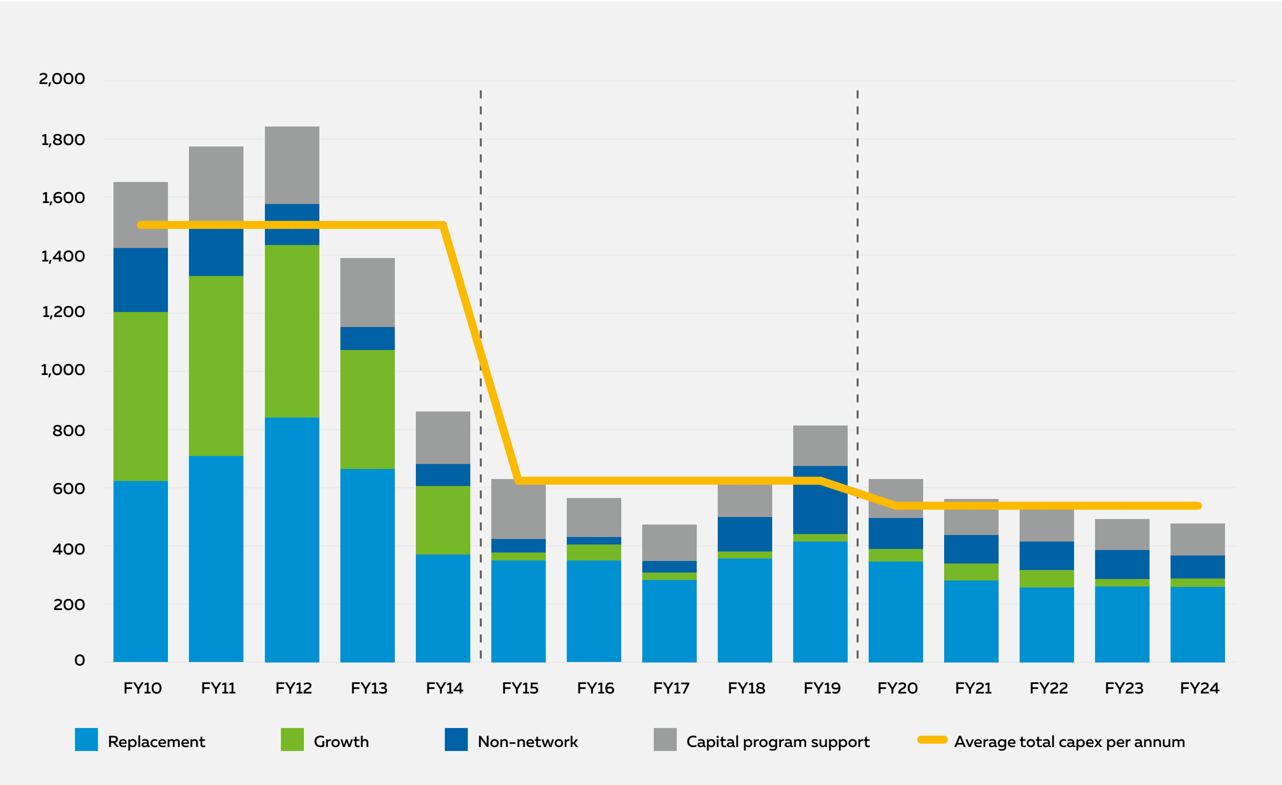
We provide the network capacity required to meet our customers' forecast requirements. Looking forward, we are reducing costs to our customers by improving asset utilisation as we increase the use of our existing network capacity, which has been provided by past asset investments.

5.1.2 Forecast trend in total capex is stable

Our revised total capex forecast for the 2019–24 regulatory period is $428 million (14%) lower than the amount we expect to invest in the current 2014-19 regulatory period. As shown in Figure 5.2, revised total capex is significantly lower than historical levels of capex. This is driven by the significant reduction in growth, capital support and replacement capex. This lower level of capex helps ensure we avoid the peaks of the past, which challenge our goal of affordability.

Figure 5.2

Forecast by capex driver for 2019–24 compared to previous years ($million, real FY19)



Source: Ausgrid analysis

The lower levels of total capex reflect a relatively low growth environment and the benefit of past investments, as well as decisions we discussed with customers, including:

- Deferring some replacement expenditure which cost-benefit analysis indicates is optimal at this time, given the rate of technological change
- A review of our fleet replacement costs to deliver a lower cost outcome
- Efficient deferral of some property remediation investment.

The detailed evidence to support our revised forecasts is presented in later sections of this chapter and supporting attachments.

5.1.3 What we heard and how we've responded on total forecast capex

Table 5.2 summarises the matters raised by customers and the AER and how we have responded in this Revised Proposal.

Table 5.2

What we heard and how we responded

	WHAT WE HEARD	HOW WE'VE RESPONDED
1. Total capex forecast	The AER concluded that we had not demonstrated that our capex forecasts reflected the capex objectives and criteria. As such, the AER substituted its own estimate for total capex in its Draft Decision.	We have addressed the AER's reasons for not accepting our total capex forecast and reduced our proposed expenditure. In particular, we have updated and enhanced the supporting business cases for our capex projects and programs and provided further evidence that our revised forecast meets the capex objectives and criteria.
2. Capex decision making processes	The AER considered that based on the information provided with our Initial Proposal it was not apparent that we had applied a sufficient top-down assessment to reduce our total capex forecast. Customers communicated a similar view.	Our top-down review processes are integral to our capex forecasting approach. At the start of the regulatory proposal process, our total capex program was substantially higher and has gradually been refined through internal review and challenge to reach the revised forecasts of $2.69 billion. However, to address the issues raised in AER and customer feedback, we enhanced our internal capex review and challenge framework for the Revised Proposal, which now includes a detailed review by the Investment Governance Committee. This change has strengthened the role of internal review and challenge processes.
3. Justification for projects and programs	The AER sought more evidence of the need for some capex projects and programs, including risk-based cost-benefit analysis. In relation to our major projects, the AER commended our cost-benefit analysis but suggested refinements to some inputs.	We have taken on board the AER's suggestion and developed more comprehensive cost-benefit analysis for our repex programs, IT and property. The cost-benefit analysis provides clear economic justification for our projects and programs, in accordance with the efficiency and prudency tests in the NER. Looking forward, we will continue to develop our options analysis tools and will involve our customers in this process.
4. Affordability	Customers told us that affordability is their number one concern and that they wanted to see clear evidence that significant efforts have been made to reduce capex. Customers had concerns that we had not developed the capex program and forecast with affordability as a key consideration. Customers thought that further productivity improvements could be made to our capex program.	To address the issue of affordability, we have worked hard to ensure that we have the balance right. Our revised expenditure incorporates enhanced productivity improvements and innovative delivery plans. Where possible we have revised our timeframes for projects and programs to reduce our expenditure requirements.

	WHAT WE HEARD	HOW WE'VE RESPONDED
5. Demand management	The AER supported three of our six proposed demand management projects. The AER's analysis suggested that the other three projects provided a lower cost-benefit than the capex alternative. The AER also sought more information on our high voltage augmentation program.	We accept the AER's findings regarding demand management projects and have provided the additional information sought with regard to high voltage augmentation.
6. Non-network solutions	Customers asked us to look at ways of adopting new technology to provide the services that customers want.	Our OTI capex program will allow us to implement new technologies with a view to improving the way we monitor and operate our network. These projects have the goal of reducing capital and maintenance expenditure into the future and enabling us to respond to our customers' changing requirements. We have provided supporting material to justify the prudency and efficiency of these projects, in accordance with the requirements of the NER.
7. Benefits from past investment	Customers referred to past levels of investment and wanted to know what the benefits were, especially in terms of reliability and capacity.	Historical expenditure has enabled us to deliver a more reliable, safe and resilient network at the same time as our customer base has grown. We discussed with our customers how we have leveraged past investments to meet future needs. We also have plans to shift load to improve network utilisation.

5.1.4 Our total forecast capex compared to the AER's Draft Decision

We have worked to address the issues and questions raised by the AER about our replacement, growth and non-network projects and programs. In this Revised Proposal, we provide further information and analysis to support the need, timing, and volume of our proposed expenditure, and justify the prudence and efficiency of the forecast. Our revised forecast reasonably reflects the capex objectives and criteria.

Table 5.3 and Figure 5.3 below show how our revised capex forecasts compare to our Initial Proposal and the AER's substitute estimate in its Draft Decision.

Table 5.3

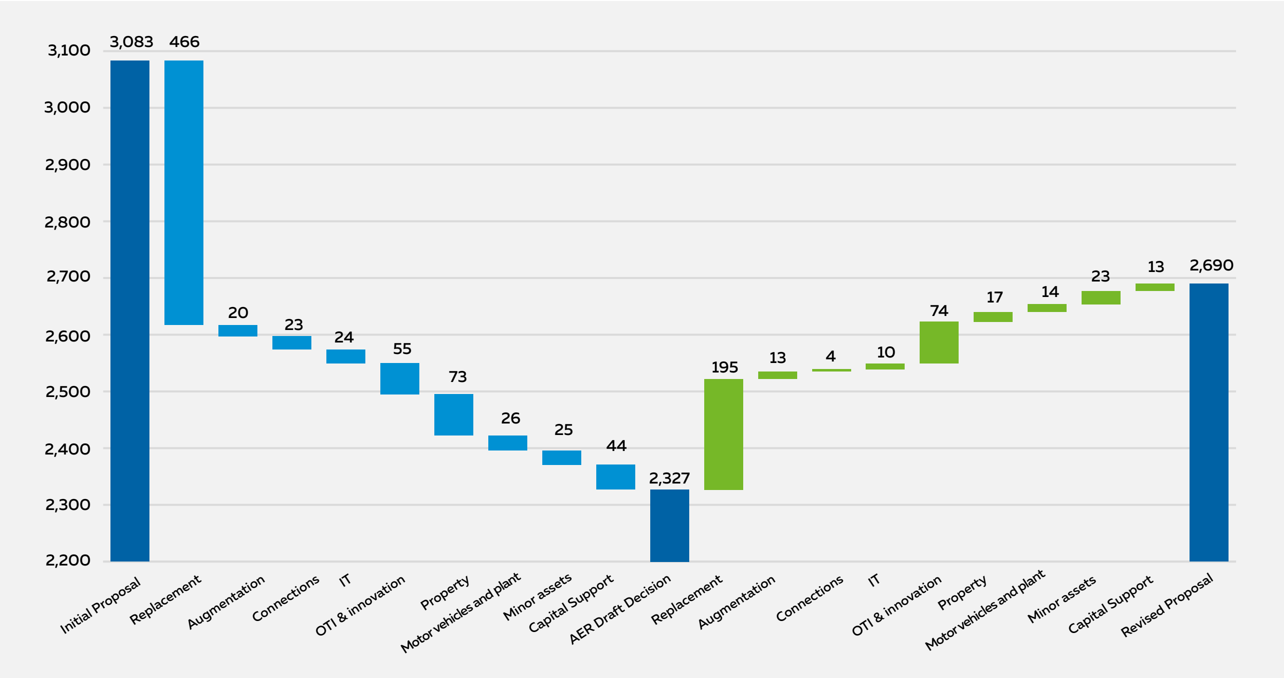
Our total capex forecasts compared to the AER's Draft Decision 2019–24 ($million, real FY19)

	AUSGRID ORIGINAL PROPOSAL	AER DRAFT DECISION SUBSTITUTE	AUSGRID REVISED PROPOSAL
Repex	1,673	1,207	1,402
Augex	189	169	182
Connection	52	29	33
ICT	158	134	144
OTI	58	3	77
Property	208	135	152
Motor vehicles and plant	99	73	87
Minor assets	25	0	23
Capital support	621	577	590
Total	**3,084**	**2,327**	**2,690**

Source: Ausgrid analysis

Figure 5.3

Ausgrid total capex forecasts compared to the AER's Draft Decision 2019–24 ($million, real FY19)



Source: Ausgrid analysis.

In the remainder of this chapter, we explain how we have responded to the AER's Draft Decision and customer feedback.

5.1.5 Enhanced internal review and challenge process

Following the feedback received from customers and the AER about our Initial Proposal, we carefully reconsidered the way we develop, review and challenge our capex forecasts. In addition to making general enhancements based on the feedback received, there have been a number of important initiatives progressing in parallel with the determination process that address the AER's questions regarding review and challenge of the forecasts for regulatory determinations.

In summary, the key changes to the way our forecasts are prepared include:

- Enhanced role of the Reset Regulatory Executive Committee (RREC)
- Enhanced role of the Investment Governance Committee (IGC)
- Network Asset Management System certified to ISO 55001:2014 Asset Management System Requirements.

In preparing our Initial Proposal, the RREC was established to support the delivery of a compliant, credible and reasonable regulatory proposal that aligned with the strategic direction set by the Board and Ausgrid's corporate objectives. The RREC reports to the Ausgrid Board and includes Board members in its membership.

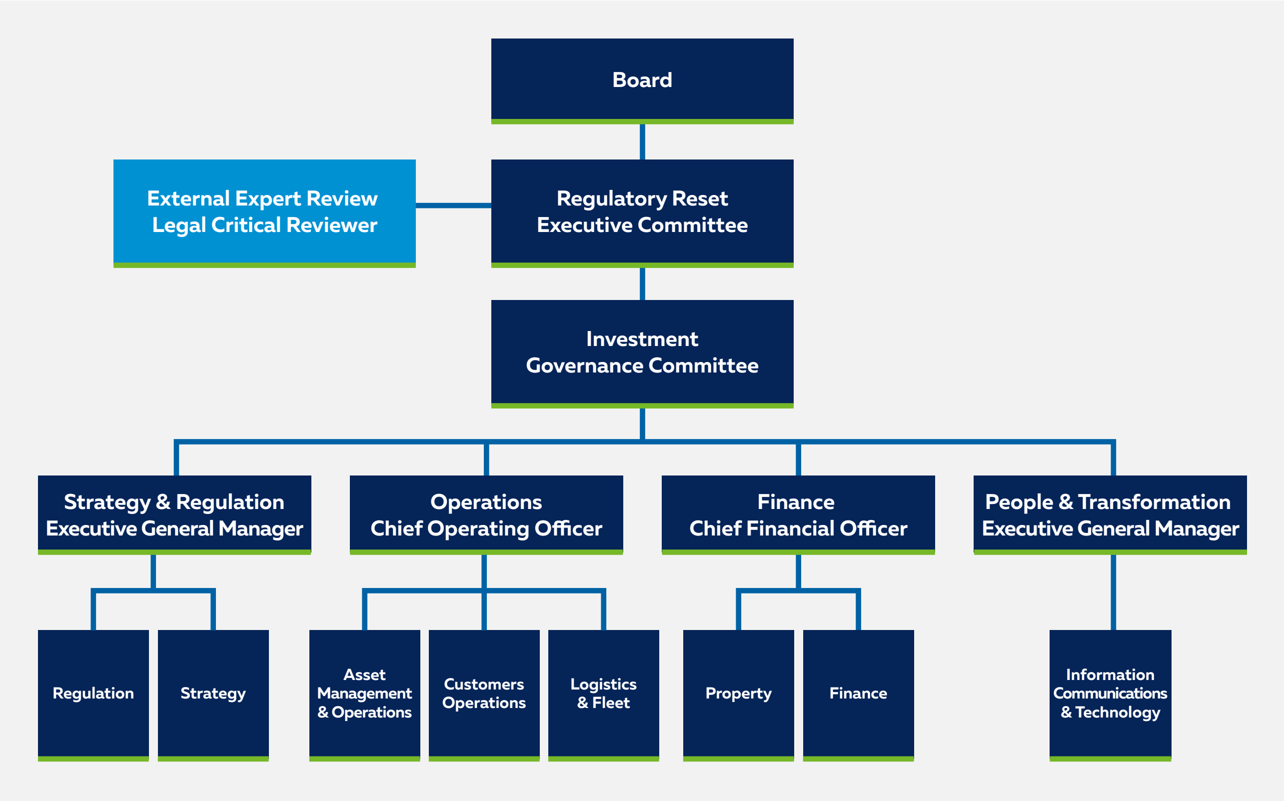
Following the AER's Draft Decision, the RREC charter was amended. This was to formalise the RREC's review and challenge role; strengthen the requirement to consider feedback from stakeholder consultation; and specify that it was to take account the long-term interests of consumers in its deliberations.

Prior to being considered by the RREC, the revised capex forecasts were subject to review and challenge by the IGC. The IGC, typically used to review and challenge projects prior to their funding and commencement, was tasked with the role of challenging and verifying that forecasts are fully substantiated before proceeding to the RREC. A General Manager with accountability for each expenditure category is also required to review and challenge the forecast capex before it is subject to review by the IGC.

The governance and decision-making framework for the capex forecasts is shown in the Figure 5.4 below. This is not an organisational chart. It is representative of the functions that have proposed investment in the 2019–24 regulatory period.

Figure 5.4

Governance framework for revised capex forecast



The enhanced risk management framework and the involvement of RREC and IGC has strengthened the review and challenge processes for preparing the revised capex forecasts. As noted above our network asset management system has also been certified to ISO55001 and provides an underlying assurance that our asset management processes and approach is prudent and efficient, in accordance with the NER requirements.

In summary, these initiatives have tested and improved our capex forecasts in this Revised Proposal and have played a valuable role in ensuring that our forecasts are prudent and efficient. As a result, our total revised capex forecasts satisfy the NER capex objectives and criteria and are in the long-term interests of customers.

5.2 Revised repex program

Our revised repex forecast is $1,402 million. As shown in Figure 5.5, this represents 52% of our total capex program. Repex is our largest capex category. Repex includes capital investment to replace assets at the end of their life. It also includes expenditure to renew assets in order to extend their life. The key drivers of our repex forecast are:

- Ensuring the safety of our customers, our staff and the general public
- Meeting our compliance and regulatory obligations
- Maintaining the current level of performance of the network
- Recognising that prudent deferral creates future options for more efficient development of the network as a result of technological changes.

Figure 5.5

Replacement capex as a proportion of total capex forecast in 2019–24

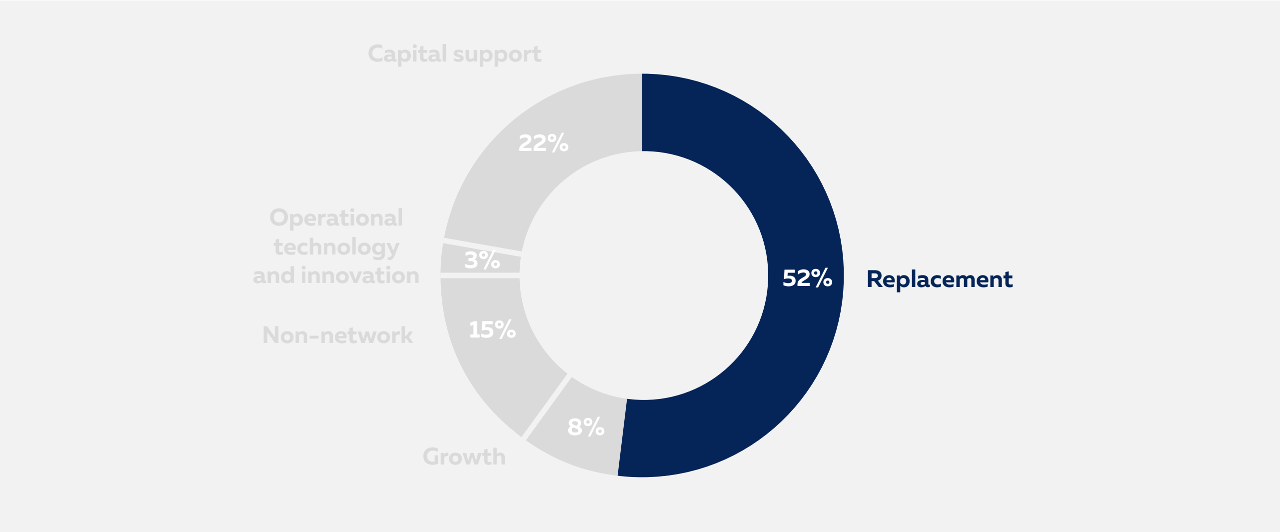


Table 5.4 compares our revised repex forecast with our Initial Proposal and the AER's Draft Decision. The 'modelled repex' relates to the replacement of assets for which the AER applied its repex model to form its position in its Draft Decision, while the 'unmodelled' component was the part of the proposed program unable to be reliably modelled using the AER's repex model.

Although more than the AER accepted in its Draft Decision, we consider our revised forecast arrives at a better balance of safety, reliability and sustainability, while still prioritising affordability.

Table 5.4

Our total repex forecasts compared to the AER's Draft Decision 2019–2014 ($million, real FY19)

	AUSGRID INITIAL PROPOSAL	AER DRAFT DECISION SUBSTITUTE	AUSGRID REVISED PROPOSAL
Modelled repex	930	664	804
Unmodelled repex	504	450	445
132kV cables	165	93	93
Strategic property	33	0	0
ADMS	41	0	60
Total	**1,673**	**1,207**	**1,402**

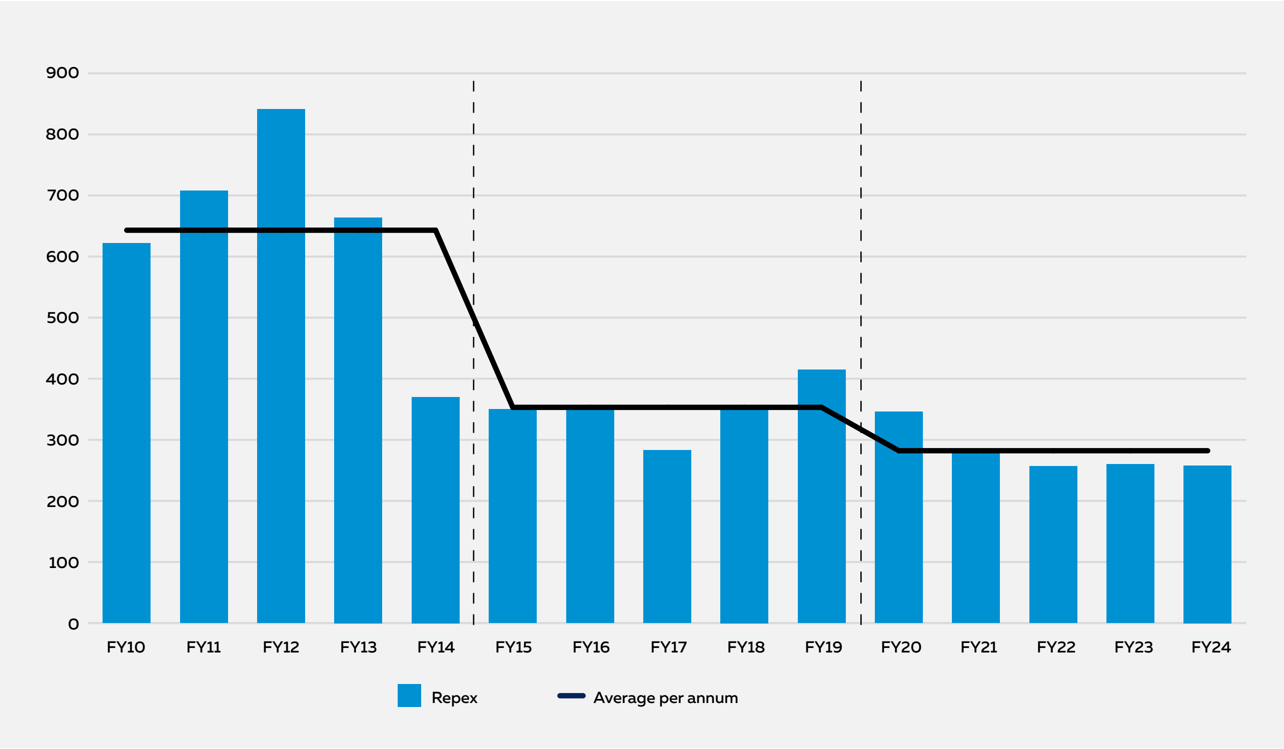
Source: Ausgrid analysis

5.2.1 Trend in repex

Our revised repex forecast is substantially lower than our historical expenditure. The total revised repex forecast for the 2019–24 regulatory period is $352 million (20%) lower than our expected expenditure of $1,754 million in the current period.

Figure 5.6

Repex forecast for 2019–24 compared to previous years ($million, real FY19)



Source: Ausgrid

We recognise that this kind of trend analysis is insufficient on its own to demonstrate that our revised forecast repex is prudent and efficient. However, it provides a useful cross-check that our detailed modelling and review process have produced a robust forecast that is capable of acceptance by the AER. In particular, it should be noted that the overall repex trend is downwards, despite our ageing asset base.

5.2.2 What we heard and how we've responded on our repex forecast

In Table 5.5, we have summarised the matters raised by customers and the AER about our repex forecast and how we have responded.

Table 5.5

What we heard and how we have responded

	WHAT WE HEARD	HOW WE'VE RESPONDED
1. Repex forecast	The AER sought further information and justification for our revised repex program. Similarly, our customers also expected more quantitative analysis to support our planned expenditure.	In response, we have developed more comprehensive cost-benefit analysis for our repex projects and programs. This further information forms part of this Revised Proposal.
2. Reliability levels	Customers said that the current levels of reliability are adequate and there should not be more investment to improve them.	There are no projects or programs specifically targeted to improve overall reliability.
3. Top-down assessment	The AER concluded that we had not applied a sufficient top-down assessment to the repex forecasting approach. The AER wanted to see more evidence that we had captured synergies between programs, projects and work areas in determining our expenditure requirements.	We undertake a top-down assessment of expenditure requirements in developing our Area Plans, which combine augmentation, connection and asset replacement work. As such, our Area Plans capture synergies by developing an integrated work program. In response to the Draft Decision, however, we have adopted a further 'top down' challenge through the application of the AER's repex model and our enhanced review and challenge process.
4. Cost-benefit analysis	The AER expressed concern that we had provided limited justification for key programs and projects. The AER therefore encouraged us to provide additional supporting justification in our Revised Proposal.	In response to the AER's comments, we have enhanced our approach to cost-benefit analysis. We also engaged external experts to provide assurance that our analysis is robust.
5. Repex model	The AER highlighted that in applying the repex model to conduct top-down assessment, we had not applied its refined repex modelling approach.	Our revised repex forecasts have been assessed against the AER's updated model. We will continue to work with the AER to improve the model.
6. Modelled repex	The AER applied the repex model in deriving an alternative forecast for 'modelled repex' categories. The AER substitute estimate for this repex component is $664 million. This is $266 million (29%) less than our forecast of $930 million. The AER relied on trend analysis, repex modelling, bottom-up assessment, and a technical and engineering review to form its position.	We have used the repex model to assess our repex programs. Several of our asset categories are not suited to repex modelling, for example, new and changed programs where there is insufficient benchmark information. Therefore, we propose that the AER should not rely on the results from the repex model for these asset categories. We have prepared cost-benefit analysis that supports the timing, volume and costs of repex programs for these categories.
7. Unmodelled repex	The AER extrapolated our actual spend in the first four years of the current period to a five-year period (on a pro-rata basis). The AER commented that we had not provided sufficient cost-benefit analysis to justify our initial forecast.	We have review our programs in light of the feedback from the AER with consideration of refined needs and historial performance. Our review led us to reprioritise our programs, including staging some programs over two future regulatory periods.

	WHAT WE HEARD	HOW WE'VE RESPONDED
8. 132kV cable replacement	AER supported capex of $93 million for our 132kV fluid filled cable program, compared to our forecast of $165 million. The reduced allowance reflected the AER's conclusion that we had not provided a specific compliance obligation that requires the removal of a number of underground cables.	Following discussions with our customers and the AER, we have agreed not to pursue funding for the remaining cable replacements. We will continue to monitor the performance of the remaining cables and if action becomes necessary draw funding from our approved capex allowance, based on priorities.
9. Powering Sydney's Future	Customers sought a better explanation for the interaction between the 132kV cable replacement program and Powering Sydney's Future program.	There are a number of sub transmission cables supplying the Inner Sydney area that are approaching the end of their serviceable lives. We assume that TransGrid will proceed with the Powering Sydney's Future program. Our proposed capex only includes costs for cables which are not addressed by TransGrid through Powering Sydney's Future program.

5.2.3 Modelled repex

We are proposing $804 million in modelled repex in the 2019–24 period in our Revised Proposal. This is 21% higher than the $664 million the AER accepted in its Draft Decision and 14% lower than the $930 million in our Initial Proposal.

The revised modelled repex forecast for our replacement programs is supported by enhanced cost-benefit analysis. We have reviewed our replacement capex projects and programs using a condition-based assessment of our assets and applying an improved risk based cost-benefit analysis approach to our high volume low value replacement programs.

Our revised forecast for modelled repex programs (excluding major projects with previous cost-benefit analysis provided), by AER Regulatory Information Notice (RIN) asset category, is set out in Table 5.6 below. It shows that for all categories our Revised Proposal is equal to or below the modelled outcome produced by our risk-based cost-benefit analysis. The difference ($131 million) represents expenditure that will not be incurred by Ausgrid and hence our customers will not have to fund.

Further information on the revised analysis for repex is presented in Attachments 5.01 and 5.13.

Table 5.6

Replacement program cost-benefit analysis models

MODEL	INITIAL PROPOSAL	MODEL OUTCOMES	REVISED PROPOSAL	
Poles	$156	$144	$138	↓
Low Voltage CONSAC/HDPE	$116	$104	$95	↓
High Voltage Overhead Lines	$47	$59	$51	↓
Low Voltage Overhead Service Lines	$55	$60	$49	↓
High Voltage Underground Cable Reactive	$34	$46	$43	↓
Low Voltage Dedicated Mains	$45	$72	$43	↓
Circuit Breakers (excludes switchboards)	$51	$43	$43	←→
High Voltage Fuse Switches	$50	$46	$36	↓
Distribution Substations	$32	$27	$24	↓
Low Voltage Underground Cable Reactive	$26	$25	$26	←→
Pole Top Substations	$20	$23	$22	←→
High Voltage Air Break Switches	$16	$19	$15	↓
Major Transformers	$13	$21	$17	↓
Sub-transmission Isolator and Earth Switches	$7	$10	$9	←→
High Voltage Underground to Overhead Connection	$8	$15	$6	↓
High Voltage Drop-out Fuses	$8	$26	$7	↓
Sub-transmission Towers	$5	$8	$8	←→
CBD Distribution Transformers	$18	$7	$4	↓
High Voltage CBD Isolator and Earth Switches	$16	$2	$2	←→
Sub-total	**$723**	**$756**	**$639**	↓
Not Modelled for Revised Proposal	$31	-	$23	↓
Modelled Total	**$754**	**$756**	**$662**	↓
Un-modelled	$382	-	$342	↓
Total	**$1,136**	**-**	**$1,004**	↓

The adoption of a revised forecast below what our cost-benefit analysis indicates we should be spending in the 2019-24 regulatory period reflects the top-down pressures we have applied to our Revised Proposal. We are also responding to customer expectations that we will not undertake work which has a positive net present value.

We also recognise that technological advancement is changing the way networks are operated and creating uncertainty about how to best meet customer needs into the future. Where there is uncertainty regarding future outcomes, investing in long lived assets now may preclude other options in the future. For this reason, we are comfortable with a revised repex forecast that is lower than what our cost-benefit analysis indicates we should be spending in the 2019–24 regulatory period. Spending less now provides us with greater flexibility and optionality to meet customer needs into the future.

Technological change, as well as providing us with a more flexible grid, will also provide us with much better information about the risks associated with our network. We expect that new technologies will allow us to better understand and manage those risks. This provides us with additional assurance that spending less repex now won't impact our ability to maintain the reliability, safety and security of the network. The need to undertake this deferred capex, however, will depend on the rate of technological change, and there is a risk that this deferred capex may need to be undertaken in the future.

Our engagement with stakeholders, especially our customers, has also influenced our investment approach. Customers have told us that while they place substantial value on safety and reliability of our network, they want us to prioritise affordability in the 2019–24 regulatory period. We consider the adjustments we have made to our modelled repex, leading to a forecast below the outcomes produced by our cost-benefit analysis, aligns to this priority.

Expanded quantitative analysis

To meet the requirements of the capex criteria and objectives in the Rules, and to provide our customers with the confidence that our Revised Proposal is prioritising affordability in the 2019–24 regulatory period, our forecast needs to be supported by robust quantitative analysis.

We provided further cost-benefit analysis for six high volume replacement programs with our Initial Proposal in addition to cost-benefit analysis of major projects. The AER considered this analysis but concluded that additional information was required to make its assessment. In its Draft Decision, the AER stated:

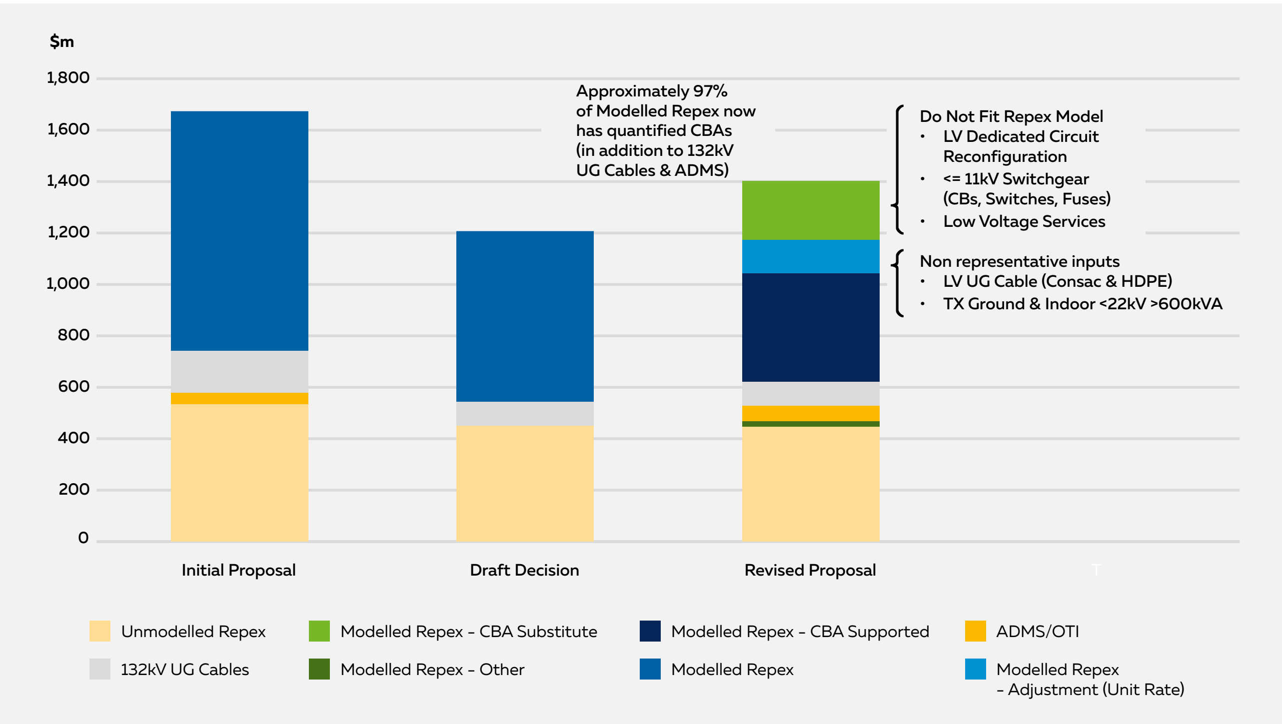
> *...while we acknowledge the need for some replacement programs during the 2019–24 regulatory period, the analysis provided in August 2018 for the six programs does not demonstrate that Ausgrid's proposed repex for each program is prudent and efficient. We encourage Ausgrid to provide additional supporting justification for its modelled repex forecast, including cost-benefit analysis, in its revised proposal.*[2]

Subsequently, we developed around 20 revised cost-benefit analysis models. Together with our internal review and challenge processes, these updated models have formed the basis of our forecast for modelled repex in our Revised Proposal.

The expansion of our cost-benefit analysis is set out in Figure 5.7 below. It shows that, through extending the use of quantitative risk-based modelling, cost-benefit analysis now covers over 97% of our modelled repex program for the 2019–24 regulatory period. In our view, this expansion in the coverage of our cost-benefit analysis should address the AER's request that we provide additional justification for our modelled repex forecast. The modelling approach we have applied–and why we consider it to be robust–is discussed in the next section.

Figure 5.7

Proportion of our repex forecast subject to cost-benefit analysis ($million, real FY19)



Source: Ausgrid analysis

2 AER, Draft Decision: Ausgrid distribution determination, November 2018, p. 5-72.

Cost-benefit analysis modelling approach

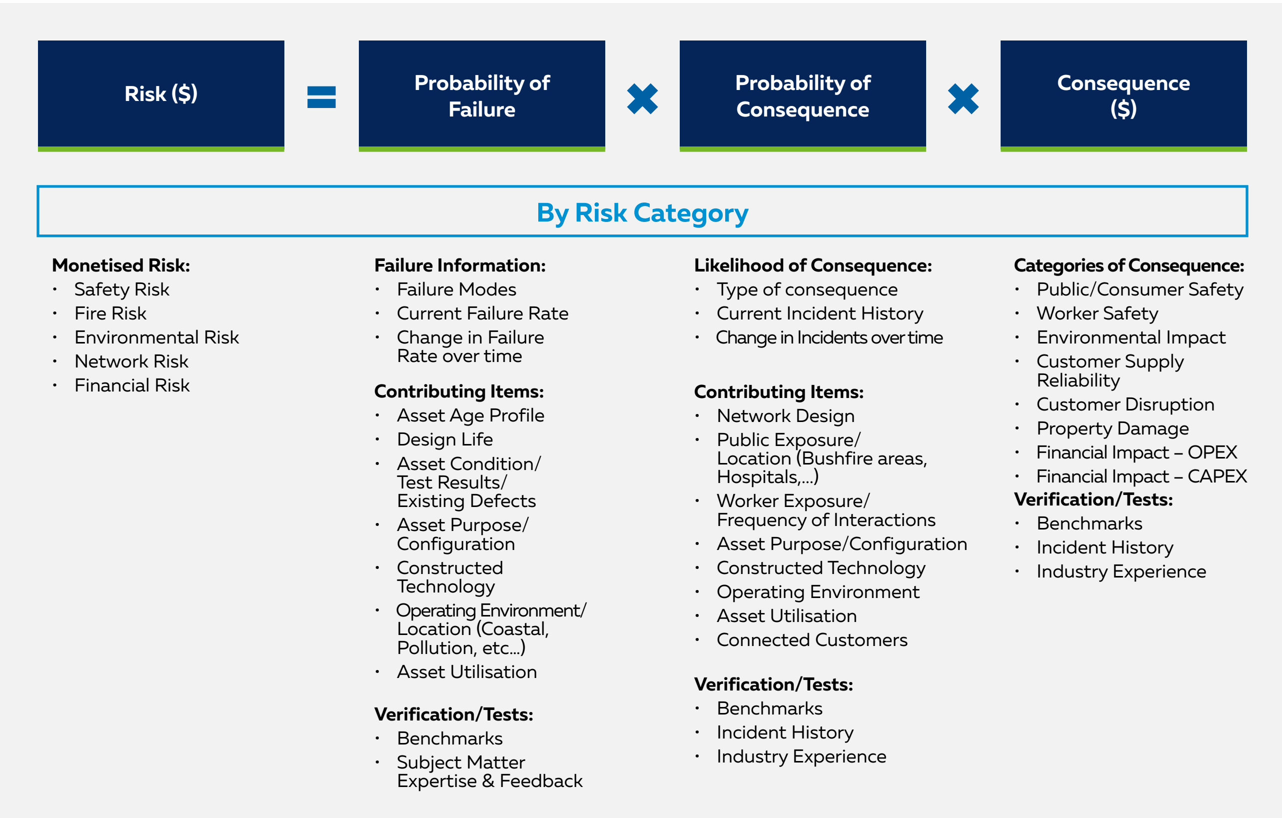
Determining when to replace network assets is a complex task. Replacing assets too early results in consumers bearing costs earlier than necessary. Waiting too long to replace assets results in increased asset failures. This can result in economic costs such as loss of supply, potential safety impacts and damage to property and the environment. Distributors such as Ausgrid therefore need well developed methods to inform when to replace assets such as poles, wires and substation equipment.

To inform our capex replacement program, we have developed a robust cost-benefit methodology for high volume replacement programs which uses a series of models to assess the appropriate timing of replacement investment decisions. The methodology (Attachment 5.13.M.0) supporting the replacement program is based on the principles of ISO31000: Risk Management and considers risk in terms of likelihood and consequence. The cost-benefit methodology sits within a broader framework for the justification of replacement expenditure (see Attachment 5.13.0).

The monetised value of risk is the key input in the cost-benefit methodology. The risk management inputs and factors that affect the quantified risk values is shown in Figure 5.8.

Figure 5.8

Cost-benefit modelling analysis inputs



Source: Ausgrid

While a single approach to the determination of risk is applied, there are variations in the modelling method based on the available information and the appropriateness of the approach for the asset class being reviewed. We have developed models for around 20 asset classes.

Once the risk of each asset class has been assessed, it is possible to undertake a cost-benefit assessment with sensitivity analysis undertaken for each key parameter. The cost-benefit modelling monetises asset risk in order to evaluate the risk against the cost and determine the appropriate timing/volume for replacement within each model. The modelling does this by calculating the annual benefit realised for every year an investment is deferred, based on the reduction in risk.

In order for an investment to proceed, the risk mitigated must exceed the proposed investment. That is, the benefit of the risk mitigated and any other benefits must exceed the annual deferral benefit. The risk mitigated is therefore determined by the change in risk between the asset being replaced and the risk of a newly installed asset.

Given the cost-benefit analysis has monetised risks and benefits for each asset within an asset class, all assets in a given year with a risk value greater than the annual deferral benefit are considered for replacement.

This cost-benefit analysis and investment evaluation process is outlined in Figure 5.9.

Figure 5.9

Cost-benefit evaluation method

Source: Ausgrid

We engaged experts to review and challenge our cost-benefit analysis. CutlerMerz supported the development of the models and provided independent validation of our modelling inputs. We engaged Frontier Economics to provide an independent review of the appropriateness of the methodology and recommendations for modelling improvements. We incorporated these improvements in the final methodology and modelling and have presented the results in our Revised Proposal.

Frontier Economics provided a report setting out its findings. It concluded that the methodology we have applied to assess the appropriate timing of replacement investment across asset categories conforms to sound principles of cost-benefit analysis.[3] In terms of affordability–which customers have told us they want Ausgrid to prioritise in the 2019–24 regulatory period, it is significant that Frontier Economics noted:

> *If anything, Ausgrid's methodology appears to understate the benefits of replacement by not adjusting the probabilities of consequence of various severity failures upon the replacement of an aging assets by a new asset.*[4]

We have provided Frontier Economics report at Attachment 5.13.M.21 as well as the summaries and models which contain our cost-benefit analysis at Attachments 5.13.M.1-19 and 5.13.M.1A-19A respectively.

5.2.4 Unmodelled repex

Consistent with the AER's Draft Decision, our Revised Proposal has considered repex in terms of modelled and un-modelled repex. Un-modelled replacement represents those items that have been excluded from the AER's repex modelling analysis.

We considered the feedback provided by the AER and stakeholders on our un-modelled replacement program forecast and have revised our forecast. Overall, our revised forecast for un-modelled replacement is lower than our original proposal of $504 million and lower than the AER's Draft Decision of $450 million. Key changes include:

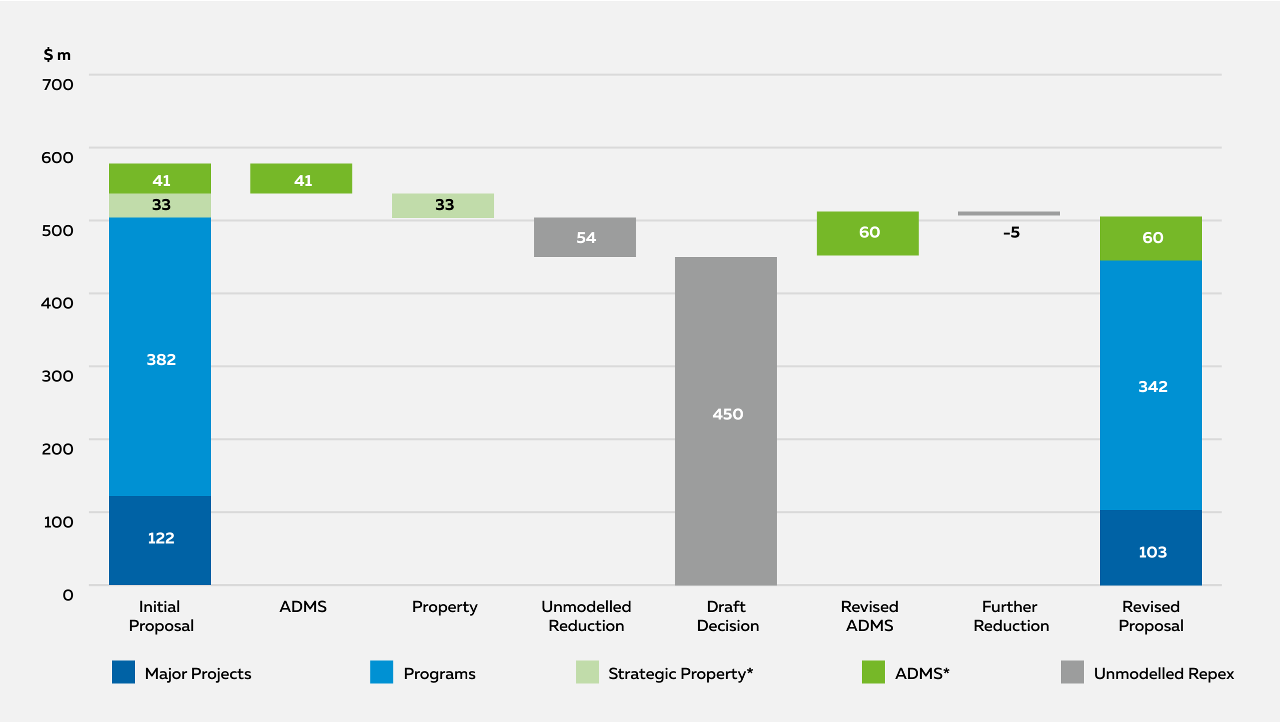
- A reduction in SCADA, Control and Protection of almost $13 million. This is primarily due to a revised forecast in modem upgrades to align to an updated timeline for the 3G roll-off.
- A reduction in Oil Containment upgrades by $20 million considering potential alternative solutions
- A reduction in Tower Refurbishments by $5 million through deferral into the next regulatory period
- A reduction in Distribution Substation Civil upgrades by $5 million considering the potential for further synergies to be identified with adjacent works
- The removal of two programs valued at $4 million for relay replacement
- A reduction of approximately $10m in major project costs due to refined project needs in the revised forecast.

The updated forecasts have greater consideration of historical expenditure in these programs.

3 Attachment 5.13.M.21 Frontier Economics (2018) Review of capex CBA methodology, December 2018, p5.
4 Attachment 5.13.M.21 Frontier Economics (2018) Review of capex CBA methodology, December 2018, p5.

Figure 5.10

Summary of unmodelled repex changes ($million, real FY19)



Source: Ausgrid
*AER transfers of strategic property and ADMS to Augex and Non-network categories respectively.

5.2.5 132kV cables

We proposed a 132kV fluid filled cable capex program of $165 million in our Initial Proposal. The basis of the program was to address the risk of fluid leakage from these cables into the environment. This was consistent with undertakings made to the NSW Environment Protection Authority (EPA), as well as to mitigate against expected unserved energy due to the increasing failure rates and long repair times for these cables.

The AER accepted 132kV cable project capex of $93 million for the 2019-2024 regulatory period where projects have positive cost-benefit analysis or were already committed. The AER did not support the remaining projects which did not have positive cost-benefit analysis for the proposed timing but which were included to make good on commitments to the NSW EPA to reduce fluid leakage over time.

Following discussions with the AER and customer advocates, we have agreed not to pursue funding for the remaining 132kV replacement projects in our Revised Proposal. In parallel with completion of the works approved by the AER, we will instead continue to monitor performance of the remaining cables, liaise with the EPA and if action becomes necessary, draw any required funding from across our approved capex allowance, based on priorities.

5.2.6 Advanced Distribution Management System

In our Initial Proposal we proposed to invest $41 million in an ADMS in the 2019–24 regulatory period. This expenditure is at the centre of a program to replace our aged control system and transform our network management environment to take advantage of technological change and better serve the needs of our customers.

The ADMS was proposed to replace the legacy distribution network management system. The ADMS will also permit the rationalisation and integration of several legacy ancillary systems which support operations, planning and design.

In its Draft Decision, the AER considered that, while there may be a need for the ADMS program, we had not provided sufficient information to justify the proposed replacement program. The AER did not include capex for the ADMS in its substitute estimate. Customers indicated that they supported the ADMS in principle and wanted to understand the benefits of the investment for customers.

In response to the AER's and customers' observations, we have further developed the cost-benefit analysis following vendor design workshop and updated vendor pricing. The analysis compares a number of options to address the need to replace the legacy distribution network management system. The options are compared against a base case of continuing with the current distribution network management system. The cost-benefit analysis, quantitative and qualitative assessment supports implementing the full ADMS options against the base case and all other options.

Following the submission of our Initial Proposal, further planning and design workshops were held with vendors and the Commonwealth Government, resulting in a change to the scope of the ADMS requirements. This changed scope included introducing a staged approach to de-risk the implementation and addressing the requirement to onshore all Ausgrid data during implementation.

The increased scope due to these requirements changed the project cost from $41.3 million to $59.9 million during the 2019-24 regulatory period. Further information about the ADMS program, including a summary of the costs and benefits, can be found in Attachments 5.13.N to 5.13.N.7.

5.2.7 Our revised repex forecast is prudent and efficient

In this Revised Proposal, we have addressed the matters raised in the AER's Draft Decision and the feedback from our customers and stakeholders. We have revisited our plans to determine whether there is scope to defer replacement capex or implement efficient non-network alternatives.

In preparing our revised repex forecasts we:

- Undertook further cost-benefit analysis to demonstrate that our proposed expenditure is justified from an economic perspective. To address affordability concerns, we have not included all of the expenditure that the cost-benefit analysis models indicate is economically justified.
- Reviewed our demand management projects to ensure that opportunities to substitute replacement projects with non-network solutions are fully reflected in our capex forecast.
- Revisited the application of the AER's repex model to provide a top-down review of our forecasts using the AER's latest modelling approach.

In reviewing and updating our original repex forecasts using the methods described above, we have responded to the specific matters raised by the AER and our customers. This detailed review, coupled with the improvements in our governance and decision-making processes provide strong assurance that our revised repex forecast is prudent and efficient, and reasonably reflects the capex objectives and criteria in the NER.

5.3 Revised growth capex

5.3.1 Our revised growth capex forecast

Growth capex includes augmentation and customer connection related projects and programs. Augmentation refers to works on our shared network needed to meet increases in demand for energy. Connection refers to work that provides reliable supply to customers who want access to the shared network. In our revised forecast we have applied the AER's Draft Decision to re-categorise some of our proposed network property acquisitions from replacement to growth.

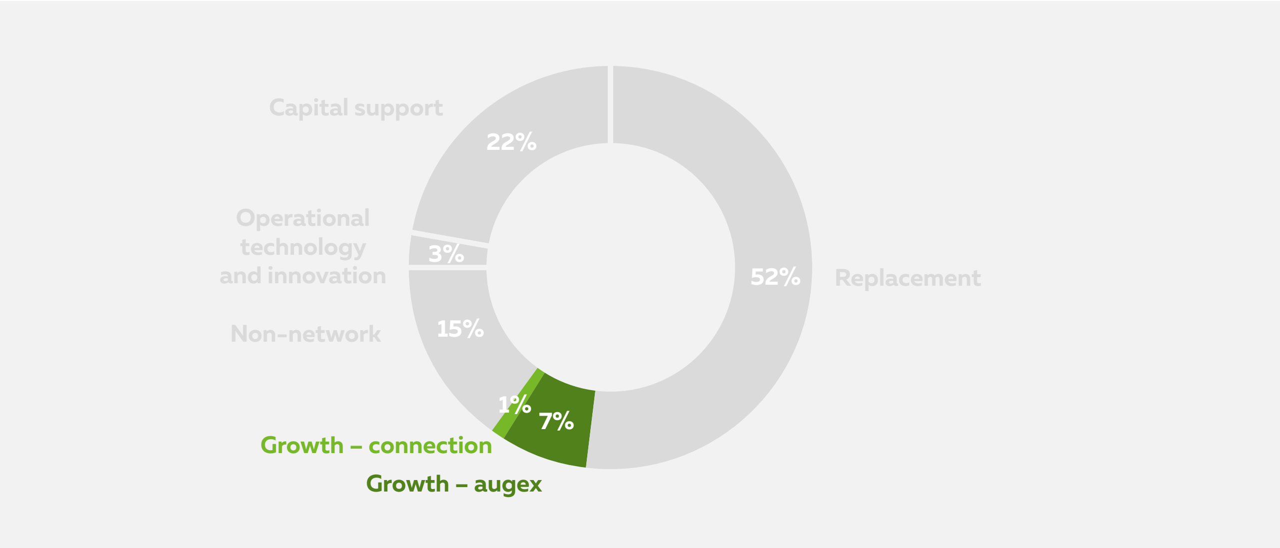
Our revised forecast for growth capex totals $215 million (or an average of $43 million per annum) ($real, FY19) in the 2019–24 regulatory period, comprising:

- revised total augex of $164 million over the regulatory period, which increases to $182 million when the network property acquisitions that were accepted in the AER's Draft Decision are included.
- revised total connections capex forecast of $33 million over the regulatory period. This forecast corrects for an error in our Initial Proposal, and updated forecasts of peak demand and the probability of projects that require connection to our shared network proceeding.

Our growth capex is $26 million or 11% lower than our Initial Proposal and $17 million or 9% above the AER's substitute forecast in its Draft Decision.

Figure 5.11

Growth capex as a proportion of total capex program in 2019–24



Source: Ausgrid analysis

While we are seeing moderate peak demand growth at a system level, demand on some parts of our network is growing quickly. We are experiencing unprecedented growth in road and rail transport infrastructure projects, residential high-rise developments and data centres. Most of the new asset investments will be in 'hotspots' on our network. The hotspots we are experiencing are mostly in the Sydney region.

The breakdown of the growth capex forecast into augmentation and connection is shown in the Table 5.7.

Table 5.7

Forecast growth capex for 2019–24 ($million, real FY19)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Augmentation	33	49	54	20	26	182
Connection	10	7	6	5	4	33
Total growth	**44**	**57**	**60**	**25**	**30**	**215**

The majority (85%) of the proposed growth capex program is for augmentation capex (augex). Connection forecasts are low in comparison to augmentation capex because under NSW contestability arrangements customers organise and fund the cost of direct connection to the network.

In response to customer feedback prior to our Initial Proposal, we undertook not to change our connections policy in terms of how customers are charged for connection. This means that new customers (such as property developers) will continue to fund the costs of assets required to connect their loads to the shared network. The value of this customer funded capex is not added to the regulatory asset base and therefore existing customers do not have to share the costs of these assets.

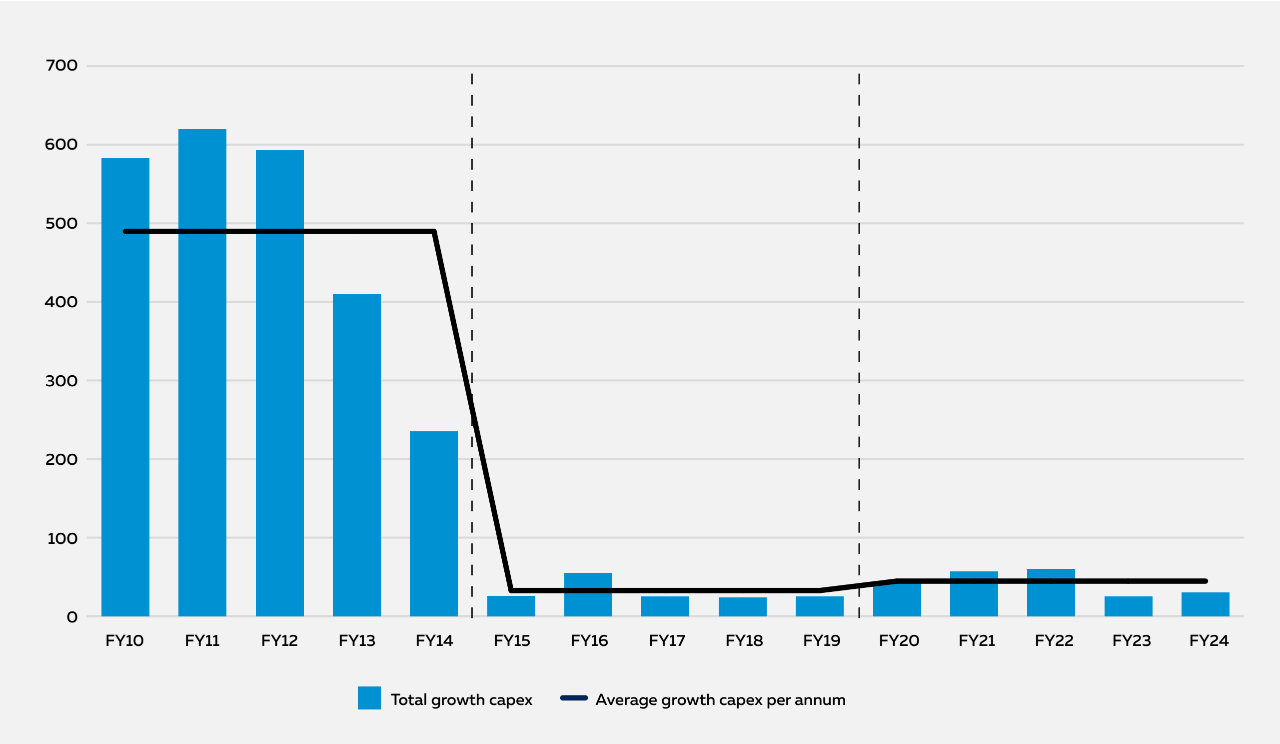
5.3.2 Trends in growth capex

Our revised growth capex forecast is relatively low compared to historical levels. It represents around 9% of the amount we invested in the 2009-14 regulatory period.

The substantial reduction in the forecast level of growth capex compared to the past is driven by moderate peak demand growth compared to the rapid increases during the 2009-14 regulatory period and the relaxation of NSW licence conditions relating to network reliability standards. We are now able to leverage the significant investments made in the past to deliver safe, secure and reliable electricity without imposing significant additional costs on customers.

Figure 5.12

Trends in actual and forecast growth capex ($million, real FY19)



Source: Ausgrid analysis

5.3.3 What we heard and how we've responded on growth capex forecast

The AER's Draft Decision did not accept our growth capex forecasts. We have summarised what we heard from customers and the AER, as well as how we've responded, in the following table. The main areas of concern raised related to peak demand forecasts and the level of information we provided to demonstrate the prudence and efficiency of specific projects.

Table 5.8

What we heard and how we responded

	WHAT WE HEARD	HOW WE'VE RESPONDED
1. **Growth (augmentation and connection) forecast**	The AER accepted our (amended) connection forecast but did not accept all of our augex forecast. For augex the AER stated that we needed better information to demonstrate the need for a number of proposed programs and projects. Customer advocates broadly accepted our original growth (connection and augex) capex forecast with the caveat that it was expected we pursue demand management, load shaping, and distributed energy resource opportunities to reduce costs.	We have reduced our growth capex in response to new information received through our business-as-usual annual network planning review process. We have re-examined whether there is scope for non-network solutions to reduce the need for network investment and further substantiated our proposal for demand management to defer high voltage reinforcement capex. We have also considered whether we can make better use of existing capacity instead of constructing new assets.
2. **Peak demand forecasts**	The AER concluded that our system peak demand forecasts were reasonable, noting that it will review any revisions we make to demand forecast in our Revised Proposal. Some customers considered that we had taken a conservative approach to the potential impact of energy efficiency, innovative demand management and customer responses to new forms of electricity pricing. As a result, they thought our forecast was overstated.	We have revised our peak demand forecasts for the latest economic information and new customer connections. We have sought external advice and updated our modelling to estimate the impact on demand of rooftop PV, battery storage and energy efficiency.
3. **Major projects**	The AER and customers sought further information in relation to key growth capex projects at Macquarie Park, Rozelle, Alexandria, White Bay and Pyrmont. The AER and customers sought further explanation of the scope, cost and configuration of several of the proposed major projects.	We have reviewed a number of our major projects as part of our annual planning review process. Revised information about probability of particular major projects proceeding, peak demand changes and scope of projects have resulted in revisions to our original augex and connection forecasts.
4. **Sufficient levels of growth capex**	The AER and customers supported growth capex to ensure businesses are able to secure new connections to the grid in a timely manner.	Our revised growth forecast is driven by our forecasts of future load growth from major transport infrastructure, residential property developments and data centres.
5. **Strategic property**	The AER accepted our strategic property purchases for White Bay, but did not accept our strategic property purchases for non-specific zone substation sites in Sydney and Hunter.	We have accepted the AER's Draft Decision. As a consequence, our growth capex forecasts include $17.8 million in strategic property (re-categorised from repex), consistent with the Draft Decision.
6. **Demand management**	The AER accepted some, but not all, of the demand management opex in our Initial Proposal. In particular, the AER did not accept our proposal for a $5 million opex step change for demand management to mitigate the need for augmentation of the 11kV network, which is estimated to otherwise cost $17 million. The AER sought further information on the net benefits of the demand management and network options in this case. Customer groups were strongly supportive of demand management initiatives.	In response to the AER's request for further analysis we improved the cost-benefit analysis underpinning our Revised Proposal for a step change in opex to defer $17 million of 11kV network augmentation. As explained in further detail below, the updated analysis better demonstrates how the benefits of the proposed demand management opex exceed those of augmentation capex. As indicated in this further analysis, our proposed demand management opex is prudent and efficient, and is in the long term interests of customers.

5.3.4 Our growth capex forecasts compared to AER Draft Decision

Our revised growth forecasts are presented in Table 5.7 below, alongside the AER's Draft Decision and our Initial Proposal. In response to the issues raised by customers and the AER, we have:

- reduced our augmentation capex forecast;
- updated peak demand forecasts for the latest input data;
- updated our modelling of distributed energy resources;
- reviewed the potential for demand management and conducted further analysis in relation to one of our demand management projects;
- updated our customer connection information.

Table 5.9

Our total growth capex forecasts compared to AER Draft Decision 2019–24 ($million, real FY19)

FY19 $MILLIONS	AUSGRID INITIAL PROPOSAL	AER DRAFT DECISION	AUSGRID REVISED PROPOSAL
Augmentation	189.1	168.6	182.3
Connection	52.2	29.2[5]	32.8
Total growth	**241.3**	**197.8**	**215.1**

5.3.5 Factors influencing our revised growth forecast

Demand forecasts

Peak demand is a key driver of growth capex requirements. We have updated our peak demand forecasts to take account of the most recent information available following the submission of our Initial Proposal. Updated information includes economic data and revised customer connection information.

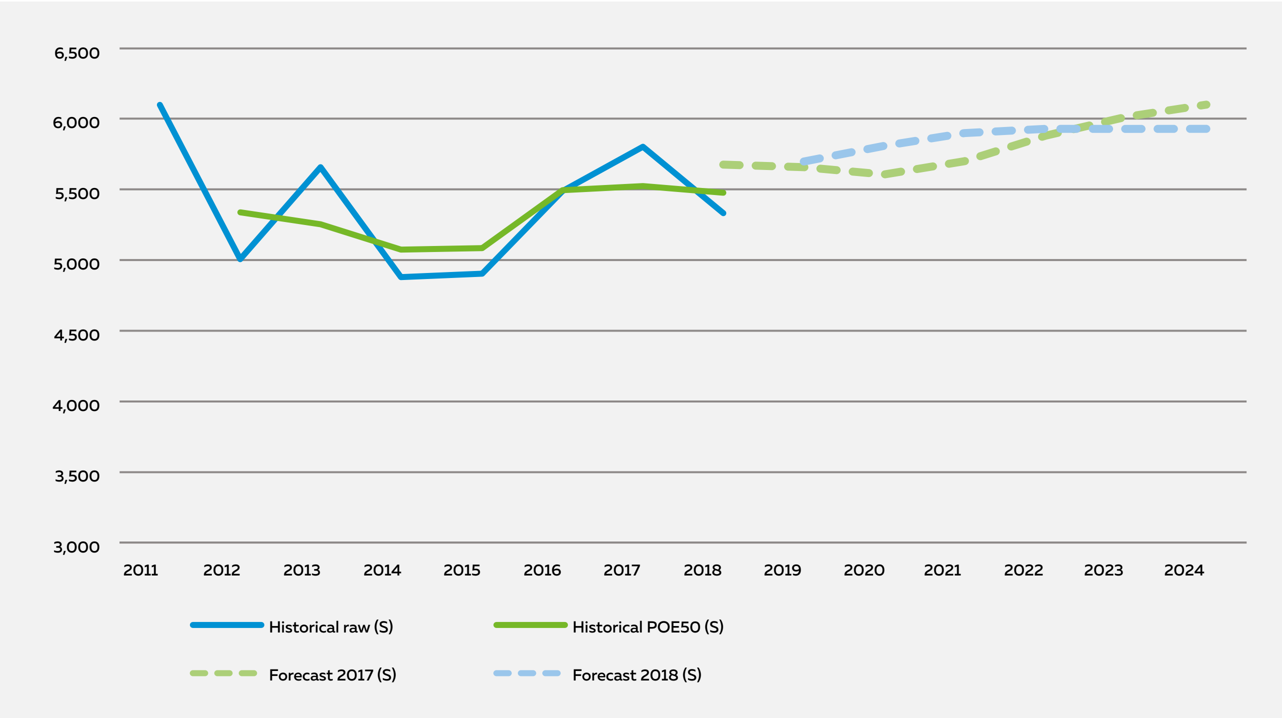
The latest capex forecast is based on our 2018 spatial demand forecast which projects system demand to increase by about 0.8% pa over the 2019–24 regulatory period. The 2018 revised forecast is lower than our Initial Proposal forecast of 1.5% per annum. The peak demand forecast used for 2019–24 capex planning was based on 2017 data which has been updated for the latest information.

The change in the peak demand forecast has deferred the need for a number of augmentation projects over the 2019–24 regulatory period. Our revised system total summer (S) peak demand forecasts is shown in Figure 5.13.

5 In our Initial Proposal we forecast connection capex to be $59.2 million. This figure included anomalies which were corrected in consultation with the AER after we submitted the Initial Proposal.

Figure 5.13

Forecast summer maximum demand for 2019–24 compared to historical changes (MW)



Source: Ausgrid analysis

At the spatial level, around 54% of zones in summer and 43% of zones in winter are expected to experience growth in maximum demand over the next seven years (based on compound annual growth). This is a reduction from the 2017 forecast where 62% of zones in summer and 60% of zones in winter are expected to experience growth over the next seven years.

Further information about the 2018 peak demand forecasts used in the Revised Proposal can be found in Attachment 5.01 and Attachment 5.07.

Distributed energy resources

As shown in the figure above, our revised demand forecast at the end of the next regulatory period is slightly lower than our original forecast. In preparing these updated forecasts, we revisited the projected impact of rooftop PV, battery storage and energy efficiency.

This lower growth trajectory is primarily due to the impact of energy efficiency, rooftop PV and battery storage countering higher underlying demand. We are also expecting lower economic growth in NSW, which tends to suppress energy demand in our network area. We also made refinements to block load and large customer requirements, and modelled the most recent economic data on economic growth, population growth and the impact of electricity prices.

Demand management

In this Revised Proposal, we have undertaken a detailed cost-benefit analysis to determine whether the initiative is justified. This updated analysis shows that the demand management opex of $4.1 million (a reduction from $5 million in our Initial Proposal) offers an efficient capex-opex trade-off to defer $17.9 million in capex. Our revised capex forecasts therefore incorporate the savings from this demand management initiative. Further information can be found in Attachment 6.05.1.

Connection capex

Our connection capex has been updated to reflect the latest available information regarding new customer connections. The most material change relates to changes in timing of large customer connections. For example, CBD and South East Light Rail project has been delayed several times, and each delay pushes non-contestable connection capex into the next regulatory period.

We have retained our proposed connection policy, which determines what capital costs are shared across all network users and what capital costs are borne through capital contributions by the initiator (eg. property developer) of a particular investment in the network. The costs of capital contributions are not rolled into the regulatory asset base and therefore not recovered from all customers through network charges.

5.3.6 Justifying the revised growth forecast

We have reduced our growth capex forecasts in response to the AER's Draft Decision and customer feedback. Further consideration and justification for key projects and programs that form part of our Revised Proposal are discussed below.

Table 5.10

Growth projects and programs

MAJOR PROJECT	INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Rozelle subtransmission substation	We initially proposed $17.4 million to construct a 33kV busbar and switch room at the Rozelle 132/33kV subtransmission substation, and to replace the existing 30MVA transformer with a 60MVA unit.	The AER considered that, based on information provided in the Feasibility Report, Ausgrid should only require two bus sections and six feeder panels to supply the existing and additional load. The AER included this configuration in its substitute estimate, which reflects a lower forecast than originally proposed by Ausgrid.	We accept the AER's findings. The revised augex requirement is $15 million which is $2.4 million lower than the initial forecast.
11kV network reinforcement	We proposed $80.7 million for the 11kV network reinforcement program without demand management and $63 million with demand management. As already noted, we proposed a $5 million opex step change for demand management to mitigate against a further $17 million of augmentation for the 11kV network.	The AER reviewed the modelling provided and considered the methodology to forecast augmentation needs on its 11kV network as reasonable. However, the AER questioned our application of a 10% diversity factor between feeder peaks and zone substation peaks. The AER commented that in the absence of any evidence to justify our proposed diversity factor, its substitute estimate for this program was $58.4 million.	Our project review confirms that the 11kV network reinforcement and the accompanying demand management initiative are justified. To address the AER's Draft Decision we have provide further information in Attachment 5.23 to explain the basis for the 10% diversity factor.

More information about the growth projects and programs can be found in Attachment 5.01.

5.3.7 Our revised growth capex is prudent and efficient

In this Revised Proposal, we have carefully considered the feedback from the AER and customers. As explained above, we have revisited our plans to determine whether there is scope to reduce growth capex by revisiting our demand forecasts, revising non-network solutions and making better use of existing capacity. We have used the most up-to-date information in our revision of growth projects and programs.

Our revised growth capex forecasts are based on:

- Best available information used for the peak demand forecasts
- Revised modelling for energy efficiency, solar PV and batteries
- Revised strategic property portfolio to reduce capex
- Enhanced evidence of the need, options, and timing for the augmentation of our network

- Maintaining the existing connection policy which means that the customer who causes the need for augmentation makes a reasonable contribution to the cost and helps to reduce the RAB per customer
- More accurate customer connection information.

We have demonstrated that our revised growth capex forecast is prudent and efficient and meets the capex objectives and criteria. The revised forecast complies with the NER requirements and will allow us to continue to deliver outcomes that are consistent with our customers' expectations and our compliance obligations.

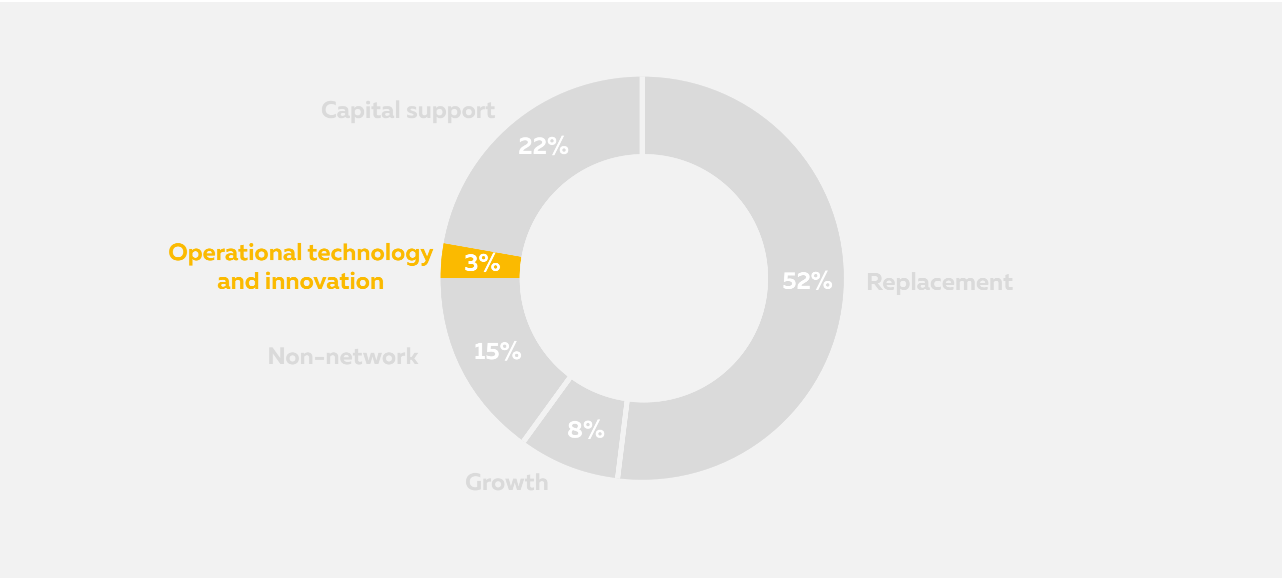
5.4 Operational technology and innovation

The OTI program includes our core system operational technology requirements as well as an innovation program covering a wide range of network technology implementations and pilots. The OTI program will enable us to upgrade core control system equipment and implement new technologies that will provide us with the capability to manage bi-directional energy flows on our network. The program will also enable us to comply with critical infrastructure licence conditions through expenditure on cyber security.

At about 3% of our total forecast capex, our OTI program is a relatively small component of our investment portfolio but will nonetheless deliver significant benefits to customers.

Figure 5.14

OTI program as a proportion of total capex program in 2019–24



Source: Ausgrid analysis

5.4.1 Revised forecast

Our Revised Proposal contains an OTI capex forecast of $77 million as shown in Table 5.11 below. The programs that make up our OTI forecast are as follows:

Network Innovation Program

As outlined in Chapter 3, we have a number of projects planned for the 2019–24 regulatory period that will assist in the transformation of our network. This innovation program will provide opportunities to improve our network monitoring capability and implement technologies that will allow us to incorporate greater numbers of distributed energy resources and electric vehicles on our network.

As explained further below, we also propose to establish a Network Innovation Advisory Committee (NIAC) to inform our innovation portfolio and provide advice on the projects that are undertaken.

Planning and Technology Data Usage

This program will drive improvements in our digital imaging and mapping capability, allowing us to seek further efficiencies in our capex programs. For example, we will expand our use of LiDAR (light detection and ranging) to create a digitised picture of the Ausgrid network. This will allow us to change the way we execute routine tasks such as maintenance inspections and surveying, providing further opportunity for efficiencies.

Core system refresh

This program allows us to fund critical upgrades and refresh of core control system servers, workstations, routers, switches and other equipment. This program was accepted by the AER in its Draft Decision.

Additional operational technology (cyber) security

Since lodging or Initial Proposal in April 2018, we have sought external review of our cyber investment and preparedness. That review has recommended that we expand our cyber security investment in the next regulatory period. While this program will continue to be refined in line with industry developments, Ausgrid will be required to increase its proposed cyber security in the 2019–24 regulatory period. This program represents an additional $20 million of OTI capex.

Table 5.11

OTI revised forecast ($million, real FY19)

	INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Network Innovation Program	43	0	42
Planning and Technology Data Usage	12	0	12
Core System Refresh	3	3	3
Additional operational technology (cyber) security	0	0	20
Total	**58**	**3**	**77**

5.4.2 Response to AER's Draft Decision and stakeholders

In its D raft Decision, the AER did not approve most of our OTI capex. The AER indicated that it would consider our revised cost-benefit analysis as part of its Final Decision. Our Network Innovation Program and Planning and Technology Data Usage programs cost-benefit analysis have since been independently reviewed and submitted as part of this Revised Proposal. The outcomes of these reviews are explained further below.

During recent stakeholder engagement, consumers have expressed support for a role in driving Ausgrid's network innovation program. To this end, we have proposed the establishment of the NIAC to help inform Ausgrid's innovation portfolio and provide advice on the projects trials that are undertaken. We want customers to be involved in helping shape the future of our network.

Quantified economic benefits from our innovation program

In its Draft Decision, the AER stated that it would review the cost-benefit analysis for our network innovation program as part of our Revised Proposal. We indicated to the AER that we would review and refine our network innovation program prior to submitting our Revised Proposal. Our updated project justification and cost-benefit analysis for this program can be found at Attachment 5.13.L and 5.13L.2 respectively.

We subsequently engaged GHD Advisory (GHD) to independently review our network innovation program and provide recommendations for refining our cost-benefit analysis. GHD's independent report can be found at Attachment 5.13L.1.

In its report, GHD scrutinised the project justifications, cost-benefit analysis costs, unit rates and assumptions for the 11 innovation projects that comprise our innovation program. GHD found that the assumptions we made are reasonable and that the 11 projects are forecast to deliver a 10-year net present value of $46.9 million over the next 10 years. Importantly, GHD noted that in some cases the scope of benefits could be expanded to include environmental benefits and other externalities.

Based on GHD's report, we have amended some of the assumptions used in our cost-benefit analysis. These amendments have not materially changed the expected net economic benefits for customers from our program.

Table 5.12

Expected cost-benefit ratio from network innovation projects

PROJECT NAME	EXPECTED COST-BENEFIT RATIO
HV Microgrid Trial	1.37
Network Insight Program	3.10
Fringe of Grid Optimisation	3.02
Advanced Voltage Regulation	1.75
Grid Battery Trials	1.52
Advanced EV Charging Platform Trial	1.33
Portable All-in-One Off-Grid Supply Units	1.12
Self Healing Networks	1.19
Dynamic Load Control	1.05
Asset Condition Monitoring	1.72
Line Fault Indicators	1.11

Our innovation program is not directed at research and development with the goal of developing new technology. Rather, this program will allow us to test the suitability of new technologies and new ways of doing things on our network. Broadly speaking, the innovation program is directed towards:

- Finding more efficient ways of doing things in the future, through initiatives such as microgrids and EV charging platforms
- Evolving our network to meet changing customer expectations through initiatives such as advanced voltage regulation and network insights program.

In its report, GHD acknowledges the constraints to network innovation and explains why innovation is now more important than it has been in the past:

"The long term interests of consumers includes accessibility to the grid and adaptability to their changing energy behaviours. In accordance, network service providers must change the way they manage the grid and regulators must also change the way that they govern that process."

GHD's report confirms that the overall innovation program has a net economic benefit for customers. The innovation program will allow us to pilot new technologies with a view to reducing our capex and opex spend into the future. We are of the view that this reflects prudent and efficient expenditure and promotes the long-term interests of our customers.

In our conversations with customer advocates, it was suggested that this network innovation funding should be overseen by a committee comprising of Ausgrid staff and consumer representatives. We agree with this suggestion, which is explored further below.

Customers driving the direction of our network innovation program

As explained in Chapter 3, stakeholders told us that they want a greater role in driving the direction of innovation in electricity networks. Given the rapid advances in technology, customers want to see how we are evolving our network to meet their changing needs. We agree that customer engagement is essential if our network is to evolve in the way customers want.

We support this engagement, and our Revised Proposal includes a draft Terms of Reference for the establishment of a NIAC to oversee our innovation program. The purpose of the NIAC is to place the customer at the centre of investment decisions as we transform our network. The NIAC will provide a forum for Ausgrid to collaborate with consumers on determining future investment relating to innovation and the transformation of our network. Importantly, as technology evolves it may become apparent that certain innovation projects are no longer appropriate and investment is better directed elsewhere. The NIAC will oversee and provide advice on this prioritisation.

We propose that the Network Innovation Program ($42 million) and Stage 3 (Advanced Applications) of the ADMS project be overseen by the NIAC. Importantly, if any of the capex overseen by the NIAC is not spent in the regulatory period, Ausgrid will not receive a benefit under the Capital Expenditure Sharing Scheme.

Quantified economic benefits from planning and technology data usage

In its Draft Decision, the AER did not approve our proposed capex associated with the planning and technology data usage program. In response to the AER's Draft Decision we have had our cost-benefit analysis for this program independently reviewed by GHD. Our business case, cost-benefit analysis and independent review can be found at Attachment 5.13L.3 to 5.13L.5.

GHD found that the assumptions we made in our cost-benefit analysis are reasonable and that the program will deliver net economic benefits to customers of $21.6 million over 15 years.

5.5 Non-network overview

Our non-network assets support the safe and reliable delivery of energy-network services. They include property (land and buildings), ICT and our motor vehicles, plant and minor assets.

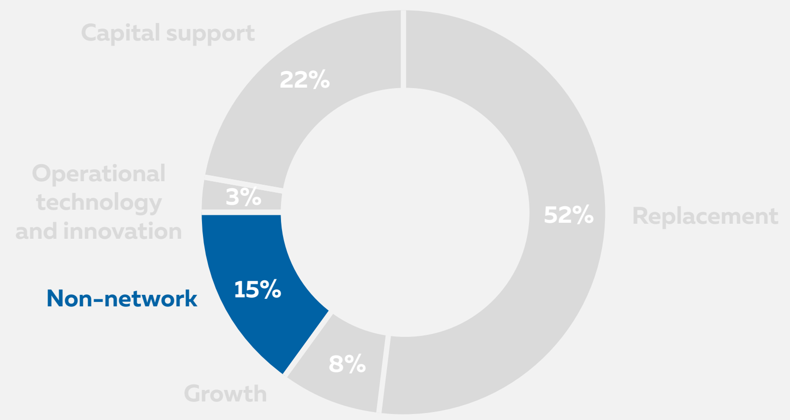
Non-network investment is needed in the 2019–24 regulatory period to sustain recent efficiency gains. As we continue our transformation program, Ausgrid must now adapt to an annual operating cost base $100 million lower than five years ago and a workforce nearly 3,000 full time equivalent (FTE) employees below our FY12 levels. Prudent non-network investment – equipping our business with the support assets needed to provide customers with safe and reliable network services, despite the significant reduction in our opex and personnel – will allow us to respond to this challenge.

Following an internal review and challenge, we have revised our total non-network capex forecast to $405 million. This is 14% lower than our Initial Proposal. Additional information, including greater transparency about the customer benefits of our planned capex program which was not available to the AER when it made its Draft Decision of $342 million, has also been provided with our Revised Proposal.

Our non-network program makes up 15% of our total proposed capex for the 2019–24 regulatory period.

Figure 5.15

Non-network capex as a proportion of total capex program in 2019–24



Source: Ausgrid analysis

Table 5.13

Proposed non-network capex for 2019–24 ($million, real FY19)

	INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Property	188 [6]	135	152
ICT	157	134	144
Motor Vehicles & Plant	99	73	87
Minor assets	25	0	23
Total	**469**	**342**	**405**

5.6 Non-network property

Ausgrid's non-network property assets include offices, depots and specialist sites located throughout Ausgrid's distribution area. Capex is required to mitigate the risk of safety hazards causing harm to our workforce and the general community. Each project is based on quantitative analysis identifying the least cost option (including deferral) and an independent appraisal of deliverability within the 2019–24 regulatory period.

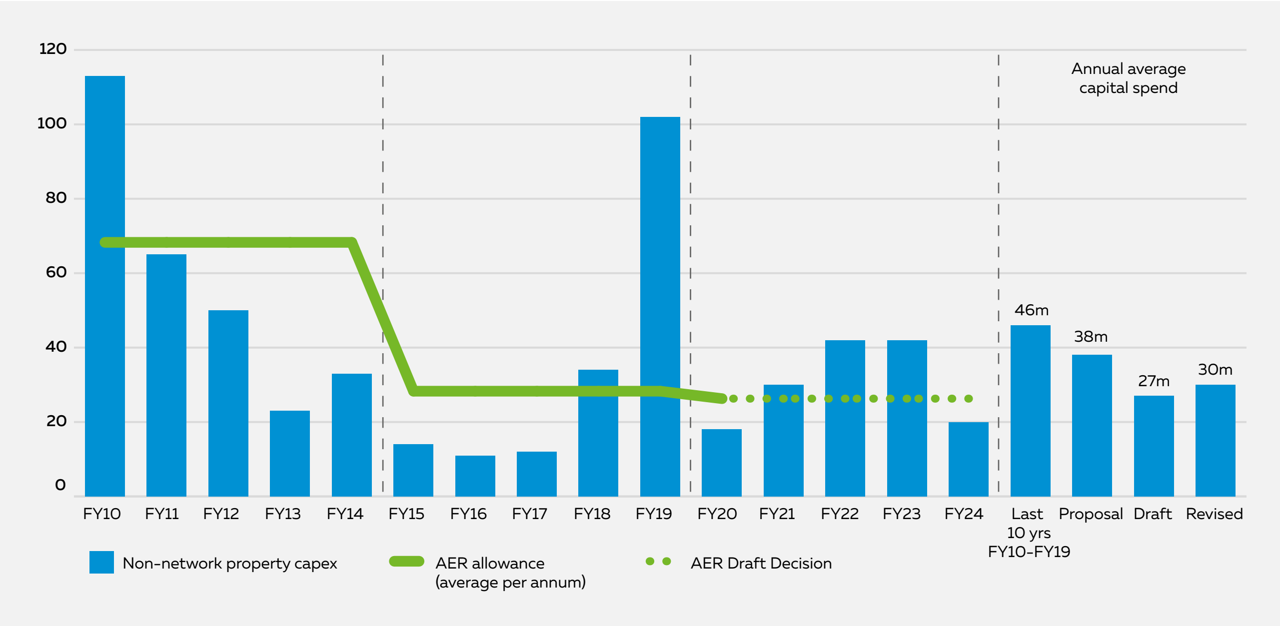
5.6.1 Revised forecast

We propose a revised non-network property capex in the 2019–24 regulatory period of $152 million.

The figure below sets out our forecast relative to our historical spend. It shows that, on average, our proposal is equal to $30 million (real, FY19) per annum. This is 35% lower than our historical capex for non-network property, which has averaged $46 million since FY10.

6 Note that our Initial Proposal presented our forecast as $208 million. This was in fact our non-network property capex forecast across all our lines of business (standard control services, alternative control services and unregulated services). The CAM allocated standard control services component should have been presented as $188 million in our Initial Proposal.

Figure 5.16



Historical and forecast non-network property capex ($million, real FY19)

Delivering a revenue reduction of $54 million

When viewed as a whole, our capex program for non-network property, inclusive of asset disposals, will lead to a $54 million revenue reduction. This is equal to a cumulative costs saving over the 2019–24 regulatory period, of $30 per customer.

A decision made by Ausgrid management in the 2014–19 regulatory period to consolidate our non-network property portfolio to a more efficient level is driving this cost saving for our customers. This led to the disposal of assets totalling $138 million, the proceeds from which must now be reflected in an adjustment to our opening FY20 RAB.

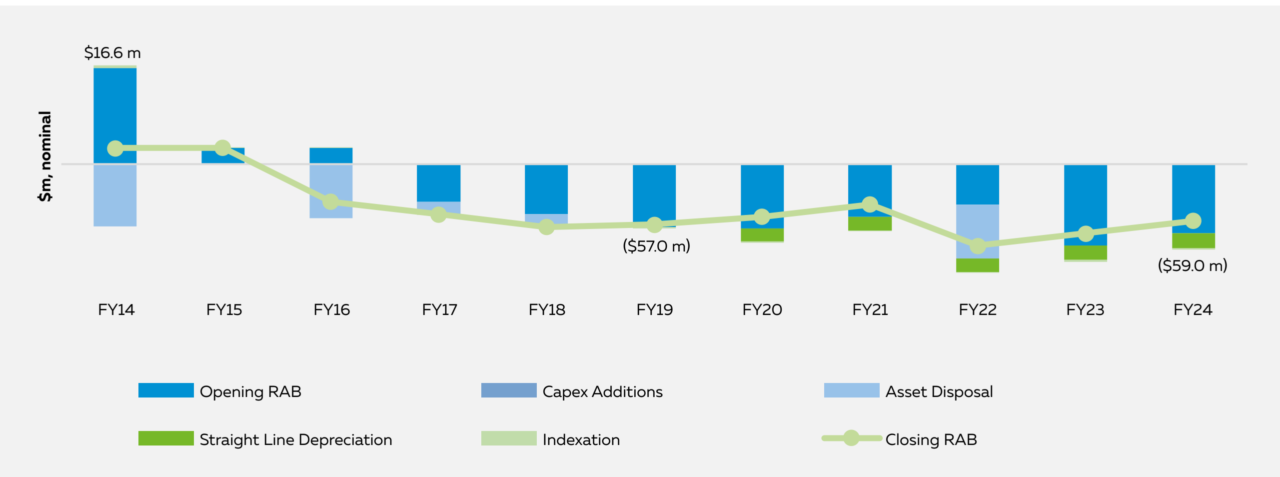
In our view, this demonstrates that Ausgrid has taken a customer centric approach to our non-network property investment decisions. It also underscores the prudence of our investment strategy.

Figure 5.17 tracks the RAB impact of our land disposals. It shows that this asset class is forecast to hold a value of negative $57 million ($nominal) as at 1 July 2019. Importantly, when an entire asset class becomes negative by the end of a regulatory period, the additional value from the sale of assets (in excess of their depreciated value in the RAB) must be returned, in full, to customers in the following regulatory period.

Table 5.14 shows that our disposals and planned capital additions has a negative impact on our revenue requirements, delivering a bill saving to our customers in each year.

Figure 5.17

Impact of disposals on RAB land asset class ($million, nominal)



Source: Ausgrid analysis

Table 5.14

Revenue impact of negative land asset class in our RAB ($real, FY19)

	2019–20	2020–21	2021–22	2022–23	2023–24	TOTAL
Revenue impact ($m)	(16)	(13)	(12)	(8)	(5)	(54)
Revenue impact ($customer)	(9)	(7)	(7)	(5)	(3)	(30)

5.6.2 Key property projects

Listed in Table 5.15 are the key projects that make up our forecast. Each of the sites relate to existing buildings of an advanced age, many of which are contaminated with dangerous materials. The asbestos referred to in the table below is recorded on the asbestos register. All hazardous materials (including asbestos) represent no immediate threat to Augrid staff or the public in its undisturbed state.

Table 5.15

Overview of key property projects

	OVERVIEW	PLAN
Homebush depot	65 years old. Asbestos contamination and a number of buildings have been condemned and closed. The site also contains key network infrastructure.	Demolish aged and dilapidated buildings and develop a depot that complies with our health and workplace safety regulatory obligations.
Oatley depot	56 years old. Contains hazardous materials. Residential growth limits alternative sites in South-West Sydney.	Demolish the existing facility and rebuild a modern, fit-for-purpose depot on the north-western side of the existing property, away from residential encroachment.
Hornsby depot	80 years old. Asbestos contamination and structural integrity risks identified within the building.	Demolish, remediate and dispose of Hornsby site. Develop a new depot at an existing Ausgrid Ku-ring-gai location.
Wallsend depot and admin building	Wallsend Depot is 55 years old and contains contamination. The administration building is 30 years old and construction and relocation will unlock an opportunity to dispose of land and return the benefit of the asset sale to our customers.	Proposal is to develop a fit-for-purpose depot and dispose of a corporate site. The future sale of the Wallsend site will cover the majority of the capital cost of redeveloping our administration building in another location.
General depot refurbishment and workplace improvement	Driven by a need to respond to ad hoc safety risks and deliver a modern working environment that sustains the recent operating efficiencies we unlocked during transformation.	Refurbishment works on depots not included in a major project will address immediate safety and regulatory obligations as well as improve ways of working.

5.6.3 Response to the AER's Draft Decision and customer views

We have considered the AER's Draft Decision and the findings made by EMCa when preparing our Revised Proposal for non-network property. Ausgrid also engaged independent experts to inform key aspects of our forecast. This included Colliers International Project Management, Jones Lang Lasalle and Napier & Blakeley.

Timing of projects

In its report to the AER, EMCa stated:

> *It seems more likely than not that Ausgrid will find opportunities and reasons to defer or perhaps stage some of what it has proposed during the next Regulatory Control Period. On balance, therefore, we would expect deferrals and reconsiderations at subsequent Gates of its Investment Governance Framework (IGC), to result in Ausgrid spending less than it has currently forecast.*[7]

We have considered this observation made by EMCa and the conclusions drawn by the AER in its Draft Decision. In response, we sought independent advice about whether the capex programs included in our Initial Proposal are

7 EMCa, Ausgrid Revenue Proposal 2019–24, Review of aspects of Ausgrid's forecast capital expenditure, August 2018, p. 108.

deliverable within the 2019–24 regulatory period. This advice is provided at Attachment 5.20.7 and described in greater detail below. No issues regarding deliverability were identified.

Ausgrid has, furthermore, subjected each non-network property program included in our Initial Proposal to a further internal review and challenge process. In the lead up to submitting our Revised Proposal, the IGC met twice to consider the five-year plan for remediating the identified health and safety issues at our non-network properties. The IGC is the peak investment body within Ausgrid. Under its charter, it is responsible for reviewing all major investment proposals put forward by management.

During this review and challenge process, management recommended that all five building replacement programs included in our Initial Proposal should be completed within the 2019–24 regulatory period. The IGC acknowledged that there were significant merits to taking this approach. This is particularly given:

- economic analysis supporting the completion of each program within the next five years
- the opex savings which are unlocked to the benefit of our customers when a dilapidated building passed its technical life is replaced with a modern equivalent
- independent advice supporting the deliverability of all five programs within the 2019–24 regulatory period.

Taking into consideration these benefits, the IGC nonetheless required management to review whether there was scope to modify the timing of any of the planned projects, without significantly increasing Ausgrid's risk profile. To assist in making this determination, the IGC requested that management circulate additional information on whether there is scope to defer any of the planned projects beyond the 2019–24 regulatory period.

In considering the range of factors presented before it, the IGC determined that management's original plan to complete all five non-network property programs within the next five years should be modified. This resulted in a decision to defer the Wallsend administration office building so that that only a single year of its construction will now fall within the upcoming 2019–24 regulatory period. It forecast that this will result in a deferral of $20 million in capex, with has been factored into our revised forecast of $152 million.

Our decision to defer the commencement of the Wallsend administration office project will delay the productivity benefits which we expect from the redevelopment. We have nonetheless reached the view that our re-scoped investment program over the next five years results in a more optimal timing of our capital investment program. This is because, by staging the Wallsend depot and administration office projects, we will be able to:

- further enhance our ability to deliver our planned investment program within the 2019-24 regulatory period
- provide our employees at both Wallsend sites with a relocation and temporary accommodation option while each project is underway, reducing workplace disruptions during construction

In addition to this, the deferral of $20 million in SCS capex will promote affordability over the 2019-24 regulatory period, which customers have told us is their main priority.

Options analysis

In its Draft Decision the AER observed:

> *Ausgrid's options analysis for each project scope was essentially "all or nothing". We would consider that between a full rebuild and "do nothing" options, there is a range of options to address individual risks identified in Ausgrid's analysis. These options could be potentially lesser in scope and cost relatively less.* [8]

Ausgrid agrees with the AER. The application of an "all or nothing" approach to our options analysis would skew our investment decisions in a way that is unlikely to be in the long-term interests of our customers. For that reason, we wish to clarify that our analysis did not take such an approach.

Undertaking a "do nothing" option is not open to Ausgrid. The condition of each building targeted for investment gives rise to serious risks and hazards that Ausgrid must, under the *Work Health & Safety Act 2011* (WHS Act), take steps to eliminate so far as is reasonably practicable. This regulatory obligation, together with our commitment to keep our workforce and the public safe from harm, drove our options analysis to consider two investment scenarios involving either:

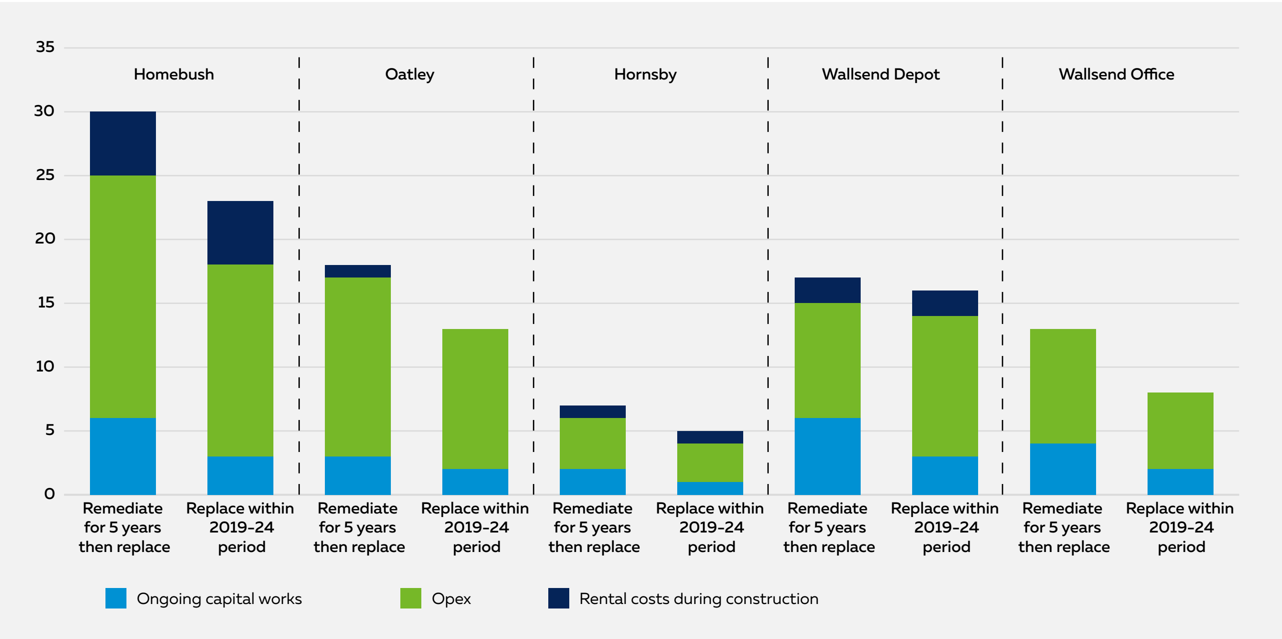
- **Remediate option:** continuing to operate a building while undertaking significant remedial works that allows us to comply with our regulatory obligations and keep our workers and the public safe in the short term until a major rebuild can occur. Any remediation will still need to consider a replacement in the medium to long term given the advanced age of the targeted buildings.
- **Replace option:** replacing a building with one that complies with workplace health and safety laws by either rebuilding the properties at the existing sites or moving to a new site.

8 AER, Draft Decision – Ausgrid Distribution Determination, November 2018, p. 5–10.

The costs and benefits of these two options have been carefully analysed, with advice from commercial property experts Jones Lang Lasalle in relation to the long-term cost under each option. The results of this analysis are set out in Figure 5.18 below. It shows that we have factored in "ongoing capital works" in both the "remediate" and "replace" investment scenarios. These costs are higher under the remediate option given the additional work required to maintain a building that has passed its technical life and entered a condition of significant age-based dilapidation. Any short term remediation still needs to factor a long term replacement given the advanced age of the current buildings on each proposed site.

Figure 5.18

Total 10-year capital and operating costs at each site ($million, real FY19)



Market sensitive information relating to the cost of rebuilding each site, while not presented above, has been factored into our net present cost (NPC) analysis. Including these capital costs, we found that the lowest NPC at each site was an option where the building under consideration is replaced in the 2019–24 regulatory period. This outcome is driven by lower ongoing capital works and, as discussed below, the significant productivity benefits which we can unlock by replacing a dilapidated, expensive to maintain building with a modern, cheaper to operate depot or administration office.

Our investment approach has also been informed by the expert views of a project management firm. As part of its review and challenge role, the IGC required Ausgrid management to engage an independent firm to review the merits and risks of a "new build" option compared to fully refurbishing existing buildings. This resulted in Colliers International Project Management providing us with a report advising that a new build strategy is more advantageous from a risk point of view. Among other things, it minimises the risk of contamination by hazardous materials, latent site conditions and aged infrastructure. A new build option also provides greater certainty in cost planning and the construction process compared a full refurbishment or ad hoc remediation approach. New build projects can also be delivered in an accelerated manner compared to full refurbishments.

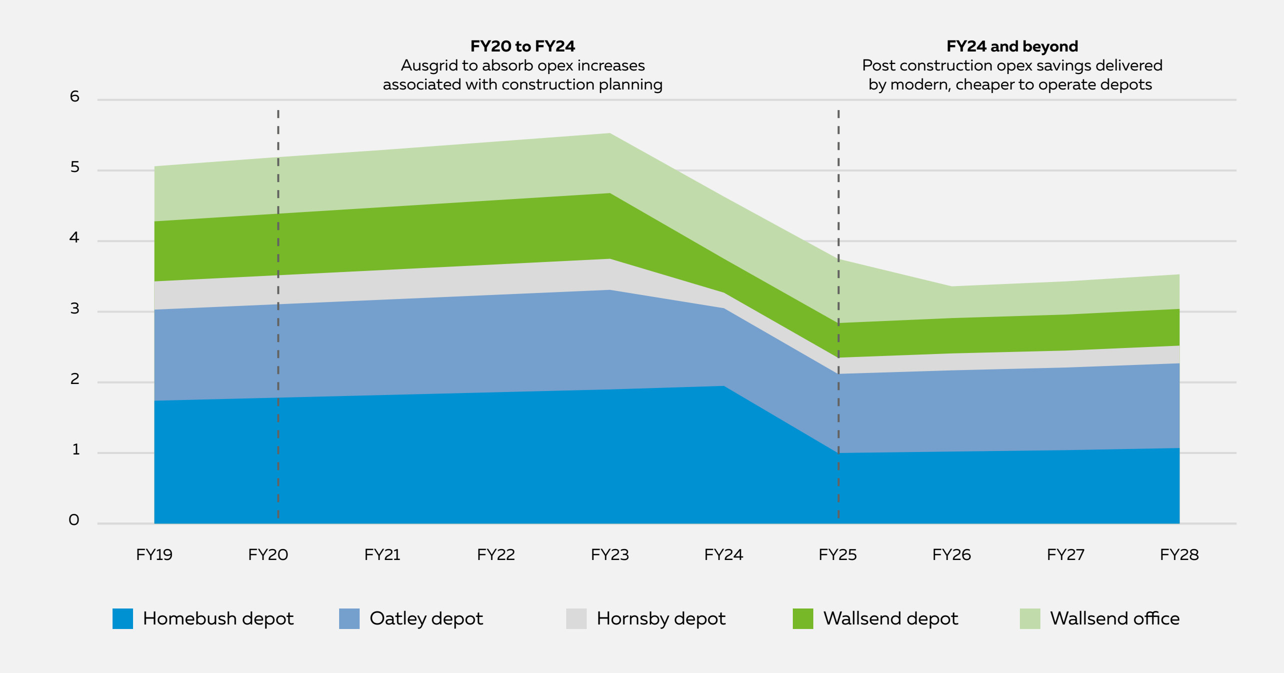
Customer benefits: Opex savings

Our capital investment analysis factors in the opex savings that are realised when an office or depot built in the 1950s to 1970s is upgraded to a modern fit-out. JLL advised that we should achieve, on average, a 50% reduction in the operating costs at each site once a building is replaced. We consider this to be a reasonable assumption based on the advice of JLL as a property investment expert.

The annual opex savings from each planned site replacement are set out in the figure below. It shows that, in gross terms, a $1.79 million opex saving will be unlocked by our planned capex program. These gross savings do not incorporate 'one-off' costs Ausgrid will incur in the lead-up to each replacement project, such as temporary accommodation during construction and the costs associated with relocating staff, which we are proposing to absorb in the 2019–24 regulatory period.

Figure 5.19

Building operating costs pre and post investment ($million, nominal)



Source: Ausgrid analysis

Including one-off planning costs, our property related opex is forecast to increase in the 2019–24 regulatory period. This, however, is a timing issue. When viewed over a longer, 10-year period, JLL concluded that each of the options selected as part of our planned capex program carries the lowest NPC. This is in part shown above with the significant step down in our property related opex from FY25 onwards.

Customer benefits: Disposals in the 2019–24 regulatory period factored into our forecast

Our planned investment program in the 2019–24 regulatory period incorporates further land sales in addition to those already made in the current regulatory period. These disposals are contingent on our replacement programs at our Hornsby depot and Wallsend administration building going ahead as planned.

Once alternative sites have been developed, the prudent disposal of land surplus to our needs will deliver substantial benefits to our customers. As shown in the table below, up to 65% of the Hornsby depot and 68% of the Wallsend administration building capex can in effect be self-funded through land sales. This will deliver benefits to our customers through the construction of modern, cheaper to operate buildings that address all the identified health and safety risks, at the lowest possible cost.

We anticipate the disposals of land at our Hornsby depot site and the Wallsend office site to occur after the 2019-24 regulatory period. Ultimately, this will lead to further customer bill savings. This is in addition to the $30 per customer saving that they will receive in the 2019–24 regulatory period following land sales in the current period.

Table 5.16

Planned disposals as a percentage of replacement cost

	DISPOSAL AS % OF REPLACEMENT COST
Hornsby depot	65%
Wallsend admin building	68%

Deliverability and investment strategy

In its Draft Decision the AER raised concerns about whether our proposed non-network building replacement programs at five sites could be delivered within the 2019–24 period. It observed:

> *We would consider that when all five major property projects were implemented in parallel, it would put unusually high strain on Ausgrid's internal delivery capability. We conclude… it (planned investment program) is unlikely to be achieved in practice.*[9]

Noting the AER's concerns, we engaged Colliers to undertake an independent assessment of our ability to deliver our planned capex program. This assessment was also requested by our IGC. Colliers' review did not identify a deliverability risk. The project management firm further advised that the program could be delivered in full through the employment of consistent delivery methodologies, phasing works over the 2019–24 regulatory period and segmenting development-application approvals. Further to this, Ausgrid will implement a "one program" delivery method when implementing our property capex program. This approach, based on best practice industry advice from Colliers, will enable planning delivery, design and procurement efficiencies across the program which is different to Ausgrid's previous practice of delivering each capital project as an individual project with different teams assigned to each.

5.7 Non-network ICT

Our ICT capabilities support the safe and reliable delivery of network services to our customers. In the 2019–24 regulatory period, we need to invest in maintaining these capabilities and also respond to a changing technological landscape, emerging risks and developing customer expectations.

We will achieve this through using our capex program to invest in the stability of our existing systems as we transition to a 'cloud' based offering. Post implementation, this will bring the benefit of a lower service costs. We will also invest in keeping pace with continually evolving—and increasingly sophisticated—cyber threats and, through the use of data and digital platforms. Our proposed expenditure will enable our business to adapt so that we can sustain the efficiency savings unlocked by our transformation program.

5.7.1 Revised forecast

We propose a revised non-network ICT capex of $144 million ($real, FY19). This is lower than the $157 million ICT proposal we initially put forward to the AER. The AER accepted $134 million[10] in its Draft Decision – a 15% reduction.

Our revised forecast, broken down by project, is outlined in the table below. It shows that most of our proposed capex relates to application maintenance – a business-as-usual investment that is needed to maintain stability of our ICT infrastructure until we are able to fully transition to the cloud.

Table 5.17

Ausgrid's non-network ICT proposal ($million, real FY19)

		INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Comply	Regulatory compliance & Licencing	4.9	4.9	4.9
	Technology Licencing Growth	1.3	1.3	1.3
Protect	ICT Security	19.8	19.8	19.8
Maintain	End of Life Application Upgrades	29.0	29.0	29.0
	Mandatory Patch & Release Management	13.3	13.3	13.3
	SAP Core Maintenance	38.1	38.1	38.1
	Infrastructure Capacity Maintenance	11.3	11.3	11.3
	Telecommunications Capacity & upgrades	11.4	11.4	11.4
	Workplace Technology	4.6	4.6	4.6
Adapt	Information Management	8.9	0.0	3.7
	Digital Transformation	14.4	0.0	4.4
Total		**157.0**	**133.8**	**144.4**

9 AER, Draft Decision – Ausgrid Distribution Determination, November 2018, p. 5-10.

10 In total, the AER accepted $137.2 million in ICT capex (inclusive of $3.4 million for "control system core refresh" which we have allocated to operational technology in our Revised Proposal).

Revised forecast is the lowest ICT capex in the NEM

Our customers, through their representatives, have told us that they have concerns about the level of ICT capex that has been accepted in recent years in regulatory decisions. The CCP10 made the following submission in response to our Initial Proposal:

> *It is an understatement to say that CCP10 are very uncomfortable with the level of IT spend being undertaken by not only Ausgrid, but also many other network businesses.*[11]

Ausgrid has taken into account the views of stakeholders by benchmarking our Revised Proposal against the ICT spend accepted by the AER in each businesses' most recent five year regulatory determination.

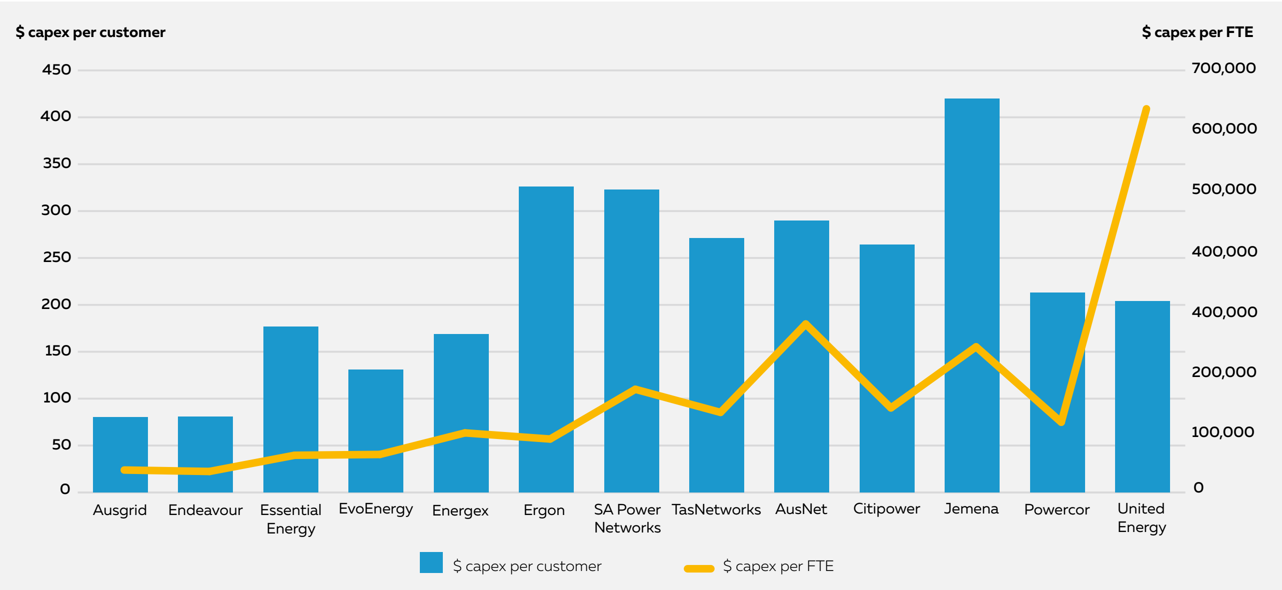
Figure 5.20 shows that our Revised Proposal is equal to the lowest ICT capex per customer in the NEM. In our view, this provides a strong indication that the level of expenditure we have put forward for the 2019–24 regulatory period is in line with the costs of a prudent and efficient business.

We shared the analysis below with our stakeholders in the lead up to submitting our Revised Proposal. It was acknowledged that on a capex per customer basis Ausgrid performs strongly. Additional analysis was also sought – specifically, benchmarking of our planned capex program on a capex per FTE basis.

This additional analysis is plotted in Figure 5.20 too. It shows that our revised ICT forecast benchmarks strongly on this metric. Our forecast of $144 million equates to $39,441 per FTE. This is at the frontier of efficiency among all business with the NEM, along with Endeavour Energy ($37,069 per FTE).

Figure 5.20

Benchmarking of Ausgrid's non-network ICT ($million, real FY19)



Source: Ausgrid analysis

Leveraging the cloud to deliver long-term savings

Over the 2019–24 regulatory period, Ausgrid will respond to a shift in the ICT technology landscape by transitioning our core ICT infrastructure to the "cloud".

11 Consumer Challenge Panel, CCP10 Response to AER Issues paper and revenue proposals for NEW Electricity Distribution Businesses 2019–24, August 2018, p. 69-70.

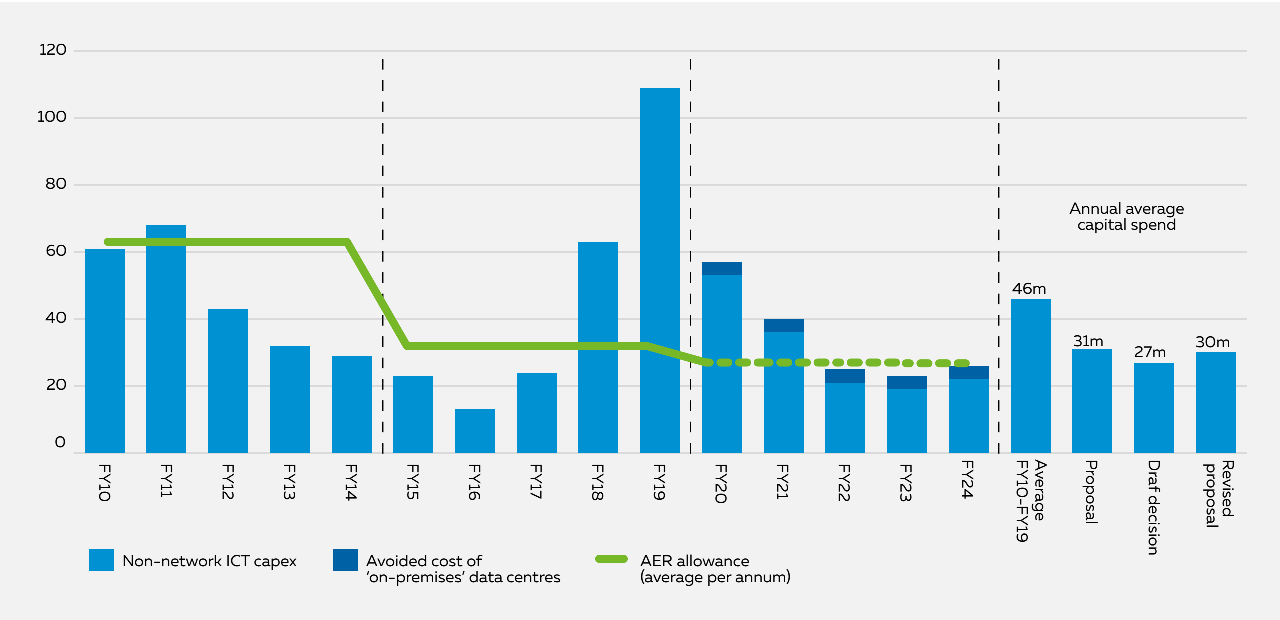
The "cloud" will enable Ausgrid to consume computer resources, such as data storage and ICT applications, as a utility – just like we would do with electricity – rather than having to build and maintain computing infrastructure in house.

We currently rely on on-premise data centres. The relatively short technical life of these assets requires them to be replaced regularly, and that makes ownership capital intensive. A primary benefit of "going to the cloud" will be that, post implementation, we will no longer have to own and replace these assets. In turn, this will deliver long-term capital savings.

The figure below sets out our forecast, relative to our historical spend. It shows that, on average, our forecast ICT capex program is equal to $30 million per annum. This is 35% lower than our actual capex in the last ten years, which has averaged $46 million since FY10. Also shown below is an estimate of our likely ICT capex if we did not migrate to the cloud, and instead sought to replace, like for like, our current on-premise data centres. In total, we estimate that not undertaking our planned transition to the cloud would require an additional $4 million ($real, FY19) per year in capex.

Figure 5.21

Ausgrid's non-network ICT capex ($million, real FY19)



Source: Ausgrid analysis

The capital savings we achieve in the 2019–24 regulatory period will be ongoing. Our planned migration away from on-premise data centres will enable us to leverage cloud based "Infrastructure as a Service" (IaaS) and "Platform as a Service" (PaaS) arrangements. This shift from capex to opex-based service offerings will achieve a total cost of service reduction, while also increasing the flexibility of our operations.

5.7.2 Response to the AER's Draft Decision and stakeholders

The AER's Draft Decision sought additional information about our Adapt program. Stakeholders also made submissions that their support for this program was contingent on robust cost-benefit analysis.

Adapt program

Our Adapt program, initially valued at $23.3 million, was not accepted at the draft-decision stage.

Since then, we have reduced our proposed expenditure to $8.1 million by reducing the scope of the program. In response to AER and stakeholder feedback, we have also revisited our business cases to support the two investment streams that make up our Adapt program (Information Management and Digital Transformation).

The AER's main reasons for not accepting the Adapt program was "insufficient economic analysis" and "lack of evidence of benefit incorporation into overall forecast".[12] Our updated business case analysis (Attachment 5.19) set out this information in more detail.

Information Management steam of Adapt program

The Information Management (IM) stream of our Adapt program is forecast to cost $3.7 million.

In the 2019–24 period, we will need to invest in the IM tools commonly used by large infrastructure businesses to manage complex capital investment programs. This follows a review finding that our current IM maturity levels are low. Two sub-programs are included in the IM stream, as outlined below.

- **Advanced analytics program** (total of $4.8 million)

  By the end of FY20, we will establish an advanced analytics platform. This will involve building the ICT capabilities to generate and analyse "big data" and to apply advanced algorithms to solve business problems. In particular, our platform will enable us to generate valuable insights more effectively from:
  - Volumes of data
  - Structured data (such as energy use, weather patterns, images of substations)
  - Unstructured data (such as complaints from customers)
  - velocity (i.e. real time data).

  We will seek technical support from a small team of data scientists, platform engineers, and visualisation experts, to help simplify the end-user experience and enable us to utilise, maintain and upgrade the platform, without the need for long-term support.

- **Data Quality and Information Management Realignment program** (total of $1.4 million)

  This investment will take place after the analytics deliver more systematic controls and practices to help develop the maturity of Ausgrid's foundational IM capabilities. Key areas of investment include:
  - Information Governance – Establish fit-for-purpose target operating model information to meet our information governance needs.
  - Enterprise Information Architecture – Establish a Utilities Industry Information Model to help improve visibility within the business around where information is generated, discovered, ingested, transferred and analysed.
  - Data Quality Management – Establish processes and guidelines for realignment of data from systems, to consolidate, simplify and develop a single source of the truth
  - Data Catalogue – Establish a catalogue of services and resources to help business users know what's available.

12 AER, Draft Decision – Ausgrid Distribution Determination, November 2018, p. 5-91.

Customer benefits

The benefits of our planned IM investment have been factored into other components of our capex program. We have embedded a 10% productivity improvement target in the labour component of our total capex forecast. To meet this target, we will have to leverage new technologies capable of unlocking greater productivity from our human resources, without putting safety or the quality of our service at risk. Improved IM tools will be an essential part of the technology mix we rely on to deliver capital projects smarter, faster and in line with this 10% productivity improvement target.

We have also undertaken economic analysis which has identified that our advanced analytics program will provide the technology required to sustain up to $10.4 million in FTE savings unlocked during our transformation program. These savings relate to manual data processing tasks which are increasing in scope in the 2019–24 regulatory period. In the absence of capital investment which extend our IM capabilities, we would be required to re-hire these FTEs to manage our increasing data management needs.

Digital transformation program

The Digital Transformation stream of our ICT Adapt program is forecast to cost $4.4 million.

We have recently transformed our business. This was predominately achieved through a reduction to our workforce of more than 2,200 FTEs since FY15, many of whom were in administration and back-office roles.

Critically, this transformation took place without putting in place the full suite of tools required to sustain these efficiencies. The Adapt program – and specifically the Digital Transformation stream – is targeted at filling this gap in our capability. It is made up of three programs: Process digitalisation, Single View of the Customer, and Wearables Technology.

- **Process digitalisation** (total of $2.1 million)

  The process digitalisation program will automate many of the manual process that our remaining workforce currently rely on. This will allow us to avoid re-emerging FTE cost pressures in our field services, asset management, finance and people and culture branches.

- **Single view of the customer** (total of $1.4 million)

  We will deliver a new Customer Relationship Management (CRM) tool in FY19. Our "single view of the customer" program will build on this new CRM tool by delivering additional functionality

  This program includes a Customer "chatbot" function on our digital channels, a customer complaint's module, and enhancements to our social media platform. It will also provide a bushfire module that will allow us to use software that allows us to automate information sharing with the NSW rural fire services.

- **Wearable technology strategy** (total of $0.9 million)

  Ausgrid recognises the significant safety and other benefits which can be realised through wearable technologies. These tools, such as live video headsets, have the potential to provide real time video feedback to our control room and can facilitate virtual reality training in a controlled, safe environment for apprentice technicians.

  We have significantly reduced our initial planed investment in wearables technologies from $4.7 million to $0.9 million. We consider our revised forecast to be sufficient to run a pilot of this emerging technology which has the potential to unlock significant efficiencies, to the long-term benefit of our customers.

Customer benefits

We have calculated the net economic benefits of the Digital Transformation program at $6 million per annum. These savings will be delivered by offsetting emerging costs pressures, which although we have yet to incur, Ausgrid is forecasting to arise within the 2019–24 regulatory period if we do not invest in digital technologies.

Principally, these benefits will be achieved through avoided FTE costs. Our business is becoming more data driven and to handle this inflow of information our staff are increasingly relying on manual processes. This presents us with an option in the 2019–24 regulatory period to either hire additional FTEs or to make a one-off capital investment which digitalises and streamline these processes at lower net present cost.

5.8 Motor vehicles and plant

Our fleet of vehicles and trucks supports our operations in the field by providing a safe and reliable mode of transportation. "Plant" assets refers to the equipment we use in the field—such as elevated work platforms, vehicle loading cranes, and pole-hole borers/erectors.

5.8.1 Revised forecast

We are putting forward a revised fleet, plant and minor assets forecast of $87 million. This is around $12 million lower than our Initial Proposal of $99 million. Our revised forecast, by asset class, is set out in Table 5.18.

Table 5.18

Fleet and plant forecast ($million, real FY19)

		INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Motor Vehicles	Car	7.3	5.4	7.5
	Light commercial	23.0	17.0	11.2
	Elevated work platform	44.9	33.2	22.6
	Crane borer plant HCV	5.9	4.3	19.2
	Heavy commercial vehicles	13.0	9.6	12.3
	Subtotal	94.0	69.6	72.8
Plant	Subtotal	4.6	3.4	13.8
Total		**99**	**73**	**87**

5.8.2 Responding to the risks brought on by recent underinvestment

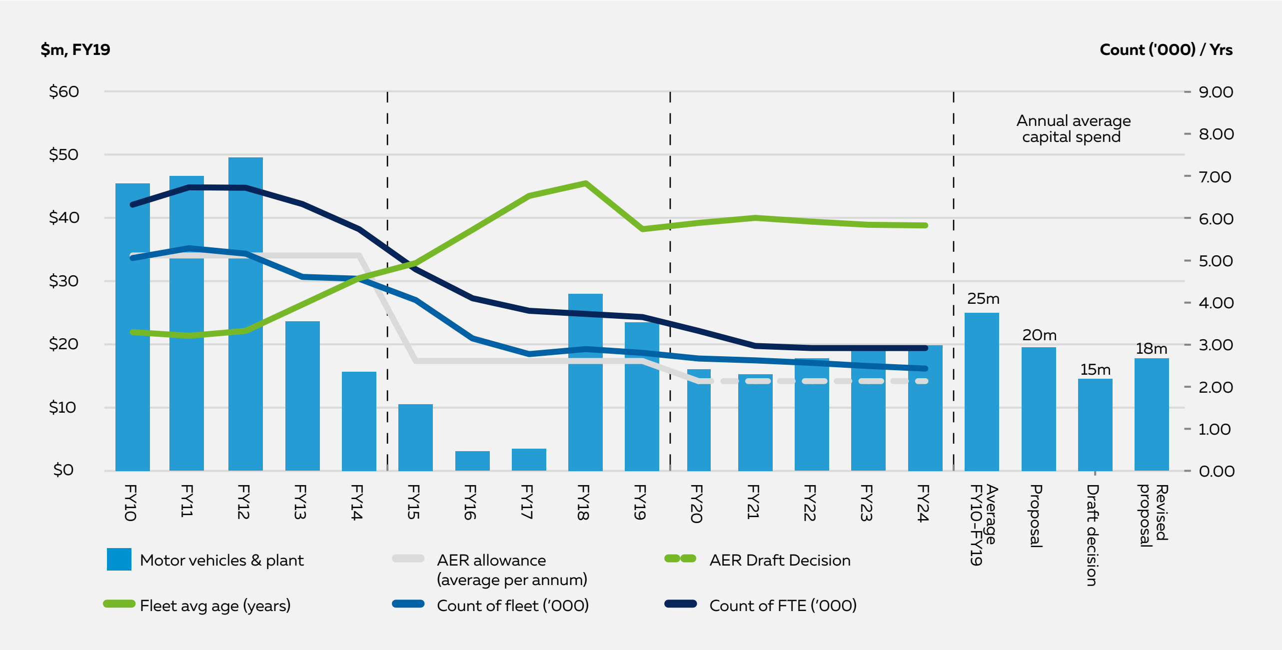
Our fleet capex forecast has been developed in the context of historical underinvestment in recent years.

In the 2014–19 regulatory period, we undertook a motor-vehicles rationalisation process. This formed part of a broader transformation strategy targeted at improving business efficiencies and was also influenced by uncertainty surrounding our 2014–19 revenue allowance and a long-term lease-transaction process.

Figure 5.22 sets out our actual capex on motor vehicles and plant in the current period, compared with our forecast in the upcoming 2019–24 regulatory period. It shows that our Initial Proposal included a forecast that would have restored our level of investment to the historical average. Since then, however, we have undertaken additional analysis that revealed a lower forecast would be sufficient to meet investment requirements. This additional analysis is set out in a revised financial model, the inputs of which have incorporated the views of our IGC during our internal review-and-challenge processes, as well as the AER's Draft Decision and stakeholder comments about prudent and efficient investment practices. The revised financial model is set out in full in Attachment 5.24.2.

Figure 5.22

Historical and forecast motor vehicle capex



Source: Ausgrid analysis

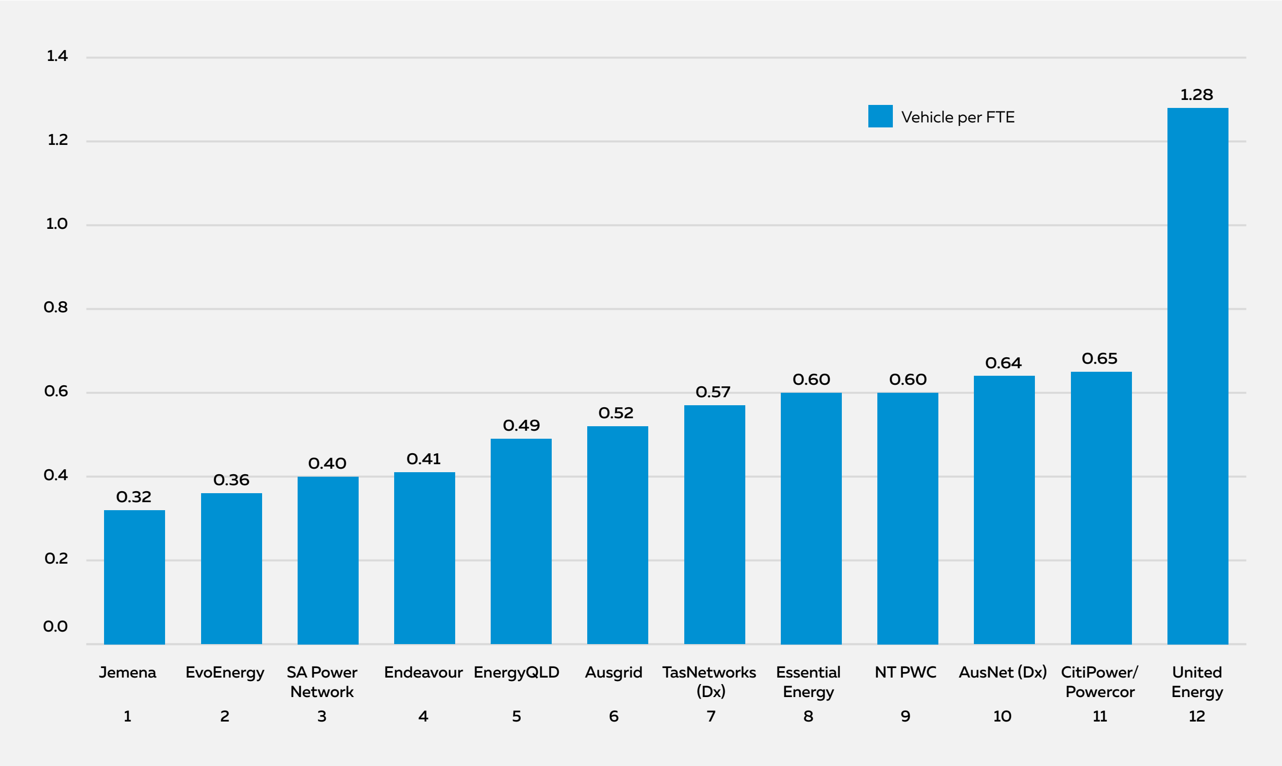
Benchmarking anlysis

We can obtain an indication of the benefits we are delivering our customers in terms of efficiency by measuring our performance against our peers in the NEM.

Ausgrid's fleet of motor vehicles per FTE compared against other businesses in the NEM is set out in Figure 5.23. Vehicle per FTE was used to provide an indication of efficiency as it provides a guide with respect to the utilisation, and therefore productivity, of these assets. In the lead up to the submission of our revised proposal, the AER and stakeholders also indicated that motor vehicle per FTE was their preferred measure for benchmarking an electricity distributor's relative efficiency.

Figure 5.23

Motor Vehicles Per FTE Employee



It is shown above that Ausgrid performs well against our peers in the NEM. We have a vehicle per FTE ratio of 0.51 which is roughly in line with Energy Queensland (0.49). Our vehicle to FTE ratio is based on Ausgrid's expected employee count of 3,651 FTEs as of 1 July 2019 and our forecast motor vehicle count of 1,907 as of the same date.[13]

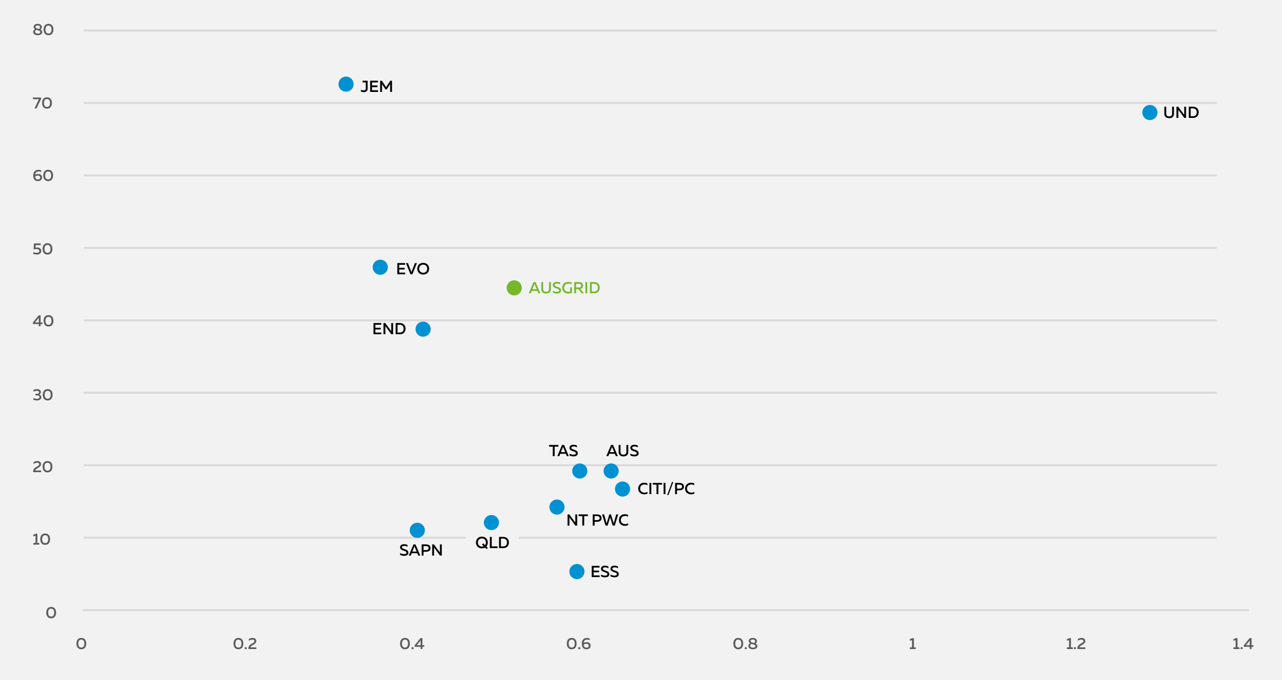
While our analysis reveals that some businesses have a lower vehicle per FTE counts than Ausgrid, a significant driver of this appears to be factors outside of management control. For example, Jemena (0.32) and EvoENergy (0.36) both have lower vehicle to FTE ratios, yet they have relatively small networks. Jemena has 6,345 km of line length while EvoEnergy's has 5,333 km. Ausgrid, by comparison, has 41,642 km of line length – equivalent to 12 EvoEnergy networks. In practice, this means that our field crews have considerably more network to maintain and drive to, and from, when there is a fault. To do this safely and reliably, requires additional motor vehicles.

For completeness, we considered our performance on a vehicle per FTE basis in conjunction with the respective customer densities of each distributor in the NEM. Figure 5.24 plots this relationship. It shows two businesses with a higher network density than Ausgrid have a lower vehicle per FTE count (Jemena and EvoEnergy). In general, however, there does not appear to be a strong relationship between these metrics.

13 Data on the fleet count and FTEs of each other business in the NEM is based on their last published Regulatory Information Notice (RIN) response. Note we have combined CitiPower and Powercor for benchmarking purposes given their shared corporate structure. This is consistent with past AER decisions. See for example, 'AMI transition charges applications'.

Figure 5.24

Motor Vehicles Per FTE Plotted Against Customer Density



We have undertaken the above benchmarking analysis to see if we are delivering for our customers in terms of efficiency. Ausgrid cautions against using partial performance indicators, and benchmarking in general, to deterministically adjudicate on the efficiency of an investment program.

Nonetheless, we consider our performance against other businesses, particularly when adjusting for exogenous factors such as the size of our network and customer numbers demonstrates no inefficiency. This reveals, in our view, that the transformation program we have undertaken in recent years has delivered customer benefits, in terms of the efficiency of our existing motor vehicle fleet.

Sustainably managing the age of our fleet

Age is a key driver for motor vehicle and plant investment. Over time these assets decline in condition, become more prone to breakdown, present safety risks and are costlier to operate and maintain.

In the 2019–24 regulatory period, we plan to manage the age of our motor vehicle and plant assets within a 'sustainability benchmark'. We calculated this benchmark as the midpoint in the technical life of an asset. SG Fleet – an asset management firm specialising in motor vehicles and plant equipment – advised us on this approach and provided us with the data to make the calculation.

We selected the midpoint in an asset's technical life as our target benchmark. This is because when the average age of an asset class reflects the mid-point of its technical life, it provides an indication that we are sustainably managing the age, and therefore the condition of these assets. In contrast, when an asset class has an average age that is:

- below the midpoint of their technical life – there is likely to be a high volume of assets of a **young** age indicating that too many assets may been recently replaced
- above the midpoint of their technical life – there is likely to be a high volume of assets of an **old** age indicating that too few assets may been recently replaced

The table below tests our Revised Proposal against this sustainability benchmark. It shows that for each asset class the average age will be in line with, or above, our benchmark. This indicates to Ausgrid that our planned motor vehicle and plant investment aligns with a sustainable management of the condition, safety and efficiency of these assets. Ultimately, we consider this to be in the long-term interests of our customers.

Table 5.19

Historical and forecast motor vehicle capex

	AVERAGE AGE OVER PERIOD	BENCHMARK SUSTAINABLE AVERAGE AGE	DIFFERENCE
Passenger vehicles	2.3	2.5	-0.25
EWPs	9.0	7.5	+1.49
Heavy commercial vehicles	8.0	7.5	+0.47
Light commercial vehicles	4.1	3.5	+0.60
Plant equipment	7.8	7.5	+0.32

We have also considered how the average age of each asset class will change over the 2019–24 regulatory period.

Figure 5.25 sets out this information for each motor vehicle category and our plant equipment. It also shows the spread of ages within an asset category; for example, in FY19 the youngest EWP asset is four years old and the oldest is 15 years. This is an important consideration because the spread in the age of an asset class can influence its performance relative to our sustainability benchmark.

This analysis shows that for certain asset classes (heavy commercial vehicles and plant equipment) we have an average age that is above our sustainable benchmark set at the midpoint of their technical life. By the end of our investment program, in FY24, our Revised Proposal will address this risk by bringing the average age of these asset categories into life with our benchmark.

Other asset categories (EWPs and light commercial vehicles) start off below our sustainability benchmark but by FY24 are above, on average, the midpoint of their technical life. Ausgrid has considered the risks which this presents and determined that any additional expenditure to mange the age of these assets would not align with what our customers have told us during our stakeholder consultation, nor with the priorities that they place on energy affordability.

Figure 5.25

Change in age of vehicles over the 2019–24 regulatory period

5.8.3 Response to the AER's Draft Decision and stakeholders

The AER's Draft Decision raised specific concerns about our unit cost escalation and assumptions regarding an efficient replacement lifecycle for elevated work platforms (EWPs).

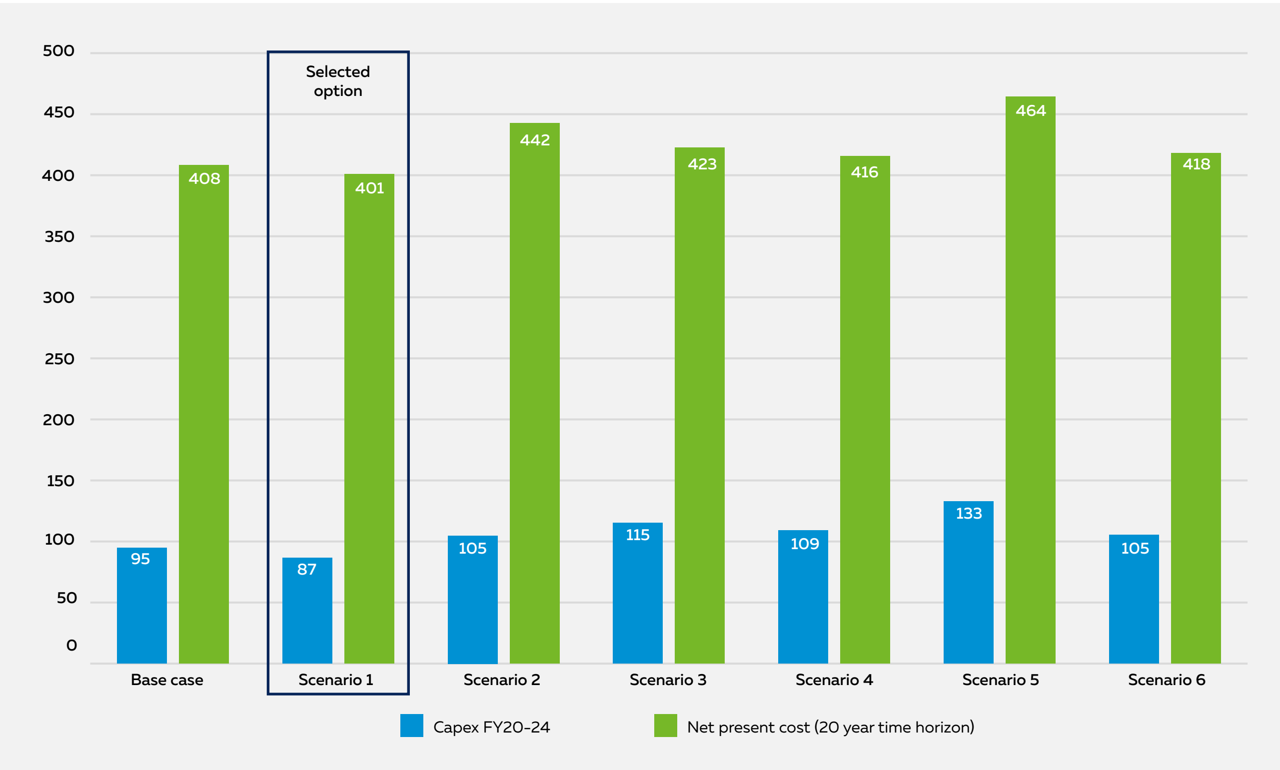
We have considered the AER's concerns as well as the views of our stakeholders. This has led to us adopting the same unit cost escalation and EWP replacement lifecycle assumptions that the AER applied in its Draft Decision. We have also updated our financial modelling to improve its transparency and incorporated feedback from our stakeholders by embedding a reduction in our motor vehicle and plant equipment replacement rate in the 2019–24 regulatory period.

Revised proposal based on the lowest net present cost

We updated our financial modelling between submitting our Initial and Revised Proposal. This updated modelling ran multiple investment scenarios using different assumptions regarding price, escalation and replacement lifecycles. The results of this analysis and the assumptions underpinning each option are summarised in Figure 5.26. It is shown that the scenario forming the basis of our Revised Proposal has the lowest NPC for Ausgrid and, ultimately, our customers. This NPC analysis was run over a 20-year time horizon from FY20 to FY39 and factored in both capital and ongoing operating and maintenance costs.

Figure 5.26

Investment scenarios for motor vehicle and plant program ($million, real FY19)



	BASE CASE	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4	SCENARIO 5	SCENARIO 6
Unit price source	Supplier quote	Historical average	SG Fleet data	Supplier quote	Historical average	SG Fleet	Historical average
Escalation source	Not applied	Glass data escalation	Not applied	Not applied	Glass data	Not applied	Glass data escalation
Replacement life cycle	15 years	15 years	15 years	10 years	10 years	10 years	15 years
Light vehicle	-10%	-30%	-10%	-10%	-10%	-10%	0%
EWP	-10%	-15%	-10%	-10%	-10%	-10%	0%
Heavy vehicle	-10%	-15%	-10%	-10%	-10%	-10%	0%

The investment scenario we have selected, as stated above, applies the AER's Draft Decision in relation to unit cost escalation. This involved using our historical unit rates for motor vehicle and plant equipment and escalating them using a data source provided by an independent advisory firm (Glass). Similarly, we have responded to the AER's concerns about our assumed EWP replacement lifecycle by applying the same assumption (15 years) as in the AER's Draft Decision. We will reconsider the optimal replacement rate during this period.

Implementing a smaller, more productive fleet

When consulting on our Revised Proposal, stakeholders told us that they would expect that our count of motor vehicle and plant equipment would decline over the 2019–24 regulatory period. This is as we improve the efficiency of our business and take steps to rationalise our fleet population to a smaller, but more productive level.

The investment scenario that we selected includes significant rationalisation of motor vehicles and plant assets. This rationalisation process is made up of a 30% reduction to the rate of replacement for light vehicles, 15% to heavy vehicles and 15% reduction to EWPs.

Figure 5.27 sets out the impact that this will have on our fleet count relative to our population of these assets in prior years. This change is then set out on an FTE basis in Figure 5.28. It shows that, per FTE, we are forecasting a large decline in the number of passenger vehicles (cars) we expect to operate in the 2019–24 regulatory period. Light commercial vehicles are increasing per FTE. However, this aligns with our business strategy to move to a more agile workforce. LCVs are also more productive – unlike a car, they can be used to transport tools and equipment which field crews use onsite.

Figure 5.27

Historical and forecast motor vehicle and plant count

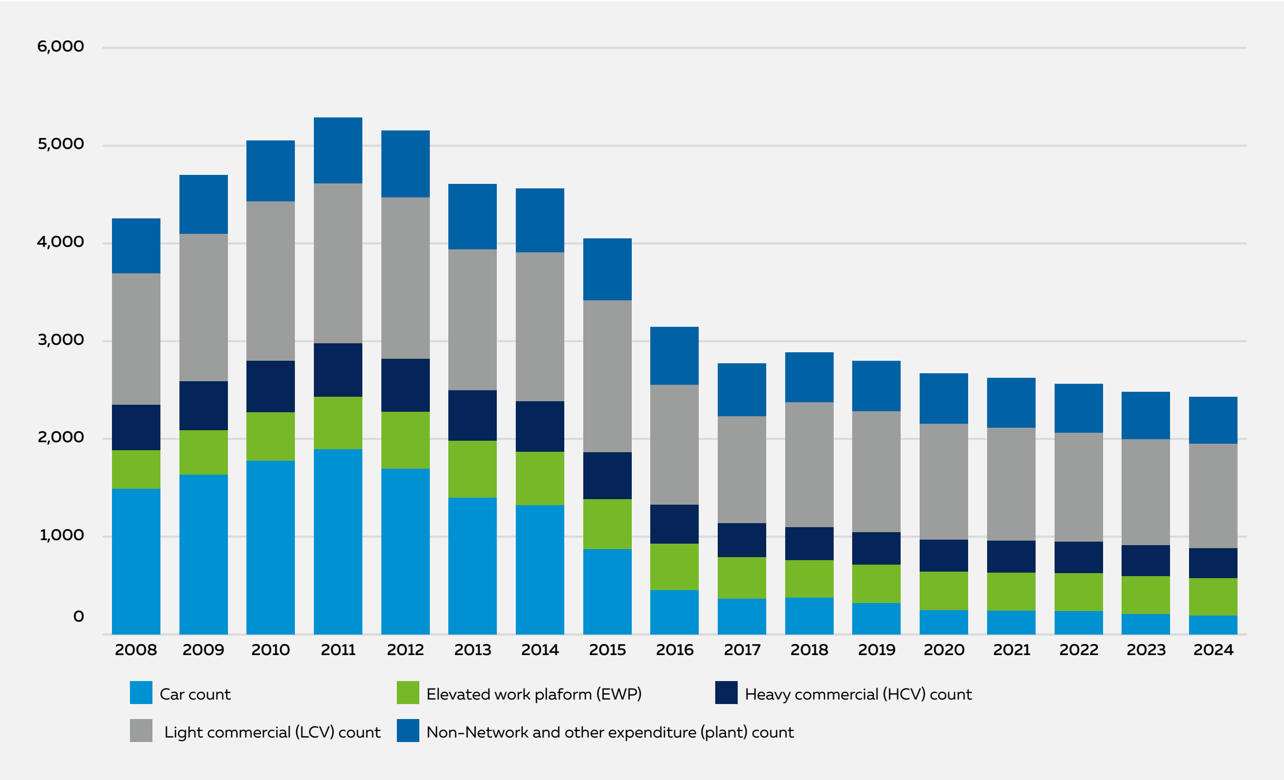
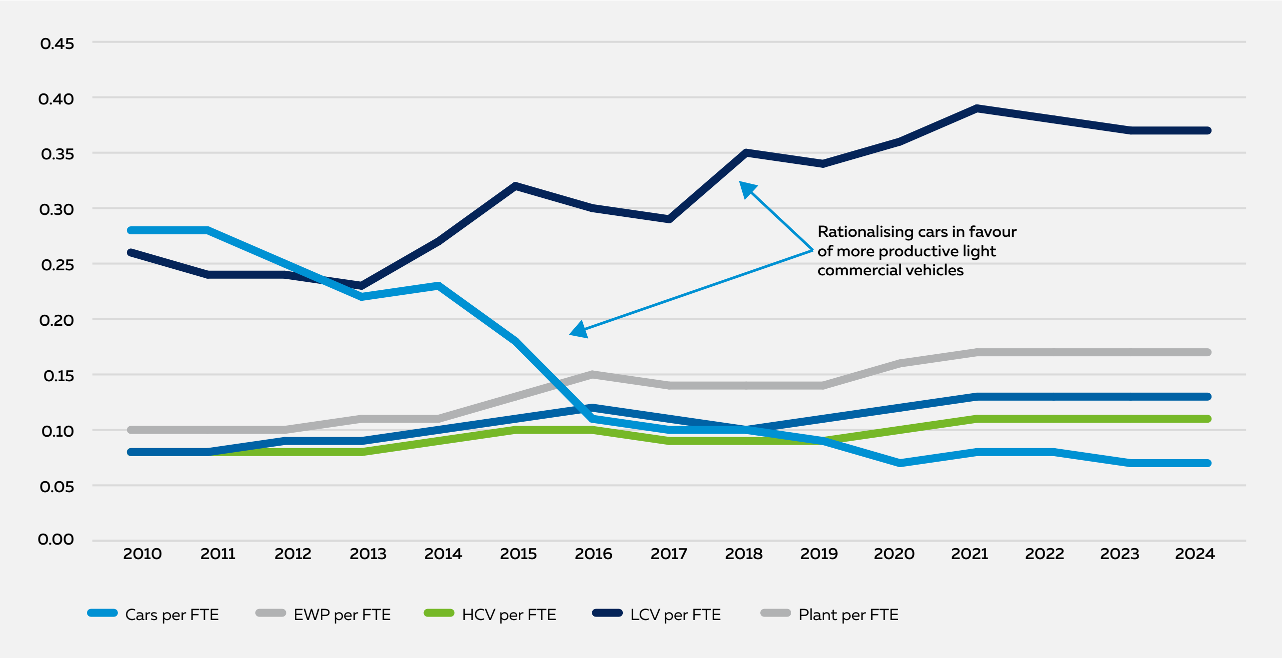


Figure 5.28

Historical and forecast motor vehicle and plant count per FTE



5.9 Minor assets

Our Revised Proposal forecasts $22.7 million in minor assets capex over the 2019–24 regulatory period. This expenditure category includes tools that have an individual or group value below $1000, as well as portable testing equipment and office furniture.

The AER did not accept any of our proposed minor assets capex in its Draft Decision. It stated:

> *We (the AER) have made no allocation for minor asset expenditure in the absence of information in regards to historical expenditure for this aspect of Ausgrid's forecast.*[14]

We understand that the AER sought additional information as "minor assets" is not a standalone cost category in our annual reporting to the AER.

To provide the AER and stakeholders with greater visibility of our historical minor asset capex, we engaged PwC to review these costs. PwC verified that our historical minor assets capex has been reported to the AER as "other" in the 'Non-Network template' of our annual response to the AER's regulatory information notice (RIN). PwC's report is set out in Attachment 6.06.

We applied PwC's findings in the development of our Revised Proposal. Our minor asset costs are recurrent in nature and therefore, to develop our forecast, we have trended forward the historical expenditure which PwC verified in its report. This is the same forecasting approach the AER applied in its recent decision for EvoEnergy, when it assessed a corresponding category of expenditure.[15]

In developing our base level of minor asset capex, we have adopted an average of the last seven years' worth of expenditure. We took an average of seven-years given that it would adjust for the annual variability in investment requirements from year-to-year. A longer-term view also smooths out historically-low investment in recent years which has arisen from the disruptions caused to our business by the lease transaction issue.

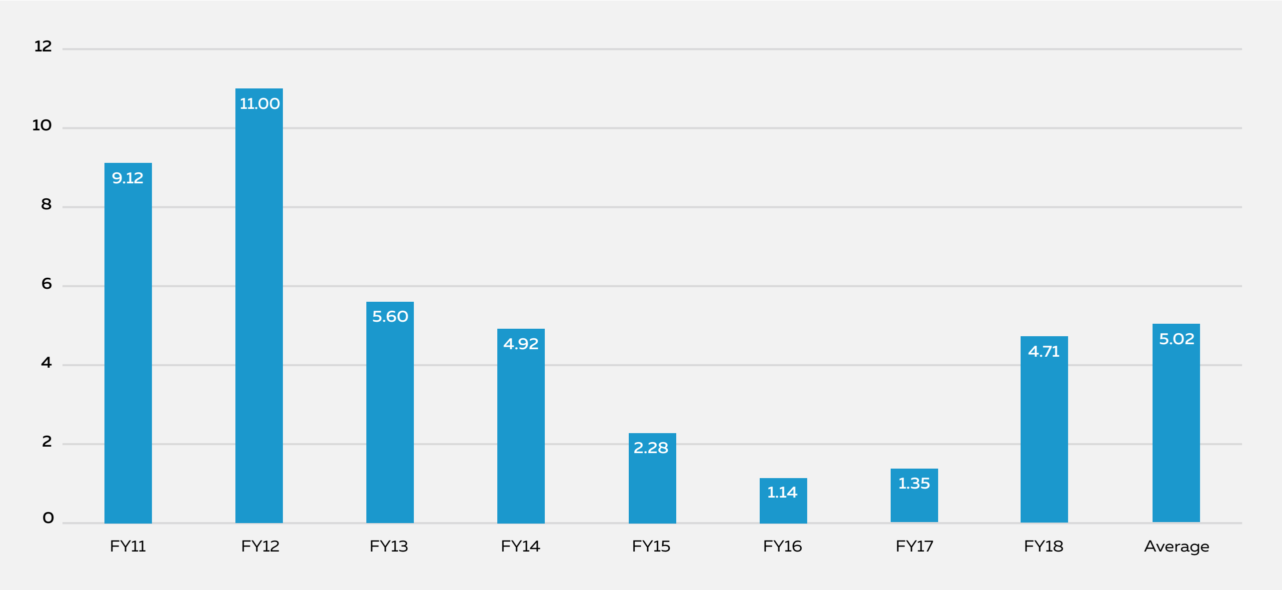
Our historical trend in minor assets capex which we have used to develop our forecast is set out below. It shows, on average, our minor asset capex has been $5 million per year since FY2011. This average is in line with Ausgrid's actual capex in our most recently completed financial year (FY18). By applying this trend over the 2019-24 regulatory period, we forecast minor asset capex of $22.7 million. This is after applying our CAM to dervied the SCS componeent.

14 AER, Draft Decision: Ausgrid 2019–24 period, November 2018, p.5-110.

15 AER, Draft Decision: EvoEnergy 2019–24 period, September 2018, p.5–63.

Figure 5.29

Historical minor asset – total capex ($million, real FY19)

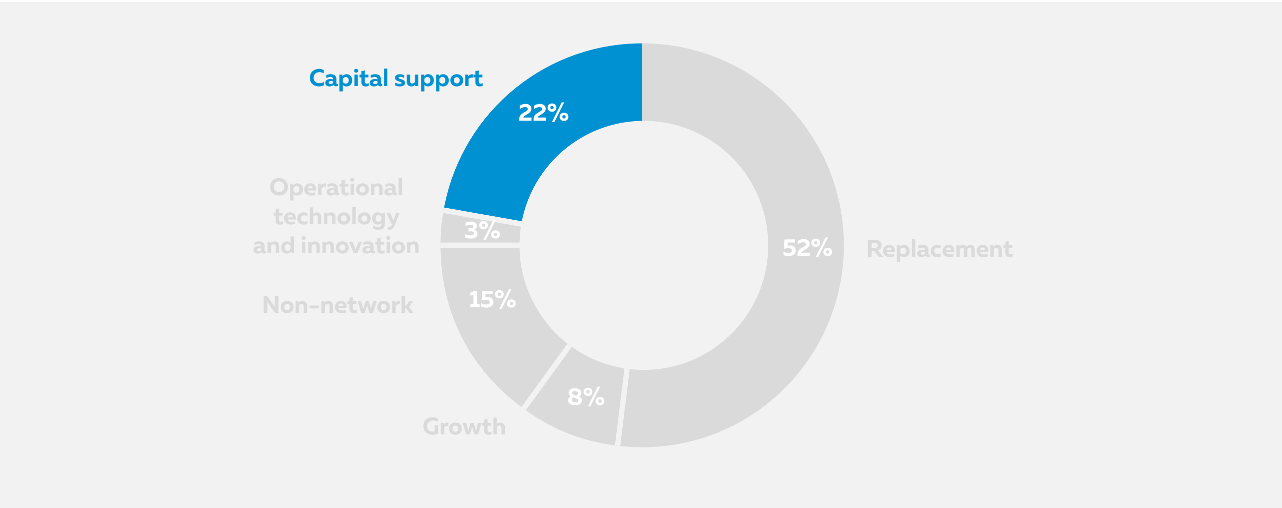


5.10 Capital support costs

Capital program support (also known as capitalised overheads) includes the indirect costs we incur in the delivery of both our network and non-network capex programs. These costs cannot be allocated to individual projects, and so are bundled together as overheads. As shown below, our capital program support costs make up about 22% of our total forecast capex in the 2019–24 regulatory period.

Figure 5.30

Capital support as a proportion of total capex program in 2019–24



5.10.1 Revised forecast

We forecast $590 million in capital overhead support costs in the 2019–24 regulatory period. This is about 2% more than the $577 million the AER accepted in its Draft Decision.

The indirect costs that support our capex program include network planning, our corporate support functions, fleet, logistics and procurement, and ICT. These costs are not directly attributable to any one capex program or project. They are capitalised in accordance with Australian Accounting Standards and allocated to standard control services in accordance with our Cost Allocation Method (CAM) approved by the AER.

In its Draft Decision, the AER considered our approach to forecasting our capital support costs in the 2019–24 regulatory period to be reasonable '.[16] The AER stated:

> *we (the AER) are satisfied that, as a whole, Ausgrid's methodology for forecasting overheads overall reasonably estimates prudent and efficient expenditure over the 2019–24 regulatory control period.*[17]

While acknowledging the reasonableness of our approach, the AER did not accept the capital support costs we put forward in our Initial Proposal. This was in line with its Draft Decision to reduce the direct capex associated with our network and non-network programs. The AER noted that 'reducing the scope of the capex program should reduce support requirements'.

Our revised capex proposal includes more direct capex for network and non-network than the AER approved in its Draft Decision. As a result, our revised capital overhead support costs are higher than the AER Draft Decision. We forecast $590 million in capital overhead support costs in the 2019–24 regulatory period.

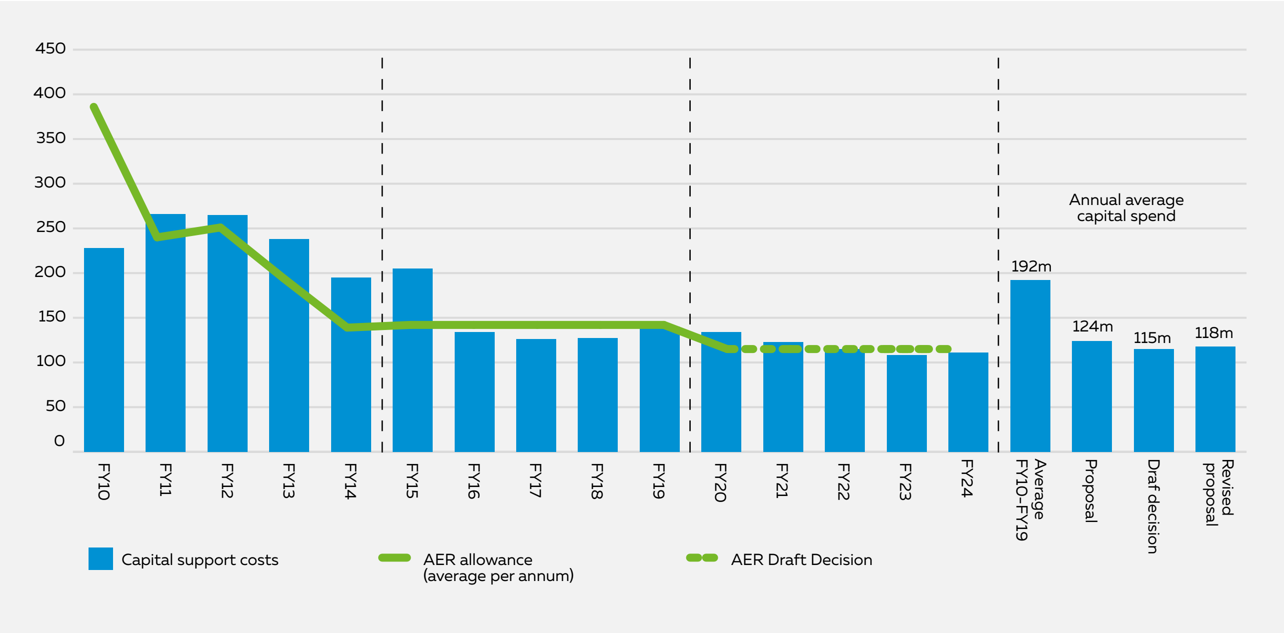
5.10.2 Our forecast reflects our prudent and efficient costs

We have actively implemented measures to realise efficiencies in our program support costs. These measures, delivered by our transformation program, have reduced the total cost pool of our overheads, resulting in a reduction in our capital support costs.

Figure 5.31 tracks the efficiencies we have been able to unlock. It shows that capital support costs averaged $192 million per annum in the last 10 years, whereas over the 2019–24 regulatory period we are forecasting $118 million per annum. Ultimately, this reduction will benefit our customers as they will pay less for the indirect support costs that are essential to the safe, reliable and efficient delivery of our capex program.

Figure 5.31

Historical and forecast capital support costs ($million, real FY19)



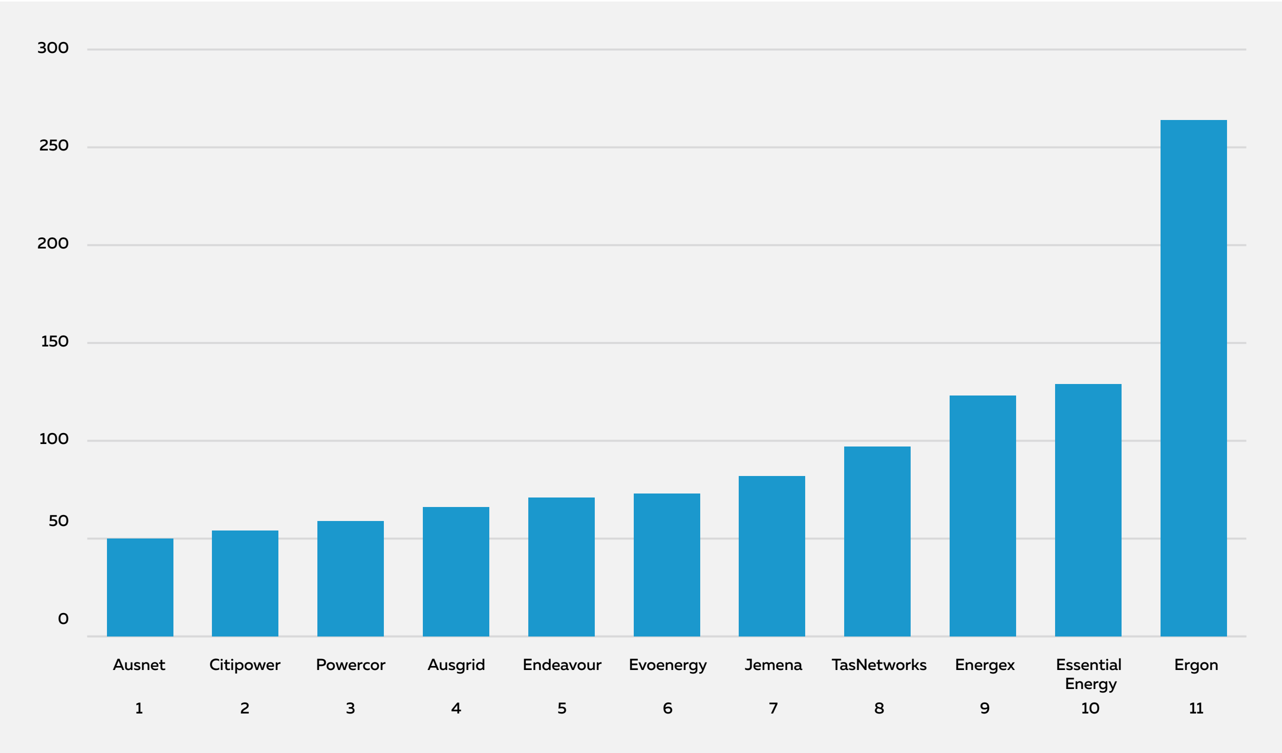
16 AER, Draft Decision – Ausgrid Distribution Determination, November 2018, p. 5-116

17 AER, Draft Decision – Ausgrid Distribution Determination, November 2018, p. 5-118

We have, in addition, tested the efficiency of our Revised Proposal using benchmarking. We began by just comparing our forecast capital support costs against our peers in the NEM (see Figure 5.32). To provide a more complete view, we then benchmarked our total expenditure (totex) on overheads, inclusive of both capital and operating costs. This analysis is set out in Figure 5.33. It shows that on a per customer basis both our capital support costs and totex overheads are among the lowest in the NEM. We are in fact at the efficient frontier, along with United Energy, at the totex level.

Figure 5.32

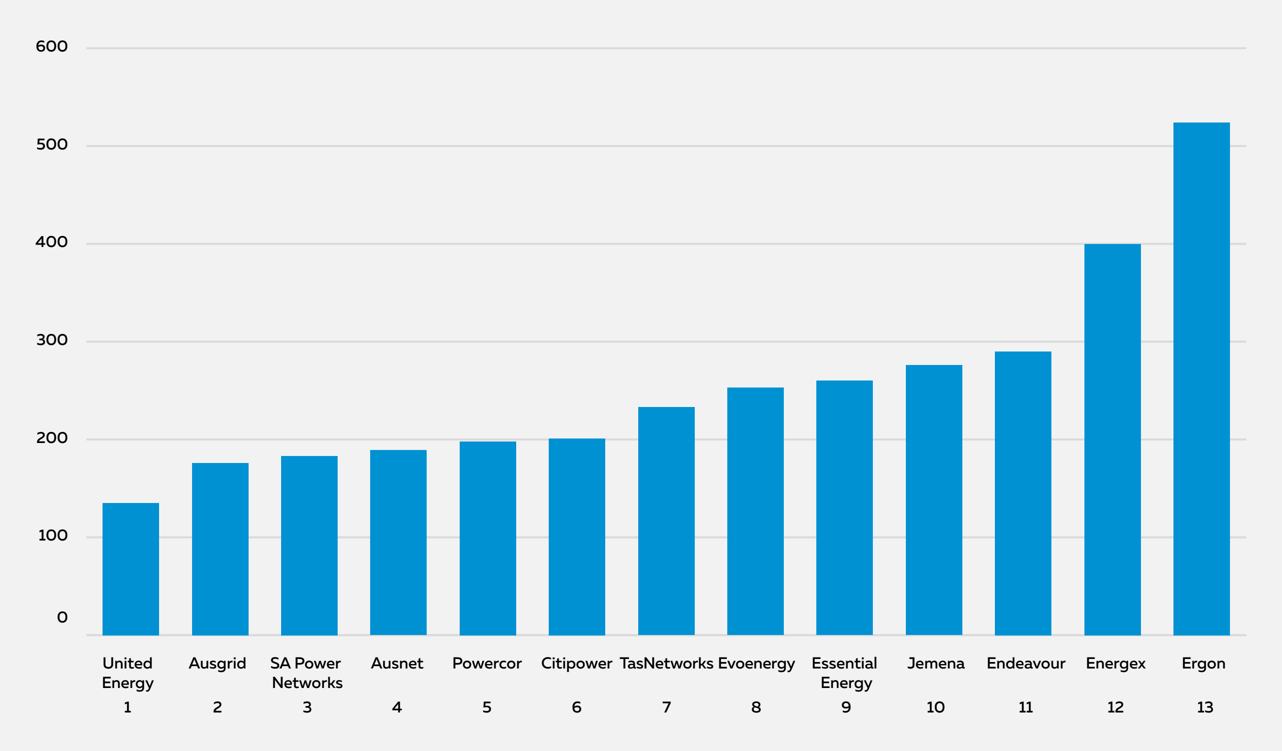
Annualised capital overhead support costs per customer



Note: Capital support costs data for Ausgrid is a 5-year average for the FY20-24 regulatory period based on our revised proposal. Endeavour, Essential, Evoenergy and TasNetworks is a 5-year average for the FY20-24 regulatory period from the initial proposal reset RIN for each business. Overhead data for Energex, Ergon, SA Power Networks from 2016/17 CA RIN; Ausnet, CitiPower, Jemena, Powercor, United from 2017 CA RIN.

Figure 5.33

Totex overheads per customer



5.11 National Electricity Rules compliance

As outlined in our Initial Proposal, the NER sets out specific requirements in relation to our capex forecasts. In particular, our forecasts must achieve the capex objectives, which include the requirement to provide safe and reliable distribution services to our customers, and to comply with our regulatory obligations. The NER also stipulates that our expenditure forecasts should reflect the efficient and prudent costs of achieving the capex objectives.

The information set out in this chapter and Attachment 5.01 demonstrates that our revised capex forecast addresses the AER's Draft Decision and the feedback from our customers and stakeholders. We are confident that our revised capex forecast complies with the Rules and is capable of acceptance. In particular we note:

- Repex: We have revised the way we prepare our repex forecast involving bottom-up perspective and a top-down review by applying the repex model. Our enhanced governance framework provided another level of scrutiny to ensure we met the NER requirements and customer expectations. We believe our revised repex forecast is prudent and efficient.
- Growth capex: We have revisited our plans to determine whether there is scope to reduce growth capex, by revisiting our demand forecasts; revising non-network solutions; and making better use of existing capacity. We have used the most up-to-date information in our revision of growth projects and programs.
- We have taken account of customers' concerns regarding affordability in preparing our capex forecasts.
- Our network capex forecast includes productivity improvements over the 2019–24 regulatory period.

In forecasting our capex requirements, we must achieve an appropriate balance between the pressure to reduce expenditure further and the importance of maintaining safety and reliability while managing network risks efficiently, both now and in the future. For the reasons set out in this chapter and Attachment 5.01, we believe we have achieved an appropriate balance.

5.12 Material to support our capex proposal

Attachment 5.01 provides further information to support our revised capex forecast for the 2019–24 regulatory period. We have provided information in a way that reflects the AER's assessment process and its feedback in its Draft Decision. We are open to providing any other information requested by the AER and customers.

Further information has also been provided in Attachments.

06

Operating expenditure


Ausgrid

06

OPERATING EXPENDITURE

Continuing productivity improvements for customers

Our Revised Proposal

Our Revised Proposal operating expenditure (opex) forecast reflects our commitment to increasing efficiency within the 2019-24 regulatory period. Our forecasts embed the significant cost decreases we have achieved through our transformation program, delivering ongoing savings of $100 million per year.

We have contributed to the AER's current productivity review and, in the absence of a final decision have applied the AER's Draft Decision trend of 1%. Due to business specific constraints we have sought to apply the trend from FY21; having the effect of lowering our opex by $52 million over the regulatory period.

Our demand management projects have been revised in response to AER's observations. We have accepted the AER's decision not to approve our price reform research step change and will undertake the research within the total opex allowance.

Our revised opex forecast is a total of $2.3 billion over the 2019-24 regulatory period (including debt raising costs). The Revised Proposal is $119 million (5%) lower than the Initial Proposal and $20 million lower than the AER's Draft Decision. This reflects our focus on customers' concerns about affordability balanced against our obligations to responsibly manage network risk and performance.

How our Revised Proposal responds to customers

Our customers told us that affordability was their number one concern. Customers have acknowledged we have made significant progress in reducing our underlying opex over the current period, but they considered there was further scope for improvement in our forecasts.

In consultation with our customers we committed to:

- continue to pursue productivity gains
- challenge ourselves to achieve the AER's productivity trend from FY21
- absorb transformation costs associated with giving effect to the changes in our capital expenditure (capex) program from the Initial Proposal, and
- use demand management, wherever it is efficient to avoid capital investments.

This chapter sets out how we will deliver for customers absorbing costs equivalent to a 10.6% productivity improvement.

How our Revised Proposal responds to the AER

The AER's substitute estimate for total opex of $2.3 billion is $98.4 million (or 4.0%) lower than our initial opex forecast. Our Revised Proposal is $20.3 million (or 0.9%) lower than the AER's Draft Decision.

In responding to the AER's Draft Decision, we have provided additional information supporting our proposed base year costs and step changes, verifying the efficiency of these costs.

We have revisited our approach to estimating productivity growth over the 2019-24 regulatory period and have applied the AER's Productivity Draft Decision trend of 1.0%, however, due to business specific reasons we have applied this from FY21.

In our Revised Proposal, we believe we have addressed the issues raised by the AER and that our revised opex forecast reflects the opex objectives and criteria.

6.1 Our proposed opex embeds the cost savings achieved from our transformation and is $664 million lower than we forecast for the current period

We are forecasting $2.3 billion ($real FY19) of opex (including debt raising costs) over the 2019-24 regulatory period. This is $20.3 million less than the AER's Draft Decision and $118.7 million (or 4.9%) less than our Initial Proposal. We have embedded significant cost decreases in our revised opex forecast that were achieved through our transformation program. We are also challenging ourselves to deliver further efficiency improvements by committing to further productivity improvements in the 2019-24 regulatory period.

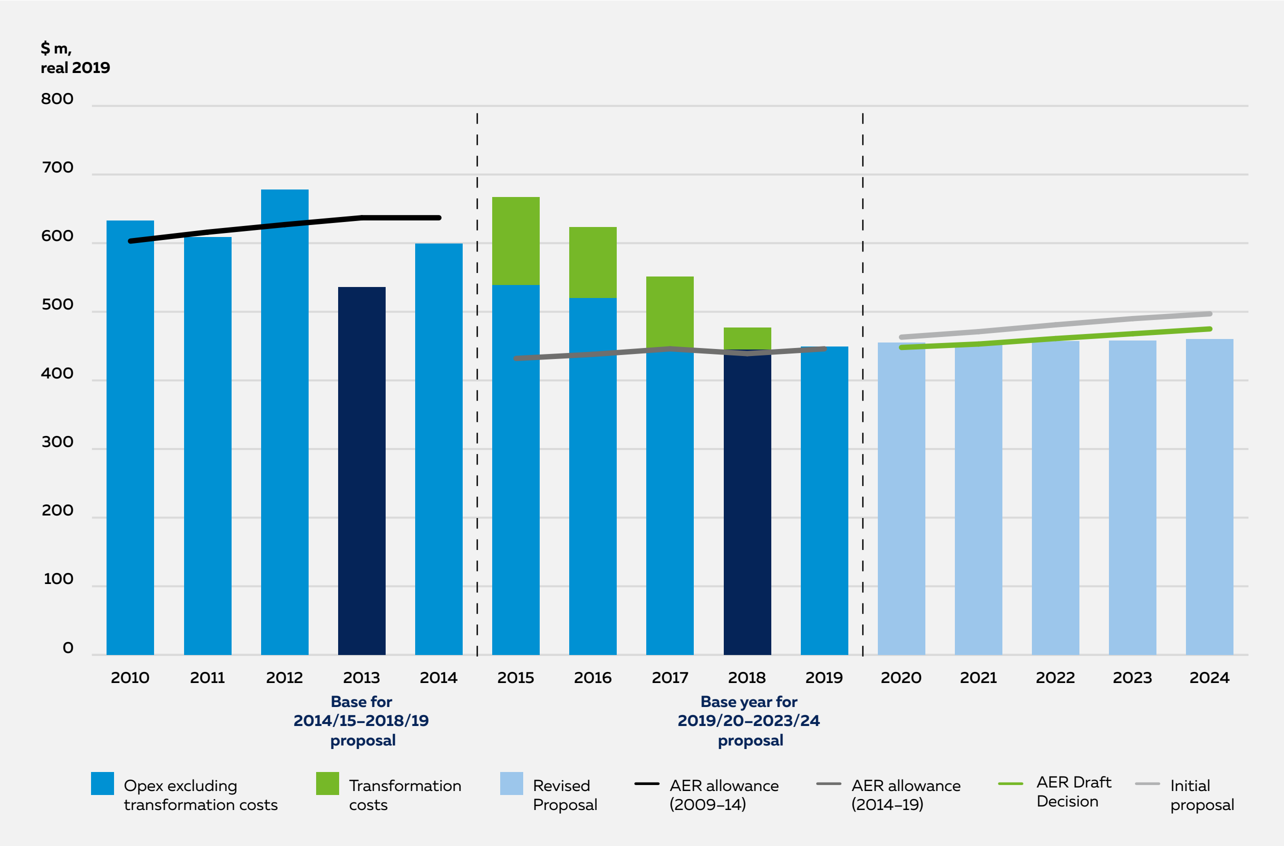
In this Revised Proposal, we have addressed the matters raised by the AER in its Draft Decision and the feedback we received from our customers. We have also updated our forecasts to reflect the most recent information available. We believe our revised opex forecast meets our corporate objectives of providing affordable, reliable and sustainable services to our customers and satisfies the requirements of the National Electricity Rules (NER).

In our Initial Proposal, we explained that opex makes up around a third of the revenue we recover from customers. In general, opex reflects activities and costs that are ongoing and recurring. It includes the costs of:

- operating and maintaining our physical assets, such as our poles, wires, substations, monitoring and control systems
- responding to emergencies, such as fallen trees on our power lines
- corporate support function
- undertaking customer-related functions, such as providing call centre services.

Figure 6.1

Actual and forecast opex for FY10 to FY24 ($million, real FY19)



Note: Opex excluding debt raising costs.

The remainder of this chapter explains how we have responded to the AER's Draft Decision. Our revised opex forecast addresses the matters raised by the AER, customers and stakeholders, and we believe is capable of acceptance by the AER in its Final Decision.

6.2 Revised opex proposal

Our revised forecasts reflect the most recent information, including FY18 actual costs for Emergency Recoverable Works and revised CPI forecasts. The main differences between our revised opex forecast and our Initial Proposal are:

- The approach to rolling forward the base year from FY18 to FY19 – we have adopted the AER's Draft Decision approach for rolling forward the base year.
- Trend escalation – we have updated our labour price escalation forecasts using the AER's standard approach, as outlined in the Draft Decision, and incorporated the most recent information on labour price forecasts. We have also adopted the AER's revised approach for estimating the output growth escalation factors.
- Productivity factor – we have revised our approach to forecasting productivity in light of the AER's Draft Decision. We have adopted the AER's Productivity Draft Decision forecast of productivity growth of 1.0% pa to apply from FY21 as a placeholder in our Revised Proposal. We intend to update this with the AER's Final Decision estimate during consultation with the AER following the release of the Productivity Final Decision in March/April 2019. This approach sets us a challenging productivity target and we intend to achieve this as a result of the efficiency initiatives included in our Revised Proposal.
- Step changes – we have accepted the AER's Draft Decision for the price reform research step change, which removes the proposed expenditure from our forecasts. We are still committed to undertaking price reform research, but will do so without seeking additional funding through our total opex allowance. We have also revised our demand management projects in response to the AER's observations in its Draft Decision, and in light of new information to ensure that they are efficient and meet the needs of our customers.

As part of this Revised Proposal, we have included additional supporting information to support our proposed base year adjustment and demand management projects, as sought by the AER in its Draft Decision. We believe these amounts meet the opex criteria and we hope meet our customer expectations and should now be accepted.

Table 6.1

Revised opex proposal compared to AER Draft Decision ($million, real FY19)

OPEX	FY20	FY21	FY22	FY23	FY24	TOTAL
Initial Proposal opex	463	471	481	490	497	2,402
AER Draft Decision opex	448	453	461	468	475	2,305
Revised Proposal opex	455	455	457	458	460	2,285

Note: Opex excluding debt raising costs.

6.3 What we heard and how we've responded in our Revised Proposal

The key differences between our Initial Proposal and the AER's alternate forecast were due to the following components:

- Base opex adjustment – The AER's alternate estimate excluded our proposed adjustment to the base year for the reclassification of emergency recoverable works
- Trend – The AER's alternate estimate adopted a revised approach to forecasting output growth, whereas we had applied the AER's previous approach. The AER's labour price growth estimate was also lower than the estimate in our Initial Proposal
- Step change – The AER's alternate estimate included a lower amount than we had proposed for demand management, and did not include our proposed step change for research into, and engagement on, network price reform.

A summary of the AER's Draft Decision on key aspects of our opex proposal is shown in Table 6.2 below. It also summarises what we've heard from customers and how we've responded to the AER's Draft Decision.

Table 6.2

Preparing our revised opex proposal

	AER DRAFT DECISION	WHAT WE HEARD FROM CUSTOMERS	HOW WE'VE RESPONDED
1. Base opex	The AER accepted our base year opex as reasonably reflecting an efficient level of opex consistent with the opex criteria.	The Consumer Challenge Panel (CCP10) noted that the current base year is "soft" (high) to the point of being inefficient.	In response to customer feedback, our Revised Proposal adopts the AER's opex allowance for FY18 (as outlined in the AER's 2015 Determination) as our base year. We consider this is representative of our efficient recurrent opex requirements for 2019-24. This embeds a further efficiency of $8.4 million in our proposed base year. This differs from the view in our Initial Proposal, which anticipated adopting actual underlying opex (excluding non-recurrent costs) for FY18, consistent with the AER's standard methodology. Section 6.5.2 discusses this in further detail.
2. Base opex adjustment for Emergency Recoverable Works	The AER's alternate estimate of opex in the Draft Decision did not include our proposed adjustment to the base year. The AER concluded that it would require further information before accepting our proposal.	Consumers did not comment on our proposed base year adjustment.	We have provided the additional information sought by the AER to support our Revised Proposal. Section 6.5.3 discusses this in further detail.

	AER DRAFT DECISION	WHAT WE HEARD FROM CUSTOMERS	HOW WE'VE RESPONDED
3. Rolling forward the base year (FY18 to FY19 increment)	The AER substituted our assumption of the allowed opex in FY19 under the previous determination with a simple rate of change from the FY18 base year, as no EBSS applied during the current period.	Consumers did not comment on how we escalated our base year to estimate FY19 opex.	We have adopted the AER's revised approach to roll forward the base year to estimate FY19 opex, and calculating output growth. Section 6.5.4 discusses this in further detail.
4. Price growth	The AER calculated an alternate estimate of labour price growth as the average of Ausgrid's (BIS Oxford) and the AER's (Deloitte Access Economic) forecasts.	Customers did not comment on the price growth component of our forecast opex.	We have adopted the AER's approach to estimating labour price growth. However, we have incorporated the latest forecasts, resulting in a different forecast to the AER's Draft Decision. Section 6.5.5 discusses this in further detail.
5. Output growth	The AER updated its approach to calculating output growth, adopting the average of the four models in the 2017 Annual Benchmarking Report[1] to calculate the weighting of the output growth factors.	Customers did not comment on the output growth component of our forecast opex.	We have revised our approach to forecasting the output growth adjustments to reflect the AER's Draft Decision. Section 6.5.5 discusses this in further detail.
6. Productivity growth	The AER applied a zero productivity growth forecast in its Draft Decision. However, it is concurrently reviewing the approach to forecasting productivity, the outcomes of which will be taken into consideration in the AER's Final Decision.	Customers disagreed with our decision not to apply a productivity trend over the 2019-24 regulatory period. The CCP10 proposed a minimum productivity adjustment of 1.5 – 2.0% pa. This was based on the results of opex Partial Factor Productivity (PFP) analysis from 2012-16 of the four businesses with the highest opex PFP in the 2013 benchmarking report, and labour productivity forecasts.	We acknowledge and have taken on board the issues raised by customers in relation to our opex efficiency. We have also considered the AER's Draft Decision Paper on forecasting productivity growth for electricity distributors. We have adopted the AER's Productivity Draft Decision forecast of productivity growth of 1.0% pa to apply from FY21. We intend to update this with the AER's Productivity Final Decision estimate during consultation with the AER following the release of the Productivity Final Decision in March/April 2019. Section 6.4.2 discusses this in further detail.

1 The AER's 2017 Annual Benchmarking Report looks at four different econometric models to compare the relative operating efficiency of service providers in the NEM. These models are: Opex multilateral partial factor productivity, Cobb-Douglas stochastic frontier analysis (SFA), Cobb-Douglas least squares econometrics (LSE), and Translog LSE.

	AER DRAFT DECISION	WHAT WE HEARD FROM CUSTOMERS	HOW WE'VE RESPONDED
7. Step changes	The AER included $8.5 million in our base opex for demand management, compared to our estimated $26.1 million. The AER did not consider that four projects were justified and sought more information on them. The AER did not include our proposed step change for price reform research as it considered this type of activity to be part of a distributor's standard business activities. The AER considered that it should be accommodated within the existing costs and base year opex.	Customers were also not supportive of the proposed price reform research step change, suggesting that this expenditure should be funded out of existing opex. However, customers were supportive, in principle, of our proposed demand management step change.	We have revised our opex proposal in response to the AER's Draft Decision. We have also taken on board the comments from customers on the step changes included in our Initial Proposal. We have reviewed our proposed step changes and excluded the proposed step change for price reform research from our revised opex forecasts. We have revised our demand management projects in light of new information to ensure that they are efficient and meet the needs of our customers. Section 6.5.6 discusses this in further detail.
8. Total opex	The AER did not accept our total opex forecast. As noted above, the AER's substitute estimate for total opex of $2.3 billion (including debt raising costs) is $98.4 million (or 4%) lower than our initial opex forecast. In its Draft Decision, the AER concluded that this substitute estimate met the opex criteria.	Customers acknowledged that we have made significant progress in reducing our underlying opex over the current period, but considered there was further scope for improvement in our forecasts.	We have revisited our forecasts in response to the AER's Draft Decision. In developing our Revised Proposal, we have also taken into consideration feedback from customers. As noted above, this has resulted in a revised opex forecast of $2.3 billion (including debt raising costs), which is $20.7 million (or 0.9%) lower than the AER's Draft Decision. We believe this reasonably reflects the opex criteria and is in the long-term interests of customers.

Benefits for customers

Our customers have told us that electricity price increases in recent years have created an environment where future prices are a central concern. We have made a concerted effort since 2012 to transition to a more efficient level of opex through an ambitious program of transformation that was designed to "right-size" our cost base and improve our efficiency. These efficiencies are embedded in our base year opex. This has given us a solid base so that we can address customers' concerns regarding affordability without compromising network safety, security or reliability.

Our Revised Proposal recognises these concerns, and we have embedded further productivity improvements in our forecasts:

- We set our base year opex according to the FY18 opex allowance previously set by the AER (of $426.4 million, $ nominal), which is lower than our actual opex of $434.0 million ($ nominal) in FY18
- We face additional cost increases of $223.0 million due to changes in uncontrollable costs, capex-opex trade-offs and regulatory changes over the 2019-24 regulatory period, which we are proposing to absorb
- We plan to deliver improved customer outcomes without passing through additional costs. As outlined in our Initial Proposal, these improved outcomes include changes to our vegetation management practices, implementing an Advanced Distribution Management System (ADMS) and achieving enhanced engagement with our culturally and linguistically diverse customers.

Essentially, our Revised Proposal commits us to delivering more for a lower level expenditure—which means we are building on productivity improvements that we have achieved to date. In addition, we have set ourselves a productivity challenge, which requires us to achieve a further productivity improvement of 1.0% pa from FY21. This is explained further in the following sections.

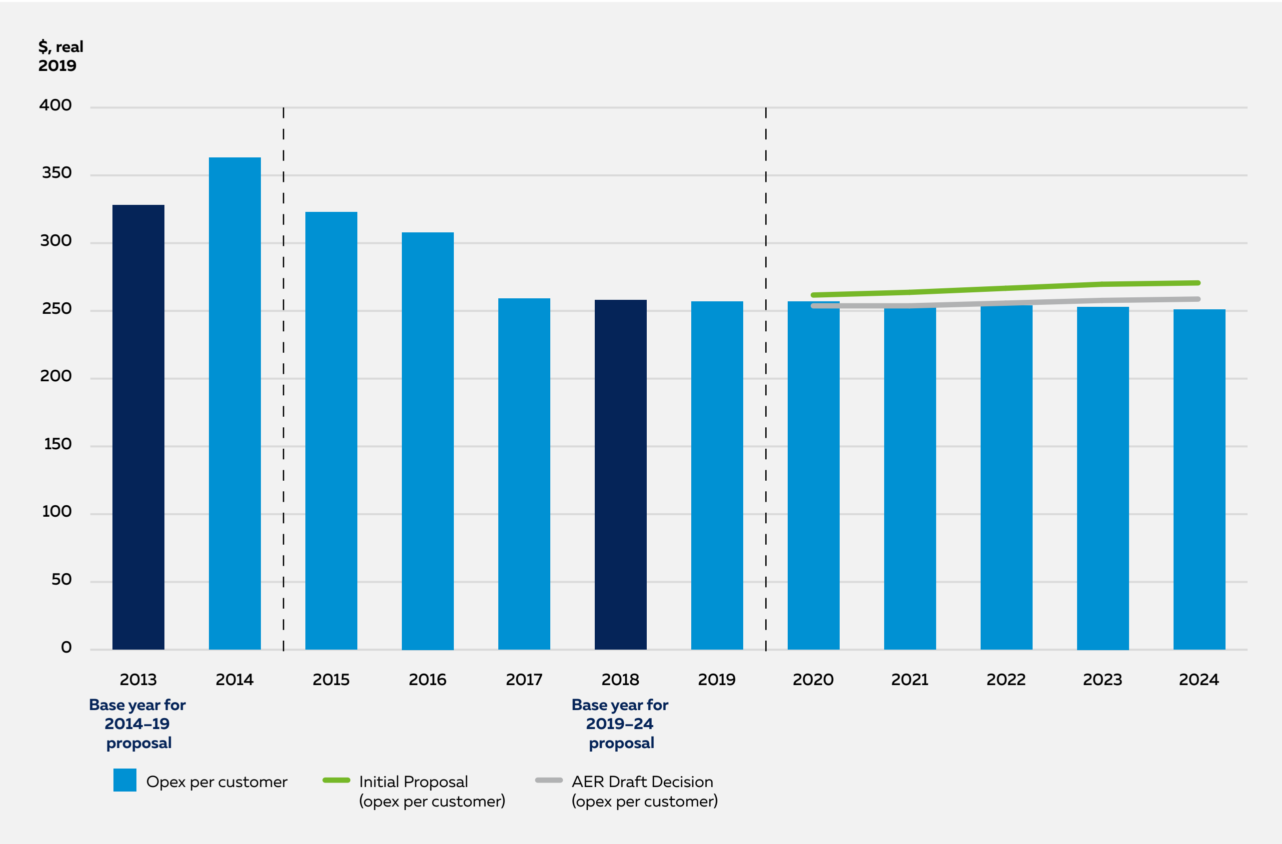
6.4 We have delivered significant opex reductions over the 2014–19 regulatory period, and we will seek further productivity improvements going forward

As noted in our Initial Proposal, we operated with a higher cost base in the past, but have worked hard to reduce our costs. Overall opex is increasing slightly over the next regulatory period, largely due to growth in our customer numbers. However, on a per customer basis, our revised forecast opex is declining over the next regulatory period–maintaining the savings achieved in the current regulatory period as well as passing through efficiencies we are challenging ourselves to achieve over the 2019-24 regulatory period. In our Initial Proposal, our opex per customer was forecast to increase slightly, rather than decline.

Figure 6.2 shows our forecast opex per customer alongside our actual opex per customer over the period FY13 to FY24, excluding transformation costs.

Figure 6.2

Actual and forecast opex per customer (excluding transformation costs) for FY13 to FY24 ($real FY19)



Note: Opex per customer excluding transformation costs and debt raising costs.

As shown in our Initial Proposal, and demonstrated below, our opex productivity has improved significantly from 2015 before reaching a more steady state. We have made significant progress over a range of benchmarking measures, including the opex multilateral partial factor productivity (MPFP) and partial opex measures, bringing our performance into line with our peers. We will continue to challenge ourselves over the 2019-24 regulatory period to deliver further productivity improvements and continue to pursue the efficiency frontier. See Attachment 6.01 for further details on our benchmarking.

Assessing our performance against the AER benchmarking analysis

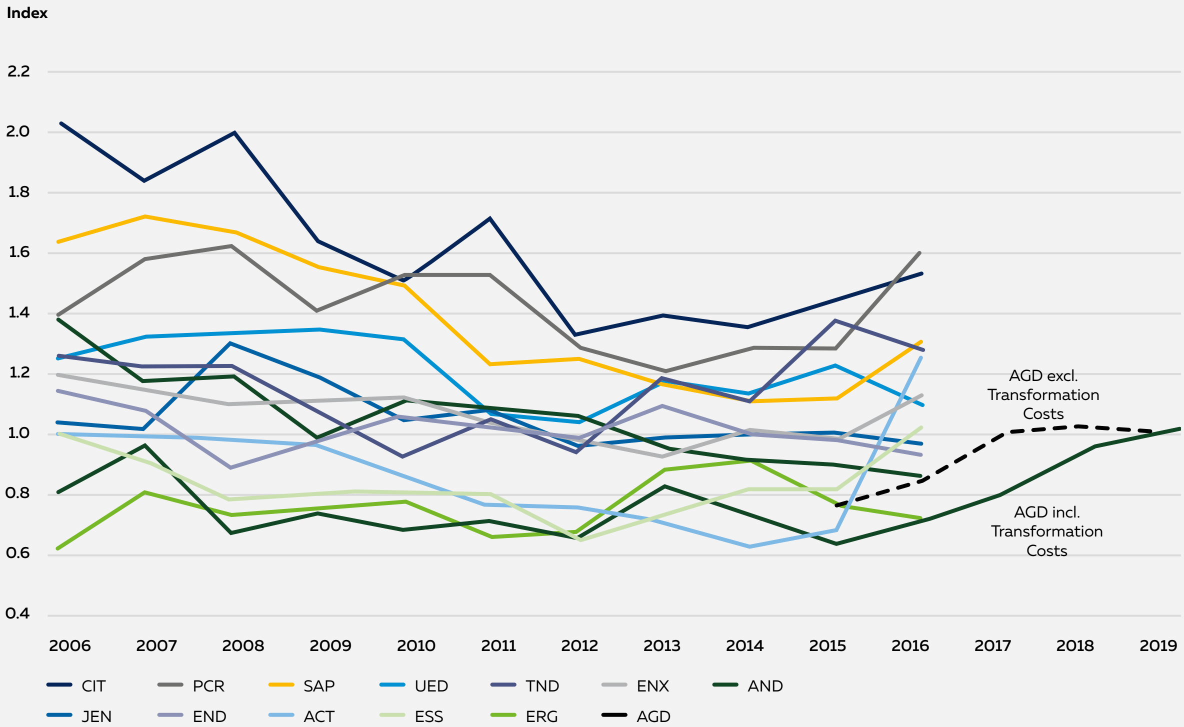
We have assessed our performance against the results of the AER's benchmarking analysis in the Draft Decision and the AER's 2018 Annual Benchmarking Report.

The benchmarking analysis in the AER's Draft Decision indicated that our proposed base year reflected a reasonable estimate of the prudent and efficient level of base opex for the purposes of forecasting opex over the 2019–24 regulatory period. In summary, the opex MPFP analysis shows that Ausgrid's opex productivity with, and without, transformation costs has significantly improved over the 2014-19 regulatory period, as shown in Figure 6.3. These results are consistent with the benchmarking analysis in the AER's 2018 Annual Benchmarking Report.

Over the last two years of the current period, our opex productivity is forecast to increase significantly, reflecting the results of our transformation program. The AER's analysis also forecasts Ausgrid's opex productivity to improve, relative to other network businesses, which lifts our ranking. When our transformation costs are excluded from the analysis, our productivity performance in each of the first four years of the current period improves. This shows that our proposed FY18 base year opex represents a significant improvement in opex productivity relative to the current regulatory period, and other businesses, in FY16.

Figure 6.3

Opex multilateral partial factor productivity



Source: Economic Insights, Assessment of Ausgrid's base year opex, August 2018

The comparison above demonstrates that our customers can have confidence that our transformation program has already delivered improvements, which promotes our objective of keeping network bills affordable without compromising network safety or reliability. This is consistent with the AER's conclusions on our proposed base year in the Draft Decision.

6.4.1 Efficiencies embedded into our proposed opex

A key issue raised by stakeholders on our Initial Proposal was the extent to which our forecasts should anticipate future productivity gains. They noted that we have delivered substantial savings in recent years and future productivity should therefore be included in our forecast opex.

We recognise that our efficiency journey is not over. In our Initial Proposal, we identified a number of cost categories where we expect costs in the 2019-24 regulatory period to be higher than those included in our base year. These additional costs can only be met if we make productivity gains in the next regulatory period. These embedded productivity improvements amount to savings of $223.3 million or 8.9% over the 2019-24 regulatory period. These are in addition to the $8.4 million efficiency improvements we are embedding in our base year opex by adopting the AER's allowance for FY18 (as outlined in the 2015 Determination) instead of our actual opex in FY18.

Stakeholders also noted that the information provided to support these additional costs was not sufficient to support their inclusion as a productivity off-setting factor. We have provided additional information on these costs. The cost drivers for them are largely due to regulatory changes, capex-opex trade-offs and changes in uncontrollable costs:

- **Regulatory changes:**
  - Increased cyber security software and support costs, as well as physical security costs as a result of new regulatory obligations contained in our Distributor Licence Conditions and the Security of Critical Infrastructure Act 2018, which came into effect in July 2018 and requires us to improve security controls to manage risks to national security.
- **Capex-opex trade-offs:**
  - Increased ICT opex relating to subscription and licencing for cloud-based solutions as part of our prudent migration away from capital intensive "on-premises" data centres. This results in a capex reduction of approximately $20 million over the 2019–24 regulatory period (see Chapter 5 for details on our shift to cloud-based data storage solutions).
  - Transformation costs associated with achieving a lower capex program – the reduction in our capex program from our Initial Proposal requires us to undertake further transformation to effect this reduced program.
- **Changes in uncontrollable costs:**
  - Emergency management and nature-induced maintenance costs are well below historical average costs[2], reflecting the absence of any major storm events during the base year. We consider this to be an abnormally low cost level compared to the historical average, and we predict increases of major weather events in the future.[3]
  - Land tax – our Initial Proposal identified land tax as an area of costs which were growing at a rate materially above the trend component of our forecasts due to the significant growth in land value from prior years and the tax based on an average of the land value over three years. We have revised our forecast growth of land tax to take into account the most recent forecasts for land prices[4] . Our revised forecast estimates $14.6 million additional opex over the 2019-24 regulatory period above the amount forecast through the base-step-trend approach.

As outlined in our ICT capex proposal,[5] a number of our ICT capex programs are aimed at delivering capabilities (e.g. automation of manual processes) to help us achieve the productivity savings we are challenging ourselves to achieve and offset ICT opex increases that are expected to be incurred over the 2019-24 regulatory period. In addition to the costs associated with cyber security and cloud-based solutions noted above, these cost increases include:

- Increased licence costs for supplementary data and analytics tools, to ensure we can benefit from the capabilities of our foundational investments in Big Data we have made within the current period, and
- Increased SAP maintenance costs as a result of running SAP S/4HANA in parallel to SAP to unlock benefits from 2024, as outlined in our ICT capex proposal.

2 Our base year is $8 million, (or 32%) lower than the average of these costs over the 2014–19 period, excluding costs associated with the 2015 storm pass through event.

3 Extreme weather events across Australia are projected to worsen as the climate warms further, including harsher fire weather and the intensity of extreme rainfall events, which are projected to increase across most of Australia. (see Climate Council, Cranking Up The Intensity: Climate Change and Extreme Weather Events, available at: https://www.climatecouncil.org.au/resources/cranking-intensity-report/)

4 We engaged BIS Oxford Economics to provide land price forecasts for the 2019-24 regulatory period.

5 See Chapter 5 for further details about our ICT capex proposal.

These costs have not been included in our opex proposal, as we expect the anticipated productivity benefits that will be delivered by the various streams of the Adapt program will offset these cost increases (see Chapter 5 for further details).

Our focus on continually improving our cost efficiency is driving us to make further operational changes in the 2019-24 regulatory period, which will incur implementation and transition costs, but are expected to deliver efficiencies in the future. These include:

- Additional opex associated with replacement and refurbishment of properties – our capex proposal includes the refurbishment and replacement of a number of properties. For properties that are being replaced/refurbished in the same location, there is additional opex associated with rent for temporary accommodation during the construction period as well as relocation costs. We expect opex savings identified in the property business cases to commence from FY24 as the first property replacements and refurbishments are completed. [6]
- Implementation of ADMS – the implementation of an ADMS has associated opex to cover training and transition costs during the roll-out. These are one-off costs incurred across the 2019–24 regulatory period. The implementation of the ADMS is expected to drive significant operating efficiencies across major operational groupings, with benefits expected to be realised from FY21. [7]

We are not seeking to pass these costs through to to customers, rather, productivity improvements will offset these costs.

Table 6.3

Efficiencies embedded in our opex proposal ($million, real FY19)

OPEX	FY20	FY21	FY22	FY23	FY24	TOTAL
Regulatory changes						
Cyber security	4.16	4.16	4.16	4.16	4.16	20.78
Physical security	0.80	0.80	0.80	0.80	0.80	4.00
Capex-opex trade offs						
Shift to cloud IT storage	3.97	6.84	7.61	5.93	5.93	30.27
Transformation costs are associated with lower capex program	47.82	13.21	0.00	0.00	0.00	61.03
Uncontrollable costs						
Emergency response opex	8.28	8.35	8.52	8.72	8.96	42.83
Land tax	4.09	4.07	3.23	2.15	1.06	14.60
ICT opex increases						
Implementation and transition to SAP upgrade	4.45	4.12	3.01	3.01	-1.83	12.76
Data analytics	2.36	2.53	2.73	2.93	3.13	13.67
Efficiency improving initiatives						
Additional opex associated with property replacement/ refurbishment program	0.00	0.00	1.47	3.50	0.89	5.86
Implementation of ADMS	2.60	4.00	9.40	0.70	0.80	17.50
Total	**78.53**	**48.08**	**40.92**	**31.89**	**23.88**	**223.31**

Note: The negative number for Implementation and transition to SAP upgrade in FY24 represents a net saving (or reduction) in IT opex in that year as a result of the transitional period to SAP S/4HANA ending.

6 See Chapter 5 for details about our property capex proposal.

7 See Chapter 5 for details about the costs and benefits of the ADMS.

6.4.2 Productivity

The AER's Draft Decision applied zero productivity growth in its alternate opex forecast, however, it noted stakeholder concerns with this approach. The AER subsequently released a Draft Decision paper on forecasting productivity growth (Productivity Draft Decision) in November 2018, which it intends to apply when making its Final Decision on our Revised Proposal.

Overall, we agree with the AER and stakeholders that DNSPs should be achieving productivity growth over the medium to long-term. However, we have a number of concerns with the AER's proposed approach to forecasting productivity growth. Our key observations for consideration are: [8]

- The AER proposes using the opex MPFP estimates only for the period 2012-16. The approach of using such a short time period can result in misleading estimates, particularly if the estimate is taken over partial economic cycles. Therefore, this estimate should be viewed with caution[9]. In particular, we note:
  - Average annual productivity estimates are extremely sensitive to the choice of the start- and end-points. The AER's choice of 2012 as the starting point for its MPFP analysis results in the highest possible average annual productivity estimate out to 2016, when compared to other start-points.
  - The subset of "not materially inefficient" DNSPs' year-on-year efficiency results selected by the AER to estimate the frontier shift do not appear to be due solely to frontier shift. We do not consider an estimate of frontier shift that is based on a subset of DNSPs that include both negative productivity change and productivity changes of 7.7% pa as being plausible indicators of future opex productivity growth.
- The AER relies on ABS productivity data for 2012 to 2017 for its labour productivity analysis, which relates to an incomplete economic cycle. The ABS data should only be considered on the basis of full productivity cycles or a very long time period, as using data from a partial economic cycle can result in misleading estimates.
- The AER's recent econometric models (from November 2018), which use only the 2012-17 time period, indicates that DNSPs' opex needed to increase in order to deliver the outputs used to drive the AER's opex forecasts. Introducing an external productivity challenge that is not captured in the econometric models, and therefore not aligned with the outputs used to drive the opex forecasts, increases regulatory risk, and this risk is higher for those DNSPs for which the AER makes a catch-up efficiency adjustment.
- The AER has proposed using undergrounding[10] as an estimate of productivity. However, while undergrounding may lead to lower opex, we do not consider this as opex productivity. Further, using the historical average growth across all DNSPs could set perverse incentives for DNSPs. Instead, if the AER seeks to incorporate undergrounding into its opex forecasts, then the DNSPs' individual undergrounding forecasts could be incorporated into the AER's opex forecasting process using the econometric modelling coefficient.

Our Revised Proposal acknowledges the AER's Productivity Draft Decision. We wholly support the AER's undertaking of the productivity review, as part of the continuous improvement of regulatory techniques. Our submission to the AER's Productivity Draft Decision provided additional evidence for the AER to consider in making its Productivity Final Decision, which suggested a lower estimate of productivity growth was more robust. Despite this, we have adopted the AER's Productivity Draft Decision forecast productivity growth of 1.0% pa as a placeholder in our Revised Proposal. We intend to update this with the AER's Final Decision estimate during consultation with the AER following the release of the Productivity Final Decision in March/April 2019. This approach sets us a challenging productivity target in the best interests of customers, and we intend to achieve this as a result of the efficiency initiatives included in our Revised Proposal.

8 See Ausgrid submission, AER Draft Decision Paper, Forecasting productivity growth for electricity distributors, 21 December 2018 and Appendix 6.01 for further details.

9 It is standard practice to consider TFP growth over complete economic cycles (OECD, 2003, Measuring Productivity: Measurement of Aggregate and Industry-Level Productivity Growth, p. 119) The ABS notes similarly that the effects of temporary influences can be minimised by analysing averages of productivity statistics between growth cycle peaks (ABS website, 5260.0.55.002 – Estimates of Industry Multifactor Productivity, 2016/17). The Australian Energy Market Commission noted in its 2011 review into the use of TFP that at least eight years of robust and consistent data will be required to establish a TFP growth rate that could be used in a TFP methodology for price and revenue determinations (AEMC, 2011, Review into the use of total factor productivity for the determination of prices and revenues, p 23).

10 Undergrounding refers to the change in the proportion of the distribution network that is underground. The AER has suggested that an increase in the proportion of distribution networks that is underground is increasing which has positive opex productivity effects.

The only difference between how we are applying the forecast productivity growth to our forecast opex and the AER's standard approach is that we are applying the forecast productivity growth from FY21. This is because:

- Our base year opex includes embedded efficiencies that we will work hard to achieve, as outlined in section 6.4.1.
- We have gone through a significant period of transformation over the 2014-19 regulatory period that has enabled us to deliver very significant reductions in our opex. However, this has had a profound impact on our organisation and, as such, we require a period of time to bed down the existing transformation before delivering further productivity improvements. These fluctuations in productivity are recognised in well-regarded administrative science and human resources management literature, in which a number of short-term challenges arising from reductions in a business' workforce, which have the potential to give rise to a temporary decline or stagnation in productivity, are identified.[11]
- We have embedded a number of efficiencies into our opex forecasts by excluding a number of cost increases (as outlined in section 6.4.1) from our forecast. These include the costs we will incur as we transition to a lower level of capex. We will cover these costs by pursuing productivity initiatives to offset these cost increases.
- We are required to guarantee employment for a minimum number of employees to 30 June 2020 pursuant to regulatory obligations under the Energy Networks Assets (Authorised Transactions) Act 2015.

Our Revised Proposal includes a number of efficiency initiatives which are aimed at sustaining efficiency savings achieved in the 2014-19 regulatory period, and delivering further efficiency improvements, which will help us to deliver future productivity improvements. These include the Adapt program, our property refresh program and retirement of aged fleet.

Overall, the productivity challenge we are committing to reduces our total opex forecast by 10.6% for the 2019-24 regulatory period. In our view, this Revised Proposal addresses the productivity issues raised in the AER's Draft Decision, the AER's Productivity Draft Decision and by our customers and stakeholders.

11 Mone, M. A., 1994, Relationships between Self-Concepts, Aspirations, Emotional Responses, and Intent to Leave a Downsizing Organisation, Human Resource Management; Summer 1994; 33, 2, pp.281-298; Cascio, W. F., 1993, Academy of Management Executive, Vol. 7 No. 1, pp.95-104; and Wagar, T., 1998, Exploring the consequences of workforce reduction, Canadian Journal of Administrative Sciences, 15(4), pp.300-309.

6.5 Rationale for our Revised Proposal

6.5.1 Our opex forecast is based on the AER's base-step-trend methodology

In our Revised Proposal, we continue to apply the AER's forecasting methodology to develop our opex forecast. As noted in our Initial Proposal, the base-step-trend approach has the following benefits:

- It is simple and transparent
- It has been used effectively by the AER and other businesses
- It locks in the significant cost savings we have achieved through our transformation program.

The figure below summarises how we have applied this methodology in this Revised Proposal. The updated inputs reflect our response to the Draft Decision and the latest available information.

Figure 6.4

Our application of the AER's base-step-trend forecasting method

Our application of the AER's base-step-trend forecasting method

1. **Start with 2017/18 proposed base year**
   We start with the AER's opex allowance for 2017/18, which is lower than our actual opex in 2017/18. We consider that this is representative of the efficient costs needed to operate and maintain the network in 2017/18. This differs to our Initial Proposal view, which anticipated adopting actual underlying opex for 2017/18. Our proposed base year is consistent with the AER's view of efficient costs in the Draft Decision.

2. **Included Emergency recoverable works (ERW)**
   Our base year opex does not include the costs of repairing our network after it is damaged by a liable third party (ERW). These costs will be included from 2019/20 so we have added them to the base year ($6.29 million, being actual historic costs less what we can recover).

3. **Base Year**

4. **Trend the base forward using the rate of change**
   We trend base year opex forward by taking into account expected growth in input prices (0.5% per year on average), output (0.7% per year on average) and productivity (1.0% per year from 2020/21).

5. **Add step changes**
   We have added step changes for costs not included in our base year opex, i.e. demand management projects, (around $2 million per year).

6. **Add "bottom up" opex**
   For debt raising costs (around $7.8 million per year) we have used a specific or bottom up forecasting approach, which better reflects the nature of these costs.

7. **Forecast opex for 2019/20 to 2023/24**

The table below compares our revised forecast for each component of the methodology with the AER's Draft Decision and our Initial Proposal.

Table 6.4.

Comparison of our Initial Proposal, AER Draft Decision and Revised Proposal ($ million, real FY19)

OPEX COMPONENT	INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Base opex	2201.0	2197.1	2194.9
Base pex adjustment: Emergency Recoverable Works	26.8	0	31.4
Trend: Rolling forward the base year (FY18 to FY19 increment)	33.3	18.4	20.1
Trend: Price growth	56.0	32.4	29.8
Trend: Output growth	56.1	49.1	44.7
Trend: Productivity growth	0	0	-46.5
Step changes	29.1	8.5	10.2
Other costs: Debt raising costs	40.2	38.7	39.2
Total	**2442.5**	**2344.1**	**2323.8**

Note: numbers may not add due to rounding

Each opex component is discussed in turn below.

6.5.2 Base year

The AER's Draft Decision tested our proposed base year opex using multiple techniques, including revealed opex over the 2014–19 regulatory period, a review of expenditure cost categories and recent benchmarking analysis. The results of the AER's analysis indicate that our proposed base year opex reasonably reflects an efficient level of opex consistent with the opex criteria.

Stakeholders did not universally agree, however, we understand that we need to earn customer trust and so we have revised our approach to selecting the base year, and the productivity trend for our forecasts.

Our Revised Proposal adopts the AER's opex allowance for FY18 (as outlined in the AER's 2015 Determination) as our base year. We consider this is representative of our efficient recurrent opex requirements for the 2019–24 regulatory period. This differs to our Initial Proposal view, which anticipated adopting actual underlying opex (excluding non-recurrent costs) for FY18, consistent with the AER's standard methodology.[12]

Our actual underlying opex of $447.3 million in FY18 is comparable to the AER's alternate benchmark estimate in the Draft Decision of $439.4 million. However, despite major reductions in our costs, our actual opex in FY18 was higher than the AER's allowance for FY18. Recognising our customer concerns around affordability, we propose to adopt the AER's opex allowance for FY18 as our base year rather than our actual underlying opex.

Our revised estimate of our base year opex is consistent with the AER's alternative opex base year estimate in the Draft Decision.

12 The AER's standard forecasting methodology, as outlined in the Expenditure Forecast Assessment Guideline, and the AER's Draft Decision, adopts actual operating expenditure as the base year.

6.5.3 Base year adjustment: Emergency Recoverable Works

In our Initial Proposal, we adjusted our base year to account for a change in classification of our services between the current regulatory period and the 2019–24 regulatory period.

The AER's alternate estimate of opex in the Draft Decision did not include our proposed adjustment to the base year. In its Draft Decision, the AER concluded that it would require further information before accepting the proposal.

We have provided additional transparency around our historical accounting treatment of Emergency Recoverable Works (ERW) in support of our Revised Proposal. We engaged PwC to verify the historical financial treatment of ERW and address the AER's request for further information in the Draft Decision. Their report is provided in Attachment 6.06.

PwC reviewed the ERW revenue and expenses from 2014–2018 and confirmed these figures had not been previously reported to the AER as part of the standard control costs. PwC concluded that:

> *Our procedures confirmed that ERW balances, extracted from Ausgrid's audited historical financial information, have been historically categorised as part of the unregulated business and therefore have not been previously reported to the AER in the RIN reporting submissions during the period FY15-FY18, nor duplicated in other classifications (for example Standard Control opex).*

We estimated the adjustment for ERW as the annual cost of repairing the damage to the network (based on FY18 actual costs), less the revenue we would expect to recover from third parties found liable for causing damage to our network (based on 2017/18 actual receipts from third parties). We revised our forecast to include actual FY18 costs, rather than estimated costs which were higher than we had estimated in our Initial Proposal. See Attachment 6.01 for further details of how we calculated this adjustment.

Table 6.5 shows how we derived our proposed adjusted base year opex.

Table 6.5

Adjustment for ERW ($million, real FY19)

OPEX	2017/18
Proposed base year opex	438.98
Add adjustment for net cost to Ausgrid of ERW	6.29
Proposed adjusted base year opex	445.27

6.5.4 Rolling forward the base year

Our Initial Proposal included incremental opex between the base year and the final year of the current regulatory period, in line with the formula outlined in the AER's Expenditure Forecast Assessment Guideline (the Expenditure Forecast Assessment Guideline). This had the effect of applying the trend adjustments in the AER's 2015 Determination.

The AER's Draft Decision did not apply the Expenditure Forecast Assessment Guideline formula to estimate opex in FY19 because no Efficiency Benefit Sharing Scheme (EBSS) was applied during the current regulatory period. The AER noted that the Expenditure Forecast Assessment Guideline formula is designed to ensure a distributor is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year, consistent with other years in the regulatory period. However, as Ausgrid was not subject to the EBSS over the 2014-19 regulatory period, this consistency is not required. Instead, the AER calculated FY19 opex by escalating the base year by the rate of change to account for key drivers of opex growth (price, output and productivity growth) between the base year (FY18) and the final year of the current regulatory period.

We accept the AER's Draft Decision approach and have applied the trend adjustments (discussed on the next page) to roll forward the base year to FY19.

6.5.5 Trend adjustments

In accordance with the AER's methodology, we "trend" our adjusted base year forward to take account of how opex changes over time, reflecting:

- **Real price growth** – to reflect movements in prices that are expected to be different to inflation
- **Output growth** – to account for changes in how much output we expect to deliver
- **Productivity growth** – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

Table 6.6 shows the derivation of our total forecast rate of change.

Table 6.6

Forecast rate of change

RATE OF CHANGE	FY19	FY20	FY21	FY22	FY23	FY24
Price	0.19%	0.20%	0.38%	0.63%	0.77%	0.68%
Output	0.71%	0.68%	0.61%	0.63%	0.67%	0.62%
Productivity	0.00%	0.00%	1.00%	1.00%	1.00%	1.00%
Total	**0.90%**	**0.88%**	**-0.02%**	**0.25%**	**0.43%**	**0.29%**

Our revised forecasts for each of the three trend adjustments are explained below.

Real price growth

In our Initial Proposal, we explained that we engaged BIS Oxford Economics to forecast future labour costs. For materials, we assumed that costs would increase in line with CPI. To calculate the weighted average price increase, we assumed that 59.7% of our opex is labour related. We explained that this percentage is consistent with the AER's standard approach.

In relation to real price growth, the AER's Draft Decision did not accept our Initial Proposal. Instead, the AER adopted the average forecast growth in the wage price index (WPI) for the New South Wales utilities industries of:

- their own consultant, Deloitte Access Economics, and
- our consultant, BIS Oxford Economics.

The AER applied the same weights as we proposed to account for the proportion of opex that is labour and the proportion that is non-labour.

For this Revised Proposal, we have accepted the AER's Draft Decision approach to using the average of Deloitte Access Economics and BIS Oxford Economics forecasts. We have applied updated forecasts from BIS Oxford Economics to calculate the average forecast change in real labour costs, shown in Table 6.7.

Table 6.7

Forecast change in real labour costs (%)

LABOUR	FY19	FY20	FY21	FY22	FY23	FY24
BIS Oxford Economics labour forecast	0.71%	0.66%	1.22%	1.53%	1.74%	1.44%
Deloitte Access Economics labour forecast	-0.08%	0.00%	0.06%	0.57%	0.83%	0.84%
Average labour forecast	**0.31%**	**0.33%**	**0.64%**	**1.05%**	**1.28%**	**1.14%**

Our Revised Proposal forecasts for the combined effect of the labour cost increases and the assumed CPI increase in the costs of materials are shown in Table 6.8.

Table 6.8

Forecast real price growth (%)

RATE OF CHANGE	FY19	FY20	FY21	FY22	FY23	FY24
Price	0.19%	0.20%	0.38%	0.63%	0.77%	0.68%

Output growth

As explained in our Initial Proposal, we have included an allowance for the projected increase in output in accordance with the AER's standard methodology. This methodology measures growth in terms of customer numbers, circuit length, energy throughput and ratcheted maximum demand. The impact of the projected growth on opex is determined by using an econometric model developed by the AER's consultants, Economic Insights.

In its Draft Decision, the AER adopted the average of the output growth rates forecast using the specification and weights derived from the results of the four benchmarking models it presented in its 2017 Annual Benchmarking Report.[13] This was an update to its previous approach, which used the weights from a single econometric model.

For our Revised Proposal, we have adopted the AER's revised approach to forecasting output growth, as set out in the Draft Decision. We have also used the revised weights, as published in the AER's 2018 Annual Benchmarking Report.

Our revised forecast changes in outputs and the opex growth factors as set out in the tables below.

Table 6.9

Forecast change in outputs (%)

OUTPUT	FY19	FY20	FY21	FY22	FY23	FY24
Customer numbers	1.23%	1.05%	0.87%	0.88%	0.94%	0.93%
Circuit length	0.32%	0.42%	0.43%	0.57%	0.58%	0.52%
Ratcheted maximum demand	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Energy throughput	-0.73%	0.86%	1.49%	1.45%	1.65%	0.58%

Table 6.10

Forecast change in outputs (estimated change in opex for a 1% change in output)

OUTPUT	SFA CD	LSE CD	LSE TLG	MPFP
Customer numbers	70.80%	67.56%	51.48%	31.00%
Circuit length (km)	16.80%	11.81%	13.86%	29.00%
Ratcheted maximum demand (MW)	12.40%	20.63%	34.66%	28.00%
Energy throughput (GWh)	0.00%	0.00%	0.00%	12.00%

The table below is a product of the previous two steps.

Table 6.11

Forecast output growth (%)

RATE OF CHANGE	FY19	FY20	FY21	FY22	FY23	FY24
Output	0.71%	0.68%	0.61%	0.63%	0.67%	0.62%

13 The AER used the output specification and weights derived from the following four econometric models: Opex multilateral partial factor productivity, Cobb Douglas SFA, Cobb Douglas LSE, and Translog LSE

Productivity

For the reasons set out in section 6.4.2, we have updated our productivity growth factor as set out in Table 6.12.

Table 6.12

Forecast productivity (%)

RATE OF CHANGE	FY19	FY20	FY21	FY22	FY23	FY24
Productivity	–	–	1.00%	1.00%	1.00%	1.00%

6.5.6 Step Changes

As explained in our Initial Proposal, step changes are increases or decreases in our opex, associated with meeting new or changed regulatory obligations or opex-capex trade-offs. In our Initial Proposal, we forecast two step changes:

1. Identified demand management projects, which will deliver capex savings
2. Price reform research to inform and expedite our transition to more cost-reflective pricing as required by the AEMC's rule change for Distribution Network Pricing Arrangements.

The AER's Draft Decision included $8.5 million in its alternative opex forecast for demand management, accepting three of Ausgrid's proposed demand management projects. It did not include a step change for the price reform research project.

We reviewed our Initial Proposal in response to the AER's Draft Decision:

- We accept the AER's Draft Decision not to include a step change for the price reform research.
- We have reviewed our proposed Demand Management (DM) programs in line with our revised capex program.

Further details are provided below.

Demand Management

In our Initial Proposal, we explained that 40 replacement projects (comprising over $500 million in investment) were assessed for DM potential. We proposed to proceed with six of these projects where the benefits of implementing a DM solution (i.e. the benefits from deferring replacement capex) outweighed the costs. We also proposed a number of smaller projects associated with local high voltage (HV) augmentation of the network.

The AER did not accept all of the proposed DM projects. It's Draft Decision was to accept an opex step change for three replacement projects (Mascot, Lidcombe and St Ives), but reject an opex step change for the remaining three projects and the HV augmentation program.

We have revised our DM projects in response to the AER's Draft Decision and to take into account new information to ensure that they are efficient and meet the needs of our customers. We undertook a cost-benefit analysis and probabilistic assessment approach to inform our network capex forecast.

For the 2019-24 regulatory period, we are proposing a DM program consisting of two significant projects associated with the replacement or retirement of aged assets and a number of smaller projects associated with local augmentation of the network. Our Revised Proposal is in line with the AER's Draft Decision.

As requested by the AER, we have provided an improved cost-benefit assessment for the HV augmentation program to underpin our request for a step change in opex to defer elements of this program of works. The updated cost-benefit assessment shows that demand management opex of $4.1 million offers an efficient capex-opex trade-off to defer $17.9 million in capex.

Our forecast DM opex is shown in Table 6.13. See Chapter 5 for details on the proposed DM projects.

Table 6.13

Forecast DM opex ($million, real FY19)

OPEX	FY20	FY21	FY22	FY23	FY24	TOTAL
Lidcombe	0.00	0.00	0.52	0.53	0.54	**1.60**
Mascot	1.17	1.21	1.22	0.24	0.68	**4.52**
HV augmentation	0.17	0.57	0.62	1.42	1.32	**4.09**
Total	**1.34**	**1.77**	**2.37**	**2.19**	**2.54**	**10.21**

Price reform research

Our Initial Proposal explained that we intend to launch a comprehensive research program to inform potential pricing decisions over the 2019-24 regulatory period and thereafter. We explained that the research will seek to understand the attitudes towards energy service pricing amongst customers, community groups, retailers and aggregators.

The AER's alternate opex forecast removed our proposed step change increase in opex for research into, and engagement on, network price reform. While the AER supports further consideration and engagement by Ausgrid on how to best transition to cost reflective pricing, it considers this type of activity to be part of a distributor's standard business activities and therefore accommodated within the existing costs and base year opex. Further, the AER does not consider this represents a cost increase associated with a new regulatory obligation.

Whilst we feel that significant investment in customer education, engagement and involvement in pricing is a necessary pre-requisite for effective reform, we accept the AER's Draft Decision on the price reform research step change and have not included it in our Revised Proposal. We are still committed to undertaking price reform research, but we will seek to achieve the same outcome without such a comprehensive program.

6.5.7 Other costs

As noted in our Initial Proposal, some expenditure is forecast on a 'bottom up' basis, outside the base-step-trend forecasting methodology. In particular, it is standard regulatory practice to adopt a 'bottom up' approach to forecasting debt raising costs, which are an unavoidable aspect of raising debt. These costs include; underwriting fees, legal fees, company credit rating fees and other transaction costs.

In our Initial Proposal, we explained that we adopted the AER's preferred method to forecast this cost by applying a benchmark debt raising unit rate to the debt portion of our RAB.

6.6 Summary of opex forecasts

Our total revised opex forecast is presented in the table below. As already noted, the base-step-trend forecasting approach determines the forecast at an aggregate level. However, for the purposes of this document, we show how this total opex forecast is allocated between opex categories. We have derived this allocation using the categories reported in our RIN responses, which is based on the categories of forecast spend in the base year (FY18). The same allocation has been applied to our total opex forecast over the 2019-24 regulatory period. The actual allocation between categories over the 2019-24 regulatory period may change to that presented in Table 6.14, however we will manage any variances within the total opex allowance.

Table 6.14

Total forecast opex ($million, real FY19)

OPEX	FY20	FY21	FY22	FY23	FY24	TOTAL
Maintenance	140.42	140.39	140.74	141.35	141.76	704.7
Network Support	113.27	113.68	114.55	114.85	115.53	571.9
Property	62.75	62.73	62.89	63.16	63.35	314.9
Information Technology	51.17	51.16	51.29	51.51	51.66	256.8
Corporate support	86.98	86.96	87.17	87.55	87.81	436.5
Total forecast opex (excluding debt raising costs (DRC))	**454.58**	**454.92**	**456.64**	**459.42**	**460.11**	**2284.7**
Distribution	419.70	420.04	421.68	423.30	424.89	2109.6
Transmission	34.89	34.88	34.97	35.12	35.22	175.1
Subtotal	**454.58**	**454.92**	**456.64**	**458.42**	**460.11**	**2284.7**
Other opex (DRC)	7.76	7.84	7.88	7.86	7.83	39.2
Total forecast opex (including DRC)	**462.34**	**462.76**	**464.52**	**466.27**	**467.94**	**2323.8**

Note: Totals may not add due to rounding.

6.7 National Electricity Rules compliance

As outlined in our Initial Proposal, the NER sets out specific requirements in relation to our opex forecasts. In particular, our forecasts must achieve the opex objectives, which include the requirement to provide safe and reliable distribution services to our customers, and to comply with our regulatory obligations. The NER also stipulates that our expenditure forecasts should reflect the efficient and prudent costs of achieving the opex objectives.

The information set out in this chapter and Attachment 6.01 demonstrates that our revised opex forecast addresses the AER's Draft Decision and the feedback from our customers. We are confident that our revised opex forecast complies with the requirements of the NER and aligns with the expectations of our customers. We have discussed these forecasts with many customer groups and we believe we have their support. Therefore we believe our forecasts are capable of acceptance by the AER in its Final Decision. In particular, we note:

- Our proposed base year is consistent with our peers and the AER's alternate estimate of our base year, reflecting our achievement of substantial savings over the 2014-19 regulatory period,
- We have transformed our business to provide a more efficient cost base and to embed a culture of efficiency, including active consideration of opex-capex trade-offs, and
- We have taken account of customers' concerns regarding affordability in preparing our opex forecasts and have set ourselves a challenging productivity target in our forecasts by embedding efficiencies in our base year and including a 1.0% productivity factor from FY21, which results in a reduction to our total opex forecast of $269.8 million or 10.6% for the 2019-24 regulatory period.

In developing our revised opex forecasts, we have applied the AER's preferred base-step-trend methodology, including the adjustments outlined in the Draft Decision. Accordingly, our forecasts lock in the ongoing saving of $100 million per year we have made through transforming the business.

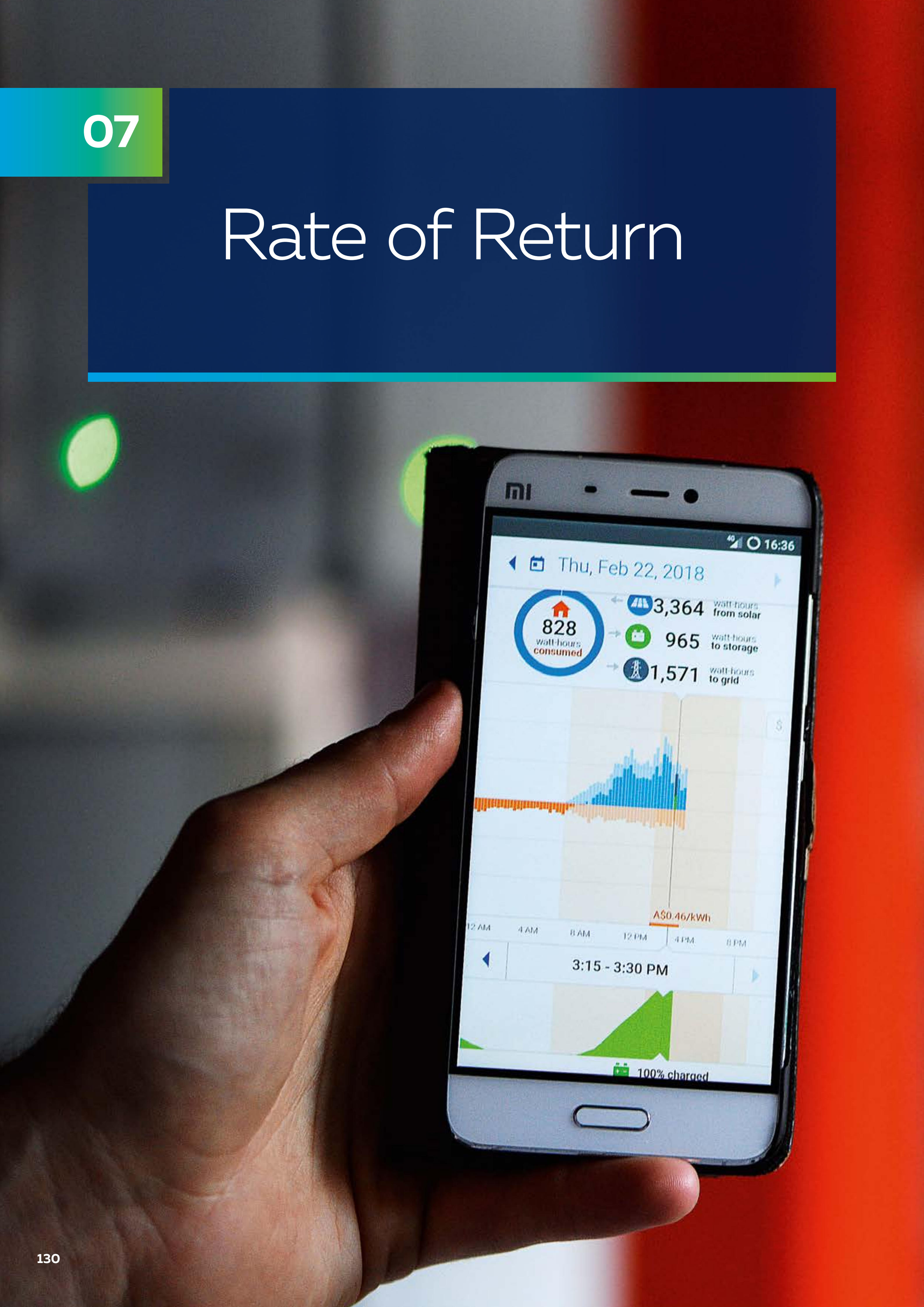
In forecasting our opex requirements, we must achieve an appropriate balance between the pressure to reduce expenditure further and the importance of maintaining safety and reliability while managing network risks efficiently, both now and in the future. For the reasons set out in this chapter and Attachment 6.01, we believe we have achieved an appropriate balance and that our forecast is in the long-term interests of customers.

6.8 Material to support our opex proposal

Attachment 6.01 provides further information to support our revised opex forecast for the 2019–24 regulatory period. We have provided information in a way that reflects the AER's assessment process and its feedback in its Draft Decision. We are open to providing any other information requested by the AER and stakeholders.

07

Rate of Return



7.1 We have accepted the AER's final decision on its Rate of Return review

We explained in our Initial Proposal that we had adopted an estimate of the rate of return, using a transition to the "10-year trailing average" approach to the cost of debt, and also adopting the AER's 2013 Rate of Return Guideline (2013 RoR Guideline) parameters for the cost of equity. In preparing our Initial Proposal, we adopted the 2013 RoR Guideline methodology because in October 2016 the Australian Energy Market Commission (AEMC) introduced, via amendments to the National Electricity Rules, transitional arrangements to specify that the 2013 RoR Guideline methodology would apply to the 2019–24 regulatory determination for Ausgrid (and a number of other network service providers). The AEMC's stated objective in introducing these transitional arrangements was to provide affected network service providers with regulatory certainty.

In its Draft Decision, the AER applied the 2018 Draft Rate of Return Guideline (Draft 2018 RoR Guideline) when determining Ausgrid's allowed rate of return for the 2019-24 regulatory period. Further, on 17 December 2018 the AER published its Final Decision on its Rate of Return review. The Council of Australian Governments (COAG) Energy Council has determined that the National Electricity Law should be amended to replace the existing non-binding rate of return guideline with a binding rate of return instrument. The legislative amendments have been passed into law and are now legally binding. This binding rate of return instrument applies to service providers currently under review, including Ausgrid.

We have also received feedback from our consumers that adopting the Draft 2018 RoR Guideline would deliver lower prices and be in line with customer priorities. We understand the feedback and we also understand that affordability is a significant concern.

In light of the binding 2018 Rate of Return Instrument and consistent with the feedback we have received through our customer consultation, in our Revised Proposal we have adopted the approach set out by the AER in the Final 2018 Rate of Return Instrument (2018 RoR Instrument). In doing so, we have adopted, as a placeholder, the allowed rate of return set out by the AER in its 2018 RoR Instrument. Table 7.1 presents Ausgrid's proposed rate of return in accordance with this approach.

Table 7.1

Our rate of return proposal for 2019–20

	AUSGRID INITIAL PROPOSAL	AER DRAFT DECISION	AUSGRID REVISED PROPOSAL
Overall weighted average cost of capital (WACC)	6.33%	5.96%	5.99%
Return on equity	7.20%	6.30%	6.40%
Return on debt	5.75%	5.73%	5.72%
Gearing	60%	60%	60%
Gamma	0.4	0.5	0.585

Notes: Our return on debt estimates adopt the averaging periods set out in confidential Attachment 7.02 of our Initial Proposal, which has been approved by the AER. The risk-free rate increased slightly compared to the proposed value but remains unchanged at one decimal place.

Ausgrid also notes that the overall WACC, the return on equity and the return on debt will be updated by the AER close to the start of the 2019-24 regulatory period, using the latest market information available at the time, and in accordance with the AER's 2018 RoR Instrument.

7.2 What we heard and how we've responded in our Revised Proposal

7.2.1 Our Initial Proposal

In our Initial Proposal, we explained that we applied the AER's 2013 RoR Guideline to estimate all elements of the allowed rate of return and gamma consistent with recent AER decisions. Our Initial Proposal took this approach in light of the Australian Energy Market Commission's October 2016 rule determination on amendments to the National Electricity Rules, in relation to the Rate of Return Guideline Review.

In applying the 2013 RoR Guideline together with the latest available market data, we proposed an overall allowed rate of return (nominal, WACC) of 6.33% for the first year of the forthcoming regulatory period. We noted that the cost of debt will be updated annually for changes in prevailing debt yields.

We explained that the prevailing conditions in the market for equity funds suggest a higher return on equity than would be calculated using the AER's 2013 RoR Guideline. However, we noted that Ausgrid had taken onboard feedback from stakeholders that consumers of electricity in NSW are currently facing cost of living pressures. Therefore, Ausgrid proposed to accept the return on equity commensurate with the AER's 2013 RoR Guideline.

7.2.2 Consumer feedback

As part of the 2019–24 reset process, we have undertaken extensive consultation with our customers. The feedback we have received is that consumers consider that adopting the outcomes of the Draft 2018 RoR Guideline will deliver lower prices and be more in line with customer priorities than the approach we took in our Initial Proposal, which was to adopt the 2013 Rate of Return Guideline.

In response to our Initial Proposal, the Consumer Challenge Panel submitted that: [1]

> *The AER is currently undertaking a review of its approach to rate of return, and the Commonwealth Government has stated that it intends that this rate of return will be binding on all network businesses, including the three NSW businesses and the AER. It is likely that this legislation will be passed before the New South Wales regulatory proposals are finalised and, therefore, we expect that the new binding rate of return guideline will apply. We support this outcome.*

In addition, Energy Consumers Australia submitted that: [2]

> *The AER notes in its Issues Paper that Ausgrid has adopted the approach to setting the allowed rate of return set out in the 2013 Rate of Return Guideline and subsequent determinations. They go on to say that should the revised 2018 guideline be released by the end of the year and be binding on the distribution businesses, as proposed by the COAG Energy Council, it would apply to the 2019–24 final determinations for the three NSW businesses.*
>
> *In the event that the legislation does not come into effect, we submit that the allowed rate of return should be calculated using the parameters and approaches proposed by the AER in its 2018 Final Guideline.*

7.2.3 The AER's Draft Decision

In its Draft Decision, the AER rejected our proposed rate of return of 6.33%. In doing so, the AER stated that:

- The 2013 RoR Guideline is non-binding;
- The COAG Energy Council has (since the AEMC's 2016 rule change, and since we submitted our Initial Proposal) determined that the National Electricity Laws will be amended to establish a binding rate of return instrument that would apply to all network service providers under review, including Ausgrid;
- The legislative amendments to the National Electricity Laws have not yet passed, so the AER continues to operate, under the current rules, and under the 2013 RoR Guideline;
- The AER has considered all submissions made on the Draft 2018 RoR Guideline before making a final determination on the rate of return to apply to Ausgrid for the 2019-24 regulatory period.

The AER's Draft Decision proposed an alternative rate of return of 5.96%, with a return on equity of 6.30% and a return on debt of 5.73% in the first year of the 2019–24 regulatory period.

1 CCP, CCP10 Response to AER Issues paper and revenue Proposals for NSW Electricity Distribution Businesses 2019–24, August 2018, pp. 8–9.

2 ECA, Ausgrid Regulatory proposal 2019–24: Submission to the AER Issues Paper, August 2018, pp. 10–11.

7.3 Our Revised Proposal

In light of the binding 2018 Rate of Return Instrument and consistent with the feedback we have received from customers on our Initial Proposal, our Revised Proposal applies the AER's 2018 RoR Instrument as the basis for determining Ausgrid's allowed rate of return for the 2019–24 regulatory period.

Our Revised Proposal adopts an overall rate of return (nominal, vanilla) of 5.99% for the first year of the 2019–24 regulatory period. We propose that this rate of return will be updated in each year of the regulatory period in line with changes in the transition to a trailing average return on debt allowance.

7.3.1 Rate of return

Our Revised Proposal for the nominal vanilla WACC for 2019–20 is 5.99%. This estimate will need to be updated close to the start of the 2019–24 regulatory period (for the risk-free rate and the return on debt) using the methodology set out in the AER's 2018 RoR Instrument.

Table 7.2 sets out each parameter estimate that underpins this nominal vanilla WACC estimate, as well as Ausgrid's proposed basis for estimating each parameter.

Table 7.2

Ausgrid's rate of return proposal and basis for estimation

PARAMETER	2018 RATE OF RETURN INSTRUMENT	AUSGRID APPROACH	AUSGRID REVISED PROPOSAL
Risk-free rate	Estimated using:[3] • Yields on 10-year Commonwealth Government Securities (CGS) • A 20 consecutive business day averaging period, as close as practicably possible to the commencement of the regulatory period.	• Adopt 2018 Final Rate of Return Instrument • Use 20-day averaging period to 16 November 2018	2.70%
Equity beta	Fixed estimate of 0.6.[4]	• Adopt 2018 Final Rate of Return Instrument	0.6
Market risk premium	Fixed estimate of 6.1%.[5]	• Adopt 2018 Final Rate of Return Instrument	6.1%
Return on equity			6.40%
Return on debt	Return on debt allowance calculated as follows:[6] • Apply 10-year trailing average • Continue with 10-year transition from "on-the-day" approach to 10-year trailing average approach • Use of 10-year debt maturity • Simple average of Bloomberg, RBA and Thomson Reuters curves • Application of two-thirds weight on BBB rating and one-third weight on A rating	• Adopt 2018 Final Rate of Return Instrument • Averaging period set out in confidential Attachment 7.02 of our Initial Proposal, which has been approved by the AER	5.72%
Imputation Tax Credits (Gamma)	Fixed estimate 0.585[7]	• Adopt 2018 Final Rate of Return Instrument	0.585
Gearing	Fixed at 60%.[8]	• Adopt 2018 Final Rate of Return Instrument	60%

3 AER, 2018 Rate of Return Instrument, Explanatory Statement, December 2018, p.125.
4 AER, 2018 Rate of Return Guideline, Explanatory Statement, December 2018, p.142.
5 AER, 2018 Rate of Return Guideline, Explanatory Statement, December 2018, p.220.
6 AER, 2018 Rate of Return Guideline, Explanatory Statement, December 2018, p.276.
7 AER, 2018 Rate of Return Guideline, Explanatory Statement, December 2018, p.307.
8 AER, 2018 Rate of Return Guideline, Explanatory Statement, December 2018, p.64.

7.3.2 Other parameters related to the rate of return

Additionally, in this Revised Proposal we:

- Adopt a placeholder estimate of expected inflation of 2.42% in accordance with the AER's position on the regulatory treatment of inflation (published in December 2017). The consumer price index inflation forecasts in the Reserve Bank of Australia's November 2018 Statement on Monetary Policy imply that the estimate of expected inflation remains unchanged from the estimate determined by the AER in the 2018 RoR Instrument. Ausgrid notes that this estimate of inflation will need to be updated by the AER with the latest information available for the Final Decision.
- Adopt the AER's standard approach to estimating debt raising costs. Assuming a nominal vanilla WACC of 5.99%, we propose an allowance for debt raising costs of $39.2 million in FY19 prices over the 2019–24 regulatory period. In accordance with the AER's standard approach, this estimate will need to be updated by the AER close to the start of the 2019–24 regulatory period in the event that the estimate of the vanilla WACC estimate is updated.
- Adopt the AER's standard approach to estimating equity raising costs. In accordance with this approach, and the AER's 2018 RoR Instrument, we propose an allowance of zero for equity raising costs.

08

Alternative control services


freedom
on the move

08

Alternative control services

Our Revised Proposal

Alternative control services are customer specific or customer requested services which the AER regulates by setting a maximum fee known as a 'price cap'. This method of pricing enables a 'user pays' approach.

Our alternative control services include public lighting, non-advanced metering and ancillary (non-routine) services. Customers have told us they want Ausgrid to prioritise affordability in the 2019-24 regulatory period. We consider that our Revised Proposal for alternative control services aligns to that priority.

Public Lighting – Ausgrid will undertake a mass rollout of light-emitting diode (LED) luminaires. Moving to a more advanced lighting technology will help us maintain reliability at existing levels. LED luminaires are also significantly more energy efficient, lowering our carbon footprint and leading to a more sustainable, environmentally responsible service.

Metering – Our opex is 28% lower per customer below levels the AER has accepted for other electricity distributors, indicating that we are delivering value for money.

Ancillary Network Services – We have also applied the AER's benchmark labour rates in the development of our prices.

How our Revised Proposal responds to customers

Public lighting

We will transform our public lighting service by completing a mass rollout of 125,000 energy-efficient LED luminaires; equal to half of all streetlights on public roads in our service area. Providing significant cost and environmental benefits across our network area.

Metering

Our Revised Proposal pursues affordability by delivering a real price reduction of 12% in annual metering charges for a customer on a basic accumulation meter. Our metering opex will start at $23.2 million in FY20 and decline to $18.8 million by FY24, a 19% reduction.

Ancillary network services

We have adopted the AER's Draft Decision on the key input (labour) into our ancillary network services, meaning that the prices our customers pay will be reflective of the AER's estimation of the efficient cost of service provision.

How our Revised Proposal responds to the AER

We accept most aspects of the AER's Draft Decision for alternative control services. This includes lower luminaire failure rates assumptions for public lighting, and reduced labour rates of between 1.4% and 10.8% for ancillary network services.

Our metering proposal does not apply some aspects of the AER's Draft Decision, including the application of a negative step change which we do not consider to be required given our application of the AER's preferred structure of metering charges.

8.1 We will deliver price reductions for our customers by embedding cost savings across all of our alternative control services

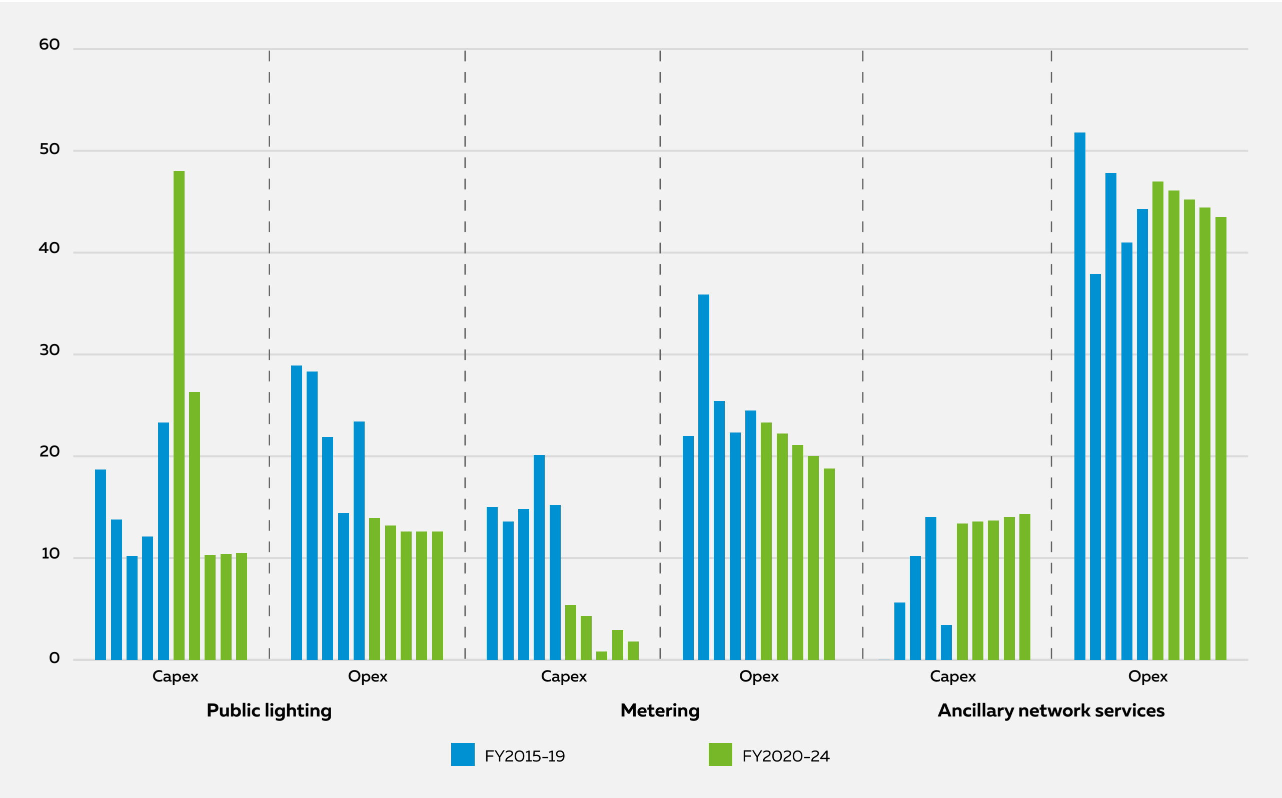
Alternative control services are customer specific or customer-requested services. The AER regulates them by setting a maximum fee known as a 'price cap' which is charged separately from our general network prices. This enables a 'user pays' approach, in which only the customers who use our public lighting, metering or ancillary network services pay for them.

Our alternative control services proposal for public lighting, non-advanced metering and ancillary network services adopts most aspects of the AER's Draft Decision and, by embedding savings into our cost build up, delivers sustainable price reductions for our customers over the 2019-24 regulatory period.

Figure 8.1 sets out our annual capex and opex for each category of alternative control services over the current 2014-19 regulatory period and the upcoming 2019-24 regulatory period. It shows a significant downward trend in opex for both public lighting and metering services. Opex is forecast to increase for ancillary network services, however this is beyond our control as it is driven by the introduction of new services from FY20 stemming from the AER's ring fencing guidelines.

Figure 8.1.

Annual opex and capex in the 2014–19 and 2019–24 regulatory period ($million, real FY19)



Other notable features of our alternative control services capex and opex in Figure 8.1 include:

- **Public lighting** – our planned mass LED[1] rollout will lead to a one-off increase in our public lighting capex during the first year of the 2019–24 regulatory period, but a corresponding decline in opex, which will deliver a total lower cost of service for our customers
- **Metering** – our forecast metering capex is limited to indirect, CAM allocated costs, while our forecast opex incorporates a decline over the 2019–24 regulatory period, as our existing customer base transitions to more advanced metering services offered in contestable markets

1 Light emitting diode (LED).

- **Ancillary network services** – over the 2019–24 regulatory period we will be required to perform less metering related ancillary network services, and this has been incorporated into our opex forecast, along with a lower allocation of indirect, CAM allocated capex.

8.2 What we heard and how we've responded in our Revised Proposal

Table 8.1

Components of our proposal

	WHAT WE HEARD	HOW WE'VE RESPONDED
1. Public lighting	Customers want us to maintain recent levels of engagement and to act quickly on our LED rollout.	We are committed to working collaboratively with our public lighting customers and are planning a mass rollout of 125,000 LED luminaires.
2. Metering opex – Step change	The AER adjusted our base level of opex via a negative step change for an apparent reduction in "fixed" costs.	Our opex will organically 'step down' via the AER's preferred structure of metering charges so an additional step change is not required.
3. Ancillary network services	Greater transparency is needed in billing.	Our simplified charging structure will assist in providing greater transparency.

8.3 Public lighting

Public lighting is an essential service that promotes safety of communities and roadway users. Ausgrid is the largest operator of public lights in Australia and provides this service across our entire network area.

Our public lighting service encompasses the provision, construction and maintenance of public lighting assets within our local network service area. Public lighting services are separately identified and regulated, but delivered by our distribution network business. This unlocks efficiencies in forecasting, planning and operations which are in the long-term interests of customers.

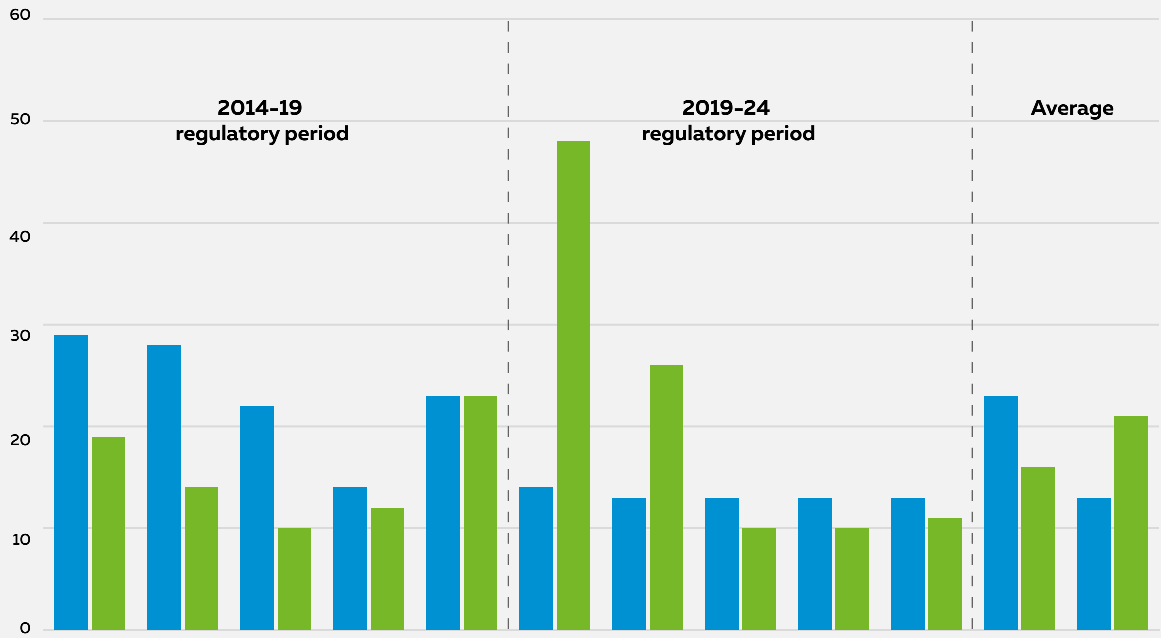
8.3.1 Revised expenditure forecast

Our revised public-lighting proposal forecasts $64.9 million in opex and $105.6 million in capex for the 2019–24 regulatory period.

Figure 8.2 sets out our public lighting expenditure profile for both opex and capex. It does this for each year of current 2014–19 regulatory period and the upcoming 2019–24 regulatory period.

Figure 8.2

Forecast and historical public lighting expenditure ($million, real FY19)



	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	Average FY15–19	Average FY20–24
Opex	29	28	22	14	23	14	13	13	13	13	23	13
Capex	19	14	10	12	23	48	26	10	10	11	16	21

It can be seen in the above that our public lighting opex is forecast to steadily decline. This is primarily because we are rolling-out LED luminaires which are less costly to operate than older lighting technologies. Our customers will ultimately retain the benefits from this rollout, given that the operating cost savings LEDs unlock will be passed on to them through lower maintenance charges.

> Mass roll-out of 125,000 LED luminaires by the end of the 2019–24 regulatory period

We are forecasting a step change in capex in FY20, as shown above. This too is driven by our planned rollout of LED luminaires – an investment program which our customers strongly support. For them, LEDs deliver a lower total cost of service. Not only are they cheaper to maintain, they also use less energy and deliver savings to our customers through lower energy bills, and reduced emissions, which shrink their carbon footprint.

By the end of the 2019–24 regulatory period, we aim to have rolled-out 125,000 LED luminaires, equal to half of all our streetlights on minor and major roads, which will transform our public lighting service and deliver significant benefits to both our customers and the environment.

8.4 Metering

We own and operate over two million type 5 and 6 meters. A type 6 meter, or "accumulation meter", only records electricity consumption over a period of time, whereas a type 5 meter, otherwise known as a "manually read interval meter or MRIM", can record both how much and, importantly, when electricity is used (in no greater than 30 minute intervals).

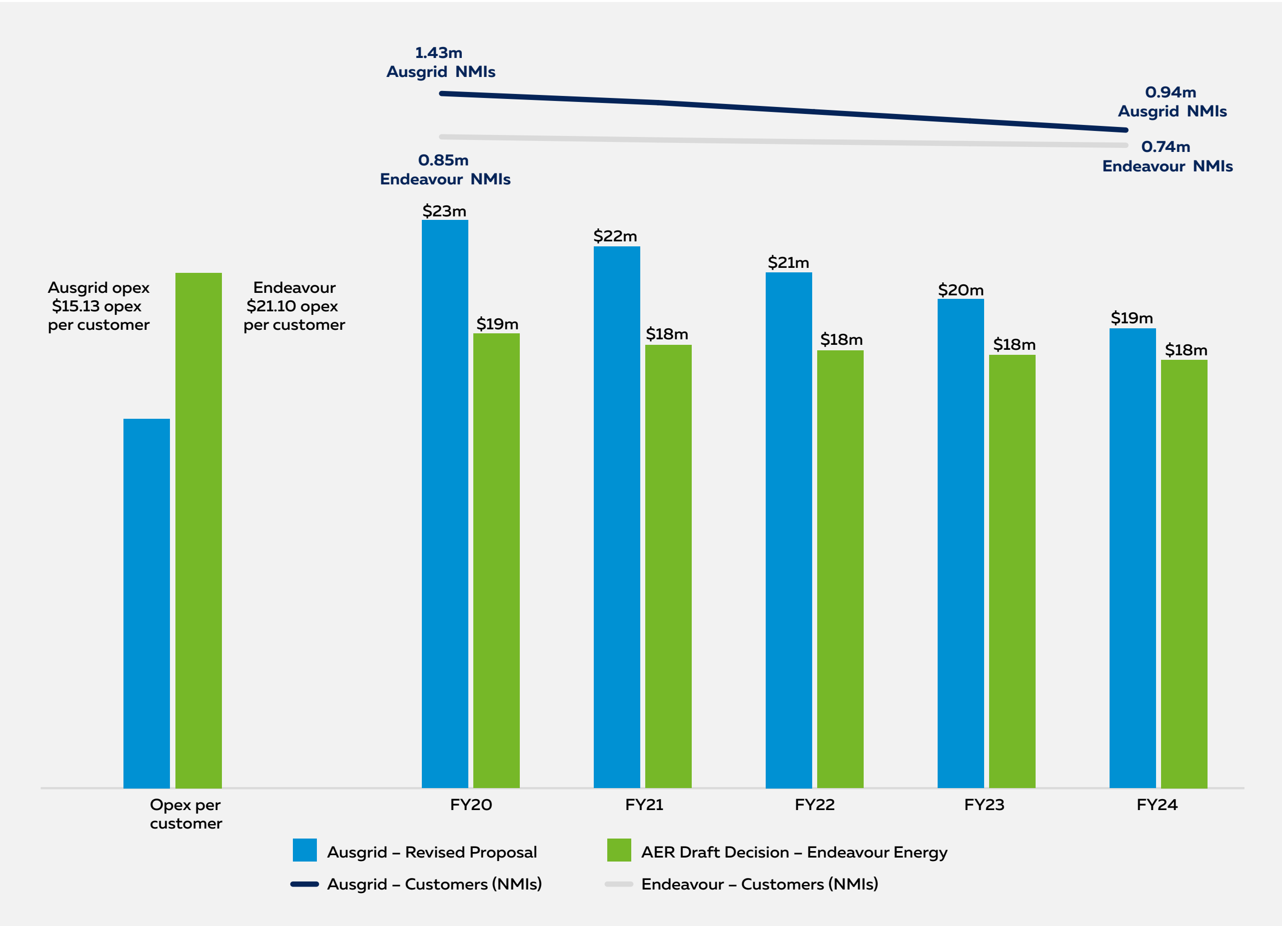
8.4.1 Revised Proposal stacked up against our nearest comparator firm

We are forecasting $105.4 million in metering opex in the 2019–24 regulatory period. To test the efficiency of this forecast, we benchmarked it against what the AER considered to be efficient for our closest comparator firm in the NEM.

Figure 8.3 shows the results of our benchmarking analysis. On a per customer basis, it reveals that our Revised Proposal is significantly more efficient than what the AER accepted in its Draft Decision for Endeavour Energy's 2019–24 regulatory period. Our Revised Proposal is based on a metering opex forecast of **$15.13 per customer** whereas the AER considered a metering opex of **$21.10 per customer** for Endeavour Energy to be efficient.

Figure 8.3

Opex per customer, total opex and customer numbers ($real FY19)



Our lower opex per customer underscores the efficiency of our forecast in total. This, too, is demonstrated in Figure 8.3. It shows that in FY20 we are forecasting a higher total opex than Endeavour Energy, which we would expect as we have about 500,000 more national metering identifiers (NMIs) at that time. Our total opex then declines over the period to a total opex more in line with Endeavour Energy in FY24, though we forecast to still have 200,000 more NMIs.

8.4.2 Building block expenditure

Our Revised Proposal applies the price-cap control mechanism the AER specified for alternative control type 5 and 6 metering in its final framework and approach paper.

To develop our proposed price caps, we have applied the 'building block approach'. This involved forecasting the revenue required to deliver type 5 and 6 metering services over the 2019–24 regulatory period. Table 8.2 sets out this aspect of our Revised Proposal.

Table 8.2

Our revised building block proposal ($million, real FY19)

	INITIAL PROPOSAL	AER DRAFT DECISION	REVISED PROPOSAL
Direct capex	0	0	0
CAM allocated capex	15.9	15.9	15.2
Opening metering RAB as of 1 July 2019	218.2	218.2	207.4
Metering opex 2019–24	105.8	93.06	105.1

Note: Metering opex includes debt raising costs.

8.5 Ancillary network services

Ancillary Network Services are non-routine services Ausgrid provides to individual customers on an 'as requested' basis. Examples of these services include providing design-related information for connections to be made to our network, special meter reads and site-establishment fees.

The main cost input into our ancillary network services is labour. For this cost input we have applied the AER's benchmark labour rates for each of the six categories for labour we use in the delivery of ancillary network services. These benchmark labour rates are compared against our Initial Proposal in Table 8.3.

Table 8.3

Our revised labour rates ($real FY19)

	INITIAL PROPOSAL	REVISED PROPOSAL	DIFFERENCE
Admin	99.84	102.26	2.42
Technical Specialist	160.10	153.39	(6.71)
Engineer	199.01	191.74	(7.27)
Field Worker	150.00	147.83	(2.17)
Senior Engineer	236.51	210.91	(25.60)
Engineering Manager	278.88	255.54	(23.34)

09

Incentive schemes and pass through

09

INCENTIVE SCHEMES AND PASS THROUGH

Responding to incentives to deliver for customers

Our Revised Proposal

The incentive schemes are an important component of incentive-based regulation, and they complement the AER's approach to assessing efficient costs. The schemes provide important balancing incentives to encourage us to pursue expenditure efficiencies and demand side alternatives, while maintaining the reliability and overall performance of our network.

Ausgrid proposes:

- the application of the Efficiency Benefit Sharing Scheme (EBSS). The EBSS allows customers to share the benefits of Ausgrid's reduced operating expenditures with customers retaining approximately 70 per cent of the savings achieved, leading to lower network prices going forward;
- the AER's Capital Expenditure Sharing Scheme (CESS) be applied to the 2019–24 regulatory period. The CESS allows customers to share the benefits of Ausgrid's increased capital expenditure efficiency; we believe it is in the best interest of consumers to continue the application of the CESS in the 2019-24 regulatory period. For the purpose of determining the proposed reward amounts for the current regulatory period's performance, our Revised Proposal adopts some of the minor adjustments set out in the Draft Decision;
- the modifications to the Service Target Performance Incentive Scheme (STPIS) outlined in the AER's 2018 STPIS amendment should apply for the upcoming regulatory period. This ensures that our customers benefit from the AER's recent amendments to the STPIS applying from 2019;
- the application of the Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance Mechanism (DMIAM) for the 2019–24 regulatory period, without any modification; and
- the adoption of the definitions set out in the AER's Draft Decision in relation to pass through events, with the exception of the definition of 'terrorism event.' We propose a definition that encompasses physical and non-physical disruptive activity such as cyber-attack. We have also amended two small typographical issues relating to the Insurer's credit risk event.

How our Revised Proposal responds to customers

Customer groups were concerned that the lack of productivity assumptions in our initial proposal could create unwarranted, positive expected EBSS bonuses. Our Revised Proposal addresses this concern as we have introduced productivity assumptions in our opex forecast for 2019-24.

In our Revised Proposal, we have proposed the application of the 2018 STPIS amendment, because we consider this to be in the best interests of consumers. In particular, the revised STPIS scheme parameters will provide a greater incentive for us to restore supply to customers faster once they have experienced an outage.

As a result of our consultation process with customers, we are proposing to exclude a number of categories of expenditure from our capital expenditure allowances in application of the CESS for the 2019-24 regulatory period.

Our Revised Proposal also includes four pass through events to ensure we can respond efficiently to certain low probability, high impact events happening on our network, such as natural disasters or terrorism events. The cost to customers of managing these events is minimised if they are treated as pass through events in the 2019–24 regulatory period.

How our Revised Proposal responds to the AER

Ausgrid's Revised Proposal largely reflects the AER's Draft Decision on the application of the various incentive schemes, with only minor adjustments, such as CESS exclusions which work in the interest of customers.

Our Revised Proposal includes four pass through events to ensure we can respond to certain events happening on our network, such as natural disasters or terrorism events. These are low probability but high impact events which Ausgrid will be able to manage at the lowest cost for our customers if they are treated as pass through events in the 2019-24 regulatory period.

Our proposed amendment to the definition of 'terrorism event' is consistent with our understanding of the AER's intent, but it seeks to clarify that a 'terrorism event' may include non-physical acts such as cyber-attacks.

9.1 Efficiency Benefit Sharing Scheme

The EBSS assists in improving affordability, by providing us with incentives to continuously reduce our operating costs and giving our customers a fair share of any savings we achieve.

In our Regulatory Proposal, we proposed that the EBSS[1] should apply in the 2019–24 regulatory period, subject to several cost exclusions. The EBSS incentivises Ausgrid to pursue efficiency improvements in opex by rewarding us for delivering our services at a lower opex than our forecast allowance. The efficiency gains in opex are shared 70:30 between our customers and us[2] . The EBSS promotes efficiency improvements in providing network services which flow through in the form of lower network prices in future regulatory periods.

The AER accepted our proposal in its Draft Decision and said that it is of the view that it is reasonably likely to rely on our revealed costs over the 2019-24 regulatory period to forecast opex in the following regulatory period. In its Draft Decision [3], the AER noted the submissions of CCP10, and explained that the EBSS is an important part of the incentive regulation framework. The AER supports the EBSS along with other tools, such as benchmarking, to incentivise businesses to pursue efficiency improvements in opex.

More details about the EBSS and our proposal are presented in Attachment 9.01.

9.2 Capital Expenditure Sharing Scheme

Capital Expenditure Sharing Scheme 2019-24

The CESS will allow our customers to benefit from improved capital efficiencies through lower regulated prices in future periods. The CESS shares capital expenditure efficiency gains on a 70:30 basis, with our customers receiving 70% of efficiency gains achieved by the business.

In its Draft Decision, the AER said it intends to apply the CESS in the next regulatory period [4]. The AER also explained that it intends to update the formulae in the CESS to reflect its May 2018 TransGrid final determination. Our stakeholders did not express a strong view on how the CESS should be applied. Ausgrid supports the continued application of the CESS as it will drive better customer outcomes through reduced network prices.

Ausgrid continues to propose that the penalty or reward under the scheme should be calculated in accordance with the AER's current CESS guidelines. Additionally, as a result of our consultation process with customers, we are proposing to exclude the following categories of expenditure from our capex allowances in application of the CESS for the 2019-24 regulatory period:

1. Our network innovation program
2. An Advanced Distribution Management System
3. Additional cyber security.

Capital Expenditure Sharing Scheme 2014-19

The AER's Draft Decision made some minor adjustments to our proposed CESS reward amounts for our performance in the current regulatory period as follows:

1. The AER has applied updated inflation figures based on the actual inflation for FY18. The AER has also applied unlagged CPI in calculating discount rates, which differs from our Initial Proposal.
2. The AER reversed movements in capitalised provisions (i.e. accrual to cash basis for capex) over FY15–FY19, which reduced capex and the forecast RAB.

In our Revised Proposal, we have accepted and applied the AER's inflation updates. However, our reported capex numbers do not include the movement in provisions as explained in section 4.3.1. As a result, we have not adopted the AER's adjustment to our reported capex in the calculation of our CESS payments.

1 AER, Better Regulation – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013
2 AER, Better Regulation – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, p.36-37.
3 AER, Draft Decision – Ausgrid Distribution Determination, 2019 to 2024 – Overview, page 32.
4 AER, Draft Decision – Ausgrid Distribution Determination 2019-24, Attachment 9 – CESS, page 9-14.

9.3 Service Target Performance Incentive Scheme

9.3.1 Service Target Performance Incentive Scheme reliability incentives

AER Draft Decision

At the time the AER published its Draft Decision, Ausgrid agreed with the AER's proposal to apply its then current version of the STPIS for our upcoming regulatory period. However, since the Draft Decision, the AER has released its 2018 amendment to the STPIS. Ausgrid believes it is in the best interests of consumers for the amended scheme to apply to us for the upcoming regulatory period. This section outlines our approach to applying the amended scheme and associated parameters.

Application of the 2018 STPIS amendment and the Distribution Reliability Measures Guidelines

The AER published an issues paper outlining its intention to review the STPIS in January 2017 following a review of distribution reliability measures by the Australian Energy Market Commission (AEMC). Ausgrid participated in that review and a draft amendment to the STPIS was published in December 2017. The final scheme amendment was published in November 2018 and although we are not required to apply the amended scheme in the upcoming regulatory period we believe these reforms are, on balance, in the best interests of consumers. We therefore propose to apply the revised STPIS for the upcoming regulatory period.

Ausgrid also seeks to apply the new definitions for reliability metrics in the associated Distribution Reliability Measures Guideline published by the AER in November 2018. This will require re-calculation and verification of historical reliability performance to ensure the accurate setting of performance targets going forward.

Determining Incentive Rates

Value of Customer Reliability

The Value of Customer Reliability (VCR) is a key component of the STPIS scheme. For our initial proposal, we applied the approach previously approved by the AER for the current regulatory period, based on values for CBD and other feeder categories from AEMO's 2014 VCR survey, escalated to the start of the regulatory period.

We note that the AER adopted this same basis for the VCR values in its Draft Decision, however the AER did not escalate these values to the start of the regulatory period. In order to ensure consistency in the application of monetary figures in the calculation of the incentive rates, we believe it is appropriate and necessary that all monetary values are as of June 2019 including the VCR, as recognised in Clause 3.2.2(b) of the scheme.

Our Revised Proposal contains updated VCR figures, based on the same underlying source adopted by the AER in its Draft Decision, however escalated to June 2019 figures in accordance with the intent of the STPIS. This escalation uses measured inflation as per the Australian Bureau of Statistics reports, and forecast inflation from the Reserve Bank of Australia as of November 2018. This is consistent with the AER's approach to escalation in its opex modelling in its Draft Decision.

Our revised VCR figures for the purposes of the STPIS are as follows:[5]

FEEDER CATEGORY	$/MWH SEPT 2014	$/MWH JUNE 2019
CBD	$ 44,170	$ 47,848
Other	$ 38,350	$ 41,543

SAIDI/SAIFI Weighting

As described above, we agree, on balance, that the scheme changes put forward by the AER in the 2018 STPIS amendment are in the best interests of consumers. To ensure that our customers do not have to wait five years for these reforms to be implemented, we seek to apply the revised STPIS scheme parameters for the weighting of SAIDI and SAIFI in the calculation of the applicable incentive rates for the upcoming regulatory period. This will have the impact of increasing SAIDI incentive rates and decreasing SAIFI incentive rates, providing a greater incentive for us to restore customer supply faster once they have experienced an outage.

Forecast Energy Consumption

We have updated our forecast energy consumption figures for the regulatory period and we have incorporated this into our revised incentive rate calculation, in accordance with the scheme methodology.

5 Indexed historical values for VCR have been used pending further consideration following completion of the AER VCR review in 2019.

Calculated Incentive Rates

Considering the above changes to input parameters, and applying the proposed amendments to the STPIS scheme outlined in the AER's draft revision of the STPIS, we have determined the following incentive rates should apply to the STPIS scheme for the 2019–24 regulatory period.

CATEGORY	SAIDI INCENTIVE RATE	SAIFI INCENTIVE RATE
CBD	0.0069	1.1061
Urban	0.0575	3.8559
Short Rural	0.0073	0.5481
Long Rural	0.0001	0.0123

Reliability Performance Targets

As noted in the AER's Draft Decision and our Initial Proposal, the final application of STPIS for the upcoming regulatory period should be based on the average performance of the preceding five years. We have adjusted our input values to incorporate FY19 reliability performance in this Revised Proposal. Ausgrid has historically reported momentary interruptions as outages less than 1 minute, and single or two phase outages as impacting 100% of customers. In our application of the 2018 STPIS amendment and the associated Distribution Reliability Measures Guideline, we have also recalculated and independently verified our historical performance over the past five years to incorporate the AER's revised definitions for:

- Momentary interruptions (outages less than 3 minutes)
- Single phase low voltage outages (33% of customers impacted)
- Single phase high voltage outages (67% of customers impacted).

The amended historical performance and targets based on the five-year average and the revised definitions are shown in the table below:

	CATEGORY	2013/14	2014/15	2015/16	2016/17	2017/18	AVERAGE
SAIDI	CBD	3.66	7.47	7.50	14.49	12.34	9.09
	Urban	59.37	53.76	59.56	66.59	60.28	59.91
	Short Rural	150.73	142.96	124.52	112.31	109.28	127.96
	Long Rural	430.59	327.78	571.94	813.05	337.23	496.12
SAIFI	CBD	0.011	0.071	0.010	0.033	0.063	0.038
	Urban	0.685	0.512	0.573	0.606	0.604	0.596
	Short Rural	1.388	1.225	1.045	1.064	0.932	1.131
	Long Rural	3.096	1.662	2.680	3.390	1.528	2.471

Based on the amended historical performance data shown above, our revised targets are shown in the table below:

CATEGORY	SAIDI TARGET (MINUTES)	SAIFI TARGET (INTERRUPTIONS)
CBD	9.09	0.038
Urban	59.91	0.596
Short Rural	127.96	1.131
Long Rural	496.12	2.471

9.4 Demand Management Incentive Scheme and Innovation Allowance

In accordance with the AER's final framework and approach, our Initial Proposal incorporated a demand management scheme with two components:

- **The Demand Management Incentive Scheme (DMIS)** – provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management, and
- **The Demand Management Innovation Allowance Mechanism (DMIAM)** – provides distributors with funding for research and development in demand management projects with the potential to reduce long-term network costs.

Together, the DMIS and DMIAM are intended to reduce network costs over time, lowering prices in future regulatory periods. In its Draft Decision, the AER accepted our proposal to apply the DMIAM and DMIS for the 2019–24 regulatory period, without any modification.

The DMIS contains three elements:

- a cost uplift on expected costs of efficient demand management projects
- a net benefit constraint, to ensure the incentive payment for any project cannot be higher than that project's expected net benefit
- an overall incentive constraint, which limits the total incentive in any year to one per cent of the distributor's allowed revenue for that year.

In accordance with the DMIS, the AER's distribution determination will provide that the cost multiplier (uplift) applicable to any eligible project will be the cost multiplier specified in the version of the DMIS that is in effect under clause 6.6.3 of the NER at the time at which the eligible project becomes a committed project.

The DMIAM comprises:

- a fixed allowance of $200,000 ($real FY17), plus 0.075 per cent of the annual allowed revenue for each regulatory year, as set out in AER's Post-Tax Revenue Model (PTRM) for Ausgrid
- project eligibility requirements
- compliance reporting requirements.

The Consumer Challenge Panel (CCP10) submitted that our DMIA allowances for 2019–24 need to be carefully considered against recent actual expenditure. CCP10 also submitted that all incentive schemes should be reviewed cohesively to make sure that businesses are incentivised to save costs and actively pursue non-network solutions.

In relation to the CCP10's submissions, the Draft Decision [6] notes that Ausgrid will be required to provide supporting documents as required under the new DMIS and DMIAM each year to prove that the expenditures meet the minimum requirements. The AER will determine the eligibility and specific incentive payments for each project according to the criteria specified in the new DMIS and DMIAM.

9.5 Pass-through events

Revised proposal

Our Revised Proposal accepts the AER's proposed definitions of 'insurance cap' and 'natural disaster' event.

As outlined in Attachment 9.01 Proposed Pass through definitions, we have fixed two small typographical issues relating to the Insurer's credit risk event.

Our Revised Proposal accepts the AER's inclusion of a 'terrorism' pass through event but proposes an amendment to the AER's Draft Decision to include reference to non-physical terrorism events such as cyber-related activities. Our proposed amendment to the terrorism pass through event definition is shown in **bold** in the table below:

Terrorism event	Terrorism event means an act **(including, but not limited to, the use or threat of force, violence or other disruptive activity)** of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: • from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and • increases the costs to Ausgrid in providing direct control services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: • Whether Ausgrid has insurance against the event, • The level of insurance that an efficient and prudent NSP would obtain in respect of the event, and • Whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

6 AER, Draft Decision - Ausgrid Distribution Determination 2019 to 2024, Attachment 11 - DMIS, page 11–7.

Rationale

The AER agrees a 'terrorism' pass through event could encompass cyber-attack events. The AER acknowledged this in its November Draft Decision when it did not accept our proposed reference to "attacks or disruptive activities, or of the deliberate introduction of malware" in the terrorism event definition. The AER stated:

> *referring expressly to one species of terrorist attack (cyber threats) tends to raise questions as to whether other types of attack are included.*

We agree with the AER. It is due to the existence of specificity regarding other forms of terrorism in the current definition that we seek to amend the terrorism pass through event definition. As presently drafted, the terrorism event definition refers to physical acts such as "the use of force or violence or the threat of force or violence" but is silent on non-physical disruptive activity such as cyber-attack, sabotage and coercion.

By remaining silent on non-physical disruptive activity, the current drafting does, as the AER describes, create uncertainty as to whether non-physical acts can fall within scope of the terrorism event. While the AER may be of the view that the terrorism event in its Draft Decision could capture non-physical terrorism events, the qualifying words which refer to the use of force or violence may lead a third party, such as a court, to a different view.

It is this uncertainty that has led Ausgrid to propose a small amendment to the AER's definition of Terrorism event. In order to remove any ambiguity that the terrorism pass through event could include non-physical disruptive activity, Ausgrid proposes that the qualifying words in the event definition be re-drafted to read:

> *(including, but not limited to, the use or threat of force, violence, or other disruptive activity)*

The words "or other disruptive activity" have been included to remove any uncertainty about whether non-physical terrorism events are covered by the terrorism event pass through definition. Ausgrid considers that the words "other disruptive activity" would make it clear that a terrorism event could be caused by both physical and non-physical acts.

If the AER agrees that non-physical disruptive activity such as cyber-attack could be included within the terrorism event definition, then it should not object to the inclusion of words which make that clear. In Ausgrid's view, the proposed words achieve that goal.

Benefits for customers

Cyber security and cyber terrorism are receiving increasing focus in today's digital age. The Commonwealth Attorney General's Department has highlighted the risk to the Australian economy from computer intrusion and the spread of malicious code[7]. Electricity distribution assets have been recognised as critical infrastructure by the newly established Critical Infrastructure Centre.[8]

The 2017 Finkel review also raised concerns about emerging threats to the power system, including cyber-attacks.[9] The report recommended that an annual report into the cyber security preparedness of the National Electricity Market should be developed by the Energy Security Board. Among other things, the Finkel report recommended that the annual report should include:

> *A stocktake of current regulatory procedures to ensure they are sufficient to deal with any potential cyber incidents in the National Electricity Market.*

In its Draft Decision, the AER approved $20 million in capital expenditure to allow Ausgrid to meet its licence condition obligations and reduce the risk of our critical systems being impacted by cyber-attacks. Despite this, the increasing number, type and sophistication of cyber security threats could impact our ability to comply with our regulatory requirements.[10] Since lodging our Initial Proposal we have had our cyber preparedness externally reviewed and expect further regulatory requirements in this space. Further details are outlined below.

We consider that amending the definition of 'terrorism event' to clarify that non-physical acts such as cyber-attack are included within the scope of the event will ensure that Ausgrid can continue to meet its regulatory requirements should such an event occur. Of course, any costs associated with such an event will only get passed through to customers if they are material and Ausgrid meets the other regulatory obligations outlined in clause 6.6.1 of the Rules.

7 www.ag.gov.au/RightsAndProtections/CyberSecurity/Pages/default.aspx

8 Australian Government, Critical Infrastructure Centre, Security of Critical Infrastructure Bill 2017 – Explanatory Document, October 2017, p 7.

9 Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, Commonwealth of Australia June 2017, p22.

10 Australian Cyber Security Centre, 2015 Threat Report, p4.

Future regulatory obligations

Cyber related obligations

Since lodging our Initial Proposal in April 2018 we have sought external review of our cyber investment and preparedness. That review indicated that while not clearly defined at this stage, additional cyber related regulations may be imposed on Ausgrid in the future. The review therefore recommended that we expand our cyber security investment in the next regulatory period. We have therefore proposed an additional $20 million of Operational Technology and Innovation (OTI) capex. In conjuction with our new Technology Review Committee, we will assess the cost implications of any new obligations at the appropriate time.

Future customer access to data requirements

The Commonwealth Government announced the introduction of a consumer data right in November 2017. Initially, the consumer data right framework will apply to the banking sector, where it will be known as 'Open Banking'. The framework will then be rolled out across other sectors, such as energy and telecommunications. In 2018 the ACCC consulted on a Consumer Data Right Rules Framework that will support the regime. The regime will be implemented through changes to the *Competition and Consumer Act 2010* (Cth).

The *National Electricity Retail Rules* already contain provisions which allow customers to request access to their consumption data.[11] The AEMC introduced these provisions in order to empower customers to make more efficient consumption decisions. Access to data also provides greater scope for businesses to innovate and provide tailored products for customers.

The NSW Select Committee on electricity supply, demand and prices in NSW has recently recommended that the NSW investigate steps to develop a Consumer Data Right in the electricity sector as a matter of priority.[12] The Finkel review also recommended that the COAG Energy Council facilitate measures to improve consumers' access to their energy data.

It is likely that information provision requirements under the Consumer Data Right framework will be far more comprehensive than existing requirements under the *National Electricity Retail Rules*. The ACCC has acknowledged the complexity of the new framework. When applied to the electricity sector, new regulatory obligations could place significant costs on distributors. Ausgrid will assess the cost implications of new obligations and the need for a potential cost pass through at the appropriate time.

Distributed Energy Resources register

On 13 September 2018 the Australian Energy Markets Commission (AEMC) made a final rule for the Australian Energy Market Operator (AEMO) to establish a register of distributed energy resources, including small scale battery storage systems and rooftop solar. The register will give network businesses and AEMO visibility of where DER is connected to help in planning and operating the power system.

The register must be in place by 1 December 2019 and AEMO must make and publish its first guideline to establish the register by 1 June 2019.

Establishing the register is likely to have material cost implications for Ausgrid, depending on the final form of the AEMO guideline. The AEMC rule places obligations on service providers to source specific DER information from customers. This is despite distribution networks usually having little contact with end customers. We will assess the cost implications of the new rule once the obligations on Ausgrid become clearer.

11 *National Electricity Retail Rules*, clause 86A.

12 Select committee on electricity supply, demand and prices in NSW, November 2018.

10

Pricing structures and policies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ATLANTIC SALMON
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OCEAN TROUT
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10

PRICING STRUCTURES AND POLICIES

Paving the way for the energy sharing economy

Our Revised Proposal

Our Revised Proposal for the 2019–24 regulatory period explains how we will set prices to recover the revenue approved to provide an affordable, reliable and sustainable electricity supply for our customers in the long term.

Overall our Revised Proposal will reduce the network component of the average residential bill in FY20 by 11% or $71. This percentage change differs from the overall Ausgrid revenue reduction of 16% earlier in our Revised Proposal as the network component of customer bills also includes non-Ausgrid related costs such as TransGrid Transmission Use of System charges and NSW Government Climate Change Fund charges.

Key pricing reforms in our Revised Proposal include:

- introducing demand tariffs for residential and small business customers
- simplifying our default tariffs for residential and business customers
- aligning charging windows for business customers
- planning for new tariffs with more flexible controlled load tariffs and an embedded network tariff.

Our Revised Proposal is the result of an extensive engagement and co-design process undertaken between Ausgrid and customers through our Pricing Working Group (PWG), and is a major milestone in the delivery of the Australian Competition and Consumer Commission (ACCC) recommendation 14[1] to accelerate the take up of cost reflective network pricing.

As highlighted by the ACCC, the successful implementation of these critical reforms relies on the ongoing support and collaboration of customer groups, government and retailers to ensure the objectives of the reforms are met and the best long-term interest of customers is served.

Our Tariff Structure Statement including Explanatory Notes (Attachment 10.01) provides the information required under the National Electricity Rules (NER).

1 Australian Competition and Consumer Commission (2018) Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry – Final Report, July 2018, www.accc.gov.au.

How our Revised Proposal responds to customers

Since submitting our Initial Proposal we have continued to work closely with customer representatives, primarily through our PWG, to collaboratively design a pricing strategy that meets our customers' needs.

The pricing strategy in our Revised Proposal responds directly to customers' feedback to:

- accelerate the transition to a 'causer pays/benefits' model of recovering energy supply costs
- reflect customers' preferences for more control over their bills
- be responsive and remain flexible to emerging issues such as developments in technology
- introduce a demand-based tariff as the default tariff for new customers.

Customers' views are varied and it may not be possible to design a tariff strategy that is embraced and supported by all. However, we believe that through continued collaboration with our customers, particularly on key issues such as communications, and complementary measures to mitigate customer impacts, together we can accelerate the transition to a fairer, more affordable and more sustainable energy supply system for all.

How our Revised Proposal responds to the AER

In its Draft Determination the AER recognised Ausgrid as one of the more advanced distributors in the National Electricity Market in terms of the penetration of cost reflective pricing and the cost reflectivity of its existing tariffs. The AER broadly supported the direction of our Initial Proposal, but set out a series of changes required before it would approve our Tariff Structure Statement. Our Revised Proposal is a pricing package which addresses the changes the AER seeks and provides the additional information requested.

The reforms in our Revised Proposal align directly to the AER's findings to:

- have a single default tariff for all residential and all small business customers
- offer customers a choice between cost reflective tariffs (i.e. between a time of use energy tariff and a demand tariff)
- align demand charging and peak energy charging windows
- maintain a flat tariff for customers with accumulation meters
- use a 12 month data sampling period for customers replacing a faulty accumulation meter to help them understand their demand charges.

10.1 Our pricing proposal prioritises affordability, reliability and sustainability

The total revenue we can collect from our customers to provide affordable, reliable and sustainable electricity is capped by the AER. Our Revised Proposal sets out a proposed approach to collect revenue from our customers in a way that best reflects the cost of providing the network and gives price signals to achieve efficient network use, while minimising negative customer impacts.

Our aim is to move towards prices that:

- promote the efficient use of our network by our customers and encourage efficient investment in distributed energy resources and energy efficiency
- are consistent with achieving long-term benefits for customers, to make our network services more affordable, reliable and sustainable
- reduce peak demand, which is the principal driver of our future costs, and will reduce costs for all customers in the long term
- provide a more equitable way to recover our total network costs, leveraging the capabilities unlocked with the introduction of smart meters.

Table 10.1 summarises how pricing promotes affordable, reliable and sustainable network services.

Table 10.1

How network pricing promotes a more affordable, reliable and sustainable energy supply system

Affordable	• Rewards customers who actively manage their contribution to peak demand and place a low cost burden on the shared system. • Encourages customers to use our network when the cost of doing so is low, leading to lower rates overall. • Promotes fairer outcomes between customers with different characteristics (for example those with and without distributed energy resources or peaky load). • Ensures all customers make a fair contribution to the cost of the network service they use. • Gives customers more choice and control over how they are billed for access to the grid while still promoting the development of more innovative retail products to further increase the choices available.
Reliable	• Reduces incidences of spikes in demand that can lead to network outages. • Encourages a more responsive demand-side to deliver the reliability outcomes that our customers expect at a lower cost.
Sustainable	• Unlocks new potential energy sources for customers who cannot currently benefit from distributed energy resources, by levelling the playing field for shared energy schemes such as community solar and storage. • Encourages customers to use distributed energy resources in a way that helps them to better manage their consumption at peak and non-peak periods, and lowers grid costs for all. • Encourages the adoption of electric vehicles without unnecessarily increasing grid costs. • Promotes the lowest cost transition to a lower carbon economy.

Table 10.2 summarises the major pricing reforms in our Revised Proposal for the 2019–24 regulatory period.

Table 10.2

Components of our Revised Proposal: major pricing reforms for the 2019–24 regulatory period

PROPOSED REFORM	DESCRIPTION	BENEFITS FOR OUR CUSTOMERS
Introduce demand tariffs	Introduce a set of demand tariffs (i.e. tariffs which include a demand charge component) for residential and small business customers: • a demand tariff as a default assignment for new connections and customer-initiated meter replacement or upgrade • a time of use demand (TOU demand) tariff as a second cost reflective option • a demand (introductory) tariff as a sampling tariff to ease the transition to a demand tariff where a customer's meter change is due to failure of an accumulation meter	Ensures customers retain greater control of the network component of their bills while moving to cost reflective tariffs Gives customers choice about how they are charged for their energy Encourages customers to invest in cost effective distributed energy resources that help them to better manage their consumption at peak periods Promotes fairer outcomes between customers with different demand characteristics (those with and without distributed energy resources, or peaky load) Provides greater certainty for those considering or making investments in new technology Gives customers who are new to cost reflective charging mechanisms time to learn about and adjust their usage patterns, but does not confuse customers with a 12 month sampling period where this is unlikely to be beneficial (e.g. new connections or customers that experience a step change in their demand profile when they install distributed energy resources) Accelerates the development of more innovative retail tariffs that manage the risk of both wholesale and network costs for customers
Simplify our default tariffs	Streamline current tariff structures for residential and business customers and make our tariffs easier for customers to understand	Makes it easier for our customers to understand and make choices
Align charging windows for small business customers	Align charging windows for seasonal peak energy, seasonal peak demand charges and annual capacity charge to 2 pm to 8 pm on working weekdays	Provides more cost reflective peak price signals Enables easier understanding and better management of network charges Achieves consistency within the business tariff segment
Plan new tariffs: controlled load tariffs and an embedded network tariff	Introduce two new, more flexible controlled load tariffs and an embedded network tariff as placeholders, with no customers assigned from 1 July 2019, and with specifications to be developed in consultation with the PWG and other stakeholders	Prepares the network and customers for the introduction of electric vehicle charging and increasing use of smart appliances, allowing customers to get more value from their investments while protecting other customers from incurring undue cost increases Prepares for increased use of embedded networks, and reduces the cost impact of this on other network connected customers Allows for further research and engagement and consultation with customers and stakeholders on the specifications of the tariffs

10.2 What we heard and how we've responded in our Revised Proposal

Our Revised Proposal responds to feedback from the AER, stakeholder submissions, and ongoing discussions with customer representatives and other stakeholders. In framing our Revised Proposal, we have carefully considered the matters raised by the AER and other stakeholders in the Draft Decision and the feedback provided by members of our PWG and retailers who have been engaged separately on a one-on-one basis.

We set up our PWG following the submission of our Initial Proposal in April 2018 to guide our pricing reforms. Members of the PWG are the AER Consumer Challenge Panel, Energy Consumers Australia, Energy Users Association Australia, NSW Business Chamber, Public Interest Advocacy Centre, St Vincent de Paul Society and Total Environment Centre. The PWG had multiple working sessions in late 2018 to discuss and co-design the pricing reforms in our Revised Proposal. The PWG helped us deliver a pricing strategy that fairly recovers the costs of providing network services, while also giving customers the transparent price signals, choice and control that will enable them to benefit from more efficient use of the network.

Our pricing strategy resulting from this collaboration now includes default demand tariffs for residential and small business customers with smart meters from 1 July 2019. Our revised Tariff Structure Statement is now aligned with the AER's Draft Decision on demand tariffs being a default cost reflective tariff for new connections and for meter replacements and upgrades.

While there was common agreement on the benefits of cost reflective tariffs, there were mixed views on key aspects of the reform such as the speed of transition, the preference for demand tariffs or time of use tariffs, the nature of any opt out option, the application of a 12 month sampling period, and the role of retailers, amongst other issues. The tables below separately identify the issues raised by the AER and other stakeholders where there were mixed views presented and we were required (in conjunction with the PWG) to adopt a position (Table 10.3), and where issues were raised with no contradictory views that could be more readily adopted as part of our pricing strategy (Table 10.4).

Table 10.3

Contentious issues: the views presented, and the positions adopted in our Revised Proposal

ISSUE	WHAT WE HEARD	POSITION ADOPTED	RATIONALE
Transition to cost reflective tariffs	• Should be accelerated	✓	• In conjunction with our PWG we have adopted a strategy consistent with that of the AER, customer representative groups and the ACCC (recommendation 14), to accelerate the transition to cost reflective tariffs. • We believe this is in the best long-term interest of our customers to reduce network costs and accelerate the development of innovative retail products that will drive down overall energy system costs. • Our strategy to accelerate adoption of cost reflective pricing needs to be delivered in conjunction with an appropriate suite of protection mechanisms to avoid unwarranted customer bill impacts, and needs to be linked to the rollout of appropriate supporting technologies (i.e. smart meters) to ensure customers have the ability to respond. • We believe that, with the ongoing support of customers, and other critical risk mitigation strategies in place, the arguments put forward by some stakeholders against an accelerated introduction of cost reflective pricing can be mitigated, ensuring this valuable long overdue reform can finally proceed.
	• Should be slowed	—	
Data sampling period	• Compulsory for all customers undergoing a meter change	—	• The question of whether to apply a transitional tariff with a data sampling period to all customers undergoing a meter change was debated on multiple occasions during the PWG sessions. Customer groups put forward the view that there would be many circumstances (such as when a customer is already on a cost reflective tariff, or when a customer gets a new meter as a result of installing solar) when the temporary introduction of a data sampling period would not provide any benefit. Instead PWG members argued that in these instances a sampling period would be likely to do more harm than good, causing unnecessary confusion and reducing certainty around the value and hence the decision to invest in distributed energy resources. • As a result our Revised Proposal provides a 12-month sampling period through a demand (introductory) tariff for customers with an accumulation meter who do not initiate their change to a smart meter. • Whether or not the retailer passes on relevant information in customers' bills, the ability to access and analyse usage data will help customers with the transition.
	• Only in those circumstances where it is unlikely to cause undue confusion or damage to customer confidence	✓	

ISSUE	WHAT WE HEARD	POSITION ADOPTED	RATIONALE
Opt out	• Not available	—	• Stakeholders almost universally endorsed the introduction of an opt out tariff in conjunction with a default demand tariff, though some views were put forward that mandatory assignment with no opt out would be preferable from a cost reflective viewpoint. It was generally acknowledged that this would result in unacceptable customer impacts and opt out options would need to be available. • In alignment with the AER's feedback, the proposal outlined in Pricing Directions: a Stakeholder Perspective statement (Attachment 10.14), and the majority view of the PWG, our Revised Proposal includes a cost reflective opt out tariff option that allows customers who undergo a meter upgrade to choose an alternative cost reflective tariff to help reduce adverse bill impacts. • The opt out tariff has been appropriately priced to act as an insurance product for those customers who do not wish to be charged under a full demand tariff. The pricing differential between the opt out and the default tariff is intended to encourage those who can to stay on the more cost reflective default tariff, and to cover the cost of the typically more peaky and hence more costly customers who choose the opt out tariff. • This was seen as preferable to allowing opt out to a flat tariff as a flat tariff: a) does not send a price signal that encourages customers to reduce their contribution to critical peaks and hence the costs they incur on the network, b) does not address cross subsidy issues, and c) would stifle the development of innovative retail products where retailers take on the risk associated with customers' network charges and are hence incentivised to take steps to manage that risk on their behalf. • Through our engagement with retailers it became clear that many are already considering (if not already offering) 'simple' flat energy tariffs that customers with underlying cost reflective network tariffs will be able to choose. We are encouraged by this development and see this as the most economically efficient path to providing the levels of choice and control customers seek, while still maintaining the incentives to influence demand patterns to reduce network and overall system costs in the long term.
	• Only to a cost reflective tariff such as an alternative demand tariff or a TOU tariff	✓	
	• To an appropriately priced flat tariff	—	
Default cost reflective tariff	• Should be a demand tariff	✓	• The AER and customer representatives overwhelmingly supported the adoption of a demand based tariff, not a TOU tariff, as the default cost reflective tariff for new residential and small business customers, for those who have a smart meter and for those who initiate a meter upgrade. • Our Revised Proposal adopts a demand tariff that has been co-designed with customers as the default cost reflective tariff in these instances.
	• Should be a TOU tariff	—	

ISSUE	WHAT WE HEARD	POSITION ADOPTED	RATIONALE
Demand measure	• Should be a 12 month maximum demand measure	—	• We adopted the monthly maximum demand model as the preferred model as this gives customers more control than a 12 monthly period, while being easier to understand than an average of multiple days. • We note that retailers indicated they could very well pass through any monthly demand charge as an annual demand charge in the retail bill, as this would better align with their customers' demonstrated preferences. • Customer representatives argued that while an averaging mechanism may seem attractive at first glance as it can reduce the risk of customers being unduly penalised for one day of excessive usage in a period, we did not adopt it as customer representatives reported that communicating such a mechanism in a simple way has proven very difficult to achieve in practice. • We agree with the views of some customer advocates that more sophisticated demand measures should be explored and adopted as soon as practical, but we believe that their success will depend on the availability of supporting technologies that enable automated behavioural response and take the onus off consumers to actively manage their peak energy usage on a day to day basis. As this level of technology support is not sufficiently widely available today, we believe including these measures in this Revised Proposal is not warranted.
	• Should be based on a monthly maximum demand measure	✓	
	• Should be based on an average of n maximum demand measurements in a period	—	
	• Should be a more sophisticated signal such as a critical peak demand	—	
Collection of residual cost	• Should be equally spread across fixed, peak, shoulder, off peak, and demand components	—	• Many views were put forward by stakeholders on the most appropriate way to collect residual costs. • The AER supported our proposed increase in the fixed network charge on balance, but customer advocates made clear their preference for no real increase in the fixed network charge. • One submission was concerned that our pricing proposal did not adequately consider improving capacity utilisation. • Given the diverse views, by working with the PWG, our Revised Proposal adopts a strategy of collecting residual costs in a least distorting manner that: a) encourages customers to use the network at times when there is little cost implication of doing so, b) holds fixed prices steady in real terms, and c) keeps the peak price signal as close to long run marginal cost as possible, ensuring customers are not unduly incentivised to make what would otherwise be inefficient investments in energy efficiency solutions or distributed energy resources. • We note that in adopting this approach we are, in this instance, not in complete alignment with customers' Pricing Directions statement (Attachment 10.14), which preferred environmental costs to be priced into network charges. As environmental costs are not correlated with consumption levels on the network, we believe that environmental costs should be priced in at the point of generation or consumption and not be incorporated as part of network charges.
	• Should be collected solely through an anytime energy charge	—	
	• Should be collected in a way that encourages improved capacity utilisation	✓	
	• Should be collected in a way that accounts for environmental costs	—	

ISSUE	WHAT WE HEARD	POSITION ADOPTED	RATIONALE
Complexity of network tariffs	• Is appropriate as network tariffs are, first and foremost, designed for retailers rather than customers	✓	• The view overwhelmingly put forward in submissions by customer representative groups was that tariffs should be designed first and foremost for retailers, though the language used to describe network tariffs should be easy to understand and supported by clear and simple communications. • Retailers on the other hand generally submitted that network tariffs that are too complex are not acceptable as they are not understandable by consumers and create difficulties for retailers trying to integrate them into their billing systems (where they pass the network tariff onto customers in full). • During our engagement with retailers it became increasingly apparent that introducing cost reflective demand tariffs was very likely to accelerate the development of innovative retail products that not only manage wholesale price risk on behalf of customers, but also incentivise retailers to develop products that allow them to manage underlying network charges for customers and hence help customers respond to price signals that lower the cost they impose on the grid. • As a result our Revised Proposal introduces a set of cost reflective tariffs that represent a step up in complexity from tariffs that have traditionally been used, however we are confident that this change carries relatively little risk. Retailers, aggregators and other emerging technology players are already developing products capable of responding to complex tariff structures in ways that customers cannot and we believe this change will be in the best long-term interest of our customers.
	• Is not appropriate as customers must be able to understand and respond to network tariff structures, and retailers must be protected from complex changes to their billing systems	—	
Customer impacts analysis	• Should assume a base level of demand response	✓	• Customer representative groups were broadly in favour of assuming some level of demand response when assessing customer impacts, citing recent studies that support the approach and a tendency for some of the peakiest (and hence most impacted customers) to have a greater ability to shift load. • We agree with this approach and have adopted a conservative estimate of an average demand response when assessing likely impacts, particularly in the residential segment. Recognising concerns raised about the extent of any demand response that can be achieved and that certain classes of small businesses have significantly less ability to shift load, our customer analysis includes impacts both with and without a demand response.
	• Should not take demand response as a given	—	

Table 10.4

Non-contentious issues: what we heard, and how we have responded in our Revised Proposal

ELEMENT	WHAT WE HEARD	HOW WE'VE RESPONDED
Tariff for customers with legacy accumulation meters	• The AER suggested we maintain a flat tariff for customers with accumulation meters instead of our proposed inclining block tariff.	• Our Revised Proposal maintains a flat tariff and does not have an inclining block tariff.
Funding for demand tariff research	• The AER and other stakeholders did not support funding our proposed research program into demand tariffs.	• We believe that further research is required to understand how demand tariffs will most effectively be used in the context of changing customer behaviours and emerging consumer technologies. However, our Revised Proposal assumes that we will seek to leverage the work being proposed by others (such as Energy Consumers Australia), encourage collaboration between networks to minimise costs and absorb the residual cost of any research programs we undertake.
Alignment of peak TOU and demand charging windows	• The AER sought further justification for using a year-round peak window for demand charges for business customers. • The AER and other stakeholders considered aligning the demand charging window with the peak energy charging window to be more understandable for business customers.	• Our Revised Proposal aligns seasonal charging windows for peak energy, demand and capacity for business customers. • Our Revised Proposal has two demand charging windows which align with our TOU energy windows for business customers.
Alignment of residential and small business tariffs	• The AER supported simplification and consistency of tariffs for residential and small business customers. • Customers supported aligning tariffs for residential and small business customers so there is no difference between the two groups.	• Our Revised Proposal provides a set of demand tariffs with similar structures for residential and small business customers, although prices are different where they reflect different underlying costs.
Pricing principles • Long run marginal cost • Residual costs • Annual pricing • Individually calculated tariffs	• The AER accepted our long run marginal cost approach. • The AER sought more information on how we will base tariffs on long run marginal cost and our approach to recovering residual costs. • The AER sought more information on our approach to annual pricing and any variations to our indicative pricing schedules. • The AER sought more information on how we determine individually calculated tariffs.	• Our Revised Proposal explains our pricing approach to residual costs. • Our Revised Proposal explains what new information may lead to changes in our indicative pricing schedules for our annual pricing proposals. • Our Revised Proposal provides more information on how individually calculated tariffs are calculated.
Structure of Tariff Structure Statement	• The AER encouraged all distributors to present their Tariff Structure Statement in a targeted two-document structure.	• Our Revised Proposal has a two-document structure with a Tariff Structure Statement binding us over the regulatory period and accompanying Explanatory Notes as an Appendix explaining our reasons for our positions.

ELEMENT	WHAT WE HEARD	HOW WE'VE RESPONDED
Alignment across networks	• Multiple stakeholder submissions wanted networks to align tariff structures across networks (where possible).	• Our Revised Proposal adopts many of the same structures and mechanisms being proposed by our peer networks in NSW. • We have started and are committed to continuing a process to bring network tariff structures into closer alignment where this makes sense, recognising the differing needs and cost drivers of each network.
Customer education and communications	• Multiple stakeholder submissions highlighted the importance of communications in facilitating the transition to cost reflective tariffs, including the potential development by networks of online tools to help customers understand their usage patterns and options.	• Our Revised Proposal outlines a holistic communications strategy that will be developed and executed in conjunction with retailers, customer representative groups and peer networks.

10.3 Key components of our Revised Proposal

Our Tariff Structure Statement (Attachment 10.01) presents the components of our pricing including tariff classes, assignment to tariff classes and tariffs, tariff structures, charging parameters, and our pricing principles, consistent with the NER. Key components of the pricing reforms in our Revised Proposal are discussed below.

10.3.1 Introducing demand tariffs

Our Revised Proposal introduces a set of three demand tariffs for residential and small business customers from 1 July 2019:

- a demand tariff with a flat energy consumption charge and a two rate (seasonal) demand charge for new residential and small business connections, for those initiating a meter change to a smart meter, and for those customers with an existing smart meter
- a demand (introductory) tariff with a flat energy consumption charge and a two rate (seasonal) demand charge, available for 12 months only, for existing customers with an accumulation meter when they replace their meter due to meter failure
- a TOU demand tariff with seasonal TOU energy consumption charges and a flat demand charge for any customer with a smart meter to choose as an alternative to the assigned tariff.

The demand (introductory) tariff is a sampling tariff that helps customers replacing a faulty accumulation meter to learn their consumption and demand patterns before facing a cost reflective demand tariff. A TOU demand tariff is another cost reflective tariff available as an opt out and suitable for customers used to paying for energy by time of use.

We maintain our secondary tariffs for controlled loads. All other tariffs including our current cost reflective seasonal TOU tariff will be closed to new customers. Customers with an accumulation meter will continue on their current tariff (closed), and customers with an interval meter will be assigned to the existing seasonal TOU tariff. Customers with a smart meter will be reassigned to the new demand tariff.

Over 330,000 of our 1.56 million residential customers and half of our 140,000 small business customers are on a seasonal TOU tariff. But our existing seasonal TOU tariff does not leverage the full capabilities of smart metering and is not expected to maintain its cost reflective properties in the long term. From 1 July 2019, when customers on the seasonal TOU tariff change their meter to a smart meter, they will be assigned to a demand tariff. Any customer assigned to a demand tariff can ask to be reassigned to our new TOU demand tariff, which still introduces a small demand component, but provides a more recognisable option for customers who are used to paying for the energy under a consumption-based TOU structure.

10.3.2 Simplifying our default tariffs for residential and business customers

Compared to our Initial Proposal, our revised Tariff Structure Statement:

- reduces the number of default tariffs for residential customers and for small business customers using less than 160 MWh a year
- simplifies our business tariffs by retiring obsolete tariffs and reassigning existing customers to suitable tariffs on 1 July 2019
- maintains our existing low voltage tariffs for usage over 160 MWh a year.

10.3.3 Aligning charging windows for business customers

Our Revised Proposal aligns our seasonal peak energy and seasonal peak demand charging windows with our annual capacity charging windows for our business customers. We maintain the current (FY19) business seasonal charging window of 2–8 pm on working weekdays to ensure alignment of peak energy, peak demand and capacity charging windows for business tariffs. Our residential customers have a different peak charging window of 5–9 pm on working weekdays in the winter months of June, July and August. While it would be simpler to have the same charging windows for both residential and small business customers and reduce the number of tariffs, it would not be as cost reflective due to the different usage patterns of residential and small business customers. In total, residential demand is more variable by season reflecting domestic heating and cooling needs, while business demand is less variable by season and time of day.

10.3.4 Planning for new tariffs: more flexible controlled load and embedded network tariffs

Our Revised Proposal also plans for the introduction of three new tariffs to prepare for changes in expected network use within the regulatory period:

- Our new controlled load tariffs recognise the changing needs of the grid and the likely uptake of new technologies such as electric vehicle charging and use of smart appliances by our residential and business customers. These secondary tariffs are intended to be more flexible than our existing controlled load tariffs, and provide customers with these types of technologies greater choice and control on how they are charged for the energy those devices use, and how they are rewarded for using that flexibility to reduce grid costs for others.
- Our embedded network tariff recognises the increasing interest and growth in embedded networks, and the undue cost impacts faced by other regulated customers when embedded network operators profit from the difference between existing network tariff structures without reducing the cost they impose on the shared network, and hence shift those costs onto others.

All three tariffs are currently proposed as placeholder tariffs with no customers assigned. We will develop the specifications after further engagement and consultation with the PWG, customers and other stakeholders (supported by further research as required) before including the details of the new tariffs in our annual pricing proposal.

We recognise that having placeholder tariffs without indicative structures or prices in our Tariff Structure Statement is not ideal, but is necessary to ensure flexibility in the face of rapid technological and customer behavioural change. This is consistent with the objective of flexibility outlined by stakeholders in the Pricing Directions statement (Attachment 10.14). This flexibility, particularly in areas facing the most significant potential change in the next five years, but where we do not yet have sufficient evidence to understand the most appropriate structure, will help us to maintain a network charging framework that is both equitable, and promotes a more affordable and more sustainable energy supply system.

10.4 Our pricing principles

10.4.1 Explaining our pricing principles

Our Tariff Structure Statement, and accompanying Explanatory Notes and attachments, present our pricing principles and approach to setting tariffs in detail. Our approach is based on:

- ensuring revenue is between standalone and avoidable cost for each tariff class
- ensuring our tariffs reflect long run marginal cost
- ensuring our tariffs reflect the efficient costs of providing services
- ensuring our tariffs mitigate the impact on customers.

Our Revised Proposal has the same approach to pricing principles as our Initial Proposal, and is aligned with both the NER and the objectives outlined in Pricing Directions: a Stakeholder Perspective statement (Attachment 10.14).

10.4.2 Varying indicative prices

Our Tariff Structure Statement presents our indicative pricing schedules for all our tariffs for each year of the regulatory period and Attachments 10.10, 10.11 and 10.13 present the Distribution Use of System, Transmission Use of System and Climate Change Fund components of the pricing schedules for each year.

We are required to explain any material variations between the indicative prices in the Tariff Structure Statement and the prices in our annual pricing proposal. While we do not expect there to be material variations, our indicative pricing schedule will vary depending on the latest available data for our price modelling including revenue and energy volume. Our energy volume forecast in Attachment 10.15 is based on information available in October 2018, which does not include complete consumption data for FY18 due to the timing of quarterly billing.

We will update our energy volume forecast for our next annual pricing proposal in April 2019 with Gross State Product and Household Disposable Income data released by the Australian Bureau of Statistics in November 2018. We will also have complete annual consumption data for FY18, including the contribution of all tariffs to maximum demand, to inform our annual pricing proposal.

10.5 Managing customer impacts

We present the customer impacts of our new prices for our tariffs, including our new demand tariffs, in our Tariff Structure Statement – Explanatory Notes (Attachment 10.01) using graphs and summary tables to show the distribution of impacts. This detailed impact analysis examines all potential customer transition paths, including changes that will occur on 1 July 2019, changes that could be triggered at any time within the five year period (based on the timing of a customer upgrading their meter), and changes that will occur over the duration of the period for customers staying on the same tariff. We summarise impacts that will occur on 1 July 2019 for typical low voltage customers in each tariff below.

10.5.1 Our typical residential customer bill decreases

Our Revised Proposal results in savings to our residential customers. Table 10.5 shows the network component of the bill for a typical customer on our two most common existing tariffs will be lower in FY20 than in FY19 and the bill for a typical customer on either of our two new demand tariffs in FY20 will be lower than our existing tariffs in FY20. Residential customers on a demand tariff who reduce their demand on the network in the demand charging windows but without changing their total energy consumption save more.

Our 'typical' residential customer on a legacy flat energy tariff with energy consumption of 5 MWh a year has a 12% reduction in the network component of their annual bill in FY20, compared to the bill in FY19. Over 1 million customers on this tariff will benefit from our lower prices.

Our 'typical' customer saving that assumes a specific annual consumption is different from the 'average' residential customer impact of 11% referred to earlier in this Revised Proposal, where the 'average' is calculated by dividing the total network revenues collected from residential customers (including controlled load) by the total number of residential customers.

We note that customers will experience a range of impacts, depending on the particular tariff, the level and composition of energy consumption, and whether they have controlled load or not.

Table 10.5

Residential customer bill impacts – typical customer

TARIFF	TYPICAL USAGE MWH PA	NETWORK COMPONENT OF BILL IN FY20	PERCENTAGE AND $ CHANGE FROM FY19	BILL WITH 10% REDUCTION IN DEMAND
Existing: EA010 Non-Time of Use	5	$565	-12% (-$75)	
Existing: EA025 Time of Use	5	$556	0% (-$2)	
New: EA116 Demand	5	$504		$482
New: EA115 Time of Use demand	5	$554		$549

Note: Excludes GST. Percentage change not available for new tariffs as they did not exist in 2018/19.

10.5.2 Our typical small business customer bill decreases

Our Revised Proposal results in savings to our small business customers. Table 10.6 shows the network component of the bill for a typical customer on our two most common existing tariffs will be lower in FY20 than in FY19 and the bill for a typical customer on either of our two new demand tariffs in FY20 will be lower than the existing tariffs in FY20. Small business customers on a demand tariff who reduce their demand on the network in the demand charging windows but without changing their total energy consumption save more.

Our 'typical' small business customer on a legacy flat energy tariff with energy consumption of 10 MWh a year has a 12% reduction in the network component of their annual bill in FY20, compared to the bill in FY19. Almost 68,000 small business customers on this tariff will benefit from our lower prices.

Customers will experience a range of impacts, depending on the particular tariff, the level and composition of energy consumption, and whether they have controlled load or not.

Table 10.6

Small business customer bill impacts – typical customer

TARIFF	TYPICAL USAGE MWH PA	NETWORK COMPONENT OF BILL IN FY20	PERCENTAGE AND $ CHANGE FROM FY19	BILL WITH 10% REDUCTION IN DEMAND
Existing: EA050 Non-Time of Use	10	$1,298	-12% (-$169)	
Existing: EA225 Time of Use	10	$1,268	-2% (-$27)	
New: EA256 Demand	10	$1,240		$1,212
New: EA255 Time of Use demand	10	$1,251		$1,245

Note: Excludes GST. Percentage change not available for new tariffs as they did not exist in 2018/19.

10.5.3 Our typical medium business customer bill decreases

Our Revised Proposal results in strong savings to our medium business customers using between 40 MWh and 750 MWh a year, and a smaller saving to large business low voltage customers (those using over 750 MWh a year), with the difference moving our larger low voltage customers closer to cost reflectivity. Table 10.7 shows the network component of the bill in FY20 for a typical customer on each of our two medium business tariffs and for a typical large business customer.

Table 10.7

Medium and large business customer bill impacts – typical customer

TARIFF	TYPICAL USAGE MWH PA	NETWORK COMPONENT OF BILL IN FY20	PERCENTAGE AND $ CHANGE FROM FY19
Existing: EA302 40-160 MWh pa	70	$6,795	-13% (-$1,047)
Existing: EA305 160-750 MWh pa	300	$25,376	-10% (-$2,717)
Existing: EA310 > 750 MWh pa	1,000	$61,646	-4% (-$2,270)

Note: Excludes GST. Usage is for a 'typical' customer on each tariff.

10.5.4 Impacts from demand tariffs reduced with demand response

We calculate the customer impacts of the new demand tariffs presented in our Tariff Structure Statement – Explanatory Notes (Attachment 10.01) using several scenarios with energy consumption remaining the same, including:

- impacts where customers do not exercise any opt out option or make any demand response
- impacts improved by customers selecting an alternative tariff that best suits their individual circumstances
- impacts improved by the opt out option and a demand response, where customers reduce maximum half hourly demand in the demand charging windows by 10%.

Our preliminary analysis indicates that customers with peaky demand are impacted the most by demand tariffs, but that this impact is strongly mitigated by applying 'opt out' options or a moderate demand response. Studies on typical demand responses in climatic conditions comparable to Sydney are difficult to find. However, results show that customers exposed to a price signal in the form of a demand charge do make a demand response. Weighting the results of the available studies[1] by the number of customers in each suggests that a 10% demand response could be expected on average and, if anything, is likely to be a conservative estimate in a temperate climate. The 10% demand response is also prudent as different customers will have different demand characteristics, and a 10% average response across all customers means, by definition, half achieving more and half achieving less. Customers with the peakiest load will typically be able to achieve a higher demand response.

Our preliminary analysis also indicates that impacts from our tariff reform are geographically dispersed and are not concentrated in areas of relative socio-economic disadvantage. We are committed to continuing to strengthen this analysis with further demographic data, and will do this in close collaboration with customer groups to facilitate the development of targeted complementary measures in the lead up to 1 July 2019. Our initial results suggest no specific socio-demographic group tends to be impacted more than any other.

10.5.5 Managing impacts with complementary measures

We will work closely with stakeholders including our Customer Consultative Committee and PWG, customer advocates such as the Energy and Water Ombudsman of NSW (EWON), government, retailers and industry to develop and promote a package of complementary measures to support the introduction of demand tariffs and manage customer impacts. Complementary measures can help customers to manage costs, both before and/or after they receive a bill. These measures are likely to include:

- Energy efficiency measures and programs with funding for appliances, heating, lighting and cooking including:
  - active monitoring and energy management: in house energy management systems to help customers monitor use in real time
  - online energy calculators modified to analyse and calculate peak 30 minute demand and cost and help customers choose the most cost effective retail tariff
- Demand management and demand response programs including network, retailer and customer led demand response initiatives
- Technology measures including installation of distributed energy resources supported by government rebates – this may include the installation of solar hot water systems or heat pump technology, and would be likely to extend to access to community solar and battery storage schemes suitable for those who cannot install distributed energy resources themselves
- Helping eligible customers access existing Government rebate schemes.

Some measures will be available to all customers, while other measures will have eligibility criteria to target assistance.

10.5.6 Communicating our changes

We recognise that introducing demand tariffs is a significant change for some of our customers. We will continue working with customer advocates including the EWON and our PWG, as well as retailers to support the development of effective communications to support our tariff changes. We are working with retailers on the implementation of the proposed tariffs and the retail products they are likely to offer to ensure that any communications to customers are aligned and relevant to their experience. We are also discussing our changes with our fellow distributors in NSW, Endeavour Energy and Essential Energy, to continue to drive a consistent approach where possible, recognising the differences in customer demographics and cost drivers between networks.

Our customer communications strategy will explain the need for change, highlighting improved control for customers.

In communicating the changes to customers, we will emphasise:

- why we are changing our tariffs and how the changes will benefit customers by ensuring a more equitable, affordable, reliable and sustainable electricity supply
- how customers can manage their bills and what tools and information are available to assist them including a comprehensive communications campaign such as 'Shift, Stagger, Save', and online tools and calculators to choose a tariff and better understand and manage usage
- options and procedures for customers to choose other cost reflective tariffs
- complementary measures and assistance available for customers in need.

We note that the timing of the AER's Final Determination in April 2019 and our proposed introduction of our demand tariffs from
1 July 2019 provides only limited time to communicate changes to customers, retailers and other stakeholders, so it is important that all stakeholders are aligned and supportive to achieve the desired outcome.

1 The studies are summarised in: Hledik, Ryan (2014) Rediscovering residential demand charges, *The Electricity Journal*, 27(7), pp. 82-96.

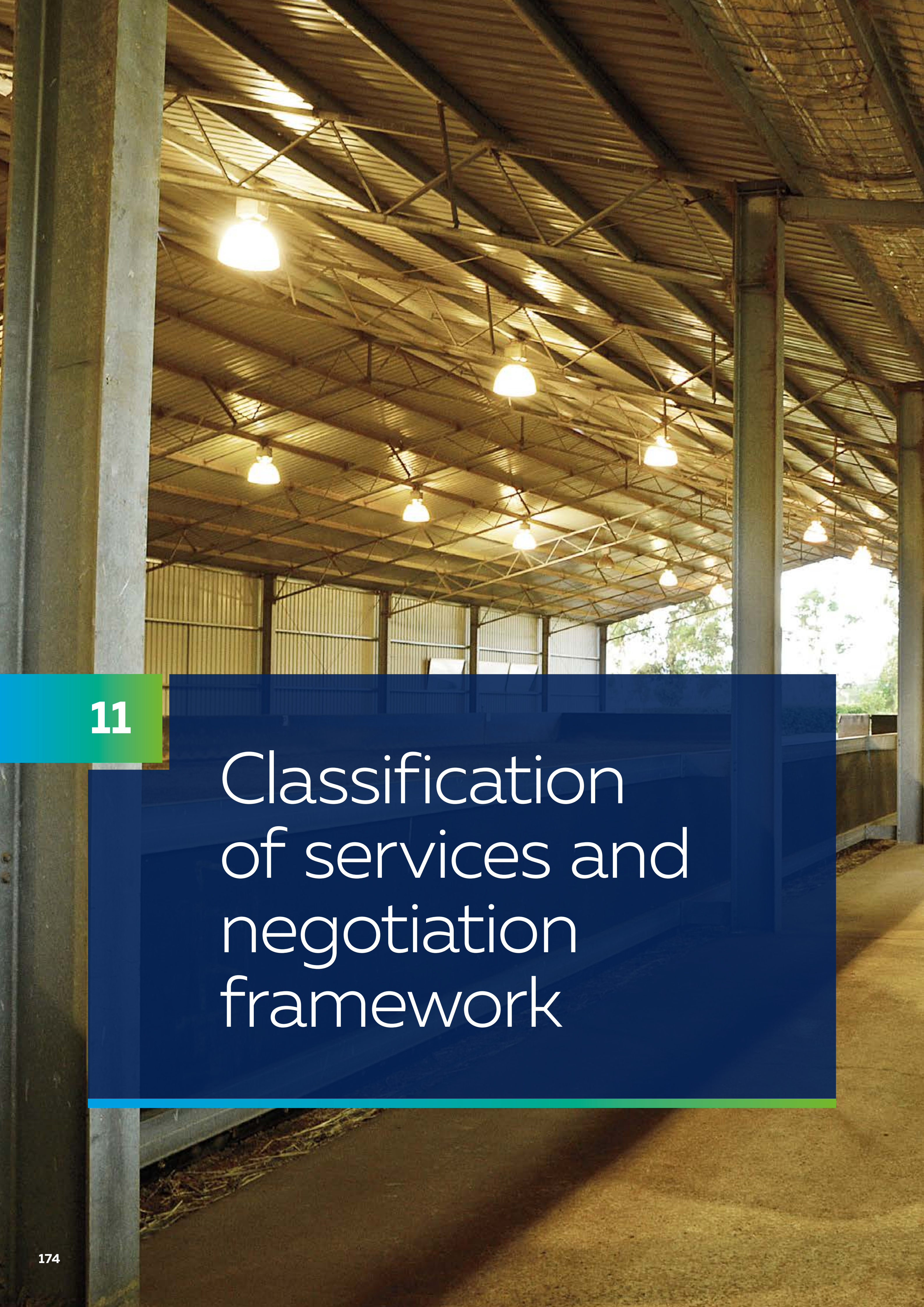
10.6 Supporting material

The attachments listed in Table 10.8 support our Revised Proposal. Attachments which have been revised since our Initial Proposal or are new for our Revised Proposal are shown in bold.

Table 10.8

Supporting material on pricing reform

ATTACHMENT	STATUS
10.01 Tariff Structure Statement	Revised to reflect our Revised Proposal, including Explanatory Notes (Appendix A to Tariff Structure Statement)
10.02 Procedure for assigning customers to a tariff class	No change from Initial Proposal
10.03 Long Run Marginal Cost model	No change from Initial Proposal
10.04 Long Run Marginal Cost methodology report	No change from Initial Proposal
10.05 Tariff model (Standard Control Services)	Revised to reflect our Revised Proposal
10.06 ES7 Network Price Guide, July 2019	Revised to reflect our Revised Proposal
10.07 Price elasticity	No change from Initial Proposal
10.08 Transmission pricing methodology	No change from Initial Proposal
10.09 Methodology for avoided TUOS charges	No change from Initial Proposal
10.10 Indicative pricing schedule – DUOS charges	Revised to reflect our Revised Proposal
10.11 Indicative pricing schedule – TUOS charges	Revised to reflect our Revised Proposal
10.12 Indicative pricing schedule – ACS charges	Revised to reflect our Revised Proposal
10.13 Indicative pricing schedule – Climate Change Fund	Revised to reflect our Revised Proposal
10.14 Pricing directions: a stakeholder perspective	No change from Initial Proposal
10.15 Energy volume forecast, January 2019	New for Revised Proposal



11

Classification of services and negotiation framework

11.1 Our approach to service classification ensures better customer outcomes

Revised Proposal

Our Revised Proposal accepts most aspects of the AER's Draft Decision in relation to service classification. However, we propose that the new 'rectification of simple customer fault' activity has a 30 minute window, rather than 20 minutes as outlined in the AER's Draft Decision.

In its Draft Decision, the AER proposed the inclusion of a new activity as part of the 'common distribution service'. That new activity, 'rectification of simple customer fault', allows distributors to restore supply where:

- the need for rectification work is discovered in the course of the provision of distribution services
- the work performed is the minimum required to restore safe supply; and
- the work can be performed in less than twenty minutes and does not normally require a second visit.

We welcome the inclusion of a new activity in the AER's Draft Decision. The new activity ensures that our staff will be able to fix simple faults at a customer's premises in order to restore supply. However, this new activity does not allow Ausgrid to restore supply for customers if the work will take more than 20 minutes to perform.

We have reviewed data contained in our service reporting system to estimate the time it takes to fix simple customer faults. Consistent with advice we have previously provided to the AER,[1] Ausgrid considers that 30 minutes is a more appropriate time limit.

Rationale

As a distribution network operator, Ausgrid considers that it has a duty of care to protect customers who may be at risk if they were required to source rectification services from contestable markets. A customer can be at risk not only on the basis of health and safety, but also due to locational circumstances (e.g. remoteness). We have indicated to the AER that will continue to assist customers that are at risk (and who we assess as 'vulnerable' customers).

In its final Framework and Approach paper, the AER allowed Ausgrid to provide fault rectification services for life support customers, but did not extend those protections to vulnerable customers who do not rely on life support equipment. In our proposal, we submitted that Ausgrid staff should be allowed to rectify simple faults where the health and safety of a customer could be placed at risk.

As we have previously submitted to the AER, we expect that work to restore supply would be strictly limited to fixing simple faults on the customer's side of the network connection such as a defective:

- barge fuse/service fuse
- service connector
- neutral link/active link
- Residual Current Device safety switch/circuit breaker/fuse/main switch
- ineffective earthing

In its Draft Decision, the AER recognised that a stringent application of the Ring Fencing Guideline could result in poor outcomes for customers. In particular, the limitation on fault restoration services would likely require a separate visit by an electrical contractor and therefore additional costs for the customer. The AER therefore proposed a new activity called 'rectification of simple customer fault' that will allow distributors to restore a customer's supply under certain circumstances.

The AER's new activity does not distinguish between different types of customer, and therefore the proposed 20 minute time limit applies to both vulnerable and non-vulnerable customers. What this means is that Ausgrid would be prevented from restoring supply for vulnerable customers if the staff member on hand considers that the work would take more than 20 minutes to perform.

Should the AER's draft position be replicated in its Final Decision, we would continue to restore supply for vulnerable customers. We would also continue to report breaches of the AER's Ring Fencing Guideline where we restore supply for vulnerable customers under our Vulnerable Customer Protocol if the work takes more than twenty minutes to perform.

As previously mentioned to the AER, we support the rectification of simple customer faults in circumstances where Ausgrid staff are responding to a 'no supply' call out by a customer. Any work that is beyond that necessary to restore supply (e.g. the repairing of a hot water service) would remain contestable.

1 Ausgrid advice to AER, *Minor Restoration Works Service Classification – Request for Feedback*, 7 September 2018.

In support of our proposal we have reviewed over 5000 call out jobs that occurred during 2017. The data was extracted from the Computer Aided Service System which records all service jobs and filtered for simple work types as listed in the dot points above. The data showed that the average time on site was 38 minutes (see Appendix 11.02)

Prior to any work being undertaken, Ausgrid's EMSO (Emergency Service Officer) must establish the reason for the 'no supply' call. Often this involves engaging with a customer. The EMSO then completes a mandatory safety hazards assessment check. We estimate that this preliminary assessment work takes around 10 minutes to complete.

Based on the average site time of 38 minutes and a pre-assessment time of approximately 10 minutes, we estimate that simple faults of the types listed above will take approximately 30 minutes to complete.

Consistent with advice we have previously provided to the AER, Ausgrid considers that a 30 minute time limit is a practical and reasonable time limit to be included in the definition of 'rectification of simple customer fault'.

Benefits for customers

As the AER recognised in its Draft Decision, a strict application of the Ring Fencing Guideline would likely result in poor outcomes for customers.[2] Where an Ausgrid EMSO attends a supply outage and identifies a 'simple fault' behind the connection point, prohibiting the Ausgrid staff member from fixing it would result in an extended power outage for the customer and additional costs.

Under our Revised Proposal, any customer who calls Ausgrid with a 'no supply' issue can expect a 24/7 response from Ausgrid and an efficient restoration of supply where the problem is a 'simple customer fault'.

11.2 Negotiated services

The AER accepted our proposed negotiated distribution services framework in its Draft Decision. Consequently, we make no further submission in relation to our proposed negotiation framework.

2 AER Draft Decision 2019–24, *Attachment 12 – Classification of Services*, p12–9.

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Appendix A: Glossary

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ABBREVIATION	MEANING
($, nominal)	These are nominal dollars of the day
($, real FY19)	This denotes dollar terms as at 30 June 2019
2014-19 regulatory period	The period that comprises both the transitional regulatory control period 1 July 2014 to 30 June 2015 and the subsequent regulatory control period 1 July 2015 to 30 June 2019
2019–24 regulatory period	The regulatory control period commencing 1 July 2019 and ending 30 June 2024
Initial Proposal	Ausgrid's Initial Regulatory Proposal for the next regulatory period submitted under clause 6.8 of the Rules
Revised Proposal	Ausgrid's Revised Regulatory Proposal for the next regulatory period submitted under clause 6.10 of the Rules
ACCC	Australian Competition and Consumer Commission
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Augex	Augmentation capital expenditure
B2B	Business to Business
CAM	Cost Allocation Model
CAPEX	Capital expenditure
CCC	Consumer Consultative Committee
CCP10	Consumer Challenge Panel Sub-Committee 10
CESS	Capital Expenditure Sharing Scheme
COAG	The Council of Australian Governments
COTA	Council on the Ageing NSW
CRM	Customer Relationship Management
DER	Distributed energy resources
DM	Demand management
DMIA	Demand Management Innovation Allowance
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme

ABBREVIATION	MEANING
DNSP	Distribution Network Service Provider
Draft 2018 RoR Guideline	AER's 2018 Draft Rate of Return Guideline
DRC	Debt raising costs
DSO	Distribution system operator
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EMSO	Emergency Service Officer
ENOPEN	Electrical Network Operation Envelope Platform
EPA	NSW Environment Protection Agency
ERW	Emergency Recoverable Works
EUAA	Energy Users Australia Association
EWON	Energy & Water Ombudsman NSW
EWP	Elevated Work Platforms
FTE	Full time equivalent
Gamma	Imputation Tax Credits
GWh	Gigawatt hours
HCV	Heavy commercial vehicles
HV	High voltage
IaaS	Infrastructure as a Service
ICT	Information, communications and technology
IGC	Investment Governance Committee
IM	Information Management
km	Kilometres
LCV	Light commerical vehicles
LED	Light-emitted diode
LiDAR	Light detection and ranging
LSE	Least squares econometrics
MPFP	Multilateral partial factor productivity

ABBREVIATION	MEANING
MW	Megawatt
MWh	Megawatt hours
NCOSS	NSW Council of Social Services
NEL	National Electricity Laws
NEM	National Electricity Market
NER or the Rules	National Electricity Rules
NIAC	Network Innovation Advisory Council
NMI	National metering identifiers
NPC	Net present cost
NUOS	Network Use of System
OPEX	Operating expenditure
OTI	Operational Technology and Innovation
PaaS	Platform as a Service
PFP	Partial factor productivity
PIAC	Public Interest Advocate Centre
PTRM	Post-tax revenue model
PWG	Pricing Working Group
RAB	Regulatory asset base
Repex	Replacement expenditure
RFM	Roll forward model
RIN	Regulatory Information Notice
RREC	Reset Regulatory Executive Committee
SFA	Stochastic frontier analysis
STPIS	Service Target Performance Incentive Scheme
TEC	Total Environment Centre
TOTEX	Total expenditure
TOU	Time of use
TRC	Technology Review Committee
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
UDIA	Urban Development Institute of Australia
VCR	Value of Customer Reliability
VoC	Voice of Customer
WACC	Weighted average cost of capital
WPI	Wage price index


Ausgrid