essential energy

empowering
communities

Empowering communities to share and use energy for a better tomorrow

2019-24 Revised Regulatory Proposal

January 2019

Contents

List of attachments

About this Revised Proposal

Informed by customers

Chapter Summary

- We have prepared this Revised Proposal for 2019–24 for the Australian Energy Regulator (AER)
- We have largely accepted the AER's Draft Determination
- Any points of difference have been informed by input from customers and stakeholders

Message from Essential Energy's Chief Executive Officer

In consultation with our customers and stakeholders, Essential Energy has prepared this revised version of our Regulatory Proposal for the AER in response to its Draft Determination. As the AER accepted the majority of our Proposal, this Revised Proposal addresses the few areas that were not fully accepted by the AER.

John Cleland Chief Executive Officer

We live in a rapidly changing energy market. This means that our business must constantly listen to our customers, stakeholders and regulators and reflect their feedback in how we evolve.

During 2017 and 2018, Essential Energy consulted extensively with customers and stakeholders to better understand how our services are valued, and how we can balance customer needs with delivering a safe, reliable, affordable and innovative electricity distribution network. We used these findings to develop our Regulatory Proposal for the 2019–24 period (Proposal) and submitted it to the AER in April 2018.

This work was recognised by the Energy Consumers Australia and Energy Networks Australia when we received the 2018 Consumer Engagement Award.

The AER has evaluated our Proposal and issued a Draft Determination on 1 November 2018 that largely accepts it. This Revised Regulatory Proposal (Revised Proposal) makes it clear where we agree with the AER's Draft Determination. It also addresses the areas that were not accepted in full by the AER. Therefore, it should be read in conjunction with our Proposal and the AER's Draft Determination.

Since the AER released its Draft Determination, we have consulted further with customers and stakeholders and embedded their feedback into areas of our Revised Proposal.

Our Revised Proposal accelerates the best of what Essential Energy does today and embraces our emerging role as an active facilitator of domestic and grid-scale renewable energy.

This Revised Proposal has been informed by customers and stakeholders and I believe it truly reflects what our customers need, want and expect. I hope you agree.

I invite you to read it then provide your feedback through the AER's website, aer.gov.au, or directly to Essential Energy using one of the communications channels listed on this page.

I look forward to reading your comments.

John Cleland

Chief Executive Officer

Send us your feedback

Website: www.essentialenergy.com.au/yoursay

Email: yoursay@essentialenergy.com.au

Post: Head of Stakeholder Engagement, Essential Energy, PO Box 5730, Port Macquarie NSW 2444

Phone: 13 23 91

Social media: Facebook YouTube Twitter LinkedIn

Our Values

What we care about

Make safety your own

Be easy to do business with

Make every dollar count

Be courageous, shape the future

Be inclusive, supportive and honest

Introduction

The context for this Revised Proposal

Essential Energy provides a range of distribution services to electricity customers in regional, rural and remote New South Wales (NSW). These include:

> connecting customers to the poles and wires (network);
> managing the network;
> providing some Metering Services;
> Public Lighting Services; and
> non-routine services, such as special meter tests.

As a regulated electricity distribution business, Essential Energy is subject to economic regulation by the AER under the National Electricity Rules (NER). This means most of our distribution services are subject to revenue and/or price controls determined by the AER, which usually apply for a regulatory period of five years.

This Revised Proposal follows publication of the AER's Draft Determination on the Proposal we submitted in April 2018.

Based on stakeholder feedback, it sets out our recommendations for the areas that were not accepted by the AER in its Draft Determination. It also outlines our revised recommended revenue requirement and how this will be reflected in customer charges over the five years from 1 July 2019.

This Revised Proposal only addresses those parts of Essential Energy's Proposal and Proposed Tariff Structure Statement (TSS) that have been updated.

Dollars presented in this Revised Proposal

Unless otherwise stated, the dollars referred to in this Revised Proposal are as at 30 June 2019. This aligns with the dollar treatment in the AER's revenue model.

How this document is structured

Our Revised Proposal is a response to the AER's Draft Determination, so it does not repeat the detailed expenditure plans and information contained in our Proposal.

It is supported by customer and stakeholder Fact Sheets and a Customer Overview document that:

> provide a Plain English summary of the Revised Proposal;
> describe how we have engaged with customers and stakeholders to develop it, and how we have responded to the important matters they raised; and
> include the key risks and benefits for customers;
> provides a comparison between our total revenue requirements for the 2014–19 and 2019–24 regulatory periods, explaining any material differences between them.

We have prepared this document to comply with NER requirements and attach a compliance checklist at Attachment 1.1 indicating where each requirement is addressed. We also attach a log of confidential information at Attachment 1.2.

Executive Summary

Responding to changing customer needs in the new energy market

Chapter Summary

> We have shaped our Revised Proposal in consultation with our customers and stakeholders

> By investing in our business transformation program and applying the AER's final Rate of Return Guideline, we will reduce our customers' real network charges over the 2019–24 regulatory period

> We are proposing amendments to four areas in our Revised Proposal

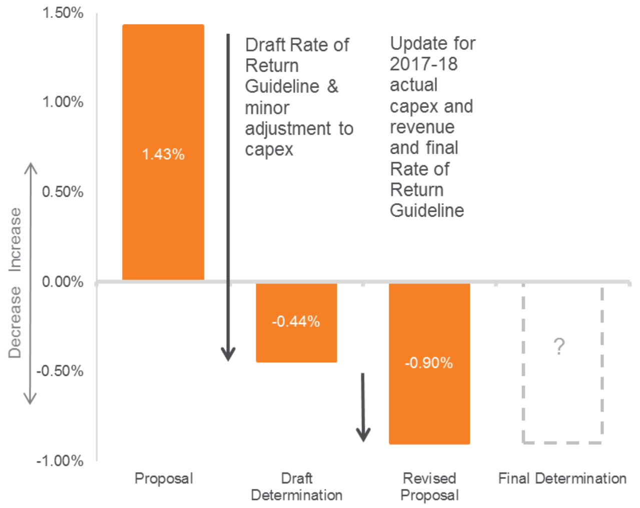
Executive Summary

We lodged our Proposal for the 2019–24 regulatory period with the AER on 30 April 2018. The AER issued its Draft Determination on 1 November which largely accepted our Proposal.

Real distribution network charge decreases for customers

Our Revised Proposal reduces our real annual revenue requirement by 0.90 per cent across the 2019–24 regulatory period. This equates to an average real decrease in average annual distribution network charges of 0.92 per cent across the same period.

Average real annual change in revenue 2019-24



In addition to our business transformation and the AER's changes to the allowed rate of return, there are two further reasons for this real distribution network charge decrease:

> Lower than expected 2017–18 capital expenditure, which has reduced the 1 July 2019 forecast opening RAB; and

> Higher than expected 2017–18 revenue, which has increased the current regulatory period over-recovery amount, further reducing the revenue requirement.

Customer and stakeholder engagement

This Revised Proposal has been shaped by our award-winning Proposal engagement program comprising over 3,000 customer and stakeholder interactions.

Since the AER published its Draft Determination, we have undertaken three further deliberative customer forums and stakeholder deep dive workshops, one Customer Advocacy Group meeting and multiple one-on-one meetings with retailers and key stakeholder groups.

These largely focused on areas of our TSS that were not accepted by the AER. We also gained insights into stakeholders' views of what our network of the future looks like. The results have influenced the direction of our Revised Proposal.

We also undertook a dedicated Public Lighting stakeholder engagement program, with Local Councils and their representatives, to address issues identified in stakeholder submissions on our Proposal.

"It was great that Essential Energy took the time to hear from real members of the community and listen to their opinions on the issues."
Wagga Wagga customer

"It was great to be able to express my views and know that I was able to 'have my say' and for it to be heard."
Port Macquarie customer

What has changed

Having accepted the majority of the AER's Draft Determination, the key changes in our Revised Proposal, other than those driven by updates for our 2017–18 actuals and the AER's final Rate of Return guideline, are:

> Classification of Services table - to encompass two services we have identified since submitting our Proposal that will improve outcomes for our regional, rural and remote customers;

> TSS - to address AER and stakeholder feedback on calculating and assigning distribution network charges;

> Ancillary Network Services (ANS) prices - to ensure recovery of our efficient costs; and

> Public Lighting prices – following dedicated stakeholder consultation on our model.

Beyond 2024

The business strategy that underpins this Revised Proposal will enable Essential Energy to reduce our costs, prepare for the future and empower our customers to share and use energy for a better tomorrow.

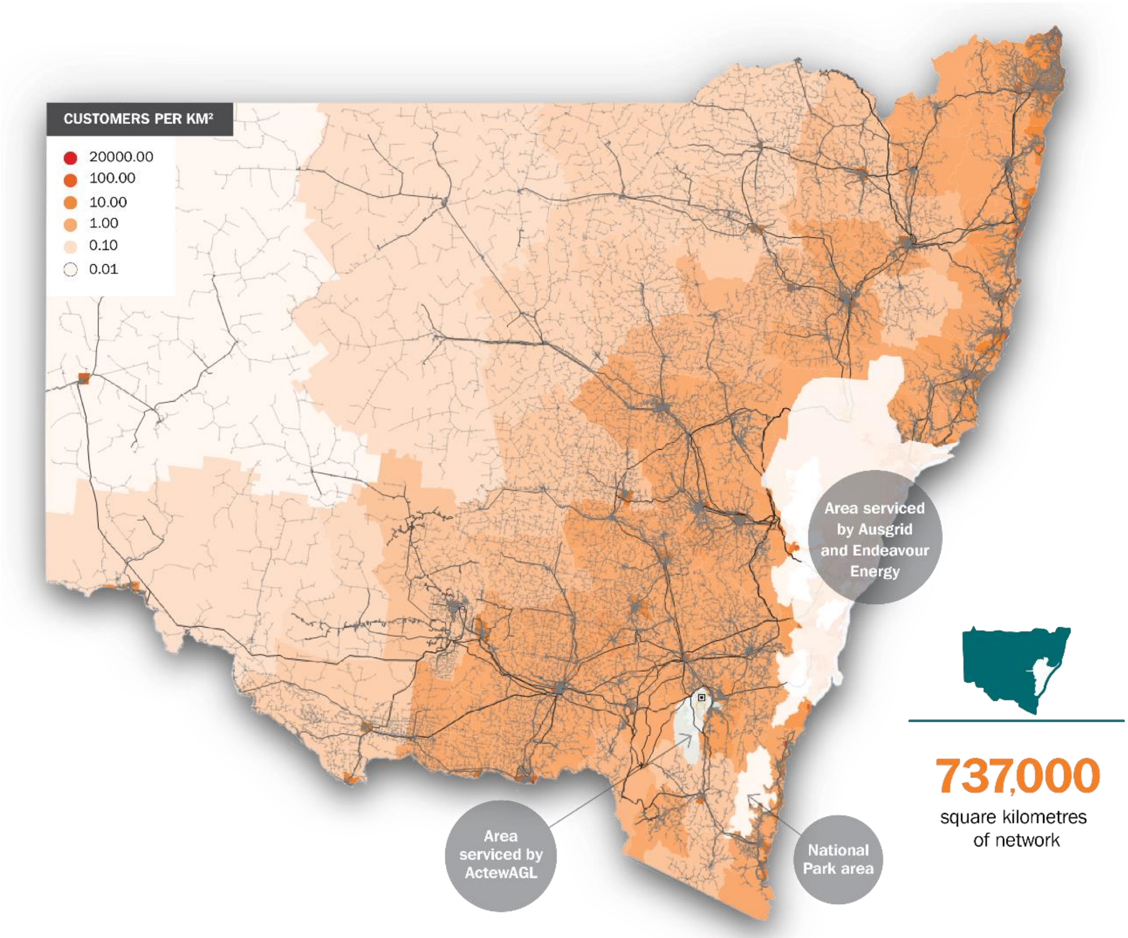
About Essential Energy

Empowering communities to share and use energy for a better tomorrow

Chapter Summary

> Essential Energy operates and maintains one of Australia's largest distribution networks
> We deliver electricity to our customers safely, reliably and sustainably
> Everything we do is guided by our vision to empower communities to share and use energy for a better tomorrow
> We continuously evolve in response to how our customers want to use our network, including embracing new technologies
> Our Corporate Strategy drives our decisions and sets the future direction for our business

About Essential Energy



1,381,758
power poles – which equates to 1.6 power poles for every customer

>840,000
customers

737,000
square kilometres of network

95%
of NSW & parts of southern Queensland

377
zone substations and 140,000 distribution substations

183,612km
of overhead powerlines – equivalent to driving around Australia 13 times

1,905km
length of our longest powerline – services 335 customers

4.6 customers
per km of powerline – the lowest customer density in the National Electricity Market

36 years
average age of network assets

1m
spans in designated bushfire zones

15,409
lightning strikes per year on the network

Extreme variations
in both weather and terrain

40m kms
travelled by our employees each year

Vegetation management
our largest operating expenditure

Our Corporate Strategy is shaping our future focus

This Revised Proposal aligns with our Corporate Strategy (Strategy), which provides a road-map for Essential Energy's future direction.

The Strategy prioritises the strategic initiatives detailed in our Proposal. It informs our activities and investment for the next 10 years and will ensure Essential Energy can continue to meet our customers' changing needs.

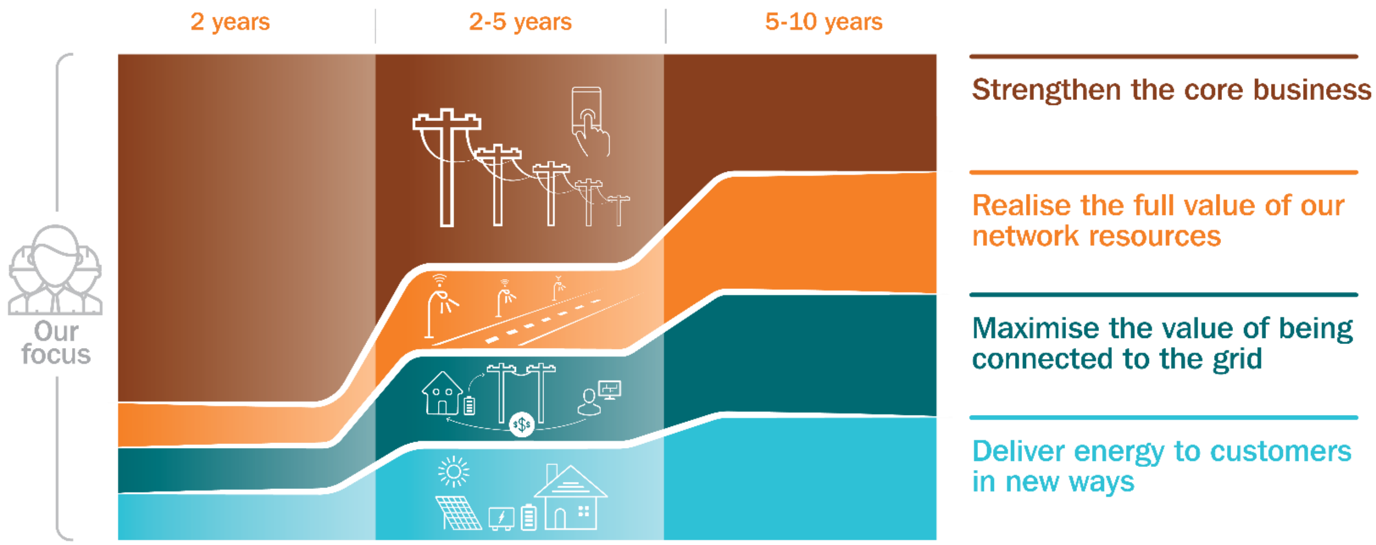
It is important that our business can adapt to the future energy market, whatever form it may take. As such, our Strategy does not dictate a particular future state. Instead, it provides a pathway to ensure we will always be ready for change and capable of providing the services our customers require.

To develop the Strategy, we identified the distribution network capabilities required to deliver the future services our customers may demand. This involved determining which areas of Essential Energy already support our goals, those needing further development, and new areas to consider. Business transformation emerged as our major priority.

We then designed a program of initiatives to fill the gaps between our current state and this future state, aligning them with four strategic objectives.

The resulting Strategy will drive all our strategic decisions over the next decade, ensuring we can deliver new business capabilities and positioning Essential Energy at the forefront of a rapidly changing industry.

Our Corporate Strategy



Our Customer Engagement

Informed by our customers

Chapter Summary

> Building on key themes identified in earlier customer and stakeholder engagement programs, we continued to work with customers following the AER's Draft Determination

> The strategies, investments and activities outlined in this Revised Proposal reflect these ongoing discussions

> They place customers at the centre of our business strategy while meeting our regulatory obligations

Our Customer Engagement

Putting customers at the centre of everything we do

Essential Energy recognises the critical role electricity plays in enabling the daily lives of the communities and businesses we serve across regional, rural and remote NSW.

To do our job effectively, we must know what these communities need and expect of us today and in the future. Through meaningful collaboration with customers and key stakeholders, we can minimise electricity distribution charges, make more informed investment decisions, and deliver electricity services that better reflect customer and stakeholder preferences.

Customer and stakeholder engagement goes beyond our day-to-day service delivery. It also plays a major role in our business transformation and our vision of 'empowering communities to share and use energy for a better tomorrow.'

Our customers have varying levels of interest in, and knowledge of, Essential Energy and our industry. Therefore, when seeking input into our Revised Proposal, we used a variety of approaches.

This was recognised when Essential Energy received the Energy Consumers Australia and Energy Networks Australia 2018 Consumer Engagement Award.

> ***"[Essential Energy] showed they had proactively engaged with their consumers to better reflect their views and priorities and allow that to shape services."***
> **Rosemary Sinclair, CEO Energy Consumers Australia**

Our customer and stakeholder groups

GROUP 1
NO KNOWLEDGE
Stakeholders who are future customers or new customers.

GROUP 2
LIMITED KNOWLEDGE
Stakeholders with limited knowledge.
Interactions mainly via their retailer.

GROUP 3
MODERATE KNOWLEDGE
Stakeholders who interact with Essential Energy and have some understanding of industry and usage.

GROUP 4
HIGH KNOWLEDGE
Stakeholders who have worked closely with Essential Energy and industry and have extensive knowledge.

A customer-focused culture

We have developed a customer and stakeholder culture at Essential Energy that reaches far beyond the Regulatory Proposal cycle.

Our business-wide Corporate Stakeholder Engagement Plan incorporates our Stakeholder Engagement Framework and an ongoing program of stakeholder and issues-mapping that links directly to Essential Energy's Vision, Purpose and Corporate Strategy.

> ***"Essential Energy's customer engagement …is a very good way of embedding a culture of good engagement in the day-to-day operation of the business."***
> **Public Interest Advocacy Centre**

We continually seek independent review and opinion from core customer and stakeholder reference groups, including our Customer Advocacy Group. This provides a proactive forum for consultation, engagement and insight across Essential Energy's customer base on matters relating to electricity supply and associated services. The Group's members represent the interests of domestic, industrial, commercial, primary production, Indigenous, rural and remote and low-income customers. They meet regularly throughout the year.

Engagement strategies and plans must be built on a culture of genuine intent. Participation by all levels of the organisation, from the CEO to office and powerline workers, is central to our approach and comes with a willingness to engage in robust discussion and ongoing dialogue.

In its 2017–2018 *Evaluation of Consumer Engagement by NSW DNSPs*, the Public Interest Advocacy Centre recognised Essential Energy's approach to stakeholder engagement as: "…*building a culture of engagement in the business [that] indicates a high-level commitment…*"

‘Always On’ customer engagement

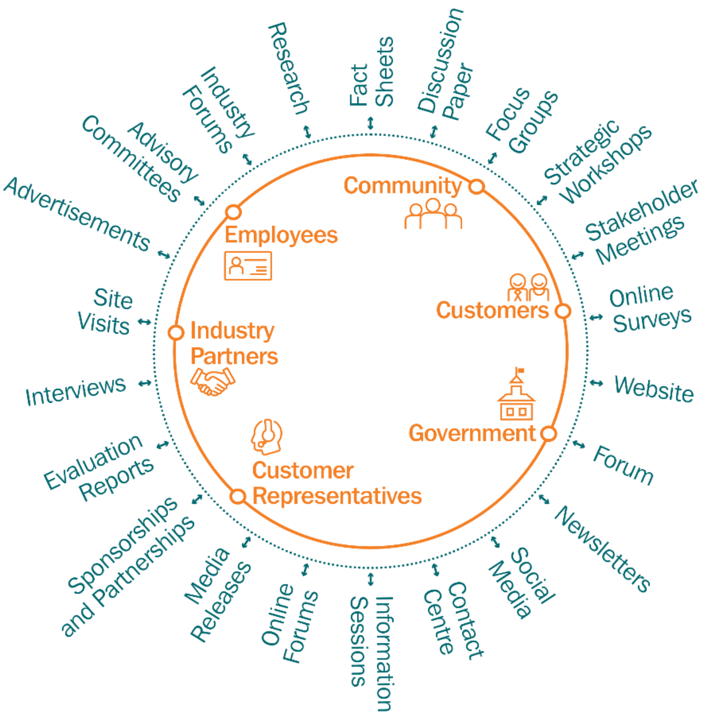
In developing our Regulatory Proposal, we embarked on an intensive program of customer and stakeholder engagement that began in early 2017.

The program directly engaged residents, customer advocates, small business owners and large commercial enterprises across our network footprint. This ensured the views and expectations of Essential Energy’s regionally, culturally, demographically and economically diverse customer base were accurately and meaningfully reflected in both our Proposal and Revised Proposal.

To maintain independence, we engaged Woolcott Research and Engagement and Farrier Swier to facilitate deliberative workshops and other engagement activities with customers and stakeholders.

We shared information and received feedback through online, phone and face-to-face channels using a range of tools. These included infographics, videos, surveys, workshops, presentations and reports. Where possible, these were tested with customers for clarity and understanding beforehand.

All communication materials and engagement approaches reflected the diversity of the customers we serve and were tailored for each customer group, including culturally and linguistically diverse and Aboriginal and Torres Strait Islander representatives.



Engagement in practice

Our engagement program comprised four key phases of activity, building from an initial understanding through to refining the key elements in our Revised Proposal. We published a summary report after each phase. The reports relating to Phases 1, 2 and 3 were attachments to our Proposal. The report for our most recent engagement work (Phase 4) is attached to this Revised Proposal (see Attachment 4.1).

Safety, affordability and reliability remained as customers’ top priorities, followed by customer service, renewable energy, bill transparency and innovation.

Our customers’ top priorities

- **Safety is essential for doing business**
- **Affordability**
- **Reliability**
- **Good customer service and communication**
- **Encourage renewables**
- **Bill itemisation**
- **Innovative technologies**

PLANNING

JUN 2016 TO DEC 2016

Listening and engagement sit at the centre of our business. We have been meeting with our Customer Advocacy Group for over 20 years

Our dynamic Stakeholder Engagement Framework is embedded into strategic planning, reflects stakeholder consultation and empowers customers to inform business decisions and engagement approaches

We held stakeholder interviews with customer representative groups and met with Essential Energy's Customer Advocacy Group to consult on our Stakeholder Engagement Framework and early approach to the proposal

We engaged independent experts Woolcott Research and Engagement to facilitate customer and stakeholder engagement for the 2019-24 Regulatory Proposal

We designed a consultation program that recognised customer diversity and varying levels of interest and knowledge about our business

1,590
Customer & Stakeholder interactions

UNDERSTANDING OUR CUSTOMERS

A Discussion Paper provided background information about our business and an open invitation to seek opinions on proposed capital, operating and investment decisions

We held interviews, surveys and deliberative forums with customers and stakeholders to understand what matters to them most

Customers identified the key customer values that have fundamentally informed the development of this Regulatory Proposal

We launched Essential Engagement, an online forum for people to 'Have Your Say' on key initiatives in our Regulatory Proposal

Customer feedback was shared in the Woolcott Engagement Program Summary Report – Phase 1

Phase 1: Consultation

JAN TO JUN 17

> Online survey: 752 residential customers and 250 small to medium businesses
> 'YourSay': 34 residents and 4 businesses
> 11 interviews with large customers and stakeholders
> 7 deliberative customer forums with 513 attendees and internal and external observers
> 1 Customer Advocacy Group meeting
> 1 Vegetation Management Consultation Group meeting
> 1 Streetlight Consultative Committee meeting

DEEP DIVE

Using a range of engagement activities, deeper consultation was held on customer priorities and issues impacting the Regulatory Proposal

An Engagement Focus Paper was published and used as a tool to support customer consultation and discussion

Customer feedback was shared in the Woolcott Engagement Program Summary Report – Phase 2

NOV 17

We refreshed:

Our Vision…
empowering communities to share and use energy for a better tomorrow

Our Purpose…
to enable energy solutions that improve life

Phase 2: Consultation

JUL TO SEP 17

> Online survey: 754 residential customers and 250 small to medium businesses
> 'YourSay': 11 residents
> 16 interviews with large customers and stakeholders
> 7 deliberative customer forums with 518 attendees with 54% repeat participants and internal and external observers
> 2 pricing workshops with 10 stakeholder groups
> 2 Customer Advocacy Group meetings
> 1 Streetlight Consultative Committee meeting
> 4 retailer meetings
> 1 LED streetlighting meeting with local councils

TESTING

AER SUBMISSION APRIL 2018

We tested 'what we heard' and 'closed the loop' by continuing our engagement activities across our footprint in NSW

On 9 February, we released our draft Regulatory Proposal for public consultation

Phase 3: Consultation

JAN TO FEB 18

- Public release of engagement findings and draft Regulatory Proposal
- Draft Regulatory Proposal invitation for feedback
- YourSay online dialogue
- 3 "closing the loop" customer forums
- Online survey
- Employee engagement
- 1 Customer Advocacy Group meeting
- 1 Vegetation Management Consultation Group meeting
- 1 Streetlight Consultative Committee meeting

300+ Customer & Stakeholder interactions

REFINING

AER DRAFT DETERMINATION 1 NOV 2018

The AER largely accepted our Regulatory Proposal so we responded mainly to the areas where the AER asked for further consideration

Phase 4: Consultation

NOV TO DEC 18

- 3 deliberative customer forums
- 3 stakeholder deep dives
- In-depth interviews with large customers and retailers
- Dedicated streetlighting model consultation
- Essential Engagement online forum
- 1 Customer Advocacy Group meeting

100+ Customer & Stakeholder interactions

1,598 Customer & Stakeholder interactions

REVISED PROPOSAL TO AER JAN 2019

ONGOING CUSTOMER ENGAGEMENT

Phase 4 customer engagement: Refining

Our most recent phase of engagement began immediately after the AER published its Draft Determination. We wanted to make sure customers understood the Draft Determination and how it related to the original discussions, and to seek feedback on the areas of our Proposal where the AER wanted more discussion.

Further customer forums, stakeholder deep dives and one-on-one interviews enabled us to shape our Revised Proposal in the key areas highlighted by the AER.

What customers told us

Customers overwhelmingly supported the AER's Draft Determination and were comfortable that their views had been captured and reflected accurately in our Proposal.

The main discussion areas for the Revised Proposal were those highlighted by the AER: Public Lighting and our TSS.

The table opposite summarises the outcomes. For detailed results, see the relevant chapters and attachments:

Tariff Structure Statement

> Chapter 12 - Our Approach to Pricing
> Attachment 12.1 - Revised TSS

Public Lighting

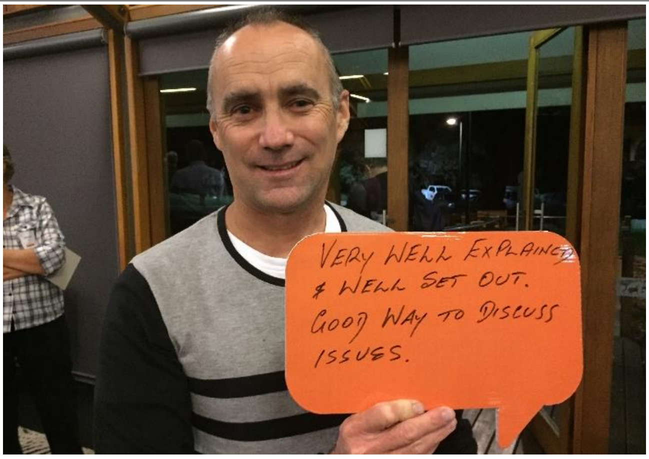
> Chapter 13 - Alternative Control Services
> Attachment 13.1 – Public Lighting Proposal

Engaging beyond the regulatory cycle

The customer and stakeholder engagement programs for our Proposal and Revised Proposal provide a valuable starting point for ongoing consultation in a rapidly changing energy environment.

Our ambition is to embed an 'Always On' culture in our business that shifts the customer conversation from 'project-based' to one where customer and stakeholder views and opinions are central to all our business activities.

Our Stakeholder Engagement Plan is an important step towards achieving this and sets the ground rules for our activities.



Our engagement principles

Curious	We engage early and design our engagement activities to meet the needs of stakeholders, actively seeking feedback to learn and improve.
Accountable	We act transparently, measuring and evaluating the quality of our engagement and ensuring outcomes are visible to stakeholders.
Courageous	We are action-orientated and open-minded, and act with integrity. Our business is continually informed and shaped by our engagement.

Summary of engagement outcomes (Phase 4: Refining)

Engagement topic	Customer feedback	% Customer support	Reflected in Revised Proposal
AER Draft Determination			
What do you think of the AER's Draft Determination?	Overall support for the AER largely accepting Essential Energy's Proposal.	Not posed as a question, but majority gave verbal support	N/A
Distribution network charges			
Should customers be treated differently depending on how they use the network?	All customers should be treated the same, regardless of how they use the network or their energy solution.	66%	Agree – we will assign Residential and Small Business customers in the same way, regardless of whether they have new technologies or not.
Should Residential and Small Business customers automatically be moved to a distribution network charge that is Fixed Charge and Time-of-Use, OR Fixed Charge, Time-of-Use and Demand charge?	The transition should adopt a distribution network charge based on Fixed Charge and Time-of-Use charge. There was general anxiety that, with a Demand charge, if you make one mistake, you pay for it the whole month, and this felt punitive.	Responses were expressed across other questions asked (sample size is too small to be reliably reported).	Agree – we will assign Residential and Small Business customers to a Time-of-Use charge and keep a demand-based charge as an option.
Should the Demand charge for Residential and Small Business customers be based on both peak and shoulder periods (7am –10pm weekdays), OR peak period only (5–8pm. weekdays)?	Demand charges should be based on peak period only as this offers greater opportunity for customers to change behaviour and provides a smaller window to be 'penalised'.	58%	Agree – we will apply the Demand charge for Residential and Small Business customers only in the peak period.
How charges are applied			
Do you prefer to move to cost-reflective pricing if you have upgraded to a smart meter when the meter is installed, OR 12 months after the meter is installed?	While a wide range of views were expressed, 48% of residential customers preferred to wait 12 months to move to cost-reflective pricing, while 42% of residential customers supported an immediate move to cost-reflective pricing so the benefits could be realised as quickly as possible.	48% wait 12 months 42% move immediately	Mixed views – we propose an immediate change as it is simpler and allows customers access to savings earlier. Customers can opt out to an alternative network charge. We also support a review of customer's charges after 12 months on the Time-of-Use charge.
Should customers and/or retailers be able to opt out of cost-reflective pricing?	Customers wanted to retain the option to opt out due to general anxiety that momentary errors on a cost-reflective distribution network charge could result in higher prices. They viewed the ability to opt out as providing greater customer choice.	88%	Agree – we have maintained a flat charge option but have priced it to be less attractive than our more cost-reflective distribution network charges.
Network of the future			
Do you think stand-alone power systems are a good solution to the challenge of minimising network costs for all customers?	Customers supported further stand-alone power systems research that would provide a better understanding of cost, reliability and maintenance benefits.	N/A	Agree – we have provided further details about our planned trials in the Innovation chapter.

Delivering Value

Continuing our customer value journey

5

Chapter Summary

> Providing the safe, affordable and reliable network service that customers want is key to ensuring we deliver value and underpins our Revised Proposal

> There are factors underlying the growth of our Regulatory Asset Base that need to be considered

> Our transformation investment will deliver multiple cost reduction and service improvement benefits

5 Delivering Value

Delivering Value

We regard delivering value as an ongoing commitment. Essential Energy's four core business objectives embed value into every aspect of our services, so we can serve the long-term interests of our customers, shareholders and other stakeholders.

Business Objectives

- Continuous improvements in safety culture and performance
- Operate at industry best practice for efficiency, delivering best value for customers
- Deliver real reductions in customers' distribution network charges
- Deliver a satisfactory return on capital employed

Our Proposal outlined how our transformation program is building a better business that will continue to meet the needs of customers and shareholders now and into the future. The AER accepted the expenditure and savings related to this program in its Draft Determination.

The customer engagement programs for our Proposal and Revised Proposal have provided us with a better understanding of what value means to our customers, with safety, affordability and reliability emerging as the top priorities. This has informed our approach to developing the future expenditure and service plans we outlined in our Proposal.

Addressing stakeholder feedback

AER and stakeholder feedback on our Proposal, relevant to this chapter, were in relation to two issues.

- The lack of detail around where the strategic investment costs and associated benefits sat within the Proposal (AER and Consumer Challenge Panel 10); and
- The growth of our Regulatory Asset Base (RAB), which was giving rise to real network charge increases despite the significant cost reductions we proposed (Consumer Challenge Panel 10 and Energy Users Association of Australia).

This chapter aims to address these concerns.

Real network charges are decreasing

Our Proposal contained small average real network charge increases, even with significant reductions to our costs and the Rate of Return. This was primarily because of our network investment, which was greater than the depreciation in network value over the same period.

The Proposal stated our support for adopting the draft Rate of Return Guideline (Guideline), and the final Guideline once it is published. The AER applied the draft Guideline in its Draft Determination. This resulted in a significantly lower Rate of Return and was the primary contributor to the average real annual revenue decreases of 0.44 per cent presented in the AER's Draft Determination.

We have updated our Revised Proposal to reflect actual 2017–18 revenues and capital expenditure, as well as the final Rate of Return Guideline. These changes give rise to greater average real yearly revenue decreases of 0.90 per cent.

Our Revised Proposal
average real network charge
decreases of 0.92%

Our transformation investment and benefits

Our customer engagement program highlighted customers' support for our proposal to invest in technology to improve efficiency and lower operating costs. Our Corporate Strategy will deliver long-term efficiencies through using this approach.

We intend to deploy modern core systems and build advanced data analytics to ensure we have the capability to enable our transformation. The proposed business improvements will create future value for all Essential Energy's stakeholders by avoiding price spikes for our customers and helping us to build a sustainable distribution network.

Appendix A contains more detail about these investments, their benefits, and how they have shaped our operating, support and capital expenditure forecasts.

Understanding RAB growth

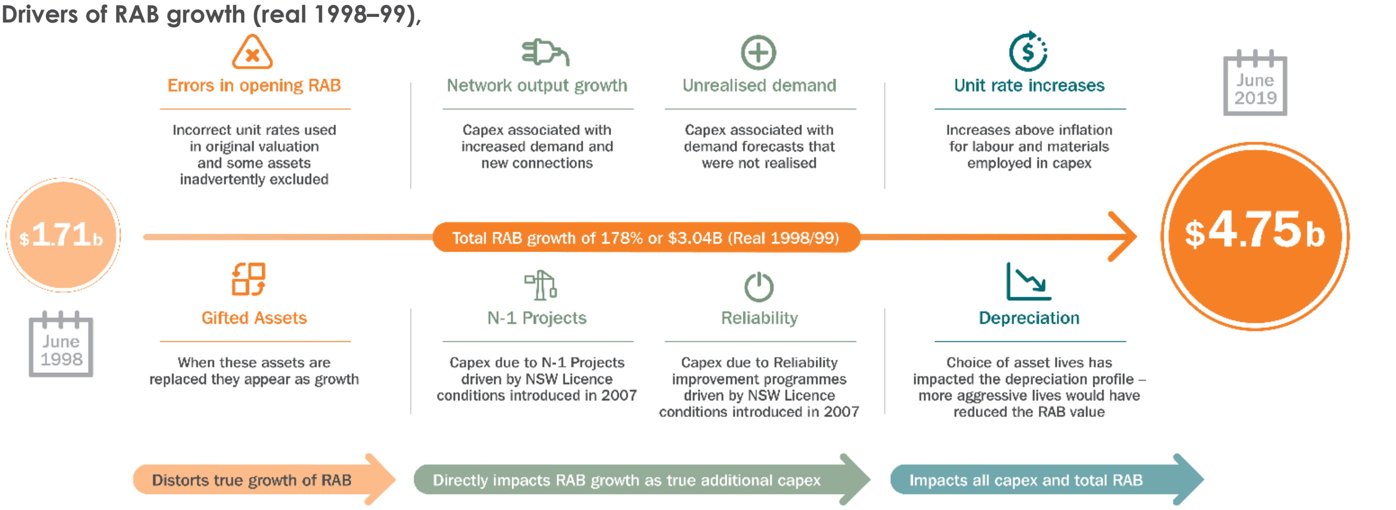
At 30 June 1998, our RAB was valued at $1.71 billion. It is forecast to reach $8.15 billion by 30 June 2019, equivalent to about $4.75 billion when discounted back to 1998 real dollar terms. This is a total RAB growth since 1998 of $3.04 billion (real 1998–99), or 178 per cent.

We engaged consultants, Houston Kemp, to review our RAB in detail and identify the main drivers of its past and future growth.

They found the drivers overlap and cannot be viewed in isolation but can be grouped into three main areas (see diagram).

1. Actions that distorted the true RAB growth;
2. Capital expenditure related to network growth and 2007 NSW licence conditions; and
3. Elements that have inflated the RAB.

Drivers of RAB growth (real 1998–99),



1. Distortion of true RAB growth

Two issues exaggerate perceived growth in the RAB and understate the actual depreciation of assets. Adjusting the RAB for both elements would reduce real RAB growth by 79 per cent.

Errors in the opening RAB

The 1 July 1998 opening RAB valuation had:

> errors in the cost valuation technique used to establish the RAB; and

> inadvertently excluded some system assets.

Gifted assets

The significant customer-capital-contributed assets that provide Standard Control Services should not form part of the RAB because they were funded by customers. When these assets are replaced, they are added to the RAB and appear as growth

2. Factors that led to true RAB growth

Network output growth

Capital expenditure in network growth (from customer demand and connections) is responsible for 72 per cent of the RAB increase.

Unrealised demand

A substantial driver of investment in our network is the need to meet expected future load growth (demand) forecasts. There has been a small amount of network investment on the expectation of demand growth that did not eventuate. Removing capital expenditure related to unrealised demand from the RAB would reduce RAB growth by five per cent.

N-1 projects and reliability capital expenditure

Between December 2007 and July 2014, the NSW Government mandated N-1 and reliability standards for electricity networks. If the expenditure incurred on N-1 projects was removed from the RAB, it would reduce RAB growth by 30 per cent.

The analysis specifically investigated capital expenditure for reliability improvements over the 2009–14 regulatory period. Removing the expenditure incurred on reliability projects during that time would reduce RAB growth by nine per cent.

3. Items that have inflated the RAB

Unit rate increases

Modelling for the effect of real increases in unit capital expenditure costs showed a material impact on RAB growth of 26 per cent.

Depreciation

Essential Energy adopts depreciation rates that fall between the lower end of privately-owned distributors and the upper end of publicly-owned distributors. If higher (more aggressive) regulatory depreciation rates were applied, the RAB growth would potentially be reduced by 42 per cent.

Houston Kemp's conclusion

The analysis highlighted that there are several explanations for the growth in Essential Energy's RAB.

Correcting for the undervaluation of the opening RAB, the material increases in capital expenditure unit costs and the marked improvement in network reliability, the adjusted real growth in the RAB would be 46 per cent, which is less than the adjusted growth in demand and connections of 62 per cent.

Where to now for the RAB?

We have engaged Houston Kemp to investigate options for managing our future RAB growth. They have put forward a number of options, including a change to our capitalisation policy, a change to our regulatory depreciation approach or a move to stand-alone power systems.

We will consider and possibly look to implement one or a combination of these potential options over the 2019–24 regulatory period.

Innovation

Enabling energy solutions that improve life

6

Chapter Summary

> Our business is undergoing significant change as we respond to a rapidly evolving energy market

> We plan to use innovative technologies to reduce costs, refine asset management and improve customer interaction

> We are piloting and trialling new asset management techniques

Innovation

We recognise that we cannot continue to provide energy in the same ways while also making the most efficient use of our network. Technology is changing and providing opportunities to reduce costs. This is where our innovation projects come in. We are committed to exploring and deploying new ways of providing our customers with electricity while improving capital utilisation and reducing costs to all our customers.

To ensure that our innovation program aligns with our customers' values we have asked them what they think about innovation. This engagement has shown us that our customers are willing to embrace technological change and innovation so long as it is cost-effective and fair. We have taken this feedback on board and have used it to inform our innovation projects.

To improve the utilisation of our network over 2019–24 we will work towards:

- improving reliability only to the worst-served customers on our network
- revising how we make decisions to replace network assets
- trialling the use of Distributed Energy Resources (DER) to improve value
- increasing the visibility of conditions on our network.

We are undertaking a number of specific innovation projects to achieve these objectives and to help meet our customers' needs at the lowest cost, whatever the future might bring.

Better use of the network to serve our fringe of grid customers

Our stakeholders told us they want to better understand how our capital expenditure program interacts with our plans to make better use of our network (in other words, better capacity utilisation).

As part of our Proposal, we forecast that 2019–24 capacity utilisation would remain relatively constant from an overall network point of view, mainly because of relatively flat forecast demand growth.

Outside core business transformation, there is potential to make better use of the network and reduce customer costs by altering how we deliver energy to customers on the fringe of the grid. For example, replacing long feeders that serve a handful of customers with stand-alone power systems.

Even if we can start to achieve cost savings in these areas, capacity utilisation at the zone substation level will remain largely unchanged. While the opportunity for improving our capital utilisation spend at the grid fringe is real, it still depends on the cost curve of energy storage and changes in the regulatory environment.

For more information, see our submission to the Australian Energy Market Commission's *Review of the Regulatory Frameworks for Stand-alone Power Systems*.

As part of our stakeholder consultation for this Revised Proposal we asked our stakeholders for their views on stand-alone power systems.

"I think it's a great idea for those out further, with bad reliability."
Dubbo customer

"I'd like to think this would mean my power supply would be more reliable and the bill would be less."
Port Macquarie customer

Using new technologies to solve traditional network challenges

Replacing existing assets on a like-for-like basis is not cost-effective in all locations. We will continue to explore alternative solutions for our most remote customers through pilot programs and trials for non-network solutions. Transitioning away from like-for-like replacement is key to enabling Essential Energy to improve the overall utilisation of our remaining network.

Existing regulatory barriers mean we may not always be able to implement alternative solutions. However, we are working with policy-makers and regulators to encourage the development of a regulatory framework that enables the adoption of flexible, cost-effective, non-network solutions, especially in areas with low customer density. It is vital these changes are supported by appropriate consumer protections.

Our recent stakeholder engagement found strong support for this move.

"It's good. You don't need to rely on a retailer, you are independent, don't have to pay a middle man."
Dubbo customer

"This should only be introduced if there is no additional cost for these customers. We have already decided that all customers in these situations shouldn't be disadvantaged."
Wagga Wagga customer

Using new technologies requires data so we can develop and manage specific solutions for very localised areas of the network. The optimal outcome would meet the needs of affected customers and improve network charges (by reducing costs) for the broader customer base.

Building on existing Distributed Energy Resources development work

A range of new approaches will enable us to better serve our 'poles and wires' customers. One concept, developed with the Institute of Sustainable Futures, is our 'Networks Renewed' project. As part of this project, we encouraged customers within a constrained area of the network to install a battery and solar system. These systems could be paid 'grid credits' for discharging energy into the network during peak demand.

With the support of trial customers, we have been able to avoid investing in augmenting the local network. Based on these results, we intend to develop the autonomous operation of these types of systems. Stage 1 will begin in February 2019 and will focus on developing the required network information, visibility and operational technology.

This will enable us to define the physical limits of the network with 'operating envelopes' that are published to DER, empowering them to respond and be paid to support the network at times of need.

This project links directly with the Energy Networks Australia (ENA) Open Energy Network project, which follows on from the important joint CSIRO/ENA *Roadmap* (Roadmap). It has highlighted the importance of the 'operating envelope' concept in maximising the opportunity for DER to take part in future markets. It is also an example of how industry collaboration is successfully informing the regulatory structures and technical challenges of moving to a decentralised energy future.

Enabling a network of the future

As technologies emerge, our customers' and stakeholders' needs will evolve. Our strategic responses will be directly informed by ongoing consultation with them.

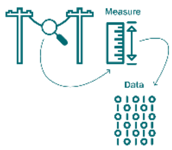
Many disruptions, challenges and opportunities lie ahead and Essential Energy needs to prepare, so we can provide the network services our customers will need in the future. In developing our Corporate Strategy, we have shaped our efforts to ensure the enabling actions we will take are:

> 'no regrets';
> aligned with industry leads such as the *Roadmap* and *Finkel Review*;
> designed to facilitate a future network, in whatever form it may take; and
> aligned with our customers' priorities.

We have identified three core areas as enablers for providing customers with a platform on which we can build other opportunities and services. In the short-term, Essential Energy will focus on pilots and trials for these three areas.

Dynamic DER Capacity
Maximise the opportunity for customers' DERs to participate in future markets

Network Visibility
We need access to real-time data on what is happening on our network—the basic enabler of optimised dynamic network capacity



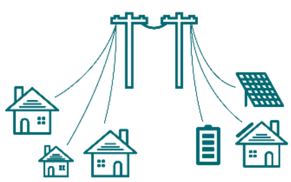
Network Information
For DER to be used dynamically, we need visibility of our low voltage network, so we can adequately manage network capacity

We appreciate they are not the only areas requiring development for future network capability.

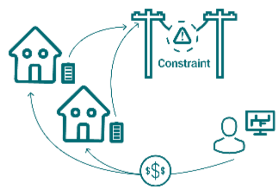
We are therefore planning smaller trials to test specific outcomes and inform our future plans in other areas we have identified through industry trends and customer feedback. These projects will be partly funded through the Demand Management Innovation Allowance (DMIA), and successful outcomes will be progressed using the Demand Management Incentive Scheme (DMIS).

We expect several of these areas will be informed by sharing our DMIA trial outcomes with other distributors. We are committed to working with other distribution businesses to share our experiences as this will accelerate the value of our innovation investment for customers.

Community energy

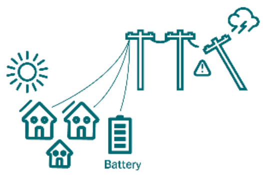


Network services market



Dynamic EV capacity

Reliability-led microgrid



Framework and Approach

Establishing the right framework and incentives for the next regulatory period

Chapter Summary

> We accept the AER's Draft Determination on our Classification of Services, incentive schemes, control mechanisms and forecast depreciation

> We are proposing minor additions to the Classification of Services table to improve customer outcomes in regional, rural and remote locations

Framework and Approach

We accept the AER's Draft Determination in relation to the:

- classification of our distribution and other services;
- control mechanisms for our various distribution services;
- incentive schemes to apply for the 2019–24 regulatory period; and
- application of forecast depreciation to the roll-forward of our RAB at the start of the next regulatory period (2024–29).

We have provided additional detail for two items:

- potential changes to the Service Target Performance Incentive Scheme (STPIS); and
- our support for the AER's reclassification of some services that are currently being provided under a ring-fencing waiver for the current regulatory period.

We propose two changes to the Classification of Services table to encompass services we have identified since submitting our Proposal.

Changes to the STPIS

New STPIS Guideline

The AER recently replaced the 2009 *STPIS Guideline* with the 2018 *STPIS Guideline*, which is not intended to apply to Essential Energy until the 2024–29 regulatory period.

We would like to maintain the 2009 STPIS for 2019–24, but see the new Distribution Reliability Measures Guideline that accompany the 2018 *STPIS Guideline* introduced earlier, through a revision to the Regulatory Information Notice.

If, however, the AER and all NSW and Australian Capital Territory distributors agree to the earlier application of the new scheme, we would be willing to accept its earlier adoption.

Trial of a new customer service measure

We do not consider that the current STPIS customer service measure accurately captures customer satisfaction with our services. In conjunction with our Customer Advisory Group, and potentially other distributors, we intend to collate and trial some alternative customer service measures during the 2019–24 regulatory period that could apply in future STPIS (from 2024).

This data will help shape discussions with our customers and stakeholders as to whether we should propose an alteration to the STPIS customer service measure in our 2024–29 regulatory submission to the AER.

Servicing customers regardless of location – Provider of Last Resort

We agree with the AER's Draft Determination to classify services that were previously included in our ring-fencing waiver application of December 2017 as Alternative Control Services (ACS). In our application, we requested a "Provider of Last Resort" waiver and outlined controls we have put in place to ensure the competitive market has a suitable opportunity to respond to requests for work that we receive from our customers.

Since the AER granted us the reclassification waiver, we have been operating in accordance with our waiver. The AER's Draft Determination therefore confirms and formalises the process that is already in place, which we have used since August 2018.

To date[1], we have advertised 105 pieces of work on our website. Of these, Accredited Service Providers responded to 30 jobs and we have completed 71 pieces of work.

The number of works being completed by Essential Energy demonstrates this process is needed to ensure all our customers can access the services they require. With Accredited Service Providers fulfilling almost one third of the advertised jobs, the process is not impeding the competitive market.

The AER has accepted the controls within our internal process for providing this service and we will continue them into the next regulatory period. Our regional customers supported this service classification and we believe it strikes the right balance between allowing customers to enjoy the benefits of competition and having a fall-back option for customers in areas with no competition.

[1] As at 30 November 2018, when a further four jobs were currently being advertised on our website.

Revising service classification descriptions

We propose additional wording for two activities in the Classification of Services table to include services we have identified since submitting our Proposal.

Our proposed Service Classification changes (additions shown in orange text)

Service group/Activities included	Further description	Proposed Service Classification
Common distribution services		
Common distribution services (formerly network services)	The suite of services involved in the use of the distribution network for conveying electricity (including the service that ensures the integrity of the related distribution system), which includes but is not limited to: > … > works to fix damage to the network (including emergency recoverable works) or to support another distributor during an emergency event. o Emergency recoverable works include repairing third party damage to network assets and rectification of urgent faults or defects related to private assets (standard distribution or subtransmission type assets).	Standard Control
Ancillary Network Services – services closely related to common distribution services but for which a separate charge applies		
Urgent restoration and security of supply following a fault on a customer's high voltage network	At the request of the customer, the investigation, repair and testing of customer assets to restore and secure supply following a fault on the customer's high voltage network that requires urgent rectification.	Alternative Control

Clarify emergency recoverable works

We propose extending the activities included under "Common distribution services" to make it clear that "emergency recoverable works" can include situations where third parties damage network assets, but also the rectification of urgent faults or defects related to private assets (standard distribution and subtransmission type assets). For example, works undertaken to restore power after a pole has been hit by a car or works to replace private poles which are at immediate risk of failure. Any payments recovered from third parties are offset against the costs of emergency recoverable works.

In our experience some of our regional, rural and remote customers often cannot source a private provider to rectify urgent defects on private assets in the time required. We propose that this work would only be carried out at the request of the customer when a competitive provider cannot be sourced within the required timeframe.

Given the time-critical nature of this work, there is insufficient time to use Provider of Last Resort controls. The two-week advertising period would cause unacceptable safety and bushfire risks and increase the likelihood of power outages.

Our proposed change provides a suitable customer outcome with limited impact on the competitive market.

Urgent restoration and security of supply following a fault on a customer's high voltage network

We propose including this as a new Alternative Control Service.

In many instances, our high voltage customers, particularly those located in regional areas, cannot procure services for the urgent restoration of supply following faults on their high voltage assets. The works are often highly specialised and there is limited scope for these services to be provided in the competitive market on an urgent basis.

These are often large industrial customers such as mines where loss of supply can cause financial loss and potential safety issues, for example loss of ventilation in an underground mine or animal welfare issues, such as loss of temperature control in battery hen sheds.

The urgency of these works means this service cannot be accommodated within the two-week advertising timeline under the Provider of Last Resort process. There is a limited existing competitive market for these services and the negative customer outcome under the current Classification of Services justifies this proposed change.

Where requested by the customer, allowing Essential Energy to restore supply in a timely manner following a fault on a customer's high voltage network will enhance customer outcomes without compromising competitive outcomes. We experience about 10 to 20 such instances every year.

Our Revenue Requirement

Balancing safety, reliability and affordability

8

Chapter Summary

> We are proposing real average network charge decreases of 0.92 per cent over the 2019–24 regulatory period

> Our proposed revenue requirement:

- reflects the AER's Draft Determination and updates for the final Rate of Return Guideline and 2017–18 actuals;
- balances our need to invest in and maintain a safe and reliable network for today and tomorrow with meeting customers' affordability expectations; and
- reflects the impact of further efficiencies, building on those we began in the current regulatory period

Our Revenue Requirement

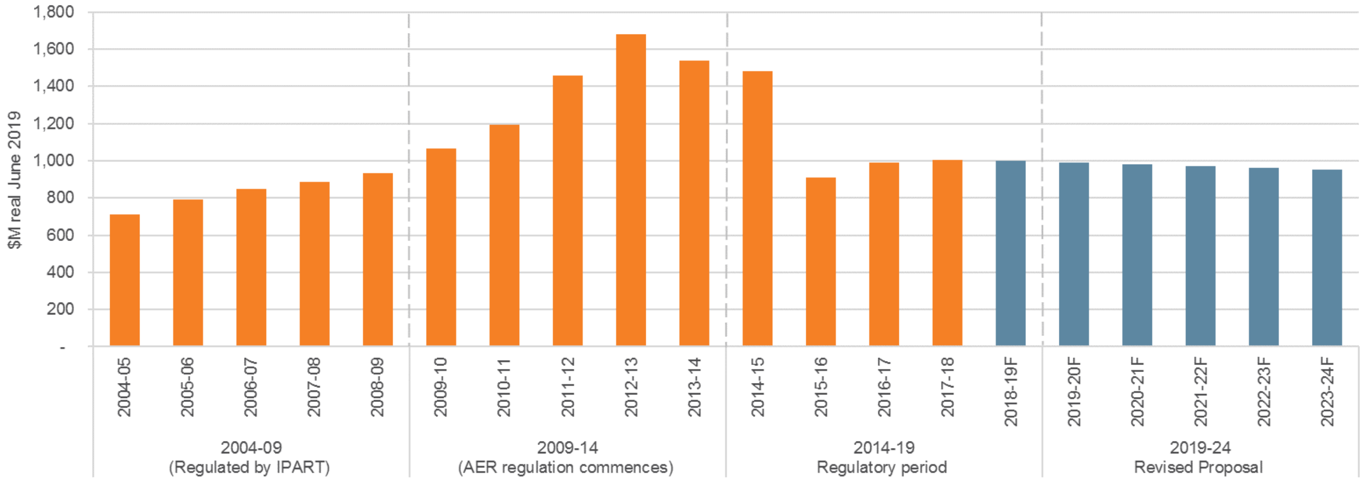
We accept the AER's Draft Determination on our Annual Revenue Requirement and pass-through events to apply for the 2019–24 regulatory period. Our Revised Proposal contains updates to reflect the application of the final Rate of Return Guideline and our actual 2017–18 results.

The total Standard Control Services revenue Essential Energy proposes to recover from customers over the 2019–24 regulatory period is $4,853 million (real June 2019).

Standard Control Services smoothed revenue and annual revenue change ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Proposed annual smoothed revenues	988	979	971	962	953	4,853
Proposed annual real revenue decrease	0.90%	0.90%	0.90%	0.90%	0.90%	4.41%

Standard Control Services Revenue ($m real June 2019)



Changes in our Revised Proposal

Our 2017–18 actual capital expenditure has replaced our forecast. This has lowered the opening RAB for 2019–20.

This update would normally result in an increased reward under the AER's Capital Expenditure Sharing Scheme (CESS). However, we have chosen to accept the AER's Draft Determination on the CESS as it reduces customer distribution network charges, which aligns with the value our customers' place on affordability.

Our Revised Proposal total revenue is $70 million (real June 2019) lower than the AER's Draft Determination.

We have calculated this requirement in accordance with the NER, using the AER's prescribed revenue model, the Post Tax Revenue Model (PTRM). Our PTRM is in Attachment 8.1.

The inputs we used to calculate the revenue requirement are in Appendix B and include the Roll-forward Model (RFM) of the regulatory asset base in Attachment 8.2.

AER review of the regulatory tax allowance

The AER is currently undertaking a review of the regulatory tax allowance. Their final report proposes changes to the tax allowance calculation that will be processed through alterations to the PTRM and RFM. The AER will consult on these model changes over the next few months and apply them in its Final Determination on our Revised Proposal. We expect the changes to lower our revenue requirement.

TOTAL REVENUE REQUIREMENT 2019-24
$ million
(real June 2019)

$2,351
RETURN ON CAPITAL
To repay our debt and equity holders for the funds invested in our network

+

$645
RETURN OF CAPITAL
Reflects the decline in asset value as they age

+

$1,718
OPERATING EXPENDITURE
Recovery of our efficient operating costs

+

$39
REVENUE ADJUSTMENTS
Incentive scheme rewards/penalties and other adjustments

+

$103*
TAX ALLOWANCE
Allows us to meet our corporate income tax liabilities

+

($4)
REVENUE SMOOTHING

=

$4,853
(average annual revenue requirement of $1,028m)

* The tax allowance will be adjusted in the AER's Final Determination to reflect the outcomes of the AER's Review of the regulatory tax allowance

Numbers may not add up due to rounding

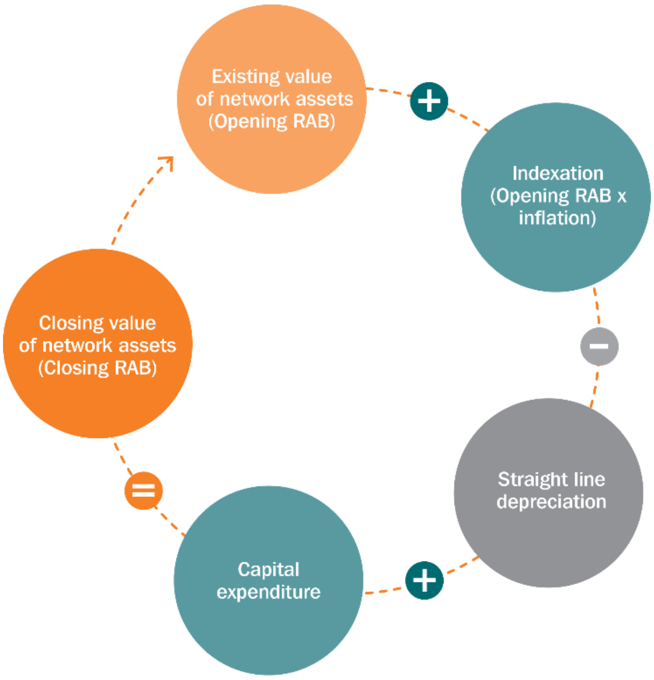
How we calculate the revenue we need

To work out Essential Energy's revenue requirement for a regulatory period, we require four components: operating expenditure, capital expenditure, Rate of Return and RAB (as at1 July 2019). We combine them using the AER model.

Under the NER, this is known as the 'building block' approach. The AER model is based on five components that form the revenue 'building block': return on capital, return of capital, operating expenditure, revenue adjustments and a tax allowance. The components are added together to determine the revenue we need to recover our costs and provide a return to our shareholder.

Our expenditure levels can be a little lumpy, depending on when projects start, so the AER model allows us to 'smooth' our revenue requirement to help limit variations in customer distribution network charges. We then use customer consumption forecasts to establish the distribution network charges we need to charge to reach our revenue requirement. The proposed network charges are shown in our Revised TSS.

How the regulated asset base is calculated



Further information

For further information about Essential Energy's revenue requirement components, refer to Appendix B.

Operating Expenditure

Improving efficiency

Chapter Summary

- We accept the AER's Draft Determination on operating expenditure
- Our forecast operating expenditure includes significant productivity savings that will further benefit customer distribution network charges
- We will achieve this through technology investment and more sophisticated asset management

Operating Expenditure

We accept the operating expenditure allowance in the AER's Draft Determination. It is equal to the amount in our Proposal and will enable us to deliver Standard Control Services efficiently.

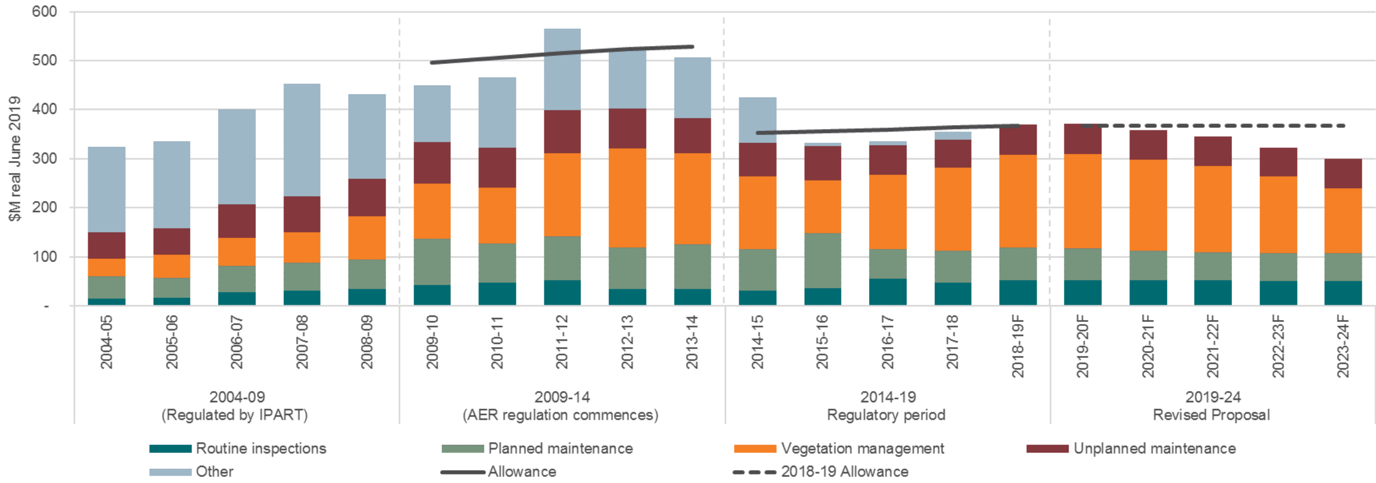
For more detail on specific operating expenditure activities for the 2019–24 regulatory period, see our Proposal.

Revised proposed operating expenditure ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Proposed operating expenditure/ AER Draft Determination	375	362	350	327	303	**1,718**

The number above do not include debt raising costs

Proposed operating expenditure compared to historical expenditure ($m real June 2019)



Addressing stakeholder feedback

While stakeholders were grateful for the succinct, customer-friendly wording and graphics of our Proposal, some stakeholders found it difficult to locate a detailed cost breakdown.

Others queried the level of our overheads and how productivity savings were reflected in overheads.

We have addressed this feedback in our Revised Proposal in Appendix A, which:

- separates overheads from direct operating expenditure;
- indicates the amount of productivity savings included in our proposed operating expenditure;
- includes a section related to the overheads story in our business;
- makes it clear how the benefits of our strategic initiative investment are reflected in our operating expenditure and overheads.

Capital Expenditure

Maximising value for our customers while maintaining safety and reliability

Chapter Summary

- We accept the AER’s Draft Determination on capital expenditure
- Our forecast expenditure includes significant productivity savings that will be achieved through technology investment and more sophisticated asset management
- In line with customer expectations, our proposed network investment for 2019–24 aims to maintain network reliability

Capital Expenditure

We accept the capital expenditure allowance in the AER's Draft Determination (which is equal to our Proposal adjusted for a small Consumer Price Index (CPI) error).

We also note and support the AER's approval of our Connection Policy which was provided as an attachment to our Proposal.

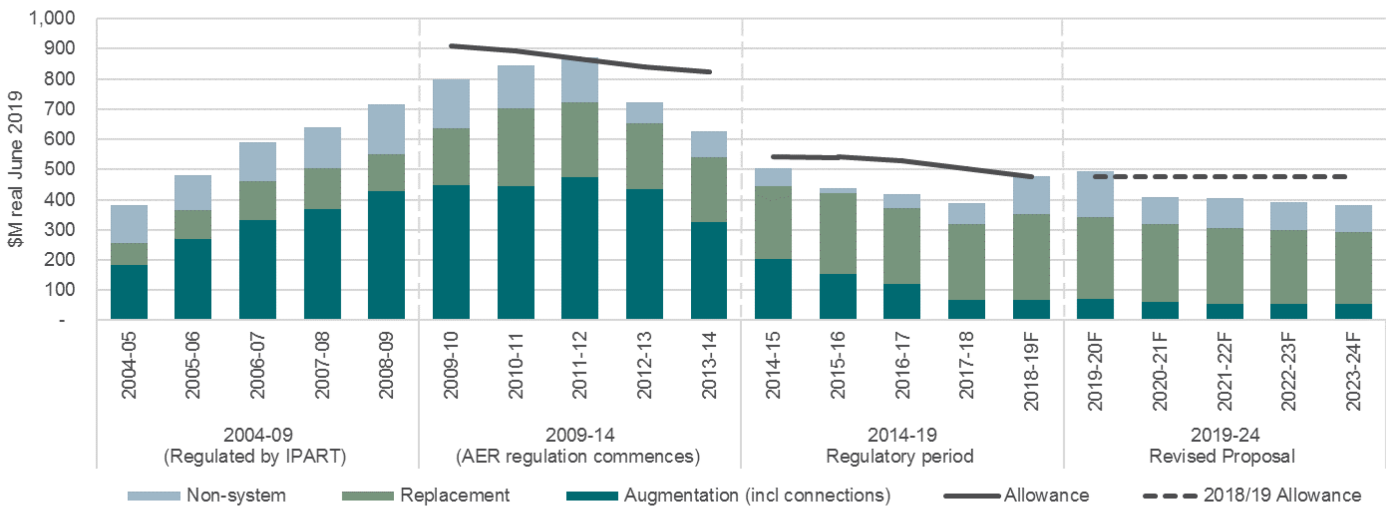
For more detail on specific capital expenditure activities over the 2019–24 regulatory period, see our Proposal.

This allowance will enable us to deliver Standard Control Services efficiently. There is additional information about how our strategic investment and associated benefits have impacted our forecast in Appendix A.

Revised proposed capital expenditure ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Proposed capital expenditure/ AER Draft Determination	495	408	406	392	381	**2,081**

Proposed capital expenditure compared to historical expenditure ($m real June 2019)



Addressing stakeholder feedback

While stakeholders largely supported our proposed capital expenditure plans, they sought clarification on:

> how we intend to maintain or improve the capacity utilisation of our network; and

> how technology benefits will translate into improved business efficiency.

We have addressed the first point in this chapter and the second point in the Capital Expenditure section of Appendix A.

Addressing AER feedback

The AER's Draft Determination expressed mainly positive feedback for our capital expenditure proposal and was satisfied that, overall, it complied with the NER's capital expenditure criteria.

There were a few areas for future consideration and improvement that already align with our future plans.

Capital expenditure during the current regulatory period

2017–18 actual capital expenditure

Our capital expenditure for 2017–18 totalled $387 million, which is $58 million lower than the forecast in our Proposal.

This shortfall was mainly attributable to a reduction in replacement expenditure largely due to:

> delays in awarding contracts to ensure best value for money; and

> reallocating resources to vegetation management activities (which are usually 100 per cent outsourced) to meet an agreed plan with the Independent Pricing and Regulatory Tribunal of NSW (IPART) before the 2018–19 bushfire period began.

There was also a short-term pull-back in non-system capital expenditure while we reset our business structure ahead of undertaking our transformation program.

Allowed Rate of Return

Balancing the need to attract investment with customers' affordability concerns

11

Chapter Summary

> We have applied the AER's final Rate of Return Guideline in our Revised Proposal

> This gives a Rate of Return of 5.96 per cent for 2019–20

> We have listened to community feedback and are aware that electricity affordability is a key concern

> We believe this Rate of Return balances customer and shareholder needs

Allowed Rate of Return

We have applied the 2018 final Rate of Return Guideline (final Guideline) in our Revised Proposal. This approach is supported by our stakeholders.

We have estimated an indicative Rate of Return of 5.96 per cent for the first year of the 2019–24 regulatory period. This rate is marginally higher than the AER's Draft Determination.

The rate is based on placeholder rates for certain parameters that will be updated with current market information before and during the regulatory period.

See Appendix C for further detail about the parameters.

		Proposed WACC* rate 2019–20
Gearing	60%	5.96%
Cost of debt	5.73%	
Cost of equity	6.32%	

* Weighted average cost of capital

Imputation credits (gamma)

We accept the value of 0.585 for gamma to align with the AER's final Guideline.

Our proposed inflation rate

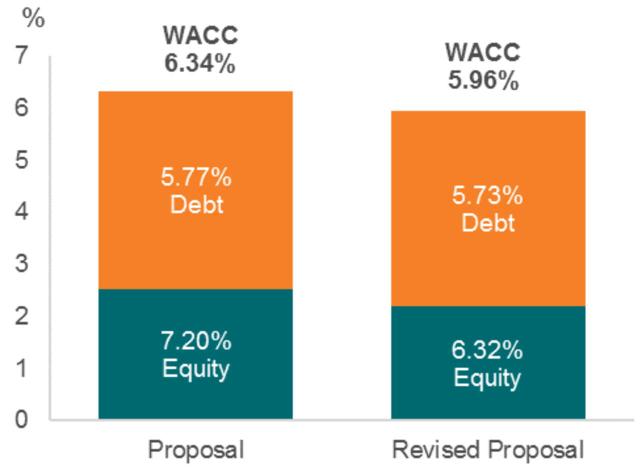
We propose an estimated inflation rate of 2.42 per cent for 2019–24. This is a placeholder rate that aligns with the AER's Draft Determination and is based on the AER's current inflation methodology. This estimate will be updated closer to the start of the 2019–24 regulatory period.

Consulting with customers and stakeholders

While preparing this Revised Proposal, we continued to invest in customer and stakeholder engagement to ensure that, wherever possible, it reflects all our customers' requirements.

As return on capital is the major component of our allowable revenue, it has a large impact on pricing and affordability. Our stakeholders support our adoption of the final Guideline.

Rate of Return composition for 2019–20



"Essential Energy has clearly … accepted application of the (pending) 2018 Guideline. Consumer groups welcome this."

Consumer Challenge Panel 10[1]

"We welcome the approach of Essential Energy … [to applying the 2018 binding Guideline]."

Energy Users' Association of Australia[2]

[1] Consumer Challenge Panel 10, *Submission to the AER on NSW Electricity Distribution Businesses Revenue Proposals 2019–24*, August 2018

[2] Energy Users' Association of Australia, *Submission to the AER on NSW Electricity Distribution Determinations 2019–24*, August 2018

Our Approach to Pricing

Evolving distribution network charges that better reflect our costs

12

Chapter Summary

> Our average distribution network charges will reduce by 0.92 per cent a year over the 2019–24 regulatory period before inflation

> By 2024, distribution network charges will be 34 per cent lower in real terms than in 2012, when we began our transformation

> We have consulted customers about the proposed changes to our TSS and made decisions based on their feedback

Our Approach to Pricing

The AER accepted the following aspects of our Pricing Proposal in its Draft Determination:

> a revenue cap mechanism for Standard Control Services;

> a price cap mechanism for ACS;

> application of the AER's existing controls for managing under-recovery or over-recovery of our allowed revenue;

> retaining the existing method for recovering costs related to transmission businesses, other electricity distributors, avoided transmission charges for eligible embedded generators, and jurisdictional scheme payments relating to Government obligations;

> our negotiating framework;

> our customer classes;

> the structure of cost-reflective distribution network charges for all customers

> providing customers with a choice of cost-reflective distribution network charges;

> distribution network charge assignment and structure for Large Business customers;

> our approach to setting fixed charges for Residential customers; and

> flat distribution network charges for customers with accumulation meters.

The AER did not accept some areas of our proposed TSS. We revisited these areas with our stakeholders during the engagement program for this Revised Proposal and have incorporated their feedback.

Addressing AER and stakeholder feedback

The Tariff Structure Explanatory Statement (TSES) (TSS Attachment 1) contains a full description of specific items raised by the AER and stakeholders in relation to our TSS and how we have resolved these.

At a high level, we have:

> adjusted the demand charge for Residential and Small Business users to exclude the shoulder period;

> maintained the ability for Residential and Small Business customers with a smart meter to opt out to an Anytime (flat rate) distribution network charge; and

> removed the mandatory assignment to a demand distribution network charge for customers installing new technologies such as solar photovoltaic (PV), batteries and electric vehicle charging points. These customers will be assigned to distribution network charges in the same manner as other Residential and Small Business customers.

Indicative changes to our distribution network charges

The actual distribution network charges our customers pay during 2019–24 will depend on:

> the AER's final determination for Essential Energy for the 2019–24 regulatory period;

> any changes in the relative portion of revenues recovered from each distribution network charge and component during the 2019–24 regulatory period;

> the transmission costs and climate change levy passed through to Essential Energy;

> cost of debt placeholder rates (based on current information), updated annually, as discussed in Chapter 11 and Appendix C; and

> application of incentive schemes.

While we cannot predict the exact impact of these factors on our charges, the NER require us to provide a pricing schedule as part of our TSS that sets out the indicative charges we will apply for each year of the regulatory period.

We propose real average annual decreases in the distribution component of customers' electricity bills of 0.92 per cent for the 2019–24 regulatory period.

Forecast changes to average charges

The average changes to distribution network charges are calculated by dividing our proposed annual revenue requirements by the total energy consumption forecast for each regulatory year. Average changes may vary for each customer, depending on their consumption level. They will also likely differ to the percentage change in revenue.

Forecast change in average distribution charges (% change in real charges)

	2019–20	2020–21	2021–22	2022–23	2023–24	Average
Average real change in distribution charges	-0.87%	-0.77%	-0.71%	-1.15%	-1.12%	-0.92%

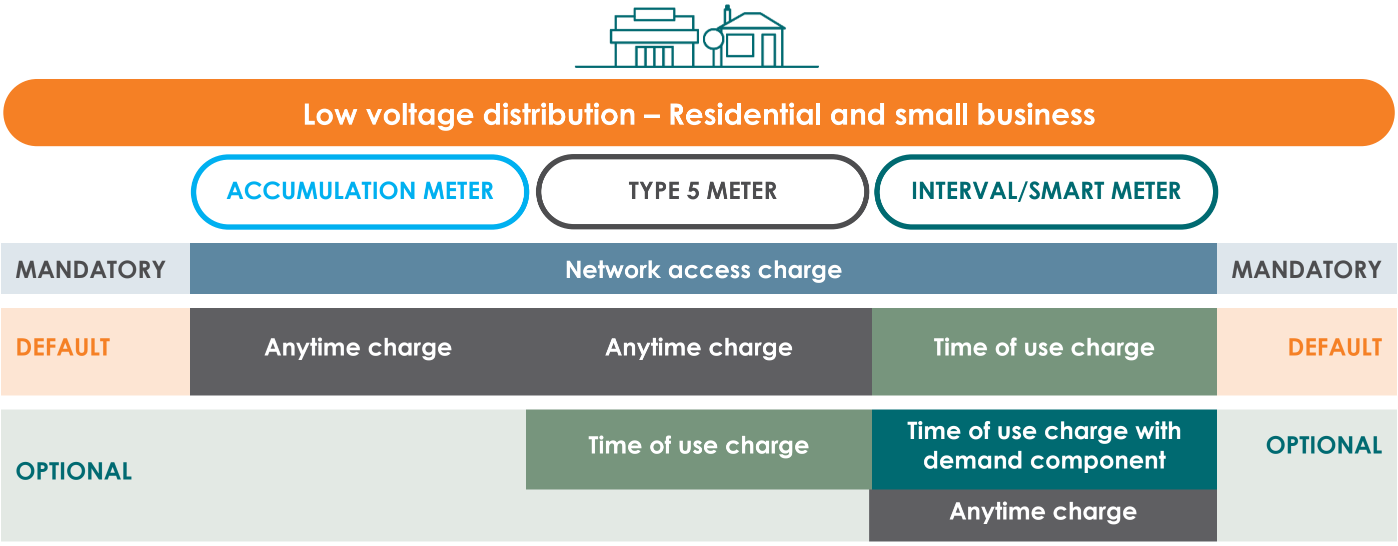
Revised TSS

The AER uses our TSS to assess our compliance with the NER, which requires us to develop distribution network charges that reflect the efficient cost of providing network services to individual customers. Our Revised TSS (Attachment 12.1) explains how we will apply distribution network charges to our customers over the regulatory period.

Once our Revised TSS is approved by the AER, it will replace our current TSS.[2]

We are proposing just one change to the assignment of customers to distribution network charges in our Revised Proposal – all Residential and Small Business customers with an interval/smart meter will be assigned to a Time-of-Use network charge.

Changes to our assignment of customers to distribution network charges for 2019-24



[2] The life of our current TSS is the three financial years, from 2016–17 to 2018–19.

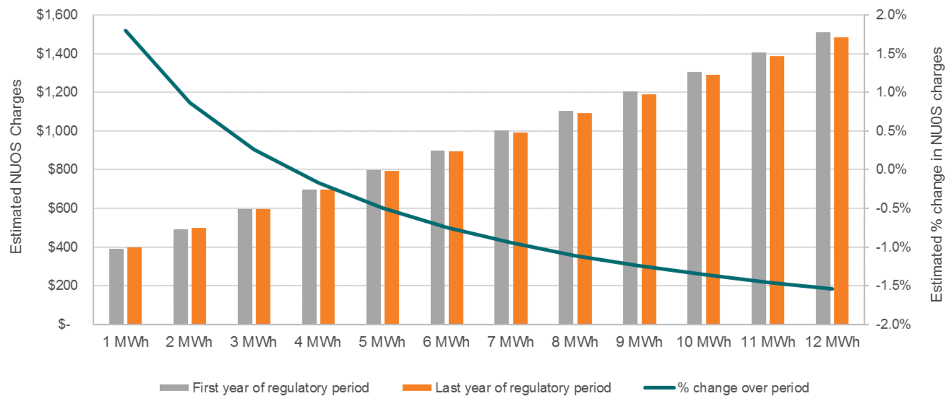
Customer bill impacts

Our proposed network charging approach is different for the 2019–24 regulatory period than in our current TSS and will lead to changes in customers' distribution network charges. Average distribution network charge changes may vary for each customer, depending on their level of consumption.

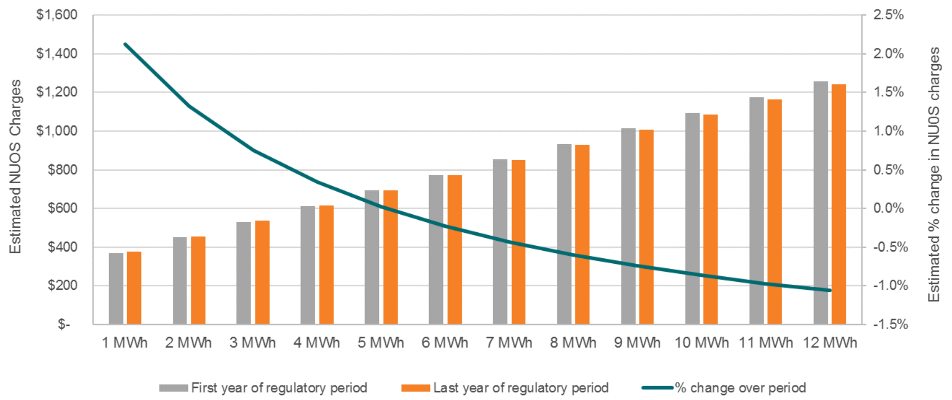
For more information on our charges, including forecast changes to individual charges and customer bill impacts, refer to our TSS at Attachment 12.1.

Comparison of estimated 2019–20 and 2023–24 Residential NUOS charges for different network charging types[3] (real $2018-19)

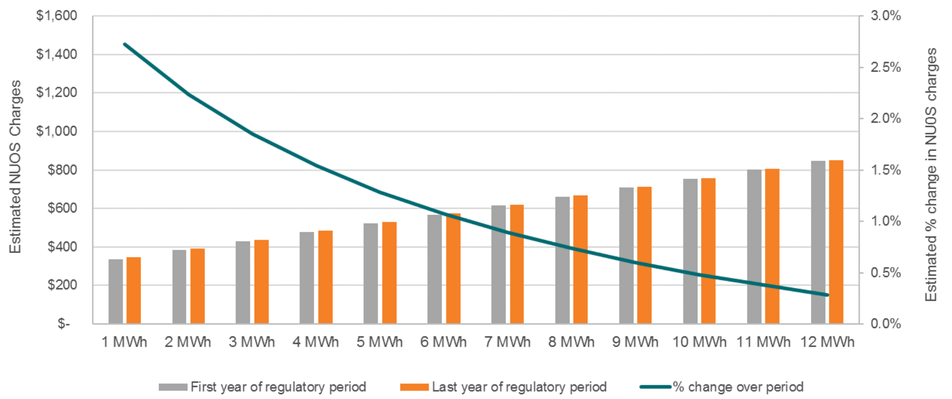
Residential 'Anytime' flat rate network charge



Residential Time-of-Use network charge



Residential demand network charge



[3] NUOS = Network Use of System

Alternative Control Services

Meeting the need for customer-requested services while minimising costs

13

Chapter Summary

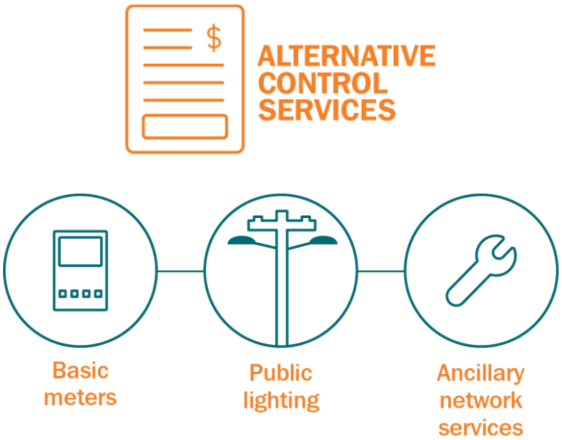
> We accept the AER's Draft Determination for Metering Services

> We have worked closely with our stakeholders to amend our component-based Public Lighting model

> We largely accept the AER's Draft Determination regarding Ancillary Network Services, but are proposing minor changes to ensure recovery of our efficient costs

Alternative Control Services

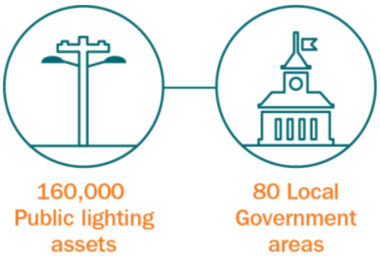
Alternative Control Services are typically provided directly to a specific customer, who pays for the full cost of providing that service. These services include some Metering Services, Public Lighting and Ancillary Network Services (such as customer connections).



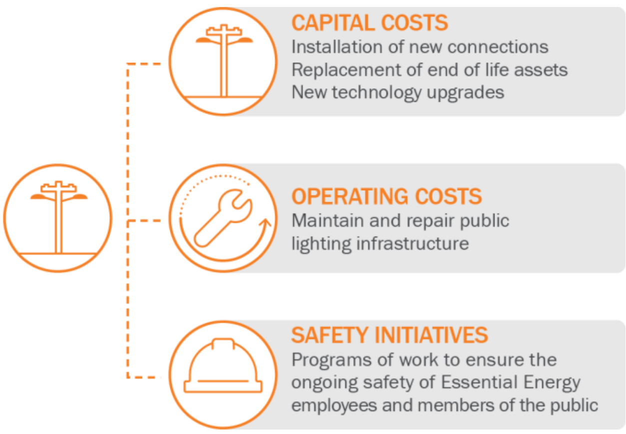
Public Lighting Services

Overview

Essential Energy provides Public Lighting Services to local councils, including the operation, maintenance, and replacement of public lighting assets. These services are vital to the communities we serve.



We incur three main costs when providing Public Lighting Services. They include initiatives to ensure the ongoing safety of the public and our employees, including removing redundant assets that pose safety risks. Our Public Lighting prices are designed to recover the efficient costs associated with these activities.



Stakeholder engagement

Our Proposal put forward component-based pricing for the 2019–24 regulatory period which was supported by stakeholders. This was accepted by the AER in its Draft Determination.

After submitting our Proposal, we provided an unredacted version of the model for comment to Councils, their consultants, and other interested stakeholders. Their feedback was that our model was not easy to navigate and important customer information was difficult to find. In addition, submissions on our Proposal from Orana Regional Organisation of Councils (OROC) and Riverina Eastern Regional Organisation of Councils (REROC) to the AER highlighted several issues that required further investigation.

As a result, we began a targeted Public Lighting Services engagement program with OROC and REROC (representing all 53 Councils in the Southern Lights project) and their appointed consultants, who jointly represented approximately 60 per cent of Essential Energy's Council areas. The aim was to agree a revised Public Lighting model for submission with our Revised Proposal. The AER was also invited to participate.

We held four meetings and shared information with stakeholders to address all the issues identified in the OROC and REROC submissions. This dedicated forum allowed for constructive engagement and made things clearer to all participants. It also resulted in several important adjustments to our Public Lighting model that we have factored into our Revised Proposal.

Attachment 13.1 highlights each issue raised in the OROC and REROC submissions and how we have addressed them in our Revised Proposal.

Revised Proposal Public Lighting model changes

Impact of the new NSW Public Lighting Code (new Code)

The new Code comes into effect from 1 July 2019 and will be a mandatory condition of Essential Energy's distribution licence. The AER was aware of the impending changes to the Code and highlighted that we should include any resulting cost impacts in our Revised Proposal.

The new Code has applied one key productivity change that does not align with Essential Energy's Proposal and this has marginally increased our operational costs for spot replacement. These additional costs will be absorbed by Essential Energy and recovered through efficiency gains.

Failure rates of high wattage mercury vapour and metal halide lamps

The AER made several changes to the failure rates of high wattage mercury vapour and metal halide lamps in the Draft Determination model. The amended failure rates do not reconcile with our actual failure rates, nor manufacturers' published failure rates.

We have revised our inputs to match the failure rates included in our Proposal to ensure the true cost of these assets is appropriately recovered.

Omission of non-system capital expenditure recovery

We use non-system assets (fleet, building, technology, tools, equipment, furniture and fittings) when performing Public Lighting Services. However, these costs were mistakenly excluded from the Public Lighting model in our Proposal.

Our Revised Proposal includes a non-system capital recovery rate to ensure the non-system capital investment costs incurred in delivering Public Lighting Services are rightly recovered from Public Lighting customers. The AER accepted the recovery of these costs for Metering Services in its Draft Determination.

Additional material costs for bulk repair

The AER's Draft Determination removed our additional material costs for bulk repair. Further review found that these costs were incurred to upgrade wiring and old fuse assemblies during bulk LED upgrades. These were mistakenly included as an operating cost in our Proposal. They have been correctly included as a capital cost in our Revised Proposal.

Night Patrol for category V lights

Through consultation we reviewed our Night Patrol costs. This revealed that some costs were included that were not reflective of the service being provided. We have corrected this in our Revised Proposal.

Time to perform spot repairs

Through consultation, Essential Energy has reviewed the average amount of time it takes to complete a spot repair. Our Revised Proposal has reduced the hours down from that in both our Proposal and the AER's Draft Determination.

Pole Design Costs

The Draft Determination removed all design costs. Essential Energy acknowledges that design costs are not always incurred, however there needs to be a mechanism in place to recover costs when there are. Our Revised Proposal removes design costs from poles that would typically be installed on Category P roads and includes a reduced rate for larger category V type poles.

CPI rate

We have updated the CPI rate for converting 2018–19 dollars into 2019–20 dollars to match the 2.42 per cent current placeholder rate used in the AER's Draft Determination for Standard Control Services.

Further information and supporting data for these changes to our Public Lighting Services model and associated prices is in Attachments 13.1 and 13.2.

We have developed our proposed Public Lighting prices in accordance with the AER's price cap formula—see Attachment 5 of our TSS.

Ancillary Network Services

We agree with the majority of the AER's Draft Determination, however we propose minor changes to some ANS service descriptions and the recovery of Security Lighting services. We also propose adjustments to the calculation of fully-loaded ANS labour rates. These changes have been reflected in our Revised Proposal and associated ANS prices.

Revised Proposal ANS model changes

Security Lighting Services

While the AER accepted our charges for Security Lighting Services, it noted that our proposed rates were low compared to Endeavour Energy and Ausgrid.

We have reviewed our Public Lighting model and made a number of changes including: correcting the life of these assets to better reflect their average installed life; adding an energy charge; and revisiting the maintenance approach to better reflect actual maintenance practices. These changes will reduce the likelihood that our costs are under-recovered.

Fleet costs relevant to ANS staff should be included in the direct cost's calculation

The Draft Determination's ANS labour build-up excluded the fleet cost for relevant staff from the direct costs to which overheads were applied. This treatment differs to our Cost Allocation Methodology (CAM) and understates the direct cost base on which overheads are applied, resulting in under-recovered overheads for ANS.

Our Revised Proposal's ANS labour rates have been adjusted to include the fleet operating cost for relevant staff in the direct costs calculation. This is consistent with the calculation approach we applied in our Proposal.

Additional staff on-costs are incurred when performing work outside normal hours

Payroll tax and workers compensation costs are directly related to full-time equivalent work hours – the costs are unavoidable. Our Proposal included an additional on-cost rate of 9.63 per cent for overtime hours and we again include this rate in our Revised Proposal.

The recovery of non-system capital expenditure relevant to ANS should be included in ANS prices

The ANS labour costs in the Draft Determination did not include the recovery for non-system capital expenditure (fleet, building, information, communication and technology (ICT), tools, equipment, furniture and fittings) that we put forward in our Proposal. These capital costs are allocated to ANS under our CAM and are not encompassed in the overhead rate. Excluding these non-system capital costs from the calculation of ANS prices will lead to an under-recovery of costs for Essential Energy. The AER accepted the recovery of these costs for Metering Services in its Draft Determination.

Our Revised Proposal ANS labour rates have been adjusted to include a non-system capital expenditure recovery rate. This is consistent with the calculation approach we applied in our Proposal, although the rate has been updated to reflect the lower WACC rate resulting from the final Rate of Return Guideline.

CPI rate

We have updated the CPI rate used to convert 2018–19 dollars into 2019-20 to match the 2.42 per cent current placeholder rate used in the AER's Draft Determination for Standard Control Services.

Impact of relevant changes on ANS labour rates

Some of the Draft Determination ANS labour rates for the forthcoming regulatory period were below the current rates approved for the 2018-19 year.

After amending for the various items noted above, our Revised Proposal ANS labour rates are more cost-reflective of our true labour costs and remove the dip in labour rates between 2018-19 and 2019-20.

How our Revised Proposal ANS labour rates compare to current AER approved rates and the Draft Determination

Real $ 2019-20	Ordinary time		
	2018-19 AER approved rate	AER Draft Determination	Revised Proposal
Admin	$102.33	$104.73	$114.85
Para legal	-	$104.73	$114.85
Indoor tech	$158.97	$157.12	$172.30
Outdoor tech	$190.45	$177.61	$208.47
Prof/Engineer	$203.97	$196.38	$215.36
Field worker	$145.04	$151.40	$179.73

Real $ 2019-20	Overtime		
	2018-19 AER approved rate	AER Draft Determination	Revised Proposal
Admin	$139.85	$178.09	$200.54
Para legal	-	$178.09	$200.54
Indoor tech	$217.28	$267.17	$300.86
Outdoor tech	$249.97	$300.16	$337.03
Prof/Engineer	$268.98	$333.93	$376.04
Field worker	$187.91	$255.60	$286.84

Our Revised service descriptions, ANS labour costs build-up and price model are in Attachment 13.3.

Our proposed ANS prices are provided as Attachment 3 in our TSS.

Glossary

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14 Glossary

Term	Meaning
2009–14 regulatory period	The regulatory control period commencing 1 July 2009 and ending 30 June 2014
2014-19 regulatory period	The regulatory control period commencing 1 July 2014 and ending 30 June 2019
2019-24 regulatory period	The regulatory control period commencing 1 July 2019 and ending 30 June 2024
AER	Australian Energy Regulator: national regulator for the electricity industry
Alternative Control Services (ACS)	Specific user-requested services: Public Lighting; Type 5 and Type 6 Metering (generally Residential and Small Business customer meters); and Ancillary Network Services
Ancillary Network Services (ANS)	Ancillary network services are provided to individual customers, their retailer or their Accredited Service Provider on an as-needs basis.
CAM	Cost Allocation Methodology – the AER-approved method of sharing costs between business units and services
Capital expenditure	Funds used to buy or upgrade physical assets such as power poles or buildings
CESS	Capital Expenditure Sharing Scheme. An incentive scheme that Encourages us to improve efficiency of capital expenditure.
CPI	Consumer Price Index – a measure of inflation
Customer class	A group of customers who share a common set of characteristics that allow them to be grouped together to ensure similar customers pay similar charges
Customer engagement	Program of two-way communications through which Essential Energy collects customer feedback
Demand charge	Charge based on the maximum amount of electricity a customer uses at any one time, measured in Kilowatts or kilovolt ampere.
DER	Distributed Energy Resources – refers to smaller generation units that are located on the consumer's side of the meter
Distribution network charge	A cost charged to distribution network customers to recover the efficient costs of providing distribution network services. Commonly referred to as a 'tariff'
DMIA	Demand Management Innovation Allowance – An AER allowance that encourages trials of innovative technologies to manage network demand
DMIS	Demand Management Incentive Scheme – An AER incentive scheme that encourages networks to investigate alternative solutions to manage network demand
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme – An AER incentive scheme that encourages networks to improve efficiency of operating expenditure
Energy Networks Australia (ENA)	National industry association representing Australian electricity networks and gas distribution businesses
Finkel Review	Review of the national electricity market commissioned by Federal and State energy ministers and presented in 2017 by Australia's chief scientist, Dr Alan Finkel, as a blueprint for national energy security
ICT	Information, Communication and Technology
Imputation credit (gamma)	A tax credit passed on to shareholders by a company
IPART	Independent Pricing and Regulatory Tribunal of NSW
Load	The demand for electricity on the network
Microgrid	Local energy grid where energy is locally exchanged between customers that is connected to the traditional grid but can operate separately
NER	The National Electricity Rules: these govern the operation of the national electricity market
NSW	New South Wales
NUOS	Network Use of System: this is the charge for using Essential Energy's distribution network, as well as the pass-through of transmission type costs and jurisdictional scheme amounts such as the Climate Change Fund
Operating expenditure	Funds to inspect, maintain and operate our network
OROC	Orana Regional Organisation of Councils
Peak demand	The maximum electricity demand customers place on the electricity network
Price cap	Set by the AER, the maximum increase that Essential Energy can apply to customer prices
Prices/Pricing	A cost charged to customers to recover the efficient costs of providing either Standard Control Services or Alternative Control Services.

14 Glossary

Term	Meaning
	Standard Control Services distribution prices are commonly referred to as a 'tariff'
Pricing component	Different cost factors that work together to reflect the efficient costs of providing network services to customers, comprising network access, consumption and demand charges
Pricing schedule	The list of prices and pricing structures for each of our Standard Control Services and Alternative Control Services, published annually. The Standard Control Services pricing schedule is also referred to as Network Price List and Explanatory Notes
Pricing structure	How pricing components are combined to give the pricing structure/distribution network charge
Proposal	Essential Energy's April 30 2018 Regulatory Proposal for the 2019–24 regulatory control period submitted under clause 6.8 of the NER
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base; the regulatory value of the assets Essential Energy uses to provide distribution services
Real	Dollars before the impact of inflation, as measured by CPI
REROC	Riverina Eastern Regional Organisation of Councils
Return on capital	Return on investment generated for the funds (capital) invested; used to fund repayment of debt and measure profitability.
Revenue cap	Controls the maximum revenue that the AER allows Essential Energy to collect for each year of the regulatory period
Revised Proposal	Essential Energy's Revised Regulatory Proposal for the 2019-24 regulatory control period submitted under clause 6.8 of the NER
RFM	Roll-forward Model
Smart meter	Digital device that measures and records each customer's electricity usage every half an hour and transmits the data to their electricity provider
Smoothed revenue	Forecasting method that smooths out fluctuations
Solar PV	Solar Photovoltaic
Standard Control services	Essential Energy's core activities: providing access to, and supply of, electricity to customers
STPIS	Service Target Performance Incentive Scheme: AER's financial incentive scheme, which rewards or penalises Essential Energy for reliability and customer service outcomes
Tariff	See Distribution Network Charges
TSS	Tariff Structure Statement
WACC	Weighted Average Cost of Capital: a way to work out the expense of funding future capital projects. The lower the WACC, the cheaper the funding.
WARL	Weighted-average remaining life

Our Expenditure in Detail

Appendix A

Our Transformation Investment and Benefits

Essential Energy's Strategic Plan will deliver long-term efficiencies through technology investment. Our customer engagement program showed that our customers support this approach.

Our proposed business improvements will create future value for all Essential Energy's stakeholders, avoid price spikes for our customers and help us to build a sustainable distribution network.

The tables summarise our 2019–24 strategic initiative investment expenditure and the estimated program benefits by type of expenditure.

Strategic initiative investments ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Direct capital expenditure	38	17	11	-	-	**66**
Direct operating expenditure	-	-	-	-	-	**-**
Overheads (support)	27	18	12	5	2	**64**
Total strategic initiative expenditure	**65**	**35**	**23**	**5**	**2**	**130**

Numbers may not add up due to rounding

The bulk of the proposed investment relates to technology (ICT) capital and operating expenditure. A portion relates to forecast staff redundancies as the efficiencies of the spend are realised.

Strategic initiative benefits ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
CAPITAL EXPENDITURE						
Direct capital expenditure	13	24	31	34	36	**138**
Overheads (support) benefits	3	6	12	15	17	**53**
Total capital expenditure benefits	**16**	**30**	**43**	**49**	**53**	**191**
OPERATING EXPENDITURE						
Direct operating expenditure	-	0	3	9	15	**27**
Overheads (support)	3	7	13	15	16	**54**
Total operating expenditure benefits	**3**	**7**	**16**	**24**	**31**	**81**
Total strategic initiative benefits	**19**	**37**	**58**	**74**	**84**	**273**

Numbers may not add up due to rounding

Capital Expenditure

Breakdown of proposed capital expenditure

A breakdown of Essential Energy's proposed capital expenditure—as accepted by the AER in its Draft Determination—is shown in the tables.

Proposed capital expenditure ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Replacement	269	257	252	244	239	**1,261**
Connections	8	8	8	8	8	**39**
Augmentation	64	53	45	47	46	**256**
ICT	59	29	34	21	21	**164**
Property	41	11	13	16	13	**94**
Fleet	31	30	34	40	34	**169**
Other non-system	24	19	19	16	21	**99**
Total	**495**	**408**	**406**	**392**	**381**	**2,081**
AER Draft Determination	**495**	**408**	**406**	**392**	**381**	**2,081**

Numbers may not add up due to rounding

Proposed capital expenditure with overheads separated ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Replacement	168	164	162	158	154	**806**
Connections	5	5	5	5	5	**25**
Augmentation	40	34	29	31	29	**163**
ICT	59	29	34	21	21	**164**
Property	41	11	13	16	13	**94**
Fleet	31	30	34	40	34	**169**
Other non-system	16	13	13	11	15	**68**
Corporate overheads	101	90	88	86	87	**452**
Network overheads	35	31	27	24	24	**142**
Total	**495**	**408**	**406**	**392**	**381**	**2,081**
AER Draft Determination	**495**	**408**	**406**	**392**	**381**	**2,081**

Numbers may not add up due to rounding

Operating Expenditure

Proposed operating expenditure/AER Draft Determination 2019–24 ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Direct operating costs	232	227	223	210	196	**1,088**
Corporate overheads	47	44	39	36	33	199
Network overheads	93	88	84	76	70	411
Controllable operating expenditure	**371**	**358**	**346**	**323**	**299**	**1,698**
Debt-raising costs	4	4	4	4	4	**21**
Proposed operating expenditure	**375**	**362**	**350**	**327**	**303**	**1,718**
AER Draft Determination	**375**	**362**	**350**	**327**	**303**	**1,718**

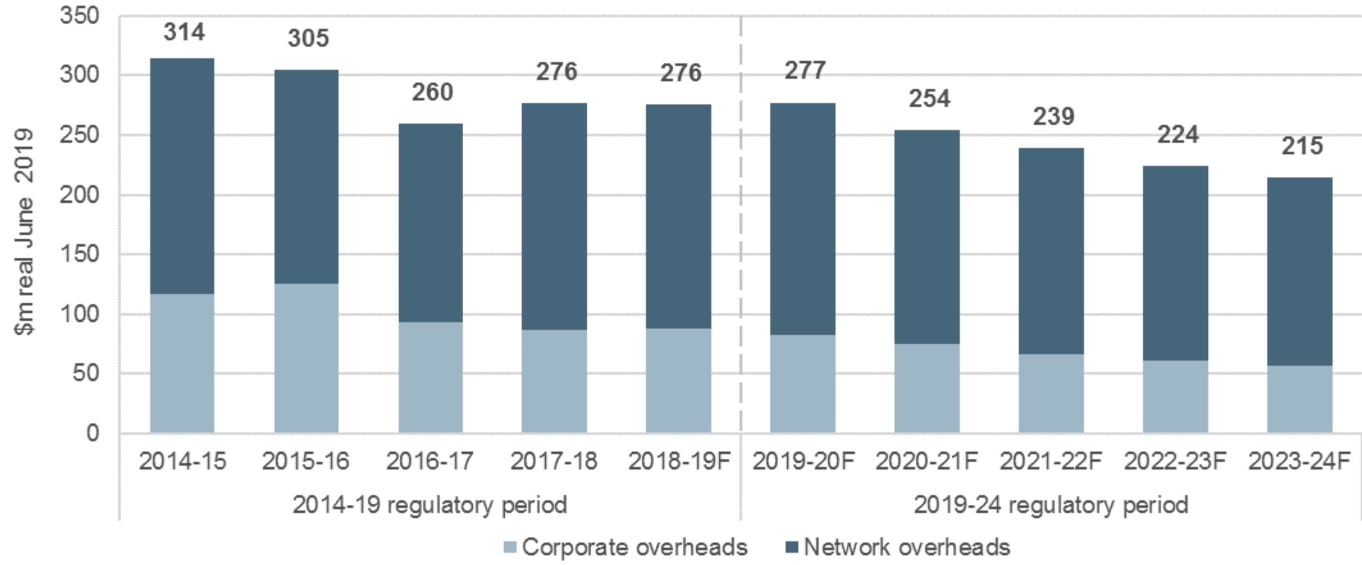
Numbers may not add up due to rounding

Overheads

Since 2014–15, Essential Energy's overheads have decreased as part of our transformation journey. We forecast they will continue declining over the 2019–24 regulatory period as we realise further efficiency gains from our planned strategic initiative expenditure. Most reductions will be realised in our network overheads through improved field efficiencies, although we also expect some reductions in our corporate overheads.

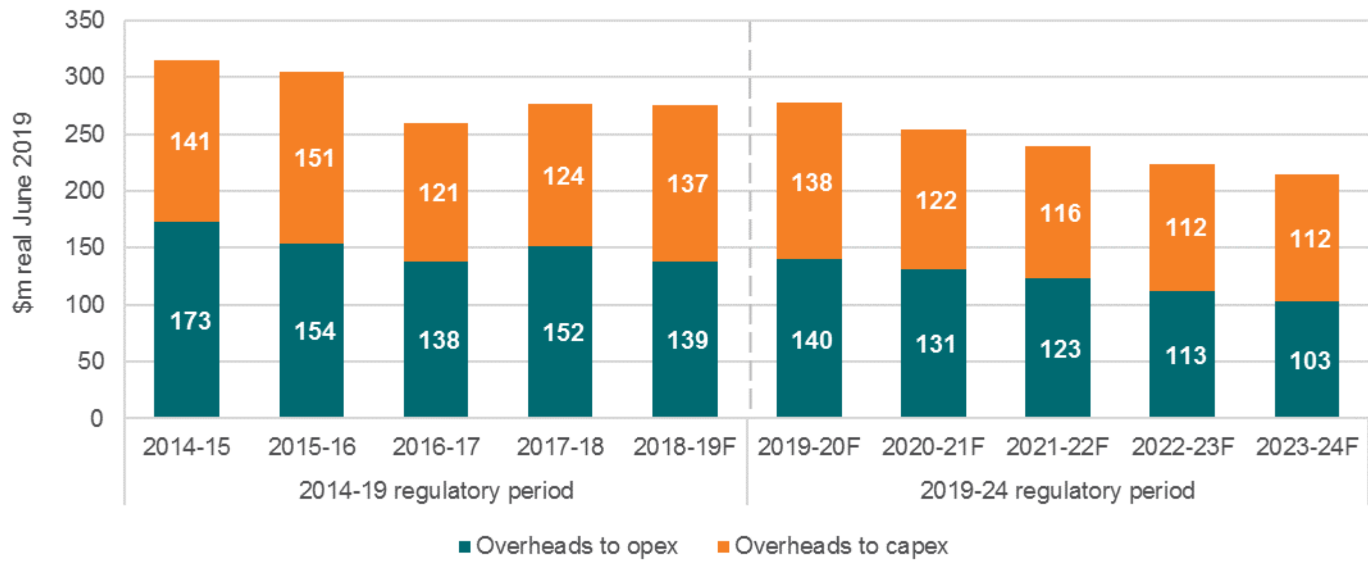
Our analysis shows that by 2023–24, our total overheads will be 31 per cent lower than in 2014–15.

Total Standard Control Services overheads ($m real June 2019)



The downwards trend in allocation of overheads across our operating and capital projects expenditure is clear in this graph.

Overheads allocated to operating and capital projects ($m real June 2019)



NB. Due to rounding, the numbers in this graph do not exactly equal the numbers in the previous graph.

Our overheads should be considered as a whole

Under Essential Energy's AER-approved CAM, we apply our overheads on the basis of direct costs.

This approach means the portion of operating and capital costs as a percentage of total expenditure directly impacts the level of overheads applied.

Every distributor has its own approach to the capitalisation of overhead costs and its own AER-approved CAM. These differences mean that reviewing the rate of overheads applied to either operating or capital costs will not tell a complete or accurate story.

When considering the efficiency of distributors' overheads, the entire overheads pool should be considered.

Overview of our overheads application

> Our overheads are allocated between operating and capital projects on a direct cost basis.

> The bulk of our overheads can be attributed to both operating and capital projects.

> A small portion of our overheads are applied to operating projects only. These costs do not have the direct relationship to capital projects required under accounting standards e.g. staff training costs and redundancy costs.

> Customer-contributed assets and non-system expenditure (fleet, property, ICT etc.) do not attract overheads and are not included in the calculation of our overhead rates.

Essential Energy's capitalisation approach

Here is a simple two-year example.

> Overheads are flat at $280 million a year.

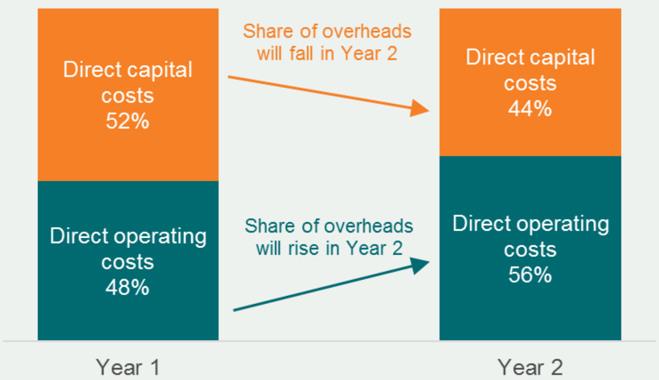
> Direct operating costs are $250 million a year.

> Direct capital costs are $270 million in the first year and $200 million in the second year.

Step 1. Calculate the allocation rates

> Operating costs represent 48 per cent of total costs in the first year [250 million/ (250 million +270 million)], but this increases to 56 per cent in the second year [250 million / (250 million +200 million)].

> Correspondingly, capital costs represent 52 per cent in Year 1 and 44 per cent Year 2.

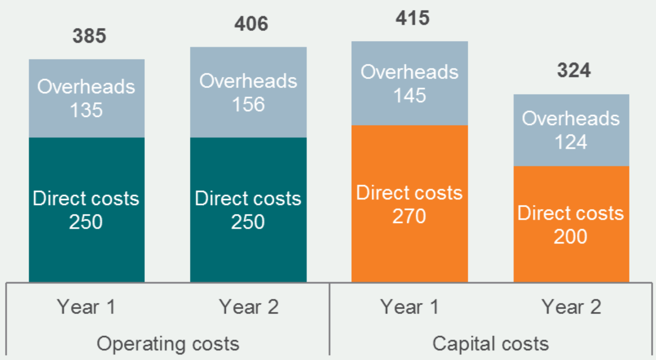


Step 2. Calculate the overheads amounts

> Operating costs would attract $135 million of overheads in Year 1 [48% x $280 million] and $156 million of overheads in Year 2 [56% x $280 million].

> Capital costs would attract $145 million of overheads in Year 1 and $124 million of overheads in Year 2.

Step 3. Report the split of direct and support costs



Step 4. Interpreting the result

> It appears that Essential Energy's total operating costs have increased. Yet our direct operating costs and total overheads remain unchanged between years.

> In fact, overall the business costs are lower, but this is not visible if the ratio of overheads to operating costs is considered outside the big picture.

The distortion is attributable to the proportion of direct operating expenditure relative to direct capital expenditure.

> The outcome is more complicated when overheads and direct operating costs also vary, but the principles remain the same.

Our Revenue Requirement Components

Appendix B

Revised Proposal Revenue Requirement

Building block components for our unsmoothed annual revenue requirement ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Return on capital	474	477	473	467	459	2,351
Return of capital	88	115	135	156	152	645
Operating expenditure	375	362	350	327	303	1,718
Revenue adjustments	(20)	15	15	15	15	39
Tax allowance (net)	19	19	20	23	22	103
Total proposed unsmoothed revenues	**937**	**989**	**992**	**988**	**951**	**4,857**

Numbers may not add up due to rounding

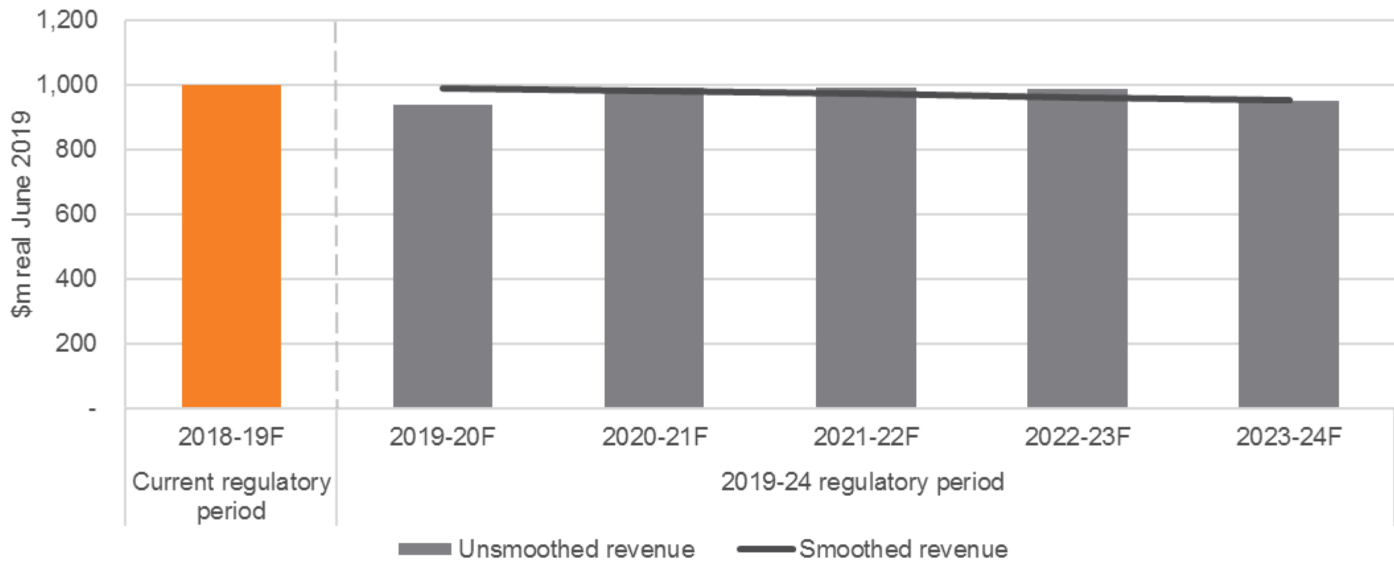
We will recover our revenue requirement for 2019–24 by charging customers for our Standard Control Services.

To minimise pricing variations caused by fluctuations in our expenditure, we have smoothed our Revised Proposal revenue. The resulting revenue profile has been calculated using the AER's PTRM (see Attachment 8.1). This ensures our smoothed revenue for 2019–24 is equal to the unsmoothed revenue for the same period in net present value terms.

Smoothed annual revenue requirements ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Proposed smoothed revenues	988	979	971	962	953	**4,853**

Smoothed and unsmoothed annual revenue requirement profile ($m real June 2019)



The approved cost of debt will be updated annually during the 2019–24 regulatory period in accordance with the AER's final Guideline. This means that for each year, the allowed Rate of Return would be different, depending on the annual cost of debt. We would apply the revenue adjustment using the AER's approved revenue cap control mechanism formula.

Our Approach

We have used the AER's PTRM to develop our building blocks and the associated revenue requirement. For more detailed explanations of the expenditure and Rate of Return components, see:

> Chapter 9 - Operating Expenditure;
> Chapter 10 - Capital Expenditure; and
> Chapter 11 - Allowed Rate of Return.

Regulatory Asset Base

We use the RAB to calculate the return on capital and return of capital components of our annual revenue requirement by:

> multiplying the opening RAB for each year of the regulatory period by the approved WACC to determine the return on capital; and
> offsetting straight-line depreciation against indexation of the opening RAB each year to determine the regulatory depreciation.

The estimated starting value of our RAB as at 1 July 2019 is $8,146 million (in nominal terms). We have calculated this amount using the AER's RFM (see Attachment 8.2) and in accordance with the NER.

The RAB value has been updated from our Proposal to include 2017–18 actual capital expenditure. It reflects the roll -forward of actual capital expenditure for 2014–15 to 2017–18 and estimated capital expenditure for 2018–19.

Indicative opening RAB value as at 1 July 2019 ($m nominal)

$m nominal	2014–15	2015–16	2016–17	2017–18	2018–19F
Opening RAB	6,774	7,157	7,388	7,577	7,798
Add: actual and estimated capital expenditure	479	417	411	388	494
Less: regulatory depreciation	96	186	222	167	141
Less: adjustments for 2013–14 actual capital expenditure					5
Closing RAB	**7,157**	**7,388**	**7,577**	**7,798**	**8,146**

Numbers may not add up due to rounding

Capital expenditure

More information about our capital expenditure plans can be found in the Capital Expenditure chapter in our Proposal and Appendix A.

Revised proposed capital expenditure ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Capital expenditure	495	408	406	392	381	**2,081**

Numbers may not add up due to rounding

Regulatory depreciation

We have applied the AER's preferred approach to calculating regulatory depreciation, as shown in the RFM. The AER's approach applies a Weighted Average Remaining Life (WARL) calculation to all existing and forecast new assets in the RAB using the straight-line depreciation methodology. Within the AER's PTRM, the value of regulatory depreciation is calculated as WARL-based straight-line depreciation less the indexation of the RAB value for inflation.

To calculate the RAB indexation values, we have used a forecast inflation rate of 2.42 per cent, in line with the AER's draft determination. This is a placeholder rate and is based on the AER's current inflation methodology.

Revised proposed regulatory depreciation ($mreal June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Straight-line depreciation	281	313	335	358	356	**1,643**
RAB indexation	(193)	(198)	(201)	(202)	(203)	**(997)**
Regulatory depreciation	**88**	**115**	**135**	**156**	**152**	**645**

Numbers may not add up due to rounding

As required by the NER, we have developed this Revised Proposal using our nominated depreciation schedules.

RAB roll-forward

To calculate the return on capital building block component, we started with the forecast RAB value as at 1 July 2019 and rolled it forward over each year of the 2019–24 regulatory period, using our proposed capital expenditure and regulatory depreciation values.

Forecast RAB roll-forward values for 2019–24 regulatory period ($m nominal)

$m nominal	2019-20	2020-21	2021-22	2022-23	2023-24
Opening RAB	8,146	8,573	8,887	9,185	9,452
Add: actual and estimated capital expenditure	517	435	443	439	436
Less: regulatory depreciation	90	121	145	171	172
Closing RAB	**8,573**	**8,887**	**9,185**	**9,452**	**9,717**

Numbers may not add up due to rounding

Allowed Rate of Return

Our proposed Rate of Return of 5.96 per cent was calculated in accordance with the AER's final Guideline.

As in the AER's Draft Determination, the placeholder rate for cost of debt is forecast to decline over the 2019–24 regulatory period. As such, our modelling is based on an average Rate of Return of 5.72 per cent.

In accordance with the PTRM, this Rate of Return estimate is multiplied by each year's opening RAB value to estimate the return on capital building block component. Chapter 12 and Appendix C provide further information.

Forecast rate of return parameters

	2019–20	2020–21	2021–22	2022–23	2023–24	Average
Overall Rate of Return	5.96%	5.84%	5.72%	5.60%	5.48%	**5.72%**
Cost of equity	6.32%	6.32%	6.32%	6.32%	6.32%	**6.32%**
Cost of debt	5.73%	5.52%	5.32%	5.12%	4.92%	**5.32%**
Gearing	60%	60%	60%	60%	60%	**60.00%**
Utilisation of imputation credits	58.5%	58.5%	58.5%	58.5%	58.5%	**58.50%**

Operating expenditure

This table shows the revised proposed operating expenditure relating to the provision of Standard Control Services. There is more detail about our operating expenditure plans in the Operating Expenditure chapter in our Proposal and Appendix A.

Revised proposed operating expenditure ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Controllable operating expenditure	371	358	346	323	299	**1,698**
Debt-raising costs	4	4	4	4	4	**21**
Total operating expenditure	**375**	**362**	**350**	**327**	**303**	**1,718**

Numbers may not add up due to rounding

Corporate tax

To estimate the cost of corporate tax, we have used the current corporate tax rate of 30 per cent and a value for imputation credits of 58.5 cents per dollar of tax paid, in accordance with the final Rate of Return Guideline. We calculated our estimates using the PTRM.

The AER's current review of the regulatory tax allowance will likely impact (lower) this aspect of our revenue requirement.

For more detail, see Chapter 12 and Appendix C.

Revised proposed corporate tax allowance ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Corporate tax	19	19	20	23	22	**103**

Numbers may not add up due to rounding

Revenue adjustments

The NER allows Essential Energy to adjust the proposed annual revenue requirement for revenue increments or decrements arising from the impact of:

- incentive schemes that apply during the current regulatory period;
- residual under-recovered or over-recovered revenues associated with applying the revenue cap mechanism in the current regulatory period; and
- using shared assets to provide unregulated services in the 2019–24 regulatory period.

Efficiency Benefit Sharing Scheme (EBSS)

As part of its determination for the 2014–19 regulatory period, the AER decided not to apply the EBSS to Essential Energy's operating expenditure. Consequently, we have not forecast any EBSS revenue increments or decrements for the 2019–24 regulatory period.

Capital Expenditure Sharing Scheme

As part of its determination for the 2014–19 regulatory period, the AER applied the CESS to Essential Energy's capital expenditure for the first time, beginning in 2015–16. We accept the AER's Draft Determination on our CESS reward and have not updated the CESS reward for our 2017–18 capital expenditure underspend.

Revised proposed CESS revenue increment ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
CESS reward	14	14	14	14	14	**69**

Numbers may not add up due to rounding

Demand Management Innovation Allowance

The AER's DMIA encourages the trial of innovative demand management projects. Essential Energy plans to identify, develop, refine and implement lower-cost solutions relating to network capacity (technology and non-technology) that meet the demand and energy needs of customers while maintaining acceptable network safety, reliability, security and power quality standards compared to traditional augmentation and replacement solutions.

We accept the DMIA amount approved by the AER in its Draft Determination.

Revised DMIA increment ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
DMIA	1	1	1	1	1	**5**

Forecast over-recovery of revenue for the 2014–19 regulatory period

As part of our 2014–19 remittal decision, any revenue recovered from customers in the 2014–19 regulatory period that exceeds $100 million is to be returned to customers. We are currently forecasting an over-recovery above this amount of $34 million. We calculated this amount in line with the AER's Draft Determination formula and have included it as a revenue decrement in the 2019–20 year.

Proposed shared asset revenue reduction

Shared assets are regulated network assets that we use to provide regulated and unregulated services. The AER may reduce Essential Energy's forecast annual revenue requirement in any regulatory year to reflect the forecast costs of using shared assets that are being recovered from unregulated revenues. In making this decision, the AER must have regard to its shared asset principles and guideline.

According to the shared asset guideline, the use of shared assets is material when a distributor's annual unregulated revenue from shared assets is expected to be greater than one per cent of its total smoothed revenue requirement in any year of the relevant regulatory period.[4] If the materiality threshold is met, the AER determines cost reductions based on forecast revenues from the unregulated services the distributor is expected to provide. If the materiality threshold is not met, no shared asset cost reduction applies.[5]

We have applied the AER's shared asset guideline and calculated the materiality of our expected use of shared assets to earn unregulated revenue over the 2019–24 regulatory period. The guideline states that "If the total unregulated revenue is expected to be greater than one per cent of the regulated revenue, we will apply a cost reduction".

The table indicates that our forecast unregulated revenue from shared assets does not exceed the one per cent materiality threshold of our Revised Proposed regulated revenue. Therefore, it is not necessary to apply any shared asset cost reduction to our Revised Proposed annual revenue requirement for any year in the 2019–24 regulatory period.

Materiality of shared asset use ($m real June 2019)

$m real June 2019	2019–20	2020–21	2021–22	2022–23	2023–24	Total 2019–24
Revised proposed annual revenue	988	979	971	962	953	4,853
Materiality threshold (1%)	10	10	10	10	10	49
Forecast unregulated revenue from shared assets	5	5	5	4	4	23

[4] AER, *Better Regulation, Shared Asset Guideline*, November 2013, p. 8

[5] AER, Better Regulation, Shared Asset Guideline, November 2013, p. 6

Allowed Rate of Return

Appendix C

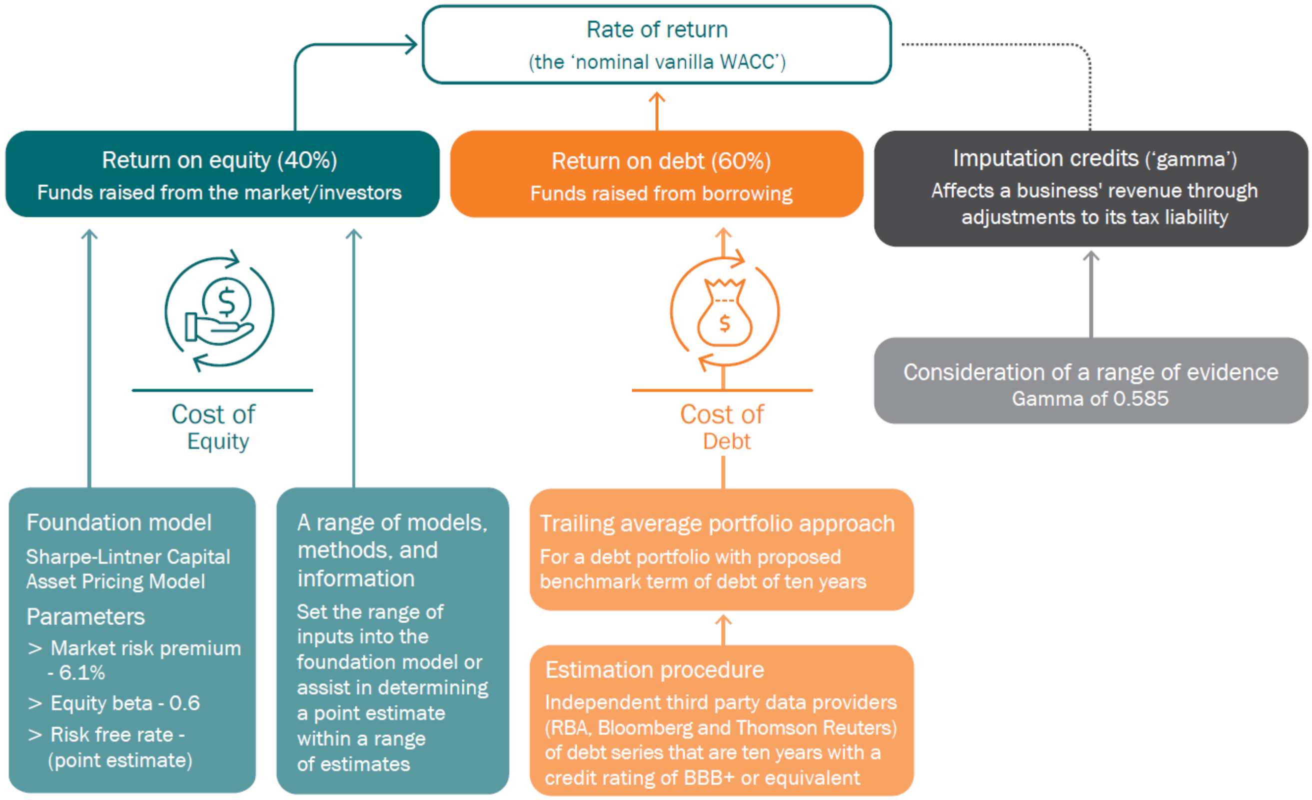
Allowed Rate of Return

We used several key parameter values to calculate our WACC estimate for the first year of the 2019–24 regulatory period, based on the methodology in the AER's final 2018 Rate of Return Guideline.

Rate of Return parameters	Value
Cost of equity (Nominal post-tax)	6.32%
Cost of debt (Nominal pre-tax)	5.73%
Gearing	60%
Nominal vanilla WACC	5.96%
Gamma	0.585
Inflation	2.42%

Calculating the Rate of Return

The diagram outlines the Rate of Return framework set out in the final Guideline.



Sources: AER and Essential Energy

Benchmark parameters

We have applied the benchmark parameters from the final Guideline in this Revised Proposal. Our Rate of Return estimate is a weighted average of our cost of debt and cost of equity estimates—the WACC.

Benchmark parameters	Value
Gearing	60%
Credit rating	BBB+
Debt maturity term	10 years

Debt-raising and equity-raising costs

The process of raising debt finance and equity finance incurs transaction costs should be recognised in regulated revenue allowances over the 2019–24 regulatory period. We included debt-raising costs of $21million (real June 2019) which was agreed by the AER in its Draft Determination. We include equity raising costs of $2 million (real June 2019) in this Revised Proposal using the methodology in the AER's PTRM.

Cost of debt

Applying the AER's final Guideline, we propose an allowed cost of debt of 5.73 per cent for the first year of the 2019–24 regulatory period. This has been calculated in accordance with the AER's 10-year trailing average approach, incorporating the 10-year transitional period. This rate is the result for year six of the 10-year transitional period in the trailing average calculation. It uses the current market rates as placeholder rates for each future annual update through to the start of the 2019–24 regulatory period.

Consistent with the final Guideline, our proposed cost of debt will be subject to annual updates throughout 2019–24.

Cost of equity

We propose an indicative allowed return on equity of 6.32 per cent, calculated using the AER's preferred methodology and the following formula:

Cost of equity = risk-free rate + (equity beta x market risk premium)

Risk-free rate— based on current market prices for 10-year Australian Government bonds. Our placeholder rate of 2.66 per cent will be updated closer to the start of the 2019–24 regulatory period.

Equity beta—measures the sensitivity of a business's return compared to movements in overall market returns. We have used a beta of 0.6, which aligns with the final Guideline.

Market risk premium—expected return above the risk-free rate for an investor to invest in a well-diversified portfolio of risky assets. We have used a rate of 6.1 per cent, which aligns with the final Guideline.

Cost of equity parameters	Value
Nominal risk-free rate	2.66%
Equity beta	0.6
Market risk premium	6.1%
Cost of equity	6.32%

Value of imputation credits

Under the NER, a regulated business such as Essential Energy should consider the value of imputation credits (gamma) when modelling revenues. This reduces the projected revenues, so they more closely reflect the impact of the corporate income tax expected to be retained by the Government. The higher the value of imputation credits (ranging from 0-1, or 0 per cent to 100 per cent) in a determination, the lower the revenues the business can expect to receive in compensation for paying corporate income tax. We have used a rate of 0.585, which aligns with the final Guideline.

Value of inflation

We have used the estimated average annual rate of expected inflation over a 10-year period to align with the term of the Rate of Return.

Essential Energy accepts the use of the AER's current approach to estimating expected inflation for this Revised Proposal, which is based on the geometric average of 10 annual expected inflation rates. This calculation uses the latest Reserve Bank of Australia forecasts of inflation for the first two years of the 2019–24 regulatory period and the mid-point of the Reserve Bank of Australia's inflation target band for the remaining eight annual rates.

The placeholder estimate for this Revised Proposal is 2.42 per cent a year, which will be updated closer to the beginning of the 2019–24 regulatory period.

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