Regulatory proposal 2021–2026

Affordable, resilient, flexible

January 2020

united energy

Good people in power

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Contents

Summary

Our regulatory proposal for the 2021–2026 regulatory period allows us to continue to deliver a safe, dependable and flexible supply of electricity to 1.45 million customers in the east and south-eastern suburbs of Melbourne and along the Mornington Peninsula, while keeping our prices among the lowest in the country.

Compared to 2020, a typical residential customer will receive reductions of $271 on their distribution and metering charges over the five year period, equating to $54 each year. Small business customers will on average receive reductions of $1,191, or $238 each year on their distribution and metering charges.

The price reductions will be delivered in an evolving and challenging operating environment, with:

- continued growth in renewable energy sources creating greater complexity in managing our network
- more extreme climatic conditions making it harder to deliver a resilient network
- a heightened level of cyber threat underpinning the need to reinforce the systems supporting our network and protect customer data
- a more dynamic market necessitating an improvement in network visibility and the provision of more data to market operators and our customers
- new legislative and regulatory obligations, such as stricter oil and noise management, which are driving changes in our approach to operating the network and its support functions.

We will continue to remain on the forefront of innovation to meet this changing landscape.

We have undergone extensive engagement with our stakeholders and customers in preparing this regulatory proposal. Three key themes arose which reflect our customers' preferences on areas where we focus our expenditure, namely an affordable network that is resilient and has the flexibility to enable them to choose how they both receive and export electricity.

Affordable

Affordability is our customers' primary concern. Our distribution and metering charges make up 28% of an average residential annual bill, and 32% of an average small business bill. Through this regulatory proposal we seek to continue to deliver balanced outcomes for our customers in terms of price and the quality of services delivered. We will maintain our affordability by offering real reductions to our customers over the 2021–2026 regulatory period with a 14% reduction in distribution and metering charges per year for a typical residential customer, and 13% for a typical small business customer.

Resilient

Safety is our number one priority. We prioritise the safety of our communities, customers and employees above all else. Our customers agree that it should be our priority, and not something to be traded for cost reductions.

We have provided a clear step-up in reliability to our customers, with a 32% improvement in minutes off supply in the current regulatory period compared with the previous regulatory period. Our network is now available 99.99% of the year. Our customers rightfully expect us to continue to deliver a resilient network to meet their increasing use of electronic appliances and devices. We will do this through ensuring the sustainability of our poles, maintaining and replacing other assets as needed, and supporting localised growth in our network.

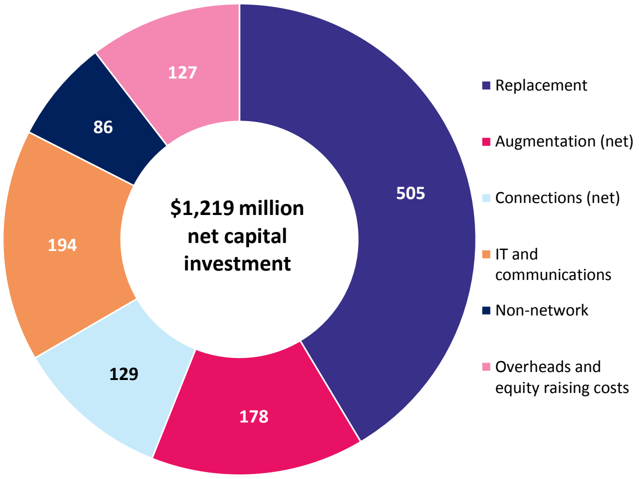
Flexible

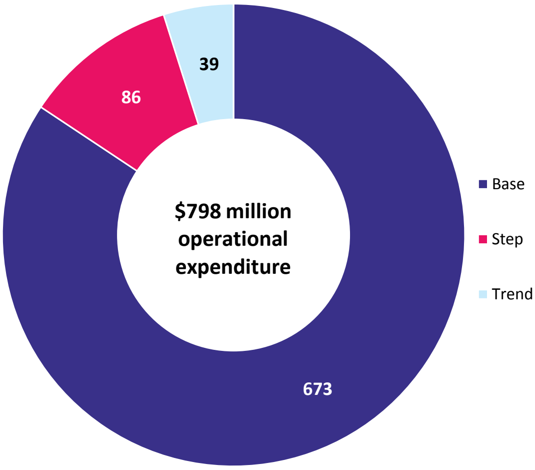
Our customers are also calling for more flexibility in the way they use our network—to both receive and export electricity—and have more information on their electricity interactions. We will invest in our network to enable greater solar and better manage the power flows on the low voltage network to support our customers' energy choices.

Snapshot of our proposal

Our proposal delivers the affordability outcomes our customers are seeking. The key aspects of our regulatory proposal are summarised below.

Summary figure 1 Forecast expenditure for standard control 2021 to 2026 ($ million, 2021)





Source: United Energy
Note: Forecast includes real escalation and network overheads

Summary table 1 Forecast summary for standard control 2021 to 2026 ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Return on assets	119.2	124.1	127.7	130.6	132.5	119.2
Regulatory depreciation	92.2	105.3	120.1	131.9	143.5	92.2
Operating expenditure	159.3	164.5	172.3	177.7	183.8	159.3
Incentive schemes	40.3	40.3	21.9	7.4	9.1	40.3
Corporate income tax	9.7	7.7	7.6	9.8	8.9	9.7
Unsmoothed revenue requirements	420.6	441.8	449.6	457.3	477.8	420.6
X factor (standard control services)	10.7%	0.0%	0.0%	0.0%	0.0%	10.7%

Source: United Energy

Summary table 2 Distribution charge impact for typical customers (%, real)

Typical annual bill	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	-13.0	-1.0	-1.0	-1.0	-1.0
Small commercial	-12.0	-1.0	-1.0	-1.0	-1.0

Source: United Energy
Note: Distribution charge impact for 2021/22 is based off 2020 distribution tariffs and is inclusive of metering charges

Key positions

The table below sets out some of our key positions in terms of the regulatory framework and approach.

Summary table 3 Key positions

Topic	Position
Service classification	We accept the AER's proposed service classification as set out in the final Framework & Approach (**F&A**) paper
Control mechanisms	We accept the AER's control mechanism set out in the F&A paper, namely: • revenue cap for standard control services • price cap for alternative control services
Incentive schemes	We broadly accept the application of the following incentive schemes set out the F&A paper: • efficiency benefit sharing scheme • capital expenditure sharing scheme • demand management incentive scheme • demand management innovation allowance • F-factor scheme • service target performance incentive scheme
Nominated pass through events	We nominate the following additional pass through events: • insurer's credit risk event • insurance coverage event • natural disaster event • terrorism event • retailer insolvency event • major cyber event • act of aggression event • electric vehicle event
Contingent projects	We have not nominated any contingent projects

Source: United Energy

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Introduction

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1 Introduction

This is our regulatory proposal to the Australian Energy Regulator (**AER**) for the five year period commencing on 1 July 2021. It sets out the revenue we require to manage the network in a safe, reliable and efficient manner for our customers and the community in general.

The regulatory proposal is supported by the following documents:

- an overview paper that has been prepared in line with clause 6.2.2(C1) of the National Electricity Rules (**Rules**) and
- appendices and attachments supporting the regulatory proposal (including the information required by the Expenditure Forecast Assessment Guideline and the Reset Regulatory Information Notice (**Reset RIN**).

This regulatory proposal, its appendices and attachments were prepared in accordance with the Rules and Reset RIN requirements.[1]

1.1 Regulatory context

We are subject to a comprehensive set of regulatory obligations designed to ensure appropriate outcomes for our customers, the community and investors. We require a fair commercial return to enable us to deliver the right level of network reliability, safety and customer service in an efficient and sustainable manner.

The AER is responsible for the economic regulation of our business. In undertaking this role, the AER is required to do so in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (**NEO**) as stated in section 7 of the National Electricity Law (**NEL**).

The objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

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

The Victorian Government retains responsibility for setting service levels, while Energy Safe Victoria (**ESV**) is responsible for safety and technical regulation in Victoria.

The AER has decided to apply a revenue cap form of control to our standard control services in the 2021–2026 regulatory period and has put in place incentive arrangements to encourage us to pursue efficiency gains, further investigate demand management opportunities, and improve service performance to customers over the regulatory period.

The AER is required to ensure that pricing outcomes, and the revenues on which they are predicated, are sufficient to enable us to undertake the capital and operating work programs required to deliver the service levels as defined by the Victorian Electricity Distribution Code (**Distribution Code**), comply with all applicable regulatory obligations and requirements and maintain the safety of the distribution system. The allowed pricing outcomes must also provide for a fair commercial return to our shareholders. We have developed our capital expenditure program and forecasts taking into account the requirements of the Distribution Code and consider that the proposed capital expenditure programs are sufficient to ensure that we comply with that instrument.

At the time of preparing this regulatory proposal, a number of important consultations or decisions remain in progress, including a review by the Essential Services Commission of Victoria (**ESCV**) of the Distribution Code, Victorian Government review of future metering arrangements in Victoria and changes to the *Environmental*

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1 UE APP10 - Supporting materials list - Jan2020 - Public

Protection Amendment Act 2018 and associated regulations. This regulatory proposal reflects our best assessment or provides a 'placeholder' with respect to the impact of these deliberations. However, changes to regulatory arrangements that are determined subsequent to the submission of this regulatory proposal may require further consideration during the AER's determination process.

In January 2019, the AER released its Final Framework and approach for the Victorian distributors commencing 1 January 2021 (**F&A**).[2] The F&A paper, amongst other things, defines the revenue control mechanism to apply in the 2021–2026 regulatory period, the AER's proposed approach to the classification of distribution services and the specific application of regulatory incentive schemes in the 2021–2026 regulatory period.

We accept the conclusions advanced in the F&A paper. As a consequence, this regulatory proposal is based on the application of a revenue control mechanism and the service classification outlined in the F&A paper.

For the purposes of 6.3.2(a) and S6.1.3(13) of the Rules, we are proposing our next regulatory period commence on 1 July 2021 and operate for a period of five years concluding on 30 June 2026.

1.1.1 Transitional arrangements for the current regulatory period

In April 2019, the Victorian Minster for Energy, Environment and Climate Change sent a letter to the AER indicating her intention to make changes to the timing of our regulatory reset. The Minister proposed to adjust the timing such that network prices would be updated on a financial year basis, rather than a calendar year basis. This would be implemented through a change to the *National Electricity (Victoria) Act 2005*.

Our current regulatory period ends on 31 December 2020. However, the Minister indicated her intention to extend the current period by six months, with the new five year regulatory period and prices taking effect from 1 July 2021.

In November 2019, the AER sent us a letter outlining the proposed interim measures to apply for the period 1 January 2021 to 30 June 2021 as a result of the Victorian Government receiving policy approval for the changes to the regulatory periods. The key interim measures are:

- rate of return: will be updated based on the 2018 Rate of Return Instrument which revised all parameters
- operating expenditure: will be based on the previous year's allowance trended forward (by the relevant rate of change), then halved
- capital expenditure: will be based on the previous year's allowance, then halved
- no revenue adjustments for the 2016-20 efficiency benefit sharing scheme (**EBSS**) or capital expenditure sharing scheme (**CESS**) calculations as these will be deferred to begin from 1 July 2021.

Our proposal for the transitional period is provided in the attached appendix.[3] The AER decision on the transitional period in expected in August 2020.

1.2 A bit about us

We deliver electricity to over 1.45 million customers in a 1,500 square kilometre area, with a customer density of around 99 customers per kilometre of line. Our network extends from the east and south east suburbs of Melbourne along the Mornington Peninsula.

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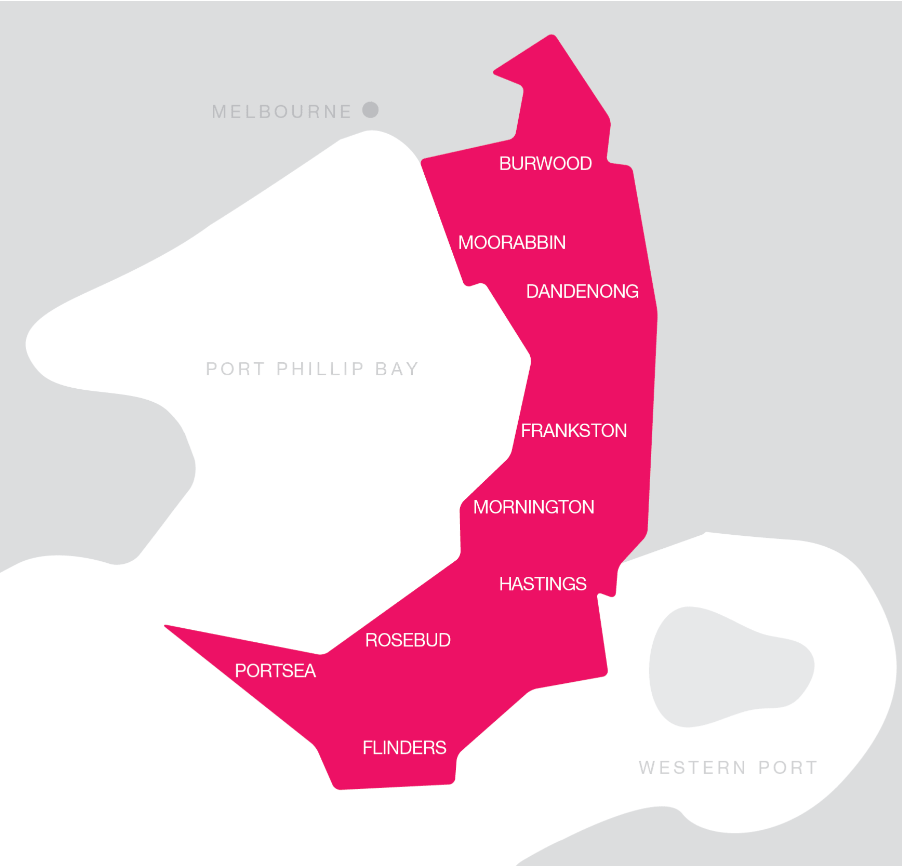
2 UE ATT044 - AER - Final framework and approach - Jan2019 - Public

3 UE APP07 - Transition period 2021 - Jan2020 - Public

Figure 1.1 Where we operate



Source: United Energy

Our network consists of a sub-transmission network and a distribution network. The sub-transmission network consists of a mix of underground and overhead lines that operate at 66kV. The distribution feeder network, which is predominantly overhead, operates at 22kV, 11kV and 6.6kV. Our network includes 47 zone substation, 13,770 distribution transformers and 215,800 poles.

1.3 Our plans meet our customer needs

To ensure a robust foundation to our regulatory proposal, we have undertaken the most comprehensive stakeholder engagement process in our history known as Energised 2021–2026. The process commenced in 2017 and has enabled us to better understand what is important to our customers both today and into the future.

Through Energised 2021–2026, our customers and stakeholders told us what they want from us over the next regulatory period. We have used the feedback to inform our expenditure plans and as result, we are confident that our regulatory proposal will deliver on the expectations of our customers.

Our customers want a network that is:

- *affordable*
- *resilient*
- *flexible*

We have heard three common themes in our discussions with stakeholders. They have told us they want affordable network services that are resilient and have the flexibility to enable them to choose how they use electricity. We have used these themes, which reflect our customers' preferences, to develop a set of expenditure plans which deliver on these outcomes.

Throughout the regulatory proposal you will identify references to these themes and how we intend to ensure our plans deliver on them.

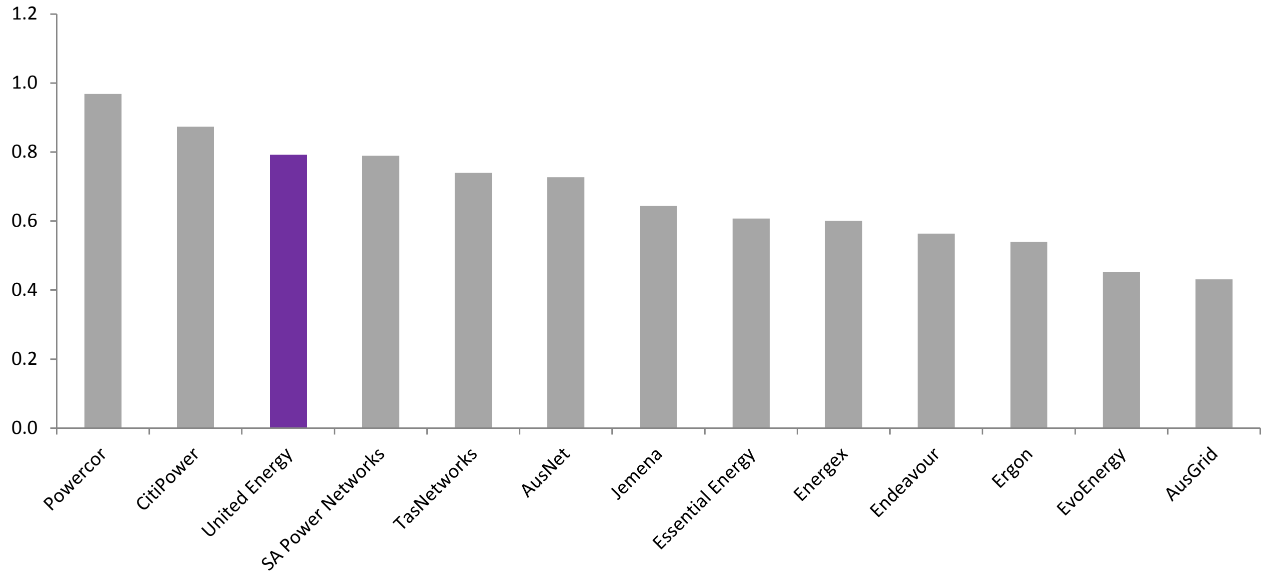
1.4 A strong track record

Over the current and past regulatory periods we have established an enviable track record of performance that can provide confidence in our regulatory proposals for the next five years.

Affordable pricing outcomes

We take pride in our strong efficiency performance that has allowed us to deliver balanced outcomes for our customers in terms of price and the quality of services delivered. Based on the analysis of the AER, we have consistently been one of the top performers over the period 2006 to 2018.

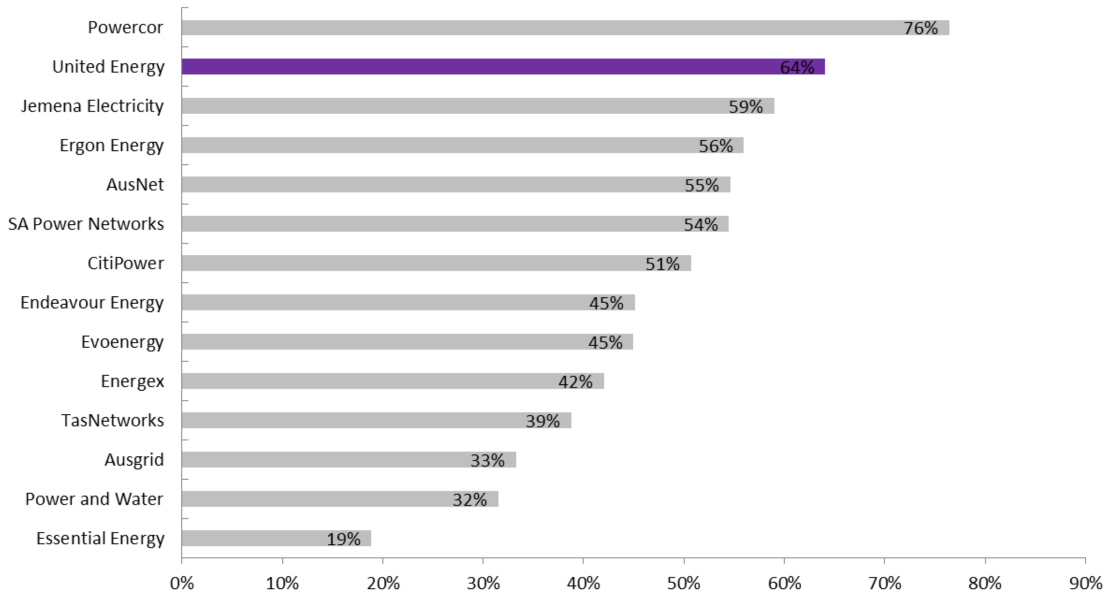
Figure 1.2 Operating expenditure efficiency scores from Cobb-Douglas stochastic frontier analysis (2006–2018 average)



Source: UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public
Note: A high score represents greater operating expenditure efficiency

Another way we have delivered value is by operating our network closer to its full capacity than almost all other distributors. That is, we get the most out of our assets. Our high network utilisation reflects our strong capital governance practices. This means customers have only paid for investments when they are needed — we don't waste money by building excess capacity too early.

Figure 1.3 Network utilisation 2018 (per cent)



Source: AER RIN data

A resilient network

Following a challenging period over the 2011–2015 regulatory period where our customers experienced around 71 unplanned minutes off supply per annum, through prudent asset management practices this has fallen to 48 unplanned minutes per annum over the current regulatory period. That is, a 32% improvement in minutes off supply for our customers.

As a consequence we are now the fourth best performing distributor network in terms of unplanned minutes off supply in the National Electricity Market (**NEM**), surpassed only by two predominantly underground central business district based networks and within four minutes of the third placed urban distributor.

Never compromising safety

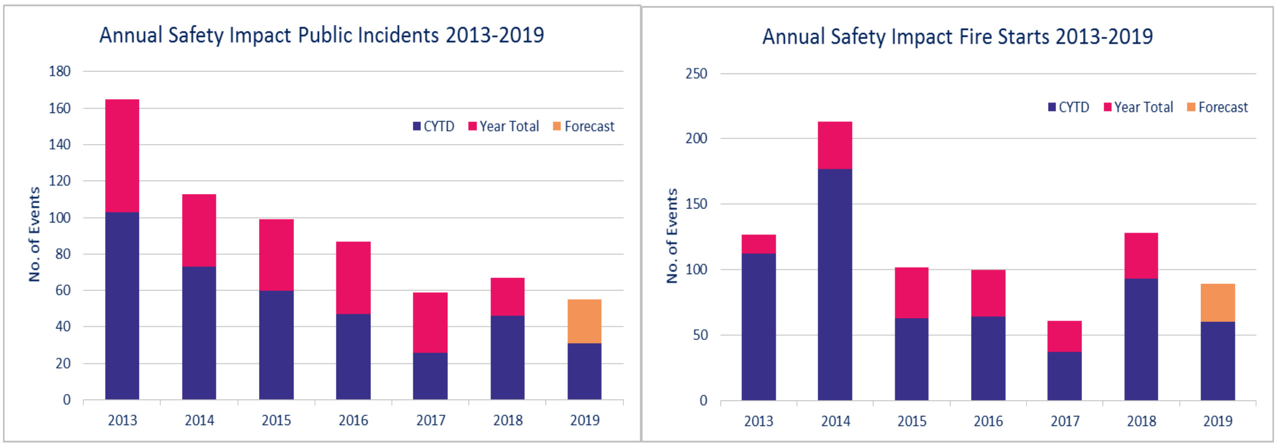
Keeping our customers, communities and employees safe has always been, and remains, our number one priority. We will never compromise safety. It is embedded in our culture and values.

We have well established network development, replacement and maintenance programs in place to reduce the probability of network assets creating a hazard or initiating a fire. These programs amongst other things address:

- overhead conductor failure
- pole failure
- cross-arm failure.

To ensure our commitment to safety, we have key measures of safety performance measured monthly which include public incidents, fire starts and asset failures. Since 2013, we have more than halved the number of public incidents across our network and have held the number of fire starts constant.

Figure 1.4 Annual safety measures: public incidents and fire starts



Source: United Energy

Of course the journey to further reduce safety incidents on our network will continue and we will never stop seeking to innovate and develop new ideas that can further minimise safety incidents.

On the forefront of innovation

We are on the forefront of innovation, which has delivered benefits to our customers.

In the current regulatory period, we received funding from the Australian Renewable Energy Agency (**ARENA**) to investigate innovative and affordable options to better manage electricity use during times of peak electricity demand.

We have actively identified and implemented opportunities to deliver savings through demand management. In the period to 2021, our demand management initiatives have already deferred over $40 million of investment. For example, instead of investing $30 million to build 50 kilometres of new line on the Mornington Peninsula, we worked with a provider to identify 11MW of demand response from the local community. We hope to continue this program into the 2021–2026 regulatory period.

We have also been recognised within Australia and internationally for establishing our Summer Saver program. This program engages with over 1,000 customers each year to manage their usage in overloaded parts of our network, and provides funds directly to those participating in the program. This is a cheaper alternative to investing in new infrastructure—so far we have avoided more than $10 million of capital works.

Our demand management programs cannot defer capital expenditure indefinitely. Our regulatory proposal contains investments to address the underlying network issues that can no longer be efficiently deferred.

Our investment decisions to replace assets in the 2021–2026 regulatory period are increasingly relying on smart technology and data analytics. For example, we have partnered with eight separate universities across Australia to identify better ways to manage our assets. This has helped us to only replace our poles, wires and major electrical plant located inside our zone substations when they need it, and to identify and resolve safety hazards before they occur.

Our work with universities helps to improve our network

In partnership with Swinburne University, we are testing the strength of our pole cross-arms that carry our lines to understand when they may break. This research will allow safer and more affordable decisions about when to replace assets.

We are also working with Victoria University and the Department of Environment, Land, Water and Planning (**DELWP**) to remotely identify broken lines. This research will help us turn off power on broken lines quickly to mitigate safety and bushfire risks.

Our other research projects include:

- customer recruitment study for demand management with Deakin University
- research into early fault detection with RMIT University to detect outages before they occur
- working with the University of Queensland to better manage the life cycle of power transformers
- supporting Monash University's project for net zero emissions
- solar forecasting with Australian National University to better utilise our network.

Identifying and implementing new ways to solve network problems leads to safer, more reliable and affordable networks.

1.5 Highlights of our proposal

An affordable network

Stakeholders have sent us a clear message that affordability is important and that many stakeholders consider current electricity prices too expensive in relation to their other daily expenses.

We already deliver some of the lowest distribution network charges in Australia but we recognise energy affordability remains a major concern to our customers.

As a result, we are proposing to reduce our distribution and metering charges by $54 per annum for a typical residential customer and $238 per annum for a typical business customer in 2021. We are also giving people the opportunity to save more by offering time of use tariffs that reward customers for using electricity at off-peak times.

A resilient network

Our customers were generally satisfied with the reliability and quality of their network services and supported current service levels being maintained. There was no willingness to trade-off current levels of reliability for cost savings however there was some interest in improving services to worst served customers. Safety was seen as critical and therefore considered too important to be a 'value' to be traded-off for cost reductions.

Consistent with customer feedback, our program of works for the next regulatory period is very much focused on ensuring the continued resilience of our network. A key focus is the replacement of circuit breakers and transformers across the network. We have been conscious to ensure we only replace these assets where the forecast risk has reached an unacceptable level to the community.

We have designed a new pole replacement program that meets not only our immediate compliance obligations, but also the community expectations of a sustainable asset management program over the longer term.

Whilst we have led the industry over the current regulatory period in deferring the need to augment our network for growth through substitution of major capital expenditure with demand management options such as Community Grid and Summer Saver, we will need to add additional transformers at a number of zone substations over the next period. Additional transformers will be required at Doncaster, Keysborough, Mornington and East Malvern. In parallel, we will seek to extend our existing demand management programs to defer high voltage (**HV**) feeder and distribution substation works.

Commercial and residential connections remain strong, driven by growth pockets in the Mornington Peninsula and Frankston. Some of the most significant individual connection projects will be the North East Link tunnel, connecting the M80 Metropolitan Ring Road with the M3 Eastern Freeway, and the Suburban Rail Link to connect Melbourne's middle suburbs.

A flexible network that supports customer choices

The energy market is changing and so too are our customers' needs. We want to support their energy choices whilst keeping prices down and our customers powered.

Over the next five years we expect to be connecting more solar than ever before with forecasts indicating more than 23% of our residential customers will have solar on their rooftops by 2026.

To ensure we are ready, we are planning investments that will continue to facilitate the expansion of rooftop solar connections, known as our 'solar enablement' program. At the same time we will invest in better network control, better data analytics and innovative ways to manage and optimise our low voltage network through 'digital network' which will reduce network costs over time whilst also delivering improved value to our customers.

The digital network initiatives embrace the opportunity presented to us through smart meters to proactively ensure the safety of the community and employees. They will enhance our ability to accurately identify the individual transformers customers are connected to, allowing more accurate communication with customers during planned and unplanned outages. The information gleaned from our digital network program will allow us to improve network tariff design, optimise the uptake of new customer technologies and proactively manage asset failures.

2

Stakeholder engagement

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2 Stakeholder engagement

Improving stakeholder engagement is a key strategic pillar of our business. We view engagement as essential to delivering customer outcomes—without knowing what customers want and need, we cannot deliver it.

Engagement is an ongoing and constant process. It is a tool we use to regularly check in with our stakeholders and ensure we deliver.

Our regulatory reset engagement, known as Energised 2021–2026, was launched in 2017. It is underpinned by our stakeholder engagement framework. Together with our communications and engagement tools, we encourage participation by the 1.8 million customers across CitiPower, Powercor and United Energy.

Throughout our engagement, it became clear that the key priorities for our customers are a network that is resilient, flexible and affordable.

This chapter sets out our engagement approach, activities and what we heard from our stakeholders. Further detail is provided in the stakeholder engagement appendix.[4]

2.1 Our engagement approach

In designing our engagement approach, we took the time to:

- critically review what we could have done better in the last regulatory reset process
- learn from best practice principles for engagement by leading authorities like the Victorian Auditor-General's Office and the International Association for Public Participation
- consider the changes in the operating environment through social and reputational risks assessments
- draw on industry engagement practices through a literature review of relevant engagement practices nationally and internationally
- seek feedback from internal and external stakeholders
- have the approach reviewed by independent experts.

In all engagement activities, we sought to be accessible, inclusive and transparent, and our goals needed to be measurable. We also set ourselves the following objectives for engagement as part of Energised 2021–2026.

[4] UE APP01 - Stakeholder engagement - Jan2020 - Public

Table 2.1 Engagement objectives

	Awareness	Meaningful influence	Improve long-term outcomes
What we wanted to achieve	Achieve a level of awareness of our organisation, our role and the regulatory framework in which we operate.	Gather customer and stakeholder inputs at appropriate times and allow them to have meaningful influence on our proposal.	Actively involve customers and stakeholders in the process so we could understand changing views and preferences, and improve long-term outcomes.
What this meant for our five year plan	Deep insights into customer perspectives on everyday lifestyle changes implicated in different energy futures, both in terms of demand side and supply side changes.	Understanding of the key points of agreement and contestation regarding considerations and trade-offs in developing our energy future.	Active involvement of customers and stakeholders to understand changing views and preferences and to improve long term outcomes.

Source: United Energy

While the engagement objectives were important to measuring our effectiveness, the outcomes we wanted from engagement were critical to designing the process. We made a point of clearly articulating the outcomes to ensure we were asking the right questions, and consulting with the right people. The outcomes for engagement were identified as follows:

- develop insight into customer perspectives on everyday lifestyle changes implicated in different energy futures, both in terms of demand side and supply side changes
- actively involve customers and stakeholders in the regulatory process to understand changing views and preferences and to improve long term outcomes
- highlight key points of agreement and contestation regarding considerations and trade-offs in developing our energy future.

In designing the engagement process we made sure to acknowledge the engagement principles outlined in our stakeholder engagement plan,[5] which were to be accessible, inclusive, transparent and measurable in outcomes.

2.1.1 Our process for engagement

It is hard to predict unforeseeable events or changes in the market. In designing our engagement approach, we started with understanding the values our customers and stakeholders place on energy. We then presented back a series of scenarios for our possible energy futures that sought to reflect these values and inform the development of a shared energy future.

A core component was to establish a shared energy future that meets the needs of our customers and the communities they live in. We co-designed these energy futures with customers, consumer advocates and stakeholders. This ensured we were designing possible and plausible energy futures that incorporated customer and stakeholder views and preferences, as well as hard data on consumption.

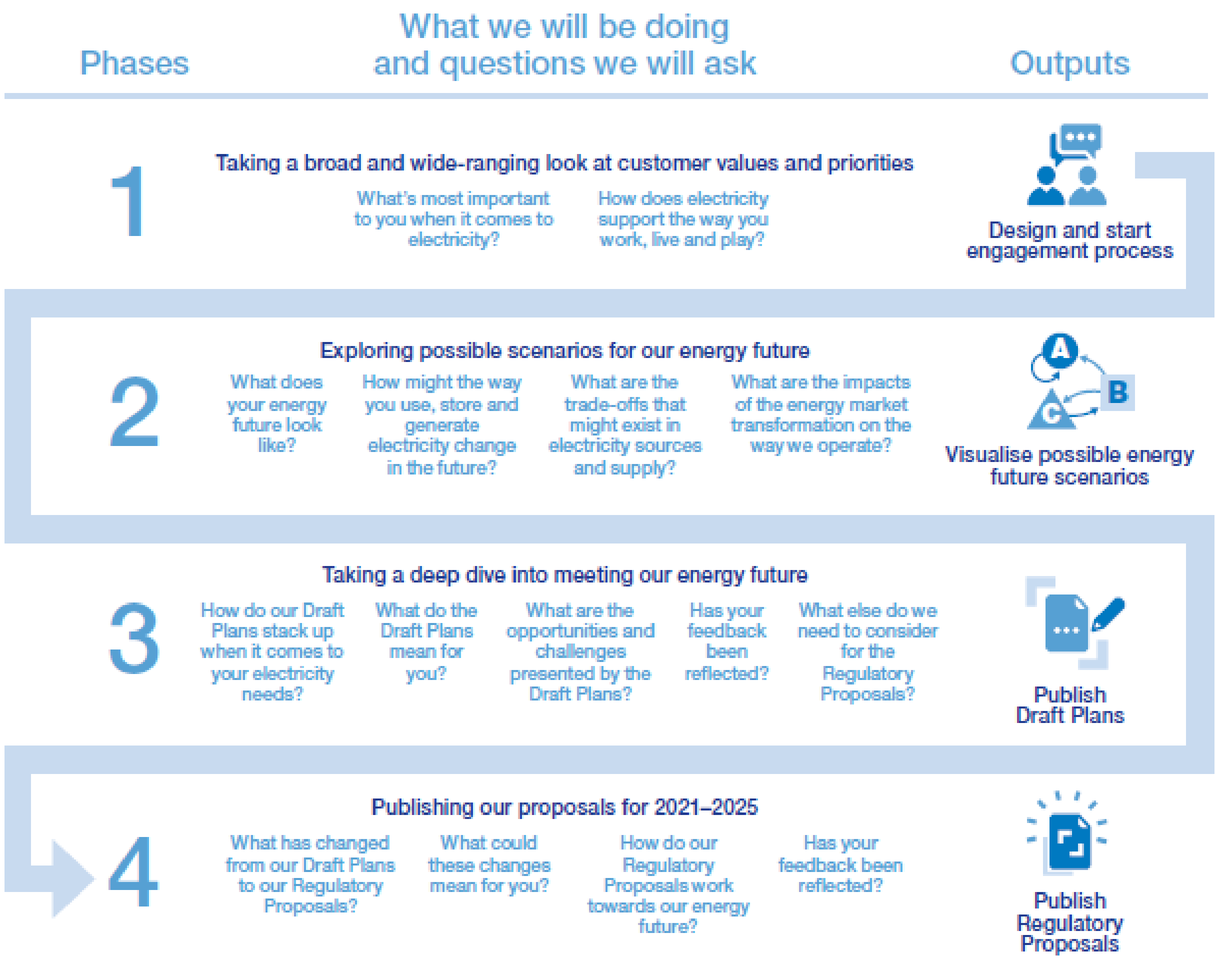
There were four key phases, plus design, that guided the design and delivery of the customer and stakeholder engagement for the regulatory reset process:

5 UE ATT069 - Stakeholder engagement plan - Nov2017 - Public

- design phase: determining what we need to learn, from who and how
- phase one: gathering insights from customers and stakeholders
- phase two: exploring possible energy scenarios
- phase three: sense checking our draft plans
- phase four: publish our regulatory proposal and ongoing engagement.

In May 2019, the Department of Environment, Land, Water, and Planning (**DELWP**) announced the intent to extend the current regulatory period. The extension sought to align with the Victorian Government Default Offer so network price changes occurring on 1 July 2021 will apply until 30 June 2026. As a result, we extended our engagement period to learn from phases 1-3 and refine our approach for phase four.

Figure 2.1 Engagement process



Source: United Energy

At each point in the above process we made sure to acknowledge our engagement principles and consider or act upon feedback by:

- building parameters around the scope of consultation to provide stakeholders with a clear process on when and where their feedback will be considered
- agreeing on outcomes upfront and evaluating the effectiveness during and after the engagement process

- publicly disclosing the outcomes of engagement and 'closing the loop' with our stakeholders, thanking them for their participation, replaying what we have heard, and explaining how their input had been used
- incorporating findings from each phase of engagement into future engagements and ultimately, the final proposals. To do so we developed a process for recording and analysing outcomes.

2.1.2 Who was involved in the conversation

The Energised 2021-2026 program ensured we had a consistent approach and shared learnings across our three networks, and allowed us to compare and identify unique factors for each network. When differences were identified we took extra measures to engage further with customers and stakeholders to ensure their needs were met. We have been able to benefit from a large pool of data relating to energy customers from across Victoria, which has in itself provided invaluable insights for our business and proposals. The overall program reached 751,671 customers and stakeholders.

2.1.3 Dedicated advisory panel

We recognised the need for a dedicated advisory panel that was capable of representing the perspective of our customers. We wanted to bring this dedicated panel along the reset process to ensure our plans for 2021–2026 reset genuinely reflect the preferences and perspectives of our customers. Therefore, we established the Energy Futures Customer Advisory Panel (**EFCAP**) as part of Energised 2021–2026.

The EFCAP consisted of 11 members with a diverse representation of customers and stakeholders and provided a collaborative platform for our business to discuss current and future energy insights. The panel provided a forum for all relevant issues and concerns regarding the development of our draft plan and regulatory proposal. As a critical source for customer insights, the EFCAP met every three to four months over a two-year period to consider concepts, projects, issues and challenges relating to the development of our proposal. These included customer perceptions and views on topics of interest, such as:

- energy futures
- network performance, including reliability, quality and security
- tariffs, including principles, pricing and affordability
- non-network solutions, including renewable and distributed energy
- connections, including small scale, large scale and load generation
- community safety, including bushfire mitigation and public lighting
- engagement, including our process, partnerships and stakeholders.

2.1.4 Summary of engagement activity

We provided a range of innovative ways for customers and stakeholders to be engaged and provide input, and looked for innovative ways to encourage participation as part of Energised 2021–2026. This was to demonstrate our commitment to improving our engagement process. Across the stages, the approach and depth of the engagement varied. The International Association for Public Participation (**IAP2**) spectrum[6] was used in tailoring the approach and the tools. The table below outlines the tools that were used across the Energised 2021–2026 engagement program and the desired level of engagement and purpose of each tool.

[6] UE ATT143 - IAP2 - Public participation spectrum - Public

Table 2.2 Key engagement activities, level of engagement and what feedback was sought

Engagement activities	Level of engagement	Purpose of engagement	Description	United Energy specific metrics
Talking Electricity website	Inform-consult	Provide a centralised online hub for important information, updates and news about our progress	An online engagement website with links to each network www.talkingelectricity.com.au	15,330 page visits
Newsletters	Inform	Provide regular updates on our progress throughout the process	People could register via the website. Newsletters were sent out monthly	489 subscribers
Pop up displays	Inform-consult	Provide information, subscribe new customers and seek high level insights about energy usage	Displays held in high traffic public areas across both metropolitan and regional hubs	Pop up displays in Rosebud with 24,500 reported foot traffic and Around the Bay in Queenscliff with 3,500 foot traffic
Focus groups	Consult	Collect exploratory insights on values, customer priorities for the future, renewables, electricity bills and customer impacts	Small group discussions with customers in Richmond, South Melbourne, Bendigo, Geelong, Mildura, Werribee, Sandringham, Dandenong and Rosebud	Focus groups held in Sandringham, Dandenong and Rosebud
Interviews	Consult	Discuss energy futures, impacts to business, connections, tariffs, energy sources and future investment plans around energy	Major customers in finance, transport, tourism, food production and retail	24 interviews
Surveys	Consult	Understand values and preferences on key issues addressed in the proposals Understand scope, limits and level of support for some of our flagship programs in the draft plan and proposal	Survey of residents and small to medium business customers across the three networks	2,656 surveys with residential and small to medium businesses with access to insights from 7,793 surveys across all our networks
Meetings	Consult-involve	Detailed discussion about all elements of the draft plan and our proposals	Over 700 meetings with local, state and national stakeholders and groups across the three networks	714 meetings with 2,353 interactions
Workshops	Consult-involve	Discuss and decide on the approach to topics like pricing, data, renewables and connections	32 forums where technical teams and groups from across the network engaged 970	579 participants over 30 forums or workshops

Engagement activities	Level of engagement	Purpose of engagement	Description	United Energy specific metrics
			customers and stakeholders	
Citizen led deliberative forums	Involve	Dynamic forums for the public to hear from experts about energy futures and provide feedback on their values, the trade-offs, customer impacts and priorities	A deliberative process involving the delivery of 9 forums using the same customers over the course of the two-year engagement program. One deliberative process was delivered for each network.	266 participants during 4 deliberative forums
Future Networks Forums	Consult-involve	Co-design energy futures to test with customers and ensure we prepared possible and plausible options for discussion Discuss proposed options to enable solar exports and current and future demand response programs and incentives to encourage customers to shift their energy load to off-peak periods	Two held in Melbourne with informed stakeholder groups from state and local government, as well as consumer advocates, regulators and industry groups	78 participants in two joint network forums
Advisory panel	Involve	Detailed discussion about all elements of the proposal, including approach, modelling, insights, market trends, regulation, pricing, connections, community safety, renewables, customer impacts, performance, the draft plan and our proposals	Dedicated panel with representatives from the AER, Energy Consumers Australia, DELWP, National Electrical Contractors Association, Newstead 2021, St Vincent De Paul, United Dairyfarmers Victoria, the Victorian Chamber of Commerce and Industry and AiGroup	19 customer reference panel members 1,120 interactions with customer reference panel members 18 panel meetings with our customer reference members
Draft plan, and engagement reports	Consult-involve	Cover the insights we've collected along the process, how feedback has been considered and how we'll work towards the proposed energy future	Published online and in printed copies	Draft plan published for United Energy and viewed 1,250 times
Podcast	Inform	Inform customers of the draft plans; the purpose of the plans and what it includes	Published online and available through Sound Cloud or www.talkingelectricity.com.au	319 podcast listens from across our networks

Engagement activities	Level of engagement	Purpose of engagement	Description	United Energy specific metrics
Open house	Consult	Provide an opportunity to local government and other community opinion leaders to learn more about the draft plans and provide their input	All-day forums held in Melbourne and Ballarat	16 community opinion leaders and local government representatives met in Melbourne

Source: United Energy

2.2 What we heard from customers

The challenge of involving customers and stakeholders in these conversations is that they tend to understand the work we do when it came to poles and wires, but are less clear on the link between our network infrastructure and Australia's changing energy future.

As we explored the best way to have this conversation with customers and stakeholders, we continually came back to the same question of:

How do we secure access to electricity at all times at the flip of a switch, for a reasonable price, and without negatively impacting people or the environment now and into the future?

To begin to be able to answer this question we needed to understand what value our customers and stakeholders place on electricity, and the way it is delivered across our network. Then, where possible, work with customers and stakeholders to understand possible future energy scenarios and outcomes so that we can make better decisions about how to manage the network efficiently and invest in the future, with the principle of delivering lower costs to customers.

Ultimately, we want to manage the network efficiently to deliver low-cost electricity while investing in the future.

To help drive the conversation and ensure we cover off all the important elements of the decision-making process the following conversation themes were developed:

- network performance
- pricing
- renewables
- connections
- community safety
- stakeholder engagement.

The themes, together with consideration of our ability to incorporate the feedback into our plans, led us to create a matrix that sets clear parameters around the engagement. It indicated what was or was not negotiable in the process, in other words what customers and stakeholders could or could not influence. It also guided us in determining the engagement techniques, target customers and stakeholders, and the breadth of engagement for each theme.

2.2.1 Phase one

The views and concerns of our stakeholders are vital to informing our future priorities and directions. In phase one, we first wanted to understand our customers' priorities and values to undertake meaningful and relevant engagement – now and into the future. We then took these insights to the Future Network Forum to inform the development of possible energy future scenarios.

Across phase one of the Energised 2021–2026 engagement program we engaged with a total of 2,583 customers. An additional 400 stakeholders were also engaged through this phase.

Table 2.3 Summary of phase one participation by engagement activity

Engagement activity	United Energy statistics
Survey of residential customers	603
Focus groups with residential customers	• 8 focus groups • total of 42 participants
Vulnerable customer engagement	• 1 focus group • 13 participants
Survey of small business customers	201
Interviews with commercial and industrial customers	A total of 15 were undertaken. Some of these customers are interested in more than one network, while others are network specific. There were 8 customers specific to United Energy. ANZ, Coca-Cola, Department of Education and Training, Epworth Hospitals, IXOM, Metro Trains, Telstra and Woolworths.
Stakeholder specific engagement	A total of 415 stakeholders were engaged through this phase through targeted engagement activities like meetings and workshops.
Future Networks Forum	A total of 33 participants with customer and stakeholder representatives from each of the three networks.

Source: United Energy

From the surveys, interviews and focus groups conducted we identified some overarching findings relevant to how we do business and engage with our customers:

- Our customers need to learn more about who we are and what we do.
- Our customers have a low level of understanding of electricity bills, tariffs and pricing in general.
- Our customers will not trade off reliability for cost savings.
- Around two thirds of our residential customers perceived their electricity bills to be too expensive.
- Our customers and stakeholders want to see the control put back into people's hands, with access to real-time data and customer centricity.
- Our customers wanted to have flexibility to choose how they use electricity, a dependable and safe network, and at an affordable price.

We also asked a series of questions to understand customers' values and priorities for electricity. In consolidating the customer values, we took the most recited and interrelated values from across all customer types (residential, small and medium business, and commercial and industrial customers):

- reliable supply in all conditions and at all times – no customers suggested that they would trade-off reliability for price

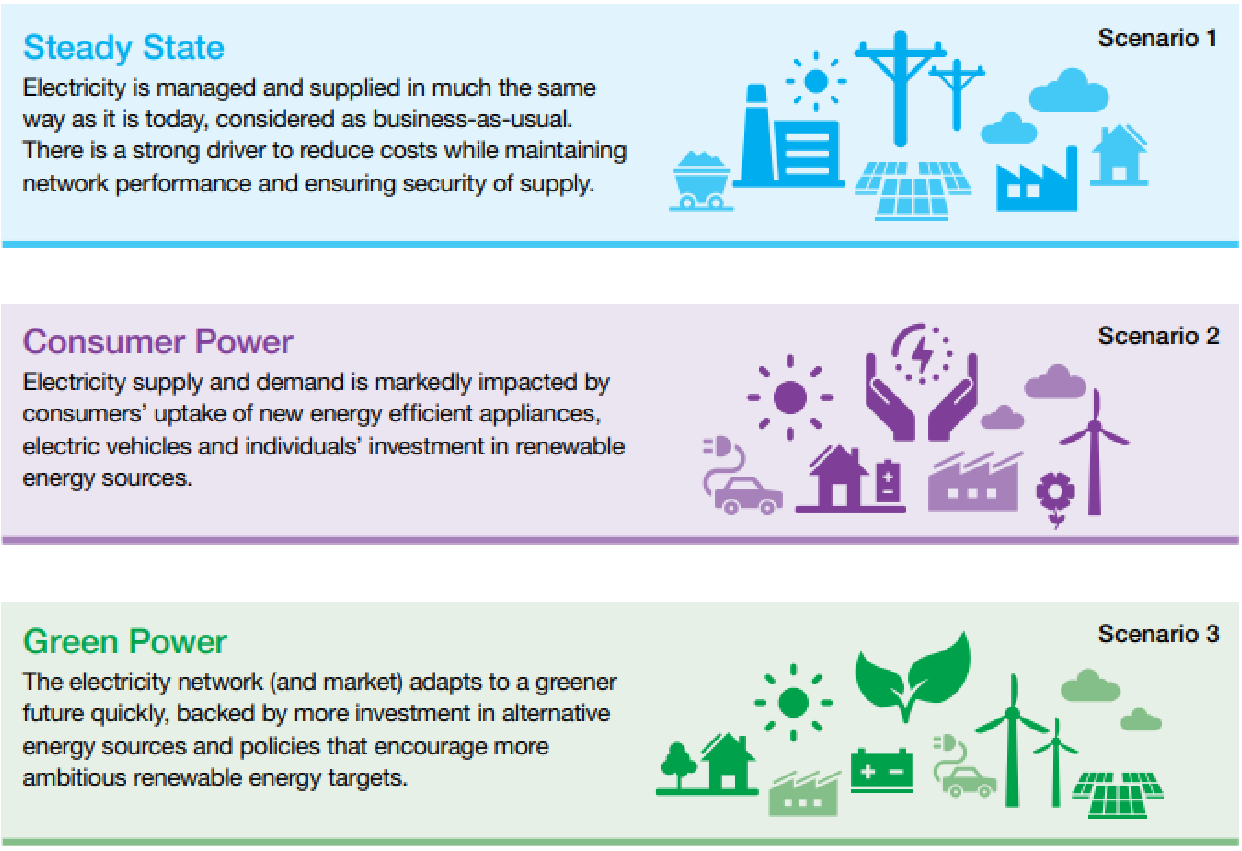
- an affordable supply of electricity that lowers bills and is fair for everyone
- customer service that provides choice for customers and up to the minute information and communications about supply
- safety for workers and the community
- quick response to supply issues, faults and outages
- sustainable network that support a greener future
- good maintenance to ensure the network stands up in all conditions
- power quality that limits spikes and surges (i.e. brown and black outs)
- discounts, incentives and programs to support people reducing their bills.

Energy future scenarios

During this phase we also co-designed energy futures with stakeholders to test with our customers.

At the Future Networks Forum, three possible future energy scenarios were presented to the participants. The participants reviewed the scenarios, suggested new scenarios, and selected their preferred and most likely scenarios to help us refine our modelling and inform the scenarios that we would take forward into phase two for further testing. The following scenarios were the outcome of the forum.

Figure 2.2 Future energy scenarios



Source: United Energy

To arrive at these three scenarios for engagement, we considered all feedback on assumptions and other possible scenarios, including:

- Green Power and Consumer Power hybrid scenario – some believed that the Green Power and Consumer Power scenarios should be merged into a hybrid scenario, as it was believed that a combination of these two scenarios was most likely to occur in the future.
- Low-Cost scenario – it was noted by several tables that all three scenarios assume a certain level of ongoing prosperity. Some suggested that a low prosperity option should be considered, where in order to reduce prices, investment into the networks would be at a lower level than in the Steady State scenario, leading to lower reliability, low innovation and low sustainability.
- Demand Destruction scenario – similar to the low-cost scenario, another table put forward a 'Demand Destruction' scenario. The main concern assumption in this scenario was around worsening wealth inequality, unaffordable housing and a high cost of living.
- Go Backwards scenario – there was also a 'go backwards' scenario put forward by some, in which there could be a radical change in government policy leading to greater support for fossil fuels, less investment in renewable energy and change to the network status quo.

2.2.2 Phase two

Through phase two engagement we tested, with our customers, the energy scenarios and value propositions developed using insights and feedback collected through phase one. These scenarios served as a mechanism to elicit feedback to directly inform our regulatory reset proposal. We wanted to know if the scenarios and value propositions reflected their views and to assist unpacking the potential social impacts of the different scenarios.

Across phase two of the Energised 2021–2026 engagement program we engaged with a total of 2,918 customers. An additional 290 stakeholders were also engaged through this phase.

Table 2.4 Summary of phase two participation by engagement activity and network

Engagement activity	United Energy statistics
Residential customer survey	601 surveys completed
Small to medium business customer survey	204 surveys completed
Deliberative forums	1 forum held in Mt Waverley with 77 participants
Interviews with commercial and industrial customers	6 interviews undertaken
Community opinion leader forums	1 forum delivered with a total of 17 participants
Investment options forum	38 participants with a mix of residents, small and medium businesses and opinion leaders
Stakeholder specific engagement	A total of 592 stakeholders were engaged through this phase through 243 targeted engagement activities.

Source: United Energy

This phase brought together feedback from customers about what is most important to them now, as well as what they wanted to see as part of the energy transformation – or their energy future. We needed to engage on the here and now to test whether values were consistent or changing, and whether they would impact our investment decisions. Customers articulated a future for a reliable and affordable network that allows for greater use of green energy.

Confirmation of customer values

Reliability and affordability continuously emerged as the key priority energy values for us to focus on. Customers want a reliable network at the most affordable price possible. Participants noted they do not have as much contact with distributors as their retailer, but when there are outages or issues to address, good customer service is expected.

Alongside reliability and affordability, some forum participants placed considerable importance on ensuring that network upgrades and maintenance activities are environmentally sustainable.

Preferred energy future

Our customers and stakeholders thought the engagement identified the Consumer Power and Green Power scenarios were the ones most aligned with their vision for 2025. In thinking about their energy vision and preferred scenario, participants felt it was highly likely that the future would bring more environmentally-friendly energy generation based on solar, wave and wind power. They expected to see the cost of batteries reduce paving the way for a higher uptake of battery storage at household and community levels. Microgrids were also seen as pivotal in future energy solutions.

Larger business and industry stakeholders showed a preference for a steady-state integrated with renewable energy and a measured reduction in tariffs by 2025 and improved power quality. Businesses are also looking for essential capital investment to maintain reliability and facilitate the transition to a flexible grid without 'gold plating' infrastructure.

Ultimately, stakeholders acknowledged Steady State as the immediate priority to reduce costs while maintaining network performance and security of supply. Over time however, increasing consumer power and interests in environmental factors were considered likely to lead to greater investment in alternative energy sources and policies that encourage more ambitious renewable energy targets.

Preferred investment options

In light of the findings, we identified six value propositions. We then invited participants from the forums back to consider several investment options for delivering the value propositions and tell us what they value the most. In August 2018, a total of 38 participants returned to the Investment Option Forum. For each value proposition, participants were briefed on what we had heard from customers previously, what is considered the key challenge in delivering the value proposition and three to four options for investment going forward.

The six value propositions were:

- making it easier to connect
- making it easier for customers to export solar and charge batteries
- making it easier for customers to use their energy data to make informed choices
- providing a safe environment for customers and workers
- providing a reliable supply of electricity
- maintaining energy affordability.

2.2.3 Phase three

We heard our customers' preferences and considerations in future energy scenarios in the last two phases. We then formulated our draft plan to capture what we had heard. In our draft plan, we included programs that work towards ensuring a provision of a safe network and a reliable supply. They also included programs that will make it easier for our customers to export solar and use batteries, make new connections and use data to make more informed energy choices.

A key priority of our draft plan was to keep prices low for our customers and design price structures that are fair and easily understood. In this phase, we particularly wanted to find out if the draft plan met their energy needs, and whether there were any trade-offs that might exist in electricity sources and supply.

Across phase three of the Energised 2021–2026 engagement program we engaged with a total of 2,918 customers. An additional 290 stakeholders were also engaged through this phase. Key elements of the phase included surveys, deliberative forums, as well as local community engagement in the form of a 'pop-up' stall, and an Open House forum with leaders from the community, politicians and other community groups to discuss the way that they receive essential services.

Table 2.5 Summary of phase three participation by engagement activity and network

Engagement activity	United Energy statistics
Residential customer survey	600 surveys completed
Small to medium business customer survey	203 surveys completed
Deliberative forums	1 forum held in Glen Waverley with 36 participants
Interviews with commercial and industrial customers	10 interviews undertaken
Community pop ups	1 pop up held in Melbourne with reported foot traffic of 220,000
Open house forums	16 local government representatives and alliances engaged in 1 forum
Vulnerable customer campaign	292 vulnerable customers engaged during 18 events
Vulnerable customer focus groups	13 participants in 1 forum
Quiz	58 quiz completed
Stakeholder specific engagement	A total of 592 stakeholders were engaged through this phase through 243 targeted engagement activities.

Source: United Energy

Dedicated engagements on our draft plan were held with culturally and linguistically diverse (**CALD**) and financially vulnerable customers. The selected customers were high on the relevant socio-economic index indicating that they were disadvantaged compared to others. Through deliberative forums, there was a high level of support from all participants for a proposal that delivered a safe and dependable network.

We also sought to understand our customers' prioritisation of preferences on improvements and trade-offs. We used the innovative approach of a mock bill calculator in our surveys to obtain their selections. Through this process, we found that our customers were most seeking improvements in:

- enabling solar export
- investing in new technology
- pole replacements.

There was support, although not as strong, for investments for access to data, resilient network and the speed to answer calls.

2.2.4 Phase four

The outcomes from all engagement have been incorporated into our decision-making and form the basis of our proposal. The proposal also illustrates where engagement has led to changes from the draft plan. Particularly, the changes influenced directly by the engagement outcomes include:

- increases in the costs for the supply of network services to deliver a resilient network that maintains reliability and improves the safety of our communities
- decreases in network charges for customers so their bill reduce in the 2021–2026 period meeting our target of an affordable supply
- investment in integrating more distributed energy resources and technology to support our customers' choice and access to new products and services.

2.3 How we used feedback in decision-making

At the conclusion of each phase for engagement we took stock of customer feedback. We ensured that every piece of feedback we received was responded to – either with a change, and action or a rationale – to ensure customers and stakeholders knew we were using their feedback.

Over time, and throughout the engagement, it became clear that the key priorities for our customers and stakeholders is that they want a network that is resilient, flexible and affordable.

The table below provides an extensive analysis of our engagement process, the feedback we received at each phase and how we responded to feedback during Energised 2021–2026.

Table 2.6 How we used the feedback

Phases	Approach	Outcomes	Our response
Explore customer values and priorities	• surveys • focus groups • interviews • online tools	Our customers needed to learn more about who we are and what we do. Our customers won't trade off reliability for cost savings. Around two-thirds of residential customers perceived their electricity bills as too high. Customers and stakeholders want to see the power put back into people's hands, with access to real-time data and a customer-centric focus.	Strengthened our communications to build awareness and a level of trust—eNews, Talking Electricity, advertising and podcast Maintaining our position as one of the most reliable networks in Australia with the network being available for over 99.99% of the year Ensuring we maintain our position as one of the most efficient networks in the NEM Commitment to deliver a customer service strategy and improving our customer-facing applications for outages, faults and consumption data
Explore scenarios for our energy future	• EFCAP • CCC • citizen-led deliberative forums • workshops, surveys and meetings	Customers have a vision for a greener future, and 75% of them thought the network should be upgraded faster than is planned, to allow for renewable energy. The preferred energy future was a steady and progressive integration of renewable energy with a measured reduction in tariffs, by 2026, and improved power quality (fewer power fluctuations)	Began developing a vision for our network that reflects our customers and stakeholders' expectations, including a progressive integration of renewables Identified future technologies at the network and community level that are likely to be integrated onto the network Identified how customer choices can be improved, including through enabling their access to more useful data Developed pricing principles to guide our decision making for tariffs
Sense checking our draft plan	• EFCAP • CCC • second round of citizen-led deliberative forums assessing investment options • deep-dives with stakeholders • workshops, surveys and meetings	Customers agreed on their values for electricity: • Providing a reliable supply of electricity • Maintaining affordability • Committing to providing a safe environment for customers and workers • Using electricity when you want or receive savings for reducing use • Committing to providing a safe network • Keeping your data and our network secure • Making it easier for you to export solar and charge your battery • Making it easier for you to connect • Making it easier for you to use your data to make informed choices	Combined reliability and safety into resilience to demonstrate their interrelatedness Committed to network price reductions Commenced consultation on time-of-use pricing structures that will support and encourage the integration of new technologies on the network Developed a vulnerable-customer campaign to improve energy and bill literacy Developed initiatives to increase the network's ability to accommodate renewables and customer-driven technologies Developed initiatives to deliver customer benefits through improved digitalisation and visibility of the low voltage network Developed initiatives to better enable customers to have easier access to their data and to make more informed choices Tested various options with customers on how we can address their needs, including presenting options and bill impact of each option

Phases	Approach	Outcomes	Our response
Preparing our proposal	• release of the draft plan • EFCAP • CCC • third round of citizen-led deliberative forums on the draft plan • deep-dives with stakeholders • workshops, surveys, meetings • open-house • community displays • podcasts	Draft plans were generally supported, particularly: • Unlimited exports for solar customers • Investing in new technology to improve reliability safety, and encourage renewable generation • Providing access to data that tells people how much energy they use at different times of the day and how much each of their appliances cost to run • Multi-modal communications about outages, faults, programs and our services	Finalised our vision for the network that reflects our customers and stakeholders' expectations, including a progressive integration of renewables and maintaining or improving existing services at least cost Redesigned our solar approach and finalised the business case through extensive consultation with wide variety of key stakeholders on options analysis and analysing customer benefit streams Finalised the business case for improved digitalisation and visibility of the low voltage network, ensuring we continue to deliver a reliable network at least cost and through deferred augmentation Finalised our business case for customer enablement using extensive feedback on customer preferences regarding access to their data Finalised our proposal for time-of-use pricing with a slower transition path to ensure all customers are supported through tariff reform

Source: United Energy

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3

Our energy future

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3 Our energy future

The way our customers are using our network is changing and so we are adapting to meet their needs now and in the future.

We are investing and innovating to prepare for our shared energy future. Customers have articulated a future for a reliable and affordable network that allows for greater use of green energy. They support programs that will make it easier for them to export solar and use batteries, make new connections and use data to make more informed energy choices.

Australia is increasingly shifting towards more environmentally-friendly energy generation based on solar, wave and wind power, together with greater use of electric vehicles and batteries. The uptake of these new innovations presents us both with new opportunities and challenges in managing the network. We will invest to enable greater export of solar onto our network, and explore the use of energy storage technology.

We will build on the foundations provided by the deployment of smart meters in our network, and further utilise their enhanced capabilities and functionality to provide greater information to our customers to support their energy choices. Together with other new technologies, we are also finding ways to better manage our network.

The world doesn't stand still and neither are we. We are excited to plan for a shared energy future with our customers.

3.1 Customers have told us their energy future

Our customers are looking to more actively participate in their energy future. They are generating, storing and exporting more electricity back into the network, marking one of the most significant transformations in the electricity industry of recent times.

Customers also want to become more involved in new demand response programs, searching more actively for the best energy prices. New market developments will support customers engaging in peer-to-peer trading whilst new technology, such as electric vehicles, will reshape future customers' energy requirements.

At the same time, customers still expect us to prioritise safety and affordability.

These changes will create better outcomes for everyone but will also make network management more complicated. As a result, we are researching, innovating and investing in new and existing technologies now to deliver the network that ensures we can meet the opportunities and challenges of tomorrow.

Figure 3.1 Our initiatives are helping to unlock new value for customers now and in the future

Customer outcomes	Ensure safety and reliability	Lower costs through efficient network management	Enable more solar exports	Support prosumers
Emerging	Asset condition monitoring LV phase identification	Electric vehicle charging optimisation Electricity theft detection	Network optimisation e.g. transformer tapping Phase rebalancing	Peer-to-peer trading Solar health notifications Streamlined customer portals
Developing	LV asset failure prediction	Demand Response programs	Dynamic voltage management	Community energy projects
Existing	Remote reconnection Neutral fault detection Streamlined connection requests	Remote meter reading New wood scan practices Vegetation management using LiDAR	Voltage and load management	Energy usage dashboards

Enablers	AMI Meters	New technology	Government policies	Industry partnerships	Engaged consumers

Source: United Energy
Note: Some initiatives can cover multiple categories (e.g. demand response programs support prosumers as well as lowering costs).

3.2 We are supporting the uptake of renewables

Australia is increasingly shifting towards renewable innovations such as solar, electric vehicles and batteries. The uptake of these new innovations presents us both with new opportunities and challenges in managing the network.

3.2.1 Growth in solar

Penetration of rooftop solar systems is increasing as it becomes more accessible to customers, through technological innovation, declining costs of renewable generation and battery storage and improvements in the way distributed energy resources (**DER**) is reliably integrated into the network.[7]

Residential customers, businesses and cities are increasingly driving this uptake in order to receive more reliable, affordable and cleaner energy.[8]

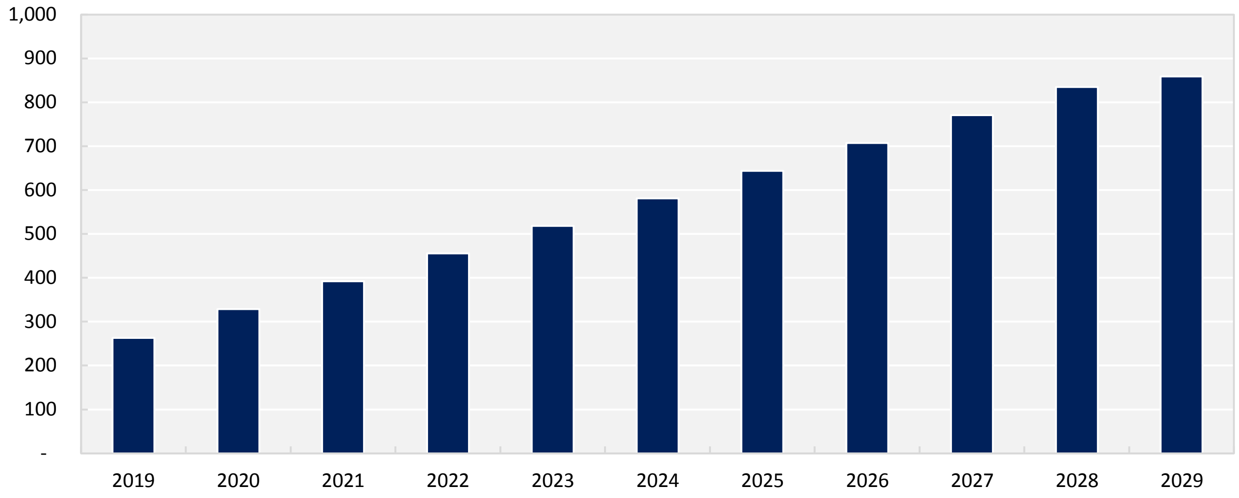
Growth in solar uptake is also being supported by government policies. The Victorian Government recently committed $1.2 billion to support the installation of solar panels on 650,000 Victorian households over 10 years.[9] It has also committed to a $40 million program to provide half-price solar batteries for 10,000 Victorian households to encourage uptake and micro grid development.[10] This is in addition to previous investments made through Victoria's Renewable Energy Action Plan, including allocation of $25 million to build commercially-ready battery storage in western Victoria.[11]

[7] UE ATT148 - Deloitte - Global renewable energy trends - Sep2018 - Public
[8] UE ATT148 - Deloitte - Global renewable energy trends - Sep2018 - Public
[9] UE ATT150 - OP - Cutting Power Bills With Solar Panels - Aug2018 - Public
[10] UE ATT151 - VicGov - Victorian infrastructure plan - Oct2017 - Public
[11] UE ATT147 - VicGov - Renewable energy action plan - Jan2020 - Public

The capacity of installed solar on our network is forecast to more than double by 2026 with solar penetration growing from 11% today to 23%. That is, around 63,000 new solar photovoltaic (**PV**) systems will be installed between 2021 and 2026. This is consistent with the impact the Solar Homes program is already having with our monthly solar connections increasing by 111% from previous levels. The forecast of residential solar uptake is shown in Figure 3.2.

More than half of residents and businesses are interested in solar export and 64% of residents believe the network should be upgraded more quickly to allow for more renewable energy connects and export

Figure 3.2 Cumulative solar uptake (MW)



Source: UE BUS 6.06 – Solar enablement –Jan2020–Public

Solar challenges the traditional one-way operation of the network creating two-way energy flows that can create technical problems. Where solar energy is not fully consumed by the customer the excess energy flows back onto the network in reverse flows, pushing up voltage levels. This in turn can create poor power quality.

To help customers to export more solar in future, we will use a range of solutions including:

- network upgrades and augmentation
- network optimisation such as transformer tapping and phase rebalancing
- non-network solutions such as voltage management and new inverter settings.

Through these solutions we will remove solar constraints in an affordable way so that most customers can export up to 5kVA. Where it is not cost effective to remove solar constraints, we will support customers to optimise their solar through Digital Network initiatives. This will allow us to unlock over 95% of the solar that would otherwise be constrained while maintaining affordability.

As well as enabling customers to generate and consume their own solar, this benefits all customers through replacing higher cost generation which places downward pressure on electricity bills for all our customers, regardless of whether they have their own solar panels or not.

3.2.2 Growth in electric vehicles

There has also been strong growth in electric vehicle uptake. In 2017, 2,284 electric vehicles were sold in Australia, resulting in a 67% increase from 2016, with Victorian purchases of 1,324 vehicles marking the highest uptake of any state or territory. [12]

We expect sales of electric vehicle in Victoria to increase eight-fold from 5,863 vehicles to 55,876 vehicles between 2021 and 2026.[13] This is supported by the increased choice customers will have over the range of vehicle models, the price points of electric vehicles on offer, both in the premium range and the $60,000 or under category, and the number of charging stations continue to grow in Australia, equating to approximately one charging station for every six electric vehicles.[14]

Electric vehicles can put pressure on network operations as they can alter peak load profiles so that they are less predictable, making network planning more difficult.

3.2.3 Growth in energy storage

Australia is expected to be one of the largest markets for battery storage in the future. This is due to the high cost of electricity, the large amount of solar uptake and the decreasing costs of battery storage, which have fallen by 80% between 2010 and 2018, and are predicted to halve again by the start of 2026.[15]

A number of networks are also conducting battery trials to help manage local network constraints and prolong the lives of existing assets, as demonstrated by the case study below.

United Energy's battery energy storage system (BESS) trial

Driven by the rapidly falling price of battery energy storage systems, we in partnership with ARENA are exploring using energy storage technology.

Under this trial, United Energy will deploy a medium-sized BESS ranging between 50kW and 100kW adjacent to distribution transformers. The BESS will be customised to address network constraints on the chosen distribution transformers.

3.3 We are innovating and using new technologies

We are preparing for our shared energy future by building on the foundations provided by the deployment of smart meters in our network, and further utilising their enhanced capabilities and functionality. We are also harnessing the opportunities that new technology provides and investing, innovating and using these new innovations to better manage our network.

3.3.1 Creating a smarter network

Victoria has full penetration of smart meters across our residential and small business customers. These meters underpin the network transformation journey from a traditional grid to an intelligent, responsive two-way

[12] UE ATT146 - CW - The state of EVs in Australia - Jun2018 - Public

[13] UE ATT144 - AEMO - 2019-20 integrated system plan - Dec2019 - Public

[14] UE ATT146 - CW - The state of EVs in Australia - Jun2018 - Public

[15] UE ATT145 - CC - Renewables and Storage Powering Australia - Feb2018 - Public

network where information and data flows enable us to support the choices that customers make. This puts us in a unique position compared to distributors in the rest of the world.

Smart meters provide us with the ability to:

- streamline the connections process and lower bills by allowing for remote connections and meter readings
- improve safety by identifying neutral faults at customer premises
- enhance supply through better automatic detection and dispatch, and rotated load shedding on peak demand days.

91% of customers support using smart meters to manage the network

These activities have enabled us to build the capabilities, skills and experience to monitor and run the network dynamically so we can enhance existing services and offer new services to customers in the future.

In the 2021–2026 regulatory period, we will selectively extend the range of our smart meters i.e. large customers and unmetered supply. This will provide us with greater visibility of the low voltage (**LV**) network. It will allow us to manage the network more efficiently in real time, through better forecasting, monitoring, diagnosis and eventually through automating capabilities, including:

- Promoting the uptake of new technologies: for example by allowing us to monitor the impact of increasing electric vehicle penetration on demand and optimise charging away from peak times. This will facilitate the uptake of electric vehicles while mitigating the risk of excess demand at peak times, preventing the need to augment the network and keeping network costs down for all customers.
- Optimising load control of customer appliances: optimising existing hot water load control and enabling new load control programs (e.g. air conditioners, pool pumps, fridges), including through utilising excess solar in the middle of the day. This will defer network augmentation, ultimately reducing customer bills.
- Enhancing cost reflective pricing: analysing smart meter data to construct more effective time-of-use tariffs or demand response to reduce peak demand and improve overall utilisation of the distribution network. This will defer network augmentation and reduce customer bills.
- Improving the equity of energy usage: identifying sites with bypass connections to reduce theft and monitoring variable unmetered supply to ensure energy usage is allocated fairly between customers and reduce average network charges per customer. Reducing energy theft will also improve safety through deterring this behaviour in future.
- Proactively managing asset failures: develop greater predictive capabilities for asset condition to better determine when assets will fail, resulting in lower customer bills through less network augmentation and avoided replacement expenditure.
- Avoiding overblown fuses: improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacing blown fuses.
- Looking after vulnerable customers: more accurate mapping of customers to the network will allow us to keep more life support customers connected during outages and provide more accurate communications to customers of planned outages.
- Keeping customers safe: improving the way we identify loss of neutral at customers' homes, which can pose major safety issues of electric shocks if left unchecked.

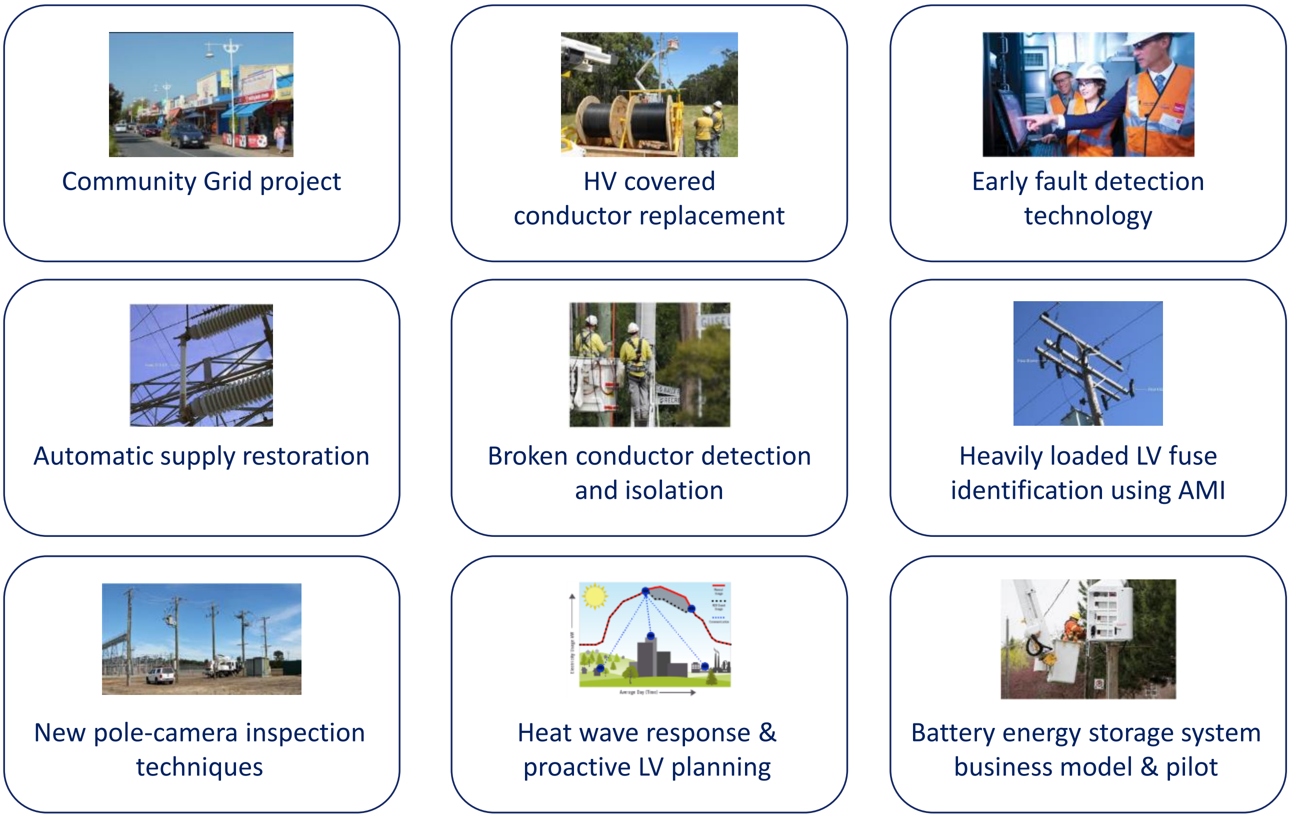
Our customers had strong views that safety should be maintained and improved across the network where possible

We commissioned Jacobs to quantify the benefits to customers of different options for extending the coverage of our smart meters. Jacobs determined that rolling out both technology and extending our device coverage would provide the largest net benefit to customers over the long term, equivalent to $89 million over a 20 year period.[16]

3.3.2 Managing assets in smarter ways

To keep up with changes in our network and our environment we are continuously seeking out the best in asset management practice. This includes harnessing the opportunities that technology provides and collaborating with industry partners.

Figure 3.3 Snapshot of current network management initiatives



Source: United Energy

For example, we have embarked on a partnership with Swinburne University to find new ways of assessing the health of our limited life poles in less invasive and more effective ways as well as developing new procedures to optimise how we manage them. This will allow us to extend the life of our assets and pass on lower costs to customers while ensuring the safety of our employees and the community.

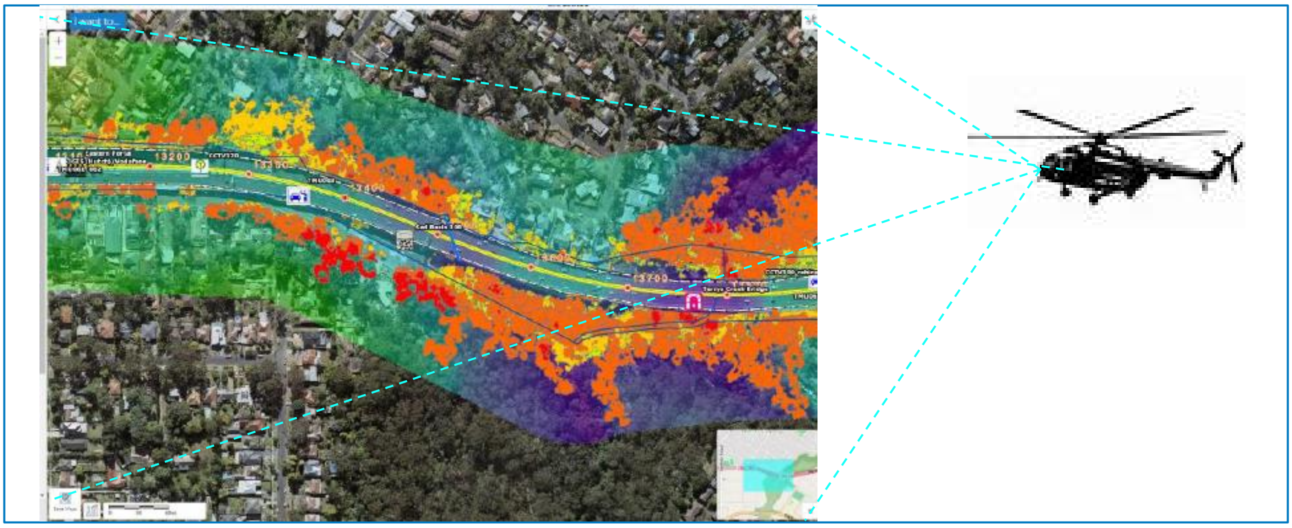
Together with a number of universities, we are conducting research and collaborating on major initiatives to improve network asset management. The relationships with these universities have been developed directly and indirectly through Energy Networks Australia and the Australian Power Institute

16 UE ATT009 – Jacobs–Digital network benefit–Dec2019–Public

We were one of the first distributors in the world to implement dynamic voltage management system (**DVMS**) technology, supported by ARENA funding. These benefits included demand response for Australian Energy Market Operator's (**AEMO**) reliability and emergency reserve trader (**RERT**) scheme, improvements in steady state voltage compliance for our customers, and increased solar hosting capability.

Light detection and ranging (**LiDAR**) has been implemented to assess line clearances and applying analytics to determine where cutting is required, or reduce unnecessary cutting, across our 1,472 m^2 network. LiDAR involves emitting a laser light and measuring the reflected light pulses in order to make digital representations of target areas.

Figure 3.4 Example of LiDAR data visualisation to identify vegetation growth



Source: United Energy

3.4 We are improving the way in which our customers can engage with us

Technological development in how organisations capture and display data across a number of industries including health and finance means consumers can access more information about products and services. Through sharing energy data with our customers, we are helping them to take more control of their energy usage.

Through use of this energy data, many of our customers are becoming interested in participating in demand response. This may involve distributors incentivising customers to decrease energy usage during peak events in order to address network constraints and help manage assets.

3.4.1 Greater use of demand response

As seen below, we are leading the way in rolling out behavioural and demand response programs.

Table 3.1 United Energy current period demand response programs

Program Name	Technology/Solution	Capacity	Target audience
Dynamic voltage management system	Voltage management at a zone substation level to reduce demand on the grid during peak periods and assist with steady state voltage Sponsor: ARENA	30MW – 42MW	All customers
Summer Saver (demand response mobile application)	Behavioural demand response for residential customers on specific distribution substations and low voltage circuits in the United Energy service area	2MW	Residential customers on specific distribution substations
Community grid project	Demand response and generation program to provide network support services for the lower Mornington Peninsula	13MW	Commercial and industrial participants on the Mornington Peninsula
Solar-storage project	Contracted residential customers with solar/storage systems to provide demand reduction to avoid periods of load shedding due to a lack of network capacity Sponsor: ARENA	0.5MW	42 residential customers on specific distribution substations
Commercial/industrial load control	Contracted commercial and industrial customers to provide demand reduction to avoid periods of load shedding due to a lack of network capacity	2MW	Commercial and industrial participants

Source: United Energy

We have been recognised within Australia and internationally for our work to establish the Summer Saver residential behavioural demand response program in 2014. Over 1,000 customers are participating each year to provide demand response at constrained distribution substations throughout our network, resulting in $10 million capital expenditure deferrals.

As we learn more about how our customers want to engage in demand response, greater numbers of customers are participating and are consistently using less energy during critical periods.

64% of customers are interested in participating in demand response programs

In order to maximise the savings these programs can deliver, we are constantly investing in understanding our customers better through various partnerships including:

- RACV channel partnership to test and learn from different brand associations and marketing channels.
- CitySmart and Queensland University of Technology research project linking load profile analysis to customer archetypes to refine customer value propositions and messaging for demand response programs.
- Deakin University project to engage focus groups to research technology adoption by customers.

We will continue to engage customers as we expand our demand response programs across our networks over the 2021–2026 regulatory period.

3.4.2 Empowering more informed and more engaged customers

As part of our demand response programs, we will also continue to learn more about how our customers want to engage with us through:

- implementing consumer segmentation research to increase customer engagement and drive better network outcomes
- understanding customer motivations and drivers so that existing and future programs incorporate their needs and expectations
- working with network planners to ensure we target the right customers in those areas of most need
- identifying the partners to help us build scale and develop programs that provide meaningful value to customers and the network.

We expect the popularity of demand response to grow over time as we continue gain insights into how our customers want to participate

Our investment in the customer enablement program will enhance the way in which customers can engage with us. It will improve customers' ease of access to our online services, such as myEnergy through consolidating our existing portals into a 'one-stop-shop'. By implementing our online connections portal, mySupply and myEnergy, customers will be able to access usage data and submit network upgrade or extension requests online, replacing the current paper-based system. We will also provide new ways for customers to engage with us such as by allowing customers to check the status of requests online and through implementing an artificial intelligence-powered 'click and chat' function so customers can talk to us in the way that suits them.

Our customers see a one-stop-shop as simplifying their lives and providing them with information to make better decisions

Our Energy Easy dashboard allows our business and residential customers to gain greater visibility of how they use energy over time, see how this compares to their neighbourhood average and use this data in the Victorian Energy Compare website to compare retail offerings and get the best energy deal. Energy Easy also allows customers with solar to see how much they are exporting back onto our network.

By facilitating customer access to their energy data, we are supporting the Australian Government's consumer data right, which aims to facilitate customers to more easily compare and switch between energy retailers for example, stimulating competition, and resulting in lower prices and better service for our customers.

3.4.3 Supporting our more vulnerable customers

As our energy system evolves, there is a danger of leaving behind ‘vulnerable’ customers. We recognise the need to support all of our customers as we continue to provide a safe, reliable, flexible, and affordable grid infrastructure. As the regulated electricity distributors for over half of the state, we can provide access to unbiased advice and insights to help Victorians manage their electricity spend.

We are currently exploring opportunities for outreach to residential customers who are economically vulnerable in our service areas.

> *“We’re in a great position to provide facts to residential customers who are struggling to pay their electricity bills because of where we sit in the electricity supply chain and our strong relationships with local communities”*
>
> *Ruchika Deora, Strategic Marketing Manager, CitiPower Powercor and United Energy*

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4

Replacement

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4 Replacement

We take great pride in the role we play in providing an essential service for our communities—a safe and dependable network service is critical each and every day. Our network is one of the most reliable in Australia, being available for over 99.99% of the year, or less than 45 minutes off supply per annum on average for our customers. Since 2013, we have also reduced the number of ground fire starts from our assets by 34%, and driven a 71% reduction in public safety incidents, consistent with our obligation to reduce safety risk as far as practicable.[17]

Our replacement investment in the 2021–2026 regulatory period to continue to provide a resilient network has been informed by insights from our ongoing stakeholder engagement program:[18]

- we are ensuring the long-term sustainability of our pole replacement program by proposing additional risk-based pole replacements, focused on lower durability poles in high bushfire risk areas
- we are leveraging our smart meters to reduce safety risks as far as practicable, including using analytics to proactively detect hazardous service lines
- we are continuing to effectively reduce the risk of bushfires from our network by replacing assets in high bushfire risk areas, such as removing expulsion drop-out fuses—our customers hold strong views that safety should be a top priority, and our fire prevention plan has been accepted by Energy Safe Victoria.

We will also continue to lead the industry with new research and innovation. This helps us make efficient, data-driven decisions to replace our poles, wires and major electrical plant inside our zone substations. We have a long history of partnerships with a number of universities across Australia to identify better ways to manage our assets, including:

- in partnership with Swinburne University, we have tested the strength of our pole cross-arms that carry our lines to understand when they may break
- working with Victoria University and the DELWP to remotely identify broken lines, so we can turn off power quickly to mitigate safety and bushfire risks
- working with the University of Queensland to better manage the life cycle of power transformers.

In addition to making greater use of our smart meter capabilities and functionalities, innovation was something our customers said they expected from us during our stakeholder engagement process.

Affordability was a common theme from our customers as well. To ensure our regulatory proposal reflects efficient replacement investment, we carefully quantify and assess risks to our customers. For example, we consider safety, reliability, financial, bushfire and environmental impacts when making investment decisions. We only invest in replacing assets when the probability weighted cost of these risks exceeds the value of the least-cost intervention.

In total, more than half of our forecast investments are supported by business cases and/or risk monetisation models. This includes all major zone substation transformer and switchgear replacements. Our approach to quantifying risks is consistent with the AER's replacement planning practice note.[19]

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17 *Electricity Safety Act 1998* (Vic)

18 As set out in the stakeholder engagement chapter of this regulatory proposal, our engagement program included a series of deliberative forums and customer surveys. These insights were presented in our draft plan, and discussed during our risk management deep-dive.

19 UE ATT099 - AER - Asset replacement planning - Jan2019 – Public

This chapter outlines our investment in the 2021–2026 regulatory period to replace existing assets:

- in section 4.1, we outline the services our forecast investment will allow us to deliver
- in section 4.2, we provide further detail on our approach to developing our investment forecast, including our asset management practices and risk monetisation process.

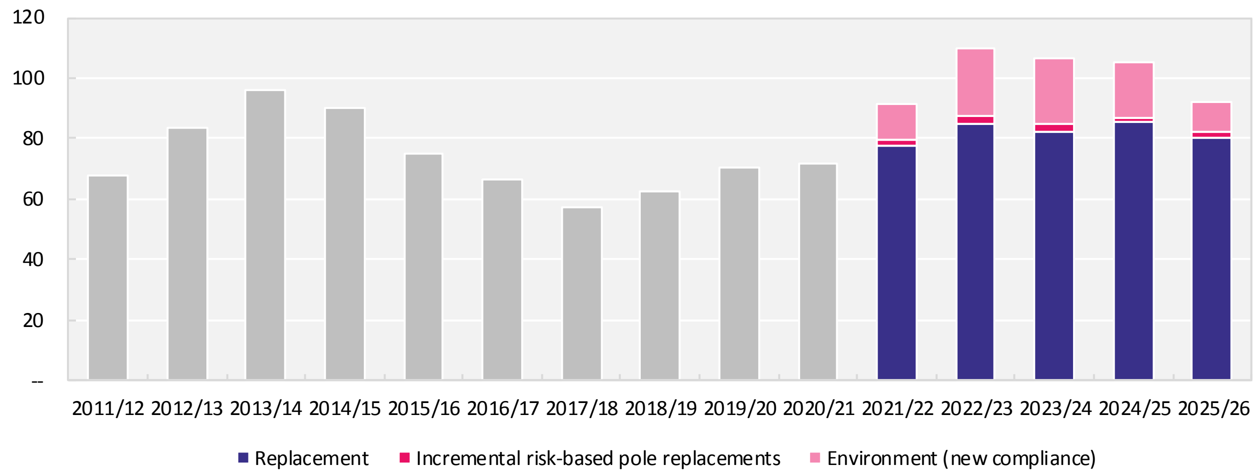
The replacement of existing assets occurs as the condition of our network infrastructure deteriorates over time, and investment is required to continue to meet our network safety, reliability, bushfire mitigation and environmental obligations. This is consistent with the capital expenditure objectives, criteria and factors set out in the Rules. Table 4.1 and figure 4.1 provide an overview of this investment over previous and future regulatory periods.

Table 4.1 Network investment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Replacement investment	91.4	109.8	106.6	105.1	92.0	504.8

Source: United Energy
Note: Forecast includes real escalation and excludes network overheads

Figure 4.1 Forecast investment to replace existing assets ($ million, 2021)



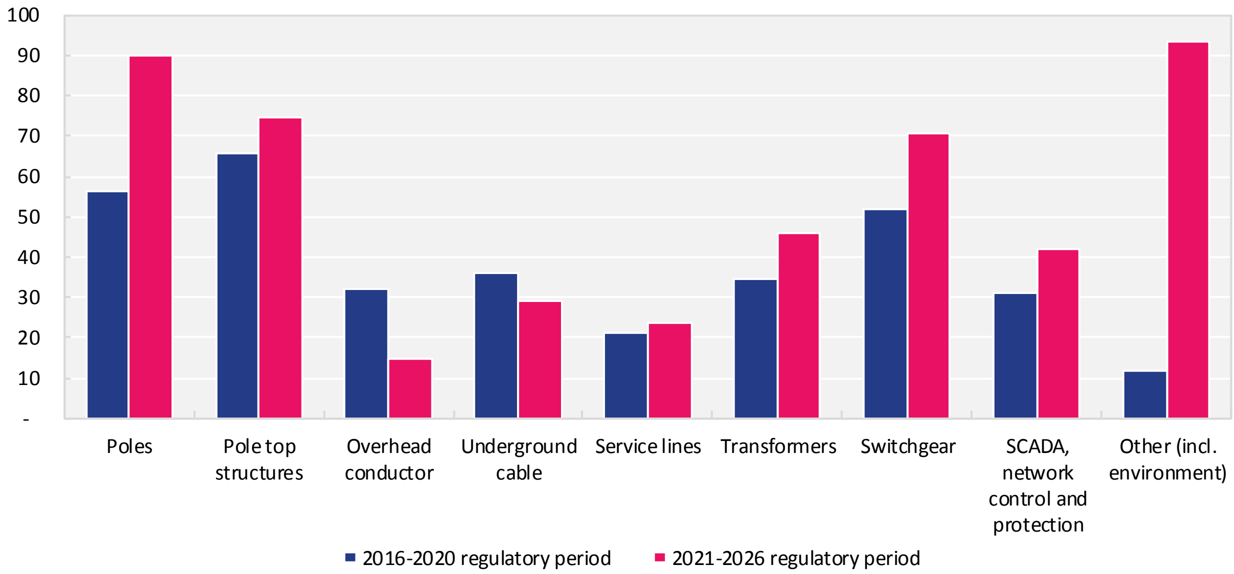
Source: United Energy
Note: Figure includes real escalation and excludes network overheads

The primary drivers of our forecast increase in replacement investment relative to our historical program are changes to:

- our pole replacement program
- environmental compliance obligations.

Our transformer and switchgear investment is also increasing, reflecting our ageing transformer population and the increasing consequences of asset failure over time (recognising we are the second most highly utilised distribution network in Australia, meaning the unserved energy at risk is high). A comparison between our historical and forecast regulatory periods, at the asset category level, is shown in figure 4.2.

Figure 4.2 Historical and forecast replacement investment by RIN category ($ million, 2021)



Source: United Energy
Note: The investment required to meet our environmental compliance obligations is included in the 'other' category
Figures exclude real escalation and network overheads

Our replacement investment forecast has also increased from our draft plan. This is primarily due to the inclusion of additional pole replacements, and a re-classification of some communications investment (from augmentation) to better align with the nature of the underlying works.

The justification for our replacement investment is supported by a series of forecast overview documents and risk models. These are summarised in table 4.2, and cover nearly $250 million of our total investment.

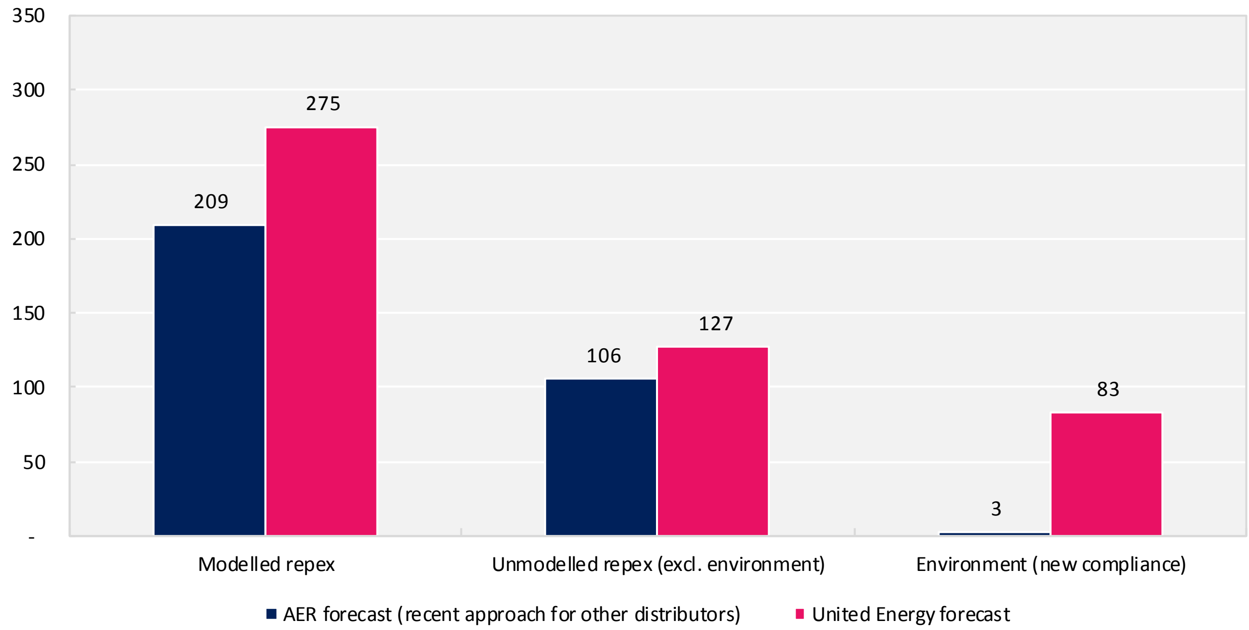
Table 4.2 Summary of material business cases: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Pole replacements: forecast overview	90.2
Zone substation transformer replacements	32.1
Zone substation switchgear replacements	19.5
Service line replacements	23.9
Environmental management program	82.7
Total business cases	**248.4**

Source: United Energy
Note: Forecasts exclude real escalation and network overheads

We have populated the AER's repex model, and have compared the outcomes of this approach to our investment forecast (shown in figure 4.3). As discussed in section 4.2.5, our forecast exceeds the AER's estimate however the key differences relate to transformers and switchgear.

Figure 4.3 Comparison of AER's recent approach to other distributors against our regulatory proposal ($ million, 2021)



Source: United Energy
Note: Forecasts exclude real escalation and network overheads

4.1 What we plan to deliver

To ensure we continue to supply the households and businesses within our communities with the electricity required to power their activities, we commit to providing the following over the 2021–2026 regulatory period:

- safe environment for our customers and workers (including mitigating bushfire risks)
- reliable supply of electricity.

We will deliver this safe and reliable network service at the least life-cycle cost.

The safety of our communities, and that of our workers, is our first priority—we never compromise on safety. We ensure our workers are extremely well trained, and our asset management practices are based on international standards.

Some network assets, however, can fail without warning and may pose a safety threat. We undertake a range of activities as part of our asset management practices to reduce the likelihood and impact of asset failures. For example, we undertake proactive, safety-driven replacement programs when we identify deficiencies in families of assets, or when new technology enables us to better mitigate risks. This is consistent with our regulatory obligations to design, construct, operate, maintain and decommission our network to minimise as far as practicable (**AFAP**) the hazards and risks to the safety of any person arising from the network.[20]

[20] *Electricity Safety Act 1998 (Vic)*, section 98

Our forecast replacement investment for the 2021–2026 regulatory period includes our ongoing and proactive safety-driven programs, and our fire prevention plans. These programs which support the delivery of a resilient network are discussed below.

4.1.1 Pole replacement program

Poles are essential to an overhead electricity distribution network. Their basic function is to support overhead electrical conductors and other pole mounted assets, and to provide safe clearance from the ground and other adjacent objects (including vegetation).

Our electricity network comprises almost 170,000 poles, mostly constructed of wood. We inspect our pole population in accordance with our legislated inspection requirements.[21] Our inspection practices include the use of innovative technologies, such as Woodscan, to improve the accuracy of our asset intervention decisions.[22]

Our existing asset management approach for poles reflects a condition-based replacement program. To date, this approach has resulted in our network having amongst the lowest wood pole failure rates in Australia.

Notwithstanding our historical low failure rates, recent industry experience demonstrates heightened probabilities and consequences of failures focused on lower durability pole types. This includes ESV's recent review of Powercor's wood pole management practices, in which the regulator supported changes to assumptions regarding the fibre-strength of wood poles (e.g. it has been long-standing industry practice to assume the fibre-strength of a wood pole would be the same in year one as it would be in year 100).[23]

Condition-based replacements alone also mean our wood pole population is ageing. In the absence of additional interventions, the continued ageing of our wood pole population is expected to result in an upward trend in the number of failures of both our LV and HV poles.

As a prudent network operator, the above factors have driven further consideration of our own pole management practices. As a result, we propose to supplement our condition-based replacement and reinforcement program with age-based factors to recognise that the fibre-strength of a wood pole will deteriorate over time. The focus of this incremental program is on our lower durability poles located in higher consequence areas.

The impact of our incremental pole replacement volumes relative to our underlying condition-based trend is shown in figure 4.4. Our condition-based pole replacement volumes, including staking, have been forecast based on a linear trend of historical replacement volumes. The upward trend in condition-based replacements is consistent with the continued ageing of our wood population. Our incremental program has been forecast based on existing condition data.

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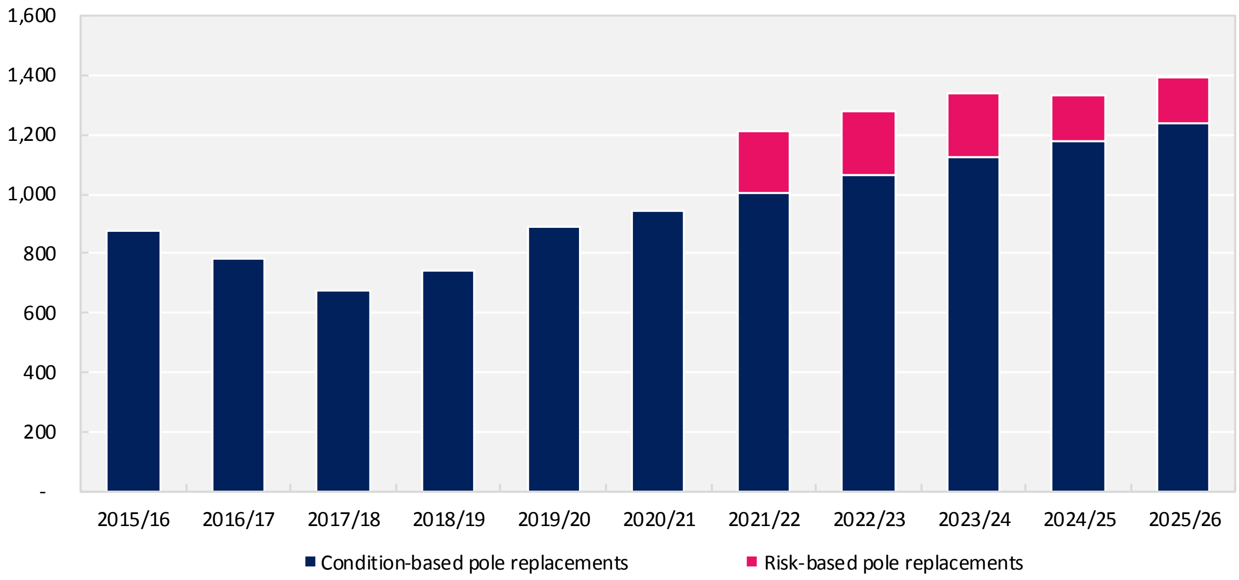
21 *Electricity Safety (Bushfire Mitigation) Regulations 2013* (Vic)

22 Woodscan is an ultrasonic scanner measuring pulses travelling between 12 contact points around the pole to detect if there are any defects inside the pole.

23 UE ATT153 - ESV - Wood pole management - Dec2019 – Public

Figure 4.4 Forecast wood pole replacement volumes



Source: United Energy

A summary of our forecast pole replacement investment is also shown in table 4.3. This includes interventions on a limited number of concrete poles that are not connected to a common-multiple earth neutral (**CMEN**), and as such, may pose a safety hazard. Further details on our asset management approach, and the full justification for our pole replacement program, is set out in our pole replacement forecast overview document.[24]

Table 4.3 Total pole replacement investment ($ million, 2021)

Description	2016–2020	2021–2026
Condition-based pole interventions (replacement and reinforcement)	53.4	75.1
Concrete poles	0.4	3.9
Risk-based pole replacement program	-	11.2
Total	**53.8**	**90.2**

Source: United Energy
Note: Figures exclude real escalation and network overheads

4.1.2 Zone substation transformer replacements

To ensure we provide a reliable supply of electricity over the 2021–2026 regulatory period, we propose to replace a number of zone substation transformers. Zone substation transformers are major network assets that transform electricity from higher to lower voltages. This allows electricity to be distributed efficiently over long distances.

24 UE BUS 4.02 - Pole replacement - Jan2020 - Public

Our asset management approach for zone substation transformers includes multiple options for meeting our required service levels. These options include the following:

- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible (e.g. replacement of bushings, refurbishment of on-load tap changers and oil, and minor refurbishments of external, easily accessible transformer components such as the paint, pumps, and gaskets, as these components reach end of life prior to the transformer winding)
- efficient deferral of replacement of transformers through online monitoring systems or other mitigation controls, such as the use of relocatable transformers (as discussed below)
- asset replacement based on condition and risk assessments, including the impact of common-cause failures.

Relocatable transformers

We currently own two mobile 66/22kV power transformers, and one mobile 66/11kV transformer. Rather than the traditional utility approach of trying to completely prevent failures, these transformers act as risk mitigation measures (i.e. reduce duration of customer outages following major failure) and allow us to efficiently manage energy-at-risk across multiple sites with a single asset.

By managing the consequence of failure, our relocatable transformers also allow us to make prudent investment decisions. For example, where a zone substation has multiple transformers with poor condition history, or high conditional and joint probability failure risk, a relocatable transformer may allow us to replace just one or two transformers (and manage the other towards failure).

To support the use of relocatable transformers, preparation works must be undertaken at at-risk zone substations. We have, and continue to prepare many of our zone substations to readily receive a relocatable transformer.

The deferral possible with a relocatable transformer varies based on, for example, the load at risk and growth rate, age and the cost of the required site works. As these factors change, asset replacement or other intervention may become the more efficient option.

The prudent and efficient option for any given transformer is assessed on a case-by-case basis, and focused on the overall risk at the zone substation (rather than the asset itself). This assessment relies on a monetisation of risk, and is discussed in detail in section 4.2.2. For example, this approach recognises that should a transformer fail in service, the impact to customers and the community will vary based primarily on the potential consequence of a failure in terms of safety, financial impacts, and supply reliability.

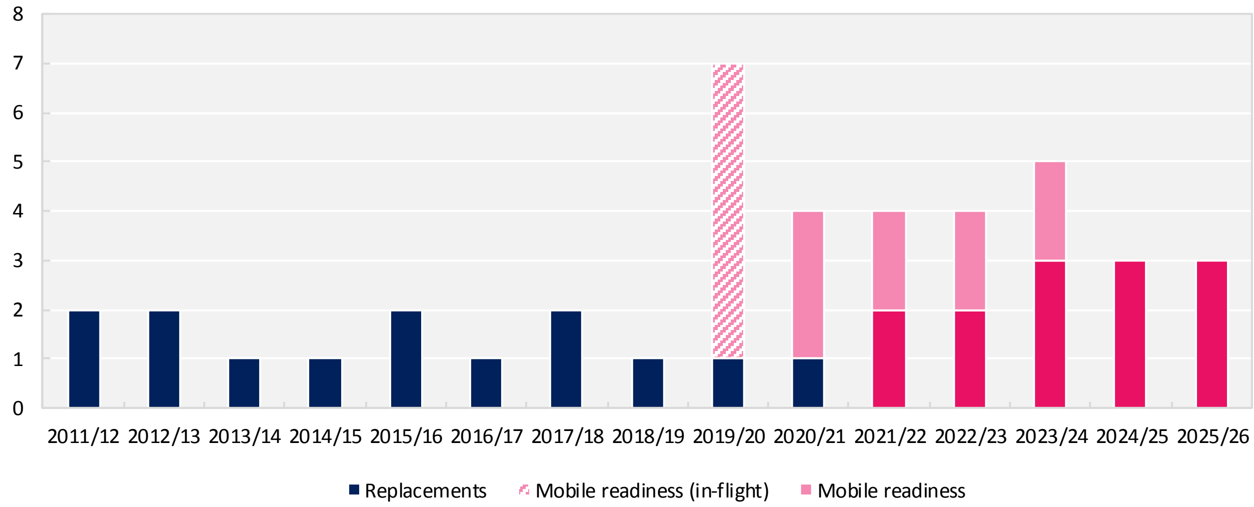
A key input into our risk assessment is the probability of an asset failing. Although the number of zone substation transformer failures is relatively low, our experience shows that several of these failure events have occurred in assets of the same make, model and manufacturer, and had the same failure mode. Such failure events reflect joint and conditional probability of failure, and are typically referred to as 'common-cause' failures. The AER recognises these events in its asset replacement planning note.[25]

Our forecast transformer replacement volumes for the 2021–2026 regulatory period are shown in figure 4.5. The increase in volumes relative to historical replacements is consistent with the application of a risk-based

[25] UE ATT099 - AER - Asset replacement planning - Jan2019 - Public, p. 64.

assessment, including alignment with the AER's replacement planning practice note. It also reflects our ageing transformer population and the increasing consequences of asset failure over time (recognising we are the second most highly utilised distribution network in Australia, meaning the unserved energy at risk is high).

Figure 4.5 Historical and forecast transformer replacement volumes



Source: United Energy

The full justification for the replacement of each of the zone substation transformers included in our 2021–2026 replacement program is set out in our attached transformer forecast overview document and corresponding risk models.[26] A summary of the total investment required for these works is in table 4.4.

Table 4.4 Transformer replacements: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Zone substation transformer replacements (total)	32.1

Source: United Energy
Note: Forecast excludes real escalation and network overheads

4.1.3 Zone substation switchgear replacements

Our current asset management approach for zone substation switchgear is similar to that previously outlined for transformers. For example, to ensure we maintain a reliable supply of electricity, our switchgear management practice includes the following:

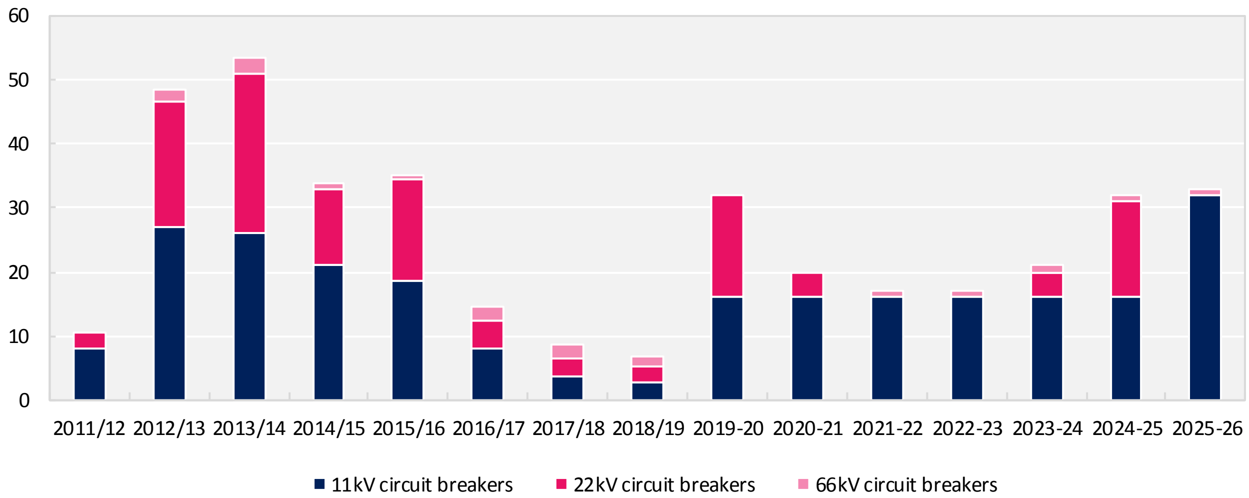
- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible
- deferring replacement of circuit breakers through online monitoring systems or other mitigation controls, including asset refurbishment
- asset replacement based on condition and risk assessments, including the impact of common-cause failures.

[26] UE BUS 4.03 - Transformer replacement - Jan2020 - Public, UE MOD 4.06 - Transformer risk - Jan2020 - Public

The targeted replacement of specific or single components is typically only technically feasible for outdoor switchgear (e.g. for outdoor switchgear, circuit breakers can be replaced but associated disconnector and earth switches retained; the replacement of specific components is more challenging for indoor switchgear due to their inherent design). In any event, the prudent and efficient option for any given asset is determined by assessing the overall risk at the zone substation, using our risk monetisation approach outlined above and in section 4.2.2.

A summary of our historical and forecast circuit breaker replacement volumes is shown in figure 4.6. The full justification for our forecast replacement volumes is included in our switchgear forecast overview document and risk model.[27]

Figure 4.6 Zone substation circuit breaker replacement volumes



Source: United Energy

Our total investment forecast for the 2021–2026 regulatory period is shown in table 4.5.

Table 4.5 Switchgear replacements: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Zone substation switchgear replacements (total)	19.5

Source: United Energy
Note: Forecast excludes real escalation and network overheads

4.1.4 Service line replacements

Since the introduction of smart meters in Victoria in 2009, we now have access to more and better data regarding the performance of our network. We are leveraging our smart meter investment to continuously improve how we manage our network—particularly the safety benefits we can now provide our customers.

One of the ways we are leveraging our smart meter data to benefit our customers is through our management of service lines that connect our LV distribution network to a customer's point of supply. There are over

[27] UE BUS 4.04 - Switchgear replacement - Jan2020 – Public, UE MOD 4.10 - Switchgear risk - Jan2020 - Public

364,000 service lines in our network which supply electricity to many of our 685,000 residential, industrial and commercial customers.

In our service line replacement forecast overview document, we outline how we developed prudent and efficient forecasts for service line replacements over the 2021–2026 regulatory period.[28] This includes our underlying business-as-usual investment, as well as the two additional proactive programs discussed below.

Our customers hold strong views that safety is a given, and is too important to be 'traded-off'. Throughout our engagement process, they emphasised that safety should always be our top priority and must be maintained or improved where possible.

As part of our stakeholder engagement program, we undertook a series of deliberative forums with our customers. At these forums, we discussed programs that leveraged our smart meter investment to proactively identify hazardous assets.

To enable customers to fully understand and explore the investment options for delivering these programs, participants were briefed on the key challenges in delivering the program, and three to four options for investment going forward. One of these programs was the replacement of polyvinyl chloride (**PVC**) grey twisted service lines (discussed in further detail below) with aerial bundled cable.

The options presented for our PVC grey twisted program included a status-quo option (i.e. consistent with our existing asset management approach), and incremental replacements to proactively reduce safety risk. Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact of selecting multiple programs throughout the entire forum.

Our customers were overwhelming supportive of using smart meters to detect and fix faults, where possible.

Neutral screen and PVC grey twisted service line replacement program

Our existing service line population includes 'neutral screen' and 'PVC grey twisted' types that were installed on our network between 1961–1989. Neutral screen service types were constructed as a single wire that has the neutral phase acting as the conductor shield (i.e. it surrounds the active phase), whereas PVC grey twisted service lines are insulated using a grey PVC cover. These service types are shown in figure 4.7.

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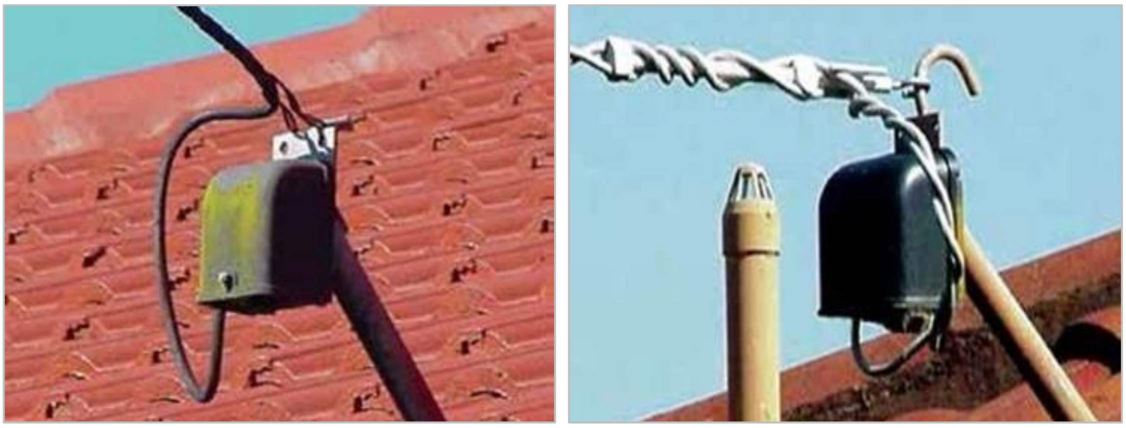
28 UE BUS 4.05 - Services replacement - Jan2020 - Public

Figure 4.7 Sample images: neutral screen and PVC grey twisted service types (respectively)



Source: United Energy

Although individual service lines pose minimal reliability risk to our distribution network—as a failure would typically impact just a single customer—service lines pose both fire and public safety risks. For example, as services are installed on a customer's premises, there is a risk of electric shocks to members of the public (e.g. this can be caused by a broken neutral or from a service line that has fallen to the ground). Experience in other distribution networks has been catastrophic, with shocks from broken neutrals resulting in deaths.

Historically, we have replaced neutral screen services on our network when they are identified during our normal cyclic inspection program, or through monitoring of neutral service impedance with our smart meters. An assessment of the total annual life cycle costs of alternative asset management options, however, demonstrates the proactive replacement of neutral screen and PVC grey twisted services is more efficient.

Our approach to forecasting replacement volumes for all service line types in our network is set out in table 4.6.

Table 4.6 **Service lines: replacement volume forecast method**

Asset management type	Forecast volumes
Inspection-based and fault response	Forecast based on the average of services replaced over the period 2015–2018 or 2016–2018, as set out in our unitised cost model. Earlier periods (e.g. pre-2015) have been excluded as these reflected higher replacement volumes due to the impact of historic proactive programs. We have also increased our service line replacement volumes to account for services replaced as part of our incremental risk-based pole replacement program (i.e. as we replace more poles, we will find more non-preferred service line types). These service line replacements represent a small percentage of our total service line expenditure. Our incremental pole replacement forecasts do not capture the replacement of these services.
Proactive program: neutral screen services	Forecast based on existing population of neutral screen services. Volumes have been set to remove a constant number of services per annum such that all neutral screen service types will have been removed from our network after 10 years. These volumes have subsequently been adjusted downwards to ensure neutral screen services captured in our inspection-based forecast are not double-counted.
Proactive program: PVC twisted services	Forecast based on existing population of PVC twisted services. Volumes have been set to remove a constant number of services per annum such that all PVC twisted service types will have been removed from our network after 10 years. These volumes have been adjusted downwards to ensure PVC twisted services captured in our inspection-based forecast are not double-counted.

Source: United Energy

We have also increased our service line replacement volumes to account for services that will be replaced due to our incremental pole replacement program (i.e. as we replace more poles, we will find more non-preferred service line types). These service line replacements represent a small percentage of our total service line expenditure. Our incremental pole replacement forecasts do not capture the replacement of these services.[29]

Our forecast investment required for managing our service line population over the 2021–2026 regulatory period is summarised in table 4.7.

[29] Further detail is provided in UE BUS 4.02 - Pole replacement - Jan2020 - Public

Table 4.7 Service line replacements: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Service lines: inspection-based	18.3
Neutral screen services	3.0
Twisted PVC services	2.3
Service lines: replacements due to incremental pole replacements	0.3
Total	**23.9**

Source: United Energy
Note: Forecast excludes real escalation and network overheads

4.1.5 Other high-volume, low-cost asset replacements

In addition to poles and service lines, much of our forecast replacement investment is for assets such as overhead conductor, underground cable and pole-top structures (e.g. cross-arms attached to our poles). We typically replace these assets based on a 'find-and-fix' or reactive approach.

As shown in table 4.8, our forecast investment for these asset categories is lower or consistent with our historical investment. The reduction in our pole-top structures forecast ensures that cross-arms and other assets that are replaced as part of our incremental pole replacement program are not double-counted (i.e. when replacing a pole, it is typically efficient to also replace the existing pole-top assets).

Table 4.8 Total lines replacement investment ($ million, 2021)

Asset category	2016/17–2020/21	2021/22–2025/26
Overhead conductor	31.9	14.6
Underground cable	35.9	29.3
Pole-top structures	65.5	75.7
Pole-top structures: reduction due to incremental pole replacements	-	-1.1
Total	**133.3**	**118.5**

Source: United Energy
Note: Figures exclude real escalation and network overheads

Our replacement volume forecasts for these asset categories are estimated based on a combination of linear trends and historical average volumes. These trends and historical averages are typically based on the previous five years of data, unless asset management changes have occurred that render more recent periods appropriate. Further detail is provided in our unitised replacement volume model.[30]

[30] UE MOD 4.11 - Unitised volume model - Jan2020 - Public

Targeted proactive intervention programs are also included in our bottom-up replacement forecasts for additional safety-driven measures that are consistent with our AFAP obligations.

The unit rates applied for high-volume, low-cost assets are based on an average over the period 2015–2018.

4.1.6 Environmental management program

We are subject to both state and federal environmental obligations, including the *Environmental Protection Amendment Act 2018* and the State Environment Protection Policies for noise, land, groundwater, surface water and air quality. Our replacement investment forecast includes projects required to continue to meet these obligations.

Historically, we have managed the risks associated with our environmental obligations primarily through a reactive approach. For example, we have investigated noise concerns associated with our zone substation transformers following a customer complaint.

From July 2020, the revised *Environmental Protection Amendment Act 2018* (Vic) will come into effect. As set out in the regulatory impact statement (**RIS**), these revisions establish a modern regulatory approach focusing on preventing waste and pollution impacts, rather than managing any impacts after an event has occurred.[31]

In order to meet these new compliance obligations—that is, to proactively prevent waste and pollution impacts prior to them occurring—our investment forecast for the 2021–2026 regulatory period includes noise reduction and bunding programs at a number of high-risk zone substations. These sites have been identified based on a desktop study to determine the following:

- bunding—oil-leak risk rating, based on the likelihood of an oil-leak arising, and the potential damage to the surrounding environment
- noise—decibel exceedance and proximity to residential properties.

The cost for proactively addressing these risks is based on an assessment of least-cost compliance options. For our bunding works, these options typically include the installation of bunding with or without a stormwater management system. For our noise program, site options include enclosing part, or all, of a site to replacing the offending asset.

The full impact of these regulatory changes, and our monetisation of the likelihood and consequence of all risks, is set out in detail in our attached environmental management business case.[32] A summary of the costs of this program are outlined in table 4.9.

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[31] UE ATT010 - Deloitte - Environment regulations RIS - Aug2019 – Public, p. 7.

[32] UE BUS 4.01 - EP Amendment Act 2018 - Jan2020 - Public

Table 4.9 Compliance with new environmental obligations: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Noise compliance program	69.5
Bunding compliance program	13.2
Other environmental investment	0.4
Total	**83.1**

Source: United Energy
Note: Increased operational expenditure is also required to meet our new compliance obligations in regards to increased monitoring and land contamination. These costs are discussed in our operating expenditure chapter of this regulatory proposal
Forecast excludes real escalation and network overheads

4.1.7 Our program will maintain our safe and resilient network

We operate a distribution network where some of our assets are located in designated hazardous or high bushfire risk areas (**HBRA**). The unique combination of weather and vegetation that occurs in south-eastern Australia makes Victoria one of the most bushfire prone locations in the world.

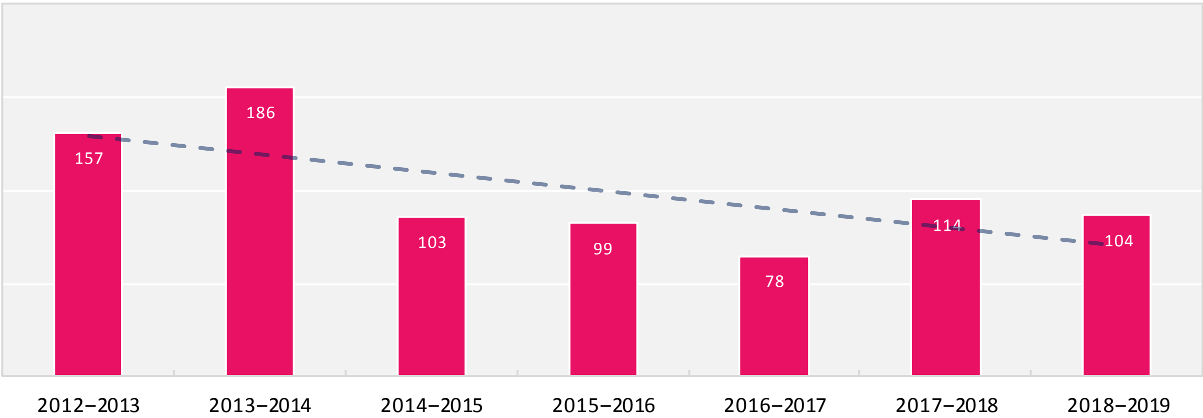
As any spark is a potential source of ignition, the consequences of a fault in our overhead electricity sub-transmission or distribution system can be catastrophic. The high temperatures, low humidity and hot gusty northerly winds that occur through summer and autumn produce a volatile fuel source that can ignite easily and burn fiercely. Such fires have caused enormous property, livestock and wildlife losses, together with loss of human life.

It is impossible to eliminate fire starts completely, but as shown in figure 4.8, the trend in ground fire starts from our assets is decreasing. Our approach to continue to effectively reduce the risk of bushfires from our network is set out in our fire prevention plan (**FPP**), which is approved by Energy Safe Victoria.[33] Projects included in our FPP are compliance obligations under the *Electricity Safety Act 1998* (Vic.).[34]

[33] UE ATT094 - Fire prevention plan – Jun2019– Public

[34] *Electricity Safety Act 1998* (Vic.), clause 113B(2).

Figure 4.8 The trend in asset-related ground fire starts is declining

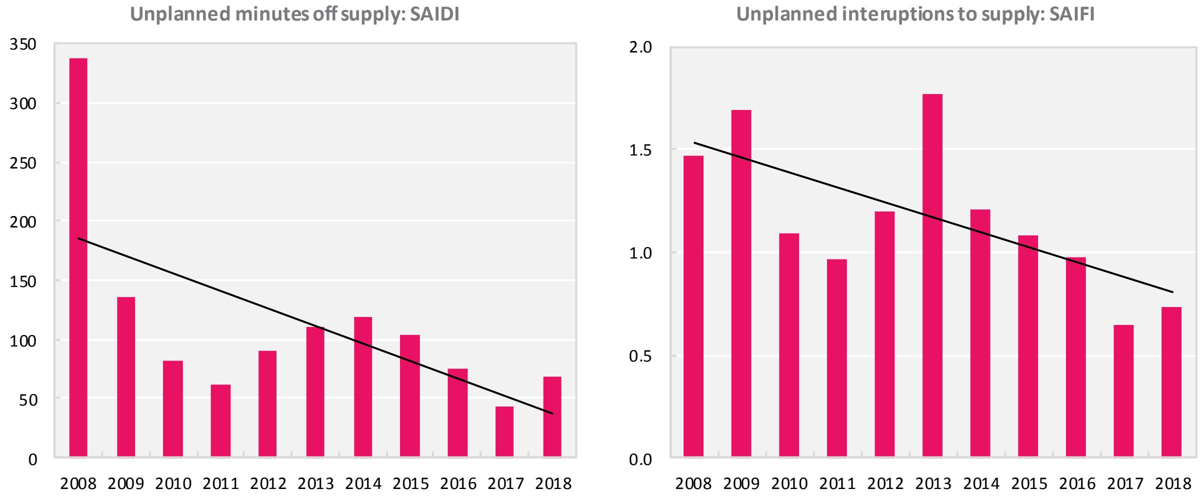


Source: United Energy

Overall, the investments included in our regulatory proposal are designed to maintain both affordability and the long-term health of our electricity assets. This includes investments needed to maintain current reliability levels on average across our network (noting that factors such as the weather will still drive variances each year).

We will also work to improve reliability where our customers value the improvement more than the cost to deliver it. As shown in figure 4.9, we have been improving our network resilience and will strive to maintain this trend.

Figure 4.9 Unplanned outages a typical customer experiences (minutes off supply; number of outages)



Source: United Energy

We know from talking to our customers that network reliability is important. Along with affordability, it consistently ranked as the key output measure throughout our stakeholder engagement forums.

Our customers are generally satisfied with the level of reliability currently experienced. Around half our customers were willing to pay more for better reliability, whereas only 16% of residential customers and just 3% of business customers were prepared to pay less for lower reliability.

Many of our customers also expressed their support for improving reliability for worst-served customers. Although our regulatory proposal does not include such programs—due to balancing other considerations, including affordability—we have improved reliability in the current regulatory period by installing additional switches and monitoring devices. When there is an electricity outage, this equipment helps us restore supply more quickly by remotely identifying and segmenting fault locations for our field crews to attend.

In addition to speaking with our residential and business customers, our engagement included a network risk management workshop with key stakeholders to detail the risk monetisation approach used to justify many of our asset replacements (including zone substation transformers). This workshop was attended by the AER, Energy Consumers Australia, and representatives from ESV. As outlined in section 4.2, our risk monetisation approach is consistent with the AER's replacement planning practice note.

4.2 Our forecasting approach

This section provides an overview of how our asset management objectives are reflected in forecast asset replacement volumes and expenditure that are prudent and efficient. Our approach is consistent with the capital expenditure objectives and criteria set out in the Rules and the AER's expenditure forecast assessment guideline.[35]

4.2.1 Our forecast asset replacements volumes are consistent with our asset management framework

Our asset management framework aligns with the requirements of International Organization for Standardization (**ISO**) 55001. This framework is the international standard in asset management.

The asset management framework describes the asset management system that is applied to our network assets. The framework includes our asset management policy, strategic asset management plan (**SAMP**), and detailed network asset management plans and strategies for all asset classes. Our asset management policy and SAMP have been provided as attachments to our regulatory proposal.[36]

Our forecast asset replacement volumes are developed based on these asset management practices. In particular, we forecast asset replacement volumes based on two broad approaches:

- risk modelling/monetisation
- historical volumes and trends.

We apply these forecasting approaches to different asset and sub-asset categories based on the characteristics of the underlying asset. For example, we typically forecast high-volume, low-cost assets using observed historical trends (adjusted for any known change in operational policy or asset specific issues), or based on historical

35 *National Electricity Rules*, clause 6.5.7(a) and clause 6.5.7(c).

36 UE ATT021 - Strategic asset management – Nov2019 - Public

replacement volumes. In contrast, low-volume, high-value assets are typically forecast based on individual risk assessments and options analysis.

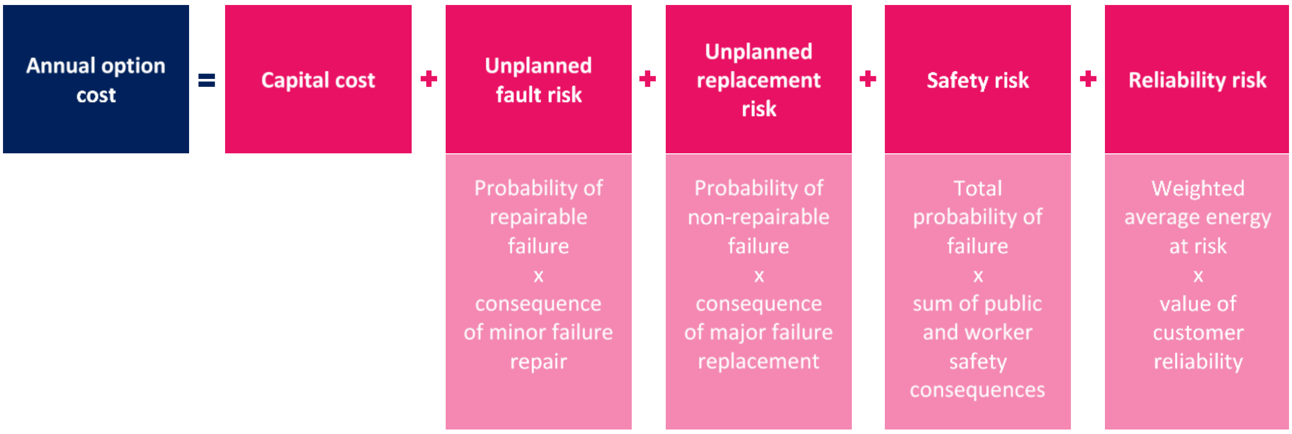
Our high-value asset forecasts are set out in the project list in our plant, station and lines replacement model, and our high-volume assets are forecast in our unitised cost build-up model.[37]

4.2.2 Our risk-monetisation modelling is consistent with the AER's asset replacement planning note

Our approach to forecasting replacement investment has recently become more sophisticated, and has transitioned from a focus on asset condition to overall system risk. Our risk-monetisation models ensure we invest only when the cost of replacing existing infrastructure is lower than the total value of the underlying risks. This means our customers pay no more than required on asset replacements.

Specifically, our approach to monetising risk when assessing investment decisions is to determine the annual asset risk cost (as shown in figure 4.10). This approach is taken for all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of each option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.[38]

Figure 4.10 Calculation of annual asset-risk cost



Source: United Energy

A summary of how we determine the key input assumptions when calculating the annual asset risk cost is provided below. A more detailed discussion is set out in our asset risk quantification guide.[39] This guide is used as an internal reference for analytical methods and data for the following purposes:

- assessing asset failure modes and their consequences
- determining probabilities of failure
- quantifying varying types of asset risk
- determining least-cost intervention approaches.

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37 UE MOD 4.11 - Unitised volume model - Jan2020 - Public

38 UE ATT099 - AER - Asset replacement planning - Jan2019 - Public

39 UE ATT139, United Energy, *Asset Risk Quantification Guide*

The probability of failure is a key input assumption in any risk monetisation model. In the first instance, we use historical asset failure rates based on our own internal data. As required, this is supplemented by failure data from other Australian distributors, or from recognised international sources (e.g. Ofgem data).[40]

For zone substation assets, where some level of asset redundancy exists, we consider a conditional probability of failure. This approach recognises common-cause failure(s) due to elements common to multiple assets. These elements may include similarities in design and construction, maintenance practices, operating duty, age or condition, and geography.

Further detail on the probabilities of failure used for individual asset interventions is provided in our forecast overview documents and risk monetisation models.[41]

The total expected cost of consequence is equal to the likelihood of the consequence of a failure event, and the consequence cost of that failure. Our approach to determining these factors includes estimating outcomes for each potential failure mode across the risk categories set out in table 4.10.

Table 4.10 Monetised network risks categories

Risk category	Example of value of risk
Fault and replacement risk	Includes costs (both capital or operating) associated with the reinstatement or replacement of damaged assets for major or minor failures; typically based on expected scope and observed historical costs
Safety	Includes potential safety impacts to the public, or our workers, as a result of an asset failure; based on the value of a statistical life or long-term injury, and a disproportion factor of three
Bushfire	Includes the consequence costs derived from the Tolhurst fire model, and disproportion factors ranging from one to six depending on the geographical area
Environmental	Includes costs of disposal of hazardous waste or environmental remediation works; typically based on expected scope and observed historical costs
Network performance	Includes the value of unserved energy as a result of an unplanned outage; based on the value of customer reliability (**VCR**) estimated by AEMO (adjusted for inflation)

Source: United Energy

Similar to our approach for estimating the probability of failure, in the first instance, we estimate the likelihood of any consequences of a failure event using our own internal data.

4.2.3 Our unit cost forecasts are based on recent historical costs

As one of the most cost-efficient distributors in Australia, based on AER benchmarking, we consider our historical costs provide a reasonable basis for forecasting future investment requirements. For high-volume, low-value assets, these costs are typically determined as the average over the period 2015–2018. For low-volume, high-value assets, we typically forecast costs based on recent efficiently delivered projects of similar scope, size and geographic location.

40 UE ATT100 - Ofgem - DNO common network asset indices - Jan2017 – Public

41 See, for example: UE MOD 4.06 - Transformer risk - Jan2020 – Public.

Our historical costs reflect our outsourced operating model, where all capital works are undertaken by independent, third-party service providers following an open, competitive tender. For example, we have a network services agreement with Zinfra to undertake all maintenance and fault responses across our network, and have recently tendered our asset inspection works.

For major projects, we have an approved panel of suppliers who compete for capital works. To ensure we achieve efficient, market-based rates, we package our works program to enable benefits to be obtained through tendering significant sized projects. Projects that are suitable to be tendered as turn-key projects are identified at conception stage, and detailed scopes of works are prepared as the basis for tender documents.

Our materials cost forecasts are also procured through rigorous contracting arrangements.

For clarity, we adjust our historical costs for forecast growth in real input prices over time, such as labour, materials and contracted services. Further discussion on our cost escalators is provided in our operating expenditure chapter.

4.2.4 We will deliver our replacement program with support from our resource partners

As outlined above, we operate an outsourced structure for constructing and maintaining our distribution network. This allows us to deliver our total capital program, including the forecast increases in investment over the 2021–2026 regulatory period, by using resources available in an open market.

4.2.5 We tested our replacement investment forecast against the AER's repex model

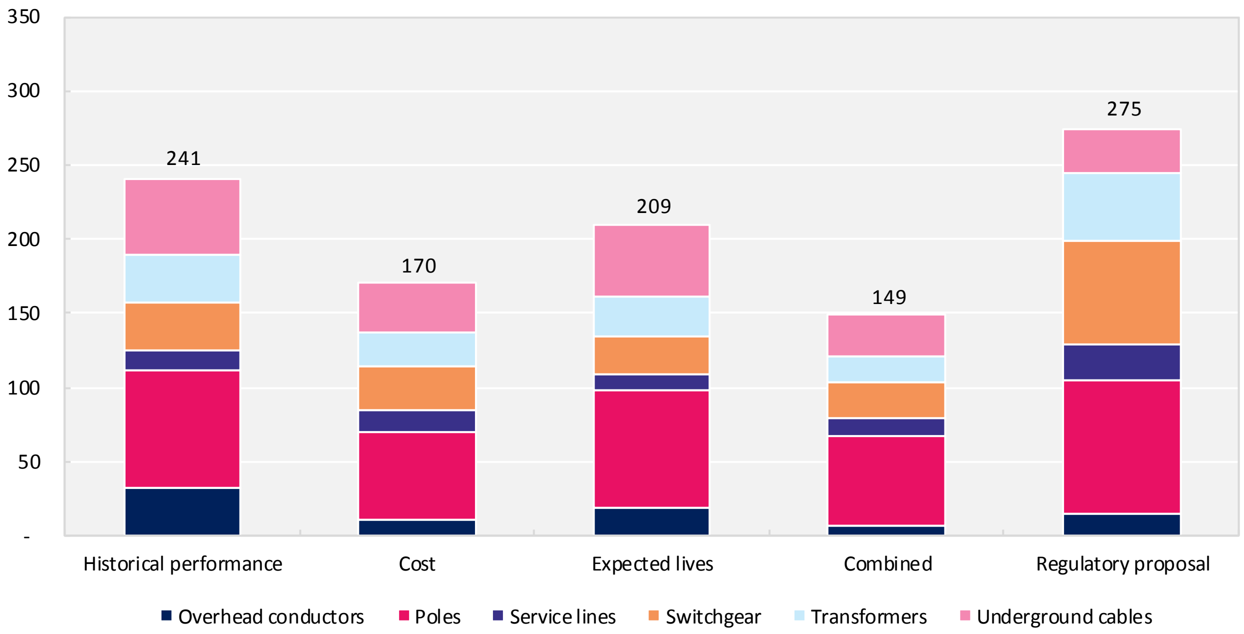
In addition to using a risk-monetisation framework to develop our replacement forecasts, we validated the prudency and efficiency of our replacement investment by comparing our outcomes to estimates from the AER's repex model. The AER's repex model provides a top-down assessment of 57% of our replacement investment forecast.

Modelled replacement investment

Our estimation of the AER's repex model is provided in figure 4.11. We engaged GHD to validate our application of this model.[42]

[42] UE ATT097 - GHD - Repex modelling review - Dec2019 – Public

Figure 4.11 AER repex model comparison ($ million, 2021)



Source: United Energy
Note: Figures exclude real escalation and network overheads

Based on the approach applied in its most recent draft decision for the South Australian and Queensland distributors, the AER will compare our regulatory proposal forecast to the higher of the expected costs and expected lives scenarios. In the figure above, this will result in a comparison to the expected lives outcome.

Our forecasts are lower than the AER's expected lives outcome for overhead conductor and underground cables, but higher for poles, service lines, switchgear and transformers. We provided an overview of our forecasts in section 4.1, and have included forecast overview documents for the categories that exceed the AER's repex model outcome.

We consider our risk monetisation modelling of asset categories and particular projects provides a more robust assessment of the prudency and efficiency of our investment forecast than the AER's repex model. The AER's repex model is a useful tool in identifying areas for further investigation, but it simplifies a complex range of factors to forecast the replacement of assets. In doing so, the AER's repex model has the following inherent limitations:

- the life of assets replaced in the past is assumed to be the same as for assets replacement in the future, such that the repex projections are backward looking and may differ significantly from a truly optimal forward looking replacement program (particularly under an AFAP framework, where technological changes can continually drive further investment)
- the number of units replaced in the past is directly proportional to historical expenditure
- asset age is used as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or changing community expectations may be the primary driver for particular asset categories.

These factors are all relevant to the recent changes to our pole replacement practices and our better understanding of the risks associated with common-cause failures (that are driving our zone substation transformer and switchgear investments).

Unmodelled replacement investment

The AER's repex model is not intended to cover our entire replacement investment forecast. For the 2021–2026 regulatory period, approximately 43% of our forecast replacement investment is 'un-modelled'.

The un-modelled portion of our replacement investment includes our investment in replacing pole-top structures, protection equipment, environmental management and miscellaneous building and civil works. A comparison of these costs for our current and forecast regulatory period is shown in table 4.11.

Table 4.11 Unmodelled replacement investment ($ million, 2021)

Description	2016–2020	2021–2026
Pole top structures	65.5	74.6
SCADA, network control and protection	31.1	42.0
Environment	2.8	83.1
Other (excl. environment)	8.9	10.5
Un-modelled replacement investment	**108.3**	**210.2**

Source: United Energy
Note: Figures exclude real escalation and network overheads

As outlined in section 4.1, we will be subject to new environmental compliance obligations in the 2021–2026 regulatory period. After excluding these from the un-modelled build-up (to ensure a like-for-like comparison), our forecast un-modelled investment is largely consistent with our corresponding investment in the 2016–2020 regulatory period.

5

Connections

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5 Connections

We will be making improvements to our connection processes by implementing an electronic connection management system that will help to reduce timeframes and improve communications with our customers.

Our residential and commercial connection demands are underpinned by pockets of high customer growth in areas such as Frankston, Greater Dandenong and the Mornington Peninsula. Large infrastructure such as the Victorian Government's Lathams Road widening project, the North-East Link, the Suburban Rail Loop and a number of rail and tram supplies are driving a step-up in our gross connections investment.

Overall, we have forecast our net connections investment over the 2021–2026 regulatory period to increase modestly compared with our historical investment. Our forecast is underpinned by independent and robust construction activity forecasts undertaken by the Australian Construction Industry Forum (**ACIF**) and recent historical investment needs; an approach previously accepted by the AER.

We have cross-checked our forecast with a range of other approaches and found ours to be at the lower end.

This chapter sets out the investment we will make over the 2021–2026 regulatory period to meet our customers' connection requirements and support our customers' energy needs. In this chapter:

- in section 5.1 we present our investment forecast and the key drivers in our network
- in section 5.2 we outline our forecast approach and cross-check our forecast with other approaches.

The table below outlines the connection forecast by its components. The drivers of this forecast are discussed throughout this chapter.

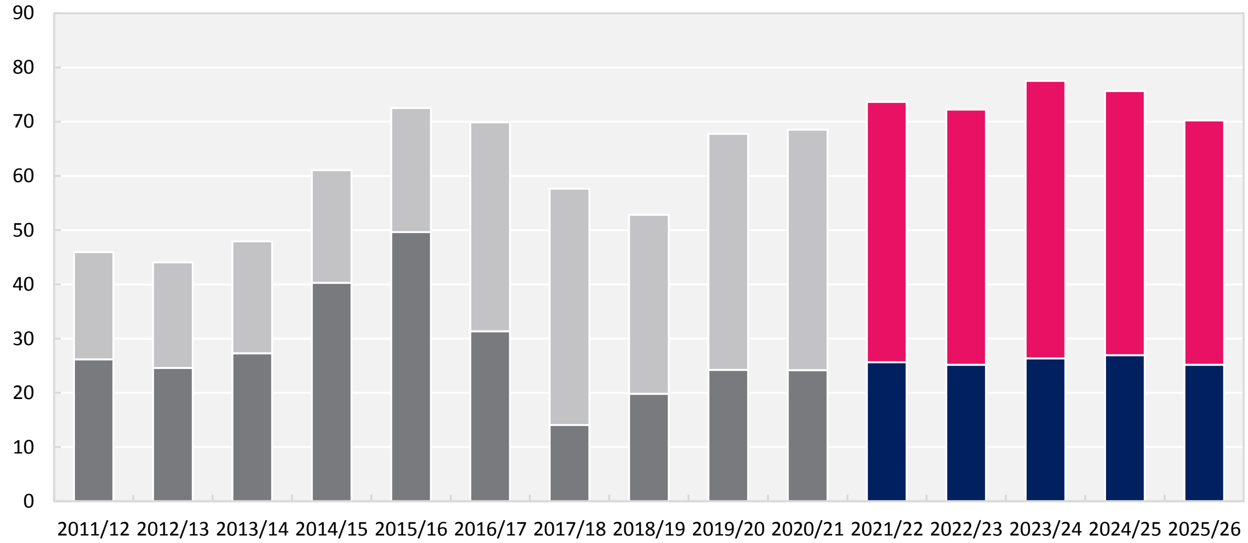
Table 5.1 Connection investment forecast ($ million, 2021)

Year	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Gross connections	73.6	72.2	77.5	75.6	70.2	369.2
Less: Gifted assets	9.5	9.7	9.8	10.0	10.1	49.2
Less: Capital contributions	41.2	40.1	44.2	41.6	37.8	204.9
Add: Rebates	2.7	2.8	2.8	2.9	2.9	14.1
Net connections	**25.6**	**25.2**	**26.3**	**27.0**	**25.2**	**129.3**

Source: United Energy
Notes: Forecast includes real escalation and excludes network overheads

The figure below shows our forecast of gross and net (that is, net of contributions received from connecting customers) connections investment.

Figure 5.1 Gross and net connection investment forecast ($ million, 2021)



Source: United Energy

Notes: 2018/19 is an estimated actual, 2019/20 is the first forecast year. Figures include real escalation and exclude network overheads

The business cases supporting this forecast are outlined below. Other supporting material is referenced throughout this chapter.

Table 5.2 Summary of material business cases

Investment	Source	Investment
Suburban rail loop[43]	Customer funded	CONFIDENTIAL
Lathams Road widening[44]	Customer funded	CONFIDENTIAL

Source: United Energy

5.1 What we plan to deliver

Our focus over the 2021–2026 regulatory period is making efficient and timely connections. This section outlines the way in which:

- stakeholder engagement has driven improvements in our connection processes
- our investments will:
  - deliver more connections to power customers' everyday activities (high volume connections)
  - facilitate infrastructure growth (low volume connections)
- our connection policy will continue to ensure customers pay for their fair share.

[43] UE BUS 5.01 - Lathams road - Jan2020 - Confidential

[44] UE BUS 5.02 - Suburban rail Loop - Jan2020 - Confidential

5.1.1 We are delivering faster connections to power our customers' everyday activities

We will be launching an online connections portal for customers, or their representatives, to submit connection requests and seek pre-approval to connect rooftop solar. This portal will allow us to both simplify the connection process and better manage the connections workflow, thereby providing an enhanced level of service to customers. This tool has already been successfully deployed by CitiPower and Powercor.

From our residential surveys, around 14% of respondents had experienced a connection, of which 79% indicated they were satisfied with the timeframe and process. Some large customers noted a lack of streamlined processes and related time delays.

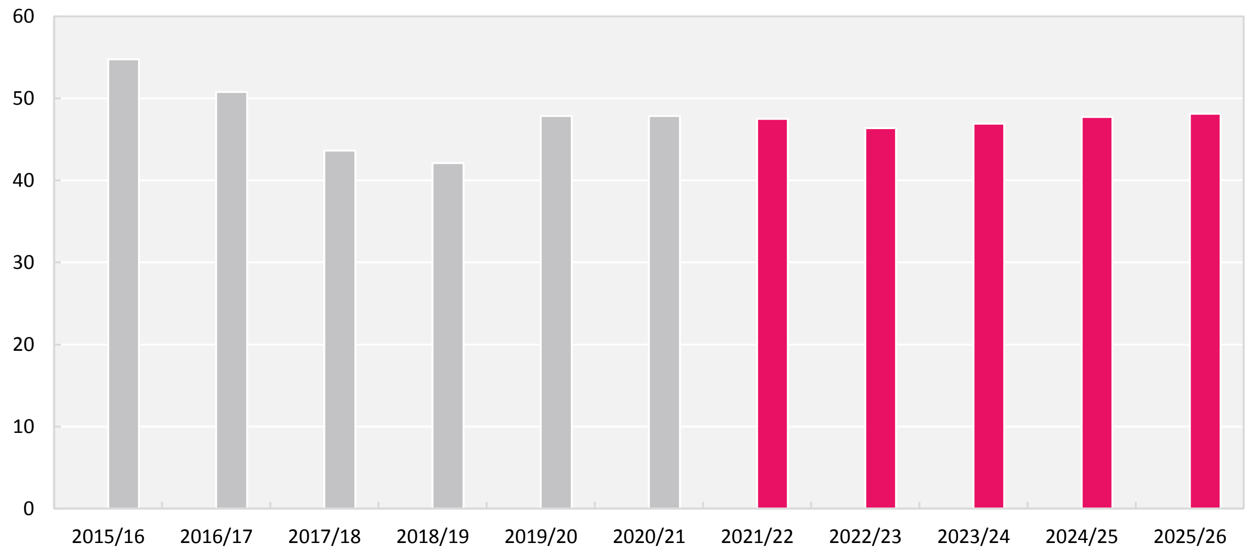
While not all customers considered an online process would fix this, we expect it will improve connection timeframes and communications with customers based on its operation at CitiPower and Powercor. This means we will be able to connect customers in a more timely way over the 2021–2026 regulatory period.

5.1.2 High volume connections—delivering connections to power customers' everyday activities

We forecast to connect 55,000 new households over the 2021–2026 regulatory period.[45] Our online connections portal will be critical given the sustained connections volume in our network over the 2021–2026 regulatory period.

'High volume' connections consist of residential and small to medium business connections. Our high volume connection demand is based on applying construction activity forecasts that have been independently undertaken by the ACIF, as discussed more in section 5.2.1. The figure below outlines our high volume connection trend and forecast.

Figure 5.2 High volume connection investment ($ million, 2021)



Source: United Energy
Note: Figures exclude real escalation and network overheads

45 Based on applying ACIF growth rates to historical connection volumes. Includes alternative control connections.

Our connection demand is underpinned by pockets of high customer growth in our supply area. Greater Dandenong is one of Melbourne's major growth areas due to its improved access through East Link, Dandenong Bypass and Dingley Arterial. Our area also continues to experience urban infill growth, such as the former 20 hectare Brickwork's site in Burwood East which is transitioning into a 950 dwelling residential hub with shopping centres and other retail business and is due for completion in 2023.[46] The continued popularity of the Mornington Peninsula as a holiday (and living) destination is also driving residential subdivisions and connection works. Further information on construction activity trends is available in ACIF's report.[47]

The apparent fall in connection investment in 2017/18 and 2018/19 was primarily driven by a change to our connections service provider in 2018 rather than being driven by an underlying reduction to connection investment demand (noting both the 2017/18 and 2018/19 financial years are calendar year averages that include 2018). In January 2018, a new service provider was appointed following a competitive market tender. The change resulted in a temporary reduction to the speed and volume of connections due to the service provider needing to:[48]

- increase its resources to meet our service provision requirements
- train its field crew in our methods and standards
- becoming familiar with our systems and processes.

Further, confidence in the construction market has improved with low interest rates, a return to rising housing prices and many of the problems from flammable cladding resolved providing more confidence in building quality and safety. Our connection volumes are returning to typical levels in 2019/2020.

5.1.3 We are underpinning infrastructure plans

We continue to underpin Victoria's infrastructure plans and the jobs associated with those projects. Low volume connections are typically used for infrastructure projects and industrial customers. We generally support these projects by making construction supply available, providing permanent supply once the project is completed or relocating existing assets to accommodate the project.

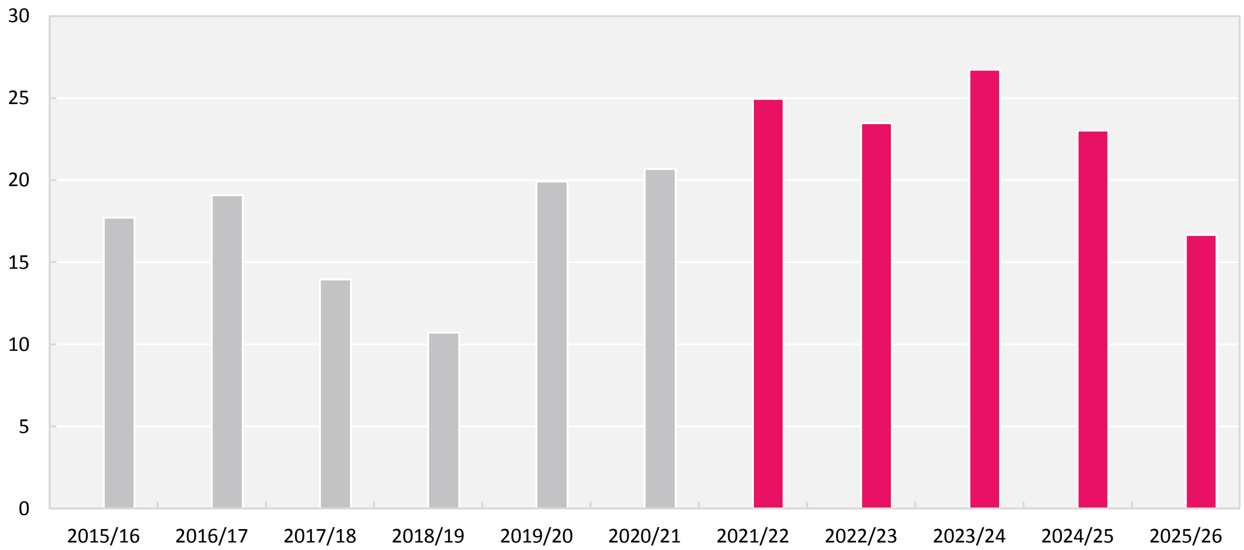
The figure below outlines our low volume connection forecast.

46 UE ATT140 - 78 Middleborough Road, Burwood East - Oct2018 - Public

47 UE ATT098 - ACIF - Australian construction market - May2019 - Public

48 When excluding the relatively simple and routine connection type of installing underground pits (United Energy function code CDA).

Figure 5.3 Low volume connection investment ($ million, 2021)



Source: United Energy
Notes: Figures exclude real escalation and network overheads

Slower economic growth and low borrowing costs have led to robust public infrastructure spending. Public works grew by 22% in 2017 to reach $67 billion boosted by sector investment in transport, energy and water infrastructure. There are many new major projects being added to an already solid pipeline.[49] In Victoria, the raft of major infrastructure projects and other public investment activities has been termed 'Victoria’s Big Build'.

From 2019/20 we have seen a step up in the low volume connection investment requirements which are set to continue until the end of 2022/23. Some of the projects we will be supporting in our network area over the 2021–2026 regulatory period include:

- Suburban Rail Link—this is a new rail link, initiated by the Victorian State Government to connect Melbourne's middle suburbs. We will be providing supply for the construction and operation of the Box Hill-Burwood-Glen Waverley and the Monash-Clayton-Cheltenham tunnels
- relocating assets to support the widening of Lathams road in Seaford—the south east is growing due to large scale residential developments in the Cranbourne, Clyde and Pakenham areas. To provide better access, the Victorian Government has initiated road widening projects
- electricity supply for the construction of the North East Link tunnel—the Victorian Government is connecting the M80 Metropolitan Ring Road with the M3 Eastern Freeway, which will be used by 100,000 vehicles a day and link key growth areas in the north and south-east[50]
- an ongoing transport infrastructure development by the Victorian Government to increase power supply capacity from growing demand on tram and train routes within our supply area
- key public services development including the new Monash Heart Hospital.

49 UE ATT050 - ACIF - Australian construction market - Nov2018 - Public

50 Victorian Government, *North East Link Project* ,<https://northeastlink.vic.gov.au/about>

There is also mounting pressure on the Federal Government to ramp-up investment in public infrastructure projects to boost economic activity.[51] While the Federal Government' pledge to bring the budget back into surplus by 2019/20 is currently taking primacy, should the economy continue to slow it will be forced to fund the gap caused by cautious private infrastructure expenditure. To this end, we consider our forecast to be conservative.

5.1.4 We ensure that our customers make fair contributions to their connections

In 2018 we published and sought feedback on our draft connection policies (together with our draft plan).

Our connection policy has been made in accordance with the AER's connection charge guideline. We have not made material changes to this policy from the 2016–2020 regulatory period. We will continue to offer two types of connection services; basic and negotiated. Customers requiring a basic connection will pay a fixed fee to cover the cost of installing a dedicated service line. Negotiated connections contribute to network upgrade costs based on the capacity of their connection in accordance with the AER's cost-revenue test.[52] The policy also outlines the circumstances when customers (typically developers) build assets and gift them to us and receive a rebate towards their cost of connection.

Together with this regulatory proposal we are seeking AER approval of our connection policy[53] and the model standing offers (**MSO**)[54] that most customers agree to when seeking a connection.[55]

5.2 Our forecasting approach

This section outlines our approach to forecasting high volume connections, low volume connections, customer contributions, gifted assets and rebates, and unit costs. We also cross-checked our forecasts against a number of metrics.

We have applied different forecasting approaches to our high volume and low volume connections. The table below summarises the approach applied to connections under each of the AER's RIN categories.

51 UE ATT042 - SCE - RBA annual report - Aug2019 - Public

52 Compared to our current connection policy, we have escalated the marginal cost of reinforcement (**MCR**) by inflation only. We note that any decrease/increase to the MCR will increase/decrease our net connection forecast.

53 UE ATT033 - Connection policy - Jan2020 - Public

54 UE ATT034 - Model standing offer with MEG - Jan2020 – Public, UE ATT035 - Basic connection policy without generation - 2019 - Public

55 Our MSO for residential rooftop solar connections were amended in 2019 to require the use of Q-V inverter settings to allow us to continue to maintain for residential customers, the flexibility they currently have in their solar export capability.

Table 5.3 Forecast approach

Connection type	Description	Forecast approach
Residential	Simple connection LV	High volume—ACIF growth rates
	Complex connection LV	
	Complex connection HV	
Commercial/industrial	Simple connection LV	High volume—ACIF growth rates
	Complex connection HV (customer connected at LV, minor HV works)	
	Complex connection HV (customer connected at LV, upstream asset works)	
	Complex connection HV (customer connected at HV)	Low volume—bottom up build/historic average
	Complex connection sub-transmission	
Subdivision	Complex connection LV	High volume—ACIF growth rates
	Complex connection HV (no upstream asset works)	
	Complex connection HV (with upstream asset works)	
Embedded generation	Simple connection LV	Low volume—bottom up build/historic average
	Complex connection HV (small capacity)	
	Complex connection HV (large capacity)	

Source: United Energy

5.2.1 Independent forecasts of connection drivers underpins our high volume forecasts

For high volume connections we have applied forecasts undertaken by the ACIF to adjust our historical connection volumes to predict future activity. This approach:

- uses forecasts of construction activity across different sectors, which underpins high volume connection volumes
- is based on robust, widely used and independent forecasts
- has been accepted by the AER—we proposed this approach for our 2016–2020 regulatory period and it was accepted by the AER.[56]

[56] UE ATT011 – AER –Final decision distribution determination – May2016 –Public, Attachment 6, pp. 36, 39, 40.

The ACIF forecasts are prepared by combining macro-economic forecasts of the domestic and international economy with information about the projected share of construction activity by sector and by region. The forecasts use the latest evidence from the Australian Bureau of Statistics (**ABS**) of Residential Building, Non-Residential Building and Engineering construction. The forecasts are undertaken bi-annually for the two regions—'Melbourne' and 'Rest of Victoria' as defined by the ABS—for 18 sectors of the economy.

Our network falls within the Melbourne region and so these are the forecasts we have adopted.[57] This forecast and accompanying ACIF report are attached to this proposal.[58]

To determine our connections investment forecast, the ACIF forecast have been applied in the following way:

- We have mapped ACIF's sector forecasts to our internal reporting connection categories (known as function codes), and then to the AER's RIN categories. We have undertaken this mapping in accordance with the main drivers of our connections. For example, ACIF's 'non-residential offices' subcategory has been matched to our function code 'CB - business supply developments'. This in turn is mapped to the 'Commercial/Industrial' RIN category. Our full mapping is outlined in our ACIF mapping attachment and reflected in our connections model.[59]
- For the first year of forecast connection volumes (2019/20) we have used the average prevailing connection volumes over 2015/16–2018/19. This is a very conservative estimate given the reduction to volumes experienced in 2017/18 and 2018/19 due to our appointment of a new service provider, as discussed above in section 5.1.2. Using the average is appropriate because:
  - some connections categories experience relatively low connection volumes meaning a single year is not representative of future years (i.e. smoothing to cater for annual volume volatility)
  - connections may begin in one year and finish in the next meaning any single year may not be a good representation of the connections work undertaken.
- From then onwards, ACIF growth rates have been applied to the preceding year's volumes.
- Our unit rates are the actual average prevailing unit rates over 2015/16–2018/19 for high volume connections. These are calculated as connection investment over 2015/16–2018/19 divided by the number of connections over 2015/16–2018/19 for each of our business connection function codes. All of our connection service providers have been selected from competitive market tender, meaning our historical rates have been market tested. As with the volumes, an average is used to account for the different mix and hence cost of connections that may occur in a single year. On balance, we consider a longer average would not reflect current market conditions. This averaging period is the same typically applied across our capital expenditure categories.

5.2.2 Our low volume forecasts are underpinned by known connection projects and history

The primary RIN category that includes our low volume connections is 'complex connection HV (customer connected at HV)'.

We have forecast low volume connections based on a bottom up build, however, where connection projects for a particular connection type are unknown, we have used historical investment. This is because we rarely receive

57 ACIF's engineering forecast are only made at the Victorian level, which we have applied.

58 UE ATT098 - ACIF - Australian construction market - Nov2019 – Public, UE ATT049 - ACIF - Construction index - May2019 - Public

59 UE MOD 5.01 - Connections capex - Jan2020 – Public, UE ATT110 - ACIF - Mapping to function codes - May2019 - Public

inquires for the entire regulatory period by the time of submitting the initial regulatory proposal. The AER has previously considered it appropriate to trend forward connections investment when connection projects are unknown.[60]

Consistent with our previous approach, we have separately forecast the low volume connections below and above $2.5 million. This is because each year there is a relativity steady need for some (even if they cannot yet be identified) low volume projects under $2.5 million, however, projects larger than this are typically driven by specific 'one off' large infrastructure projects. Overall, this approach is preferable to construction activity forecasts because these large and low volume connections are typically not directly related to broader construction activity and are driven by specific policies and customer needs.

We have provided business cases for material projects; the Suburban Rail Link[61] and Latham Road[62] relocation works listed in section 5.1.3. These connections will be customer funded.

The details of some major connection projects are commercially sensitive and therefore we have provided the full investment breakdown in confidential models to the AER[63] and a summary in our public connections model.

5.2.3 Forecasting contributions

We have forecast contributions, gifted assets and rebates based on the 2016/17–2018/19 average. We have not included earlier years in the average (as per our volume and unit rate forecasts) because prior to 2016 our capital contributions were calculated in accordance with the ESCV's *Electricity Industry Guideline No.14 – Provision of Services by Electricity Distributors*. Since 1 July 2016, our contributions have been calculated in accordance with Chapter 5A of the Rules, as applied in Victoria.[64]

5.2.4 Our connection investment is reviewed as part of our total capital investment program

We have cross-checked our forecast against alternative forecasting approaches to assess its reasonableness as outlined below:

- our first cross-check was to trend forward 2015–2018 average connection growth rates. This approach would assume that historical trends continue.
- our second cross-check was to apply the percentage change in customer numbers as forecast by the Centre for International Economics (**CIE**)[65] used in forecasting operating expenditure. This approach would not address subdivisions well (i.e. when a dwelling is subdivided it would only show up as one additional customer, however, two connections are required) and would not provide the detailed sector level forecasts we have used.

In both cross-checks, low volume connections have been applied as per our actual forecast approach.

The figure below outlines our connections forecast under our proposed approach and the cross-checks discussed above.

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60 UE ATT185 -AER –Final decision distribution determination – May2016 –Public, Attachment 6, p 65.

61 UE BUS 5.02 - Suburban rail Loop - Jan2020 - Confidential

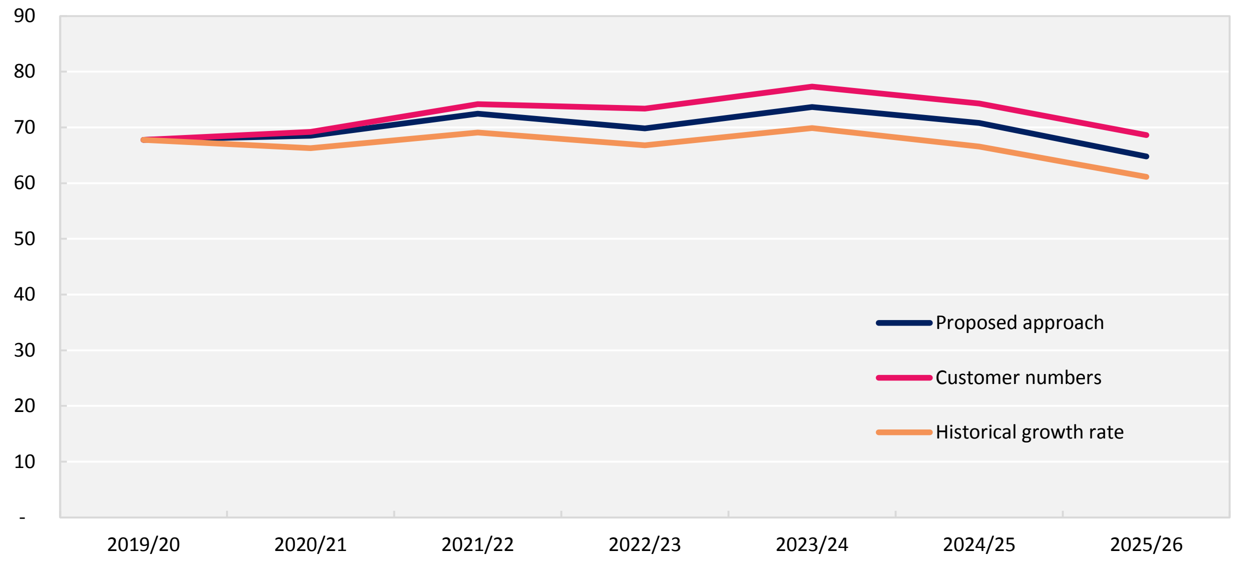
62 UE BUS 5.01 - Lathams road - Jan2020 - Confidential

63 UE MOD 5.02 - Connections major projects - Jan2020 - Confidential

64 Schedule 2, *National Electricity (Victoria) Act 2005*.

65 UE ATT019 - CIE - Customer number forecast - Jun2019 - Public

Figure 5.4 Forecast approach cross-checks ($ million, 2021)

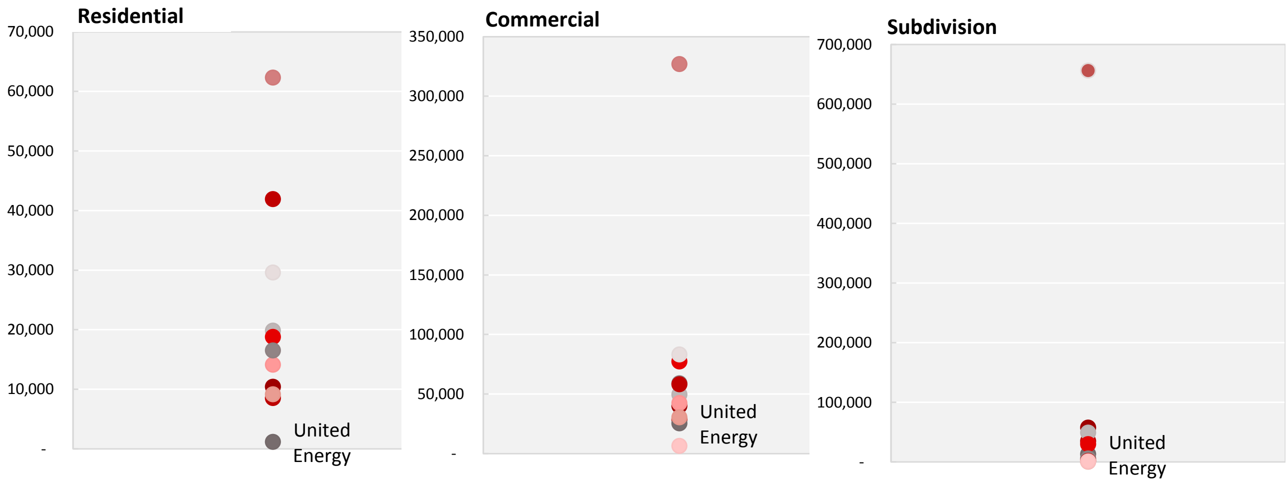


Source: United Energy

Our forecast using our proposed approach is broadly consistent with our cross-checks. Our historical growth has been robust but moderate, and so we would expect the cross-check to be more closely aligned with our actual forecast. Overall, the total connections investment under our proposed approach is in line with both cross-checks, which points to our forecasts as being reasonable.

We have cross-checked our unit rates against those of other distributors from the category analysis RIN. We have taken the average rates over 2015–2017 as shown below.

Figure 5.5 2015–2017 average unit rates by category for each distributor



Source: United Energy, Category Analysis RIN

While our rates are competitive against other distributors, this analysis demonstrates that due to network differences and different reporting methods, we do not believe the RIN information can be used to meaningfully compare unit costs.[66] The smallest range between the lowest and highest unit cost occurs in the 'residential' category, but even this has a range from $1,167 to $62,292. In 'subdivision' category, rates range from $674 to $656,037.

The efficiency of our unit rates is evident through our overall network performance. We are one of the most efficient distributors according to the AER's benchmarking, and have the third lowest network charges in the NEM. This would not be achievable without efficient rates, given gross connections make up around 25% of our forecast total capital investment. Further:

- we undertake competitive market tenders for source material supplies and our connection service providers (all of which are outsourced)
- our unit rates are based on actual costs—they are calculated as the average of our connections investment divided by connection volumes. Under the incentive framework, we have a continuous incentive to reduce operating and capital costs meaning our actual costs are efficient.

66 An example of different reporting is evident by comparing Powercor and United Energy. Powercor reports standard control load connections and expenditure, whereas United Energy reports standard control and alternative control load and solar connection volumes, and standard control connections expenditure.

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6

Augmentation

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6 Augmentation

Our augmentation investment forecast for the 2021–2026 regulatory period supports our customers shared energy future.

Our stakeholders have told us they expect we plan for a shared energy future that meets the evolving needs of our customers and the communities they live in. In particular, our customers are changing the way they use, store and sell electricity. Rooftop solar systems are already well established (and growing) and electric vehicles are expected to become increasingly affordable.

More specifically, our engagement has found the following:

- our customers want to export their excess solar energy back into the network so they can lower their bills, have greater energy independence and to help the environment
- over 75% of our customers consider the network should be upgraded faster than is currently occurring to allow for renewable energy, and they support both network investment and modernising our grid with new technology to meet customers outcomes
- our residential customers are generally satisfied with our existing reliability and power quality levels; they are not willing to trade these off for cost savings
- our large commercial and industrial customers stressed that a reliable power supply is important, but power quality issues are more frequent and have large and wide-ranging impacts on their businesses—they want us to focus on these concerns, and to provide clear and timely communication during any incidents.

Our shared energy future also recognises that Melbourne is forecast to become Australia's most populous city by 2030. We will continue to lead the industry in implementing non-network solutions to manage localised growth. Non-network solutions, including demand management and embedded generation, deliver savings to our customers. We have long recognised that utilising these solutions is prudent, particularly given rising uncertainty in future maximum demand growth and the potential impact of technological change.

For example, we are proud of being the first distributor in Australia to adopt a non-network solution through the Regulatory Investment Test for Distribution (**RIT-D**) process, deferring $30 million of capital expenditure in the 2016–2020 regulatory period on the lower Mornington Peninsula. Similarly, we were recognised within Australia and internationally for our work to establish our 'Summer Saver' residential behavioural demand response program. This innovative program has deferred $10 million of capital works, and is now part of our business as usual approach to demand response (in lieu of capital investment).

In some high-growth areas, however, particularly around Doncaster, Box Hill, Keysborough, Mornington and Malvern, network-based investments are expected to be the least-cost solution to provide a reliable supply of electricity. Many of our assets are already heavily utilised in these areas, and augmentation is required to support localised growth—at a total network level, we have amongst the highest capacity utilisation in Australia.

This chapter sets out how we are preparing our network to be flexible to accommodate the growing energy needs of our customers and key stakeholders:

- in section 6.1, we outline the services our forecast investment will allow us to deliver
- in section 6.2, we provide further detail on our approach to developing our investment forecast, including the drivers of network augmentation, an overview of our planning policies, and how we use non-network and demand management solutions to manage uncertainty or avoid the need for capital expenditure.

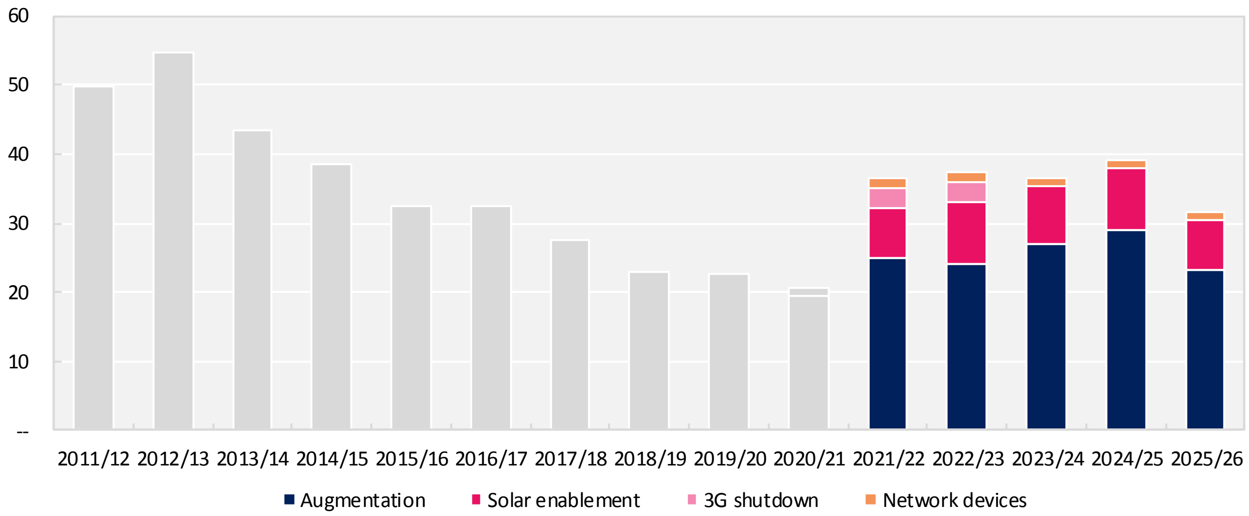
An overview of our forecast augmentation investment in the 2021–2026 regulatory period to support these growing energy needs is shown in table 6.1 and figure 6.1. Our augmentation forecast is consistent with our distribution annual planning report (**DAPR**),[67] and the capital expenditure objectives, criteria and factors set out in the Rules. Our forecasts are also consistent with our draft plan, although some investment has been re-classified into our replacement category to better align with the nature of the underlying works.

Table 6.1 Network investment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Augmentation investment (gross)	36.4	37.3	36.5	39.2	31.7	181.0

Source: United Energy
Note: Forecast includes real escalation and excludes network overheads
Note: This figure differs from summary table 1, where disposals have been netted off gross augmentation

Figure 6.1 Forecast investment to augment our network ($ million, 2021)



Source: United Energy
Note: Forecast shown includes real escalation and excludes network overheads

Our augmentation forecast is supported by a series of business cases and models for key projects or programs. This includes our solar enablement program, and investments required as we modernise our network (such as responding to the shutdown of the 3G telecommunication network, and the targeted rollout of network devices to support our transition to a more digital network). These programs are major drivers of our increased forecast. Our business cases are summarised in table 6.2, and cover over 55% of our total augmentation investment.

67 UE ATT002 - DAPR 2019 - Dec2019 - Public

Table 6.2 Summary of material business cases ($ million, 2021)

Description	Investment
Solar enablement	42.4
Doncaster (including Box Hill) supply area	6.4
Keysborough supply area	6.6
Malvern supply area	7.5
Mornington supply area	7.5
HV feeders (net of demand management)	12.8
Network communications: 3G shutdown	6.0
Digital network: network devices	6.8
Total business case	**96.1**

Source: United Energy
Notes: Our network devices justification is set out in the digital network business case, included as part of our ICT chapter
Forecasts exclude real escalation and network overheads

6.1 What we plan to deliver

To ensure our network is flexible to our customers growing energy needs, we commit to providing the following over the 2021–2026 regulatory period:

- enabling solar exports and renewable generation
- reinforcing our network to provide the core electricity infrastructure needed to maintain and manage reliability of supply risk
- modernising our network (including our communications infrastructure) to support customer outcomes.

We will continue to provide these outcomes by building on our use of non-network and demand management solutions to manage uncertainty, and provide investment deferral opportunities that reduce costs for customers.

6.1.1 We're enabling solar exports and renewable generation

Our customers have told us we should be taking steps to prepare for a future driven by increased solar, batteries and electric vehicles. These technologies provide opportunities for customers to lower their bills, have greater energy independence and build a sustainable future.

Solar enablement

Between now and 2026, solar capacity on our network is forecast to more than double. Solar panels are becoming more affordable over time, and are supported by the Victorian Government's Solar Homes initiative to subsidise the installation of solar panels on 650,000 homes and 50,000 rental properties over 10 years.

Since 2017, we have heard from thousands of our customers about their solar expectations. A summary of our engagement is below.

2017

Initial engagement

Gauged customers' current use and interest in solar:

- nine mini-group discussions
- online survey of 600 residential and 200 small and medium business customers
- seven in-depth interviews with large customers

2018

Customer preference

Asked how we should prepare the network, facilitate solar and who should pay:

- two opinion leaders forums
- deliberative forum
- online survey >800 customers
- investment options forum
- eight in-depth interviews with large and industrial customers

2019

Draft proposal

Received feedback on our proposed solar enablement approach in our draft proposal:

- draft proposal forum
- deep dive workshops with key industry stakeholders
- in-depth interviews with large customers

Options paper

Sought feedback on solar options paper, which took a more detailed look at different approaches to solar enablement:

- online survey
- solar online and stakeholder consultation
- solar design workshop/report

A key stage of our engagement process was our solar deep dive, where stakeholders told us the approaches to enabling solar we were considering at the time were too limited in scope. As a result, we developed and consulted on an options paper.

The feedback on our options paper was clear that customers can tolerate reasonable constraints (i.e. they supported dynamic control and affordable prices), but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. Our customers also viewed a 'first-in, first-served' approach to connecting solar as unfair; rather, all customers should be able to export some solar.

In our options paper, we also considered how to recover the cost of enabling solar, including:

- connection charge—an upfront charge paid by customers seeking to export solar
- 'quasi export tariff'—a reduction to the Feed in Tariff received by solar customers
- tariffs—spread across all customers.

Almost two-thirds of our customers and stakeholders preferred the costs to be paid by those connecting solar. This was also the view from consumer advocates representing financially vulnerable customers. On balance, however, we opted to spread the costs among all customers, including because the benefits from our program will accrue to all. This decision is discussed in detail in our solar enablement business case.

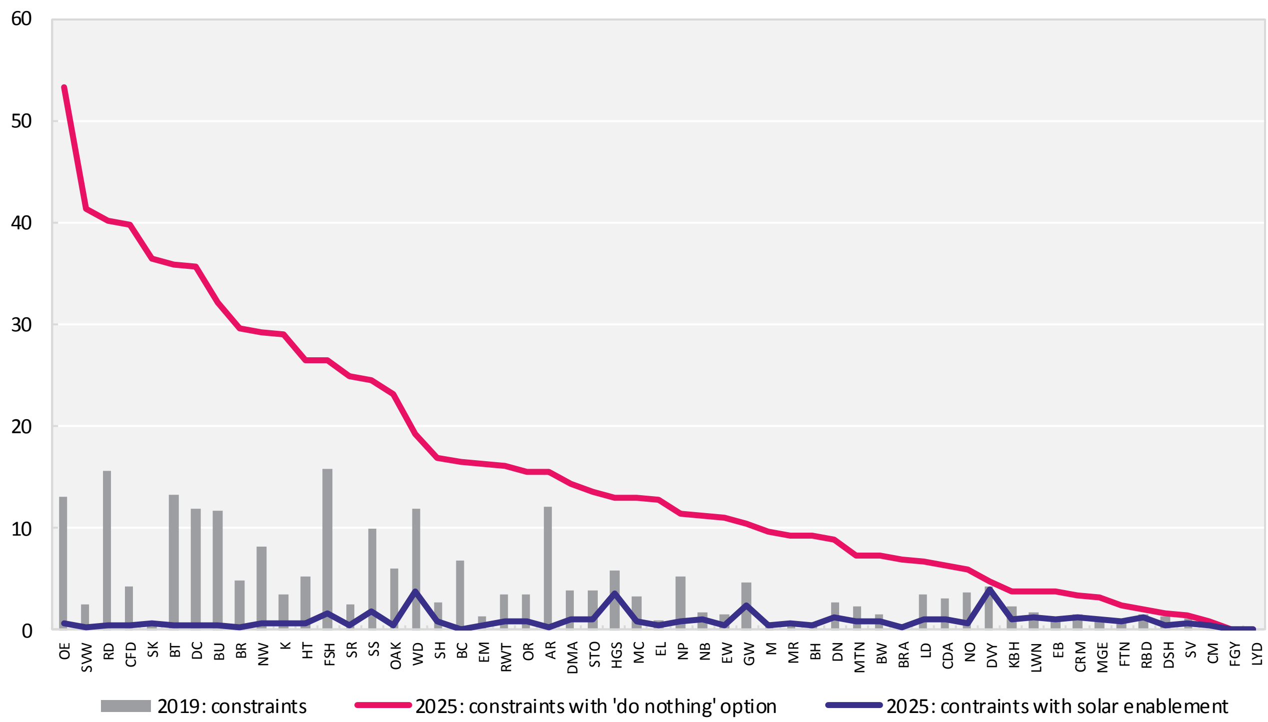
The feedback we received from our customers and stakeholders, as outlined above, has helped refine our solar enablement program. Consistent with this feedback, we will:

- enable all our customers to connect solar
- enable 5kVA solar systems that are typically being installed to be able to export for most of our customers
- remove solar export constraints where it is economic to do so (i.e. where the benefits to customers outweigh the costs)
- assist those customers where it is uneconomic to remove constraints to get the most out of their solar
- maintain our 10kW per phase eligibility threshold for basic (automatic) connections.

Our approach is also supported by extensive economic modelling. We have drawn on over 38 billion data points from our smart meters, and considered the impact on each of our 12,500 distribution transformers. We have understood the extent of network constraints for our customers to this level of detail. This has allowed us to understand the percentage of daylight hours for which solar is constrained now and in the future, as shown in figure 6.2:

- the red line indicates the time which solar is forecast to be constrained in 2025 if we undertake no action; this will result in the average customer at 30% of our zone substations experiencing constraints more than 20% of the time
- the blue line represents the outcome after our solar enablement program and the efficient level of constraint; this will result in the average customer only experiencing solar constraints for one day of the year.

Figure 6.2 Percentage of time solar is constrained by zone substation



Source: United Energy

We have then compared the cost of removing a voltage constraint with the benefits, as measured by valuing the reduction in wholesale generation fuel costs and carbon reduction benefits from solar. These are benefits that all our customers (even those without solar) will receive. The net benefit to our customers of our program is over $73 million.

The targeted nature of our investment is also consistent with our customer and stakeholder preferences for a proportional program. In table 6.3, we compare the capital investment required under our program to remove most constraints (i.e. the distance between the red and blue lines) to the cost should we attempt to remove all constraints (i.e. the area underneath the blue line).

Table 6.3 Comparison of capital investment alternatives to remove most versus all constraints ($ million, 2021)

Description	Investment
Capital investment required under our solar enablement program	42.4
Capital investment required to remove all solar constraints	102.6

Source: United Energy
Note: Forecasts exclude real escalation and network overheads
Note: Our solar enablement program also includes an information technology (**IT**) and operating component. These are included in the business case and discussed in our ICT and operating expenditure chapters.

More broadly, if we do not prepare the network for the volume of solar PV being connected, the annual amount of constrained solar generation in 2025 across our three networks (i.e. CitiPower, Powercor and United Energy) will be equivalent to 2.4 times the annual output of that produced at the Karadoc solar farm in northern Victoria.[68]

Further detail on our proposed approach to enabling solar investment on our network in the 2021–2026 regulatory period is set out in our attached solar enablement business case.[69]

6.1.2 We are reinforcing our network to provide the core electricity infrastructure

Melbourne is forecast to become Australia's most populous city by 2030, and our electricity network will provide the backbone to support much of this ongoing growth and development.

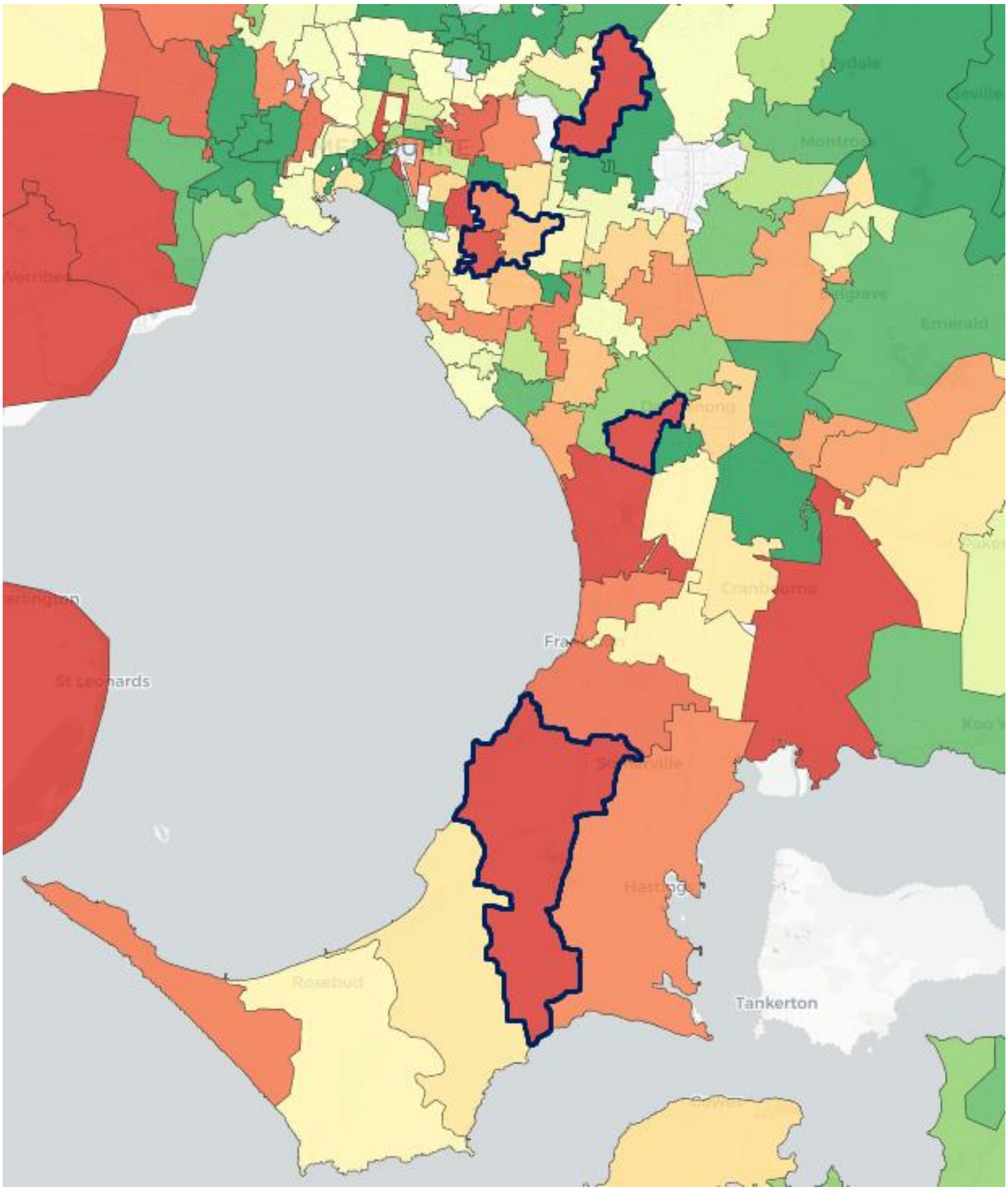
Consistent with the capital expenditure objectives in the Rules, we must plan our network to ensure we meet forecast demand for electricity.[70] In the 2021–2026 regulatory period, we will undertake major zone substation and feeder upgrade works at our Doncaster, Keysborough, Mornington and East Malvern zone substations. The network opportunity maps published by Australian Renewable Energy Mapping Infrastructure (**AREMI**), and shown in figure 6.3, highlight existing network capacity is limited in and around these areas of our network (outlined in purple).

68 Based on the rated capacity of Karadoc, and AEMO's published capacity factor for northern Victorian solar farms.

69 UE BUS 6.06 - Solar enablement - Jan2020 - Public

70 *National Electricity Rules*, cl. 6.5.7(a).

Figure 6.3 AREMI network opportunity map: available distribution capacity, 2019 (MVA)

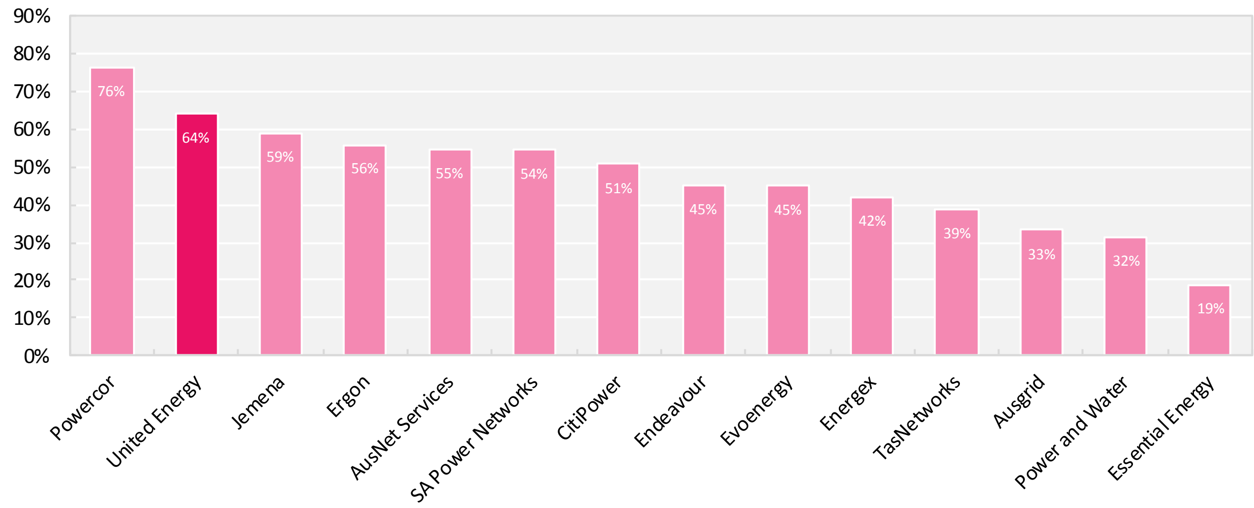


Source: AREMI

Notes: Yellow, orange and red sections represent locations where available distribution capacity is limited

The capacity limitations highlighted by AREMI also reflect that we manage one of the most highly utilised network in Australia. Our asset utilisation in comparison to other distributors is provided in figure 6.4, and shows we get the most out of our assets.

Figure 6.4 Maximum demand relative to total capacity at the zone substation level (%)



Source: AER, *Electricity distribution network service report data*, August 2019

Ensuring capacity in the Doncaster supply area

Our Doncaster zone substation was commissioned in the early 1960s to provide capacity to the Box Hill North, Doncaster, Doncaster East and Templestowe communities. These areas have developed into flourishing commercial and residential precincts, with relaxed planning regulations in the Box Hill precinct leading to the development of skyscrapers normally only seen in and around the Melbourne CBD.

In the 2021–2026 regulatory period, growth in maximum demand in the Doncaster supply area is expected to increase at an average annual growth rate of 1.3%. This is primarily driven by the expansion of the Epworth Hospital, and the ongoing development and increased occupancy in higher-density buildings.

We apply a probabilistic approach to planning all demand-driven investment decisions. Consistent with this approach, the quantity and value of energy at risk is a critical parameter in assessing prospective network investment or other action in response to an emerging constraint. The forecast increase in demand at our Doncaster zone substation, coupled with the prevailing load characteristics at the site, means the energy at risk of not being supplied should one of the existing transformers fail is relatively high. For example, after load transfers, a shortfall in capacity of approximately 20 MVA is forecast for 2028 (or loss of supply for 8,000 customers).

The energy at risk of customers in the area not being supplied by our Doncaster zone substation is also driven by the condition of the existing transformers. All three transformers at our Doncaster zone substation are over 50 years of age, and two have been assessed as being very close to end-of-life (based on condition). These two transformers were constructed under the same design standards, which means both units are of the same make, age and possess identical characteristics.

As part of our stakeholder engagement program, we held a series of deliberative forums with our customers. At our investment options forum held at our United Energy office, we discussed delivering a reliable supply of electricity in the Doncaster area with growing demand and aging assets at the Doncaster zone substation.

To enable customers to understand and explore the investment options for maintaining a reliable supply, participants were informed of the key challenges in our Doncaster supply area, and four options for investment (including no investment and demand management alternatives). Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact from other investments discussed throughout the entire forum.

Our customers supported the installation of a fourth transformer at our Doncaster zone substation, and required feeder works. It was recognised that not investing will ultimately result in higher costs overall, and does not accommodate anticipated growth.

Our preferred option to ensure we maintain a reliable supply of electricity to customers in the Doncaster supply area as the level of energy at risk continues to grow is to first establish a new feeder from our neighbouring Box Hill zone substation (as some spare capacity is available). These works will occur in 2020, and defer the need for further investment at our Doncaster zone substation until 2024. In 2024, a fourth transformer and two new feeders will be established to continue to support forecast demand.

Further details on our preferred investment option, including the alternative interventions considered, are set out in the attached Doncaster supply area business case and investment model.[71] A summary of our augmentation investment to support these works for the 2021–2026 regulatory period is shown in table 6.4.

Table 6.4 Doncaster supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Doncaster zone substation: fourth transformer and two new feeders	6.4

Source: United Energy
Note: Forecast excludes real escalation and network overheads

Ensuring capacity in the Keysborough supply area

Our Keysborough zone substation provides electricity supply to approximately 9,500 customers in Keysborough and Dandenong. These customers are predominantly residential, with a mix of light industrial and commercial establishments.

Keysborough has a high public profile as one of Melbourne's major growth areas. With improved access through East Link, the Dandenong Bypass and Dingley Arterial, the popularity of the suburb has increased substantially. This has stimulated rapid construction growth in both the residential and industrial sectors.

Our existing Keysborough zone substation, however, comprises just a single transformer. As such, there is an increasingly high level of energy at risk should the existing transformer fail—all connected customers will be off supply until load transfers are established.

We considered a range of alternatives to manage this energy at risk (in addition to the works we have already undertaken at Keysborough zone substation to support the connection of our relocatable mobile transformer).[72]

[71] UE BUS 6.02 - DC supply area - Jan2020 - Public

For the reasons set out in our Keysborough supply area business case and investment model, the most efficient intervention is to establish two new feeders and a second transformer at Keysborough zone substation.[73] The timing of this option corresponds to when the expected value of unserved energy exceeds the annualised project cost.

Table 6.5 summarises the forecast investment required in the 2021–2026 regulatory period to support the preferred option.

Table 6.5 Keysborough supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Keysborough zone substation: second transformer and two new feeders	6.6

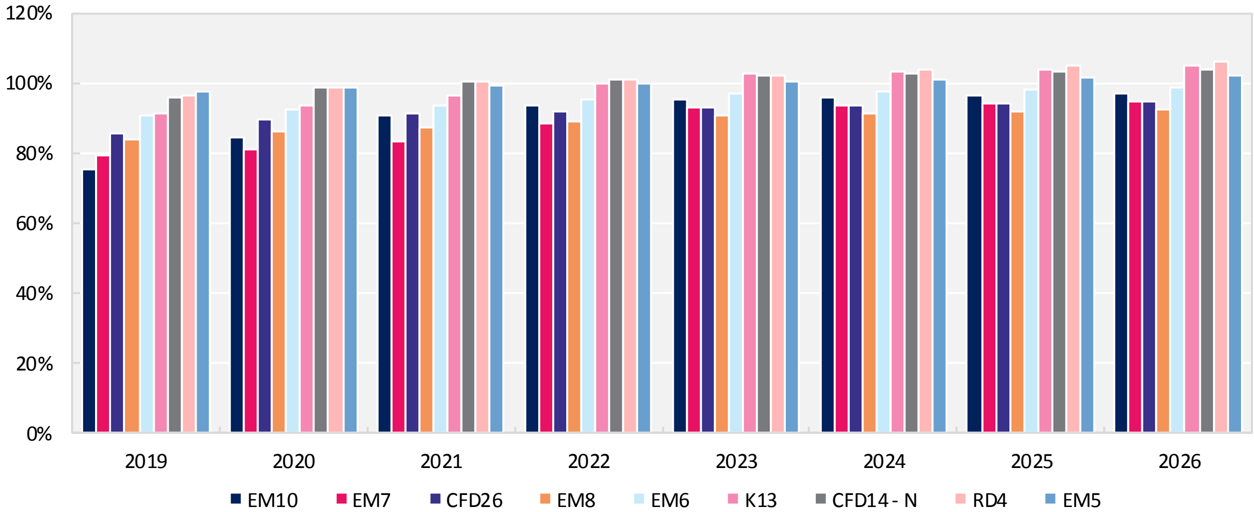
Source: United Energy
Note: Forecast excludes real escalation and network overheads

Ensuring capacity in the Malvern supply area

Our Malvern supply area services customers in Caulfield, Carnegie, Glen Iris, Glen Huntly, Malvern and Malvern East. Electricity in this area is provided by zone substations at Caulfield, East Malvern and Gardiner, and a network of over 30 distribution feeders.

Several of the feeders supplying this area are heavily utilised and are forecast to be overloaded in the 2021–2026 regulatory period. This follows ongoing commercial growth and residential in-fill projects, and forecast maximum demand increases due to new high-density residential developments (including those surrounding the Caulfield Racecourse). A summary of the utilisation forecasts for key distribution feeders is shown in figure 6.5.

Figure 6.5 Feeder utilisation: ratio of maximum summer demand to feeder summer cyclic rating (%)



Source: United Energy
Note: East Malvern (EM), Caulfield (CFD), Gardiner (K), Riversdale (RD)

72 We presently have two 66/22kV relocatable transformers, however, these relocatable transformers are currently in service and actually supplying customers (not spare transformers). Notwithstanding this, it is expected the relocatable transformer can be mobilised and connected at Keysborough zone substation within 48 hours.

73 UE BUS 6.04 - KBH supply area - Jan2020 - Public

The high utilisation of the existing feeders limits our ability to manage supply during both normal conditions and during contingencies (e.g. loss of a feeder due to unplanned faults). In the absence of any intervention, this is forecast to result in future outages for over 10,000 customers.

Our Malvern supply area business case and the corresponding investment model set out our assessment of this increasing risk.[74] As for all our demand-driven augmentation projects, this includes the comparison of multiple intervention options to a 'do-nothing' scenario, including feeder works, a new switchboard or transformer, and non-network alternatives.

The consideration of non-network alternatives is based on the cost of a non-network solution that would result in the energy at risk remaining at the same level as that forecast in the year immediately prior to the commissioning date of the preferred solution. The cost of a non-network solution is set equal to a benchmark rate, consistent with our recently implemented non-network solutions and an independent comparative analysis of other distributors' experience.[75]

Our preferred option—to permanently offload heavily utilised distribution feeders by installing three new feeders and a new switchboard at our East Malvern zone substation—is shown in table 6.6. This option maximises the net economic benefits to all customers.

Table 6.6 Malvern supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
East Malvern zone substation: three new feeders and new switchboard	7.5

Source: United Energy
Note: Forecast excludes real escalation and network overheads

Ensuring capacity in the Mornington supply area

Mornington is one of the fastest growing regions in the Mornington Peninsula. The establishment of the Peninsula Link in 2013 further increased the popularity of the area, and stimulated growth in both residential and commercial sectors.

We supply electricity to the area through our Mornington zone substation. This zone substation services approximately 23,000 customers in Merricks, Merricks North, Balnarring, Tuerong, Moorooduc and Mornington.

In the event of a major outage of one of the Mornington transformers during peak demand conditions, the expected shortfall in capacity after load transfers are established is approximately 17MVA in 2028. This equates to an expected loss of supply for approximately 7,000 customers.

We assess the options to support the growing population and increasing energy at risk in the Mornington supply area in our Mornington supply area business case and investment model.[76] Our preferred option to address the identified need includes the staggered installation of two new feeders, followed by the addition of a third transformer at Mornington zone substation.

Alternative interventions considered included permanent load transfers and non-network alternatives. The large geographic area covered by Mornington and adjacent zone substations means that many of the distribution

[74] UE BUS 6.03 - EM supply area - Jan2020 - Public

[75] UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public

[76] UE BUS 6.05 - MTN supply area - Jan2020 - Public

feeders in this supply area are long and rural in nature. This makes load transfers more challenging than meshed, urban zone substations. Further, the topology of the surrounding network means several feeders from Mornington zone substation have no tie points with adjacent zone substations.

Table 6.7 outlines the forecast investment required in the 2021–2026 regulatory period to support the preferred option.

Table 6.7 Mornington supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Mornington zone substation: third transformer and two new feeders	7.5

Source: United Energy
Note: Forecast excludes real escalation and network overheads

Ensuring capacity in our HV feeder network

Ensuring our HV feeders have capacity to meet our customers' electricity needs is an integral part of operating our network. We continually monitor our feeder capacity and apply an economic approach to balance the risk of overloads with affordability. For example, our feeder planning approach includes the following:

- asset management intervention is considered when a feeder reaches 85% utilisation. When a feeder reaches 85% utilisation, the reduction in energy at risk from an augmentation typically exceeds the augmentation cost (depending on the feeder characteristics). However, rather than augment based on this threshold, we instead use this to trigger a more detailed review
- under our more detailed review process, we consider deferment and risk mitigation options (e.g. load transfers to adjacent feeders and demand management). Where multiple adjacent feeders are highly utilised, and/or the existing network topology prevents any substantial load relief for the highly utilised feeder, a scope of works is developed
- once all deferment or low cost options such as demand management have been exhausted, major augmentations are required to maintain the feeder load within the thermal limit. At this point in time, there is significant customer load at risk because load shedding will be required under system normal conditions as well as outage conditions.

The investment required over the 2021–2026 regulatory period to ensure capacity in our HV feeder network has been developed based on the approach above, including our assessment of demand management options. These feeder forecasts have also been considered more holistically, to ensure any identified constraint is considered in the broader context of providing a reliable supply of electricity. That is, our highly utilised Doncaster feeders have been assessed in the context of a broader solution for ensuring capacity in the Doncaster supply area that includes the impact of proposed zone substation works.

Further justification for our forecast of material feeder investments is provided in our attached HV feeder and feeder demand management business cases.[77] From this business case, it is clear our approach often results in feeders exceeding 90% utilisation (and sometimes 100% utilisation) before augmentation is planned.

77 UE BUS 6.07 - Distribution feeder approach - Jan2020 – Public. We forecast smaller feeder investments in the same manner, but these are not included in our business case. UE BUS 9.03 - Feeder demand management - Jan2020 - Public

The investment from this analysis is reflected in our augmentation forecast model.[78] Separately, the model includes an adjustment item to account for the impact of our proposed HV feeder demand management program, which is discussed in section 9.1.2 and in our HV feeder demand management business case.[79] An overview of our investment for material feeder investments is set out in table 6.8.

Table 6.8 HV feeder upgrades: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Material HV feeder investment (net of demand management)	12.8

Source: United Energy
Note: Forecast excludes real escalation and network overheads

In December 2019 the Victorian Government proposed rental housing reforms, including a new minimum standard for all rental properties to have a fixed heater. The accompanying regulatory impact statement expects this will impact on 84,442 rental properties, which will most likely install reverse cycle air-conditioners.[80] Further, the standard requires the phase out of liquid petroleum gas (**LPG**) fuelled heaters, which are more prevalent in regional areas. We expect these reforms may result in localised load growth that may impact on LV network (e.g. feeders), particularly in areas with single wire earth return lines where LPG is prevalent and the network is less able to accommodate load growth. We will continue to assess the impact of these potential reforms for the revised proposal.

Supporting our distribution substation system

Our distribution substation system comprises over 12,500 distribution transformers that convert electricity between our HV and LV networks, and the LV circuits that connect to these transformers. These assets are protected by both HV and LV fuses.

Under extreme hot weather conditions, the load on these fuses may exceed their thermal limits. This causes them to operate, resulting in supply outages for all downstream customers. These outage events tend to occur at the times customers value electricity the highest, such as times of prolonged extreme heat and in the early evenings when the generation from solar PV subsides. Further, where outages occur at the same time at multiple sites, these outages can last for several hours (i.e. until field crews can attend each site).

We have previously experienced widespread outages due to overloaded transformers, most notably in the 2009, 2014 and 2018 summer periods. Following our 2009 experience, where 950 fuses operated and 54 transformer failures occurred, we established a proactive program to address over-utilised transformers and LV circuits. This program (which now includes smart-meter analytics and demand management) reduced the percentage of overloaded transformers on our network from 13% in 2009 to 4% in 2018.

Notwithstanding this investment, during the extreme heatwave summer of 2017–2018, we again experienced 10,729 customer outages from 354 fuse and distribution transformer operations. In response to this event, we agreed (along with other Victorian distributors) to a heat-relief compensation package for customers with sustained outages, in addition to their eligible guaranteed service level (**GSL**) payments.

78 UE MOD 6.01 - Augex - Jan2020 - Public

79 UE BUS 9.03 - Feeder demand management - Jan2020 – Public, UE MOD 9.05 - Demand management HV feeder - Jan2020 – Public

80 UE ATT157 - VicGov - RTR 2020 RIS - Nov2019 - Public, p. v and 53.

DELWP also undertook a post-event review which recommended making the distribution network more resilient to future heatwaves.

The importance of a resilient network has emerged as a key learning from our customer engagement program. A resilient network differs from a reliable network; a resilient network is one that can withstand rare and large events that affect our broad customer base.

We are experiencing more and more extreme weather events that place increasing pressure on our assets. Our customers expect our network can withstand these pressures, and that clear communication is critical during these events.

Consistent with the feedback from our stakeholder engagement program, our response to the DELWP review included the following initiatives to support a more resilient network:

- expand our existing reactive approach to LV circuit planning with a proactive program
- use smart meter data through our network load management tool to more accurately determine peak utilisation at the circuit level
- operationalise and expand our LV network management and demand response initiatives
- adopt leading indicators of impending overloads (e.g. changes in customer numbers) in our planning of LV circuits
- ensure our service providers and field crews are adequately resourced and mobilise to respond quickly to faults
- expand our use of analytics, including phasing, load balancing and identification of loose connections (that cause power quality issues).

For the 2021–2026 regulatory period, we will continue our established program to improve the resilience of our distribution transformers and LV circuits to these high impact events. We will do this by addressing existing and forecast overload constraints where economically prudent. This program is not targeted at, and nor will it address, day-to-day outages due to events such as transformer (end-of-life) failures and pole strikes. Rather, it addresses rare and major events.

The economic analysis considers the energy at risk for all distribution substations based on smart meter data, and categorises these as set out in the table below.

Table 6.9 Distribution substation system forecast method

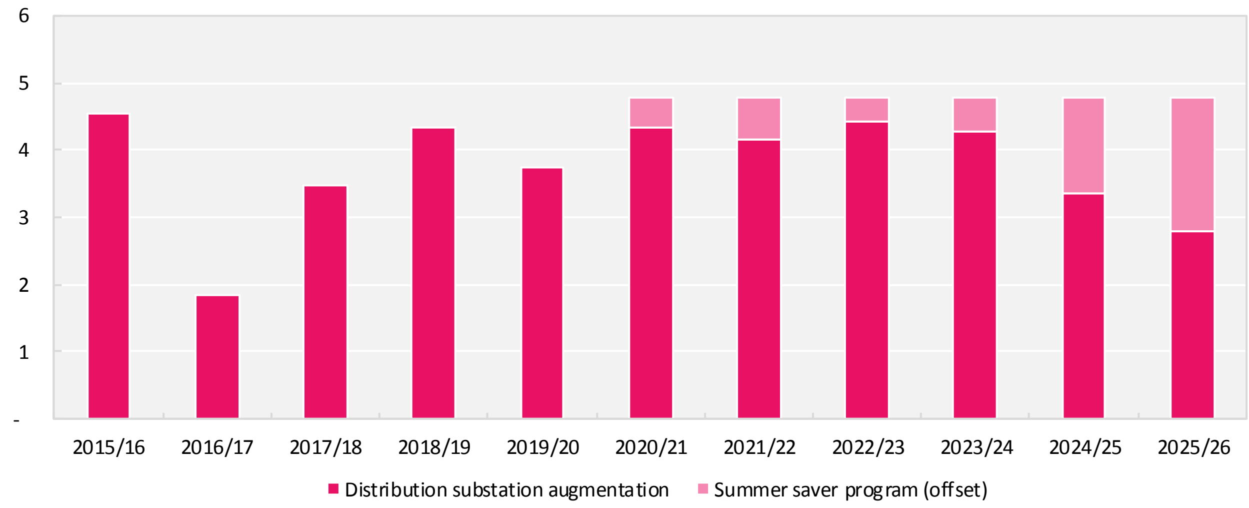
Priority	Description
P1	Sites with predicted fuse operation occurrences (i.e. customer outages) of three or more and/or actual peak utilisation greater than or equal to 160% of cyclic rating during the recent summer.
P2	Sites with predicted fuse operation occurrences equal to two and/or actual peak utilisation greater than or equal to 140% of cyclic rating during the recent summer.
P3	Sites with predicted fuse operation occurrences equal to one and/or actual peak utilisation greater than or equal to 120% of cyclic rating during the recent summer.

Source: United Energy

Our proposed investment also reflects an expected increase in the use of non-network solutions, such as our Summer Saver program. Under this program, we provide financial incentives to customers to manage their demand. This program was initially funded through the demand management innovation allowance (**DMIA**), and is now a business-as-usual alternative to traditional distribution substation augmentation. The increased uptake of our Summer Saver program is forecast due to the improved visibility and capability that our investment in a digital network will enable (i.e. a digital network will allow more substations to be targeted, and more effective rewards and customer uptake through better customer insights).

A summary of our historical and forecast investment to maintain resilience in our distribution substation system, including the reduction in expenditure for the impact of our Summer Saver program, is outlined in figure 6.6 and table 6.10.

Figure 6.6 Distribution substation augmentation ($ million, 2021)



Source: United Energy
Note: Figures excludes real escalation and network overheads

Table 6.10 Supporting our distribution substation system: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Distribution substation augmentation	24.1
Summer Saver program: augmentation savings	-5.0
Total	**19.1**

Source: United Energy
Note: Forecasts exclude real escalation and network overheads

We have ensured the investment proposed for maintaining our distribution substation system does not overlap with our solar enablement program. Our programs targeting distribution substation system augmentation will address an average of 71 issues per annum across our population of 12,500 distribution transformers. In turn, our solar enablement program will address 106 sites on average each year. The drivers for these works are fundamentally different (i.e. our distribution substation program addresses thermal constraints at peak demand, whereas our solar enablement program addresses voltage-driven issues at minimum demand), so the low volumes relative to the total population mean the chance of these programs overlapping is minimal.

6.1.3 Modernising our network to support customer outcomes

Since 2009, our customers have funded a significant investment in smart meters. We are leveraging this investment to lean more on technology and data than ever before to make smarter network decisions. This facilitates data-driven investments, and helps us better meet customer outcomes at the lowest cost.

The investment required to support smarter network decisions in the 2021–2026 regulatory period includes modernising our communications infrastructure and enabling a digital network.

Network communications: 3G shutdown

The safe and efficient operation of our network relies heavily on communicating with our infrastructure over networks controlled by independent third parties. Our access to these communications networks is changing.

Telstra's 3G communications network will be progressively retired over the 2021–2026 regulatory period to make way for 5G technology. When the 3G communications network is retired, we will lose our capability to remotely communicate with devices used to operate, control and monitor the network, and collect metering data. For example, we remotely communicate with devices on our network to perform important functions:

- regulatory compliance—vary the operating mode of assets in bushfire areas, and collect information from smart meters installed at customers' premises
- outage detection—used to detect the location of an outage, resulting in shorter outage times
- remote switching—used to switch electricity around our network to minimise the effect of outages
- remote sensing—remotely monitor the condition/operation of assets and power quality.

We investigated several alternatives to ensure we continue to provide these functions. These options included using other providers' 3G networks, targeted refurbishment of specific assets, upgrading our existing 3G control boxes and access points, or using alternative communications technologies.

The options considered were compared to the impact on customers of not investing (i.e. a 'do-nothing' option, whereby we lose all reliability, efficiency and compliance benefits). For the reasons set out in our attached business case and investment model, the preferred option is to upgrade our existing infrastructure to be 4G and 5G compatible.[81] A summary of the investment required to support this option is set out in table 6.11.

Table 6.11 3G telecommunications shutdown: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Network communications: 3G shutdown	6.0

Source: United Energy
Note: Forecast excludes real escalation and network overheads

Supporting a digital network

Distribution networks across the world are currently going through some of their largest transformations in history. These transformations are being driven by changing customer requirements, including increased participation in new demand management programs, and the expected take-up of electric vehicles and batteries.

81 UE BUS 6.01 - 3G shutdown - Jan2020 – Public and UE MOD 6.05 - 3G shutdown - Jan2020 - Public

During the 2021–2026 regulatory period, we will implement more advanced technology capabilities through our digital network initiative. This will allow us to make smarter and more dynamic network decisions to improve safety outcomes and support customers as they take up new innovations, all while keeping the costs of running the network down.

Most of the investment required to develop a digital network is included in our information technology program. This program, however, also includes a network element—specifically, the targeted rollout of network devices at contestable metered sites or distribution transformers—that is captured in the network communications component of our augmentation forecast. These devices will provide real-time consumption and power quality information.

The full justification for this program, including the corresponding options analysis, is set out in our digital network business case.[82] Table 6.12 shows the investment required for the network component of this program.

Table 6.12 Digital network: network device investment, 2021–2026 ($ million, 2021)

Description	Investment
Digital network: network devices	6.8

Source: United Energy
Note: Forecast excludes real escalation and network overheads

6.2 Our forecasting approach

This section outlines how we plan our network to ensure our customers can continue to choose how they use electricity. This includes an overview of the following:

- the drivers of our augmentation investment
- our planning policies, and how these manage risk
- how non-network solutions are assessed through cost-benefit analysis to ensure we only invest where and when it's needed.

6.2.1 Our augmentation investment is driven by both demand and non-demand factors

Our forecast augmentation investment includes both demand driven and non-demand driven projects.

Demand-driven augmentation investments

Localised maximum demand on our network is a key driver of our forecast augmentation investment. Where demand is expected to exceed the capacity of our network in a particular area, we look to intervene to ensure we continue to maintain a reliable supply of electricity to our customers. These interventions, which also have regard to risk (as discussed in section 6.2.2) may include reconfiguring our network, additional infrastructure, or implementing non-network solutions.

Our approach to forecasting demand for the 2021–2026 regulatory period combines our own detailed local knowledge with independent economic analysis by the NIEIR. A summary of our approach is set out in figure 6.7.

A more detailed discussion on our demand forecasts is provided in our demand forecasting appendix.[83]

[82] UE BUS 7.08 - Digital Network - Jan2020 – Public and UE MOD 7.12 - Digital network cost - Jan2020 - Public

Figure 6.7 Overview of our demand forecasting approach

Top-down forecast
Independent top-down forecasts of terminal station loads were developed by NIEIR, based on regional economic forecasts aligned with those used by AEMO

Post-model adjustments
Post model adjustments, such as for block loads and known embedded generation, and for independent technology forecasts (i.e. solar PV) from NIEIR

Bottom-up forecasts
Zone substation and feeder forecasts developed from local demand/generation characteristics and customer metering data

Bottom-up reconciliation
Our zone substation demand forecasts are reconciled to the top-down terminal station forecasts to ensure consistency

Source: United Energy

Non-demand driven augmentation investment

We also plan our network to manage non-demand driven factors. These include compliance obligations, considering the impact of future fault currents, voltage levels and voltage quality, and whether these factors are forecast to exceed the levels stipulated by regulatory obligations.

Fault levels

A fault is an event where an abnormally high current occurs as a result of a short circuit somewhere in our network.

We estimate prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to select and set protective devices that can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers and fuses can act to break the fault current to protect the electrical plant, and avoid significant and sustained outages as a result of plant damage.

Fault level mitigation programs are increasingly required on our network as the level of embedded generation being directly connected to our network increases.

Voltage levels

We are required to maintain customer voltages within specified thresholds set out in the Distribution Code.[84]

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors (e.g. washing machines and refrigerators), and farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Voltage levels are affected by a number of factors, including the export of electricity onto our network, impedance of transmission and distribution network equipment, length of sub-transmission and distribution feeders, implementation of rapid earth fault current limiters (**REFCLs**), and load and capacitors in our network.

83 UE APP03 - Maximum demand and customers - Jan2020 - Public

84 UE ATT158 - ESC - Electricity distribution code - Jan2020 – Public, clause 4.2

Quality of supply (to other network users)

The connection of embedded generators or large industrial customers to our network may result in a reduction of the quality of supply experienced by other customers on our network. In these circumstances, we may invest to ensure we maintain quality of supply across our network.

These investments are typically undertaken following system studies as part of the new customer connection process.

6.2.2 Our planning processes prioritise key network risks

We apply a probabilistic approach to planning all our demand-driven investment decisions. This approach involves estimating the probability of an outage occurring within the peak period, and determining the energy at risk of not being supplied.

The energy at risk of not being supplied is assigned a monetary value based on how much customers value reliability. The value of customer reliability (**VCR**) we apply is that determined by AEMO, adjusted for inflation.[85]

Our augmentation forecast only includes capital works where the cost of mitigating a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand-side solution is not feasible. We select the lowest cost option to address the risk, including assessing the viability of demand management.

Ultimately, probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, we recognise that given extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under these conditions.

6.2.3 We continue to seek non-network solutions

We consider and adopt non-network solutions, including demand management, to avoid or defer the need to invest in network augmentation when it is efficient. We seek non-network solutions through our distribution annual planning report and public forums on our entire demand-driven augmentation program, when undertaking the RIT-D process for major augmentation works, and through our demand side engagement register.

We have been leading the industry in seeking and implementing opportunities to deliver savings to our customers through non-network alternatives, including demand management and embedded generation. We recognised this as a key area where the industry needed to change and believed it was a particularly prudent decision given the rising uncertainty in future maximum demand growth and the potential impact of technological change.

For example, we were the first distributor in Australia to adopt a non-network solution through the RIT-D process, deferring $30 million of capital expenditure in the 2016–2020 regulatory period on the lower Mornington Peninsula. This project procured more than 11MW of demand response from customers in the community, and complemented this with embedded generation to defer the construction of a new 50km sub-

85 The AER is now required to develop an estimate of the VCR. The AER published new VCRs on 18 December 2019 however these have not been reflected in this regulatory proposal.

transmission line between our Hastings and Rosebud zone substations. We plan to continue to defer this capital expenditure in the 2021–2026 regulatory period by extending the non-network solution (as outlined in our operating expenditure chapter).

We were also recognised within Australia and internationally for our work to establish our 'Summer Saver' residential behavioural demand response program. This program is supported by over 1,000 customers each year, who provide demand response at constrained distribution substations and LV circuits throughout our network. This has deferred $10 million of capital expenditure, and is now part of our business as usual approach to demand response (in lieu of capital investment).[86]

We are committed to continuing our engagement with the broader industry and our customers to seek further opportunities for growing non-network solutions in the 2021–2026 regulatory period. As outlined in the operational expenditure chapter, we have proposed a step change to support growth in the use of demand management. We have done this where we are confident either we or the broader market can realistically deliver a demand response solution that delivers a lower cost outcome for customers.

6.2.4 Our unit cost forecasts are based on recent historical costs

We forecast costs for capital projects based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations. These costs reflect our outsourced operating model, where all field works are undertaken by independent, third-party service providers following an open, competitive tender.

For example, as set out in our replacement investment chapter, we have an approved panel of suppliers who tender for all major capital works. To ensure we achieve efficient, market-based rates, we package our works program to enable benefits to be obtained through tendering significant sized projects. Projects that are suitable to be tendered as turn-key projects are also identified at conception stage, and detailed scopes of works are prepared as the basis for tender documents.

Our materials cost forecasts are also procured through stringent contracting arrangements.

For clarity, we adjust our historical costs for forecast growth in real input prices over time, such as labour, materials and contracted services. Further discussion on our cost escalators is provided in the operating expenditure chapter.

6.2.5 We will deliver our augmentation program using market resources

As outlined above, we operate an outsourced structure for constructing and maintaining our distribution network. This allows us to deliver our total capital program, including the forecast increases in investment over the 2021–2026 regulatory period, by using resources available in an open market.

86 Further details on this program in the 2021–2026 regulatory period are set out in our operating expenditure chapter.

7

Information and communications technology

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7 Information and communications technology

Technological change is occurring at an increasingly accelerated pace, providing us with both challenges and opportunities.

Information and communications technology (**ICT**) is a key capability that enables us to improve customer experience, respond to changes in the energy market, drive improvements in our network planning and meet new compliance obligations.

Our recurrent ICT investments over the 2021–2026 regulatory period include:

- cyber security - enhancing our cyber-security capabilities to maintain pace with increasing cyber threats. This includes developing security on access and control of the supervisory control and data acquisition (**SCADA**) system, which is critical to network operations
- market systems - we will prudently deploy version upgrades to ensure we maintain support for our systems which manage the delivery of data for the market and our customers
- network management systems - we will to maintain the currency of the systems which manage our network such as geospatial information system (**GIS**), outage management system (**OMS**), SCADA and distribution management system (**DMS**). Maintaining currency of these systems is critical to maintaining the safe, reliable, secure and efficient delivery of network services
- cloud-infrastructure - we will reduce costs by migrating some of our existing on-premise ICT infrastructure to the cloud.

We will also maintain the currency of other systems including facilities security (e.g. security cameras), business intelligence and warehousing, telephony and enterprise market systems. Our customers view reliability, affordability and the privacy of their data as top priorities – maintaining currency of our systems ensures these objectives are met.

Our key non-recurrent ICT investments over the 2021–2026 regulatory period include:

- digital network - we will develop a smarter network that responds to the transformation underway in the energy market, ensuring we can run the network safely and more efficiently
- customer enablement – we will improve how our customers access information, saving them time and effort through unifying existing customer portals and using artificial intelligence to provide better services
- SAP upgrade - we will upgrade to the latest SAP product (SAP S/4 HANA) once vendor support on our existing product ends
- five minute settlement - we are required to provide five minute interval data for market settlement by December 2022.

At the heart of our success has been a prudent approach to adopting technology that delivers tangible benefits to our customers. We intend to continue this approach over the next regulatory period.

This chapter outlines our ICT investment in the 2021–2026 regulatory period:

- in section 7.1, we outline the our forecast investment in recurrent and non-recurrent ICT services
- in section 7.2, we discuss our approach to forecasting ICT capital expenditure.

An overview of our forecast ICT capital investment is shown in the table below.

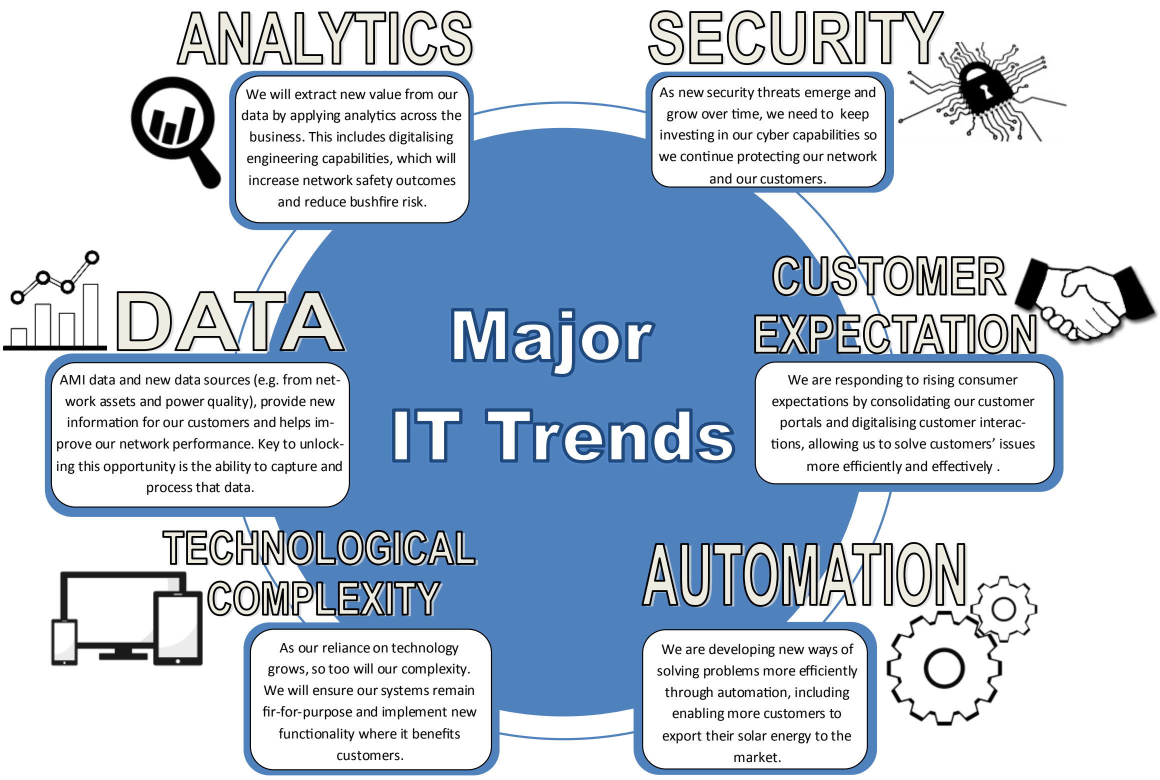
Table 7.1 ICT investment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
ICT investment	56.3	38.4	39.8	35.6	24.1	194.3

Source: United Energy
Notes: Forecast includes real escalation and excludes network overheads

Technological change is occurring at an accelerated pace driven by a number of trends. This includes an explosion in data availability, growth in data analytics, increasing cyber security threats, rising customer expectations, more automation and an increasingly complex ICT environment. These trends provide opportunities and challenges in the upcoming 2021–2026 regulatory period.

Figure 7.1 Major ICT trends during the 2021–2026 regulatory period



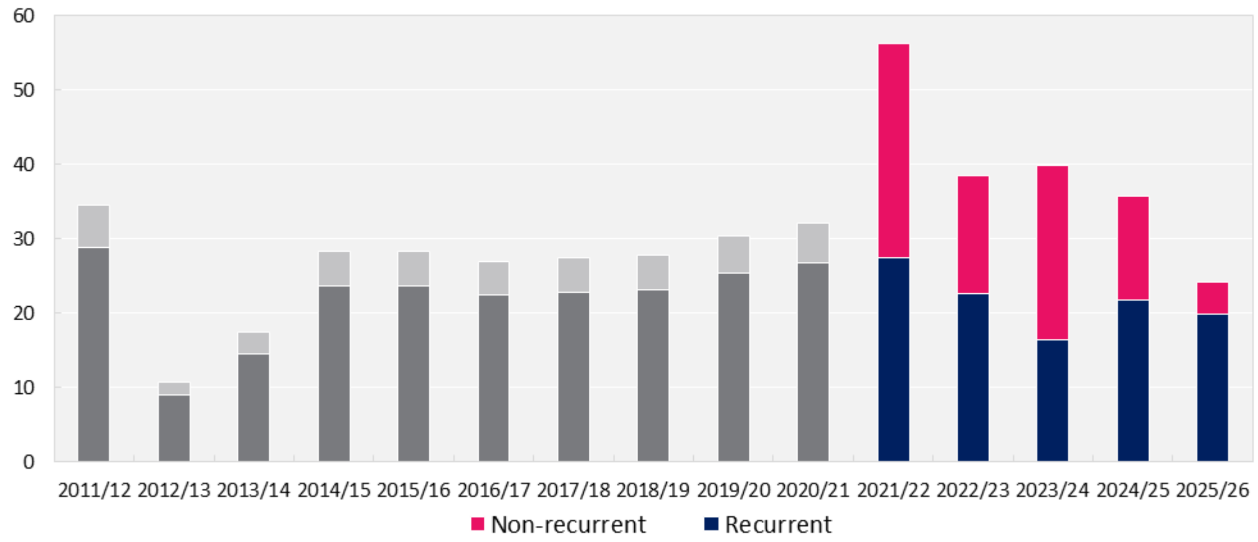
Source: United Energy

ICT ensures we can affordably provide a safe and reliable network, improve the way we deliver services to customers and support the delivery of new innovations. For example, a key way we have utilised our ICT systems is through leveraging our smart meters to provide customer benefits such as reduced outage times, lower network charges and better information on their energy usage.

We have also used ICT to improve the productivity of our network.[87] None of these productivity-driven initiatives have been funded by our customers through the AER allowances. Instead, we have self-funded these and the benefits have been shared between customers and ourselves in accordance with the regulatory expenditure incentive schemes. These initiatives have been critical to enabling us to maintain affordability of our network.

Our proposed ICT investments for 2021–2026 regulatory period are set out in the figure below, in alignment with the capital expenditure objectives and addressing the capital expenditure criteria specified in the Rules. Investment is being driven by the need to refresh our existing ICT systems. We are also taking advantage of new technologies to unlock new benefits for customers, observe new compliance obligations and perform a major upgrade to our SAP. We have aligned with the AER's ICT Expenditure Assessment Guideline[88] in defining these categories.

Figure 7.2 Proposed ICT capital expenditure for 2021–2026 regulatory period ($ million, 2021)



Source: United Energy
Note: Figures include real escalation and exclude network overheads

Our recurrent spend remains in line with history, reflecting our business-as-usual requirements. The investment profile for ICT is driven by non-recurrent projects which have been scheduled to align with externally driven timeframes, including compliance dates (i.e. five minute settlement), and to efficiently manage project interdependencies. More information about the scheduling of our projects can be found in our IT deliverability plan.[89]

We have a proven track record in delivering large ICT programs for the benefit of our customers within scope, time and budget. Our staff can adapt to changes in systems and processes and through our vendor support and third party contractors, we can ramp resources up or down as required.

87 UE APP02 - What we have delivered - Jan2020 - Public

88 UE ATT135 - AER - ICT Guideline - Nov2019 - Public

89 UE ATT007 - IT deliverability plan – January 2020 – Public

7.1 What we plan to deliver

We will deliver recurrent ICT expenditure to maintain the currency of our systems over the 2021–2026 regulatory period, as well as specific non-recurrent ICT projects. The projects are discussed in turn below.

7.1.1 Recurrent ICT investment

Recurrent ICT is investment that is related to maintaining existing ICT services, functionalities, capability and/or market benefits. The majority of our ICT investment maintains the capabilities of our existing suite of technologies.

The table below provides our proposed recurrent ICT expenditure by project.

Table 7.2 Summary of proposed ICT capital expenditure for recurrent projects ($ million, 2021)

Project	Investment
Cyber security	18.7
Cloud infrastructure	22.8
Market systems	7.4
Network management systems	24.9
BI/BW	2.3
Device replacement	3.1
Enterprise management systems	8.7
Telephony	4.4
Facilities security	4.7
General compliance	8.2
Total	**105.1**

Source: United Energy
Note: Forecasts excludes real escalation and network overheads

Each of the projects has an associated business case which provide greater detail on the proposed investment and the alternative solutions explored.

We will ensure our ICT systems remain secure from cyber threats

Customers viewed keeping our network data and their privacy secure was a core value proposition

We will improve the maturity of our cyber-security capabilities. We are part of Australia's critical infrastructure and deliver power to support our growing economy including manufacturing, transport, communications, health and finance. A disruption to the supply of electricity can have serious implications for business, government and the community. The technologies we use to help run the network are connected and accessible in ways that were not possible even just 10 years ago. While technology has provided us with many benefits, it also exposes us to risks. These risks can include corruption to our systems and files from computer viruses, sensitive data being stolen through hacking, and entities attempting to take control of the network.

These risks do not remain static with the Australian Cyber Security Centre ranking the energy sector in the top four industries most at risk of a cyber-security threat.[90] Similarly the *Security of Critical Infrastructure Act 2018* (Cth) was developed in recognition of the evolving national security risks to infrastructure including electricity assets from sabotage, espionage and coercion. Given the potential consequences involved in a security breach, we must ensure the security of our information technology and systems keep pace with new threats.

Accordingly, we have looked at a range of options and considered that our current security systems can be extended to provide more effective controls to prevent cyber security attacks and incidents. We will also refresh our security for SCADA access and control management to ensure that we retain proper authorisations to control the network.

In addition to developing costings for each option, we conducted risk monetisation in order to determine the optimal investment for customers. We engaged PwC Australia (**PwC**) to conduct an assessment on the current stability and security of United Energy's ICT eco-system.[91] The review identified key security issues requiring rectification both in this period and the 2021–2026 regulatory period relating to our threat identification and response capabilities, vulnerability identification capabilities and incidence documentation. Following this, we commissioned a further cyber security strategic review and plan, which provided a number of recommendations.[92]

These activities are captured within our recommended option, with more detail provided in the cyber security business case.[93]

We will transition to cloud

Over the 2016-2020 period, we established new applications supported by cloud-hosted infrastructure, while retaining our existing infrastructure on-premise. This arrangement has given us flexibility to choose the right technology tool for the right purpose and made it easier to alter services or providers in response to changing business requirements.

With the maturing of cloud offerings, we have an opportunity in the 2021–2026 regulatory period to migrate our existing on-premise infrastructure to cloud. We engaged BDO to provide cloud-associated costings and we conducted risk monetisation on three migration options.[94] Ultimately, customers will have lower cost if we migrate our core applications which are currently supported by on premise ICT infrastructure to cloud hosting.

In addition to customer savings, our strategy will allow us to realise the following advantages of cloud:

- adaptability to changing business requirements, as we can change services or providers more readily
- scalability to ensure that we can manage our costs, as cloud services are based on capacity and use
- reduced reliance on vendor support, as we can more easily switch service providers.

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90 UE ATT154 - ACSC - Threat report 2017 - Oct2017 - Public

91 UE ATT048–UE IT systems review– Sep2019 –Public

92 UE ATT047 – PWC - Cyber strategy review - Nov19- Confidential

93 UE BUS 7.04 –Cyber security–Jan2020–Public, UE MOD 7.05 – Cyber security cost – Jan2020–Public, UE MOD 7.06 – Cyber security risk – Jan2020–Public

94 UE ATT046 –BDO–Report for cloud–Nov2019 –Public

For more information refer to our cloud-infrastructure business case, cost model and risk monetisation model.[95]

We will maintain and support existing systems

- Market systems: our market systems provide centralised storage and validation of meter reading data and manage market communications and customer requests in accordance with our compliance requirements. Ensuring technical currency of our market systems is essential to ensure continued vendor support of the critical software and compatibility with the integrated software. We have proposed a prudent approach to adopting version updates which delivers savings to customers while ensuring our critical market compliance systems remain supported by vendors.[96]
- Network management systems: the network management systems comprise core operational systems that support us in managing network operations, such as our GIS, OMS and DMS systems. Ensuring the currency of these systems is essential for ensuring we continue to operate the network in real-time, 24 hours a day, so that we can monitor and control the network to maintain a safe, reliable and secure network.[97]
- Business intelligence and business warehousing (**BI/BW**): we will implement a low cost central data repository to improve the speed and effectiveness of reporting and decision-making, for example in relation to network management, customer service and compliance reporting. The single central data repository will be shared between CitiPower, Powercor and United Energy, consolidating four data warehouses into one, resulting a saving of $3.5 million across the three businesses.[98]
- Device replacement: our workforce use computers, phones, mobile tablets, and other devices to perform their duties. These devices require replacement on a periodic basis as the asset reaches the end of its expected life in order to maintain the current level of operational performance. These devices are essential for realising our current level of workforce productivity, which would otherwise be lost if our devices are not properly maintained.[99]

Customers viewed reliability as most important, with 86% of residential customers satisfied with current reliability levels

- Enterprise management systems: ensure we maintain currency of a number of applications relating to asset investment planning, corporate services, customer platforms, data management and field services that are reaching end of life or will no longer meet business requirements due to changes in technology, customer requirements or cyber security threats.[100]
- Telephony: maintain currency of our telephony systems used for contact centre, corporate and control room functions and migrate the general enquiries contact centre onto the telephony platform, providing incremental improvements to the customer experience.[101]

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95 UE BUS 7.10 – Cloud infrastructure –Jan2020 –Public, UE MOD 7.15 – Cloud infrastructure cost – Jan2020–Public, UE MOD 7.16 – Cloud infrastructure risk – Jan2020–Public

96 UE BUS 7.06–Market systems– Jan2020– Public

97 UE BUS 7.05–Network management– Jan2020– Public

98 UE BUS 7.03–BIBW– Jan2020– Public

99 UE BUS 7.12–Device replacement– Jan2020– Public

100 UE BUS 7.11–EMS– Jan2020– Public

101 UE BUS 7.13–Telephony– Jan2020– Public

- Facilities security: to ensure we maintain energy security and the safety of workers and the public, we will continue to invest in the physical security of our facilities, including building access controls and closed circuit television cameras.[102]
- General compliance: we are subject to various rules and obligations which specify the data and support our ICT systems must provide. These obligations are periodically amended by various government bodies and regulators to ensure aptness in a changing energy market. Our general compliance is based on the current level of expenditure on our ICT systems resulting from smaller periodical updates to the Rules and obligations (as opposed to known material structural changes, such as five minute settlement).[103]

Without investment to maintain our existing ICT infrastructure, support and maintenance costs will increase and worker productivity will decrease. Expiration of vendor support means no longer accessing security and maintenance patches in areas such as asset health, security and compliance. This may result in lower system reliability, an increased risk of security breaches and higher costs to customers.

These proposed measures have been designed to ensure we continue to provide a safe, reliable and secure network for customers while ensuring value and affordability. Our risk monetisation analysis demonstrates the cost to maintain system currency is efficient relative to an alternative scenario which would occur if systems are not maintained.

7.1.2 Non-recurrent ICT expenditure

Our key non-recurrent ICT expenditure projects are shown in the table below.

Table 7.3 Summary of proposed ICT capital investment for non-recurrent projects ($ million, 2021)

Project	Investment
Digital network	19.4
Customer enablement	13.3
Intelligent engineering	5.4
SAP S/4 HANA upgrade	25.7
Five minute settlement	17.7
Total	**81.6**

Source: United Energy
Note: Forecasts exclude real escalation and network overheads

We will develop a more digital network

The energy landscape is changing with increasing penetration of rooftop solar, batteries, and electric vehicles. However, altered usage needs and the reverse power flows created by these innovations will make it more difficult to predict and manage power flows on the network.

102 UE BUS 8.04 - Facilities security - Jan2020 - Public
103 UE BUS 7.14–General IT compliance– Jan2020– Public

In the 2021–2026 regulatory period we will extend our coverage of smart meters to improve network visibility and allow us to take advantage of new data platforms and analytics.[104] Over time, this will allow more efficient network management in near real time, through better forecasting, monitoring, diagnosis and eventually automating network control.

Customers told us they want a greener future with 41% wanting us to help enable large and small solar

This will enable us to build on existing initiatives and implement new initiatives that will enhance network safety and reduce the need for augmentation. These specific initiatives include:

- promotion of new technologies - for example by allowing us to monitor the impact of increasing electric vehicle penetration on demand and develop charging arrangements that reflect their network usage. This will encourage the uptake of electric vehicles whilst at the same time ensuring they do not add to existing network demand peaks
- optimising load control of customer appliances - optimising existing hot water load control and enabling new load control programs (e.g. air conditioners, pool pumps, fridges), including through utilising excess solar in the middle of the day. This will defer network augmentation, lowering customer bills
- enhancing cost reflective pricing - analysing smart data to design more effective time-of-use tariffs and/or demand response schemes to reduce peak demand and improve utilisation of the distribution network
- removing charging inequalities – reducing electricity theft and monitoring variable unmetered supplies to ensure they make a fair contribution towards the energy they consume. Reducing energy theft will also improve safety through deterring others seeking to undertake such activities

Our customers had strong views that safety should be maintained and improved across the network

- proactively managing asset failures - develop greater predictive measures for asset condition to better determine when an asset will fail. This will lower customer bills through reduced network augmentation and avoided asset replacement
- avoiding overblown fuses - improving phase balancing, which will allow greater utilisation of existing assets (and therefore reduce augmentation) as well as avoiding replacing blown fuses
- looking after vulnerable customers - more accurate mapping of customers to the network allowing us to better manage life support customers during outages and provide more accurate communications to customers of planned outages
- keeping customers safe – improving the way we identify loss of neutral at customers' homes, which can create a risk of electric shocks if left unchecked.

We commissioned Jacobs to quantify the benefits of three different implementation options to ensure we maximised benefits to customers.[105] These options included no digital network, solely rolling out the ICT platform and rolling out the ICT and extending network visibility through adding additional smart meters. Jacobs determined that rolling out both the ICT and extending our smart meter coverage would provide the largest net benefit to customers.

[104] UE BUS 7.08 - Digital Network - Jan2020 – Public and UE MOD 7.12 - Digital network cost - Jan2020 - Public

[105] UE ATT009 – Jacobs – Digital Network benefit – Dec2019 –Public

We will improve customer enablement

The rise in customer service expectations means our customers expect to interact with us in a variety of more meaningful and accessible ways. We understand that our customers want simple and customised experiences, and for us to be proactive in how we provide information.

61% of residents stated that they would access their real time energy usage data and 68% would use the data to seek savings

In the 2016-2020 regulatory period, we have steadily improved our customer facing applications. In the 2021–2026 regulatory period we will continue our journey to provide services that align with the expectations of our customers.

The customer enablement journey over 2021–2026 will include:

- consolidating our existing online portals into a unified access point with additional automated processes, one username and password and a single interface
- automating connections and supply requests for all customer, including HV customers and embedded generators, by investing in the online connections portal
- improving the capabilities of Energy Easy to provide data analytics and customer notifications
- improving the effectiveness of SMS notifications during outages and introducing notifications on the efficiency of customers' rooftop solar PV output and exports
- providing customers access to more frequent usage data on a mobile application to better inform their energy choices
- providing customers more targeted information on outages that impact them and information about their rooftop solar installations.

Most participants in our Investments Options forum requested we invest in a one-stop-shop

Further explanation is provided in the customer enablement business case and cost-benefit model.[106]

We will establish intelligent engineering capabilities

We will leverage new technologies to improve our engineering capabilities, improving the safety of our employees and the community as well as allowing for more effective network management. A key outcome will be improving our master data management capabilities to enable:

Customers viewed network safety as a core and unquestionable priority for us

- improved accuracy of 'dial before you dig' - enhancing our 'dial before you dig' capabilities will drive improved safety outcomes and protect network assets as our customers perform works
- decreased network design planning timeframes - more accurate data will allow us to automate processes, reduce network planning and design costs.

Further explanation is provided in our intelligent engineering business case and cost-benefit model.[107]

[106] UE BUS 7.02 - Customer enablement - Jan2020 – Public, UE MOD 7.21 - Customer enablement - Jan2020 - Public

[107] UE BUS 7.07 - Intelligent engineering - Jan2020 – Public, UE MOD 7.11 - Intelligent engineering - Jan2020 - Public

We will perform a major upgrade to SAP S/4 HANA

Our current SAP system performs many essential business functions including underpinning our financial reporting, supporting our customer connections processes and helping maintain the safety of our network through capturing the maintenance activities conducted on our network assets.

We plan to perform a major upgrade to our SAP platform which will reach the end of its lifecycle and vendor support by 2025. Upgrading SAP will ensure the continued modernisation and functionality of our network programs and corporate functions.

We scrutinised our proposed investment by conducting an analysis of five different options. Ultimately we determined that the lowest cost and risk path involved upgrading SAP to S/4 HANA, as opposed to moving to a new system or third party support model. Further, integrating to a single SAP S/4 HANA platform across CitiPower, Powercor and United Energy, rather than maintaining them as separate systems, will reduce costs for customers of three networks by $5.4 million.

For more information refer to our SAP S/4 HANA lifecycle upgrade business case and cost model and risk monetisation model.[108]

We will meet new five minute settlement compliance requirements

We will enhance our current ICT systems to meet rule changes that require us to provide five minute interval data for NEM settlement. As a result, we must augment existing ICT systems to comply with new requirements.

Under the new Rules, any smart meter installed after December 2018 must have the capability to record five minute interval energy data. By December 2022, we must have systems in place to receive and provide five minute data to the market for smart meters we installed after 1 December 2018.

The AEMC found the five minute settlement requirement will improve price signals for generation and demand management and that this will help reduce energy bills. The AEMC noted that it will provide more granular meter data to help customers improve energy efficiency, more opportunities to minimise outages at times of peak demand, and improved ways to utilise DER such as battery storage.[109]

Our current ICT systems do not have the capacity to provide five minute interval energy data to the market. We undertook a bottom up review of the system changes required to provide the data. Our analysis showed that system changes would be required to collect and validate five minute interval data.

While this is a resource-intensive project, we have a strong track record in delivering projects of a similar scale and complexity on-time and within budget. For example, we were successful at delivering the system upgrades to meet the requirements of the metering contestability Rule change.

For more information please refer to our five minute settlement business case and cost model.[110]

7.2 Our forecasting approach

7.2.1 Our starting point

We only invest in ICT when there is a benefit to customers. Our starting point for our proposed ICT investment was to assess our existing capabilities and the services they provide our customers. As part of this, we identified

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108 UE BUS 7.01 - SAP S/4HANA - Jan2020 – Public, UE MOD 7.02 - SAP cost - Jan2020 – Public, UE MOD 7.03 - SAP risk - Jan2020 - Public

109 UE ATT159 - AEMC - Five minute settlement - Nov2017 - Public

110 UE BUS 7.09 – 5 minute settlement - Jan2020 – Public, UE MOD 7.14 – 5 minute settlement - Jan2020 - Public

whether elements of our existing ecosystem were no longer providing value to customers as ensuring lean operations is a key way for us to avoid unnecessary expenditure.

We also carefully examined synergy opportunities with CitiPower and Powercor, weighing up against the risks to systems and business processes from such integration activities. This builds upon work in the 2016-2020 regulatory period aligning our vegetation management reporting system, ICT issue resolution systems and telephony systems. In the 2021–2026 regulatory period, we have identified synergy opportunities where system alignment will reduce overall project implementation costs for our customers such as the SAP upgrade and consolidation of BI/BW data storage.

We also analysed the ability of our existing systems to withstand maturing and emerging cyber-security threats. Unless we maintain and continue to develop our cyber security tools, they quickly become irrelevant and ineffective, risking the security of the network operations and data privacy.

We then forecast the efficient level of investment we would require to retain the effectiveness and security of existing capabilities. Overall, we found that most of our existing technologies will continue to provide benefits to our customers in the 2021–2026 regulatory period. This reflects the prudency of our investment choices in the past and that our ICT ecosystem has been carefully designed over time.

Lastly, we considered how new technologies can address key business requirements including enhancing safety, ensuring compliance and improving service delivery to customers. In addition to developing robust business cases for these projects, we tested these new projects with customers and other stakeholders to ensure we prioritised our investments in areas customers most value.

7.2.2 Ensuring a cost efficient approach

We ensured efficiency was at the cornerstone of developing our forecast for the 2021–2026 regulatory period, through a number of measures which are described below:

- seeking customer feedback on what's important to them: through our Energised 2021–2026 program we have sought to identify what our customers' value most about their electricity supply and what services they value into the future.
- supporting 100% of our proposal with robust business cases: through preparing robust business cases, cost models and risk monetisation analysis we have provided evidence to support the identified need and benefits for our proposed projects.
- conducting options assessment: we considered the full range of viable options to address the identified need. We included alternative options in cost models, benefits assessments and risk monetisation analysis, where relevant.
- undertaking detailed cost-benefit analysis: we weighed up the costs and benefits at a project level to determine the true value of a project for customers, including for recommended options and non-recommended options. We determined expenditure at a granular level, applying unit costs based on past projects of a similar scale and complexity, external labour rates, known vendor costs as well as seeking external validation.
- accounting for cost savings in expenditure forecasts: where we have identified projects that are driven by customer benefits but have identified expenditure savings that may be realised over the current regulatory period, we have taken these into account. In the case of operating expenditure savings, we consider these projects contribute toward the 0.5% pre-emptive productivity adjustment in operating expenditure. As an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices and have limited capacity to achieve the 0.5% productivity adjustment through business as usual activities during the 2021–2026 regulatory period. In

the case of capital expenditure forecasts, we have netted the savings from our 2021–2026 expenditure forecasts.

- conducting risk monetisation: we quantified the risks involved in deferring or avoiding ICT investment from a customer perspective, ensuring we minimise our investments while balancing risk appropriately (see box below for more information).
- subjecting the portfolio to a top down challenge: we engaged PwC mid-way through developing our proposal to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers.
- engaging a range of consultants: in addition to internal expertise on similar past projects or activities, we engaged consultants to support business case analysis and validate our overall program of work, including:
  - KPMG supported our development of a risk monetisation model[111]
  - PwC undertook a top down assessment of our proposed ICT portfolio and key projects
  - BDO provided cost analysis to support our forecast costs of cloud migration[112]
  - Jacobs undertook benefits assessment and modelling for our digital network project[113]
  - Litmus supported us to develop cost forecasts for our digital network project.

7.2.3 Driving cost efficiency through a rigorous and flexible approach to project delivery

We have a strong track record of delivering large ICT projects for our customers within scope, time and budget. Examples include implementation of ICT systems to support the deployment of smart meters and upgraded systems to enable meter contestability. As a result, we are highly adaptable to changes in systems and processes, allowing us to realise the benefits of ICT programs swiftly.

A key way we are able to deliver large projects while minimising associated projects risks and costs is through vendor support and third party contractors. Through careful planning, we can ramp up resources when a project's workload peaks, before returning labour to normal levels as the project scales down. This is especially advantageous in delivering large-scale IT projects, which require greater and lesser resources at different stages. In addition, the flexibility of this project delivery model means that we can easily adapt our delivery methods according to the requirements of the project and the changing needs of the business. In this way we ensure we appropriately resource projects to achieve our milestones effectively yet cost efficiently.

We also ensure appropriate project oversight through a rigorous governance process. This helps to ensure that key strategic decisions about the business remain in-house. Projects are co-ordinated through our project management office to ensure we have the right mix of internal and external skills. Our resources are managed at both the project and program level to ensure we take interdependencies into account.

Through all of these measures, we ensure our projects are delivered on-time and on-budget for the benefit of our customers.

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111 UE ATT008 –IT risk monetisation guide–Jan2020–Public

112 UE ATT046–BDO–Report for cloud–Nov2019–Public

113 UE ATT009– Jacobs–Digital network benefit– Dec2019 –Public

7.2.4 We take a risk-based approach to assessing projects

To inform our ICT investments, we have started analysing projects through a risk-based framework to help quantify whether a projects risk outweighs its expected cost. In this way we are able to holistically determine all the potential costs involved in an investment decision for customers. This work is based on AER guidelines and internal analysis to monetise network risk, but is adapted for the ICT landscape.

Under this approach we use a deterministic view (i.e. we consider the risks at a point in time, instead of considering how risk changes over the years under a probabilistic approach). This is due to a lack of available data to reliably predict the probability of ICT asset failure over time both internally and in the broader ICT community. However, this work provides strong foundations for developing our approach over time.

Our ICT risk monetisation approach is described as follows:

- quantify the risks involved in a 'do nothing' case of not investing to maintain vendor support, and instead using an unsupported system
- quantify the risks of the proposed and alternative options, including business-as-usual options
- compare the 'do nothing' case to the proposed and alternative options to determine the highest risk-mitigation option

We have considered two primary risks—ICT risk and business risk—and have not exhaustively covered every risk. More information these two risk categories is discussed in the box below.

ICT risk monetisation

To monetise the risks involved in our ICT programs, we consider two categories of risk: ICT risk and business risk.

ICT risk considers the immediate risks to ICT teams and users of a system. They are captured through assessing the probability and impact of the following risk types:

- outage: the direct financial consequences incurred by an ICT team in the event of an outage, including the lost productivity from staff being unable to utilise various systems as well as any remediation or workaround activities required.
- cyber security breach: the direct financial consequences for an ICT team in the event of a breach.
- suitability: the consequences of continuing to use an existing ICT asset that is unable to meet the future needs of the underlying business process it supports. This is driven by changes in process requirements over time, and is typically due to external factors (e.g. introduction of GST).
- system sustainability: the consequences from not undertaking required maintenance activities, such as internal maintenance or patches, to ensure the continued health and stability of ICT assets. This manifests as lost productivity from under-optimised systems.

The financial consequences of these ICT risks are valued in terms of lost employee utilisation time and rectification costs. Lost employee utilisation is measured according to the estimated employee hours impacted, while the rectification costs assess the number of employee hours or specialist and associated fixed costs with identifying and resolving a risk event, implementing any workaround activities and conducting activities to prevent the issue occurring again in future.

Business risk considers the wider risks encountered by the business and the community as follows:

- reliability: the system reliability consequence to the network arising from the failure of an ICT asset, and is measured via the applicable value of consumer reliability (**VCR**).
- compliance: the direct financial consequences associated with regulatory or legislative compliance breach arising as a result of failure of an ICT asset. This can be measured by compliance penalties and associated legal or regulatory costs.
- customer experience: the direct financial consequence associated with adverse impacts to customer interactions arising as a result of a failure of an ICT asset. This can be quantified according to the value of customer time, for example.
- bushfire and safety risk: the safety and health consequence to workers and the wider public, including loss arising from an injury or fatality, as well as property damage arising from the failure of an ICT asset.
- financial risk: the direct financial consequence (or loss) not taken into account in any of the above areas of consequence.

We have incorporated the following data sources:

- existing ICT data (e.g. outage data, frequency of patches applied, number of compliance updates required each year)
- other relevant network data (e.g. connection requests, de/energisations, incident data)
- documented assumptions where data is not available.

One key source of data has been the result of an incident we had, which revealed how inadequate investment in ICT systems can impact customers, as discussed in the case-study below.

Figure 7.3 Case study: Supercluster incident

Prior to acquisition, United Energy had a heavily outsourced model

- It consisted of a small management team, overseeing a large number of vendors and contractors
- As a result, a number of key strategic decisions were effectively outsourced

This led to a number of issues, including the 'Supercluster'

An unsuitable vendor solution was implemented, which had:

1. Shared storage, providing a single point of failure and creating poor reliability
2. Low performance of the disaster recovery solution
3. Limited connectivity options due to architecture

This had a number of issues impacting customers:

- Suspended meter reading, risking regulatory compliance
- Billing delays impacting ~$12m revenue
- Inability to access work schedules and service orders
- Unavailability of life support reporting
- High call times as front of house call staff had to default to manual service requests
- Extended customer outage times, and delays in live line and tree clearing

We have applied our risk monetisation assessment to our largest recurrent ICT projects including cloud infrastructure, market systems, network management, cyber security and the SAP upgrade.

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8

Non-network

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8 Non-network

Non-network capital expenditure includes property, fleet, tools and equipment. This expenditure is necessary to support the operation of the network and deliver a safe and reliable service for our customers.

We take a prudent approach to non-network expenditure, adjusting our activities over time in response to various factors to ensure that we maintain an optimised portfolio.

In the 2021–2026 regulatory period, we propose to:

- upgrade three of our depots to ensure we can continue to deliver a reliable network at efficient cost and comply with our regulatory obligations
- maintain the security of our critical assets in response to increasing security risks
- continue to use our fleet to carry out our work efficiently and reliably
- purchase and replace general tools and equipment, as required.

This chapter outlines our investment in the 2021–2026 regulatory period on property, fleet, and tools and equipment:

- in section 8.1, we outline the our forecast investment in non-network services
- in section 8.2, we provide further detail on our approach to developing our investment forecast.

An overview of our forecast non-network capital investment is shown in the table below.

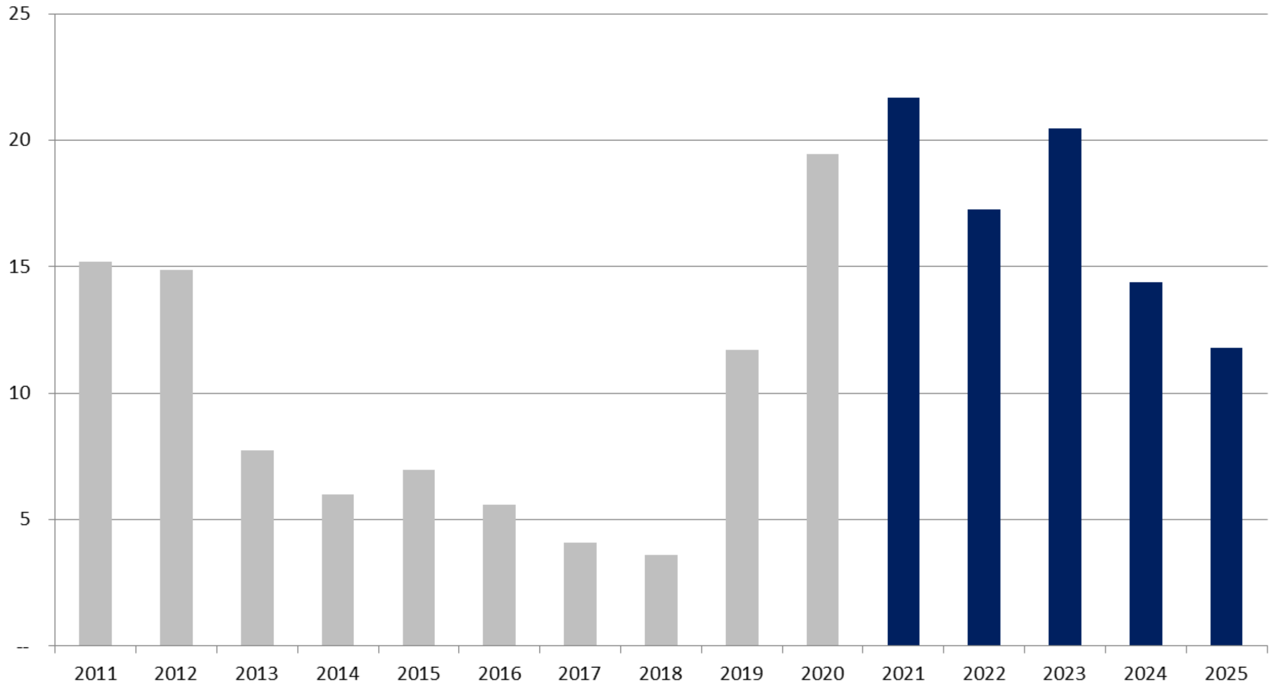
Table 8.1 Forecast capital investment for property, fleet and tools and equipment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Non-network investment	21.7	17.3	20.5	14.4	11.8	85.6

Source: United Energy
Notes: Forecast includes real escalation and excludes network overheads

The profile of our historic and forecast non-network expenditure is shown in the figure below.

Figure 8.1 Non-network expenditure ($ million, 2021)



Source: United Energy
Note: Figures includes real escalation and exclude network overheads

The justification for our non-network investment is supported by a number of business cases, which are summarised below.

Table 8.2 Summary of material business cases ($ million, 2021)

Project	Investment
Burwood depot	31.0
Keysborough depot	22.3
Mornington depot	15.6
Total	**68.9**

Source: United Energy
Note: Forecasts exclude real escalation and network overheads

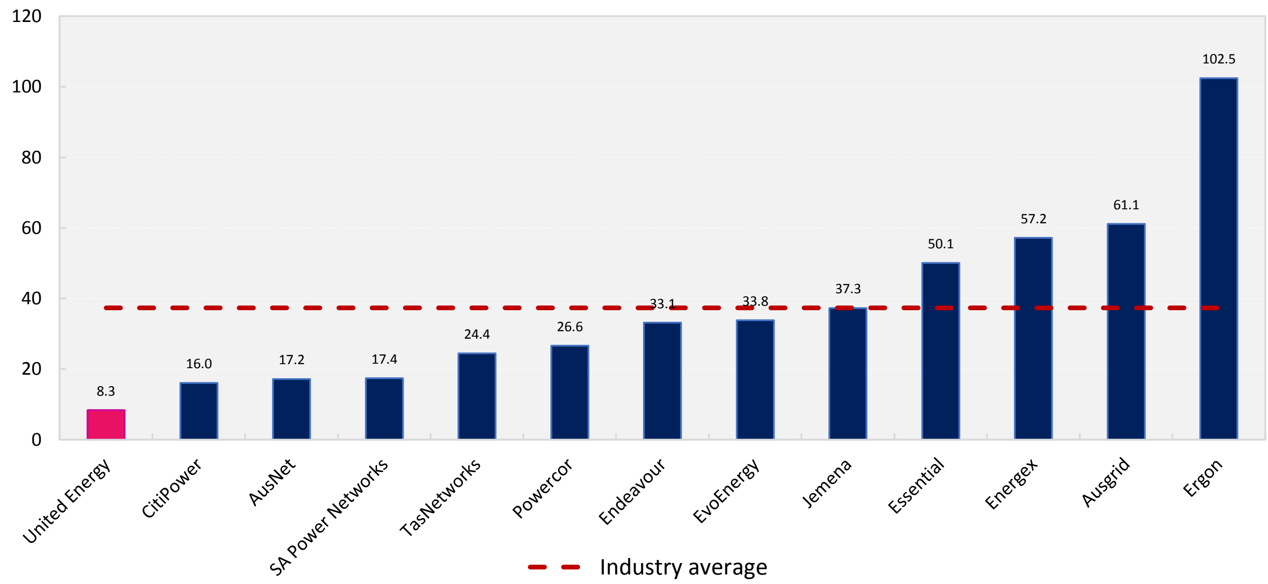
8.1 What we plan to deliver

8.1.1 Our property investment must align with expected demand and regulatory requirements

We have optimised our property portfolio to ensure we can cater for increased population growth and also ensured our asset management practices comply with regulatory obligations. Without additional investment, these constraints will ultimately increase the risk of issues to network reliability as well as the health and safety of staff and customers.

The population of the Mornington Peninsula is expected to grow by 6.9% between 2016-2026 driven by greater suburban expansion from families, workers, retirees and tourists,[114] which will place greater demand on our network. Investment in our depots has not been keeping pace with this population growth to date. Since acquisition we determined these depots were in a poor state of repair. As shown in the figure below, historically we have the lowest investment in property per customer compared to all other distributors.

Figure 8.2 Average property expenditure per customer, 2009–2018 ($ million, nominal)



Source: United Energy analysis of AER Category Analysis RIN data 2009 to 2018

As a result, some of our depots already have insufficient storage areas and inadequate space to service our fleet. Capacity constraints will be reached at three sites within the 2021–2026 regulatory period. In order to manage this, it will be necessary to expand and upgrade our depots to ensure we continue to maintain network reliability and meet our health and safety obligations to our employees and customers. Those obligations extend to building standards and planning law, occupational health and safety (**OHS**) and equal opportunity (**EO**).

Currently, there is a high risk that our facilities, such as our toilet and change room facilities, will not be compliant with these obligations as our female workforce will continue to increase in size. We will therefore seek to upgrade our facilities to cater for greater workforce diversity so that we can attract the best staff in the future. This also meets our strategic objective of increasing female representation in our field resources.

Our property regulations and obligations attachment,[115] sets out further information about these legal obligations and the consequences of breaches relating to our property portfolio.

Building standards and planning law

We have obligations under the *Victorian Building Act 1993* (Vic) (**Building Act**) to ensure that all building work, including any alterations, is carried out in accordance with a building permit.[116] The Building Act adopts the

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114 UE ATT155 - MPS - Population forecast - Nov2019 - Public

115 UE ATT057 - Property regulatory obligations and requirements - Jan2020 - Public

116 *Building Act 1993* (Vic), s 16(3).

National Construction Code, including the *Building Code of Australia* (**BCA**).[117] As a result, we are required to ensure that any alterations to our existing depots comply with the requirements of the BCA.[118]

Occupational health and safety and equal opportunity

We have obligations under OHS and EO legislation to maintain a safe working environment that is without risks to our employees' health and does not discriminate against them on the basis of their gender.[119] Similar obligations apply under the *Sex Discrimination Act 1984* (Cth).[120]

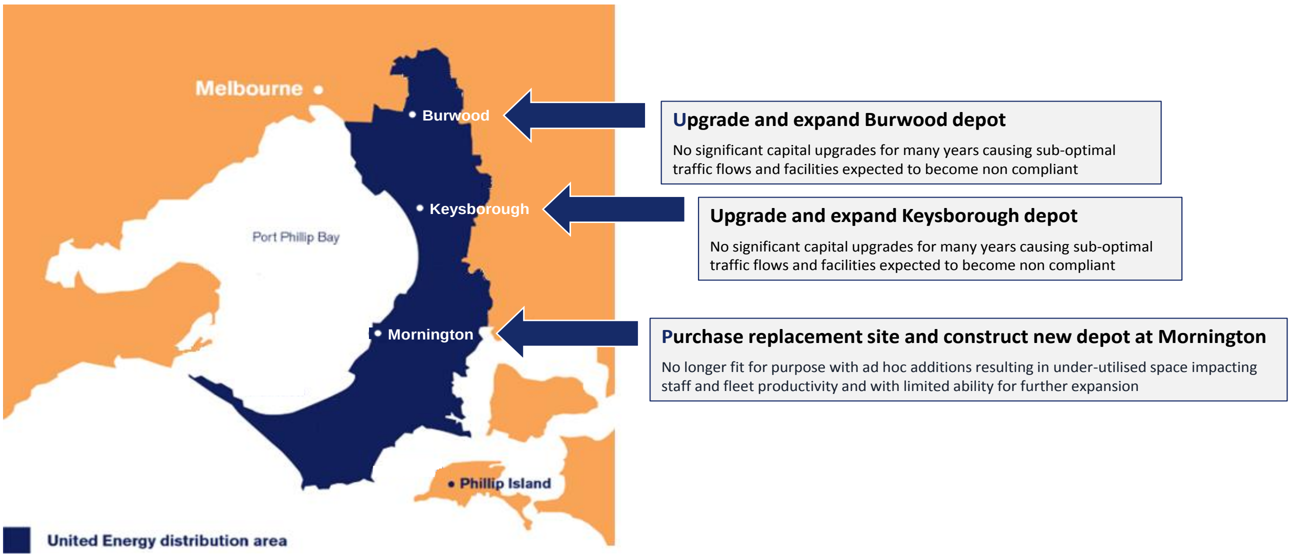
Our relevant regulatory obligations and requirements

The capital expenditure criteria require that our capital expenditure allowance for the next regulatory period reasonably reflects the efficient and prudent costs of achieving the capital expenditure objectives,[121] including compliance with all applicable regulatory obligations or requirements.[122] Each of our legal obligations discussed above constitutes a 'regulatory obligation or requirement' for the purposes of section 2D of the NEL and thus the capital expenditure objectives.

8.1.2 Our property investments

Our forecast expenditure for property includes depot upgrades, facilities security (building access control and CCTV) and disposal of property assets. We have identified three depots that will require essential works over the 2021–2026 regulatory period in addition to maintaining the security of our facilities.

Figure 8.3 Proposed United Energy depot investments



Source: United Energy

117 *Building Regulations 2018* (Vic), r 10, 12 and 13.

118 *Building Regulations 2018* (Vic), r 233(1).

119 See the *Victorian Occupational Health and Safety Act 2004*, s 21(2)(d); the *Victorian Equal Opportunity Act 2010 (Vic)*, s 6(o), 15(2) and 18; and the *WorkSafe Compliance Code: Workplace amenities and work environment*.

120 *Sex Discrimination Act 1984* (Cth), s 14.

121 *National Electricity Rules*, clause 6.5.7(c).

122 *National Electricity Rules*, clause 6.5.7(a)(2)).

Burwood depot

We will upgrade and optimise our depot in Burwood. [123] Land in this area is at a premium making the cost of moving to a new site inefficient. We will instead ensure we maximise our current depot site by redeveloping it and moving staff to temporary accommodation during the rebuild.

The proposed works are significant as the buildings at this site were constructed in the 1980s with no major capital improvements undertaken since that time. As a result, the depot is severely dated and suffers from legacy maintenance requirements, which fail to maximise the available storage space for materials. Work is also required to adapt part of the site previously used by MultiNet Gas to make it fit-for-purpose and to ensure efficient and safe traffic flow.

Keysborough depot

We will upgrade and expand our depot in Keysborough.[124] We are already starting to reach space constraints at this site and have begun leasing adjacent land as a result. This will become more expensive over time as land values increase as a result of population growth in the area. We therefore plan to purchase this adjacent land so that we have sufficient space to continue to service the region over the long term while also safeguarding cost efficiency. In addition, the current depot site is severely dated with the original 1960s interior and infrastructure remaining.

Many buildings are facing structural issues and there is a lack of adequate facilities to cater to the increases in staff over time or changes to reflect a more diverse workforce. For example, in one of our main buildings, due to legacy infrastructure there is a single female toilet while there are eight male toilets, despite the building's permanent staff having 50% female and male representation, and additionally, there are no female change rooms at the depot. We will not meet the requirements of the *Workplace amenities and work environment compliance code* (**WorkSafe Code**) if we engage more female line workers in the future. [125]

Mornington depot

We will purchase a replacement site and construct a new depot in Mornington that is fit-for-purpose to adequately service the region. [126] There are a number of issues with the current site, providing limited opportunity to adapt the depot for our requirements in the future.

The current site was purchased in 1994 and was previously operated as a Telstra depot. The last capital improvements to the site were completed approximately 15 years ago and it is no longer fit-for-purpose. The current office facilities consist of portable units that are approaching end-of-life.

In addition, there is a lack of suitable storage and yard space making it difficult to service on-site fleet vehicles. There is little ability to further develop the site as existing ground conditions provide limited opportunity to expand into neighbouring sites. The site also is not close to major arterial roads, which will make it increasingly difficult to service the region over time as greater demands are placed on the network and as roads become more congested due to continued population growth.

Further, we predict in the near future there will be insufficient toilets for female works under the WorkSafe Code.

Our customers considered that safety should be maintained and improved across the network where possible

123 For more information on Burwood please see UE BUS 8.01 - Burwood - Jan2020 - Public

124 For more information on Keysborough please see UE BUS 8.02 - Keysborough - Jan2020 - Public

125 UE ATT057 – Property regulatory obligations and requirements–Jan2020–Public.

126 For more information please see UE BUS 8.03 - Mornington - Jan2020 - Public

During the 2021–2026 regulatory period, we will invest in a new depot of sufficiently optimised size and location to ensure we can efficiently service the region and maintain good asset management.

8.1.3 Continuing to optimise our transport fleet

Fleet comprises of light or passenger fleet such as cars and utility vehicles, as well as heavy or commercial fleet, for example, cranes, elevated working platforms, trailers, crane borer and fork lifts. Our fleet of vehicles are essential to ensuring we can carry out our work efficiently and reliably.

We purchase, rather than lease, most motor vehicles. We have determined this to be the most efficient method of sourcing vehicles following internal reviews of our procurement strategy.

Our fleet expenditure is driven by activities including:

- replacement of existing motor vehicles in line with industry standards
- technological developments of in-vehicle monitoring systems, which allows us to track vehicles, in turn improving driver safety and reduce costs (such as through lower insurance premiums)
- employee growth or network-related programs of work
- compliance with legislation and standards as they apply to varying categories of fleet.

Our forecast fleet expenditure will ensure we can continue to efficiently acquire, replace or rebuild our fleet of light and heavy vehicles and comply with the changes in safety and compliance obligations.

8.1.4 We will maintain our general equipment capabilities

We forecast our general tools and equipment expenditure to remain relatively constant and consistent with our historical level of expenditure.

8.2 Our forecasting approach

8.2.1 We have undertaken a bottom-up build of our property forecasts

We have undertaken a bottom-up approach to forecast our property requirements in the 2021–2026 regulatory period. We take a prudent approach that ensures we invest efficiently and that planned activities are justified from a risk perspective.

We start by assessing whether the number, location and condition of our depots will remain effective to support network operations and deliver reliable services for our customers over the forecast period. This includes considering current and forecast:

- asset condition and maintenance costs
- reliability performance and customer growth
- planned network projects
- employee, materials storage and fleet requirements.

A range of options to determine the efficient solution to meet our operational requirements and support our customers are considered. This includes upgrades to the existing site, rebuilding depots and relocating depots. We determine the most efficient option by comparing the relative costs and benefits over the long term.

To estimate our efficient forecast expenditure,[127] we use the following approach:

- materials and construction costs are forecast based on prior depot builds of a similar size and scale. Our depot works are undertaken by external services providers which are selected through a transparent market testing process
- land purchase costs are forecast by reviewing recent land sales in the local area to determine an average per square metre rate and applying that to the land size required for the depot
- lease costs for any temporary facilities are forecast based on reviewing the average rate for suitable properties currently available for lease in the area.

8.2.2 We have undertaken a bottom-up build of our fleet forecasts

Our forecast fleet expenditure for the 2021–2026 regulatory period is based on a robust review of our fleet portfolio. This is appropriate as we have recently reviewed our fleet lifecycle management approach and are updating our policy to bring it in line with industry standards.[128] The new policy ensures efficient costs in the long run, through minimising the maintenance costs associated with older vehicles. This forecast involved determining the date each vehicle needs to be refurbished or replaced according to timeframes mandated by our policy.

8.2.3 We have aligned our general equipment forecasts with historical expenditure

Our forecast expenditure for other general tools and equipment is based on our average historic expenditure over 2016 to 2019. This approach ensures our forecasts are efficient as we expect the purchase and replacement of general tools and equipment to remain relatively constant as it has in the past.

[127] UE MOD 8.02 – Property – Jan2020 – Public

[128] UE ATT188–UE motor vehicle policy–Jul2019–Public

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9

Operating expenditure

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9 Operating expenditure

Our operating expenditure forecast for the 2021–2026 regulatory period is an efficient, prudent and realistic forecast that allows us to achieve the operating expenditure objectives of the Rules.

We are an efficiency frontier network—we benchmark as the third most efficient distributor in Australia and have the second lowest operating expenditure per customer. Our customers get value for money as we deliver electricity 99.99% of the time at the second lowest cost in Australia. We have delivered $133 million in savings for customers during the 2016–2020 regulatory period.

We are facing new challenges and opportunities

As an efficiency frontier firm, the ongoing transformation of the energy sector (e.g. the rapid uptake of renewables and a growing focus on data access and security) is placing upward pressure on our historical operating investment. Our operations are also being increasingly challenged by climate change, through extreme weather and faster deterioration of assets. To successfully transition and manage these challenges proactively, our forecasts include incremental investments for targeted step changes including:

- new obligations under the *Environmental Protection Amendment Act 2018* (Vic) and draft regulations
- strengthened security requirements for the protection of data under the *Security of Critical Infrastructure Act 2018* (Cth)
- increasing bushfire insurance premiums driven by unprecedented tightening of global insurance markets.

There are also opportunities for us to deliver customer benefits and cost savings during the 2021–2026 regulator period, including:

- enabling more solar to be connected to the network, delivering economic benefits for all customers and responding to our changing customer needs
- delivering cost savings for customers by migrating on-premise ICT infrastructure to cloud hosting
- expanding our demand management programs to reduce costs to customers of managing network constraints.

Our forecasts reflect efficient operations

Our approach to forecasting our required operating expenditure uses the AER's base-step-trend approach. We have selected 2019 as the efficient base year, and have engaged independent consultants to forecast trends in economic factors from 2021–2026 regulatory period (to be applied to the base year).

Whilst we have applied the AER's pre-emptive productivity adjustment to our efficient base operating expenditure, we must receive funding for implementing new innovative initiatives and productivity–enhancing projects necessary to achieve those productivity improvements. As we are an efficiency frontier network that has already achieved considerable productivity improvements through investments in new technologies and management practices, we have limited capacity to achieve additional productivity gains through business-as-usual operations over 2021–2026.

Operating expenditure allows us to run our everyday operations, to meet and manage our obligations and ensure our services meet relevant quality, reliability, safety and security of supply standards. Operating expenditure includes:

- information and communications technology (**ICT**) maintenance and leasing
- customer and corporate services staff

- asset inspections, maintenance and repair
- vegetation pruning around our assets
- emergency response
- various other ongoing expenses.

The table below shows the forecast operating expenditure for 2021–2026 with each component of the base-step-trend approach. We explain our approach in the following sections.

Table 9.1 Operating expenditure forecasting approach 2021–2026 ($ million, 2021)

Operating expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Base	123.3	123.3	123.3	123.3	123.3	616.6
Base adjustments	3.5	3.5	3.5	3.5	3.5	17.7
Reclassification	6.4	6.4	6.4	6.4	6.4	32.0
Output growth	1.7	3.3	4.9	6.6	8.7	25.1
Labour escalation	1.6	3.3	5.1	6.7	8.1	24.7
Productivity	-0.7	-1.4	-2.1	-2.8	-3.5	-10.5
Step changes	18.6	17.2	18.1	16.5	15.3	85.6
Debt raising costs	1.2	1.3	1.3	1.3	1.4	6.5
Total	**155.6**	**156.9**	**160.5**	**161.6**	**163.2**	**797.7**

Source: United Energy

Figure 9.1 shows the largest categories of our operating expenditure in 2019, how we have achieved savings over time and how this meets our customers' priorities.

Figure 9.1 Operating expenditure categories in 2019

IT, customer and corporate services 42%	• we have a corporate area that delivers customer service and ensure our business runs efficiently • over 2021—2026 all customer data will be handled locally • we have merged IT, customer and corporate services with CitiPower and Powercor to unlock further benefits for our customers	Data security is very important to our customers
Asset inspeciton, maintenance and repair 17%	• as part of our comprehensive asset management strategy, we inspect our assets periodically and maintan or repair assets based on their condition • we seek to maintan and repair assets where they can still be operational and safe • we are modernising our inspection practices with lasers, drones and through smart meter data	Our customers want us to be more innovative in our operations
Vegetation management 15%	• we prune trees and other vegetation around power lines periodically to a distance determined by *Electricity Safety (Electric Line Clearance) Regulations 2015* • our pruning cycle is two years, which controls pruning costs while ensuring visual amenity for our customers • in 2018 we renegotiated our external contract for vegetation management which is delivering savings for our customers	Most of our customers are satisfied with our pruning cycles
Emergency response 8%	• we have a highly trained crew who are available 24/7 for emergency response • our crews are distributed across the network to ensure prompt response to emergencies and when conducting other works • we seek to recover the cost of emergency works from third parties to minimise the impact on our our customers	Our customers rightly expect world-class safety outcomes
All other operating expenditure 18%	• other operating expenditure includes our licence fee, equipment leasing and other smaller on-going expenses • we ensure efficiency in all other operating expenditure by market-testing leasing arrangements and continually reviewing contracts	Our customers don't want us to spend $1 more than necessary

Source: United Energy

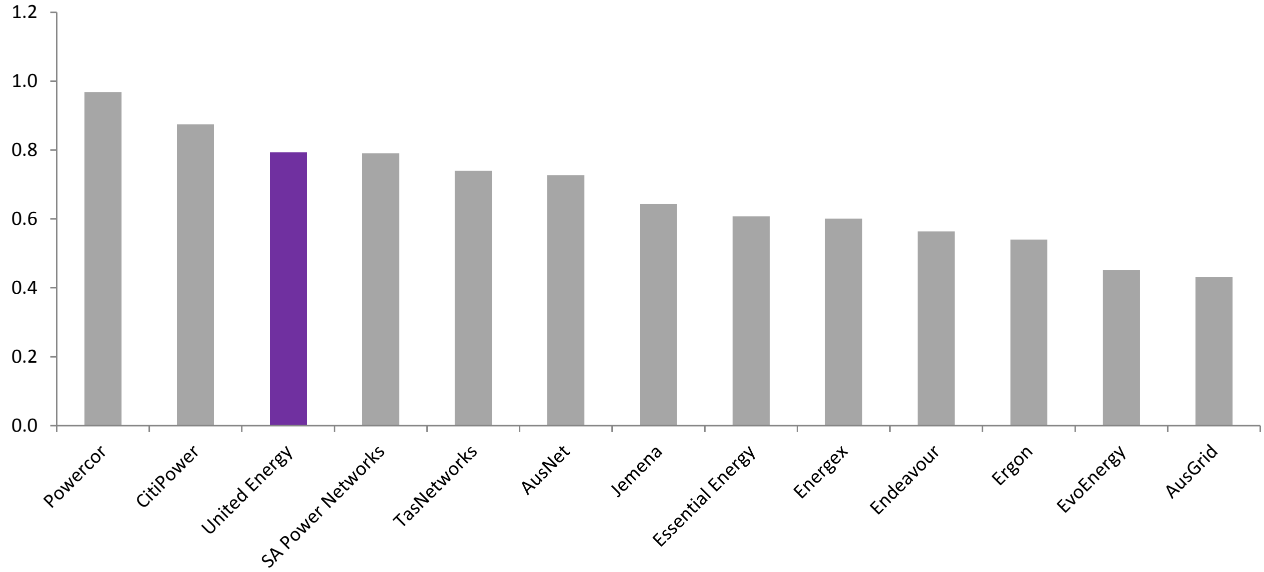
9.1 What we plan to deliver

Our operating expenditure is among the lowest in the NEM. Our customers also receive value for money through a safe, reliable and dependable network that meets their needs.

We are one of the top three efficiency frontier firms in Australia. Being on the efficiency frontier means that we define the benchmark for the least cost network operators.

The AER has identified our operating expenditure as the third most efficient in NEM, as shown in Figure 9.2.

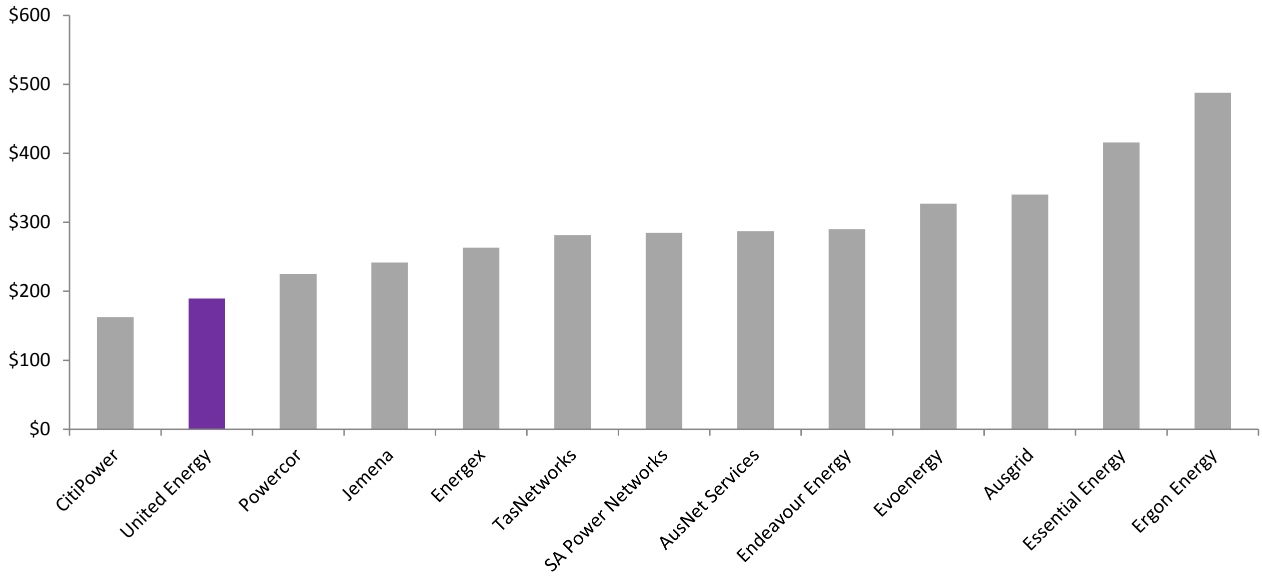
Figure 9.2 Operating expenditure efficiency scores from Cobb-Douglas stochastic frontier analysis (2006–2018)



Source: UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public

Our operating expenditure per customer is second lowest in the NEM. For example in 2018, we operated our network with 47% less operating expenditure per customer than the average distributor in New South Wales or Queensland.

Figure 9.3 Operating expenditure per customer across the NEM, 2018 ($, 2018)

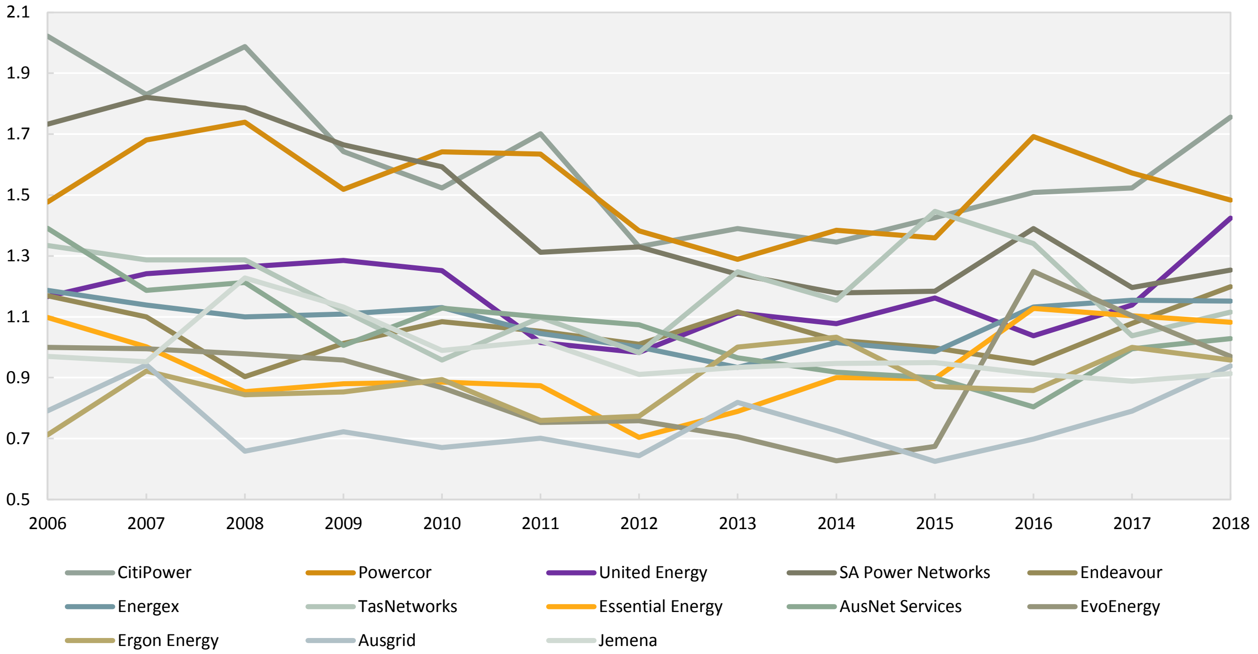


Source: UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public

During the 2016–2020 regulatory period we reduced our operating expenditure by $133 million. We achieved these savings through moving to a joint corporate service provision model with CitiPower and Powercor. The sharing of corporate services allowed us to realise economies of scale that were otherwise not available to us as a standalone entity. Synergies have been realised across customer services, corporate services, asset management practices and ICT support. We have also benefited from the joint renegotiation of service provider contracts including for vegetation management and asset inspection.

Figure 9.4 demonstrates our significant improvement in operating expenditure productivity since 2016.

Figure 9.4 Operating expenditure multilateral partial factor productivity results, 2006–2018



Source: UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public

9.1.1 We are investing to ensure we meet new or changed regulatory obligations

Our operating expenditure in our 2019 base year reflects the efficient costs a prudent operator in our circumstances would require to achieve the operating expenditure objectives.[129]

Our base operating expenditure reflects our current operating environment, having regard to our current service targets, regulatory obligations and other prevailing environmental circumstances. As an efficient frontier network, we have no contingency in our operations to absorb increasing costs from growing regulatory and service obligations, or material increases in the cost of delivering existing obligations and services due to changes outside our control.

To achieve the operating expenditure objectives, we therefore consider it prudent to account for increasing cost pressures from circumstances beyond our control through operating expenditure step changes. Table 9.2 summarises our step changes resulting from new regulatory obligations. Our assessment includes the identification of negative step changes over the 2021–2026 regulatory period. No material items were identified.

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[129] The operating expenditure objectives of the Rules for standard control services require to meet or manage expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply and maintain the safety of the distribution system.

Table 9.2 Step changes resulting from new regulatory obligations or increasing costs of existing obligations ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Five minute settlement	0.6	0.6	0.8	0.9	1.1	3.9
Security of critical infrastructure	10.1	8.8	8.9	9.0	9.1	45.9
Increasing insurance premiums	0.4	0.4	0.4	0.4	0.4	2.2
Environmental Protection Amendment Act 2018 (Vic)	3.6	3.4	3.2	1.3	0.4	11.8
Increase in ESV levy	0.4	0.5	0.5	0.5	0.5	2.5
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
Total	**15.4**	**14.1**	**14.2**	**12.6**	**11.9**	**68.1**

Source: United Energy
Note: Forecasts shown include real escalation with the exception of insurance premiums and ESV levy

We have also identified the following reviews of our regulatory obligations that are likely to result in a step change in costs during 2021–2026:

- electrical line-worker licensing—the Victorian Government at the 2018 Victorian election committed to a licensing scheme for electrical line-workers, expected to commence on 1 January 2021
- Distribution Code review—the ESCV is currently reviewing the Distribution Code, results of which are expected to be finalised during 2020.

As these changes are still under consideration, we do not have sufficient information to quantify the impact on our operating expenditure. We may propose further step changes in our revised regulatory proposal.

Five minute settlement

On 28 November 2017, the AEMC amended the Rules to change the financial settlement period for the electricity wholesale market from 30 minutes to five minutes to align with the operational dispatch of electricity. This is known as the five minute settlement rule change.[130] This requires us to capture, store, process and share meter data in five minute intervals for meters installed from 1 December 2018, rather than the current 30 minute intervals.

By December 2022, we must provide five minute data to market for meters installed from December 2018.[131]

We will incur the following incremental operating expenditure during the 2021–2026 regulatory period to comply with the new rule, which is not accounted for in our 2019 base:

- increased wide area network capacity to transport increased volume of meter data between ICT systems
- managing the increase in manual validations of meter data exceptions.

130 UE ATT159 - AEMC - Five minute settlement - Nov2017 - Public

131 UE ATT159 - AEMC - Five minute settlement - Nov2017 - Public, p. 121.

Our forecasting approach for these incremental costs, including our options analysis, is set out in our attached step change model and five minute settlement business case.[132]

Strengthening the security of critical infrastructure

In 2017, the Federal Government (**Commonwealth**) introduced a series of requirements to address the national security risks of espionage, sabotage and coercion associated with foreign involvement, through ownership, offshoring, outsourcing and supply chain arrangements, in critical infrastructure—including United Energy's electricity distribution systems).

Majority of our customers see data security as vital in current times

The critical infrastructure requirements include a subset of new requirements relating to system and data controls. To meet these requirements, we must transition to full compliance in accordance with a work plan approved by the Commonwealth as represented by the Department of the Treasury for CitiPower, Powercor and United Energy (subject to any changes agreed with the Commonwealth).

These critical infrastructure system and data control requirements are new 'regulatory obligations or requirements' (within the meaning given to that term by the NEL) associated with the provision of standard control services.[133] In its draft decision for SA Power Networks in October 2019, the AER agreed these critical infrastructure system obligations are new regulatory obligations or requirements.[134]

As a result, we will incur material ongoing operating expenditure in the 2021-2026 regulatory period that is additional to the expenditure reflected in our 2019 base operating expenditure. Further details are provided in the step change model and critical infrastructure business case.[135]

Increasing insurance premiums

We insure for general liability through insurers that operate on a global scale. Over the past 12 to 18 months, the global market for insurers has experienced significant disruption driven by increasing natural catastrophic events. In relation to bushfire risk, which is covered under the general liability insurance, recent major events with significant consequences for insurance markets include:[136]

- wildfires in Camp and Woolsey, California, in 2018 with $24 billion damage
- wildfires in Tubbs, Atlas, and Thomas, California, in 2017 with $17 billion damage
- wildfire in Fort McMurray, Alberta, Canada in 2016 with $4 billion damage.

The rising number of bushfire events in a short time period has resulted in significant insurer losses and insurer exits from the market. According to insurance specialists Marsh, in 2019 the global insurance market experienced sizeable capacity withdrawal due to a combination of insurer consolidation, appetite changes and (re)insurers hardening criteria for deploying capacity.[137]

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132 UE BUS 7.09 - 5 minute settlement - Jan2020 – Public , UE MOD 7.14 - 5 minute settlement - Jan2020 - Public

133 Compliance with those requirements is required in order to achieve the operating expenditure objective set out in clause 6.5.6(a)(2) of the Rules or, in the alternative, clause 6.5.6(a)(1), (a)(3) and/or (a)(4) of the Rules.

134 UE ATT156 - AER - SAPN Draft decision 2020-2025 - Oct2019 – Public, Attachment 6– Operating expenditure, p. 42

135 UE BUS 9.01 - Security of critical Infrastructure step change2020 – Confidential, UE MOD 9.01 - Step changes - Jan2020 - Public

136 UE ATT096 - Marsh - Bushfire liability - Oct2019 - Public

137 UE ATT096 - Marsh - Bushfire liability - Oct2019 - Public

Market exits, reductions in offered capacity and hardening of insurance criteria have resulted in a material increase in bushfire insurance premiums, increasing our overall insurance costs. Our insurance premiums for the year ending 30 September 2020 (2019/20) are 31% higher compared to 2018/19 for the same level of cover.[138] This is a second consecutive year of premium increases of 30-35% magnitude.

These premium rises are significantly higher than those expected to result from normal market conditions and present material cost increases outside our control. As such, we are proposing a step change to allow us to continue to meet the NEO while addressing challenges outside of our control.

Marsh predicts global markets for specialist insurers will continue to experience capacity disruptions over the short- to medium-term.[139] This is expected to lead to further premium increases during 2021–2026. While we expect costs will continue to grow during the 2021–2026 regulatory period, we are only proposing a conservative step change that is equivalent to the difference in our actual premiums in 2019/20 and the 2019 base year.

Our customers see safety as a given and too important to be 'traded off'. Customers want safety to be maintained and improved where possible across the network.

Our forecasting approach for these incremental costs is set out in our attached step change investment model.[140]

New *Environmental Protection Amendment Act 2018* (Vic) and draft regulations

We operate a health, safety and environment (**HSE**) management system that sets out a program of works and practices to comply with all HSE legislation and regulatory obligations, including environmental obligations.

The current legislation and regulations relevant to our environmental obligations (specific to this business case) are:

- the *Environment Protection Act 1970* (**EP Act 1970**)
- state environment protection policies (**SEPP**) and waste management policies (**WMP**).

These are administered and managed by the Environment Protection Authority of Victoria (**EPA**).

The *Environment Protection Amendment Act 2018* (Vic) (**EP Amendment Act 2018**) will repeal the EP Act 1970 from 1 July 2020 to establish a *proactive* regulatory approach of preventing waste and pollution impacts rather than managing the impacts after they occur. In August 2019, the Victorian Government published the draft Environment Protection Regulations (**draft regulations**), along with the regulatory impact statement (**RIS**), with the final regulations expected in March 2020.

The overall intent and objective of EP Amendment Act 2018 and the draft regulations is to modernise the EPA, give it more legislative powers and shift the regulatory framework from reactive to proactive—preventing harm from pollution and waste rather than managing the impacts once they have occurred. The EP Amendment Act 2018 and the draft regulations (the preferred options defined in the RIS) introduce a need for a shift in our operations to a more proactive and preventive approach to managing environmental risks.

85% of our customers supported us managing the network in an environmentally sustainable way

138 UE ATT051 - JLT - Invoice for insurance - Nov2019 - Confidential

139 UE ATT096 - Marsh - Bushfire liability - Oct2019 - Public

140 UE MOD 9.01 - Step changes - Jan2020 - Public

To comply with the new obligations we will incur material operating expenditure during the 2021–2026 regulatory period that is incremental to the 2019 base year, related to identifying, assessing and testing potential environmental risks of our operations as well as remediation works for contaminated sites. For remediation of oil contamination on land, which is the largest cost item, we have developed a desktop risk assessment and have ranked the contaminated sites according to level or risk of harm. For our cost estimate, we have included the remediation of the highest risk sites only in the 2021–2026 regulatory period.

Further detail on this change, including information on the highest risk sites, are detailed in the attached step change model and environmental business case.[141]

Increase in ESV levy

We are required to make levy payments to ESV. The levy payment schedule is set by ESV on an annual basis. On 30 April 2019, ESV communicated a material increase in its levy, including a 22% increase from 2018/19 to 2021/22 and annual 3% ongoing year-on-year increases. These material increases in the levy are beyond our control and are not captured in our 2019 base operating expenditure.

The annual cost profile for the forecast increases in the ESV levy is as per the attached schedule of fees.[142]

Financial year RIN

The Victorian Government has changed the next Victorian distributors' regulatory period from calendar years to financial years. We currently prepare financial statements on a calendar year basis which is aligned with RIN reporting on a calendar year basis. This means we only incur labour and audit costs for one set of financial accounts.

From 2021/22, a second set of financial accounts must be prepared and audited each year to enable population of the RINs on a financial year basis. The cost of preparing and auditing a second set of financial accounts is not reflected in our 2019 base operating expenditure.

We have forecast the annual cost for preparing and auditing a second set of financial accounts based on our 2018 actual costs. These costs are included in our attached step change investment model.[143]

9.1.2 Step changes that deliver new customer benefits

In addition to our compliance-driven changes, we are also investing to deliver new customer benefits. This includes operating expenditure that is not reflected in our 2019 base year that meets the following criteria:

- the benefits to customers exceed the incremental operating expenditure
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts
- reflects an efficient trade-off of operating expenditure and capital expenditure
- the step change reflects only the incremental costs above our 2019 base year and the costs are material
- the step change is not productivity enhancing.

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141 UE BUS 4.01 - EP Amendment Act 2018 - Jan2020 – Public, UE MOD 4.07 - Environmental cost - Jan2020 – Public, UE MOD 4.08 - Environmental risk - Jan2020 - Public

142 UE ATT041 - ESV - Forum minutes and levy - Apr2019 - Public

143 UE MOD 9.01 - Step changes - Jan2020 - Public

Table 9.3 summarises our step changes that deliver new customer benefits.

Table 9.3 Step changes that deliver new customer benefits ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	0.9	0.8	0.8	0.8	0.8	4.2
IT cloud migration	0.7	0.7	1.0	1.2	1.2	4.7
Demand management programs	1.5	1.6	2.1	2.0	1.5	8.6
Total	**3.1**	**3.1**	**3.9**	**3.9**	**3.5**	**17.5**

Source: United Energy
Note: Forecasts include real escalation

Solar enablement

As outlined in section 6.1.1, our customers are seeking to export excess solar back into the network. Where this is efficient (i.e. the benefits exceed the costs) we will enable this.

The net benefit to our customers of this program is over $74 million. The benefits we have calculated are the reduction in wholesale generation fuel costs and carbon reduction benefits from solar; benefits that all our customers (even those without solar) receive.

Delivering these benefits requires a mix of capital, and incremental operational investment to remove voltage constraints and enable more exports. Incremental operational expenditure, specifically, is needed to:

- 'tap down' distribution transformer voltages where possible as a less expensive option to, and reduce the need, for capital investment
- compliance and monitoring of customers' inverters settings (e.g. if installers fail to apply the required new inverter settings that reduce the voltage rise from exporting solar, voltage rises will be significantly higher than forecast—as a result, the full value of the net benefits will not be realised and there will be inequitable outcomes whereby customers without the inverter settings applied will be able to export more at the expense of others).

More information, including our considerations on why these costs are incremental and not included in our base year operating expenditure, is available in the attached business case.[144]

ICT cloud migration

We currently own and maintain the majority of our ICT infrastructure on-premise and we incur capital expenditure to grow and refresh our on-premise infrastructure capabilities. With the maturing market for cloud-based services, there is an opportunity for us to migrate some of our existing ICT infrastructure to cloud-hosting. Under cloud-hosting, ICT infrastructure is owned and managed by third party vendors and typically paid for on a subscription basis.

We reviewed our existing on premise ICT infrastructure and assessed the costs and benefits for migrating to cloud hosting over the 2021–2026 regulatory period. We engaged BDO to assist us with the assessment of the

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[144] UE BUS 6.06 - Solar enablement - Jan2020 – Public, UE MOD 6.02 - Enabling solar - Jan2020 - Public

costs of cloud-hosting.[145] Based on our cost-benefit analysis, we propose to migrate the ICT infrastructure supporting our core ICT applications to cloud-hosting during 2021–2026, with timing aligned to vendor roadmaps.

Our proposal represents an efficient trade-off between operating expenditure and capital expenditure. The proposed migration to cloud-hosting delivers savings to customers through a reduction in ICT capital expenditure which exceeds the increase in operating expenditure for cloud subscriptions. Our proposed cloud migration also provides longer term benefits of cloud-hosting, such as easy scalability and adaptability of our ICT environment to changing requirements, meaning customers will only pay for the capacity and services we need.

To deliver customer savings through efficiently migrating ICT infrastructure to cloud-hosting, we will incur material incremental operating expenditure which is not reflected in our 2019 base operating expenditure. Further details on these costs are set out in our attached ICT cloud migration business case and model.[146]

Lower Mornington Peninsula demand management program

In 2016 we completed a regulatory investment test for distribution (**RIT-D**) that established a need to invest in the lower Mornington Peninsula to maintain supply security (voltage and capacity).[147] The net market benefit from doing so was found to be around $32 million. In accordance with the RIT-D, we implemented a four year demand management program in 2018 that runs through 2021. This program was to defer $29.5 million ($2015) of capital expenditure until 2022.[148]

We have now updated actual and forecast demand to plan ongoing supply requirements for the area. The updated forecasts demonstrate the strong trend in growth has continued over the last few years, however, demand is now forecast to flatten over the next few years. This has created an opportunity to continue the demand management program and defer the capital expenditure further.

Our customers support the use of demand management schemes and programs

Our current agreement with our demand management supplier will lapse at the end of the current regulatory period. We expect the new agreement we enter into will be higher than that included in 2019 base year because:

- more demand management is required to meet the growth in maximum demand
- our 2019 payments to our provider understate the program costs due to a renegotiation of the contract that front ended payments into the 2018 year
- the current contract understated the cost of demand management due to the provider being unable to attract sufficient industrial customer participation.

Further detail on this change, including the corresponding options analysis, are detailed in the attached step change model and lower Mornington Peninsula demand management program business case.[149]

145 UE ATT046 –BDO–Report for cloud–Nov2019 –Public

146 UE BUS 7.10 - Cloud infrastructure - Jan2020 – Public, UE MOD 7.15 - Cloud infrastructure cost - Jan2020 – Public, UE MOD 7.16 - Cloud infrastructure risk - Jan2020 - Public

147 UE ATT105 - Assessment Lower Mornington Peninsula - May2016 - Public

148 This includes overheads but excludes ongoing operational and maintenance costs.

149 UE BUS 9.02 - Lower Mornington Peninsula demand management - Jan2020 – Public, UE MOD 9.04 - Demand management Lower Mornington - Jan2020 - Public

HV feeder demand management program

High voltage feeder can suffer outages if the demand for electricity on that feeder exceeds its thermal capacity. Consequently since 2014, we have implemented an annual 'Summer Saver' demand response program to ameliorate this eventuality in identified constrained areas. Summer Saver provides financial rewards to customers for voluntarily curbing demand when asked to do so.

For the 2021–2026 regulatory period, we have considered various options to address the overload risk on all our HV feeders. To assess demand management viability, we compared the annualised capital cost of addressing a feeder's overload risk to the cost of demand management, where the:

- annualised capital cost is the real weighted average cost of capital multiplied by the capital cost plus depreciation
- demand management cost is the benchmark demand management unit rate multiplied by the excess demand on the feeder.

We have undertaken this assessment on HV feeders where there is an identified need to correct overload risk arising over 2021-2026.[150] We have identified HV feeders where there is an opportunity to efficiently incur operating expenditure for demand management to defer capital expenditure for network augmentation.

58% of our customers said they were interested in participating in demand response programs

To forecast demand management costs, we have applied a unit rate based on actual demand management programs we have undertaken.[151] This unit rate has also been independently reviewed and compared to the demand management rates of other distributors by CutlerMerz. They have found our rate is at the lower end of the range of rates adopted by other distributors, and recommended our rate be used for assessing the viability of demand management projects.[152]

Further detail on this change, including the corresponding options analysis, are detailed in the attached step change model and HV feeder demand management program business case.[153]

Cranbourne Terminal Station non-network solution to address growing demand

Cranbourne terminal station supplies parts of United Energy's and AusNet Services' distribution networks. Its supply area includes Cranbourne, Cranbourne East, Lyndhurst, Clyde, Clyde North and Pakenham. Since commissioning Cranbourne terminal station in 2005, the maximum demand has grown rapidly driven by improved access to the region. [154] This has resulted in diminishing available capacity at Cranbourne terminal station, triggering the need for a fourth transformer.

In Victoria, distributors have responsibility for planning augmentation of transmission connection assets. As a party responsible for planning the connection point, we have identified a potential demand management option

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150 The demand management costs for feeders on which demand management begins in 2020 but continues over the 2021–2026 regulatory period are not included in our base year operating expenditure. Therefore we have included the forecast demand management costs arising in 2021–2026 for HV feeders where demand management begins in 2020. Note this business case does not recover costs arising prior to the 2021–2026 regulatory period.

151 This rate has been used consistently across United Energy demand management programs.

152 UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public

153 UE BUS 9.03 - Feeder demand management - Jan2020 - Public, UE MOD 9.05 - Demand management HV feeder - Jan2020 - Public

154 Major infrastructure projects improving access to the region include Eastlink, Monash Freeway widening, Thompsons Rd widening, and Pakenham & Cranbourne railway corridor improvements.

at the distribution network level to defer augmentation of the Cranbourne terminal station transmission connection assets.

We have identified a non-network solution that will defer the need for construction of a fourth transformer at Cranbourne terminal station by two years. Under this option, we will cover 38% of the incremental operating expenditure while AusNet Services will cover the remaining capital and operational expenditure.

Further detail on this change, including the corresponding options analysis, are detailed in the attached step change model and Cranbourne terminal station non-network solution business case.[155]

9.2 Our forecasting approach

We have used the 'base–step–trend' approach to develop our proposed operating expenditure for the 2021–2026 regulatory period. This approach is consistent with the AER's preferred model. Our approach is as follows:

- nominate 2019 as the efficient revealed base year
- adjust our base year expenditure to include an efficient forecast for activities which are not fully reflected in the base year expenditure, including:
  - review of non-recurrent costs
  - adjustment for services reclassified as standard control
  - adjustment for costs reclassified as operating expenditure
  - adjustment for forecast GSL payments rather than actuals in 2019
- add to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising real price escalation, output growth and productivity
- add the efficient level of forecast step changes for the 2021–2026 regulatory period
- add the efficient forecast of debt raising costs.

9.2.1 Our base year operating expenditure is efficient

We nominate 2019, the fourth year of the 2016–2020 regulatory period, as the efficient base year for our operating expenditure forecast for the 2021–2026 regulatory period. We consider our base year expenditure is efficient for the following reasons:

- the AER has classified us as one of the efficiency frontier networks in the NEM, based on its operating expenditure benchmarking analysis[156]
- we are subject to an incentive framework to which we have responded and continue to respond
- our private ownership structure promotes efficient expenditure, evident in savings generated over the past five years
- we have (among) the lowest operating expenditure per customer while continuing to provide a safe and dependable network that is available 99.99% of the time

155 UE BUS 9.04 - Cranbourne terminal station - Jan2020 - Public.

156 UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public, p.iv

- a large proportion of our operating expenditure is outsourced to external contractors who benefits from economies of scale
- we ensure efficiency of our operations by market testing and engaging competitive contracts where possible
- our labour costs are efficient and competitively priced, and our corporate and field staff are strategically located across the network to minimise travel times and response times in emergency situations.

While we consider every year during the 2016–2020 regulatory period is efficient, we have used 2019 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision.[157] The currency of this data (relative to earlier years) ensures our forecasts are based on up-to-date data. That the data is audited ensures the starting point for our forecasts is robust.

9.2.2 We have adjusted the base year to better reflect future on-going operating expenditure

We have reviewed our base year operating expenditure for any non-recurrent expenditure and future on-going expenditure that may not be reflected in the base. While no non-recurrent operating expenditure was discovered, we identified several activities for which the 2019 base year does not reflect the expenditure for these activities going forward. These are set out in the table below.

Table 9.4 Base adjustments ($ million, 2021)

Adjustments	2021/22
Adjustment for forecast GSL payments	0.2
Reclassification of AMI communications network	0.9
Reclassification of 'wasted truck visits'	0.2
Reclassification of minor repairs	5.2
2020 and half year of 2021 rate of change	3.4
Total	**9.9**

Source: United Energy

Reclassification of operating expenditure related to the smart meter communications network

Our use of data analytics with smart meter data has now become part of our business-as-usual network optimisation. Our customers have told us to keep finding more innovative ways for managing the network.

For the 2021–2026 regulatory period, we have allocated 88% of the operating expenditure for maintaining our communications network from metering to standard control services. This amount represents the percentage of data transmitted through the smart meter communications network for network management purposes, the benefits of which are shared by all customers.

157 For this regulatory proposal our 2019 operating expenditure is an estimate. Our revised proposal will be updated for our actual audited 2019 operating expenditure.

This approach is fairer outcome for all customers. For more information on smart meter communications network, and our smart meter data benefits, refer to section 13.2.3 of the metering chapter.

Our customers have told us they want us to find more innovative ways for managing the network.

Reclassification of cost of 'wasted truck visits' for faults on the customer side of the connection point

In the 2021–2026 F&A paper, the AER reclassified 'wasted truck visits' from an alternative control service in the 2016–2020 regulatory period.[158] Wasted truck visits are where we send a truck to a customer's premises after receiving a complaint about a power outage or power quality issue, only to find on arrival that the issue is on the customer side of the connection point. Our forecast operating expenditure for the base adjustment for these wasted truck visits is based on 2014–2018 actual historical expenditure.

Adjustment for reclassification of minor repairs as operating expenditure

We are proposing to reclassify 'minor repairs' from capital expenditure to operating expenditure. Typically minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired).

Treating these minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period.

We have adjusted our base year operating expenditure for the total cost of minor repairs in 2019 and removed forecast minor repairs from our capital replacement expenditure forecast. These changes are net present value neutral, which means customers are no worse-off in the long term.

This is reflected in our updated Cost Allocation Methodology.[159]

Adjustment for forecast GSL payments rather than actuals in 2019

We are required to make GSL payments to customers who experience reliability that is worse than specified performance thresholds in the Distribution Code. These payments may exhibit significant volatility across years based on a range of exogenous factors. Given this variability, we have removed actual GSL payments for 2019 from our base year expenditure, and replaced it with a forecast reflecting the average of GSL payments over the period 2014–2019. This approach is consistent with that adopted by the AER in previous regulatory decisions.

9.2.3 We trend forward our base year for expected changes in economic and network conditions

Our actual operating expenditure in the base year reflects the economic and network conditions that prevailed during the 2019 year. Over the 2021–2026 regulatory period it is reasonable to expect that these economic and network conditions will change and therefore the operating expenditure forecasts must take these changes into account to ensure we continue to achieve the operating expenditure objectives of the Rules.[160]

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158 UE ATT044 - AER - Final framework and approach - Jan2019 - Public, p. 32.

159 UE ATT124 - Cost allocation method - Jan2020 - Public

160 The operating expenditure objectives of the Rules for standard control services requires us to meet or manage the expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply, and maintain the safety of the distribution system.

The AER's Expenditure Forecast Assessment Guideline also sets out the following reasons why efficient operating expenditure in the forecast period may differ from the base level of expenditure:[161]

- real price growth—changes in labour and non-labour price inputs used in our operations. Real price growth is the growth rate in prices relative to growth in the consumer price index (**CPI**). As real input prices change our efficient level of expenditure will change
- output growth—this is changes in the network size and demand for network services. It is reasonable that as the scale of operations increases our efficient costs will increase
- productivity growth—productivity growth reflects shifts in the production possibility frontier delivered through technology advancements or other innovations. It does not reflect reductions in operating expenditure from removing inefficiencies or business-as-usual ICT upgrades.

We have developed forecasts of each of the above components and applied these to develop our efficient operating expenditure forecasts. Our approach is described below and in the supporting attachments as indicated in each subsection.

9.2.4 Forecast real price growth

Over the 2021–2026 regulatory period, input prices for labour have been forecast by our independent expert, BIS Oxford Economics (**BIS Oxford**) to grow at a faster rate than CPI. Conversely, we currently have no evidence our non-labour input prices will grow at a greater rate than CPI. We have therefore only included a real price escalation for labour in our forecast.

Real labour price growth

We engaged BIS Oxford to provide independent labour price forecasts for the 2021–2026 regulatory period. BIS Oxford developed forecasts of the Australian Bureau of Statistics (**ABS**) Electricity, Gas, Water and Waste Services (**EGWWS**) Wage Price Index (**WPI**) for Victoria. This is consistent with the AER's preferred approach to forecasting labour price growth.

We engaged Frontier Economics to assess the accuracy of BIS Oxford's forecasting history for Victorian real EGWWS WPI. Frontier Economics found BIS Oxford have been the more accurate forecaster compared to the AER's preferred forecaster Deloitte Access Economics with regards to the real growth in the Victorian EGWWS WPI.[162] BIS Oxford also provided advice on the calculation of the proposed increases to the superannuation guarantee. As per the *Minerals Resource Rent Tax Repeal and Other Measures Bill 2014* (Cth), Schedule 6—Superannuation Guarantee Charge percentage, the superannuation guarantee is scheduled to increase progressively from 9.5% on 1 July 2020 to 12% on 1 July 2025, as shown in table 9.5.[163]

Table 9.5 Change in superannuation guarantee charge (%)

Year starting on 1 July	2020	2021	2022	2023	2024	2025
Charge percentage	9.5	10.0	10.5	11.0	11.5	12.0

Source: The Parliament of the Commonwealth of Australia, House of Representatives, Minerals Resource Rent Tax Repeal and Other Measures Bill 2014 No. 96, 2014, as passed by both Houses, 2013-2014, p.37.

161 UE ATT134 - AER - EFAG - Nov2013 - Public

162 UE ATT053 - Frontier - Review of labour escalation - Dec2019 - Public

163 UE ATT186 - CTH Senate - Schedule of amendments - Dec2019 - Public, p. 37.

According to BIS Oxford's research,[164] the superannuation guarantee charge is not included in the ABS's WPI or the average weekly earnings measures and is treated as a labour 'on-cost'. The superannuation guarantee charge therefore needs to be added to the forecast increases in the WPI when escalating labour prices over the forecast regulatory period.

Our labour price growth forecasts therefore include the effect of the change in the superannuation guarantee charge, as added to the BIS Oxford independent forecasts. The forecast real labour price growth rate is shown in table 9.6.

Table 9.6 Labour price growth forecast for 2021–2026 (%)

EGWWS WPI escalation with superannuation guarantee charge increase	2021/22	2022/23	2023/24	2024/25	2025/26
Real	2.0	2.2	2.2	1.9	1.7

Source: BIS Oxford Economics, Labour Cost Escalation Forecasts 2025/26, April 2019 and United Energy.

Labour price growth over the 2021–2026 period will be buoyant as a result of strong population growth and a rebounding economy. Victoria's population, particularly in Melbourne, is expected to be stronger than the national average as migration from interstate increases. Victoria's economy is expected to rebound with stronger population growth, higher exports and household consumption from the weak Australian dollar, and stronger business investment.

EGWWS is a capital-intensive sector with a tight labour market of employees with higher skill and higher wages than most other sectors. As such, labour price growth in the EGWWS WPI is consistently higher compared to the 'all industry' average WPI.

Demand for skilled labour in the electricity sub-sector is growing at a faster rate compared to the remainder of the EGWWS sector (and compared to the remainder of the economy), as the number and type of services available increases with a transition to renewables and distributed energy resources. Comparatively, gas, water and waste sectors are stable. Industry wage data for 2016–2017 from the ABS shows that average wage levels in the electricity sub-sector are more than 50% higher than employees in the waste sub-sector and 40% higher than those in the water and sewerage sub-sector. As such, the EGWWS WPI forecast is likely to underestimate the labour price growth for the electricity distribution sector alone.

Overall, we expect the labour market for skilled labour will tighten further during the 2021–2026 period, limiting our ability to negotiate wages, particularly under collective bargaining. The BIS Oxford forecast of the EGWWS WPI reflects a realistic expectation of labour price growth for an efficient, prudent and realistic operating expenditure forecast for the electricity distribution sector.

For detailed information on drivers of the Victorian EGWWS WPI, and comparisons to other industries and jurisdictions, please refer to the attachment.[165]

Labour and non-labours weights

To develop our real price forecast we assigned weights to the price of labour and non-labour that reflect our efficient mix of labour and non-labour inputs. We propose to use our historical average revealed input mix to define labour and non-labour weights used for forecasting real price growth in 2021–2026, shown in table 9.7.

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164 UE ATT014 - BIS - Labour escalation - Apr2019 - Public

165 UE ATT014 - BIS - Labour escalation - Apr2019 - Public

Table 9.7 Labour and materials input weights in forecasting real price growth (%)

Input	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Labour	58.2	58.2	58.2	58.2	58.2	58.2
Non-labour	41.8	41.8	41.8	41.8	41.8	41.8

Source: United Energy

Using efficient revealed costs is the most prudent and realistic approach to forecasting future cost. Consistent with its Expenditure Forecast Assessment Guideline, the AER accepts the base year revealed operating expenditure as the starting point for forecasting allowances unless its benchmarking analysis identifies that level of operating expenditure to be 'materially inefficient'. Each efficient distributor's revealed operating expenditure in the base year reflects its own operating environment, which results in a unique input mix on the productivity frontier. If the AER allows the revealed cost base year but not the corresponding efficient input mix, it will either overcompensate or undercompensate efficient distributors.

The AER's incentive-based regulatory framework incentivises an efficient input mix, which will vary by distributor depending on its operating environment. The EBSS incentivises distributors to reduce total operating expenditure and there is a reputational incentive to improve benchmarking performance. If we were to reduce expenditure by maintaining an inefficient input mix, we would forgo EBSS rewards and reputational advantage from improved benchmarking results. We will therefore always be seeking an efficient input mix that maximises EBSS rewards and reputational advantage.

We propose to use an average of our actual efficient input mix over the 2014–2018 period to determine the labour and non-labour weights. Using a five-year average further addresses the AER's concern we would adjust our input mix inefficiently in the base year to favour one input over another. Our input mix over 2014–2018 reflects an efficient, prudent and realistic basis for the forecast of our input mix for 2021–2026.

The AER's preferred approach to forecasting real price growth is to apply an industry average input weight to all distributors. We engaged Frontier Economics to assess the appropriateness of using industry average input weights for forecasting labour price growth for efficient distributors. For the following reasons, Frontier Economics found there is no sound basis for the AER to apply industry average input weights to all distributors when setting operating expenditure allowances, rather than the actual input weights of individual distributors:

- adoption of actual input weights is unlikely to weaken efficiency incentives
- the AER’s approach has not been assessed for prudency and realism and is therefore not consistent with the operating expenditure objectives
- the AER uses revealed historical costs to set future allowances in some circumstances and it is unclear why the same approach cannot be taken for labour and non-labour weights
- contrary to the AER's claim that using a revealed input mix in setting allowances and an industry average in benchmarking would result in some distributors being found efficient with one measure and inefficient with another, the AER’s benchmarking analysis is not materially sensitive to the use of actual input weights.

Using revealed input weights also removes the potential for errors in the calculation of industry averages, or basing the calculations on incomplete data sets, which can lead to inefficient allowances. In its assessment, Frontier Economics found the input weights used by the AER in recent decisions to be unreliable for setting allowances. Frontier Economics found evidence that:

- the data relied upon by the AER to calculate industry average input weights have not been reported consistently by distributors, including a significant number of missing data points, and the AER appears to have undertaken no due diligence to identify this
- there are major shortcomings in the methodology used by the AER to calculate industry average input weights, including:
  - the historical time period the average input weights relate to represents a period of very material cost restructuring for some distributors which may never be repeated
  - the AER has applied an inappropriate 'rule-of-thumb' to fill in missing/unreported data
  - average cost shares are biased towards large distributors and distributors that report data across all categories
- the AER's calculations appear to contain some errors.

Frontier Economics concludes the AER's current estimate of input weights should not be used to set operating allowances for distributors. [166] Conversely, our revealed input mix is audited and efficient.

9.2.5 Forecast output growth

We forecast growth in outputs to capture increases in operating expenditure which are driven by changes in the size of the network and the quantity of services we will supply over the 2021–2026 regulatory period.

To forecast output growth, we:

- model and test various output measures as drivers of operating expenditure
- determine the significant output measures and their weights
- forecast a growth rate for each selected output measure.

Selecting output measures and their weights

To model, test and select appropriate expenditure drivers and their weights, we assessed the models used in AER's benchmarking report, prepared by Economic Insights. Economic Insights prepares four models for the AER:[167]

- Cobb-Douglas stochastic frontier analysis (econometric model)
- Cobb-Douglas least squares (econometric model)
- translog least squares (econometric model)
- multilateral partial factor productivity (**MPFP**) (non-parametric model).

We engaged NERA Economic Consulting (**NERA**) and Frontier Economics to independently assess the most appropriate models to be used in determining the weights of each output measure.[168] Both NERA and Frontier Economics found that, while there were challenges with each model, the average of two Cobb-Douglas models was the most appropriate estimate of weights for use in forecasting output growth.

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166 UE ATT053 - Frontier - Review of labour escalation - Dec2019 - Public

167 In the AER's 2019 annual benchmarking report published in November 2019, it also introduced a fifth model a Translog SFA. Refer UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public

168 UE ATT012 - NERA - Output weightings - Dec2018 – Public. UE ATT052 - Frontier - Review of output growth estimation - Dec2019 - Public

MPFP is not an appropriate model for forecasting output growth

NERA found the MPFP to be an unreliable measure of relative efficiency for the following reasons:

- the process for deriving weights from the MPFP modelling is not transparent
- the drivers included in the MPFP modelling were chosen based on tariff structure, not by assessing their effect on distributors' costs
- the weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model
- the MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely.

Frontier Economics agreed with NERA that the AER should discontinue its reliance on the Leontief model (used in MPFP) in the setting of operating expenditure allowances. Frontier Economics came to this conclusion due to severe statistical problems associated with the models estimated by Economic Insights and the multicollinearity between the customer numbers, circuit length and the time trend in the estimating equations.

Frontier Economics also found that based on the statistical evidence, energy throughput is not a material driver of operating expenditure. Their review of the statistical properties of Leontief cost functions estimated by Economic Insights for the Annual Benchmarking Report found no statistical evidence that energy throughput has a material impact on operating expenditure.

According to the MPFP model, operating expenditure would decrease with falling energy throughput. This is an inaccurate and misleading representation of actual cost drivers. In fact, the relationship between energy throughput and operating expenditure is likely to be increasingly negative—as the growth in DER reduces energy throughput it also imposes additional distribution costs that are not captured by customer numbers and ratcheted maximum demand.

In its 2019 benchmarking report, the AER acknowledged the possibility of the energy throughput measure undercompensating distributors for actual costs:[169]

> *Currently, the energy throughput output variable captures changes in the amount energy delivered to customers over the distribution network as measured at the customer meter. It does not measure energy delivered into the distribution network via distributed energy resources, such as from residential roof-top solar panels. In the extreme, an increase in rooftop solar panels could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. In this situation there could be a material increase in inputs without a corresponding increase in any or all of the output measures.*

Given analysis from NERA and Frontier Economics, we have excluded the MPFP model from our output growth forecast.

Translog models are not appropriate for forecasting output growth

Frontier Economics also found the translog cost function should only be considered for determining output weights if translog-derived weights are evaluated at output levels that are relevant to the Australian distributors. The approach adopted by the AER is to evaluate the elasticities from the model at the average output levels of

[169] UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public, pp. 48-49

all distributors in the international sample. However, these average output levels are vastly different to the output levels of Australian distributors. The elasticities should be evaluated at output levels that are reflective of the operating characteristics of the Australian distributors. However, Frontier Economics concludes if the AER believes that the elasticities are constant across all utilities in the sample, then it would be statistically more efficient to estimate these constant elasticities using the Cobb-Douglas cost function.

We are therefore satisfied our approach to forecasting output growth, using an average of the Cobb-Douglas models, results in more efficient, prudent and realistic operating expenditure forecasts compared to the use of the simple average of the four models. Our proposed forecast output growth uses the output measures from the two models—customer numbers, ratcheted maximum demand and circuit length—and set the weights for each output measure as the average of the weights produced by the two models.

Table 9.8 demonstrates the output measures and the weights we used in forecasting output growth.

Table 9.8 Output measures and weights used in forecasting output growth (%)

Output measure	Cobb-Douglas stochastic frontier analysis	Cobb-Douglas least squares	Average of Cobb Douglas models
Customer numbers	70.8	67.6	69.2
Circuit length	16.8	11.8	14.3
Ratcheted maximum demand	12.4	20.6	16.5

Source: UE ATT012, NERA Economic Consulting, Review of the AER's Proposed Output Weightings, December 2018

Forecasting growth in each output measure

We engaged the Centre of International Economics (**CIE**) to independently develop customer number forecasts and National Institute of Economic and Industry Research (**NIEIR**) to independently develop maximum demand forecasts. We have used the 2014–2018 historical average growth rates to forecast circuit length. Their forecasts are shown in table 9.9.

Table 9.9 Forecast growth for output measures (%)

Output measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Customer numbers	1.5	1.4	1.4	1.3	1.2	1.4
Circuit length	1.3	1.4	1.4	1.5	1.6	1.4
Ratcheted maximum demand	0.0	0.0	0.0	0.9	2.0	0.6

Source: UE ATT019- CIE- United Energy customer number forecasts- May 2019; UE ATT022- NIEIR- Maximum demand forecasts for United Energy terminal stations to 2030- July 2018; United Energy

Further information on our approach to customer number and maximum demand forecasts, including forecasts of solar penetration, batteries and electric vehicles and their impact on maximum demand is provided in the appendix.[170]

Table 9.10 shows our forecast output growth, as the sum–product of the forecast growth rate of each output measure and the weight of each measure.

Table 9.10 Forecast output growth rate (%)

Measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Output growth	1.2	1.2	1.1	1.3	1.4	1.3

Source: United Energy

9.2.6 Productivity growth

We have applied the AER's productivity adjustment in accordance with the AER's final decision for forecasting productivity growth,[171] as shown below.

However, as an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices and have limited capacity to achieve the 0.5% productivity adjustment through business-as-usual activities during the 2021–2026 regulatory period.

Table 9.11 Forecast operating expenditure productivity (%)

	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast productivity	0.5	0.5	0.5	0.5	0.5

Source: United Energy

Shifting the productivity frontier requires investment in innovative technology and practices

In its final decision for forecasting productivity growth, the AER determined 0.5% per year reflects the best estimate of the operating expenditure productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward. The AER stated this can come from new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.

We are one of the four networks on the efficiency frontier in the Australian electricity distribution sector. In its 2019 Benchmarking Report the AER stated:[172]

> *CitiPower, Powercor, United Energy and SA Power Networks have consistently been the most efficient distribution service providers in the NEM. These networks are amongst those service providers that are on the productivity frontier.*

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170 UE APP03 - Maximum demand and customers - Jan2020 - Public

171 UE ATT137 - AER - Forecasting productivity growth - Mar2019 - Public

172 UE ATT045 - AER - Annual benchmarking report - Nov2019 - Public, p.18

By virtue of being an efficiency frontier network, we have limited capacity to achieve productivity gains through business as usual. This places us in a uniquely challenging position compared with other networks that will more easily achieve the 0.5% per annum productivity through effectively catching-up to the efficiency frontier.

To achieve the 0.5% productivity adjustments, we would need to invest in innovative new technologies which materially change operational processes. This will be challenging given we have already revolutionised a significant portion of our operations through automation and innovation. At this point in time we cannot envisage how we would achieve the full 0.5% productivity adjustment. Consequently, the majority of our 0.5% efficiency target will need to be self-funded during 2021–2026.

We have proposed two ICT projects that are driven by customer benefits, Customer Enablement and Intelligent Engineering, which also have a modest expectation of operating expenditure benefits.[173] We consider these projects will only marginally contribute towards the AER's ambitious target of 0.5% operating expenditure savings per annum during 2021–2026.

In its ICT Guideline the AER states:[174]

> *non-recurrent ICT capex projects where the main driver are operating expenditure benefits should include a negative operating expenditure step change to at least the same of the cost of those capital expenditure projects, with any additional benefit above this negative step change may contribute to the 0.5% operating expenditure productivity assumption*

We disagree 0.5% productivity assumption can be reached without funding for capital expenditure required to achieve the savings. In forecasting the 0.5% pre-emptive productivity adjustment, the AER relied on evidence that included productivity growth attributable to non-recurrent ICT expenditure. If the AER makes a further adjustment to reduce allowed operating expenditure to reflect productivity that is expected to result from non-recurrent ICT expenditure, this is likely to result in over-estimation of the forecast productivity growth rate and an operating expenditure allowance below efficient and prudent costs.

It is particularly important to acknowledge the expenditure necessary to achieve future savings for efficient frontier networks. We have already automated our processes and in doing so, have de-risked the industry with regard to new and innovative ICT by introducing it to the Australian energy market. We have lean operations and do not have the contingency to absorb further risky and costly initiatives without reasonable reward. We can only envisage future savings from successful investment in new and risky technology—we therefore consider it crucial we receive sufficient funding for the productivity-enhancing projects that will not be rewarded through the EBSS, to allow us to achieve the operating expenditure objectives.

Relationship between productivity and step changes for regulatory obligations

The AER's decision to apply a 0.5% per year pre-emptive productivity adjustment is a shift from its previous approach of applying a 0% productivity adjustment at a time of negative measured productivity. In the past, the AER has never compensated distributors for growing cost pressures through the productivity adjustment (i.e. allowing distributors to recover more allowance by applying an adjustment for negative productivity). Rather, the AER compensated distributors for negative productivity by allowing step changes related to new or growing regulatory obligations.

According to the AER's final decision, the period of growing regulatory obligations ended between 2011 and 2012 on average across Australia. As a result, the AER based its new approach to measuring productivity on

173 UE BUS 7.02 - Customer enablement - Jan2020 – Public, UE BUS 7.07 - Intelligent engineering - Jan2020 - Public

174 UE ATT135 - AER - ICT Guideline - Nov2019 - Public, p.12

electricity distribution data post-2011. This approach was applied to econometric models as well as the MPFP model.

The AER's measure of electricity distribution productivity during 2011–2017 removes the impact of regulatory obligations on operating expenditure productivity by assuming minimal or no growth in obligations during that period. By virtue, any change in regulatory obligations should be considered in isolation of measured productivity, whether historically or forecast. This is consistent with the AER's previous approach to measuring productivity where distributors were compensated for growing regulatory obligations through step changes and not through a productivity adjustment.

By isolating the impact of regulatory obligations on productivity, the 'rate of change' calculation for forecasting operating expenditure does not account for change in regulatory obligations. To ensure we are able to achieve our operating expenditure objective of the Rules, we have considered all changes in regulatory obligations during 2021–2026 and have proposed them as step changes as outlined in section 9.1.

10

Revenue requirement

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10 Revenue requirement

We will be reducing our charges for residential and small business customers over the 2021–2026 regulatory period:

- a typical residential customer will receive reductions of $54 each year on their distribution and metering charges
- small business customers will on average receive $238 each year on their distribution and metering charges.

This chapter provides a summary of our proposed 2021–2026 annual revenue requirements for standard control services which reflect the efficient costs that we reasonably expect to incur.[175]

The AER's roll forward model (**RFM**) has been used to roll forward the regulatory asset base (**RAB**) to the start of the regulatory control period. The AER's post tax revenue model (**PTRM**) has been used to calculate the revenue requirements. We have not departed from the AER's PTRM or RFM.

The following building block components have been used to calculate the annual revenue requirement for each year of the regulatory control period:

- return on capital, calculated by applying the rate of return to the opening RAB value
- regulatory depreciation
- forecast operating expenditure
- the revenue increments or decrements for that year arising from the application of:
  - the efficiency benefit sharing scheme (**EBSS**)
  - the capital efficiency sharing scheme (**CESS**)
  - the demand management incentive allowance (**DMIA**)
  - the shared asset revenue reduction
  - estimate of the cost of corporate income tax.

We consider that our forecasts, in totality, delivers the affordability outcomes our customers are seeking.

We have a long history of responding positively to incentive schemes, and in turn delivering greater value for our customers. During the 2016–2020 regulatory period we continued this trend, recording substantial improvements in our network reliability and customer services, together with our expenditure efficiencies which delivered $333 million in savings, 70% of which is delivered to our customers.

This chapter also sets out the incentives schemes that we propose to apply to the 2021–2026 regulatory period, namely the EBSS, CESS, DMIA and demand management incentive scheme, f-factor and service target performance incentive schemes.

10.1 What we plan to deliver

The revenue we propose to recover from our customers, and the affordability we strive to deliver, are key concepts we have sought to balance in our regulatory proposal. As discussed in our respective capital and

175 We have classified our services in accordance with the AER's F&A paper published in January 2019

operating expenditure chapters, we have considered whether the programs we intend to deliver are needed, will result in customer benefits, and are delivered in the least-cost way. Importantly, we have also considered whether in totality this proposal delivers the affordability outcomes our customers are seeking.

We will be reducing our charges for residential and small business customers over the 2021–2026 regulatory period. The indicative impact on a distribution bill is shown in the table below.

Table 10.1 Distribution bill impact for typical customer (excluding metering charges) (%)

	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	-13.0	-1.0	-1.0	-1.0	-1.0
Small commercial	-12.0	-1.0	-1.0	-1.0	-1.0

Source: United Energy

Whilst these movements provide an early indication of our commitment to customers for the next regulatory period, they are indicative only. The actual prices that will be charged to customers for the 2021–2026 regulatory period remains dependent on:

- the X factors that the AER will determine for us for the 2021–2026 regulatory period
- actual energy consumption:
  - if energy consumption falls below our forecast, average charges would increase more than indicated or
  - if energy consumption rises above our forecast, average charges would decline below the estimates indicated
- the impact of incentive schemes
- the impacts of ‘unders and overs’ amounts adjusted for the time value of money due to variances between actual and forecast volumes
- implementation of our new tariff structure statement, which will take effect from 1 July 2021, subject to AER approval (our tariff structure statement and tariff structure statement reasoning appendices are attached)[176]
- the percentage changes above represent only a portion of the total network use of system charge to customers. Network use of system charges also include transmission network costs and the recovery of an amount to satisfy obligations under the jurisdictional scheme requirements. These components are outside our control.

With respect to our charging structures, we are proposing changes to residential structures to accelerate the pace of reform without jeopardising the stakeholder support that is crucial to enable change. We will introduce new two-rate residential and small business tariffs for new customer connections, customers seeking supply upgrades to three-phase and customers installing rooftop solar or batteries. The objective is to encourage customers to move discretionary electricity use into off-peak periods, when the network is under less pressure. Feedback from our customers strongly preferred the simplicity of a two-rate tariff.

[176] UE APP05 - Tariff structure statement reasons - Jan2020 – Public, UE APP06 - Tariff structure statement technical - Jan2020 - Public

10.2 Our forecasting approach

This section sets our forecast approach for the development of our revenue requirement over the 2021–2026 regulatory period for standard control services.[177] This includes the building block approach required by the Rules, our use of the AER's RFM and PTRM models, and the application of various incentive schemes for the current and future regulatory period. We have prepared our regulatory proposal in accordance with our proposed cost allocation method.[178]

Building blocks are used to derive our proposed unsmoothed annual revenue requirement for standard control services. The revenue X factors serve the purpose of smoothing revenue. The X factors are calculated to equalise (in net present value terms) the revenue to be earned by us from the provision of standard control services over the 2021–2026 regulatory period with our proposed total revenue requirement for that period.

For the purposes of clause 6.4.3(a)(6) and clause 6.4.3(b)(6) of the Rules, there are no other revenue increments or decrements to be carried forward from the previous regulatory period.

Our proposed X factors have been calculated to hold expected smoothed revenue constant in real terms over the regulatory control period, based on the stated preference of our stakeholders.

Unsmoothed and smoothed revenue, and our proposed revenue X factors, are shown in the table below.

177 We have classified our services in accordance with the AER's framework and approach paper published in January 2019.

178 UE ATT124– Cost Allocation Method – Jan2020 –Public

Table 10.2 Revenue requirement ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Return on assets	119.2	124.1	127.7	130.6	132.5
Regulatory depreciation	92.2	105.3	120.1	131.9	143.5
Operating expenditure	159.3	164.5	172.3	177.7	183.8
EBSS	32.0	31.8	13.2	-1.5	-
CESS	8.7	8.9	9.2	9.4	9.6
Other adjustments	-0.4	-0.4	-0.5	-0.5	-0.5
Corporate income tax	9.7	7.7	7.6	9.8	8.9
Unsmoothed revenue requirement	420.6	441.8	449.6	457.3	477.8
Smoothed revenue requirement	428.2	438.5	449.0	459.8	470.8
Forecast CPI %	2.4%	2.4%	2.4%	2.4%	2.4%
Revenue X factor[179]	**10.7%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

Source: United Energy

10.2.1 Regulatory asset base

We have used the AER's RFM to calculate the opening RAB from 1 July 2021:

- capital expenditure rolled into the RAB has been reduced by customer contributions and disposals
- net capital expenditure includes a half year's weighted average cost of capital (**WACC**)
- straight-line depreciation based on forecast capital expenditure has been deducted in accordance with the AER's 2016-2020 final determination
- the RAB has been adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism.

The estimated opening value of the RAB for standard control services as at 1 July 2021 is shown in the table below, and in our attached RFM.[180]

179 A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

180 UE MOD 10.08 - RFM 2016-20 - Jan2020 - Public

Table 10.3 Roll forward of the RAB from 1 January 2016 to 1 July 2021 ($ million, nominal)

	Total
1 January 2016 opening RAB from previous determination	2,083.0
Add: True-up for 2015 capital expenditure	-11.6
Add: Actual/estimated net capital expenditure for 2016-2021 (including half-year WACC)	945.1
Less: Forecast straight-line depreciation for 2016-2021	-747.3
Add: Adjustment for actual inflation for 2016-21	204.0
1 July 2021 opening RAB	**2,473.3**

Source: United Energy

To roll-forward the RAB from 2021 to 2026, we have applied the following approach:

- the RAB has been rolled forward from 2021 to 2026 in accordance with the Rules using the AER's PTRM
- the forecast net capital expenditure for the roll forward of the RAB over the 2021–2026 regulatory control has been reduced by forecast customer contributions and by forecast disposals which are based on average historic disposals.
- forecast net capital expenditure includes a half year's WACC.

The roll forward of the RAB over 2021–2026 is shown in the table below, and in our attached PTRM. [181]

Table 10.4 Roll forward of the RAB over 2021–2026 ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Opening RAB	2,473	2,651	2,813	2,968	3,109
Add: Forecast net capital expenditure (including half-year WACC)	270	267	275	273	235
Less: Regulatory depreciation	-152	-169	-188	-203	-218
Add: inflation on opening RAB	59	64	67	71	75
Closing RAB	**2,651**	**2,813**	**2,968**	**3,109**	**3,201**

Source: United Energy

10.2.2 Regulatory depreciation

Straight-line depreciation has been calculated using year-by-year asset tracking from 2011 consistent with the approach taken in the AER's 2016-2020 final determination, and shown in the attached depreciation model.[182]

181 UE MOD 10.02 - PTRM 2021-26 - Jan2020 - Public

182 UE MOD 10.03 - Depreciation 2021-26 - Jan2020 Public

Our proposed standard asset lives are shown in the table below.

Table 10.5 Standard and remaining asset lives (years)

Asset	Standard life
Sub-transmission	60
Distribution system assets	35.6
SCADA	10
Non-network general assets – IT	5
Non-network general assets – Other	7.5
In-house software	5
Equity raising	42

Source: United Energy

We have separately calculated the 2021–2026 depreciation adjustments for assets that will become redundant before 2026 and before the end of their economic life.

This only applies to the replacement of distribution transformers to enable greater capacity of solar generation on our networks by 2026. Distribution transformers must be replaced to remove old models that do not have appropriate tapping functionality and/or to increase the transformer capacity. Our methodology to accelerate the depreciation of these distribution transformers is set out in the attached model[183] and takes into account:

- the number of distribution transformers in the network that will be removed
- the average remaining life of our distribution transformers, using the standard asset life and the weighted average age of our distribution transformer population
- the remaining value of each distribution transformer, taking into account the average remaining life and the replacement value of each asset.

Our regulatory depreciation for each year of the 2021–2026 regulatory period is shown in the table below. It is calculated as straight-line depreciation less the inflation adjustment to the RAB. The estimated information rate is set out in section 10.2.4.

183 UE MOD 10.07 - Accelerated depreciation - Jan2020 Public

Table 10.6 Regulatory depreciation ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Straight-line depreciation	151.6	168.9	187.6	203.1	218.2
Less: Inflation adjustment	59.4	63.6	67.5	71.2	74.6
Regulatory depreciation	**92.2**	**105.3**	**120.1**	**131.9**	**143.5**

Source: United Energy

10.2.3 Rate of return

Our rate of return estimates has been prepared consistent with the 2018 Rate of Return Instrument (**2018 RORI**), modified in accordance with AER instructions to accommodate the Victorian Government's intent to extend the current regulatory period by six months.

Our rate of return is shown in the table below, and set out in the attached rate of return model.[184]

Table 10.7 Rate of return

	2021/22	2022/23	2023/24	2024/25	2025/26	Average
Nominal risk free rate	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%
Market risk premium	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%
Equity beta	0.6	0.6	0.6	0.6	0.6	0.6
Return on equity	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
Trailing average return on debt	4.71%	4.48%	4.24%	4.01%	3.78%	4.24%
Gearing	60%	60%	60%	60%	60%	60%
Nominal rate of return	**4.82%**	**4.68%**	**4.54%**	**4.40%**	**4.26%**	**4.54%**

Source: United Energy

Return on debt

The 2018 RORI requires return on debt to be calculated as a ten-year trailing average, updated annually. The AER have provided us with modified weightings to be used to accommodate the six-month extension to the current regulatory period.

We forecast the ten-year trailing average annual return on debt based on the placeholder averaging period of the last 20 business days in July 2019. The ten-year trailing average debt rates will be updated based on observations agreed during the agreed risk-free rate averaging periods.

184 UE MOD 10.04 - Rate of return - Jan 2020 - Public

The annual debt rates will be updated annually in accordance with the 2018 RORI based on observations during the agreed risk-free rate averaging periods.

Return on equity

Under the 2018 RORI the return on equity must be calculated as the risk free rate plus a market risk premium of 6.1 per cent multiplied by an equity beta of 0.6. The risk free rate must be calculated as the ten-year yield to maturity on Commonwealth Government Securities, measured over the agreed risk free rate averaging period.

We have calculated the return on equity using a placeholder risk free rate of 1.32% based on the placeholder averaging period of the last 20 business days in July 2019. The risk free rate will be updated based on observations during the agreed risk free rate averaging period, calculated in accordance with the 2018 RORI.

Averaging periods

The 2018 RORI proposes that there be a averaging period set for each year of the relevant regulatory period from which the data for the allowed return on debt will be drawn, and a single averaging period from which risk free rate data for the allowed return on equity will be drawn.

The 2018 RORI states that the periods can be proposed by the network no later than the lodgement date of the regulatory proposal and agreed by the AER on a confidential basis. We have proposed our averaging periods confidentially to the AER in accordance with the 2018 RORI.

10.2.4 Expected inflation

The Rules require the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation. The current PTRM method is to calculate the geometric average based on the inflation forecasts for two years sourced from the latest available Reserve Bank of Australia's (**RBA**'s) Statement of monetary policy and the mid-point of the RBA's target inflation band for eight years.

Our estimate of expected inflation, for the purposes of a placeholder for our proposal, is currently 2.40% using the PTRM method, assuming an RBA inflation forecast of 2.00% for the first two years and 2.50% for the remaining eight years.

The energy networks recently raised concerns with the AER about the current PTRM method, and potentially the inflation framework. Based on the AER's consideration of these concerns, we may amend the method used to calculate expected inflation in our revised proposal.

10.2.5 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

There is now some uncertainty associated with debt raising costs for the following reasons:

- in the SA Power Networks draft decision the AER based the debt raising cost allowance on a report from Chairmont which updated the estimate previously provided by PwC in 2013. SA Power Networks have submitted a Competition Economic Group (**CEG**) report to the AER in its response to the AER draft decision which contends that one component of debt raising costs - arranger fees - should be 6.88 basis points per annum (**bppa**) rather than the 3.97 bppa calculated by Chairmont and adopted in the AER draft decision
- the AER collected actual debt raising cost information from all regulated networks in November 2019 but it is not yet clear whether consideration of this data will result in the AER modifying its debt raising cost estimates or approach.

We have applied a placeholder debt raising cost of 8 bppa. We will respond to the AER's draft decision in which the AER would have had the opportunity to consider the data recently collected by the AER and the CEG report submitted by SA Power Networks.

The interest rate swaps which we currently have in place mature at the end of each calendar year over the next ten years. Due to the transition from calendar to financial regulatory years, there will be a mismatch between the maturity date of each existing interest rate swap over the next ten years and the commencement date for rates that need to be hedged in the future. The most efficient solution for dealing with this mismatch depends on many factors including the shape of the yield curve. It is premature for us to select a solution prior to the submission of this proposal and therefore we have not yet been able to cost a solution. Should the efficient cost be material, we will propose a cost in our revised proposal.

10.2.6 Equity raising costs

Equity raising costs are transaction costs incurred when a network raises new equity in order to fund capital investment.

The AER provides a benchmark allowance to recover an efficient amount of equity raising costs, when a network's capital expenditure forecast requires an equity injection to maintain the benchmark gearing of 60%.

Our calculation of equity raising costs is presented in the PTRM.[185] This calculation includes the latest AER parameters consistent with the 2018 RORI.

10.2.7 Efficiency benefit sharing scheme

The EBSS provides a continuous incentive for us to achieve efficiency gains in our operating expenditure. Any efficiency gains we achieve are then shared between us and our customers.

The EBSS outlined by the AER in its 2016-2020 final determination has been applied to operating expenditure over the current regulatory period to calculate the EBSS revenue increments and decrements which must be included in the 2021–2026 building blocks. Our savings are discussed in the attached appendix[186] and calculations are provided in the attached EBSS model.[187]

The EBSS scheme outlined in the final determination specified that the following operating expenditure categories must be excluded from the operation of the EBSS:

- debt raising costs
- the demand management incentive allowance
- GSL payments.

Over the 2021–2026 regulatory period, we propose to continue to apply the EBSS to standard control operating expenditure. Applying the EBSS ensures we continue to have strong incentives to pursue sustainable efficiency gains which deliver lower costs to customers into the future.

Application of the EBSS is also consistent with the AER's F&A paper and our forecast operating expenditure for the 2021–2026 regulatory period, which is based on our actual efficient 2019 operating expenditure.

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185 UE MOD 10.02 – PTRM 2021-26 – Jan2020 – Public

186 UE APP02 - What we have delivered - Jan2020 - Public

187 UE RIN005 - Workbook 5 - EBSS - Jan2020 – Public.

Consistent with the current regulatory period, we propose excluding debt raising costs and guaranteed service level payments from the calculation of the 2021–2026 EBSS carryover.

10.2.8 Capital expenditure sharing scheme

The CESS provides financial rewards for network service providers whose capital expenditure becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capital expenditure. Any efficiency gains or losses are shared between us and customers.

Our CESS savings are discussed in the attached appendix[188] and calculations provided in the attached model.[189]

Consistent with the F&A paper and CESS guideline, [190] we propose to:

- continue the application of the CESS to standard control expenditure over the 2021–2026 regulatory period consistent
- utilise forecast depreciation to establish the opening RAB for the following regulatory period 2026–2031.

Applying the CESS ensures we continue to face strong incentives to pursue sustainable efficiencies and ensure the incentives between operating and capital efficiencies remain balanced.

10.2.9 Demand management incentive allowance

The Demand Management Incentive Scheme (**DMIS**) and demand management innovation allowance (**DMIA**) mechanism provide incentives for us to explore demand management alternatives to network capital investment. We are provided with an annual fixed allowance in the form of additional revenue for each regulatory year of the regulatory period.

During the 2016–2020 regulatory period we commenced the following demand management initiatives:

- we dynamically manage voltage levels on the network on peak demand days to manage supply imbalances in the wholesale energy market
- we are assessing the potential to partner with commercial customers to alleviate network constraints by reducing demand during peak periods and targeted load shedding.

We propose to continue applying the DMIS and DMIA in the 2021–2026 regulatory period. Applying these satisfies the requirements of the National Electricity Law (**NEL**) by providing an incentive to use more demand management, which can defer augmentation and create option value, potentially lowering costs in the long term.

In December 2017 the AER revised the way that the DMIA would be calculated, which is the sum of:

- $200,000 (in the dollars of the distributor's regulatory year that ends in 2017), escalated for inflation
- 0.075% of the distributor's annual revenue requirement.

The following table shows the calculated DMIA amounts.

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188 UE APP02 - What we have delivered - Jan2020 - Public

189 UE RIN006 - Workbook 6 - CESS - Jan2020 – Public

190 UE ATT128 - AER - Capex Incentive Guideline - Nov2013 - Public

Table 10.8 DMIA amounts ($ million, 2021)

	2021/22	2022/23	2023/24	2024/25	2025/26
Demand management incentive allowance	0.5	0.5	0.5	0.5	0.5

Source: United Energy

10.2.10 Shared asset revenue reduction

Shared assets are those that are used to provide both regulated and unregulated services. The AER may reduce our annual revenue requirement for a regulatory year to share unregulated revenue with customers. In making this decision, the AER must have regard to the shared asset principles and the Shared Asset Guideline.[191]

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline sets out how materiality would be tested. It defines that the use of shared asset is material if a distributor's annual unregulated revenue from shared assets is greater than one per cent of its total smoothed revenue requirement for a particular regulatory year:

- If this materiality threshold is exceeded, then 10% of forecast unregulated revenue earned from shared assets is deducted from the revenue building blocks.
- If this materiality threshold is not exceeded, no shared asset revenue reduction applies.

The AER's shared asset guideline has been applied to calculate the materiality of our use of shared assets to earn unregulated revenue. Our shared asset revenue is primarily earned from renting poles and ducts to telecommunications companies.

The calculation of materiality and shared asset revenue reduction for each year of the 2021–2026 control period is shown in the table below.

Table 10.9 Shared asset revenue reduction ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast unregulated revenue from shared assets	9.6	9.8	10.1	10.3	10.5
Smoothed revenue (prior to shared asset reduction)	428.2	438.5	449.0	459.8	470.8
Materiality percentage (%)	2.2%	2.2%	2.2%	2.2%	2.2%
Shared asset revenue reduction	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**

Source: United Energy

10.2.11 Estimated cost of corporate income tax

The Rules require that the estimated cost of corporate income tax must be for a benchmark efficient entity. The estimated cost of corporate income tax for each year of the 2021–2026 regulatory control period have been calculated using the AER's PTRM. The tax opening asset values, remaining lives and standard lives inputs for the

191 UE ATT130 - AER - Shared asset guideline - Nov2013 - Public

PTRM have been calculated in the AER's RFM. The standard tax asset lives are consistent with the Australian Tax Office ruling Income tax: effective life of depreciating assets (applicable from 1 July 2019).[192]

We have forecast immediately deductible capital expenditure based on the average actual amount of immediately deductible capital expenditure claimed over the 2016-2018 as reported in the reset RIN. It is appropriate to use an average since the mix of capital expenditure can vary from year to year.

We have applied a value of 0.585 for the value of imputation credits consistent with the 2018 RORI.

Estimate cost of corporate income tax is shown in the table below.

Table 10.10 Estimated cost of corporate income tax ($ million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Estimated cost of corporate income tax	9.7	7.7	7.6	9.8	8.9

Source: United Energy

10.2.12 Control mechanisms

The control mechanisms are applied on an annual basis to impose limits on the prices that a network can charge. Control mechanisms for distribution use of system (**DUoS**) charges in the 2021–2026 regulatory period recover the efficient costs of the provision of standard control services. The Rules require the control mechanism to be of the prospective CPI-X form, and the AER's F&A determined that a revenue cap is to be applied. Further information on the control mechanisms is provided in the attached appendix.[193]

10.3 Other incentive schemes

Over the next regulatory period we intend to continue to seek opportunities to improve our services to our customers where those services are valued. Consequently for 2021–2026 regulatory period we propose applying the suite of incentive schemes including:

- efficiency benefit sharing scheme (**EBSS**) and capital expenditure sharing scheme (**CESS**), discussed above
- demand management incentive scheme (**DMIS**) and demand management innovation allowance (**DMIA**)
- f-factor scheme
- service target performance incentive scheme (**STPIS**).

10.3.1 Service target performance incentive scheme

The STPIS incentivises us to pursue improvements in network reliability and customer service where customers value these improvements.

We are one of Australia's most reliable networks. Our network is available over 99.99% of the year, or less than 45 minutes off supply per annum. We have improved our customer service over the current regulatory period. Over 2017 and 2018, we answered 79% of fault calls in under 30 seconds—up from 65% on average over 2010 to 2014.

192 UE ATT129 - ATO - Income tax - May2019 - Public

193 UE APP08 - Price control formula - Jan2020 - Public

We will continue to pursue improvements in our network reliability and our customer service during the 2021–2026 regulatory period.

We propose calculating the STPIS targets and incentive rates in accordance with the AER's 2018 STPIS scheme.[194]

To calculate the STPIS targets we used historical performance data over the five year period from 1 January 2015 to 31 December 2019[195] and recast our historical data to align with the new definitions in the AER's Distribution Reliability Measures Guideline.[196] This includes the correct treatment of brown-outs as interruptions. To calculate the STPIS incentive rates we applied the updated VCR as determined by the AER.[197] We have calculated the major event day (**MED**) threshold in accordance with the STPIS.

Our proposed STPIS targets, incentive rates and MED threshold are set out in the table below.

Table 10.11 STPIS targets and incentive rates for 2021–2026 regulatory period

STPIS parameter	Network segment	Target	Incentive rate
Unplanned system average interruption duration index	Urban	51.5	0.0891
	Rural short	121.5	0.0073
Unplanned system average interruption frequency index	Urban	0.657	4.6554
	Rural short	1.611	0.3689
Momentary average interruption frequency index event	Urban	1.564	0.3724
	Rural short	4.727	0.0295
Maximum event day threshold	Network	3.16	-
Telephone answering (fault calls only)	Network	72.7%	-0.04

Source: United Energy

We do not propose to apply the GSL scheme component of the STPIS scheme as we are subject to the Victorian jurisdictional scheme under the Distribution Code.

10.3.2 Small scale incentive scheme

We support the AER’s draft customer service incentive scheme which enables distributors to propose a new customer service incentive under the small scale incentive scheme framework. In accordance with the AER’s draft customer service incentive scheme,[198] we intend to continue working with our customers to develop an incentive scheme which targets services valued by our customers. We intend to submit the details of a new customer incentive scheme with our revised regulatory proposal.

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194 UE ATT125 - AER - STPIS - Nov2018- Public

195 We have used unaudited 2019 data for the regulatory proposal. For the revised proposal we will use audited 2019 data.

196 UE ATT126 - AER - Reliability measures guideline - Nov2018 - Public

197 UE ATT127 - AER - VCR - Dec2019 - Public

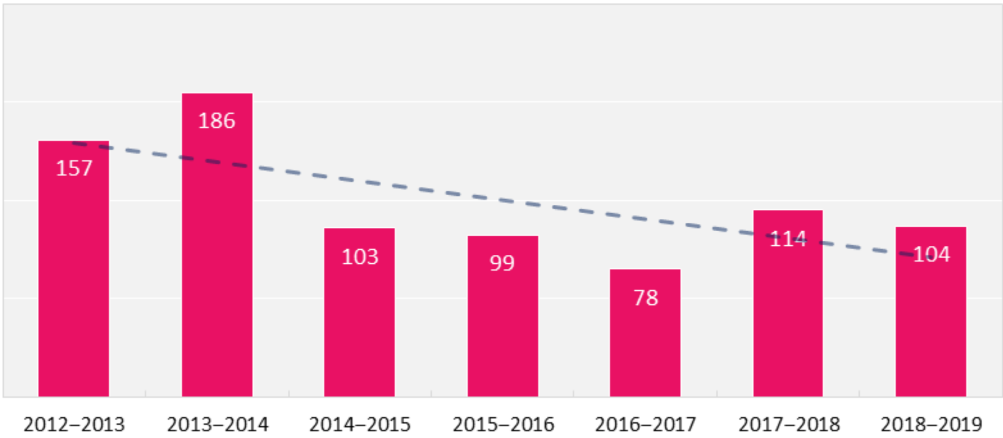
198 UE ATT131 - AER - Draft CCIS - Dec2019 - Public

10.3.3 F-factor scheme

The f-factor scheme provides incentives for us to reduce the risk of bushfires starts on our network assets.

The number of ground fire starts has trended downward since 2013 a result of our continuously investing $10 million per annum targeting ground fires. The figure below shows the recent trend in asset related ground fires.

Figure 10.1 The trend in asset-related ground fire starts is declining



Source: United Energy

We propose to continue to apply the f-factor scheme during the 2021–2026 regulatory period, consistent with the F&A paper. Applying the f-factor scheme ensures we have strong incentives to minimise the risk of fire starts on our assets.

The Victorian Government is presently reviewing the approach for setting the f-factor scheme targets and is expected to publish a revised f-factor order in 2020. Once published, we propose applying the revised f-factor order and the subsequent revised f-factor scheme determination.

11

Metering

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11 Metering

Smart meters are a rich source of data that we use to deliver better services to our customers and manage the network more efficiently. We have embedded the use of smart meter data and services in our daily operations and these have revolutionised the services we provide to customers, both directly and indirectly.

Our aim is to ensure customers will continue to benefit from us providing metering services over the 2021–2026 regulatory period. As a consequence we will further reduce our average metering charge by 23% in 2021/22. As we lower charges we will ensure customers continue to receive existing smart meter benefits as well as new services.

11.1 What we plan to deliver

We presently provide metering services to our residential and small business customers. Our metering services include installing and maintaining smart meters and remotely collecting and processing energy data received from these meters. We also continue to maintain and read a very small fleet of manually-read meters.

Victoria has been a pioneer in the NEM in adopting smart meter technology. In 2009, the Victorian Government required distributors to roll-out smart meters for all residential and small business customers. This reflected the belief smart meters have significant benefits for the market as a whole and that these benefits could be best achieved through the synergies arising from a mass rollout.

Today we have more than 692,000 smart meters across our network, covering 99% of our residential customers. We also have a web of communication devices that allow us to remotely operate and collect data from our smart meters. Our ICT systems allow us to process and validate smart meter data.

11.1.1 Customers benefit from smart meters

Our customers have and continue to benefit from smart meters and its associated infrastructure. These benefits include:

- savings — we remotely read and operate smart meters. This includes regular and special meter reads, meter testing and connecting and disconnecting customers
- enhanced customer experience — remote meter operation has enhanced the customer experience when moving in and out of housing, and has allowed us to disconnect customers instantly when requested

Our customers are very interested in easier data access and finding better ways to use their data

- more usage information and visibility — our 'Energy Easy' portal provides customers with insight into their usage patterns, empowering customers to make more informed choices on tariff offerings. Usage data is able to be uploaded directly to the Victorian Energy Compare website to assist customers in identifying the best offers. Over the 2021–2026, we will further improving the accessibility of the smart meter data to our customers through a 'one-stop-shop' portal, allowing them to even more easily access their data
- greater customer choice and participation — smart meters can be remotely configured to allow customers to export spare electricity from their rooftop solar. Smart meters also allow better targeting of demand management programs, which reward customers and assist us in deferring capital investment

Around 58% of our customers were interested in participating in demand response

- more effective communication — the 'power outage alarm' function in smart meters allows us to detect an outage at a customer's premise remotely and communicate this to the customer instantaneously. We are also able to provide better information to customers on any outage and likely restoration of supply without the need for the customer to contact us

- greater safety outcomes — smart meters allow us to remotely identify current and earthing issues at a customer's premises that may lead to electric shock. They also allow us to prioritise life support customers when load shedding is required in an emergency situation

Our customers have told us safety is a key priority and support the use of smart technologies to test and replace potentially faulty assets

- minimising investment — *Advanced Metering Infrastructure – minimum AMI functionality specification (Victoria)* (**VMSS**),[199] require the smart meters to provide power quality data—including voltage and current information at each meter. This data can be used to gain better visibility of the LV network, enabling more tailored solutions to optimise network performance reducing the need for investment and ultimately reducing tariffs. Our digital network project outlines how we plan to maximise on these benefits in 2021–2026. Smart meters also allow us to remotely control load, with customer consent, which can further lower investment requirements.

Affordability is our customers' top concern

11.1.2 Smart meter functionalities are important in delivering customer benefits

All customers with smart meters have, and continue to, benefit from remote meter reading. What is less understood however, are the indirect benefits VMSS functionalities provide in terms of providing a rich source of power quality data to use for network management and optimisation which enables more prudent and efficient investment choices. Victoria is very fortunate, unlike other Australian jurisdictions and international comparators, in that the VMSS had the foresight to ensure the smart meters captured power quality data to enable the realisation of network benefits. This provides Victoria with a long-term sustainable advantage over other jurisdictions in terms of sustainably lower tariffs.

Power quality data will also be essential in Victoria tackling climate change and meeting its renewables targets. The increasing penetration of rooftop solar (and other technologies) will result in more electricity being exported on to the LV network creating new challenges for the network in managing two-way electricity flows and controlling voltage levels. As exports on the LV network grow, we are proposing to reduce long-term costs to customers by using power quality data to optimise existing LV network assets.

The continuation and realisation of future smart meter benefits is highly dependent on key functions that are required under the VMSS. If the VMSS are not retained, Victorian consumers will potentially lose the value of current and future network benefits made available through their investment in smart meters, or at best, pay considerably more to achieve those benefits.

11.1.3 We will reduce our meter charge in 2021–2026

We are proposing to reduce our average metering charge by 23% in 2021/22. The table below summarises our annual metering charges by meter type from 2020 to 2025/26.

[199] UE ATT136 - DPI - AMI functionality specification - Sept2008 - Public

Table 11.1 Metering provision charges ($ per meter, 2021)

Meter type	2020	2021/22	2022/23	2023/24	2024/25	2025/26
Single phase	54.9	41.9	41.3	40.8	40.3	39.8
Single phase two element	54.9	41.9	41.3	40.8	40.3	39.8
Three phase direct connected meter	61.9	47.3	46.6	46.0	45.4	44.9
Three phase CT connected meters	65.6	50.1	49.4	48.8	48.1	47.6

Source: United Energy

As we lower charges we will ensure customers continue to receive existing smart meter benefits as well as additional services discussed below. More customers will also have access to smart meters as we continue to replace legacy manually-read meters on the network.

11.1.4 We will use smart meter data to assist the DER register

To better understand the level of penetration of DER across Australia, AEMO will manage a DER register from December 2019 with assistance from distributors. While customers are currently required to notify us of new and existing rooftop solar and battery installations under our connection policy, current levels of compliance are very low.

We already use smart meter data to gain a better understanding of existing installations on our network through the ability to monitor customers' exports even if they have not notified us of their installation. As the penetration of solar rooftop and batteries grows, we will continue to use the smart meter data to locate premises with exports to assist AEMO in establishing the DER behind the meter register.

11.1.5 We will make it easier for customers to use their smart meter data

We will be streamlining how customers access their smart mater data during the 2021–2026 regulatory period. As detailed in our ICT chapter 7, we will be introducing a new one-stop-shop portal and mobile application where customers can access their usage data in 15-minute snapshots, helping them better understand their usage patterns and track the usage of individual appliances by isolating appliances through usage patterns.

We will be exploring innovative ways to present this data, including measuring the efficiency of customers' exports. This will empower customers to make informed choices on energy use, explore the benefits of participating in demand management and other energy markets, and choose suitable tariff offerings.

11.1.6 Expanding our analytical capabilities

We are only at the beginning of uncovering the analytical possibilities that power quality data can provide. We expect that complementary investments in our digital networks will allow us to leverage the data in smart meters to drive further innovation into the future.

11.2 Our forecasting approach

Our proposed meter charges for the 2021–2026 regulatory period seek to recover the efficient costs of providing the metering service. Similar to standard control services, we use a PTRM to calculate the revenue based on key inputs such as the metering RAB, new capital expenditure, rate of return, operating expenditure and tax. We then determine a charge for an individual type of meter. In the sections below we identify our method and key inputs to forecast metering charges.

11.2.1 Our forecast meter volumes reflect the experience on our network

The majority of our forecast capital expenditure in the 2021–2026 regulatory period will be procuring and installing smart meters. We forecast volumes of new and upgraded customer connections, together with volumes of replacement for faulty smart meters and older accumulation meters based on a number of factors:

- we forecast new customer connections based on economic advice provided by the NIEIR and volumes of smart meters for customer requested additions and alterations based on historic trends
- we forecast volumes of meter replacement due to network faults based on historical fault rates. We reactively replace meters when they fail our meter tests, when investigating a fault based on a customer complaint
- we forecast volumes of replacement based on meter faults of smart meters, based on meter type, estimated asset life and condition. We proactively replace meters when we recognise a systematic failure mode impacting a specific type of smart meter or a family of meters
- we forecast replacement volumes for accumulation meters. At the time of our roll-out there was a small number of premises that either opted-out of installing smart meters, or were inaccessible. Over time, we have been replacing these meters as customers request a smart meter, or where the accumulation meter has failed. Our forecast approach is based on volumes of accumulation meters and experience with previous rollouts.

The table below sets out the volumes of smart meters we expect to procure and install on the network in 2021–2026.

Table 11.2 Forecast volumes of smart meters installed in the 2021–2026 regulatory period

Driver	Volumes
New connections	96,091
Supply upgrades (additions and alterations)	4,891
Replacements due to network fault	3,073
Meter fault replacement	25,051
Legacy meter replacement	3,533
Total smart meters	**132,639**

Source: United Energy

11.2.2 Our costs are market tested

We use competitive service providers for procuring smart meter and communication devices, and for their installation. This provides confidence that the cost of undertaking the capital works are efficient and market tested. We have used:

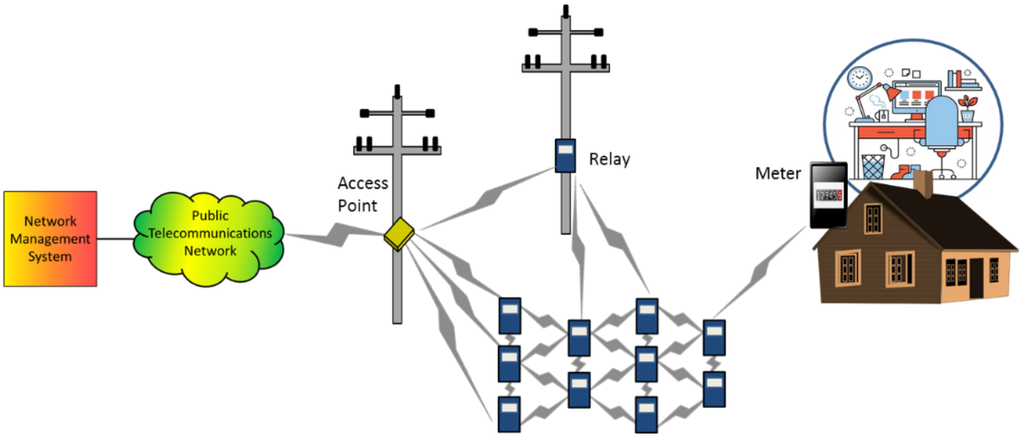
- unit rates to procure smart meters and communication devices based on current prices of our suppliers. The unit rates reflect the market-tested cost of hardware
- for installation costs, we have used labour rates based on current contracts with suppliers. We have sufficient data to identify the forecast hours and complexity for undertaking different jobs. For example,

meter fault replacement has a lower labour cost than replacement caused by network fault, due to the ability to plan ahead.

11.2.3 All customers benefit from our smart meter communications network

Our smart meter communications network comprises a series of communications devices—mainly access points and relays—and a network management system that communicate through the public telecommunications network as depicted in figure 11.1. Other devices that form part of the communications network include modems, antennas and batteries.

Figure 11.1 Communication devices



Source: United Energy

The communications network transmits smart meter data at various intervals, depending on the use of that data. Currently we collect data at the following intervals:

- usage data every 30-minutes
- power quality data every 15 minutes
- additional power quality data from various sites for data analytics every five minutes.

In 2018, power quality data accounted for 88% of all data collected and transmitted through the smart meter communications network. We expect this share to remain relatively constant by 2025/26, given transmitted meter data is mainly used for network management analytics.

Given the smart meter communications network mainly transmits data used for network management and optimisation, the benefits of the communications network investment is largely shared by all our customers. As we continue to develop our smart meter data analytics to develop innovative ways to optimise the network and defer network augmentation, all our customers will continue to benefit from the smart meter communications network.

As such, for the 2021–2026 regulatory period we have allocated the cost of communications device replacements and operating expenditure related to maintaining the communications network as:

- 88% to standard control services
- 12% to metering services.

We forecast the volume of communication devices replacements based on historical fault rates and new growth based on customer number forecasts.[200]

11.2.4 We use the base-step-trend approach to forecast operating expenditure

We incur operating expenditure to collect and verify metering data, to maintain and test meters, to provide customer services, and to operate our communication devices.

We use the AER's preferred base-step-trend approach to forecast metering operating expenditure:

- we nominate 2019 as our efficient revealed base year
- adjust our base to remove 88% of operating expenditure related to the maintenance of the smart meter communications network
- add to the base year the efficient level of operating expenditure determined by applying a rate of change that comprises labour price escalation and an increase in scale
- add a negative step change to reflect the reduction in the cost of manual meter reads resulting from the expected replacement of legacy meters.

11.2.5 Our revenue forecast is based on the post-tax revenue model

We have used the AER's PTRM to calculate the forecast revenue necessary for the efficient provision of metering services during the 2021–2026 regulatory period. The table below shows the building blocks.

Table 11.3 Building blocks of revenue requirement for metering services for 2021–2026, ($ million, 2021)

Revenue requirement building blocks	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Return on capital	6.5	6.2	5.8	5.3	4.8	28.6
Regulatory depreciation	15.1	16.6	17.9	19.4	20.9	89.8
Operating expenditure	7.3	7.6	8.0	8.4	8.8	40.1
Net tax allowance	1.4	1.3	1.5	1.7	1.8	7.7
Metering services revenue requirement	30.3	31.7	33.3	34.7	36.2	166.2
Smoothed metering revenue	**31.6**	**32.4**	**33.2**	**34.0**	**34.8**	**165.9**

Source: United Energy

[200] UE MOD 6.03 - AMI comms - Jan2020 - Public

12

Alternative control services

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12 Alternative control services

Alternative control services (**ACS**) are our customer requested services that are directly recovered from customers. They include ancillary services, such as customer connections, as well as public lighting services. Metering provision services are covered in the metering chapter.

Our ACS proposal for the 2021–2026 regulatory period incorporates service classifications made in the AER's F&A paper. This includes the reclassification of some service truck visits to standard control services, introduction of new services previously labelled as service trucks, and the classification of previously negotiated services to ACS. We will also be abolishing remote re-energisation and de-energisation, providing these services to customers with a smart meter for free.

As one of the most efficient distributors in Australia, our charges are already representative of the costs of a prudent and efficient service provider. We have heard our customers' top concern is affordability; we are therefore proposing to keep prices constant and not pass on any increasing cost pressures to customers. Our proposed charges for these services over the 2021–2026 regulatory period are set out in the attached appendix.[201]

With more quoted services from 2021, we have also updated the labour types for quoted labour rates.

Our proposal for public lighting services for the 2021–2026 regulatory period reflects customer preferences for a rapid move to more efficient light alternatives, as well as the need to improve the accuracy of cost allocation across different light types.

12.1 What we plan to deliver

12.1.1 Network ancillary services

Network ancillary services are non-routine services provided to customers on an 'as needs basis'. Depending on the service, the charge may be a fixed fee based or variable fee quoted service based on time and materials to complete the activity.

New fee based services

Fee-based services are activities which are fixed in nature and are charged on a per activity basis. For the 2021–2026 regulatory period we will make changes to our fee-based services consistent with the AER's F&A paper. We have also simplified the number of charges offered, by consolidating similar charges and amalgamating charges for activities that were rarely applied.

The most significant change to our fee-based service charges is the abolishment of the service truck visit charge. The F&A paper states a service truck visit is not a distribution service but rather an input into delivering a distribution service. As such, the service truck visit charge requires reclassification.

There are a wide range of activities currently classified as a service truck visit. To ensure future charges are reflective of costs incurred and to maintain simplicity in our charges, we have decided to reclassify our charges based on the length of time of the task. That is:

- isolation of supply or reconnection, excluding HV (usually less than 30 minutes)
- standard alteration (usually between 30 and 60 minutes)

[201] UE APP02 - What we have delivered - Jan2020 - Public

- complex alteration (usually longer than 60 minutes).

The proposed new services for 2021–2026 are outlined in table 12.1.

We have also created a single charge for short activities commonly carried out on the same day. For example, a customer may request an isolation and a reconnection with a relatively short space of time. Rather than levying two isolation and reconnection charges, we will introduce a single charge, isolation and same day reconnection, that includes two visits in the same day which is 14% lower than the combined two isolation or reconnection charges.

For the 2021–2026 regulatory period the wasted service truck visit will be reclassified as standard control in accordance with the F&A paper. As such, we have created a new charge, failed field visit, for circumstances where a field crew is sent to undertake works classified as alternative control services but they are unable to carry out the works due to circumstances within the customer's control.

Table 12.1 Proposed new services offered for 2021–2026

Fee based service	Description
Isolation of supply or reconnection, excluding HV (single) (BH/AH)	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach), or a reconnection of supply after the isolation, excluding high-voltage (**HV**) assets. It also includes requests for disconnection at the point of supply (i.e. pole or pit) and also includes service line isolations in association with No Go Zone applications
Isolation of supply and reconnection after isolation, excluding HV (same day) (BH)	This charge applies when a customer requests both an isolation of supply and a reconnection of the same point of supply on the same day during business hours, excluding HV assets
Standard alteration, 30-60 minutes (BH/AH)	This charge is for alteration services expected to last 30 to 60 minutes, including but not limited to the following services: • install or remove controlled load • move meter to new position • relocate point of attachment or service • replace meter panel • re-route mains to new pit • upgrade maximum demand or change supply capacity control • replacing fascia board. If multiple of the above services are required for the customer's alteration, this may be deemed a complex alteration.
Complex alteration, > 60 minutes (BH/AH)	This charge is for alteration services expected to be more than 60 minutes, including but not limited to the following services: • change overhead to underground • change to group metering panel • upgrade phase. It also includes multiple services during the same site visit, for example a customer requests a metering panel replacement and moving a meter to a new position in the same visit.
Failed field visit (unable to perform customer requested task) (BH/AH)	This charge applies when an ancillary service is requested by the customer or a third party but the field crew cannot perform the task once arriving at the site due to circumstances within the customer's or third party's control. This includes situations where: • the site is not ready for the scheduled work within 15 minutes of our crew arriving • the services attendance is no longer required once our crew are on site • 24-hour notice is not given for the cancellation • the site is locked with a non-industry lock preventing access for our crew • there is asbestos removal or warning on site • scaffolding obstructs the meter position prohibiting works • there is non-adherence to VESI Service and Installation Rules • any other issues associated with safety assessment of the site.

Source: United Energy
Note: BH=business hours; AH=after hours

Abolishing fee-based services

Our customers are already benefiting from smart meters through having access to remote services without the need for a site visit such as meter reading, re-energisation and de-energisation. For the 2021–2026 regulatory period we will continue to provide benefits to our smart meter customers through abolishing fees associated with remote re-energisation and de-energisation. We already provide a number of services free of charge to our customers, including:

- abolishments under 100 amps (non-complex)
- desktop and site assessments for No Go Zones.

The abolished charges for the period 2021–2026 are outlined in table 12.2.

Table 12.2 Abolished charges for the 2021–2026 regulatory period

Service group	Description
Service truck visits	To align with the F&A paper
Remote energisations/de-energisations	Immaterial costs so these services will be offered free of charge

Source: United Energy

The table below presents a description of the fee-based services we have charged for over 2016–2020 regulatory period and will continue to charge for over the 2021–2026 regulatory period.

Table 12.3 Other fee based services for the 2021–2026 regulatory period (excluding new services)

Fee based service	Description
Basic connections (BH/AH)	This charge applies for retail customers seeking a basic connection service or proposes to become a micro-embedded generator.
Meter/NMI/site investigation	This charge applies when a request is received to investigate the metering/connection at a given supply point. This request may be initiated by either the retailer or a customer.
Remote meter re-configuration	This charge applies when a request is received to reconfigure a smart meter and has the related infrastructure in place.
Field-based special read	This charge applies when a request is received to manually read a meter outside of the cycle.
Meter testing	This charge applies when a request is made to test the accuracy of a meter (or meters) at a given supply point.
Manual re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. The two options for re-energisations available: • reconnections (same day) business hours only • reconnections (including customer transfers) business hours
Manual de-energisation	This charge applies when a request is received to de-energise (including disconnections for non-payment) a supply for fuses less than 100 amps by a field visits

Source: United Energy
Note: BH=business hours; AH=after hours

Quoted services

Quoted services costs are variable in nature and levied on a time and materials basis. Table 12.4 presents a description of our quoted services for the 2021–2026 regulatory period. The quoted services have been updated to reflect new classifications in the AER's F&A paper.

For the price formula for quoted services refer to the price control appendix and for the quoted services labour rates refer to the labour rate model and ACS charges appendix.[202]

Table 12.4 Proposed quoted services for the 2021–2026 regulatory period

Quoted services	Description
Complex supply abolishment	This charge applies when a customer requests permanent removal of our supply assets on a complex site. For example, when supply is directly from a sub-station, when the abolishment requires a design to be completed safely, or when the supply is more than 100 amps.
Rearrangement of network assets at customer request, excluding public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 applies. For example, a customer requests a removal or relocation of service to allow work on private installation.
Audit design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party. Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation • any electrical distribution work completed by our approved contractor that has been engaged by a customer • provision of system plans and system planning scopes, for designers engaged by the customer • reviewing and/or approving plans submitted by designers engaged by the customer.
Specification and design enquiry	This charge applies when design or network planning is required to fairly assess the costs so that an offer can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property • the location of other utility assets • environmental considerations including tree clearing • obtaining necessary permits from State and Local Government bodies • assessment of design and network planning options • specialist services (which may involve design related activities and oversight/inspection works) where the design or construction in is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets.
Elective undergrounding	This charge applies when a customer could receive an overhead service but requests an underground service, other than where Guideline 14 applies. For example, a customer requests an underground service where we would consider it safe and prudent to install an overhead service.
High load escorts–surveying and lifting overhead lines	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads. This includes surveying and lifting of overhead lines.
High profile antenna installation	This charge applies when customers request to install a high profile antenna to an existing smart meter.

[202] UE APP08 - Price control formula - Jan2020 – Public; UE MOD 12.02 - Quoted services labour rate - Jan2020 – Public; UE APP09 - ACS charges - Jan2020 - Public

No-go zone safety-related services	This charge applies when a customer or third party requests services related to ensuring safety of no-go zone around our assets, including a supply isolation, covering assets with tiger tails and aerial markers, and other related works. For example, a customer/third party is conducting building works at a site near our assets where visual markers (tiger tails) are required for safety.
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is a negotiated connection service.
Alteration and relocation of public lighting assets	This charge applies when a customer or a third party requests alteration, rearrangement or relocation of public lighting assets.
New public lighting services including greenfield sites and new light types	This charge applies when a customer or a third party request an installation of new public lighting assets, including new light types and emerging light technologies.
Access to network data	This charge applies when a customer or a third party requests electricity network data, including aggregates smart meter data, outside of legislative obligations. For example, a third party requests large quantities of aggregated data outside of our standard practices of legislative obligations.
Complex isolations and alterations, including HV	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach) of HV assets or where there are more complex/larger scale works isolation or alternations. This also includes where works are requested to be perform after hours for multi-occupancy or complex sites. For example, after-hours isolation for customer side works at a large multi-occupancy site, such as a caravan park.
Alterations to the shared distribution network assets	This charge applies when a customer or third party initiates alterations or other improvements to the shared distribution network to enable the third party infrastructure (e.g. NBN Co telecommunications assets) to be installed/altered on the shared distribution network.

Source: United Energy

We are proposing five regulated labour types for quoted services which reflect the variety of skills needed to complete quoted service requests. Table 12.5 summarises our proposed labour types of quoted services.

Table 12.5 Description of quoted labour types for the 2021–2026 regulatory period

Labour type	Description
Administration	Tasks involving business support officers, project creation and close out, project administration.
Field worker	Tasks involving trade skilled worker, asset locators, customer connection officers, compliance officers or testers.
Technical	Tasks involving metering specialists, telecommunications officers, quality of supply officers, network facilities specialists, estimators, surveyors or quality of supply officers.
Engineer	Tasks involving designers and/or project engineers.
Senior engineer	Tasks involving senior and principal engineers, senior designers, network planning staff and/or network protection group.

Source: United Energy

12.1.2 Public lighting

We provide public lighting services for customers including local councils and the Victorian Department of Transport. The provision of public lighting services and the respective obligations of our business and public lighting customers is regulated by the Public Lighting Code.[203]

Table 12.6 summarised the changes to the treatment of public lighting services from the 2016–2020 regulatory period to the 2021–2026 regulatory period, as per the F&A paper.

Table 12.6 Changes in classification of public lighting services

Service group	2016–2020	2021–2026
Operation, maintenance, repair and replacement of public lighting assets	Alternative control service, fee based	Alternative control service, fee-based
Alteration and relocation of public lighting assets	Negotiated	Alternative control service, quoted
Provision of new public lighting	Negotiated	Alternative control service, quoted

Source: United Energy

Operation, maintenance, repair and replacement of public lights

We own and maintain more than 121,000 public lights across our network. Our responsibilities include ensuring the lights remain operational and safe, through periodically replacing or repairing luminaries, poles or brackets. In turn, local councils and the Department of Transport pay a fixed charge per light, known as the operation, maintenance, repair and replacement charge.

We have 30 types of approved lights operating on our network, spread across minor and major roads. Increasingly we have seen public lighting customers opting for more energy efficient light types such that 65% of all lights on our network are now efficient alternatives, and in the case of minor roads, 89%. Below is a summary of the existing stock of lights on our network.

[203] UE ATT005, ESC, *Public Lighting Code*, December 2015

Table 12.7 Changes in classification of public lighting services

Light category	Description	Number
MV80	Minor road light with gas discharge lamp that uses an electric arc through vaporised mercury to produce light. This light is the least efficient public light	8,419
High pressure sodium (**SHP**) 150W	Major road high pressure light with gas discharge lamp. This is the least efficient major road light	23,716
SHP250W	Major road high pressure light with gas discharge lamp	10,732
Fluorescent lamps T5	Minor road light with MV gas discharge lamp that is more efficient than a MV80 as it uses fluorescence to produce visible light	33,477
Compact fluorescent	Minor road light that is more efficient than an MV80 by running electricity through gas inside a coil, exciting the gas, and producing light	2,398
Light emitting diode (**LED**) category P	Efficient minor road light with an LED lamp. Has a longer lifespan than most lights and is more efficient than a fluorescent light	39,297
LED category V	Efficient major road light with a LED lamp	3,716
Total		**121,755**

Source: United Energy

Together with our customers, we are committed to replacing inefficient lights with more efficient alternatives. Efficient light alternatives result in lower energy bills and present an opportunity to install smart controls that will in the future enable further savings and control of lights.

The majority of our minor road lights already have efficient light alternatives through bulk council replacements. Major road lights however remain mostly inefficient. As time progresses, it will become more difficult and potentially costly to source inefficient lights and there will be declining community support.

We have already changed our practices to reflect the declining market for inefficient lights. If a minor road luminaire fails today, we will only replace it with the most efficient light emitting diode (**LED**) alternative. That means failing MV80s or T5s will only get replaced with category P LEDs. However, due to the high cost of Cat V LEDs, we do not currently replace failing SHPs with category V LEDs.

For 2021–2026, we propose to replace all failing SHPs with category V LEDs to help our customers reach their efficiency goals sooner. To minimise costs to all customers, we only replace those lights if they fail or if the replacement is necessary. Our customers will make the decision if they wish to replace the remaining inefficient lights in bulk.

In the future, if Australia ratifies the United Nations Minamata Convention on Mercury, the importation of mercury vapour lamps will be banned at the end of 2020. This will have an impact on our operations as it will require us to either use a LED lamp in an inefficient luminaire (similar to the decorative light trial below) or we replace the luminaire.

In September 2019, we held an Open House engagement with our councils, the Victorian Government and the Northern Alliance for Greenhouse Action where we presented our public lighting proposals for the 2021–2026 regulatory period. The forum participants strongly supported a complete phase-out of inefficient lights and a change in practice where all failed lights are replaced by the efficient LED alternatives. Customers also supported replacement of lamps in decorative lights with efficient photo-electric cells. Further details on outcomes of the Open House engagement are provided in the attachment.[204]

As part of our early engagement on the proposal, we have engaged and collaborated with our customers on proposed changes to the public lighting regulatory framework, proposed changes to the services we offer and the resulting draft tariffs. Our proposal for the 2021–2026 regulatory period reflects customer feedback:

- customers support a complete phase-out of inefficient lights and a change in practice where all failed lights are replaced by the efficient light emitting diode alternative
- customers support negotiated services becoming ACS
- customers support having an efficient light RAB, to more accurately capture costs associated with the provision of efficient light services
- customers support replacement of lamps in decorative lights with efficient photo-electric cells.

12.2 Our forecasting approach

12.2.1 Ancillary fee based services

Our proposed methodology revising the current ACS fixed charges for 2021–2026 has been to escalate each of our existing approved charges by the CPI. For new fee based services, a revenue-neutral volume weighted approach was used to develop the charges for each of the newly created services. This method has been chosen to align the approaches between existing and new charges. Refer to the ACS fee-based model and the ACS charges appendix for all the details.[205]

12.2.2 Public lighting fee based services

We use the AER's public lighting model to forecast the operation, maintenance, repair and replacement charge for each light type across our network.[206] We have updated the following key assumptions in the model:

- labour escalation to approved labour rates for 2016–2020
- fault and failure rates for each light type, measured as an average of actual fault and failure rates during 2016–2018 where available
- the share of lights on dedicated public lighting poles
- the cost of replacing a pole, to better reflect the actual cost incurred
- a step change in the public lighting pole non-destructive testing/inspection to account for an increase in potential identified pole defects
- capital expenditure for pole re-enforcements resulting from increased inspections, and earthing installation works on poles due to an increasing number of reported instances of unearthed conductive poles.

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204 UE ATT071 - Open house - Oct2019 – Public

205 UE MOD 12.01 - Fee based - Jan2020 – Public; UE APP09 - ACS charges - Jan2020 - Public

206 UE MOD 13.01 - Public lighting - Jan2020 - Public

We have also made a structural change to the model, based on a change in internal asset management practices and international best-practices:

- we have introduced two new light types, minor road category P light emitting diode light and major road category V LED light
- we have assumed that by 1 July 2021, we will no longer be replacing inefficient light luminaires like-for-like. Rather, all fault or failure replacements will be with efficient LED alternatives (category P LED for minor roads and category V LED for major roads). This excludes decorative light luminaires which require non-standard fittings
- we have created a new regulatory asset base for efficient light luminaires, namely all T5, compact fluorescent and LED luminaires
- for decorative lights we have assumed lamp replacements will be with efficient LED alternatives
- we have smoothed the charges to be constant over the regulatory period, with the charges remaining net present value revenue-neutral.

At our Open House forum, our customers overwhelming supported the creation of an efficient luminaire RAB to ensure customers with efficient lights are only paying for costs associated with efficient lighting. Further details on outcomes of the Open House forum are provided in the attachment.[207]

[207] UE ATT071 - Open house - Oct2019 – Public

13

Managing uncertainty

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13 Managing uncertainty

We operate in an uncertain environment in which uncontrollable external events can alter the quantity and nature of services required to be provided to our customers. While our expenditure forecasts have been prepared based on the best information currently available for what we will need to do during the 2021–2026 regulatory period, we are unable to predict each and every event that will occur.

This chapter sets out the pass through events defined in the Rules and our proposed nominated pass through events for the 2021–2026 regulatory period.

The uncertainty regime under the Rules comprises pass through events, capital expenditure reopeners and contingent projects. These mechanisms deal with expenditure that may be required during a regulatory period but which are not able to be predicted with reasonable certainty at the time of preparing or submitting a regulatory proposal to the AER.

Rather than building up our expenditure forecasts to cover every possible eventuality, we propose nominated pass through events in this regulatory proposal so as to enable us to request extra funding from the AER during the regulatory period if a large unexpected event occurs, or where we are unable to cost an anticipated event given limitations on the works we may be required to undertake. The exclusion of the costs of these uncertain events from our regulatory proposal ensures our customers face the lowest possible prices.

13.1 Pass-through events

The pass-through mechanism in the Rules recognise that we can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass through enables a distributor to recover the costs of defined unpredictable, high cost events not built into the AER's distribution determination.

13.1.1 Defined pass through events

The Rules specify the following pass through events:[208]

- regulatory change event
- service standard event
- tax change event
- a retailer insolvency event
- any other event specified in a distribution determination as a pass through event for the determination.

13.1.2 Nominated pass through events

In addition to the pass through events specified in the Rules, an event may be defined by the AER in a distribution determination. We propose the following nominated pass through events be accepted by the AER in our distribution determination.

[208] *National Electricity Rules*, clause 6.6.1.

Table 13.1 Proposed nominated pass through events

Type of event	Changes from current definition / definition in recent regulatory decisions
An insurer's credit risk event	Consistent with current definition and definition accepted by AER in recent regulatory decisions
An insurance coverage event	Amendment to the current 'insurance cap event' having regard to the changes and challenges in the global insurance market that have increased the risk of inability to obtain the full level or scope of cover under relevant insurance policy or policies
Natural disaster event	Minor amendment from current definition; consistent with definition accepted by AER in recent regulatory decisions
A terrorism event	Current definition amended to include specific reference to cyber terrorism
Retailer insolvency event	Minor amendment from current definition having regard to the current definition of the retailer insolvency event in the Rules
Major cyber event	Additional event with definition that addresses AER reservations with this event expressed in recent regulatory decisions
Act of aggression event	Additional event added with definition that addresses AER reservations with this event expressed in recent regulatory decisions
Electric vehicle event	Additional event added to address the uncertainty with electric vehicle uptake

Source: United Energy

Each of these proposed nominated pass through events is consistent with the nominated pass through event considerations. In particular, each event can be clearly identified and defined; is not covered by the pass through events specified by the Rules; has a low probability of occurrence but the potential to have a significant cost impact; is beyond a distributor's ability to prevent, substantially mitigate, commercially insure or self-insure acting prudently and efficiently; and identifies any additional factors that it is known will be relevant in assessing the amount to be passed through for the purpose of a pass through application for the event.[209]

Further, with the exception only of the major cyber event, the act of aggression and the electric vehicle event, each of the proposed nominated pass through events is consistent with the nominated pass through events accepted by the AER in its recent decisions for other service providers.

Further information on our nominated pass through events is set out in our uncertainty appendix.[210]

13.2 Application of cost pass throughs to alternative control services

We are also proposing the AER apply the pass through provisions specified in the Rules and our nominated pass through events to ACS. In assessing the pass through event, the materiality threshold applying to ACS should be modified and the approved cost pass through amount be recovered through ACS pricing, rather than standard control services charges.

[209] In accordance with clause 6.6.1(j) of the *National Electricity Rules*.

[210] UE APP04 - Uncertainty appendix - Jan2020 - Public.

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Glossary

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14 Glossary

Term	Definition
2018 RoRI	Rate of return instrument
ABS	Australian Bureau of Statistics
ACIF	Australian Construction Industry Forum
ACS	Alternate control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As far as practicable
AREMI	Australian Renewable Energy Mapping Infrastructure
ARENA	Australian Renewable Energy Agency
BCA	Building Code of Australia
BESS	Battery energy storage system
BI/BW	Business intelligence and business warehousing
BIS Oxford	BIS Oxford Economics
bppa	basis points per annum
Building Act	*Victorian Building Act 1993* (Vic)
CALD	Cultural and linguistically diverse
C&I	Commercial and Industrial
CCC	Customer Consultative Committee
CEG	Competition Economic Group
CESS	Capital expenditure sharing scheme
CCP	Consumer Challenge Panel
CIE	Centre for International Economics
CPI	Consumer price index
Commonwealth	Commonwealth of Australia
DAPR	Distribution Annual Planning Report
DELWP	Department of Environment, Land, Water and Planning
DER	Distributed energy resources
Distribution Code	Victorian Electricity Distribution Code
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DMS	Distribution management system
DUoS	Distribution use of system
DVMS	Dynamic voltage management system
EBSS	Efficiency benefit sharing scheme

Term	Definition
EFCAP	Energy Futures Customer Advisory Panel
EGWWS	Electricity gas water and waste services
EO	Equal opportunity
EPA	Environment Protection Authority
EP Act 1970	Environment Protection Act 1970 (Vic.)
ESCV	Essential Services Commission of Victoria
EP Amendment Act 2018	*Environment Protection Amendment Act 2018* (Vic)
ESV	Energy Safe Victoria
F&A	Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2021
FPP	Fire prevention plan
Final Determination	AER's 2016–2020 Final Determination
GIS	Geospatial information system
GSL	Guaranteed service level
GST	Goods and services tax
Guideline 14	Electricity Industry Guideline No. 14 – Provision of Services by Electricity Distributors
GWh	Gigawatt hour
HBRA	Hazardous bushfire risk areas
HSE	Health, safety and environment
HV	High voltage
IAP2	International Association for Public Participation
ICT	Information and communications technology
IT	Information technology
kV	Kilovolt
kVA	Kilovolt amperes
kW	Kilowatt
kWh	Kilowatt hour
LED	light emitting diode
LiDAR	Light detection and ranging
LPG	Liquefied petroleum gas
LV	Low voltage
MAIFIe	Momentary average interruption frequency index event
MCR	Marginal cost of reinforcement
MED	Major event day
MPFP	Multilateral partial factor productivity

Term	Definition
MSO	Model standing offer
MVA	Megavolt ampere
MW	Megawatt
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
Ofgem	Office of Gas and Electricity Markets
OHS	Occupational health and safety
OMS	Outage management systems
PTRM	Post tax revenue model
PV	Photovoltaic
PVC	Polyvinyl chloride
PwC	PwC Australia
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement expenditure model
RERT	Reliability and Emergency Reserve Trader
Reset RIN	Reset Regulatory Information Notice
RFM	Roll forward model
RIS	Regulatory impact statement
RIN	Regulatory information notice
RIT-D	Regulatory investment test – distribution
Rules	National Electricity Rules
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition
SEPP	State Environmental Protection Policy
STPIS	Service Target Performance Incentive Scheme
VCR	Value of customer reliability
VMSS	Advanced Metering Infrastructure –minimum AMI functionality specification (Victoria)
WACC	Weighted average cost of capital

Term	Definition
WMP	Waste management policies
WorkSafe Code	*Workplace amenities and work environment compliance code*
WPI	Wage price index

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