2021–2026

Revised proposal

united energy

Good people in power

Foreword

If If there is one thing that 2020 has taught us, it is how quickly things can change. As a result, we have also learned how quickly we can all adapt.

In January this year, we submitted our regulatory proposal which was developed through three years of intensive engagement, planning, studies and business case development.

At the time, we felt it represented the best plan we could offer to deliver more value for less cost to our customers.

In this revised proposal, we have found even more efficient ways to achieve this outcome for customers.

By listening to feedback, undertaking fresh analysis, adopting leading technology and learning from this year's COVID-19 environment, we have adapted to new priorities for households and businesses.

Personally, I have appreciated the practical and constructive feedback received from the customers and stakeholders who have participated in our engagement program and thank everyone for their contribution.

As a result, our revised proposal has been materially modified based on the feedback we have received to:

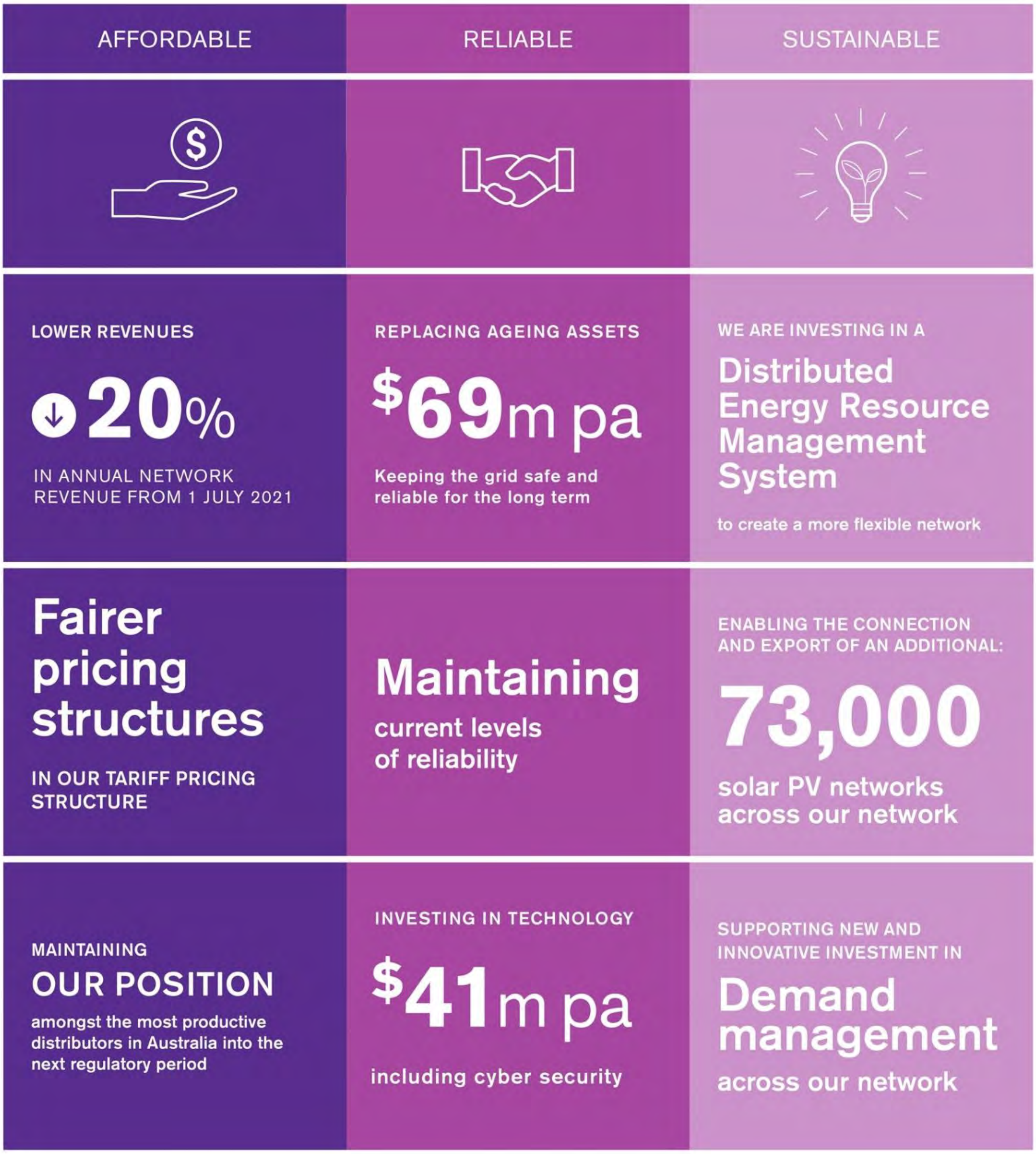
- introduce a customer service incentive scheme which motivates continual improvement in minimising the impacts of planned and unplanned outages on customers
- develop a unified approach to solar enablement and digital network investment as part of a broad future network strategy that accommodates customer choices for all forms of distributed energy
- adopt more conservative economic and consumption forecasts, except for new connection activity which is supported by industry optimism and government stimulus packages.

While over the next five years, the uncertainty around the economic recovery from COVID-19 and speed of the continued transformation of the energy industry will undoubtedly uncover new challenges for our network and business, by working within the boundaries set by the AER's final determination, we will deliver the outcomes planned and keep learning and evolving as a business with our customers at the centre of everything we do.

[redacted]

Tim Rourke
Chief Executive Officer

Revised proposal at a glance



Revised proposal at a glance

	ORIGINAL PROPOSAL	AER DRAFT DETERMINATION	REVISED PROPOSAL
Our revised proposal will reduce annual network charges by $80 in nominal terms for the average residential customer from 1 July 2021. Annual revenue will fall by 20% from 1 July 2021.	TOTAL $2,071m	TOTAL $1,834m	TOTAL $1,888m
Our operating expenditure reflects our efficient base costs which have been recognised by the AER as amongst the most efficient in Australia. It also includes a prudent allowances for changes in obligations and a productivity adjustment.	OPEX $786m	OPEX $695m	OPEX $712m
Our capital expenditure forecasts balance the need to ensure an affordable, resilient and flexible network to meet the changing needs of our customers.	CAPEX $1,130m	CAPEX $839m	CAPEX $949m

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Executive summary

1. Executive summary

1.1 Overview

Our original proposal was submitted in January 2020. It was a product of significant engagement and consultation as well as business case development, analysis and planning. Within the past year, even within the extraordinary circumstances created by COVID-19 pandemic, we have refined and further developed our proposal with input from customers and stakeholders whilst at the same time, seeking to adopt more advanced technologies, new ideas and greater efficiencies.

Our revised proposal has benefitted from this feedback and the time for reflection and deeper studies.

We especially value the contribution our customers and stakeholders have made in assisting us reach this point and we look forward to continuing the journey with them over the next regulatory period.

1.2 Why are we submitting our revised proposal now?

Every five years we submit a revenue proposal to the AER. Our current 2016–2020 regulatory period concludes on 31 December 2020. A transition period has been created by the Victorian Government to effectively extend the existing regulatory period a further six months to 30 June 2021.

On 30 January 2020 we submitted our original proposal setting out our forecast capital investment and operating expenditure plans for the next five years, as well as our total revenue requirement.

Following a detailed review of our plans, the AER published its draft determination on 30 September 2020. In response to the draft determination, we now must submit a revised proposal that responds to issues raised in the draft determination.

We have accepted much of the draft determination. We do not however, believe the entire draft determination is in the best interests of our customers. Particularly in respect to investments concerning the safety of our customers and communities, including our zone substation replacement program, service line replacements and insurance step change. Investment in replacement expenditure and connections expenditure is critical to ensuring the network continues to deliver on our customer's expectations.

Our revised proposal sets out:

- how we have responded to customer and stakeholder feedback on our original proposal
- how we have updated our forecasts given the COVID-19 pandemic and our plan to help customers meet the new challenges ahead
- how we have considered and responded to the draft determination recommendations.

Cover and Executive Summary photo: Bayside locals enjoying he hospitality of the Baia Di Vino restaurant and bar in Sandringham which is one of over 53,000 small businesses in the region supplied by United Energy and one of the attrac ions to the bayside and Mornington Peninsula's growing residential population and tourism industry.

1. Executive summary

1.3 Transforming the way we engage with our customers

We are continuing to improve how we engage and collaborate with customers and stakeholders. While there is more work to be done, strengthening our relationships with customers and stakeholders is actively improving how we make and implement decisions.

We have listened and worked closely with customer and stakeholders and received valuable feedback on our original proposal. As a result of the feedback, we adapted and further pivoted the Energised 2021–2026 approach in a new direction. We established a smaller, agile panel that represented a wide breadth of customers named the Customer Advisory Panel (**CAP**). The CAP has guided us on several key issues in our revised proposal including:

- the impact of the COVID-19 pandemic on our forecasts
- improving our customer experience with input on our customer service strategy (**CSS**) and customer service incentive scheme (**CSIS**)
- energy market transformation such as the integration of distributed energy resources (**DER**), demand management and tariff reform
- development of sustainable and safe asset management approaches.

Feedback from the active collaboration with the CAP has been used to develop our future programs of works that represent our customer views and preferences.

The CAP has also been asked to assist us in designing customer commitments which squarely put customers front and centre of our business thinking to ensure their experience with us is based on real outcomes in line with their needs, interests and priorities. We will transparently report on our commitments to customers to demonstrate we do what we say we will do in delivering better long-term outcomes and value for our customers.

At the heart of these changes is a desire for ongoing collaboration involving customers in implementing our business strategy and driving the future direction of our networks. This will be achieved by collaborating with customers on our innovation programs and talking with customer advocates about our internal processes for forecasting investment requirements, cost benefit analysis, and how we are making better use of our existing assets.

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

1.4 What does our revised proposal offer our customers?

We understand the impact the COVID-19 pandemic is having on our customers and communities. In such times we are even more determined to continue our track record of delivering real value for customers including:

- offering amongst the lowest urban network charges in Australia with a strong focus to improve electricity affordability
- providing amongst the most reliable urban networks in Australia with an emphasis on asset safety
- offering products, technology, tariff and demand management options which offer our customers value.

1. Executive summary

Our revised proposal provides a range of customer-preferred services including improving communication and management of planned and unplanned outages, reducing timeframes to connect, enabling customers to export more of their solar and making it easier for customers to access information.

To ensure we remain focused on outcomes and provide better transparency of our performance, we want to make further commitments to delivering better outcomes today and into the future. Together with the CAP we have begun a process of developing measurable outcomes-driven commitments that will ensure we deliver on the programs in our revised proposal as well as other programs that form part of our business as usual improvements. We plan to finalise the commitments in the first quarter of 2021. These commitments will be endorsed by the Chief Executive Officer and the Executive Management Team and build on the already outstanding service outcomes we deliver year on year, that separate us from our peers.

1.5 Indicative charges and bill impact

Consistent with our stakeholder feedback, we will be reducing our charges for residential and small business customers over the 2021–2026 regulatory period, compared to the current regulatory period, and what we proposed in our original proposal. The average estimated bill impact is outlined in the following table.

AVERAGE BILL IMPACT ($, 2021)

	FY22	FY23	FY24	FY25	FY26
RESIDENTIAL	-80	-1	-1	-1	-1
SMALL BUSINESS	-430	-1	-1	-1	-1

Source: United Energy

We note the final impact on customers will depend on factors such as willingness of electricity retailers to reflect our price reductions in their pricing, actual energy consumptions and the impact of incentive schemes.

With respect to our charging structures, we are proposing changes to residential and small business structures to accelerate the pace of tariff reform without jeopardising stakeholder support that is crucial for change to occur. As for our original proposal, we intend to introduce a new two rate tariff for customer connections, customers seeking supply upgrades to three phase and customers installing solar or batteries. The objective remains to encourage customers to move discretionary energy usage into off-peak periods. Our customers continue to support simplicity in tariff structures hence the adoption of a two-rate tariff. Further information on our revised pricing structures is available in our tariff structure statement attachments.

1. Executive summary

1.6 Responding to government stimulus

In response to the COVID-19 pandemic and economic slowdown, on 24 November 2020 the Victorian Government handed down its budget with $49 billion of spending over the next four years. This substantial stimulus, with a strong focus on infrastructure spend, will also have significant impacts on our network.

We expect increasing pressure on our net connections forecast being driven by the $6 billion Victoria's Big Housing Build program including over 12,000 new social and affordable homes and a 50 per cent land tax discount for build-to-rent new developments until 2040. Similarly, our gross connections forecast will come under pressure from the more than $10 billion being spent on new road and rail projects that we underpin with new infrastructure and asset relocations, and the announcement of the second Victorian Renewable Energy Target auction.

These same programs will also add to network's capacity demands that we seek to accommodate through our augmentation forecast. The augmentation forecast will face further pressure from new policies to accelerate the uptake of zero emission vehicles and the development of a gas roadmap seeking to electrify industrial gas users. While electricity demand growth may be tempered by expanded energy efficiency schemes, these effects are broad based and are unlikely to offset location specific demand drivers, and can also increase electricity demand as people switch away from gas.

Under the extra $191 million spend on Solar Homes, our distributed energy resources integration forecast (digital network program and already reduced solar enablement program) will need to accommodate an additional 42,000 solar and 17,500 more battery installations.

These impacts on our network will need to be managed within our existing forecasts as it has not been possible to update forecasts prior to our revised proposal. The AER must carefully consider the added pressured on our forecasts when making its final decision.

How to provide feedback

Customers and stakeholders are invited to review our 2021–2026 revised proposal and to provide feedback to the AER.

For more information, please see the contact details below.

Source	AER	United Energy
Visit	www.aer.gov.au	www.talkingelectricity.com.au
Email	VIC2021-2026@aer.gov.au	talkingelectricity@powercor.com.au

2

Stakeholder engagement

2. Stakeholder engagement

2.1 We are constantly learning and improving our engagement approach

In 2017 we embarked on a four-year journey with our customers and stakeholders, to develop investment plans that meet changing customer needs. Our engagement process called 'Energised 2021–2026' involved over 11,000 customers and stakeholders in an inclusive program of surveys, deliberative forums and workshops, as well as collaborative input from our Energy Futures Customer Advisory Panel (**EFCAP**) our Customer Consultative Committee (**CCC**), and review by the Australian Energy Regulator's (**AER**) Consumer Challenge Panel (**CCP17**).

We chose a path of engagement that focused on 'grass roots' customers, and catered for the breadth, depth and topics to suit our customers' interests and appetite for engagement. Ultimately, our goal throughout the journey was to learn more about our customers' values and preferences and propose a combination of programs that deliver the most valued outcomes while keeping prices low.

We have received relatively consistent feedback about our engagement over those four years—that while our engagement has been broad and comprehensive, a stronger link between engagement outcomes and our regulatory proposal was sought. In preparing our revised proposal, we have listened to our stakeholders and reshaped our engagement to a more collaborative and targeted program with key customer representatives, which complements our grass-roots approach. We established a new Customer Advisory Panel (**CAP**), comprising five informed representatives of different customer groups and policy makers. We have equipped the CAP with detailed information packs about our marquee programs and topics of engagement, allowing for deep and meaningful input into our revised proposal plans. This collaborative approach is the cornerstone of our revised proposal—together with the CAP we have reduced our expenditure proposal by $61 million to address our customers' growing affordability concerns.

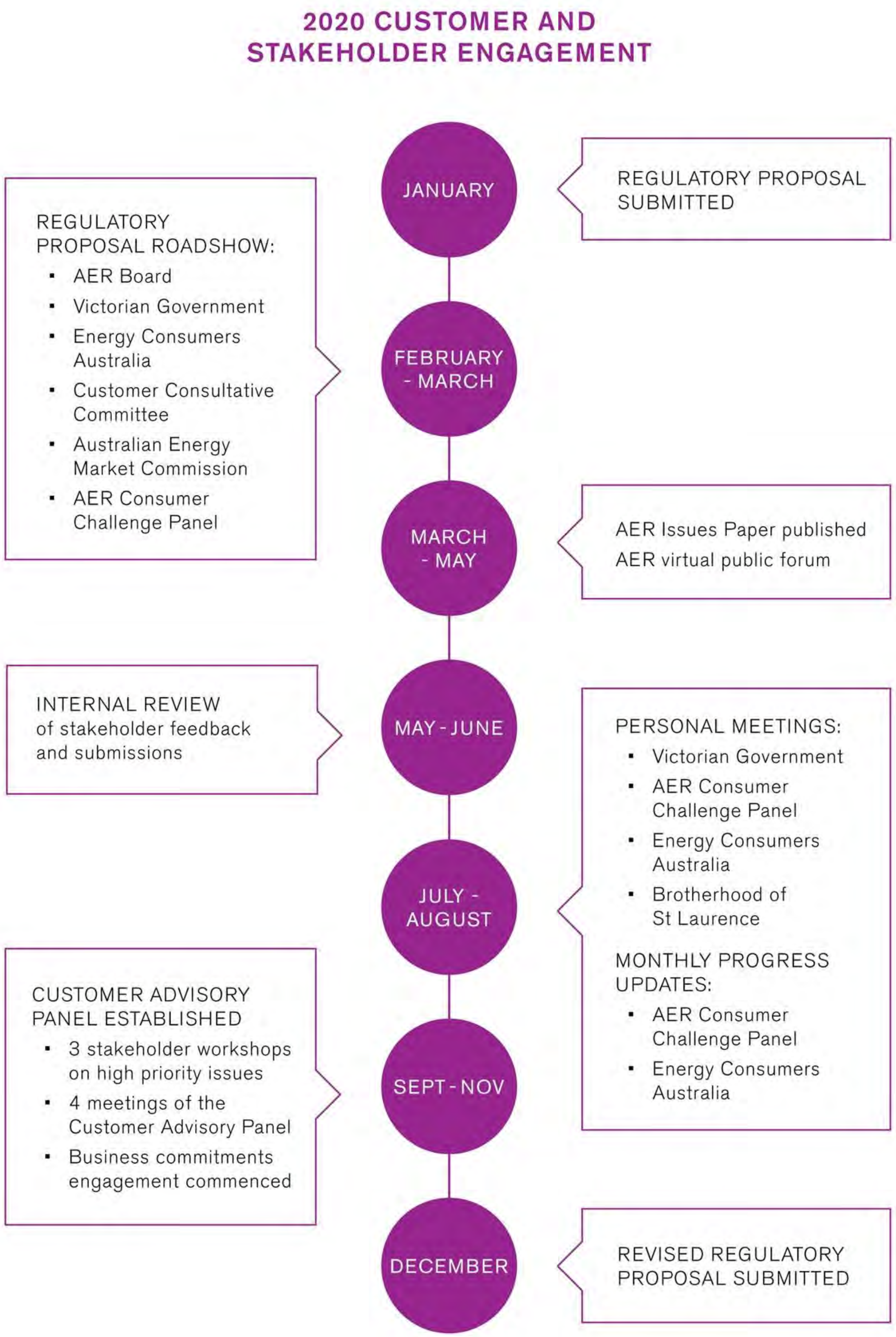
We've also learnt that despite offering what we think is the best value for customers in Australia—best reliability outcomes and outstanding customer service at the lowest prices—we can improve how we communicate the benefits delivered to our customers.

As such, despite the reduction in our revised expenditure proposal, we want to make further commitments to delivering better outcomes today and into the future. Together with the CAP we have begun a process of developing measurable outcomes-driven commitments, that will ensure we deliver on the programs in our revised proposal, as well as other programs that form part of our business as usual improvements. We plan to finalise the commitments in the first quarter of 2021. These commitments will be endorsed by the Chief Executive Officer and the Executive Management Team and build on the already outstanding service outcomes we deliver year on year, that separate us from our peers.

Most importantly—the journey does not end here, this is just the beginning. Our CAP will become one part of our business as usual stakeholder engagement and customer communication strategy summarised in this chapter and detailed within UE RRP APP02. We will also work with the CAP to develop measurable output-based commitments that we can report against to improve transparency, trust and understanding of our performance against targets.

Chapter 2 photo: Tennant Reed, Principal National Advisor, Australian Industry Group and member of our Customer Advisory Panel taking part in a meeting from his home office.

2. Stakeholder engagement



2. Stakeholder engagement

2.2 Our new Customer Advisory Panel has changed the way we engage

In response to stakeholder feedback, and through learnings from other networks, particularly SA Power Networks and AusGrid, we have established the CAP. The CAP is now a key customer advisory group to collaborate with us to develop our future program of works through collaboration and representation of customer and stakeholder views and preferences.

The CAP ensures customer and stakeholder views are embedded in decision making processes and new challenges are addressed with customer and stakeholder views at the forefront of proposed solutions. This includes in areas of overall customer research and engagement, energy market transformation, tariff reform, improving customer experience, and any other topic that impacts or is important to our customers.

We consider the CAP to be a significant part of our evolution as a business which actively involves customers in our decision making. We have collaborated with the CAP to finalise marquee programs in our revised proposal, but more than that, the CAP will be an on-going party that provides input into business decision from an early stage of consideration. Starting this early will ensure that when the 2026–2031 regulatory reset comes around, the CAP will have a strong knowledge base to effectively negotiate customer outcomes.

While our EFCAP supported consultation for our original proposal, we streamlined the CAP membership to a small but impactful group of five. The members are highly informed and influential industry stakeholders and representatives of household and vulnerable customers, commercial customers, the renewables sector and policy makers. We recruited the members based on their constituency, demonstrated customer advocacy experience, industry knowledge and understanding of the electricity distribution regulatory framework. The members are:

- Gavin Dufty, Executive Manager Policy and Research, Society of Saint Vincent de Paul
- Shelley Ashe, Associate Director, Energy Consumers Australia
- Tennant Reed, Principal National Advisor, Australian Industry Group
- Dean Lombard, Senior Energy Analyst, the Renew
- Nathan Crombie, Director, Energy Consumer Policy, Department of Environment, Land, Water and Planning.

2. Stakeholder engagement

2.3 What we've been doing since our regulatory proposal

In the time since submitting our original proposal, the world has changed immensely. The COVID-19 pandemic has posed new challenges for our customers and our daily operations, introducing a level of uncertainty in our planning unlike seen before. The COVID-19 pandemic has also elevated the importance of ensuring affordability of our services as the communities we service face unprecedented hardship.

It is in this uncertain environment that engagement becomes even more important. We don't claim to know all the answers. We have reached out to stakeholders and our CAP to get their input into how we should approach short-term and long-term planning with high levels of uncertainty, and what adjustments we should be making to our plans to account for these challenges. We engaged on this topic early, prior to the publication of the draft determination. This allowed us enough time to consider various scenarios and set up planning that includes the potential for last-minute revisions to our revised proposal arising from policy changes. Details of our engagement on this topic are provided in the table below.

We also took the time to reflect on how we have engaged to date, where we can improve our engagement outcomes, and how we can better demonstrate what our proposal means for our customers. Our new and improved approach is detailed below.

2.3.1 We've received valuable feedback from stakeholders

Immediately after submitting our original proposal, we undertook a 'road show' with key stakeholders, including the AER Board, Victorian Government, Energy Consumers Australia (**ECA**), the CCP17, Brotherhood of St Laurence, and the Australian Energy Market Commission (**AEMC**). The initial feedback acknowledged our strong performance over the current regulatory period, however stakeholders wanted us to identify more savings in 2021–2026 period and seek further support for some of our marquee programs through deeper levels of engagement.

In June and July 2020, we reviewed all presentations and submissions on our original proposal and identified the reoccurring themes and concerns that stakeholders raised. This included our customer engagement outcomes. We had a series of one-on-one meetings with key stakeholders who provided submissions and gave them an opportunity to provide further feedback on issues raised, as well as an opportunity to guide the other topics or areas they would like to see further engagement on.

Overall, we received a strong message stakeholders were seeking a better balance between affordability and outcomes, greater innovation and ambition, further engagement and a clear demonstration of how customer input has driven the outcomes we are proposing. They were asking us to demonstrate 'skin in the game' regarding delivering on these outcomes.

With this feedback in mind, we revised our stakeholder engagement activities as described in section 2.3.2.

In addition to targeted engagement, we set up regular monthly updates with the CCP17 and the ECA, to ensure transparency and a no-surprises approach for the revised proposal. This responded directly to a recommendation of the CCP17 in their submission to the AER's issues paper.

2. Stakeholder engagement

2.3.2 Our engagement for the revised proposal is more targeted

From mid-2020 we embarked on a targeted engagement program to address several key topics that were raised by stakeholders in their submissions. Part of the feedback we received related to our engagement to date being too high level, too broad and distributor-driven—as such we wanted to reshape our approach to let stakeholders tell us what they would like further engagement on, and hone in on those key issues in more time and depth.

This round of engagement with the key stakeholders shaped the topics for further engagement with a wider stakeholder group. We focused on three key topics and ran three stakeholder workshops with around 25 stakeholders per workshop, during September and October 2020, as summarised in the table below. These were run by our research partner, Forethought, to ensure independence and expertise in seeking feedback and summarising results. The extensive feedback and insights allowed us to better understand what changes our stakeholders expect to see in our revised proposal, but more broadly, what factors we should be considering and weighing up when designing our future plans.

The table below summarises our engagement through these workshops, and in section 2.4 we discuss how we used that feedback.

TOPIC	SEEKING INPUT ON
COVID-19	Stakeholder views on the short-term and long-term impacts of the COVID-19 pandemic on key assumptions within our revised proposal including energy demand, customer numbers, changing energy usage patterns, and connections, including solar.
ENERGY SECTOR TRANSFORMATION	Stakeholder perceptions of the role of the network in the energy supply chain regarding the introduction of new technologies, as well as perceptions of our rooftop solar program, enabling a more digitalised network and transitioning to time of use tariffs.
ASSET REPLACEMENT	Stakeholder perceptions of distributors' asset management practices and what successful asset management looks like, as well as initial thoughts on changes to our proactive pole replacement program since January 2020.

Source: United Energy

Forethought's summary reports, including the presentation materials, for each topic are submitted as UE RRP ATT05, UE RRP ATT06 and UE RRP ATT07.

2. Stakeholder engagement

2.3.3 We have collaborated with the CAP to get the best outcomes for customers

Following the workshops, we collected the background information and the feedback and presented it to our CAP, for purpose of getting a deeper and more collaborative input into shaping our revised proposal. Our engagement with the CAP also included a topic on 'customer experience' which was not part of the engagement with a wider group of stakeholders as:

- we had already received substantive feedback on our customer enablement program through stakeholder submissions and one-on-one meetings
- we ran a separate engagement program on our customer service incentive scheme (**CSIS**) development (see CSIS chapter).

The CCP17 participated in each session as observers. In section 2.4 we discuss how we used CAP's feedback to influence our revised proposal.

For each topic we prepared detailed pre-read materials that were shared with members a week in advance. This allowed members time to familiarise themselves the topic and minimise the need for presentations on the day. The agendas included only 15 minutes of presentation time with more than 1.5 hours of discussion time on the topics. The decision questions were shared with members a week in advance. We designed the CAP meetings this way to ensure that talk from the business was minimised and we listened more, allowing each CAP member to be heard and share their views. This is a change from how we ran meetings with the EFCAP in the build up to our original proposal and is driven by both learnings from those EFCAP meetings and stakeholder suggestions for improvement.

Following each CAP meeting, we circulated detailed minutes for member comment within a week of each meeting, including actions on us to either respond to questions/comments raised or provide an update on our revised proposal approach. Through this process, we have addressed each comment or question raised over the course of the four meetings, ensuring a frank and honest relationship with the CAP, as well as transparency and commitment from us. This 'your feedback, our response' approach has helped us to clearly demonstrate where we have adapted our revised proposal based on customer feedback.

Overall, the CAP members have been pleased with the workshops and found them valuable, highlighting the level of depth of materials provided, their ability to contribute to the sessions, as well as our post-workshop actions. The CAP members have also told us our proposed changes to how we operate, and updates to our proposed programs, are clear and include CAP's collective feedback.

2. Stakeholder engagement

The formation of the CAP is a significant step forward by CitiPower, Powercor and United Energy and is a step forward to further enhance consumer outcomes. I have found the meetings to date informative, respectful and responsive to views and expectations presented by members. As this process is developed, I believe it will lead to enhanced outcomes for energy consumers.

Gavin Dufty, CAP member

The new CAP looks to be a significant step in bringing consumer and community perspectives into CitiPower/Powercor/United Energy's decision making. So far, the businesses have shown considerable openness to CAP members, sharing key information and having frank discussions with members about the issues at hand and the alternative approaches to them. Importantly, the business has been coming back to the group at a later date to show how our feedback has influenced their decisions – this accountability is a hallmark of good stakeholder engagement. I have particularly appreciated the time we've been given before meetings to read and digest the relevant supporting documentation so meetings can be focused on the sharing of views and discussion of issues.

It's early days yet, but I am confident that this approach will help deliver good outcomes for the businesses' customers by ensuring that independent consumer perspectives are considered in business development and service delivery.

Dean Lombard, CAP member

In the final CAP workshop, we began to co-design a list of output-driven business commitments, to be finalised in the first quarter of 2021. These commitments will reflect areas of improvement and include metrics that demonstrate how we are delivering promised programs or showing 'skin in the game'.

All the CAP materials, including agendas, minutes and our responses are available under attachments UE RRP ATT08 to UE RRP ATT36.

2.4 What we've heard and how we've responded

We have heard from our stakeholders, and the AER, that we have not articulated how customer input, feedback and preferences have shaped our proposed plans. For the revised proposal we have implemented a targeted engagement program with industry stakeholders and the CAP, enabling a clear link to be drawn between the feedback received, and our revised proposal.

Overall, the collaboration with the CAP, including consideration of feedback from wider stakeholder groups, has resulted in streamlining of several marquee programs and resulting in an expenditure reduction of $61 million from our original proposal. This reflects a joint concern for the hardship our communities are experiencing at present and placing an emphasis on affordability in this time of uncertainty. Our revised proposal still allows us to deliver most of the outcomes that our customers have asked for, albeit reducing the number of 'nice to have' initiatives and focusing on the safety programs that deliver demonstrated net customer benefits.

The following six tables summarise the feedback we have received from our stakeholders since July 2020 and how we are addressing it in our revised proposal.

2. Stakeholder engagement

How we are improving our stakeholder engagement

WHAT WE'VE HEARD	WHAT WE'RE DOING
• Engagement is often at a high level with the issues and agendas guided by the distributor's staff • Unable to clearly identify the elements of the proposal that were shaped by consumer preferences • The EFCAP had lost purpose over time • Our proposal does not demonstrate 'skin in the game' regarding delivering promised outcomes	• We have introduced the CAP, with a more targeted and experienced group of members and a deeper level of engagement and collaboration or targeted topics • We have undertaken deep dives into issues identified in stakeholder submissions with industry stakeholders and the CAP • We have addressed and documented all feedback since July 2020 and have prepared proposals for the CAP that clearly demonstrate how feedback has driven the revised proposal • We have together with the CAP started on the development of a set of business commitments that will demonstrate accountability with respect to delivering outcomes • We have incorporated this feedback into an already extensive list of on-going customer engagement taking place today. For full details of our business as usual customer engagement refer to UE RRP APP02

CAP's concluding remarks:
The CAP was overall pleased with our business as usually customer engagement, including the quantitative research that informs our decision making, as well as the partnerships we have established with other agencies to help customers participate in demand response programs or better use their energy. The CAP encourages us to put more emphasis on qualitative research and customer feedback from everyday interactions, which is reflected in UE RRP APP02.

Source: United Energy

2. Stakeholder engagement

Shaping our Customer Strategy together

WHAT WE'VE HEARD	WHAT WE'RE DOING
• Our Customer Strategy should be within the company's vision statement to permeate the entire structure, up to CEO and Board level (demonstrating customer culture and centricity) • Empower the first receiver of the customer issue to resolve it was seen as a strong and meaningful value to both the staff and customer • We need to better understand how customers see value of affordable price – whether the value is because they have it, or because they seek it • 25% of customers highlighting low willingness to pay more for faster upgrades represents a large minority. A more detailed willingness to pay study may shed more light on this group • The strategy should be updated based on a post COVID world and differences between pre- and post-COVID should be tracked	• We have started to develop of a suite of customer commitments with the CAP, which will be ratified by our Executive team and Chief Executive Officer • To empower the first receivers, we are planning to implement speech analytics in our contact centre enabling us to track customer sentiment in (near) real time • We are also implementing initiatives to further streamline customer problem solving and will consider metrics to track first call resolution for customers • We see research on affordability being important and will conduct more qualitative and quantitative studies in the future, to better understand how customers value affordability and services we can offer • We will make sure the initiatives proposed in the strategy are flexible to changing customer needs and preferences – for example, since the commencement of the pandemic, we have completed two survey rounds of our customer experience surveys and will track and monitor changing trends from customer feedback
CAP's future input: We will rely on CAP's input to provide input on guidance on how best to implement the different initiatives under our Customer Strategy, and to respond to any emerging themes as they arise.	

Source: United Energy

2. Stakeholder engagement

Our revised Customer Enablement program

WHAT WE'VE HEARD	WHAT WE'RE DOING
• We need to better explain the benefit streams from the Customer Enablement program and what customer groups benefit and how • In light of current and ongoing affordability concerns, we should streamline our program and focus only on the initiatives that deliver the most benefit to customers in the immediate period • We need to demonstrate cost efficiencies and synergies between the networks • We should do a sensitivity analysis on the benefits quantification to ensure the benefits pass the sensibility test • We need to demonstrate how the Customer Enablement program fits into the broader set of innovative programs that will be rolled-out during 2021-2026, as well as tariff reform • We need to demonstrate the steps we are taking to ensure Customer Enablement does not become a 'sunk investment' in the changing energy market	• We streamlined our program to reflect the most supported initiatives to date, to remove initiatives that can be provided by the competitive market, and to keep the initiatives with the highest calculated net benefit. As such, we have reduced the cost of the joint CitiPower, Powercor and United Energy program by $15 million • We have synergised the costs of the initiatives across our three networks, and provided it as a single program for our whole customer base • We have updated our benefits analysis to be over 5-years rather than 10 years, to minimise the risk of a 'sunk investment' • We have updated our proposal to better reflect who benefits from the scheme, the sensitivities behind the benefits analysis and how the program fits into the whole regulatory proposal including tariff reform
CAP's concluding remarks: We presented the updated program to the CAP, including how we've responded to feedback, the updated costs and benefits. The CAP was supportive of the revised program and called the program 'good value' for our customers. Our revised Customer Enablement program is as presented to and approved by the CAP.	

Source: United Energy

For a detailed summary of how stakeholder feedback has shaped our revised customer enablement program, refer to UE RRP ATT15. Please also refer to the meeting minutes, UE RRP ATT14 and UE RRP ATT27 for the full summary of CAP's feedback.

2. Stakeholder engagement

Incorporating the impacts of COVID-19 in our forecasts

WHAT WE'VE HEARD	WHAT WE'RE DOING
• There is an agreement there is a higher level of uncertainty for forecasting the next regulatory period and that scenario modelling helps deal with uncertainty • Overall, the impact of COVID-19 is expected to have negative impacts on the growth of the network, resulting in lower growth than originally envisaged • CAP members supported a conservative approach to forecasting growth factors (i.e. low scenarios) with a potential for an earlier review by the AER • There should be consideration of price glide paths and reallocations, and mitigating price shocks to different customer groups • There should also be more consideration of intrastate migration, shifts in demographics, likely downsizing by households, a shift to regional areas and similar	• We have revised down our growth forecasts, accepting the conservative assumptions presented in the draft determination. This includes lower customer number forecasts, zero demand growth, an average of two forecasters for labour price growth, as well as an ambitious 0.5 per cent annual productivity target • This has resulted in a rate of change forecast of 1.9 per cent, which is significantly lower than 0.9 per cent forecast from 12 months prior • Our updated approach results in $27 million in operating expenditure we will not be seeking as a result of the economic downturn • We have also accepted the Australian Energy Market Operator's demand forecasts which result in lower augmentation and the Housing Industry Association (HIA) forecasts for residential connections • This conservative approach demonstrates delivering affordability is our priority in these uncertain times

CAP's concluding remarks:
We presented the updated proposal on how we are incorporating COVID-19 into our forecasts, including how we've responded to feedback and the AER's decision. The CAP was broadly supportive of our approach and the resulting reduction in forecast expenditure. The CAP concluded our revised proposal broadly addressed stakeholder concerns while acknowledging there is still significant uncertainty remaining.

Source: United Energy

For a detailed summary of how stakeholder feedback has shaped our response to the COVID-19 pandemic, refer to UE RRP ATT29. Please also refer to the meeting minutes, UE RRP ATT20 and UE RRP ATT36 for the full summary of CAP's feedback.

2. Stakeholder engagement

Our revised Future Network proposal

WHAT WE'VE HEARD	WHAT WE'RE DOING
• There is a call for unification of our DER programs to better reflect the total costs and benefits of the related initiatives • Our solar enablement program did not get the affordability balance right and our programs lacked innovative focus. However, affordability should not be traded off, rather optimised • Our digital network proposal did not articulate how network benefits will be delivered and in general our proposals lacked ambition in demand management (other than United Energy) • Dynamic operating envelopes were seen to be a useful tool going forward, and transformer tapping as a first step and low-cost option to enabling hosting capacity • There was a call for more consideration of self-consumption as opposed to exports • This should be monitored and incorporated into the plans post 2026, allowing the AER to clearly view how this period's program affects the next regulatory period • Stakeholders want to better understand the full picture and how the programs fit within the total proposal • Measuring success of DER integration was seen as challenging but best done with a mixture of output measures and measures of implementation and cost. • The changing nature of tariffs clearly has a role to play in future networks and that we can be creative for how we provide solutions to customers and different customer segments	• We have merged the initiatives from solar enablement and digital network under a single future network program, while our revised proposal also provides a top-down overview of all expenditure, demonstrating how different expenditure / work streams operate together • Rather than focusing on the 'efficient level of output' over a 30-year period, we have scaled down our program to deliver the highest level of output possible using a 20-year model as per the draft determination • We have refocused our solar program on more innovative solutions, such as dynamic management voltage systems (DVMS), by continuing to trial and work with leading industry bodies to enabling as much solar as possible • Our focus will be on addressing the most constrained parts of the network first, and working with dynamic operating envelopes to maximise customer benefit as soon as possible • We are re-focusing digital network to be centred around facilitating greater demand management through third party participation • We are continuing the seek the solar enablement step changes as stakeholders support tapping as the most efficient option • Overall, our future network program is $30 million lower than our original solar enablement and digital network programs • We have provided an infographic to visually demonstrate the full picture of how our future network initiatives work together and what they mean for our customers • We are working with the CAP to develop customer commitments that can demonstrate how we're delivering on the future network program, including tracking agreed metrics on output and process • We are also developing partnerships with other agencies, such as with the Australian Energy Foundation, to work with our customers on better energy use, including getting the most out of solar

CAP's concluding remarks:
The CAP strongly supported the use of dynamic envelopes which is a key feature of our digital network program, and in general supported the continual efforts to enable DER. The CAP also supported a communications campaign or partnerships to improve the use of DER before significant investment.

Source: United Energy

For a detailed summary of how stakeholder feedback has shaped our revised future network program, refer to UE RRP ATT24. Please also refer to the meeting minutes UE RRP ATT27 for the full summary of CAP's feedback

2. Stakeholder engagement

Our revised wood poles asset management proposal

WHAT WE'VE HEARD	WHAT WE'RE DOING
• There is no basis to uplifts on historical expenditure • Stakeholders wanted to see the differences between the networks and more network specific modelling • Stakeholders want to understand how we have regard to the changing nature of the electricity sector when replacing long lived assets • Stakeholders want to know what other low cost measures we are taking to reduce risk of pole failure • More information would be helpful on what is 'reasonable and practical' given our view may reflect a different risk tolerance to the regulator	Since our revised proposal, we have further tested our pole condition and decay rate data to assess the reasonableness of our trend forecast. This analysis has been calibrated to our observed performance over the 2016–2020 regulatory period, and supports our longer-term trend consistent with our original proposal. We have also accepted stakeholder feedback and are no longer proposing any risk-driven interventions. This means our revised forecast is $11m lower than our original proposal.

Source: United Energy

For a detailed summary of how stakeholder feedback has shaped our revised wood pole asset management program, refer to UE RRP ATT26 and UE RRP ATT30. Please also refer to the meeting minutes UE RRP ATT27 for the full summary of CAP's feedback.

2.5 This is not the end of the journey

We recognise collaboration with our stakeholders and customers will be key as we start preparing our network to meet our customer’s changing needs. Our engagement focus has shifted beyond regulatory resets to tackle the emerging issues such as two-way energy markets, integration of electric vehicles and tariff reform.

Accordingly, we have developed a strategy for continual customer and stakeholder engagement as part of our business-as-usual operations. With a goal of ensuring customer needs and priorities are at the centre of what we do, this strategy involves:

1. Customer research—implementing a longitudinal research study into customer perceptions and priorities to constantly monitor and report on trends and insights relevant to network decision-making.
2. Escalated governance—further strengthening the internal governance framework for assessing and considering customers insights at Board and executive levels.
3. The CAP—sustaining the CAP on an ongoing basis to provide a regular sounding board and representative body to ensure decisions and plans developed by United Energy best meet customer needs.
4. Industry collaboration—working with credible industry and community organisations to ensure we actively participate in programs which address the needs of customers and stakeholders.
5. Stakeholder engagement and communication—a continual program of mass communication, digital information and targeted stakeholder engagement to build high awareness of our network and its performance.

2. Stakeholder engagement

We believe benefits of this approach will be realised for our customers by:

- sustaining our position as one of the most affordable networks in Australia for customers to support affordability objectives for customers
- contributing positively to the safety and resilience of communities within our network region
- ensuring we are facilitating customer choices for distributed energy resources and technologies which generate environmental benefits
- continuously improving our customers' experience with us online, in the field, and in person
- better tailoring customer facing initiatives and services for customers with specific needs including financially vulnerable and those dependent on electricity for vital life support.

Ahead of the next regulatory reset (2026–2030), we also believe the benefits of this approach will be realised within our business by strengthening our cultural alignment internally with customer centric objectives and establishing a more substantial research foundation for the development of future regulatory proposals. For detailed information on this revised strategy, please see UE RRP APP02.

2.6 The AER's draft framework for considering consumer engagement

The draft determination introduced a draft framework for considering consumer engagement. We support an assessment framework that helps guide distributors, however we consider the framework should undergo a proper consultation process outside of the Victorian determination, including independent reviews by customer and stakeholder engagement practitioners.

We support a framework that encourages innovation in engagement and allows for variation and choice in engagement approaches. This includes balancing both 'shallow' engagement with large numbers of grass-roots customers and 'deep' engagement with informed stakeholders.

We also support a framework that measures success through a multitude of factors, not just a financial criterion or comparisons to historical expenditure. Factors for measuring success should include service outcomes, appropriate measures of tracking against service commitments, considerations of trade-offs between service outcomes and affordability, as well as consideration of efficiency of delivering services.

We caution against a framework that:

- relies solely on the participation of highly trained and informed stakeholders, putting less value on engagement from grass-roots customers
- measures success predominantly through expenditure reductions.

Finally, to apply the framework for each distributor's engagement process evaluation, we would encourage the AER to be more actively involved and participative in each distributor's engagement process from the outset. This would provide the AER an appreciation of what is likely to be a large body of research through many years of engagement. Assessment and interpretation based solely on the regulatory proposal will always be difficult and subject to misunderstandings and error.

We look forward to working with the AER and stakeholders further on the finalisation of the framework.

3

Impact of COVID-19 pandemic

3. Impact of COVID-19 pandemic

3.1 Introduction

The COVID-19 pandemic (pandemic) has disrupted social behaviours, business operations and Victoria's economic outlook dramatically. It is unclear how long the pandemic will last or how long the economic impacts will endure. The heightened level of uncertainty and the devastating impact the pandemic has had in Victoria have made the preparation of this revised proposal challenging.

In preparation of the revised proposal, we have carefully considered the impact the pandemic has had on our original regulatory proposal and how individual positions or assumptions may have changed. Whilst we engaged with external forecasters, we particularly wanted to understand the impacts on our customers. For that purpose, we conducted a wider stakeholder forum in September and held a separate session with our Customer Advisory Panel (CAP) in October to ensure we understood their individual and collective experiences.

As a result, we have chosen in almost all cases to adopt the draft determination forecasts including the residential connection forecasts provided by the Housing Industry Association (**HIA**) and Australian Energy Market Operator's (**AEMO**) latest demand forecasts.

Consideration has been given to the considerable impact the pandemic has had on productivity. We believe these changes in productivity will, in many cases, be permanent as we move to 'COVID normal', especially in Victoria. The AER's approach to productivity assessment, as outlined in *Final decision paper Forecasting productivity growth for electricity distributors*, has not considered events such as a pandemic. As such, it penalises distributors subject to the pandemic, especially those in Victoria where the effects of the pandemic have most strongly been felt. Nonetheless, in the interests of maintaining affordability for our customers, and recognising the severe hardship the pandemic has imposed on Victorians, we have not sought to include additional costs to offset the decline in productivity.

This chapter outlines the changes we have made for the pandemic to our original proposal.

Chapter 3 photo: United Energy teams operated under COVID-safe work practices to progress critical works and maintain safe and reliable supplies while also minimising impacts on our customers living hrough lockdown conditions.

3. Impact of COVID-19 pandemic

3.2 What we've heard and how we've responded

As part of our second phase of engagement, we identified the pandemic as a key concern for our stakeholders. Most submissions on our original proposal reflected the issue in their comments, and sought clarity as to how the pandemic would impact our proposal

WHAT WE'VE HEARD	HOW WE'VE RESPONDED
The original proposal did not consider the impact of COVID-19 pandemic on the future needs of customers and the network.	We agree with stakeholders and have made a concerted effort to address the issue in the revised proposal. This chapter is dedicated to discussing the impact from a top down perspective. Discussion of its impact from a bottom up perspective is covered in the relevant sections on augmentation, connections and operating expenditure.
Stakeholders wanted an opportunity to discuss their experiences with COVID-19.	On 9 September we conducted a session with a wider set of stakeholders to discuss the pandemic and its impact on our original proposal. The sessions were independently produced and facilitated by Forethought with minimal involvement of the business. The findings from the wider stakeholder forum where discussed with the CAP and CCP.
Rather than attempting to identify the 'most likely' scenarios, we should rely on 'low scenarios' to demonstrate conservatism.	For the most, part we have accepted the draft determination forecasts for demand, customer numbers, energy and connections. The exception has been large connection activity which we see more closely related to government fiscal stimulus.
Consideration should be given to a 'pass through' for forecasts given underlying levels of uncertainty.	This view was not held unanimously across stakeholders. As a regulated business, we are strong believers in incentive-based regulation. Proposing a pass-through mechanism would undermine those incentives and result in a regulatory model more closely resembling cost plus regulation.
It is becoming more certain that the negative effects on the community are going to be around for a long period and we should be taking that into consideration.	Our revised proposal has sought to implement and demonstrate restraint where possible. The revised proposal has accepted many aspects of the draft determination including augmentation, integration of DER and recurrent ICT. Where we have sought increases above the draft determination, these are below the amounts sought in our original proposal.
There should be further consideration of shifts in demographics, likely downsizing by households, a shift to regional areas etc.	These are all valid considerations and we discuss the changes in consumption we have observed thus far in this chapter. The longer term impacts however are less certain as restrictions are eased and government stimulus packages kick in. On that basis, we have accepted the draft determination forecasts.

Source: United Energy

3. Impact of COVID-19 pandemic

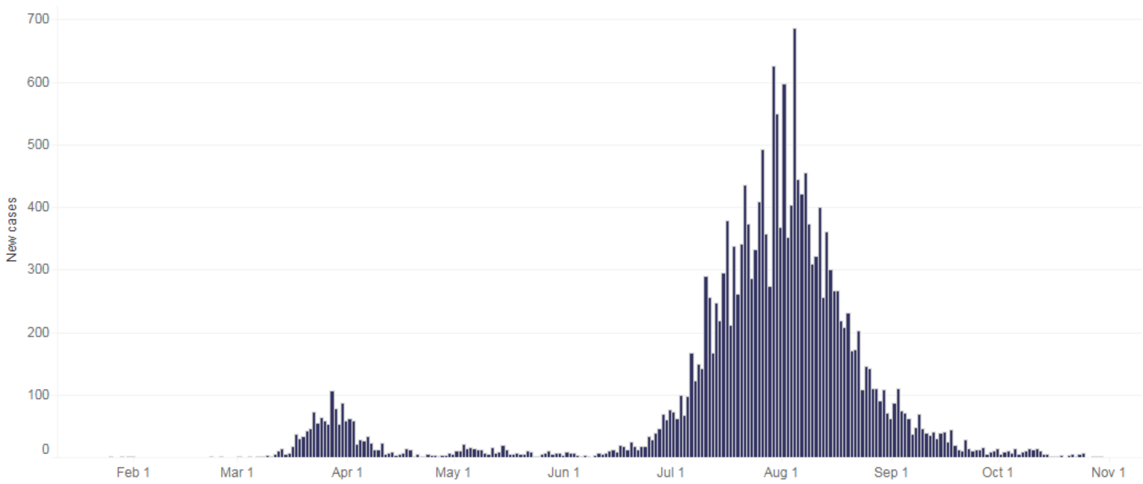
3.3 Why are we talking about the pandemic?

The pandemic we have experienced in Victoria is part of the ongoing worldwide battle with coronavirus disease 2019 (COVID-19) caused by severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2). The first confirmed case in Australia was identified on 25 January 2020, in Victoria.

Since the first case Victoria has experienced two waves of infection. The first, which involved the closure of international borders, social distancing and the closure of non-essential services commenced on 21 March before a short lived lifting of restrictions through June/July. The second wave, which triggered a more severe lockdown commenced in July and remained in effect until November.

As of 12 November 2020, Victoria has reported 20,345 cases and 819 deaths.

NEW COVID-19 CASES, VICTORIA



Source: Victorian Health and Human Service website, 12 November 2020

In response to the first wave of the pandemic, we developed a proactive, voluntary relief package (package) to assist our customers and their retailers impacted by the pandemic. The package was developed without the need for regulatory intervention with the objective to:

- provide immediate relief to small business customers that had ceased operations due to the pandemic
- provide network charge relief by rebates/deferrals for residential customers impacted by the pandemic
- provide specific support for small retailers.

The initial package was modified and adjusted based on feedback from our retailers.

The package has been in place since April and extended twice. It will remain in place until at least January 2021. The package continues to be regularly reviewed and adjusted in line with new information and via consultation with key bodies such as the Essential Services Commission of Victoria.

3. Impact of COVID-19 pandemic

NETWORK RELIEF PACKAGE - OUTCOMES AND FEEDBACK

Source: United Energy

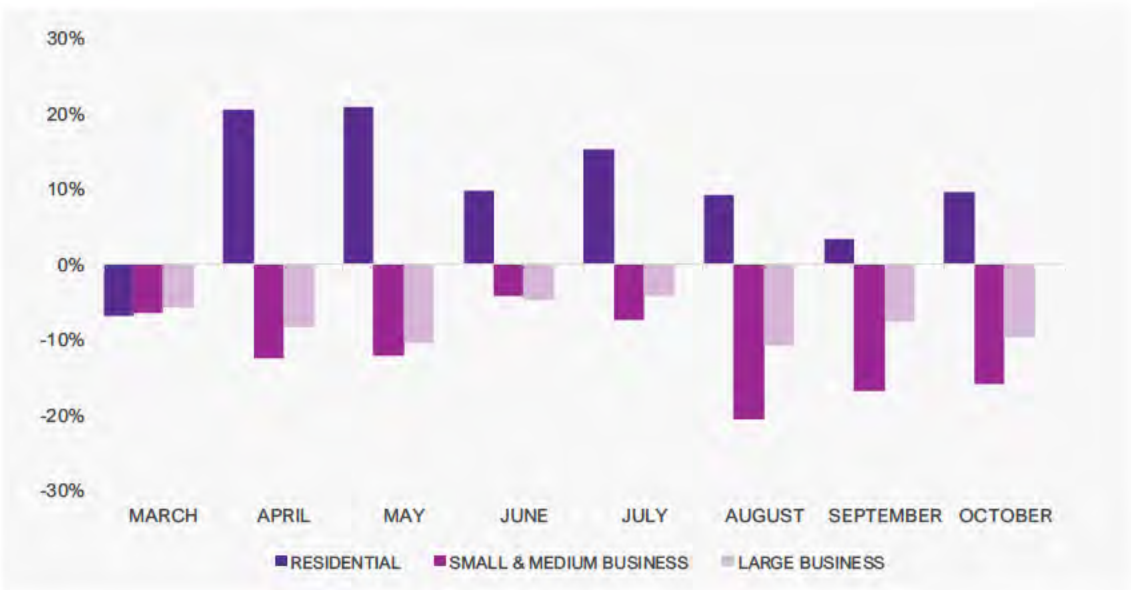
3.4 What have we experienced?

What has been our experience with the pandemic?

The figure below presents energy consumption over the period April to October 2020. Total consumption is around 0.5 per cent higher over the last five months, reflecting the large residential customer base our network services.

We estimate our actual revenue will exceed allowed revenues by 0.6 per cent in 2020.

CHANGE IN USAGE FROM 2019 TO 2020 (MWH)



Source: United Energy

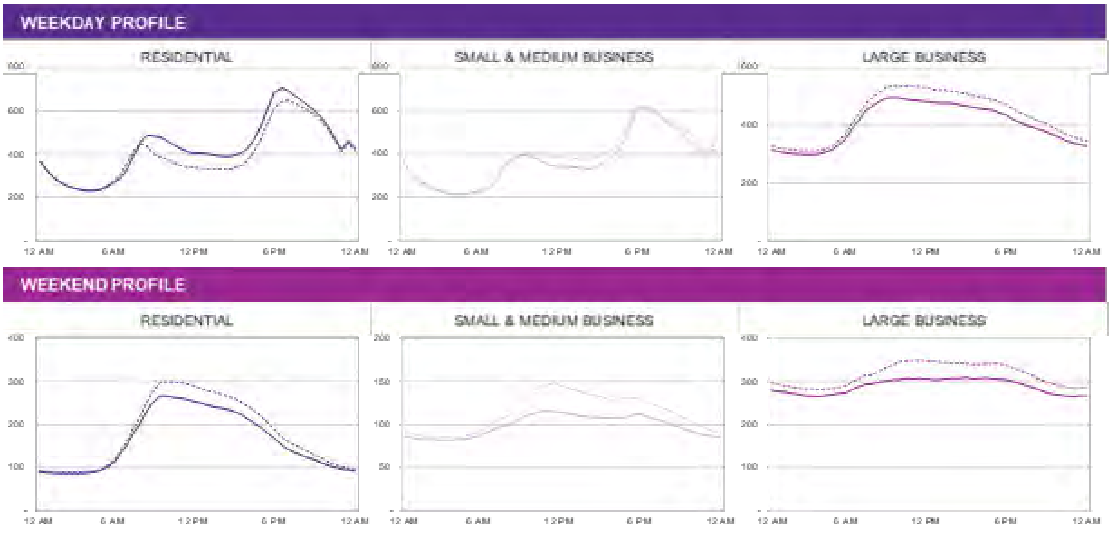
3. Impact of COVID-19 pandemic

Aside from total consumption, we have also considered changes in load profiles arising from the pandemic.

The figures below compare average energy usage between 2019 and 2020. The comparison days have been selected over periods in which temperatures were similar. This is necessary as load profiles are very sensitive to temperature.

The 2020 load profile for residential weekday consumption is marginally later in the mornings and approximately half an hour earlier in the evenings. As expected, there is a marked increase in load through the middle of the day although the overall load profile shape is not dissimilar to 2019. As is expected, consumption for commercial and industrial customers has declined but the load profiles remain similar to 2019.

AVERAGE DAILY DEMAND 2020 COMPARED WITH 2019 (MW)



Source: United Energy

In summary, there has been a decline in commercial and industrial load over 2020 compared to 2019. This is not unsurprising given Victoria's extended lockdown. What is perhaps surprising is the uplift in residential load that has offset the decline in commercial/industrial load and resulted in higher energy consumption than 2019.

Total consumption of commercial and industrial customers has declined, with the majority of the decline impacting the middle of weekdays. In contrast, weekday residential load profiles have observed increased loads through the middle of week days. Residential weekday demand has also shifted with later morning peaks and earlier evening peaks. The peaks during the morning and evening for residential customers have also increased in size, a not unexpected outcome given more people are at home.

3. Impact of COVID-19 pandemic

3.5 What were the views of our customers?

A clear message from our stakeholders since our original proposals has been the need to consider the impact of the pandemic. Such was the interest in the issue, we decided to directly engage with our stakeholders, both through a wider consultation and in a more intimate setting with our CAP.

On 9 September we conducted a session with a wider set of stakeholders to discuss the pandemic and its impact on our original proposal. The session included a wide range of stakeholders including the Brotherhood of St Laurance, St Vincent de Paul, Energy and Water Ombudsman of Victoria, Council of the Aging and the Clean Energy Council amongst many others. The sessions were independently produced and facilitated by Forethought with minimal involvement of the business.

Below summarises what we heard from stakeholders in that session. It should be noted the draft determination was not available at the time of the session.

Forecast integrity and granularity	Changing consumers trends and potential innovations	Government changes and policy risks	Potential Changes to productivity and revenue
• There was some confusion that the proposal **focussed too heavily on macro-trends rather than micro-trends**. Many saw the forecasts to be high-level and did not take into account the impact of the pandemic on a more granular level. This included giving forecasts that were industry- based, age-based, geography-based and included elasticities in age groups and elasticities in energy. • **There was no consideration of customers moving to regional centres** from Melbourne and the impact that this would have on demand forecasts for the three networks. *"Where is it based from? Is it triangulated with data from real-estate agents and appliance manufacturers and retailers?"* Workshop Stakeholder	• Some stakeholders mentioned that the forecasts did not factor in potential **increases in gas and hydrogen use in the future**. • **This also included potential innovations in solar enablement** such as a greater rollout of community battery and other changes to the grid. • **Disruptions to solar uptake / not enough information was** seen to be accounted for, within forecasts. This included reduction to solar uptake in growth belts. *"Solar has mainly been in the growth belt. Are we taking into consideration mortgage deferrals in these areas?"* Workshop Stakeholder *"The proposal was rear-vision focussed. It's not anticipating potential future impacts of COVID."* Workshop Stakeholder	• Many thought that the **forecasts should have taken greater consideration of potential infrastructure policy** that could be implementation as a result of the pandemic. If Victoria chose to invest in infrastructure programs, it could increase project delivery. • Stakeholders wanted to understand the **extent potential changes in State and/ or Federal Government** would have on infrastructure and renewable project spend. Some were conscious that Labor may lose power at the next Victorian State Election and this was expected to be taken into account within the forecasts. *"What if there's a change in government? Where's the contingency there?"* Workshop Stakeholder	• Some stakeholders thought that the forecast did not factor in the changes in productivity on major projects and the delays in manufacturing and shipping that have been experienced. This was seen important as they relate to changes in the cost of equipment. *"How has COVID impacted the cost of business on their operations? Half-crews, low productivity."* Workshop Stakeholder

Source: UE RRP ATT05

The session took stakeholders through a discussion seeking how the pandemic had impacted on them (and their constituents) and their everyday use of energy. A second session then presented a range of preliminary forecasts acquired in August 2020 as 'thought starters' from a variety of forecasters including BIS Oxford, Macromonitor and the National Institute of Industry and Economic Research (NIEIR). Participants were then invited to comment.

3. Impact of COVID-19 pandemic

For reference, the table below summarises the major differences between each forecasters' assumptions.

	BIS Oxford Base	BIS Oxford High	BIS Oxford Low	Macro-monitor Base	Macro-monitor High	Macro-monitor Low	NIEIR Base	NIEIR High	NIEIR Low
Successful vaccine	End-2021	End-2021	End-2021	2021	2021	2021	Early-2021	Mid-2021	Early-2023
Internationl borders open	Start-2022	Mid-2021	Mid-2022	Early-2022	Early-2022	Early-2022	Mid-2021	Late-2021	Early-2022
Net overseas migration returns to normal	Mid-2024	Mid-2023	Late-2024	Peak in mid-2026	Peak in mid-2025	Peak in mid-2027	Post 2025-26	Post 2025-26	Post 2025-26
Net interstate migration (when expected to increase and settle)	5,000 by 2024	5,000 by 2024	5,000 by 2024	4,500 by 2024	4,500 by 2024	4,500 by 2024	N/A	N/A	N/A
End of strict lockdown	Q4 2020	Q4 2020	Q4 2020	Q3 2020	Q3 2020	Q1 2021	Q4 2020	Q4 2020	Q4 2020
Employment recovery	Mid-2022	Start-2022	Late-2022	Mid-2022	Start-2022	Mid-2023	Mid-2023	Mid-2022	2030
Economy to pre-COVID levels	Mid-2022	Start-2022	Mid-2022	Mid-2022	Start-2022	Mid-2023	Mid-2023	Mid-2022	2030

Source: United Energy

The stakeholder forum elicited a wide range of views, reflecting the rich diversity of experience the participants had encountered through the pandemic. There was near universal recognition this was an unprecedented era of uncertainty and that there was no 'silver bullet' for forecasting the impact of the pandemic.

On 5 October, we presented Forethought's summary of the wider stakeholder forum to the CAP. The CAP was aware of the draft determination at the time of their meeting. Most CAP members also attended the wider stakeholder session.

The CAP was invited to provide feedback on the wider stakeholder forum and then to provide guidance on how we should proceed in forecasting for the purposes of our revised proposal. We received extensive feedback including:

- there is a greater than usual amount of uncertainty around the key parameters that shape our forecasts
- rather than attempting to identify the 'most likely' scenarios, we should rely on 'low scenarios' to demonstrate conservatism, and potentially seek contingent projects or another mechanism to adjust allowances for actual macroeconomic factors. This could be done by flagging the areas of most consequential uncertainty to allow for a trigger for a contingent project (i.e. population growth)
- however, it was also highlighted that this approach could mean moving away from incentive-based regulation, and that we should be cautious about proposing changes to the established framework
- there was a suggestion that we should build in implications to each of the forecasted scenarios from the baseline to give stakeholders an understanding of the impacts of the uncertainty that can happen (i.e. what does it mean if the ‘actuals’ are higher or lower than the forecasts)
- structural changes in the economy (from government policy) will become more clear after the budget has been passed down, this will make the long term impacts of the pandemic perhaps more clear
- there should be more consideration of what the parameters look like moving forward in terms of side constraints, glide paths and reallocations, and how do you mitigate those shocks going forward. This is particularly important for ensuring glide paths that minimise impacts to consumers

3. Impact of COVID-19 pandemic

- there should be more work with customers and the community through this uncertainty. For example, propose lifting up complementary measures. If there is more change, there are a significant number of complementary measures you can use to help customers deal with the change
- it was highlighted that while there is uncertainty now, it is becoming more certain that the negative effects on the community are going to be around for a long period and we should be taking that into consideration
- there should also be more consideration of shifts in demographics, likely downsizing by households, a shift to regional areas and similar.

Members of the CAP believe there is a higher level of uncertainty in forecasting the next regulatory period. Some members supported us adopting a conservative approach with the potential for an earlier review by the AER, such as an 'off-ramp' if necessary.

The adoption of a conservative approach was not because it was necessarily the 'most likely' scenario, but because it reduced risk for customers. It was noted that if an 'off ramp' solution was to be adopted, it would require us to establish trigger points/thresholds and metrics would need to be outlined in our revised proposal. CAP also noted the approach would potentially conflict with an incentive-based regulatory framework.

The CAP considered load profiles. The consensus was there is a lot of uncertainty around the short versus longer term impacts of the pandemic. It was broadly agreed there would be a middle ground, where we will not return to a pre-pandemic world, but behaviour will not continue as it has been in lockdown. There is more work required to properly capture the evolving trends. Understanding these trends was not going to be a possibility for the revised proposal.

3.6 What are we proposing?

We propose to accept the forecasts provided in the draft determination. Based on the current environment, providing an alternate set of forecasts capable of acceptance by the AER would not be possible. Whilst we are deeply concerned AEMO has consistently underestimated growth in our network, we recognise in the current environment there is too great an uncertainty for us to propose an alternative.

Our acceptance of the HIA forecasts is only for residential connections and customer numbers. We don't accept their application to large connections which, as discussed in chapter 7, are more linked to government stimulus. This is consistent with the feedback we received at the wider stakeholder forum where stakeholders felt our connection forecasts should account for changes in infrastructure policy. At the time of the forum, the outcomes of the Federal Budget were not known. Our stakeholders however felt the Federal and State Budget would be strong drivers of future large connection activity.

Our wider stakeholders and CAP emphasised the importance of affordability, and the role accepting conservative forecasts can play in making services more affordable. Conservative forecasts reduce augmentation, connection and operating expenditure allowances in the short term. However, artificially deflating allowances can result in penalties under each expenditure incentive scheme which customers have a 70 per cent share in. Nonetheless we recognise the importance of delivering immediate affordability at this juncture in time.

3. Impact of COVID-19 pandemic

Consideration was given to proposing a nominated pass through event or 'off ramp', as identified by some of our CAP members. However as also identified by other CAP members, proposing these types of events undermines the incentive properties of the regulatory framework. Like our CAP members, we are strong believers in incentive based regulation, particularly for something as fundamental as demand and customer forecasts. Further we felt proposing a pass through mechanism could create even greater uncertainty.

In accepting the draft determination forecasts, we have accepted the expenditure allowances sensitive to these forecasts including augmentation, most replacement and connection expenditure and operating expenditure rate of change. We note the AER has the discretion to update its forecasts for the final determination and arbitrarily adjust our expenditure forecasts. We don't consider such an approach to be in good faith. Further we would question the AER's ability to obtain robust forecasts in an environment where most forecasters are unwilling to provide estimates given the current economic volatility.

3.7 Will productivity be impacted?

The pandemic has impacted our productivity performance. Like most industries, we have been required to amend our work practices to reduce the risk of transmission of the virus amongst our employees and customers. The essential nature of electricity distribution means we have needed to continue to operate continuously through both Victorian lockdowns whilst minimising the impact on customers, especially residential customers who more than ever, needed a reliable and safe electricity supply, as they adapted to working from home.

Our office based staff have been able to operate from home. This has not been the case for field based staff, which form the majority of our employees. Field employees have been required to adapt to a number of immediate and perhaps permanent changes in work practices as outlined below.

DESCRIPTION	IMPACT
STORAGE SPACE FOR EWPS AT DEPOTS NEEDS TO BE CONSIDERED	Additional space required at each depot with additional EWPs.
ADDITIONAL COST IN PPE - BUFFS, FACE SHIELDS, MASKS, HAND SANITISER, WIPES, ETC.	Additional material costs.
SEGREGATION OF CREWS INTO TEAMS AND STAGGERED START TIMES	Impacts productivity both within and between depots. Restricts available people to call in for faults (staff need to be from the same team).
REDUCED OUTAGE SIZES CREATE MORE NETWORK PLANNING	Increase in planning time for schedulers and control and operations staff. Additional travel time involved travelling to outages. Urban environments, access restricted as more cars at home.
INCREASE IN OUTAGE PLANNING TO MINIMISE CUSTOMER IMPACT	More interface with customers in negotiating outages. Additional expenditure on generators to offset outages.
OFFICE DISTANCING AND CLEANING	Control room, dispatch and contact centre were all impacted through social distancing requiring additional spacing and deep cleaning between shifts.

Source: United Energy

3. Impact of COVID-19 pandemic

The changes have impacted our expenditure program over 2020. It is too early to understand the magnitude the impact on our 2020 expenditure program and how many of these changes will become permanent in future years. We have chosen not to pass these productivity changes onto our customers through adjusting our unit costs (our unit costs are almost entirely based on data prior to 2020) or by adjusting work volumes in future years. Instead we are absorbing the impacts given the devastating impact of the pandemic on our customers and affordability concerns raised in wider stakeholder forums and from the CAP.

The negative impact on productivity will challenge our ability to meet the draft determination's aggressive 0.5 per cent productivity adjustment. It is noted the draft determination remains steadfast in incorporating the assumption. Given the impact of the pandemic, and the draft determination failure to note the different situation of Victoria, we expect the real productivity impact on our business to be more in the range of 0.5 to 1.0 per cent. This highlights the inability of the AER's productivity approach to accommodate structural breaks and differences in networks and jurisdictions.

To further contextualise the productivity task, the AER has not accepted the majority of our step changes or pass through adjustments based on materiality. AER staff have advised materiality is used as a proxy for negative step changes AER staff believe we will benefit from but cannot be identified or quantified. In effect this means when added to the productivity adjustment, we have a $49 million negative step change. In other words, we must find $49 million in productivity savings before we draw close to our operating expenditure allowance. This is before the negative impact of the COVID-19 pandemic on productivity is considered or the positive step changes we have not sought recovery for.

3.8 Other consequences

The pandemic has impacted other parts of our original proposal.

Prior to the draft determination, we withdrew on 15 May a step change and capital project concerning new obligations of Environmental Protection (**EP**) Amendment Act 2018.

At the time of the preparation of our original proposal, the EP Amendment Act 2018 was expected to repeal the EP Act 1970 from 1 July 2020. The new Act establishes a proactive regulatory approach to preventing waste and pollution impacts, rather than managing the impacts after they occur. In August 2019, the Victorian Government published the draft EP Regulations (draft regulations), along with the regulatory impact statement (**RIS**). Our proposed operating expenditure step changes and capital program on bunding and noise were estimated based on the draft regulations.

In May 2020, the Victorian Government announced it was deferring introduction of the EP Amendment Act 2018 to 1 July 2021. The final regulations are also likely to be deferred to post March 2021. The deferral of the legislation and regulations created uncertainty in our future environmental obligations and did not provide us sufficient clarity to develop expenditure forecasts for the revised proposal.

As a consequence, we have included the changes to the EP Amendment Act 2018 as a nominated pass through event discussed later in chapter 11.

On 9 July 2020, the Australian Energy Markets Commission (**AEMC**) published a final determination and rule which delayed the commencement of the five minute settlement rule and global settlement rule by 3 months, so that they commence on 1 October 2021. The change effectively increased the expenditure we will incur on the project from the current regulatory period into the next one. Whilst it will impact our efficiency performance, in the interests of our customers, we have decided not to pursue the recovery of the additional costs.

4

Poles

4. Poles

4.1 Introduction

Our original proposal forecast our pole replacement requirements in three distinct categories—condition-driven replacements, an incremental risk-based program, and a program to address safety issues with our concrete poles.

Our concrete pole management program was supported by stakeholders and accepted by the AER. In contrast, stakeholders and the AER considered there was insufficient justification for the forecast increase in replacement volumes (reflected in our condition and risk driven forecasts).

In response to feedback from stakeholders, we have not included our incremental risk-driven wood pole replacement program in our revised forecast.

As discussed below, however, we have further tested our pole condition data, and calibrated observed decay rates to match our historical intervention performance over the current regulatory period. Our condition data and decay rate analysis support the increased trend reflected in our condition-driven forecast. In this context, we do not accept the AER's substitute estimate, which was based on an historical average of wood pole expenditure and has no regard to the underlying condition of our wood pole population.

This chapter outlines our response to the draft determination, and further detail on the condition modelling described above is provided in our wood pole condition model.[1]

Our revised proposal forecast for pole interventions is set out in the table below.

TOTAL POLE REPLACEMENT AND REINFORCEMENT EXPENDITURE: 2021−2026 REGULATORY PERIOD ($ MILLION, 2021)

EXPENDITURE	2021/22	2022/23	2023/24	2024/25	2025/26	TOTAL
ORIGINAL PROPOSAL	16.7	17.6	18.4	18.4	19.2	**90.2**
DRAFT DETERMINATION	11.4	11.4	11.4	11.4	11.4	**57.1**
REVISED PROPOSAL	14.2	15.0	15.7	16.5	17.3	**78.7**

Source: United Energy

4.2 What we've heard and how we’ve responded

Our proposed pole management program seeks to meet our safety obligations, as well as community expectations. This program represents a large percentage of our total forecast replacement investment, as well as being an increase on our historical level of investment.

We recognised the value in discussing our proposed investment with our stakeholders. Following our original proposal, we met with key stakeholders, including Energy Safe Victoria, the Victorian Government, Energy Consumers Australia, and the Consumer Challenge Panel. We also presented to the AER Board.

Since the draft determination, we have continued this engagement, including the following:

Chapter 4 photo: Power poles are our most visible assets in he community. We assess the condition of our poles as part of regular asset inspections.

[1] UE RRP MOD 4.07.

4. Poles

- we commissioned external engagement experts, Forethought, to facilitate a workshop to discuss how best to manage and replace poles and wires in the 2021–2026 regulatory period. This workshop included representatives from energy regulators, government, industry bodies, peak bodies and charities
- we presented our wood pole asset management practices and proposed response to the draft determination to our newly established Customer Advisory Panel (with the Consumer Challenge Panel also invited).

A summary of what we have heard from our stakeholders, and how we have responded is provided in the table below.

WHAT WE'VE HEARD	HOW WE'VE RESPONDED
Consumer representatives and the AER considered we have a pole safety record to be proud of, and therefore, saw no justification for our increased program of pole replacements.	We removed our forecast risk-driven pole intervention forecast from our revised proposal. The forecast increase in our wood pole replacement program, therefore, is solely driven by the expected deterioration in condition over the 2021–2026 regulatory period. We have further tested our condition data, and calibrated observed decay rates to match our historical intervention performance over the current regulatory period.
Stakeholders were concerned that findings for Powercor were being applied across our network (noting that different conditions, environmental exposure and failure risks exist).	Risk-driven interventions were the only area of our forecast that had regard to the findings ESV set out in its review of Powercor's wood pole asset management practices, and these have now been removed.
The Victorian Government and ESV supported our increased pole replacement program.	Notwithstanding the removal of our risk-driven intervention program, our condition-driven forecast represents an increase in historical pole intervention volumes.

Source: United Energy

4.3 Our revised wood pole replacement and reinforcement forecast

Our revised proposal forecasts a reduced volume (and therefore expenditure) for wood pole replacements to that included in our original proposal. The reduction in our revised proposal is driven by the removal of our incremental risk-driven replacement program.

For the reasons outlined below, we have maintained our condition-based wood pole intervention forecast, as per our original proposal.

4.3.1 The driver of our intervention volumes is condition, not failure rates

Our inspection regime determines when wood poles need to be repaired or replaced, based primarily on an assessment of the level of 'sound' wood remaining.

Our approach to assessing the condition and intervention (if required) of our wood poles is set out in our asset inspection and pole management manuals. We are required to comply with these practices under our Electricity Safety Management Scheme (**ESMS**), which has been accepted by ESV. Any changes to these practices that would impact the risk profile of our network requires the re-submission of our ESMS.

4. Poles

Our pole inspection and management practices have remained stable since 2010. The criteria under which a pole is categorised as 'unserviceable' has not materially changed, and if a pole is classified as unserviceable, we must intervene on that pole (i.e. we must replace or reinforce the pole). We also intervene on poles assessed as 'limited life'.

In its draft determination, the AER stated that current replacement expenditure reasonably reflects efficient costs to maintain safety and reliability, as demonstrated by very low and falling failure rates. The AER's reasons misrepresent the driver of forecast interventions and/or imply that condition will remain stable, and that failure rates are a reasonable predictor of future intervention volumes.

For the following reasons, we consider that current failure rates are not a robust predictor of future intervention volumes:

- rather than being a leading indicator of intervention volumes, failure rates are better considered a lagging indicator of whether inspection and management practices are adequate to identify a poles condition to ensure we act before failure. For example, robust inspection practices and governance over the application of these methods can drive low failure rates, but if the underlying condition of the relevant asset population is poor and/or deteriorating, high and increasing intervention volumes will still be required
- where failure rates are low relative to the total asset population—such as for wood poles—caution should be taken when drawing conclusions on fluctuations in these failure rates. For example, the draft determination shows our wood pole failure rates relative to intervention volumes since 2009. It is clear from this chart that failure rates have moved independently from intervention volumes. This likely reflects a range of factors, including inspection standards, asset condition, and environmental factors. In any event, had the low failure rates from 2011–2014 been used to forecast pole interventions for the 2016–2020 regulatory period, the resultant forecast would have manifestly underestimated the actual interventions delivered
- the relatively low failure rates we have observed over recent years have supported the continued application of our existing asset management practices. That is, while they may not be a robust predictor of future intervention volumes, they give support that our existing asset management practices have been fit for purpose for our network.

4.3.2 Our intervention forecast is consistent with the expected condition of our wood poles over the 2021–2026 period

Our condition-based pole intervention volumes, including staking, have been forecast based on a nine-year linear trend of historical replacement volumes.

The draft determination, however, considered that using nine years of data was inconsistent with other replacement programs in our unitised model, and did not account for improvements in the performance of our pole population over the nine-year period or expected performance in the forecast period.

We have since tested our condition data, and calibrated observed decay rates to match our historical intervention performance over the current regulatory period. This data shows that by 2025, we will have more poles with less 'sound-wood' in the highly deteriorated categories than we do today. We have attached our condition data and decay rates as part of our revised proposal and discuss the outcomes of this analysis below. [2]

[2] UE RRP MOD 4.07.

4. Poles

The review of our condition data demonstrates that our linear trend approach represents a more reasonable forecast of expected pole intervention volumes than the AER's substitute method (which assumes the level of unserviceable poles will remain unchanged).

4.3.3 Condition data and decay rates: assessment process and findings

We forecast the future expected condition of our wood pole population by applying observed decay rates to our existing wood pole condition data. That is, we took the existing sound wood measurement for each pole as the starting point and subtracted the observed annual decay rate for the relevant poles durability class to determine a forecast of its condition at the end of 2025.

Initially, our assessment of decay rates across our wood pole population indicated annual deterioration in sound wood of between 4–7mm. This assessment also showed that decay rates for lower durability poles were less than for higher durability poles. The magnitude and relativity of these outcomes was counter-intuitive, and suggested further review was required.

Our subsequent review of our wood pole data set found that dummy measurements for some (younger) poles were skewing the results. We also found that condition measurements indicated an increase in sound wood for some poles. As these represent measurement or data issues, these poles were effectively excluded from our analysis.

The revised rates of decay, based on the above changes, were then applied to our existing condition data. These decay rates indicated that an additional 512 unserviceable poles, and 22,255 limited life poles, will exist at the end of 2025 in the absence of any interventions. In the period from 2015–2019, and consistent with our asset management policies, we have intervened on 100 per cent of poles classified as unserviceable and 85 per cent of all limited life poles (noting these interventions are a mix of replacement and reinforcement). On this basis, we would expect to intervene on over 19,000 wood poles over the 2021–2026 regulatory period.

To further assess the veracity of the calculated decay rates, we tested how well these rates would have predicted our intervention volumes over the 2015–2019 regulatory period. This back-cast approach forecast almost 9,000 wood pole interventions over the same period, compared to actual delivered volumes of around 9,327.

Given the above, we calibrated our decay rates for this difference, such that the revised rates forecast our current period behaviour with greater accuracy. The calibrated rates now indicate annual average deterioration rates of around 2.87–3.11mm per annum.

The application of these calibrated decay rates to forecast intervention volumes over the 2021–2026 regulatory period supports intervention on at least 14,531 wood poles.[3] This compares well to our revised proposal forecast of 14,794 condition-based interventions (and demonstrates the AER's substitute estimate is materially under-stated).

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[3] This volume corresponds to the period 2021–2025. It is likely to be conservative, given the regulatory period will span the five-year period finishing six-months later (which given our age profile, would likely include a higher forecast).

4. Poles

4.3.4 Our revised proposal will maintain our existing risk profile

As outlined previously, we consider failure rates provide a lagging indicator of whether inspection and management practices are adequate. That is, they give support that, to date, our existing asset management practices have been fit for purpose for our network.

In this context—that the increase in our pole intervention forecast is not driven by proposed changes to our wood pole inspection or asset management policies—we expect our forecast will maintain the existing risk profile of our wood pole population (all else equal). Therefore, we have not undertaken cost-benefit or risk-monetisation to support increased volumes; we are simply complying with our existing asset management practices.

5

Customer service incentive scheme

5. Customer service incentive scheme

5.1 Introduction

Our research shows while the call answering service remains an essential service for our customers – particularly among our elderly and vulnerable customer groups – this measure alone is a narrow incentive for maintaining and improving customer service performance.

In July 2020, the AER published a new customer service incentive scheme (**CSIS**) guideline. The CSIS is designed to encourage distributors to engage with their customers and, if our customers desire, design alternative measures of customer service to replace the fault call telephone incentive.

Customer service is a vital part of our business. Adopting a new CSIS is a significant opportunity to deliver services our customer's value and want. We have listened and collaborated with our customers from across our networks to design a tailored incentive scheme. We are proud to present a CSIS proposal that reflects what customer service means to our customers. Our detailed CSIS is attached in UE RRP APP01.

The Australian Energy Regulator (**AER**) incentivises us to improve our customer service through the service target performance incentive scheme (**STPIS**). The customer service measure in the STPIS provides rewards or penalties depending on the proportion of fault phone calls we answer in less than 30 seconds.

Our proposed CSIS will..

respond to our customers' changing expectations

deliver the services our customers' want and value

ensure fairness of customer service and access across our different customer groups

5.2 Customer engagement

We have adopted a thorough five stage engagement approach to consult a broad range of customers, providing many opportunities for our customers to shape the scheme design and give feedback. We engaged with 914 customers across three networks CitiPower, Powercor and United Energy as well as our newly formed Customer Advisory Panel (**CAP**), the AER Consumer Challenge Panel (**CCP17**) and Energy Consumer Australia (**ECA**) on what customer service priorities were and the design of our scheme. We engaged independent customer engagement consultants, Forethought, to undertake stages two - four.

5.2.1 Stage one: preliminary research

Stage one of our engagement provided us with preliminary insights on customer service priority areas that we further explored and validated in the next stage of our customer engagement. A summary of our key findings for stage one includes:

- reliability and cost are the key priorities for all customers
- customer service and communication is an area that is key for commercial and industrial customers and becomingly increasingly important for other customers
- increasing communication and transparency, simplifying customer processes and improving customer service was seen as highly or extremely important by approximately over two thirds of residents and over half of businesses
- the level of communication with commercial and industrial customers was thought to be low and they desired a closer relationship, greater understanding of the reasons for power issues and more dialogue and collaboration on capacity and availability of electricity for business planning purposes.

Chapter 5 photo: Research with our customers has shown 55% prefer to receive information about power supplies via SMS or text message, more than double the next highest alternative, email at 20%. This has been factored into planning for the proposed Customer Service Incentive Scheme.

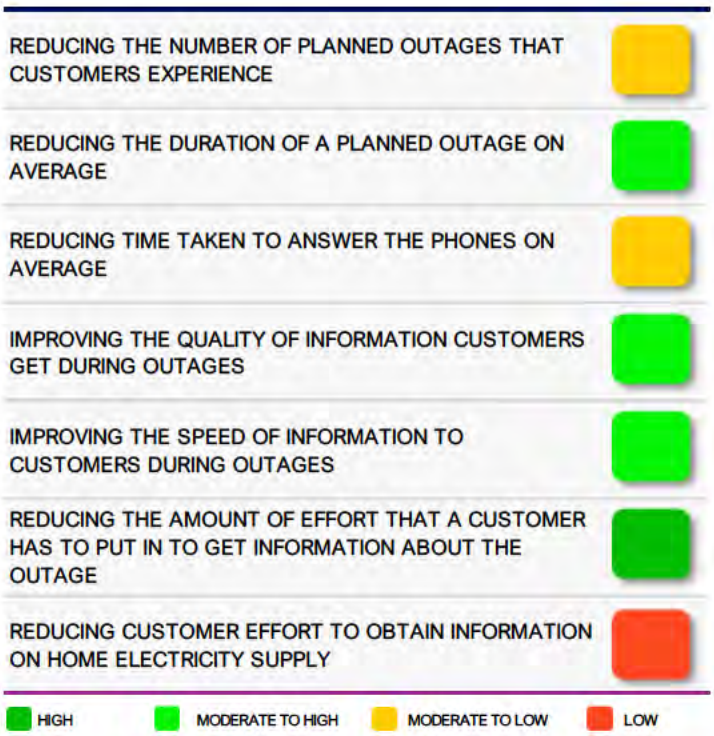
5. Customer service incentive scheme

5.2.2 Stage two: online discussion forums and small business interviews

Stage two of our engagement gave us a strong indication of the current perception customers have of their interactions with us and the value they place on the services we provide.

During the session, customers were provided the opportunity to share where they would focus their attention and investment, on a range of options (or items they identified themselves), in a 'CEO for a day' question.

United Energy customer values for different services



Source: UE RRP ATT01

As shown above:

- quality and speed of information during outages were highlighted as critical elements across all networks
- customers also value reducing planned outages
- customers placed lower value on further improving telephone answering but saw retaining performance as important
- the concept of reducing customer 'effort' did not resonate so much with our customer groups.

These points helped us design and focus the next stage of stakeholder engagement.

5. Customer service incentive scheme

5.2.3 Stage three: quantitative research

Stage three of our engagement gave us a statistically significant quantified evidence of customer preferences and values, ensuring our qualitative feedback reflected views of our wider customer base.

Stage three gave us deep insight into how customers would like to see their customer service priority areas improved including:

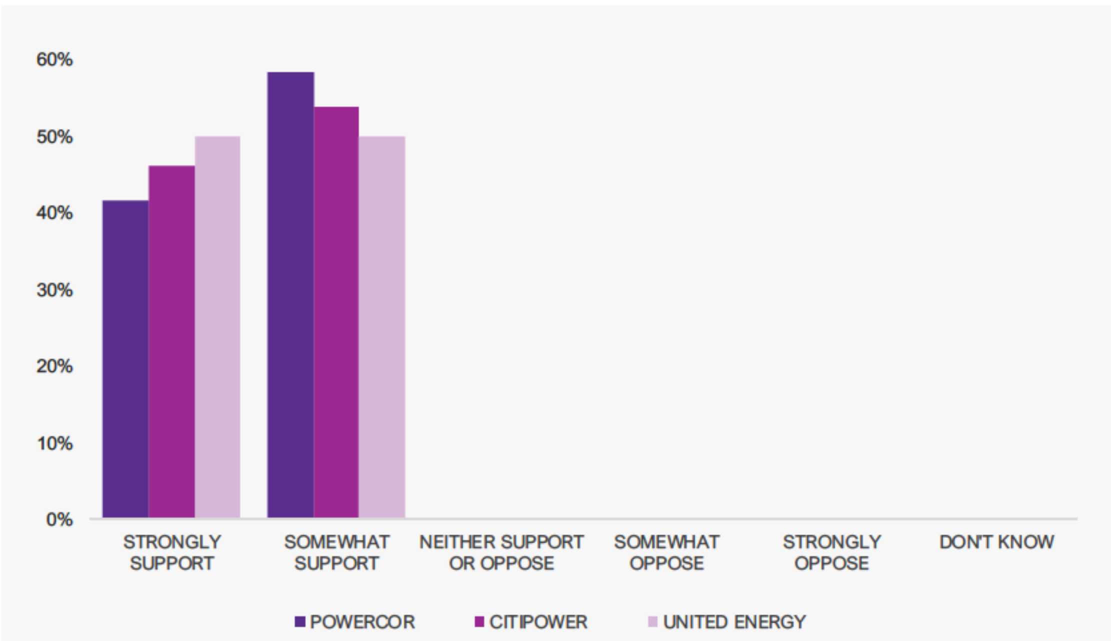
- improving SMS notification, their preferred channel of communication, during an unplanned outage—reflecting the evolution of customer engagement and the adoption of more modern technologies
- reducing planned outages
- telephone calls to the contact centre answered quickly, our customers felt the contact centre was still relevant to them, particularly in emergency situations
- our customers found us easy to deal with across a range of services and thus we did not progress a CSIS design which included an effort score rating as a measure of customer service
- as a result of our engagement program, we developed a CSIS design that included the priority customer service areas our customers identified.

5.2.4 Stage four: customer workshop and C&I interviews on CSIS design

In stage four of our engagement we received overwhelming support for the new proposed scheme from our customers, who were both keen to update the existing scheme and supported the measures we propose to introduce.

The chart below shows all residential customers either strongly supported or somewhat supported us adopting the new incentive for customer service improvements.

WOULD YOU SUPPORT YOUR DISTRIBUTOR ADOPTING A NEW INCENTIVE FOR CUSTOMER SERVICE IMPROVEMENTS OR OPPOSE THE SCHEME?



Source: UE RRP ATT03: Forethought, Customer Engagement Stage four, October 2020.

5. Customer service incentive scheme

Overall, our customers, both residential and commercial and industrial were supportive of the new proposed scheme. Following this session, we had a better understanding of which components of the scheme were most helpful to different customer groups and we were confident that the proposed scheme captured the differing priorities of our diverse customer base. One of our key takeaways from this final workshop with our customers was the phone answering remained a critical safety net for our residential customers. This echoed what we had heard in stage two and three, and we therefore decided to retain the telephone answering parameter.

5.2.5 Stage five: stakeholder feedback

Our final stage of engagement was to test our proposed CSIS with the CCP, ECA and our CAP. We presented a summary of our draft CSIS proposal to these groups.

We received positive feedback on the development of a new scheme and confirmation that the new scheme better meets customer values. These stakeholders also helped us sense-check our proposed incentive metrics, and there was general feedback that they are reasonable. Our CAP unanimously supported the new scheme. They noted it was a natural progression and a step in the right direction and there was consensus that the stakeholder engagement on the program was sufficient.

5.3 Our proposed CSIS

Our customers have told us they place value on a range of services, not only fault call answering. The new scheme will ensure we focus on improving the services customers most value and will set a new bar for service delivery.

Our proposed CSIS focuses on improving customer outcomes and moves us from a one-dimensional customer service scheme to a broad balance of three customer service measures. We are proposing to move to an incentive scheme that measures our performance on the speed and reach of our SMS notifications for customers experiencing unplanned outages, our frequency and duration of planned outages, and the speed of our telephone answering for fault calls.

Our scheme has been tailored to our customer's preferences and priorities, allowing for the evolution of customer engagement and adoption of new technologies. Through continuous and meaningful engagement, we are confident we have our customers' strong support.

SMS notifications for unplanned outages

We are proposing to send our customers an SMS notification within 6 minutes or less from the start of an unplanned outage. We have taken the average performance from Powercor and CitiPower over the most recent 18 months of data to 30 June 2020 to apply a 60 per cent baseline target, shown in the table below. The reason for this is that over the same 18 months period United Energy only sent SMS notifications to 9 per cent of their customers within an 8-minute period during an unplanned outage and only 5 per cent within 6 minutes or less. We have uplifted the target to 60 per cent requiring United Energy to improve its performance to CitiPower and Powercor levels before any incentive commences.

During our stage 2 engagement, customers told us they were interested in the quality of information being improved during an outage and in our stage 3 engagement. To address this, we propose the incentive scheme requires SMS sent are only counted if they contain an ETR, the website for the outage map and the cause (if known).

5. Customer service incentive scheme

Planned outages

We are proposing a performance measurement on reducing frequency and duration of planned outages. Our proposed targets for frequency and duration of planned outages are based on average customer minutes and number of planned outages per annum over July 2015 – June 2020, this will be measured based on System Average Interruption Duration Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**) for planned outages. Setting the targets using this approach is consistent with the AER's STPIS guideline for unplanned outages. These targets are outlined in table below.

We will be incentivised to reduce the average duration and frequency of planned outages. While planned outages remain necessary to ensure the safety and reliability of the electricity network, there is technology available for us to minimise the number of customers affected by each planned outage. These technologies provide a temporary mechanism for keeping customers on supply and include mid-span isolators, back-up generators and bypass cables.

In response to the COVID-19 pandemic we have trialled some of these technologies on our network to minimise the impacts on customers while working from home. We have found these technologies to be safe and effective.

Telephone answering

Under our proposed CSIS, the incentive for us to answer telephones in the contact centre during an outage will still be included and, we will continue to be incentivised to improve the percent of calls answered on our fault lines within 30 seconds.

Customers were supportive of continuing to include telephone answering in our CSIS design. In retaining the telephone answering service, we also recognise the important and essential nature of the telephone service for our vulnerable customers, including elderly or financial hardship customers, and in emergency situations.

Our proposed targets for telephone answering are based on the percentage of calls answered within 30 seconds over July 2015 – June 2020. Setting the targets using this approach is consistent with the AER's STPIS guideline. These targets are outlined in the table below.

CSIS TARGETS AND INCENTIVE RATES

	SMS NOTIFICATIONS	PLANNED OUTAGES	TELEPHONE ANSWERING
BASELINE TARGET	60.26%	73.81 SAIDI 0.23 SAIFI	75.24%
INCENTIVE RATE	0.04	-0.04 SAIDI -9.40 SAIFI	0.04
REVENUE AT RISK	0.15%	0.15%	0.20%

Source: United Energy

6

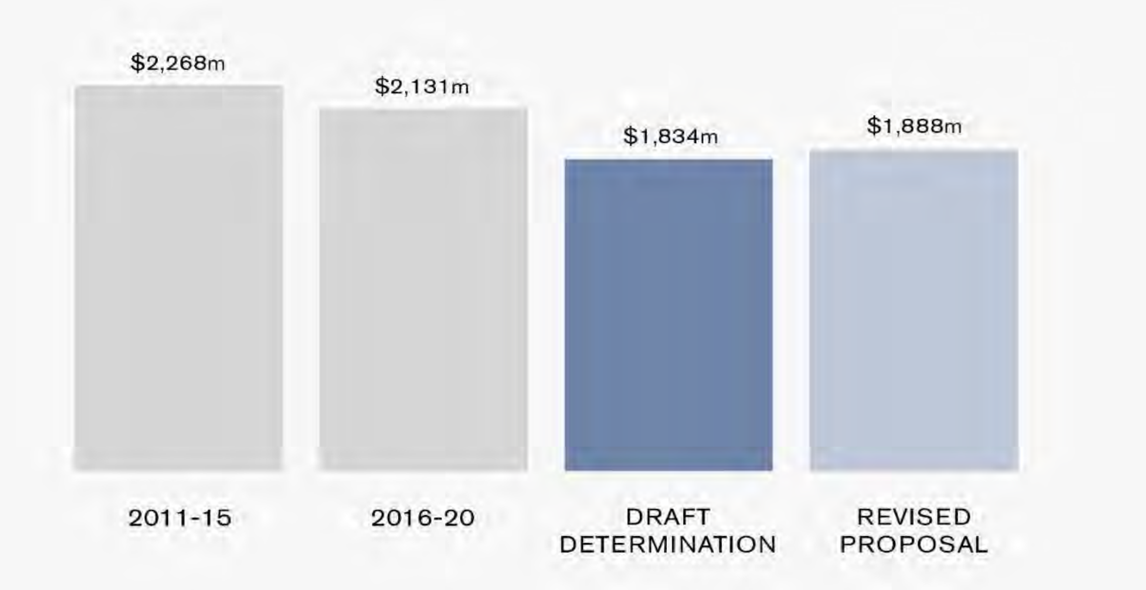
Annual revenue requirement

6. Annual revenue requirement

6.1 Introduction

Our revised proposal continues the trend of the past two regulatory periods, delivering real declines in our revenue requirement which translates to lower prices for our customers. Affordability is important, but so is service. We are proud to say we are also delivering better and safer network services for our customers.

HISTORICAL AND FORECAST REVENUE ($MILLION, 2021)



Source: United Energy

Our revised proposal includes:

- lower capital expenditure, including deferrals of some projects to ensure we are not investing ahead of technological change, the impact of the COVID 19 pandemic and recognising our stakeholders' clear priority for affordability
- an operating expenditure cost base of $712 million (nominal) over the next 5 years, entrenching our National Electricity Market (**NEM**) leading efficiencies generated over the current regulatory period, reduction in previously identified step changes, impact of the COVID-19 pandemic and identification of further cost savings since our original proposal
- adoption of the AER's rate of return instrument and tax methodology.

These measures have contributed to reducing our proposed revenue requirement for the 2016–2020 regulatory period from $2,131 million to $1,888 million ($2021) over the next five years, continuing the trend from the 2011-2015 regulatory period.

Chapter 6 photo: Our customers have become more conscious of energy consumption in heir homes during he COVID-19 lockdowns. Since April 2020, United Energy has offered a network relief package to households and small businesses financially impacted by the extraordinary conditions. This is administered by energy retailers.

6. Annual revenue requirement

6.2 What we've heard and how we've responded

Customer feedback on our original proposal highlighted the need for us to prioritise affordability and target further cost reductions.

By incorporating the feedback from stakeholder submissions on our original proposals, meeting with key stakeholders to discuss their concerns and the targeted review undertaken with wider stakeholder groups and our Customer Advisory Panel (**CAP**) on key issues, we believe we have tailored a revised proposal that better meets stakeholder needs and is preferable to the draft determination.

Our revised proposal applies the AER's 2018 rate of return instrument (**RORI**)[4] and the 2018 Tax Review Final Decision.[5] These decisions have contributed to lower revenues and lower network prices.

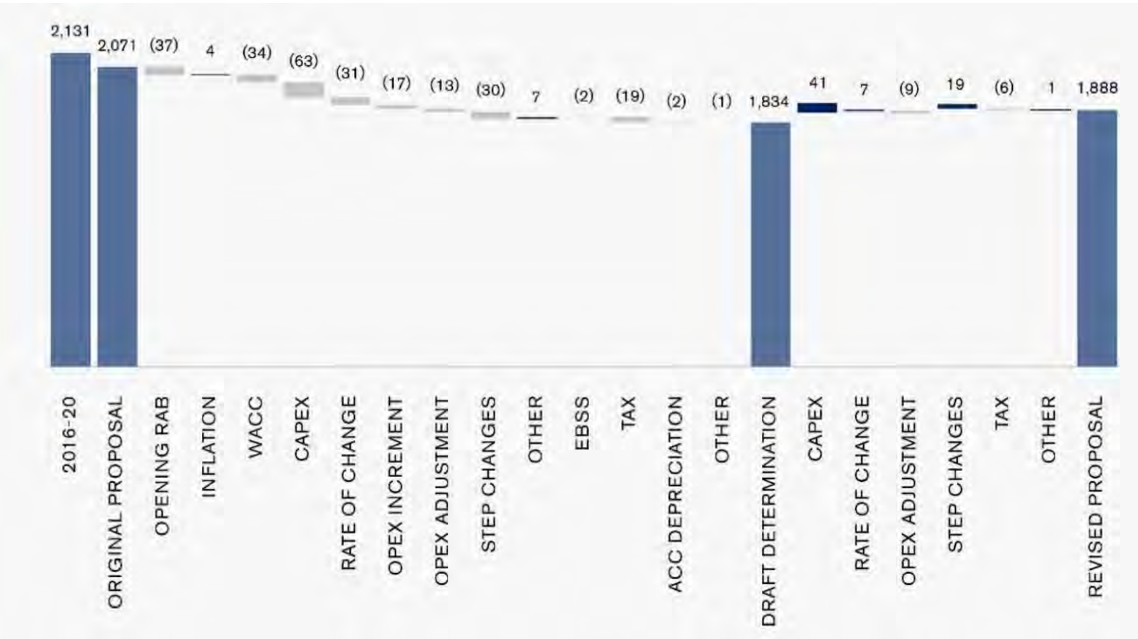
The draft determination sought additional information on both our operating and capital expenditure allowances. We have provided supporting information as requested or accepted the draft determination where appropriate. These matters are covered in chapters 8 and 9.

6.3 Our revised proposal maintains our customers paying the lowest network charges in the country

Our revised revenue requirement reflects the changes made to our expenditure forecasts, updated rate of return parameters, responses to stakeholder feedback and updated analysis. The building block components are discussed throughout the chapter.

To assist our stakeholders, below is a waterfall chart that summarises the differences between the draft determination and our revised proposal revenue requirement.

REVENUE ($MILLION, 2021)



Source: United Energy

[4] AER, *Rate of return instrument*, December 2018
[5] AER, *Final report, Review of regulatory tax approach*, December 2018

6. Annual revenue requirement

Below we present the breakdown of our revised proposal revenue requirement.

BUILDING BLOCKS ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
RETURN ON ASSETS	111.5	114.4	114.4	113.2	111.6
REGULATORY DEPRECIATION	85.4	102.8	113.8	124.2	134.9
OPERATING EXPENDITURE	145.8	146.9	152.0	157.3	163.0
EBSS CARRYOVER	28.8	32.2	13.8	-1.1	-
CESS	10.2	10.4	10.7	10.9	11.2
SHARED ASSETS REVENUE ADJUSTMENT	-1.0	-1.0	-1.0	-1.0	-1.1
DMIA REVENUE	0.5	0.5	0.5	0.5	0.5
TAX ALLOWANCE	1.1	0.8	0.6	3.6	4.3
ANNUAL REVENUE REQUIREMENT	**382.3**	**407.1**	**404.8**	**407.6**	**424.4**

Source: United Energy
Note: Numbers may not sum due to rounding

6.4 Why is the regulatory asset base still climbing?

The draft determination accepted our proposed opening regulatory asset values.

REGULATORY ASSET BASE ($MILLION, NOMINAL)

OPENING RAB AT 1 JANUARY 2016	**2,083.0**
ADD: TRUE-UP FOR 2015 CAPEX	-11.7
ADD: ACTUAL/ESTIMATED NET CAPEX	876.9
LESS: FORECAST STRAIGHT LINE DEPRECIATION	-746.1
ADD: ADJUSTMENT FOR ACTUAL INFLATION	208.5
OPENING RAB AT 1 JULY 2021	**2,410.7**

Source: United Energy
Note: Numbers may not sum due to rounding

The draft determination did not however accept our forecast RAB for the 2021–2026 period and calculated a revised allowance that:

- reduced our forecast capital expenditure for the 2021–2026 regulatory period
- updated expected inflation
- reduced straight line depreciation as a consequence of reduced forecast capital expenditure.

6. Annual revenue requirement

Our revised proposal differs from the draft determination. We have not accepted the draft determination capital expenditure allowances and have instead substituted them with a revised set of forecasts developed in conjunction with our stakeholder feedback and/or technical/economic assessments that contradict the draft determination. The revised capital expenditure forecasts have a flow on effect to depreciation. We have accepted the updated inflation rate (though we expect this to be updated for the outcome of the AER's current inflation review).

FORECAST REGULATORY ASSET BASE ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
OPENING RAB	**2,410.7**	**2,565.3**	**2,664.7**	**2,740.9**	**2,814.4**
FORECAST NET CAPITAL EXPENDITURE	240.0	202.2	190.0	197.7	190.1
STRAIGHT LINE DEPRECIATION	-142.6	-163.7	-177.0	-189.3	-201.7
INFLATION ON OPENING RAB	57.2	60.9	63.3	65.1	66.8
CLOSING RAB	**2,565.3**	**2,664.7**	**2,740.9**	**2,814.4**	**2,869.6**

Source: United Energy
Note: Numbers may not sum due to rounding

In accordance with clause S6.2.1e(4) of the National Electricity Rules (**NER**), and our revised cost allocation method, the RAB only includes actual and estimated capital expenditure properly allocated to the provision of standard control distribution services.

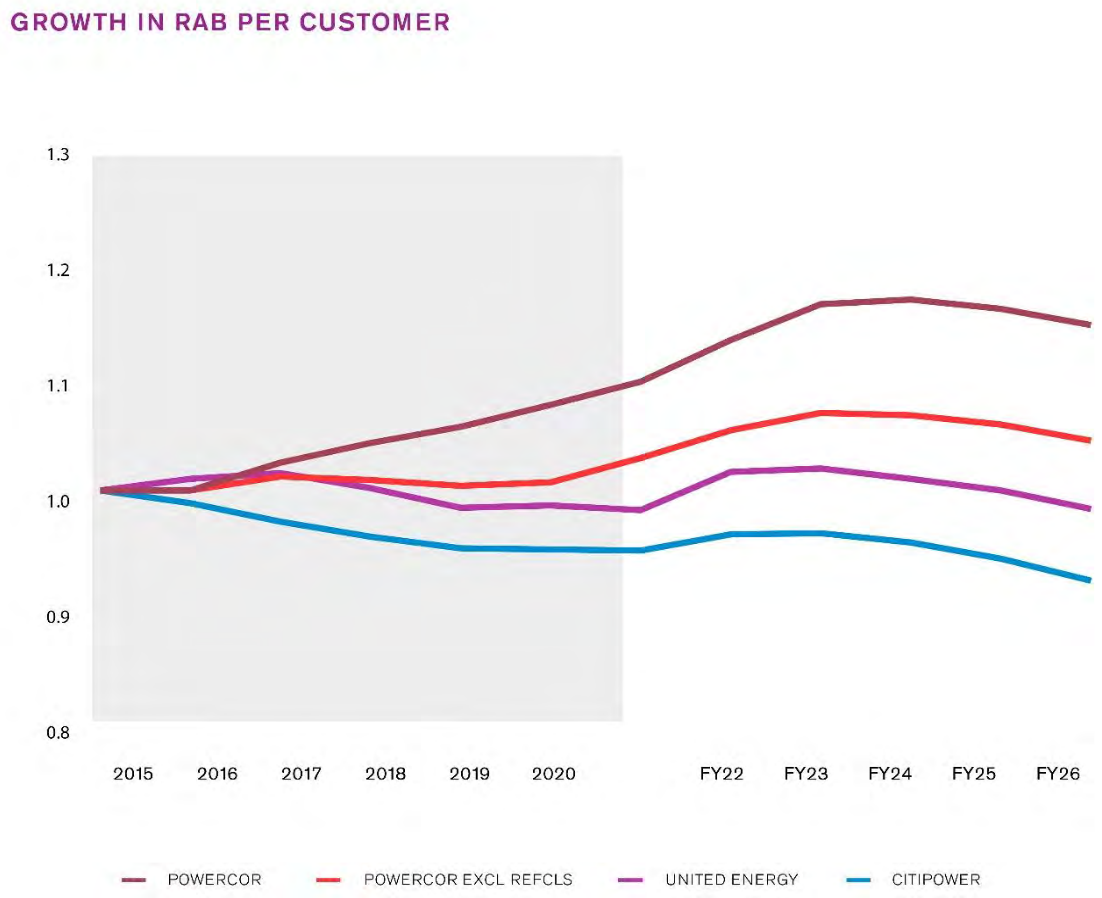
Many stakeholder submissions have focused on RAB as an important metric in considering distributor proposals and that negative RAB growth is considered a positive attribute of a proposal. We take a different view on this.

There is no definitive way to measure an efficient RAB or efficient investment. A good starting point however is to consider usage. Usage is an indicator of the value customers place on network assets and how that value has changed through time. A sustainable rate of RAB growth would be one that tracks in line with usage of the network, whether that is consumption or export.

Usage is not a direct determinant of costs. A 5 per cent increase in maximum demand or customer numbers will rarely translate directly to a 5 per cent increase in the RAB. Even so, growth in use should serve as the upper bound for asset growth. This is because real asset growth greater than network usage over the longer term will not lead to affordable outcomes for customers. Over time, customers would spend more of their income on network services and eventually be unable to afford grid-based electricity and find alternatives. A distributor would suffer as a consequence as customers looked elsewhere for their electricity services.

If a distributor's assets are growing at the same rate as its customer base, then the cost per customer remains constant. If customers' increase usage of the network increases, particularly at peak times, then it is reasonable that customers pay more for the increased costs they are placing on the grid. Note again usage is based on not only consumption but increasingly export.

6. Annual revenue requirement



Source: United Energy

While we have continued to experience positive RAB growth and have forecast to do so over the forecast period, that growth has more or less tracked growth in demand and customers reflecting the relatively strong growth of the Victorian economy, and strong migration into Melbourne.

There are also exogenous drivers of RAB growth outside of customer and demand growth. We have been required to undertake a number of compliance-based obligations over the past 10 years related to advanced metering infrastructure (**AMI**), meter contestability and 5-minute settlement. These costs are unrelated to network usage but have been determined necessary by the Victorian Government and the Australian Energy Markets Commission (**AEMC**) the to realise future efficiencies or to enhance community safety.

An emerging driver of RAB growth has been the facilitation of distributed energy resources (**DER**) integration. DER does not add to customer numbers, demand or consumption but rather reduces demand and consumption (through the netting of exports from consumption). Integration of DER still however requires investment. How DER integration investment is managed and recovered remains subject to reviews such as the Network Planning and Access for Distributed Energy Resources rule change being undertaken by the AEMC. Reviews such as these illustrate the RAB growth debate is not a simple one, and the proposition that negative RAB growth is a positive for customers is not necessarily correct.

6. Annual revenue requirement

6.5 Using the AER approach to return on capital

The draft determination did not accept our regulatory allowance for the return on capital because of the consequential impact of the draft determination on our RAB and our capital expenditure forecasts for the next regulatory period.

Our revised proposal rate of return has been prepared consistent with the 2018 RORI. Our revised proposal rate of return parameters are shown below.

RATE OF RETURN PARAMETERS

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
AVERAGE NOMINAL RATE OF RETURN	4.54%	4.29%	4.29%
RETURN ON EQUITY	4.98%	4.59%	4.59%
AVERAGE RETURN ON DEBT	4.24%	4.10%	4.10%
GEARING	60%	60%	60%
GAMMA	0.585	0.585	0.585

Source: United Energy
Note: Numbers may not sum due to rounding

On 3 November 2020 the Reserve Bank of Australia (**RBA**) announced that it was embarking on a market intervention to reduce government bond yields below the level that would otherwise have been set in the market. Bond yields were already at historic lows before this announcement. The impact will be to artificially reduce the return on equity calculated under the 2018 RORI. Frontier Economics (UE RRP ATT58) shows that return on equity calculated under the 2018 RORI is lower than recent allowances of comparable regulators. This same conclusion was reached in the recent Brattle report commissioned by the AER.

Frontier Economics sets out the implications of this artificially low return on equity for the benchmark business which include unsustainable negative cash return on equity, unsustainable negative net profit after tax and unsustainable credit rating metrics. Frontier Economics calculate that if the AER applied an inflation forecast of 1.95 per cent in the final determination, the above implications would only be partially mitigated but all three elements would remain unsustainable. This potentially has implications for how the Victorian networks are operated over the next few years.

It may not be in the AER's power to depart from the 2018 RORI for return on equity. However, it is in the AER's power to at least provide an unbiased forecast of the inflation that will be applied in their RFMs over the next regulatory period. The AER applies one-year lagged inflation in the RFMs in Victoria. This means that the inflation that will be applied for the first year of the next regulatory period will be the difference between the December 2020 CPI and the December 2019 CPI. This will be known prior to the final determination. The RBA inflation forecasts for calendar years 2021 and 2022 will match the periods from which actual inflation will be taken for the RFMs in years two and three. We urge the AER to provide unbiased inflation forecasts in the PTRM so as not to further exacerbate the artificially low return on equity.

6. Annual revenue requirement

6.6 And we used the AER approach to tax

The estimated cost of corporate income tax for each year of the 2021–2026 regulatory period have been calculated using the AER's PTRM. The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the AER's RFM. The standard tax asset lives are consistent with the Australian Tax Office (**ATO**) rulings.

We have forecast immediately deductible capital expenditure based on the average actual amount of immediately deductible capital expenditure claimed over the 2016–2019 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. The estimated cost of corporate income tax is shown below.

FORECAST TAX ALLOWANCE ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
ESTIMATED COST OF CORPORATE INCOME TAX	1.1	0.8	0.6	3.6	4.3

Source: United Energy
Note: Numbers may not sum due to rounding

6.7 Setting our regulatory depreciation allowance

The draft determination did not accept our regulatory depreciation allowance due to the consequential impacts of it not accepting our forecast capital expenditure or expected inflation assumption. The AER did however accept our proposed asset classes, the use of straight-line depreciation method and standard asset lives. We have maintained these aspects of our original proposal.

For the revised proposal we have updated our regulatory depreciation allowance to reflect our revised capital expenditure forecasts and inflation assumption.

A summary of our proposed regulatory depreciation allowance presented below.

REGULATORY DEPRECIATION ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
STRAIGHT LINE DEPRECIATION	142.6	163.7	177.0	189.3	201.7
LESS: INFLATION ADJUSTMENT	57.2	60.9	63.3	65.1	66.8
REGULATORY DEPRECIATION	**85.4**	**102.8**	**113.8**	**124.2**	**134.9**

Source: United Energy
Note: Numbers may not sum due to rounding

6. Annual revenue requirement

6.8 Sharing the benefits of efficiency with our customers

Incentive schemes are an important component of our revenue requirement. These include the efficiency benefits sharing scheme (**EBSS**), capital efficiency sharing scheme (**CESS**), demand management innovation allowance (**DMIA**) and an adjustment for the use of shared assets.

The CESS, EBSS and shared asset schemes all involve a splitting of efficiency gains between customers and ourselves. The amounts are added to the revenue allowance. For the CESS and EBSS, these benefits are split roughly 70:30, with our customers receiving 70 per cent of the benefits. For shared assets, when our annual unregulated revenue from shared assets is greater than 1 per cent, then 10 per cent of the forecast unregulated revenue earned is returned to customers.

We have also accepted all other aspects of the incentive scheme adjustments in the draft determination.

The DMIA provides us an incentive to explore demand management alternatives to network capital investments. It is provided as a fixed annual allowance in the form of additional revenue. The draft determination chooses to apply the DMIA without modification to our original proposal. We accept this decision.

SHARED ASSET REVENUE REDUCTION ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
FORECAST UNREGULATED REVENUE FROM SHARED ASSETS	10.2	10.2	10.2	10.2	10.2
SMOOTHED REVENUE (PRIOR TO SHARED ASSET REDUCTION)	387.5	396.6	406.0	415.7	425.5
MATERIALITY PERCENTAGE	2.6%	2.6%	2.5%	2.4%	2.4%
SHARED ASSET REVENUE REDUCTION	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**

Source: United Energy

6.9 The 'bottom line'

The revenue allowance arising from regulatory decisions can sometimes vary between years within a regulatory period. Minimising price volatility has been identified by our customers as a priority. To ensure we can meet that priority, we have applied revenue smoothing via a price adjustment mechanism within the PTRM.

The smoothed revenue and X factor profile have been calculated using the AER's PTRM and ensure our proposed smoothed revenues are equal to the required revenues in net present value terms.

ANNUAL REVENUE REQUIREMENT ($MILLION, NOMINAL)

	FY22	FY23	FY24	FY25	FY26
ANNUAL REVENUE REQUIREMENT	382.3	407.1	404.8	407.6	424.4
"SMOOTHED" ANNUAL REVENUE REQUIREMENT	386.5	395.7	405.1	414.7	424.6
X-FACTORS	**20.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

Source: United Energy

6. Annual revenue requirement

6.10 X factors for years 2 to 5

The draft determination has goal sought X factors for years 2 to 5 to achieve 3 per cent less smoothed revenue in the final year of the regulatory period compared with the building blocks. This results in a smaller price reduction in 2021/22, but a small real decrease in prices in the subsequent four years of the regulatory period compared to having zero percent X factors.

We propose the X factors for years 2 to 5 be set to zero per cent. This is because:

- customer and stakeholder groups preferred a full price reduction in first year to help manage hardship and stimulate growth through the COVID-19 recovery period
- under the draft determination, the small price reduction in 2021/22 will be eroded due to STPIS revenue to be received in 2021/22
- a larger price decrease on 1 July 2021 reduces the immediate bill impact for customers who may be adversely affected by changes in the Tariff Structure Statement from 1 July 2021
- it better aligns annual smoothed revenue with annual revenue requirement
- all else being equal, under the draft determination revenue profile there would need to be a 3 per cent revenue increase on 1 July 2026
- the revenue increase on 1 July 2026 is likely to be larger than 3 percent because the rate of return is likely to have returned to more normal levels.

6.11 Control mechanisms

We accept the draft determination control mechanisms except for a minor amendment we propose for standard control services. These are:

- the inclusion of customer service incentive scheme (**CSIS**) as a further component of incentive scheme adjustments (**It**). Chapter 5 explains how CSIS revenue adjustments will be calculated. We propose that the CSIS adjustment be applied with a two-year lag to performance which would mean that the CSIS adjustments would only commence in 2023-24
- the recovery of Energy Safe Victoria (**ESV**) levies and Australian Energy Market Operator (**AEMO**) fees as further components of the L-factor operating similarly to the recovery of Essential Service Commission of Victoria licence fees
- an explicit statement that a distributor can choose to defer recovery of revenue relating to an under-recovery in 2020 (due to the COVID-19 pandemic) by up to four years to assist in smoothing distribution tariffs.

7

Capital investment

7. Capital investment

7.1 Total capital investment

Our revised capital investment forecast responds to the concerns raised by stakeholders and the AER in response to our original proposal. This includes written feedback from stakeholder submissions, and ongoing discussions as part of our commitment to continue engaging on key issues such as our asset management practices, and the delivery of our future network and customer enablement programs.

We recognise the significant effort from the many stakeholders that have helped inform our revised capital investment forecast, particularly in the challenging environment of COVID-19 restrictions. The impact of the COVID-19 pandemic has been reflected in our revised forecasts, in addition to the changes being driven by continued technological advances and the ageing of our network infrastructure.

Our revised capital investment forecast is set out in the figure below. For the reasons discussed below in this chapter, we consider this investment will allow us to keep our network affordable, resilient and flexible for our customers.

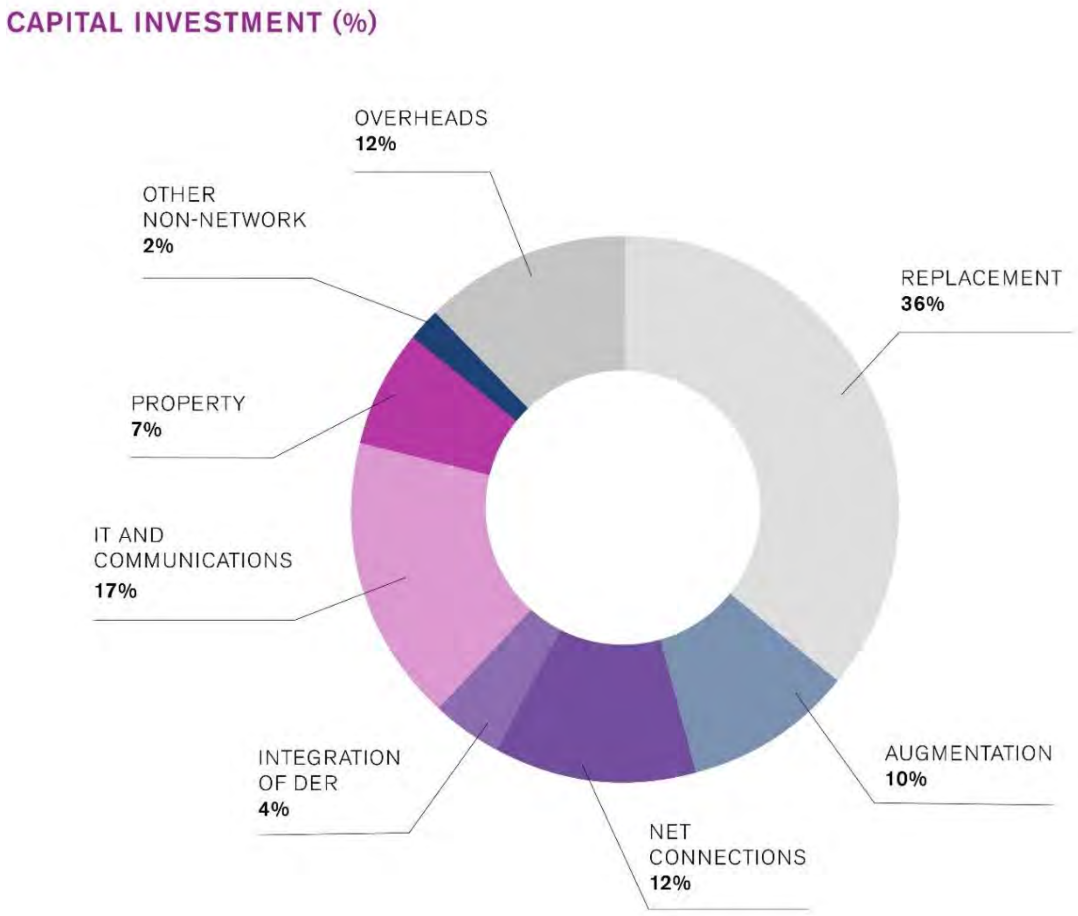
CAPITAL INVESTMENT ($MILLION, 2021)

				REVISED PROPOSAL % CHANGE FROM	
	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL	ORIGINAL PROPOSAL	DRAFT DETERMINATION
REPLACEMENT	420.1	304.4	344.4	-18%	13%
AUGMENTATION	129.7	88.6	96.1	-26%	8%
NET CONNECTIONS	129.3	99.3	114.2	-12%	15%
INTEGRATION OF DER	71.3	39.3	39.7	-44%	1%
IT AND COMMUNICATIONS	174.1	154.1	164.2	-6%	7%
PROPERTY	69.8	47.2	67.9	-3%	44%
OTHER NON-NETWORK	15.6	14.4	14.4	-8%	0%
OVERHEADS	120.4	91.6	108.1	-10%	18%
TOTAL	**1,130.3**	**838.8**	**949.0**	**-16%**	**13%**

Source: United Energy
Note: Forecast shown includes real escalation

Chapter 7 photo: Electrical services are required to support the Victorian Government's Level Crossing Removal Project which is removing 75 dangerous and congested crossings across Melbourne by 2025. Many like this one in Edithvale, are within the United Energy network.

7. Capital investment



Source: United Energy

7. Capital investment

7.1.1 Investing to keep the network affordable, resilient and flexible

Our capital investment program is focused on delivering on our customer's priorities: affordability, resilience, flexibility. These investments allow us to provide long-term benefits for the many ways our network supports our customers.

Source: United Energy

7. Capital investment

7.1.2 What we've heard and how we've responded

Much of our capital expenditure program was supported by our stakeholders, and the AER in its draft determination. We heard, however, that further work was required to better demonstrate the need for particular investments, and to better balance the priorities identified by our customers (including limiting growth in our regulatory asset base (**RAB**).

As part of our commitment to ongoing stakeholder engagement, we have continued to listen and respond to our customers in developing our revised proposal.

	WHAT WE'VE HEARD	HOW WE'VE RESPONDED
RAB GROWTH	RAB growth has been increasing over recent regulatory periods, and there is a strong case for approaching capital as a finite resource, asking at every point 'what impact will this expenditure have in affordability for all customers over the longer term?'	While we have continued to experience positive RAB growth and have forecast to do so over the 2021–2026 regulatory period, that growth has largely tracked demand and customer numbers. This reflects the strong growth of the Victorian economy, and strong migration into Melbourne. Our RAB growth also reflects the impact of compliance obligations (including smart meters), and increasingly, the facilitation of distributed energy resources (DER) integration. Our capital governance framework will continue to play a critical role in ensuring any capital investment is tested rigorously.
FORECASTING BIAS	The cycle of distributors underspending against their allowance, then forecasting increased capital requirements the following period, needs to be closely scrutinised.	Our capital investment forecast has been reduced and is now more consistent with historical trends. This forecast has regard to the challenges associated with the impact of the COVID-19 pandemic and continued rapid change in the technological landscape.
REPLACEMENT	Asset replacement is the major driver of capital investment, and close scrutiny of replacement expenditure proposals, particularly poles, is a high priority. It is in customers' interests that replacement expenditure does not follow a boom-bust cycle.	Our revised replacement forecast is lower than that included in our original proposal, such that forecast replacement investment is now consistent with longer-term historical trends (i.e. our revised forecast is equivalent to that for the 2016–2020 regulatory period). We have also removed our forecast risk-driven pole intervention forecast from our revised proposal, and better tested our forecast trend in condition-driven pole intervention against our observed historical performance.
AUGMENTATION	Recent economic circumstances brought on by the global COVID-19 pandemic will impact economic growth, particularly in the short-medium term and is likely to have wide ranging impacts on networks' investment requirements.	We recognise the impact of the COVID-19 pandemic, including on forecast demand (which is a key driver of traditional augmentation). Our original forecast was prepared pre-COVID-19, and as there is now more uncertainty in the market, we have accepted the AER's draft determination (which represents a 29 per cent reduction on our original proposal).

Source: United Energy

7. Capital investment

	WHAT WE'VE HEARD	HOW WE'VE RESPONDED
INTEGRATION OF DER	While strong consumer support exists for accommodating significant growth in DER, it may be prudent for the level of investment to meet DER growth to be reduced slightly, prioritised and staged, with less focus on physical network augmentation.	We have accepted the draft determination to scale down our solar enablement program by 69 per cent. We will continue to target the sites where we can facilitate the most DER within this scaled down program.
CONNECTIONS	Customers expect us to adopt a conservative approach to forecasting connections as a result of COVID-19 pandemic, and do not support cost increases to cross-subsidise others' connection activities.	Our observed connections growth has remained strong in 2020. However, we have accepted the draft determination to use the Housing Industry Association (HIA) index (for residential connections only). For new connections, we query whether the AER's proposed changes to our connection policy are fair for our customers.
INFORMATION TECHNOLOGY AND COMMUNICATIONS	Capital investment on non-network assets, in particular ICT, has accelerated over recent regulatory periods, and continues at historically high levels. Consumers remain concerned at the way ICT investment has become a larger proportion of the overall capital investment.	We have accepted the draft determination on our recurrent ICT expenditure, and have re-scoped our customer enablement initiative with our newly established Customer Advisory Panel.
NON-NETWORK (PROPERTY, FLEET AND TOOLS)	The AER and its consultants, EMCa, did not support the need to upgrade our Burwood and Keysborough depots on the basis of reducing the assumptions in our benefits model.	We have revised our property forecasts to reflect new information requiring the relocation of our Burwood depot, and provided additional supporting evidence to respond to concerns regarding our benefits modelling. We have accepted the draft determination on our fleet and tools expenditure.

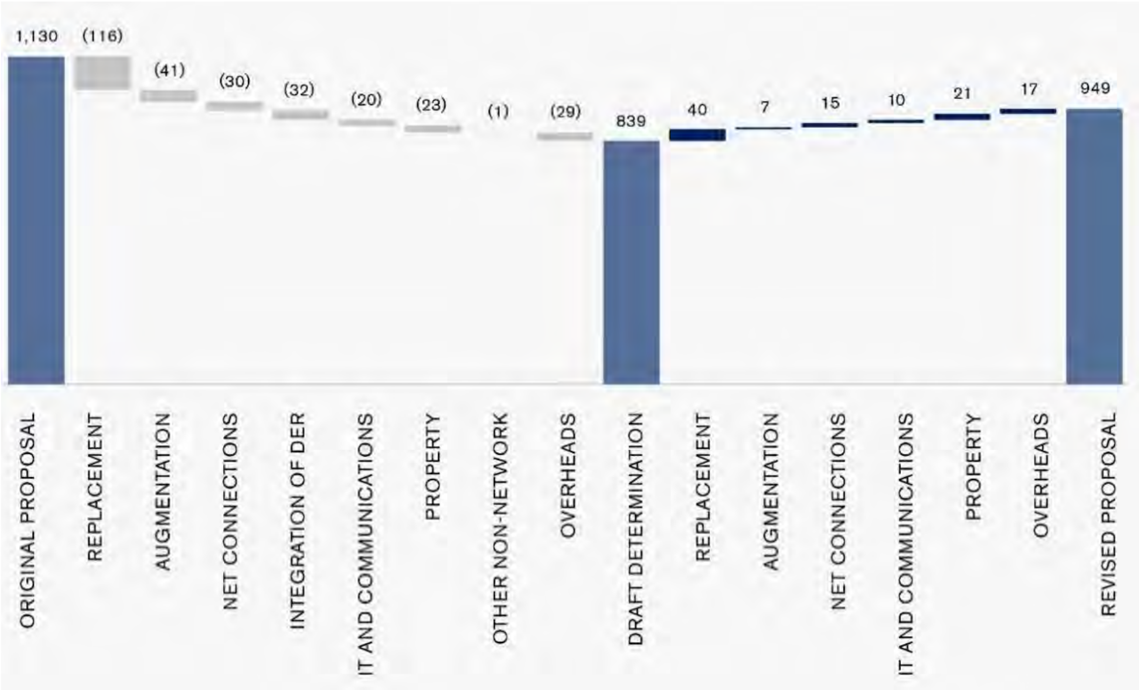
Source: United Energy

7. Capital investment

7.1.3 We have revised our capital investment forecast down

In total, our revised capital expenditure forecast represents a $181 million or 16 per cent reduction on our original capital expenditure proposal. These changes are set out below.

CHANGE IN CAPITAL INVESTMENT ($MILLION, 2021)



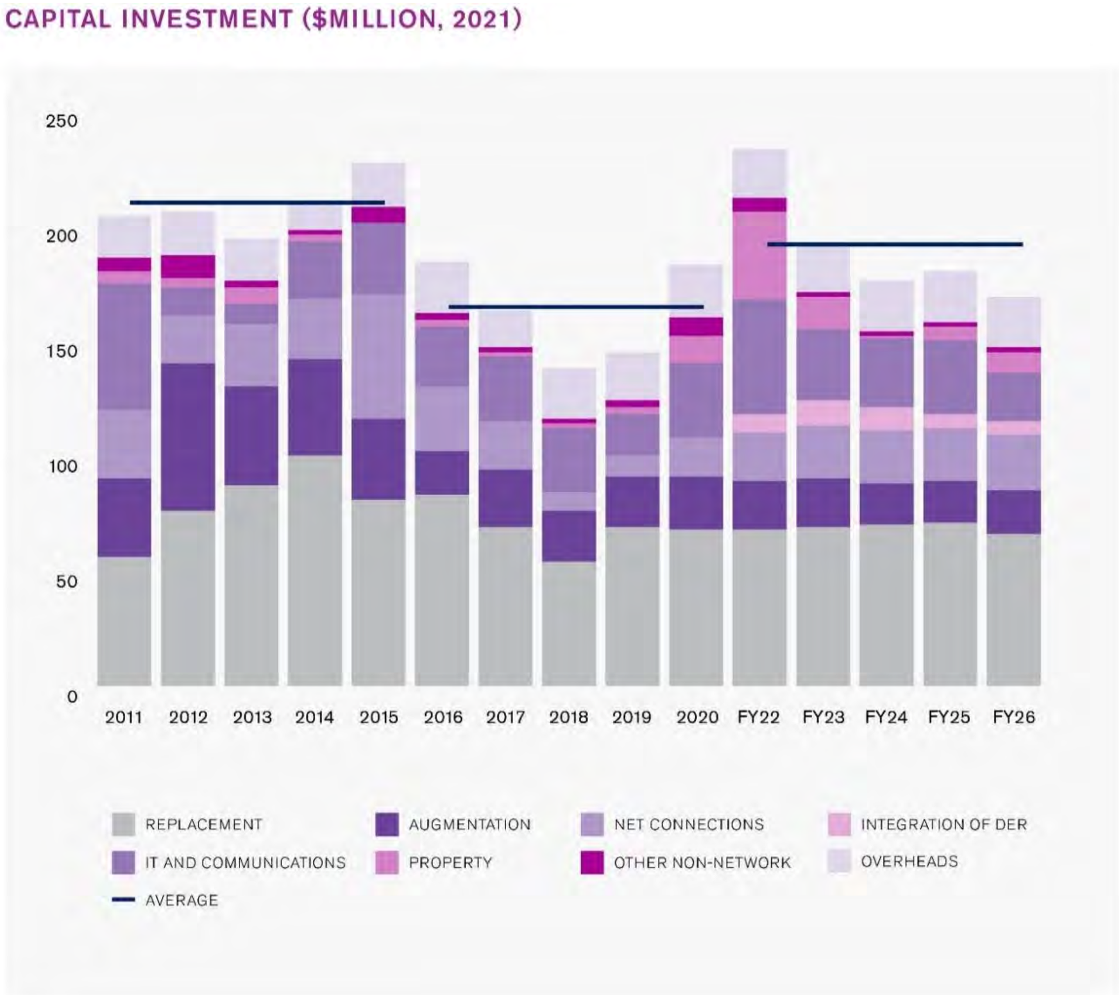
Source: United Energy

7.1.4 Our revised capital investment forecast is consistent with historical trends

We transitioned to a risk-based asset management approach in the 2016–2020 regulatory period, and achieved cost reductions through applying our stringent capital governance framework, and sharing services with our CitiPower and Powercor networks (noting that large parts of our business will continue to operate independently). These changes provided a robust platform for future success—it helped us keep our prices lower than our peers (in Victoria and other jurisdictions), while still delivering strong safety and reliability outcomes.

In the current environment, however, our stakeholders have cautioned about the impact of the COVID-19 pandemic and the continued rapid change in the technological landscape. Our revised proposal balances these risks, and while some asset categories will continue to be lumpy in their investment profile (as is the nature of large capital infrastructure), our revised capital expenditure forecast is now more consistent with longer-term historical trends. This is shown the following chart.

7. Capital investment



Source: United Energy

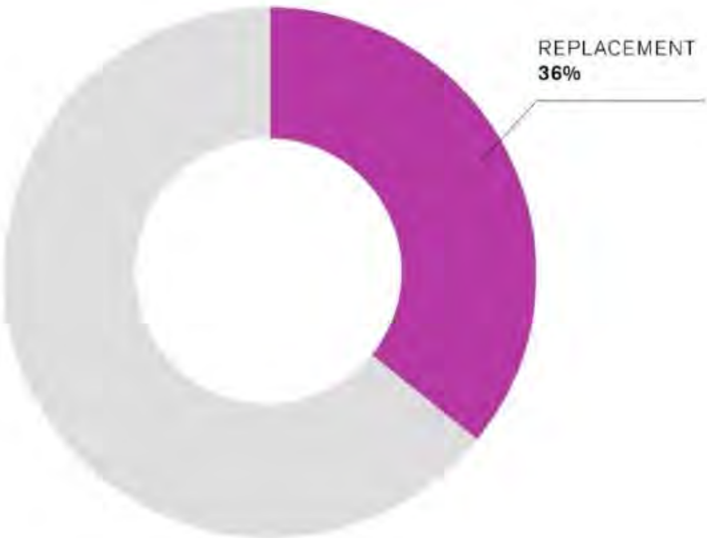
Notes: 2020 is first forecast year. Forecasts include real escalation.

7. Capital investment

7.2 Replacement

Our asset replacement program includes investments required as the condition of our network infrastructure deteriorates over time, and to ensure we continue to meet our network safety, reliability, bushfire mitigation and environmental obligations. This investment represents the largest component of our total capital requirements for the 2021–2026 regulatory period (see chart below).

REPLACEMENT AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26



Source: United Energy

As shown in the table below, our revised asset replacement forecast is lower than that included in our original proposal. Our forecast, however, is higher than the draft determination.

REPLACEMENT INVESTMENT ($MILLION, 2021)

	TOTAL
ORIGINAL PROPOSAL	420.1
DRAFT DETERMINATION	304.4
REVISED PROPOSAL	344.4

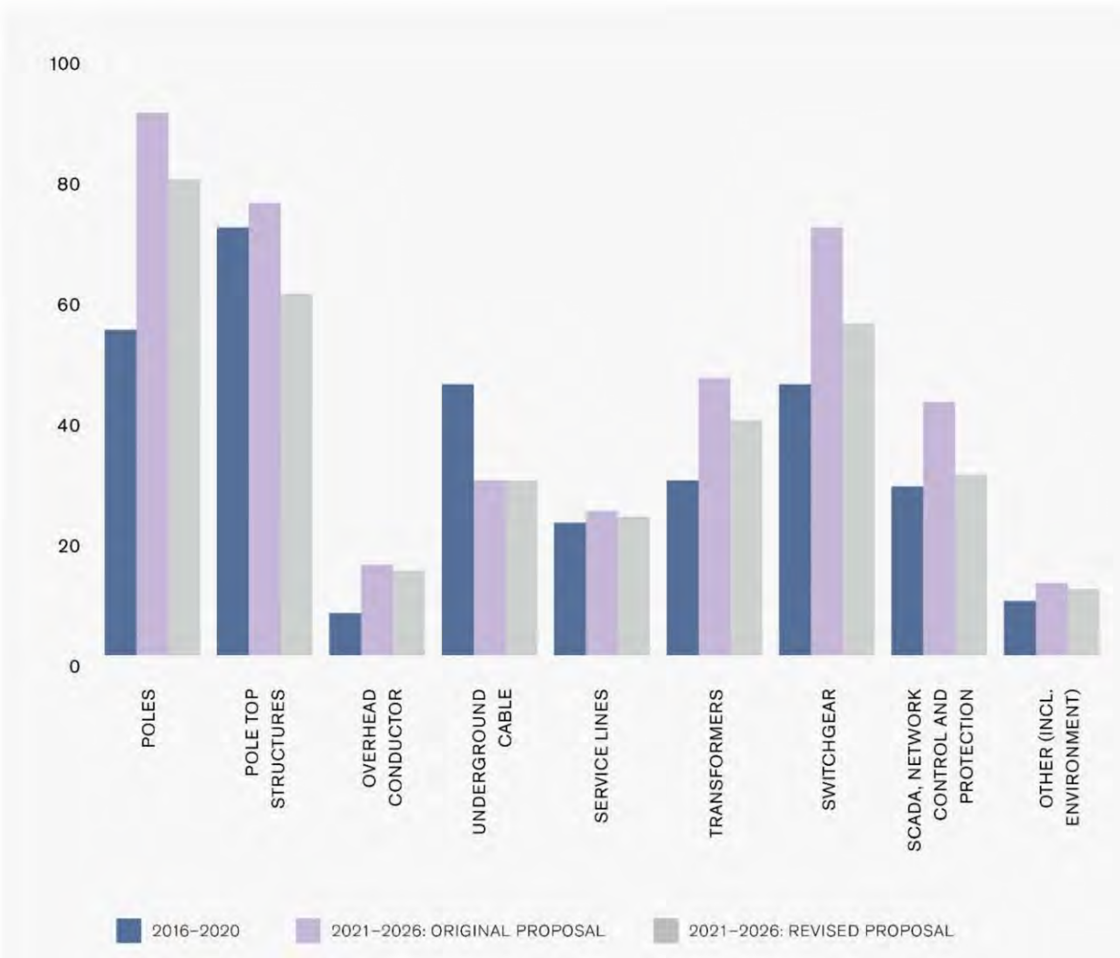
Source: United Energy

Notes: Our original proposal represents the capital expenditure assessed by the AER. For example, it does not include our forecast increase in response to new environmental obligations, as we subsequently withdrew this component of our forecast. Forecast shown includes real escalation.

7. Capital investment

The changes in our revised proposal, by asset category, are also shown in the chart below. We have accepted the draft determination for most categories, and as a result, our revised forecast is lower than or consistent with our investment over the 2016–2020 regulatory period. For the reasons discussed further in this chapter, our revised forecasts for wood poles, zone substation transformers, and service lines better represents the investment required to continue to deliver the level of service and safety that our customers expect.[6]

HISTORICAL AND FORECAST REPLACEMENT INVESTMENT BY RIN CATEGORY ($ MILLION, 2021)



Source: United Energy
Note: Forecast shown includes real escalation

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[6] A portion of our zone substation transformer replacement works are allocated to underground cables, switchgear, SCADA and other categories. This reflects the scope of works undertaken. We have accepted the AER's underlying draft decision for these categories, noting that the slight increase is simply a 'flow-on' impact from our revised zone substation transformer forecast.

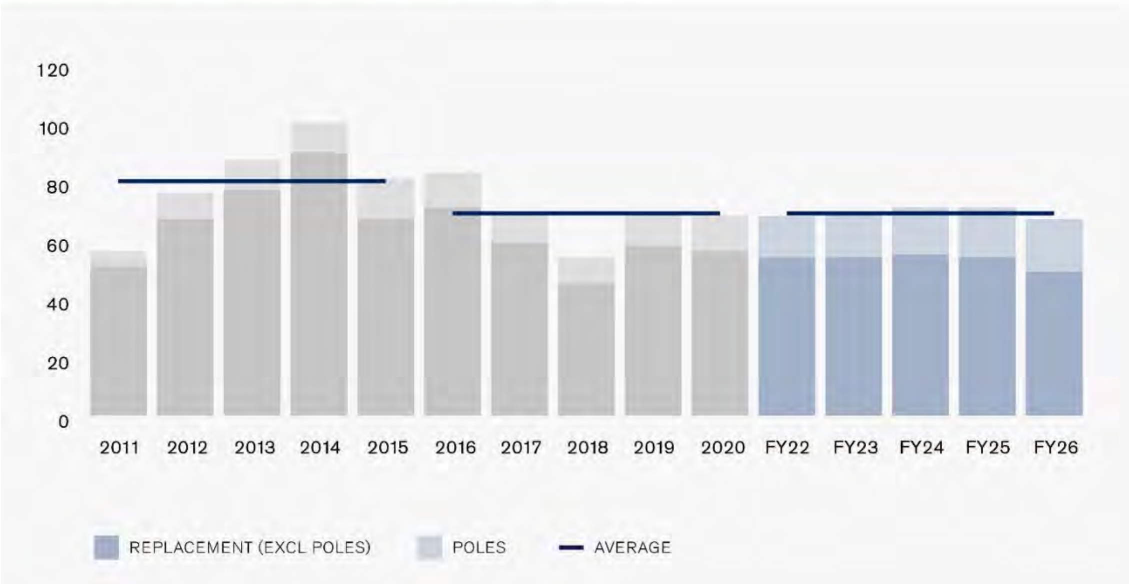
7. Capital investment

7.2.1 Trend in asset replacement

In the 2016–2020 regulatory period, we transitioned from investing in our network based only on asset condition, to investments primarily driven by risk-based assessments. This shift in our asset management practices led to a reduction in our replacement expenditure, but we were still able to maintain strong reliability and safety performance and deliver considerable savings to our customers.

The reduction in our revised replacement expenditure forecast for the 2021–2026 regulatory period results in an investment profile that is consistent with our historical trend (i.e. similar to that observed in 2016–2020, and lower than the 2011–2015 regulatory period). This trend is shown in the figure below and aligns with stakeholder expectations that we demonstrate capital restraint where possible.

REPLACEMENT INVESTMENT ($MILLION, 2021)



Source: United Energy
Notes: 2020 is the first forecast year. Forecast shown includes real escalation

7.2.2 What we've heard and how we've responded

Our stakeholders recognised the work we have undertaken to transition our asset management practices, and as such, supported many of our large replacement programs based on a risk monetisation approach—customers acknowledged these investments were necessary to continue to deliver a resilient network.

It was clear, however, that both stakeholders and the AER had reservations regarding some components of our replacement program. We have sought to address these in our revised proposal, including the removal of some programs, and the development of additional supporting material for others.

7. Capital investment

A summary of what we heard from our engagement program, and how we responded, is shown in the table below.

WHAT WE'VE HEARD	HOW WE'VE RESPONDED
We did not provide sufficient evidence to demonstrate that our forecast replacement expenditure is prudent and efficient.	We have accepted much of the draft determination, and where we are challenging specific areas, we have provided additional information to better demonstrate the need for investment. This includes business case addendums and modelling for our wood pole interventions and our zone substation transformers.
We successfully maintained the health and reliability performance of our network throughout the current regulatory period, such that the driver of increased investment requirements for the 2021–2026 regulatory period is not clear.	Our revised proposal forecast is lower than that included in our original proposal, such that forecast replacement investment is now consistent with longer-term historical trends.
Our original forecast of the impact of pending changes to the Environmental Protection Act were high and reflected a very conservative approach to compliance.	We recognised stakeholder concerns at the uncertainty associated with revisions to our environmental obligations, and revised our forecast to equal our historical spend. We will manage any impacts from the finalisation of changes to Environmental Protection Act using the existing uncertainty regime within the Rules.
Stakeholders broadly supported our monetisation approach for large asset types, including our readiness program to enable greater use of mobile transformers to manage risk and consequence of transformer failure.	We further tested and revised the probability and consequence of failure assumptions included in our zone substation transformer replacement program to better align with our own data (rather than external studies). This has resulted in a reduction in our revised proposal.
Customers consider affordability as a high priority when considering capital investments, challenging some expenditure as not being prudent even if it shows a strong positive business case. With affordability such a significant issue in customers' minds now and in the future, there is an imperative to view capital funds as a finite resource (i.e. notwithstanding many projects having attractive economic returns, we should recognise it cannot all be funded at once).	We removed several proactive replacement programs from our revised proposal forecast that had positive investment cases or were supported by risk-monetisation modelling, including the following: • high-voltage wood cross-arms in high bushfire risk areas • expulsion drop-out fuses • zone substation relay replacements.
The Victorian Government and ESV supported our increased pole replacement program.	We removed our forecast risk-driven pole intervention forecast from our revised proposal.
Consumer representatives and the AER, however, considered we have a pole safety record to be proud of, and therefore, saw no justification for our increased program of pole replacements. Stakeholders were also concerned that findings for Powercor were being applied across our network (noting that different conditions, environmental exposure and failure risks exist).	The forecast increase in our wood pole replacement program, therefore, is solely driven by the expected deterioration in condition over the 2021–2026 regulatory period. We have further tested our condition data, and calibrated observed decay rates to match our historical intervention performance over the current regulatory period.

Source: United Energy

7. Capital investment

7.2.3 Our revised asset replacement forecasts are prudent and efficient

As outlined previously, our revised proposal accepts the draft determination for most asset categories, except for wood poles, zone substation transformers, and service lines. Our wood poles forecast is discussed in detail in chapter 5, whereas our concerns with the other aspects of the draft determination are set out below.

A summary of our revised proposal for the aspects of the draft determination we have not accepted is shown in the table below. We provide additional information for each of these issues.

FORECAST REPLACEMENT INVESTMENT: 2021–2026 REGULATORY PERIOD ($ MILLION, 2021)

ASSET CATEGORY	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
WOOD POLES	86.3	53.3	74.9
ZONE SUBSTATION TRANSFORMERS	39.8	20.0	28.5
SERVICE LINES	23.9	17.8	23.1

Source: United Energy
Notes: Excludes real escalation

Zone substation transformers

Our original proposal outlined the zone substation transformer replacements we will undertake over the 2021–2026 regulatory period. This forecast was based on the risk monetisation modelling we use to identify the least-cost solution to managing zone substation risk, having regard to the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures. This approach is consistent with the AER's recent asset replacement practice note.

Our forecast for the 2021–2026 regulatory period represents an increase in the volume of transformer replacements relative to the current period. This increase is driven by the following:

- the risk of failure is increasing, based on our network experience, as our transformer population continues to deteriorate over time—without intervention, by 2025 there will be 23 transformers in our network that are older than 60-years
- we are the second most utilised network in Australia, meaning we face higher consequences of failure relative to other networks
- we do not manage assets so they never fail, but rather, we invest to manage the consequences of failure (e.g. we utilise relocatable transformers to reduce the consequence of failure)
- notwithstanding an increase in transformer replacements in the 2021–2026 regulatory period, the number of zone substations where we are managing risk is commensurate with the 2016–2020 regulatory period.

Our approach to managing zone substation transformers—in particular, our readiness program to enable greater use of mobile transformers to manage the risk and consequence of transformer failure—received support from many stakeholders, including Energy Consumers Australia (**ECA**). The draft determination also supported the use of our monetisation modelling, but raised concerns over some of the input assumptions relied upon. As a result, the AER substituted our forecast with our historical expenditure.

7. Capital investment

Our revised proposal forecasts a reduced volume (and therefore expenditure) for zone substation transformers to that included in our regulatory proposal. In total, we now expect to complete or commence works on 11 zone substation transformer replacements (rather than 17 included in our original proposal). The reduction in our revised proposal is driven by the following:

- updated demand forecasts
- the application of the AER's recent changes to the value of customer reliability (**VCR**) (which were not available at the time our original proposal forecast was prepared)
- further testing and revision of our probability and consequence of failure assumptions to better align with our own data (rather than external studies).

Our revised forecast, however, is higher than the draft determination. We do not accept the draft determination with respect to the weighting of probability of exceedance (**PoE**) or deliverability risk.

Probability of exceedance

We plan both augmentation and replacement works on our network by calculating expected unserved energy using a 70:30 weighting of unserved energy from the 50 per cent and 10 per cent PoE demand forecasts. For asset replacement projects, the AER considers 100 per cent weight should be placed on the 50 per cent demand forecast.

If we were to adopt the 50th percentile PoE demand forecast, all the proposed transformers in our revised proposal are still economic to replace in the 2021–2026 regulatory period. That is, using just the 50th percentile PoE demand forecast does not defer any replacements beyond the next period.

Notwithstanding the above, we do not accept the AER’s position, and make the following observations (which are expanded on in our attached business case):

- the 50th percentile PoE may be a realistic expectation of demand, but it is not a realistic expectation of unserved energy, which is what drives the replacement outcomes—the relationship between maximum demand and energy at risk is not linear and so using 100 per cent on the 50th percentile PoE demand significantly understates expected unserved energy
- a 30:70 split is a reasonable basis for assessing a weighted average energy at risk figure, and is no different to forming a weighted average risk figure for other asset risks—for example, a fire start may have no impact, a minor impact, or a major impact which is likely to be orders of magnitude large than a minor impact. It is necessary to derive a weighted average cost, not just assume the middle consequence is an average of the three
- our approach has been consistently applied by our network for 20 years, and applies the same weightings as the Australian Energy Market Operator (**AEMO**) in Victoria, and all other Victorian distributors. Changing this weighting just for our network, therefore, would enshrine different reliability standards for our customers
- although other jurisdictions in Australia may not adopt our specific weighting approach, they have regard to 10 per cent PoE demand forecasts in a manner that applies higher standards than our 70:30 weighting approach.

7. Capital investment

Deliverability risk

We operate an outsourced delivery model, where all capital works are undertaken by independent, third-party service providers following an open, competitive tender. Given the depth and maturity of providers available in the open market, we do not envisage capacity constraints to impact on the deliverability of our program. This reflects our experience in operating an outsourced delivery model (e.g. we have not previously experienced capacity constraints that have impacted deliverability), the size of many of the businesses that operate in this market (e.g. major engineering construction firms), and the long-lead time available for much of this program (e.g. much of the proposed program is not due for commencement for a number of years).

The AER also raised concerns that that we do not use our monetisation modelling for internal purposes, notwithstanding information provided to the AER that several in-flight transformer replacements were justified on this basis.[7]

Further detail on our revised proposal forecast, and our response to the AER's specific concerns, is set out in our attached business case addendum.[8]

Service lines

Our service lines forecast includes two separate components—our condition-driven, business-as-usual forecast, and the proactive replacement of two specific service line types (i.e. twisted PVC grey, and neutral screen services). Our condition-driven forecast is consistent with our historical spend, whereas our proactive programs were demonstrated to be the least cost approach to managing the risks associated with these service line types.

The draft determination accepted our condition-driven forecast, but stated that safety risks for our proactive program are likely to be overstated relative to observed consequence costs of public shocks, are sensitive to input variations, and that we did not account for the overlap with our business-as-usual replacements.

For the following reasons, our revised proposal maintains the forecast included in our original proposal (i.e. our revised proposal includes the proactive replacement programs for our twisted PVC grey and neutral screen service types):

- since 2010, around 5 per cent of shocks caused by faulty service lines have required medical attention. Of these, five have resulted in hospitalisations. We are unable to capture the costs to other parties associated with these shocks; rather, much like the VCR, we rely on an independent estimate of the cost of consequence (e.g. the average cost of a serious injury, as per the Safe Work Australia report). The consequence cost of a service line fault can also be catastrophic, as evidenced by fatalities or near-fatalities in Victoria, Western Australia and Queensland (although our modelling recognises the low likelihood of such events)
- consistent with our general duties obligations under section 98 of the Electricity Safety Act, we seek to minimise risk as far as practicable. We have demonstrated that our proactive programs are lower cost alternatives to condition-driven replacements, based on the best available estimates of input data (typically reflecting observed historical performance)

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[7] Further detail on our revised proposal United Energy, *Response to AER information request 031*, June 2020, Q7(i).
[8] UE RRP BUS 4.03.

7. Capital investment

- the relatively small magnitude of our proactive programs relative to the potential consequences of failure (as noted above) means that any sensitivity of our forecasts to input assumptions would be unlikely to change our obligations to manage the risk associated with these service types. The AER's sensitivity analysis is also asymmetric, insomuch as it appears to countenance down-side risks only. Given the known failure modes, the low remaining population of our twisted PVC grey and neutral screen service types, and that their age profile indicates they are at or nearing their expected life, our proactive investment programs would be prudently undertaken on a 'no-regrets' basis
- in response to an information request from the AER, we demonstrated that the replacement volumes associated with our proactive programs are incremental to our condition-driven forecast (which was based on our unitised model).[9] The draft determination does not demonstrate that it had regard to this material, and as such, incorrectly states that an overlap with our business-as-usual forecast exists.

[9] United Energy, *Response to AER information request 052*, July 2020, Q9.

7. Capital investment

7.3 Traditional augmentation

Traditional augmentation ensures the networks' capacity can accommodate our customers' needs. It also includes the communications system and assets we use to operate the network.[10] This expenditure accounts for 10 per cent of our total capital expenditure in this revised proposal as shown below.

AUGMENTATION AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26

Source: United Energy

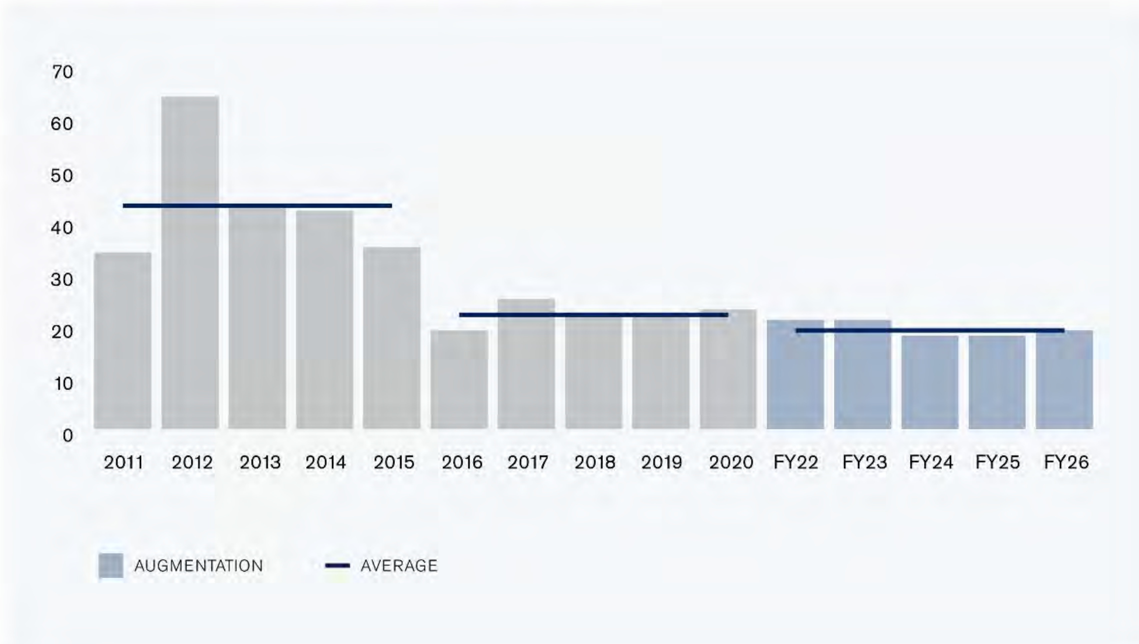
The draft determination for traditional augmentation was $88.6 million over the 2021–2026 regulatory period, which is a reduction of 26 per cent from our original proposal. We accept the draft determination for the traditional augmentation.[11] This provides an allowance below our historical traditional augmentation expenditure as shown in the following figure.

[10] The communications allowance was allocated to both augmentation (standard control service) and metering (alternative control service), which we have sought to reallocate.

[11] The difference between the draft determination and our revised proposal reflects our allocation of communications expenditure to standard control services (as discussed in chapter nine).

7. Capital investment

AUGMENTATION INVESTMENT ($MILLION, 2021)



Source: United Energy
Note: Forecast shown includes real escalation

7.3.1 The AER's assessment approach for non-communications related traditional augmentation

The draft determination is based on the value of augmentation incurred over 2016–2019. It also sought to check the reasonableness of this forecast through bottom up analysis.

Notwithstanding we accept the draft determination, we have concerns with the assessment approach. A short history of augmentation expenditure is not necessarily representative of future spend. The need for augmentation is not constant over time, even if there are similar demand growth expectations. Augmentation is driven by location specific factors such as local demand growth compared to the network's local capacity. This is not captured using a short-term historical average. Additionally, basing forecasts on historical expenditure may reward historically inefficient distributors.

Similarly, the approach to conducting bottom up analysis was in our view high level, or simplistic and would not be accepted should a distributor have proposed it. The AER:

- did not reconcile Australian Energy Market Operator's (**AEMO**) terminal station demand forecasts with zone substation forecasts, meaning location specific factors have not been properly considered
- in seeking to understand the impact of AEMO demand forecasts on our augmentation projects, used AEMO terminal forecasts prepared for the United Energy network. A number of our zone substations, however, service other network areas too. For example, Templestowe Terminal Station (**TSTS**) includes CitiPower cross boundary load from feeders connected West Doncaster (**WD**). This has significantly impacted the reconciliation factors for TSTS and hence conclusions drawn by the AER for connected projects (i.e. the Doncaster fourth transformer in this example).

7. Capital investment

- did not perform a full energy at risk assessment (i.e. it did not input the AEMO demand forecast into our energy at risk models that we provided to the AER). Instead, the AER describes its approach as follows:

> *'For zone substations where United Energy forecasted a need for demand driven augex to begin in a given year, we took the demand forecast in that year as the threshold for augmentation. We then calculated which projects met this threshold during the forthcoming regulatory control period, based on our substitute zone substation demand forecasts (prior to any use of demand management).'*

- did not consider the feeder energy at risk that contributes to the augmentation need for major zone substations
- only considered the 10 per cent probability of exceedance (**PoE**) demand forecast, contrary to the well-established practice across Victorian distributors of also considering the 50 per cent PoE[12]
- failed to update key parameters in the models
- applied zone substation demand forecasts to feeder projects, rather than undertaking feeder forecasts that account for location specific factors that drive the need for these projects
- cited EMCa's analysis that 'for 58 per cent of augmentation in this category, United Energy did not supply business cases, and EMCa found there was not sufficient evidence to support this part of United Energy's forecast.' It is unrealistic to expect business cases or detailed explanations for every expected project within a forecast. This is particularly so when a project can be up to seven years in the future at the time of preparing a proposal, and the AER's regulatory information notice (**RIN**) only requires these for material projects with a cost greater than $6 million.

Notwithstanding our concerns with the AER's assessment approach, we recognise our original forecast was prepared pre COVID-19. There is now more uncertainty in the market and a higher-level assessment approach is not unreasonable in this context.

7.3.2 Communications

We accept the draft determination to accept our proposed communication allowance. The communications allowance was allocated to both augmentation (standard control service) and metering (alternative control service).

We have not adopted the AER's allocation and have instead reallocated the allowance in accordance with our original submission. Our allocation is based on the use of the data collected—we collect data from every meter for network management purposes, not only for metering purposes. This is discussed further in section 9.4.

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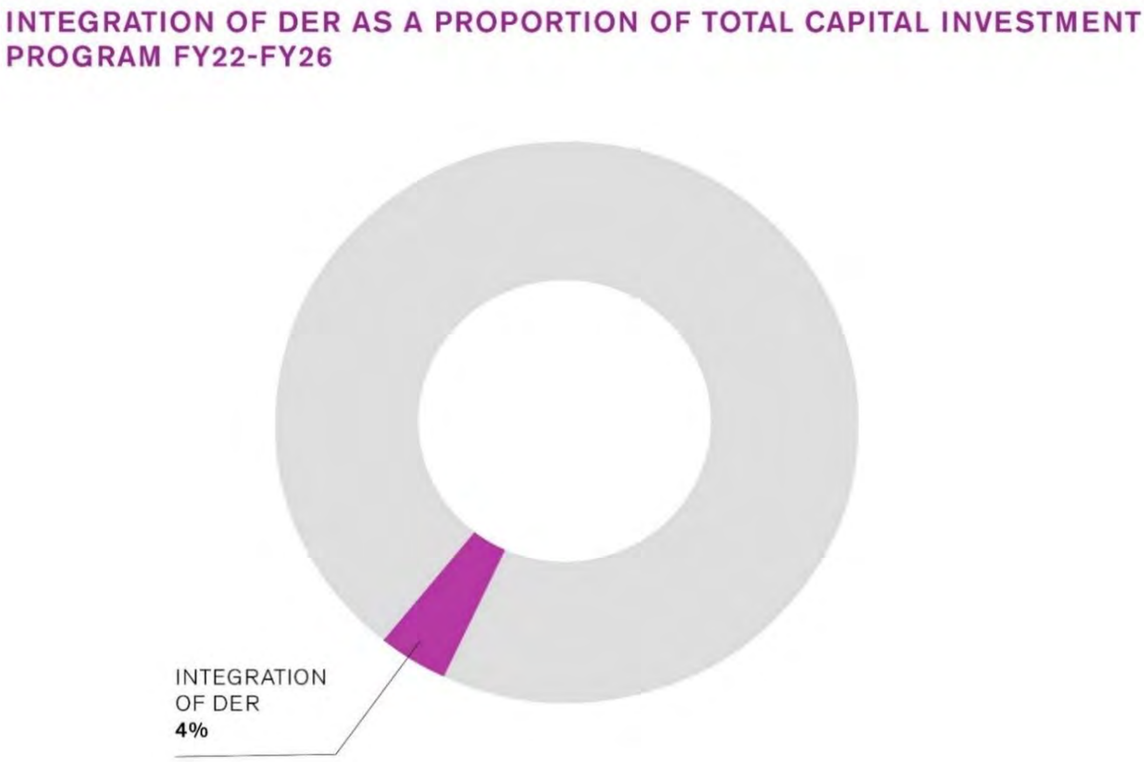
[12] We are only referring to the analysis undertaken by the AER in its bottom up assessment. This is distinct from the discussions with EMCa and the AER on the appropriateness of using a 30 per cent weighing on the 10 per cent PoE on 70 per cent weighting on the 50 per cent PoE.

7. Capital investment

7.4 Integration of distributed energy resources

Investing to help ensure our customers can effectively use their DER devices represents 4 per cent of our total capital expenditure in this revised proposal, as shown below.



Source: United Energy

The draft determination provided an integration of DER capital allowance of $39.7 million over the 2021–2026 regulatory period. This included capital expenditure for our solar enablement program and digital network program. We accept the draft determination.[14]

7.4.1 Continuing stakeholder engagement

Since submitting our original proposal, we have continued the discussion with our stakeholders on our Future Network package. This included reviewing submissions on our original proposal, holding a Future Network forum in October 2020 and discussing the program with our Customer Advisory Panel. Our stakeholders told us:

- they were seeking clarity on the interaction of our solar enablement and digital network programs, including how they interact with network tariffs
- they want us to set out a clear and transparent long-term vision for the network to incorporate future distributed energy resources

[14] We note we do not accept the AER solar enablement operating expenditure step change draft decision discussed in section 8.

7. Capital investment

- they are looking for smart 'no regrets' solutions
- affordability is key in this COVID-19 pandemic environment and given that, customers may not always be able to afford the efficient solution
- effective communication is needed around what customers can expect.

We have taken this feedback on board as set out below.

Interaction between our programs

In our Future Network forum we sought to clarify how our Future Networks package have been designed to work together:

- we are seeking to *get the most out of our existing network* through our digital network program by:
  - significantly expanding our demand management capabilities by developing a platform to facilitate market led demand management across our low voltage assets. This will reduce augmentation costs for all customers, particularly when electric vehicles take off in Victoria, and is critical for integrating intermittent renewables into the market
  - developing dynamic operating envelopes to better manager DER. This includes ensuring DER operates within the bounds of the network's capacity to minimise disruption and ensure customers get fair access. It also supports new business models such as virtual power plants by providing visibility on the amount of DER available to them at any given point in time
- we are seeking to *prepare the network for more DER were this is efficient* through our solar enablement program—by leaning heavily on technology such as our dynamic voltage management system, we are increasing the network's DER hosting capacity in a smart way. This is complemented by traditional approaches such tapping transformers and network augmentations, where the benefits to customers exceed the costs
- we have developed time of use tariffs to encourage customers to use more electricity in off peak times and times of higher solar production—much like SA Power Network's 'solar sponge' tariff, this network tariff can help to alleviate solar constraints. The network tariff's importance will significantly grow when electric vehicles take off in Victoria to ensure charging does not exacerbate peak demand loads and result in more network augmentation
- we at the forefront of finding innovative ways to support this energy transition—we have partnered with the Australian Renewable Energy Agency (**ARENA**) in a pioneering trial of pole mounted batteries will charge at times of the day when there is low demand or rooftop solar systems are exporting to both alleviate solar and peak demand constraints. We are also partnered with ARENA and Origin Energy to undertake a large-scale trial to demonstrate the use of smart chargers to manage residential and fleet electric vehicle charging
- through our connections guideline and connection model standing offers, we are mandating smart inverter settings to be applied to all new solar installations. This means solar connections will have less impact on constraining the network.

7. Capital investment

We believe that stakeholders broadly supported our approach. Our independent stakeholder engagement partner, Forethought, stated:[15]

> *‘Stakeholders were generally pleased about the Digital Network program presented however there were some questions about the proposal and its implementation over the next period.*
>
> *Most prominently, stakeholders were interested to know how the Digital Network Program would link with other assets and infrastructure in the grid as they are created in isolation to each other. Stakeholders wanted to ensure that the Digital Network gave consumers flexibility without creating stranded assets in the long-term.’*

We will continue to draw these links as we consider our Future Networks package plays a critical role in transitioning the energy market.

Our vision

Our stakeholders told us they want us to set out a clear and transparent long-term vision and roadmap for the network. We agree and after careful consideration, we believe this should be a shared vision. Forethought noted:

> *‘Key themes that stakeholders wanted the networks to engage and advise customers on were:*
>
> *…Engaging with customers about what the future of the network should look like.'*

The decisions we make have significant impacts on our customers. Therefore, starting in early 2021, we commit to running a collaborative process with stakeholders and expand upon our vision. This will involve opportunities for stakeholder submissions and discussion.

In our Future Network forum we also asked stakeholders about our role in the market transition. Forethought noted:[16]

> *'Into the future, stakeholders expected the networks to be an enabler of customer choices. This included providing technologies and behavioural interventions that enabled customers to make the decisions relating to their energy supply and consumption that were in line with their values. This included a greater ability of customers to uptake solar PV and storage by better facilitating exports from personal systems.'*

And:

> *‘ Key themes that stakeholders wanted the networks to engage and advise customers on were:*
>
> *…Providing information to customers as to how their actions impact network and end costs'*

That is, our stakeholders thought we should inform our customers about the impact their decisions have on the use of electricity. This is a shift away from enabling customers to use electricity in the way that they choose, to actively encouraging customers to use electricity in ways that benefit themselves and others. We believe we are taking steps towards this through our Future Network package.

We recognise the need for us to play an active role in the energy transition and we have sought to begin this journey through the initiatives above. We believe in a network model that supports the transition to clean and disaggregated energy supply (large scale renewables, solar PV, electric vehicles, batteries) affordably and we want to continue engaging with our stakeholders to achieve this.

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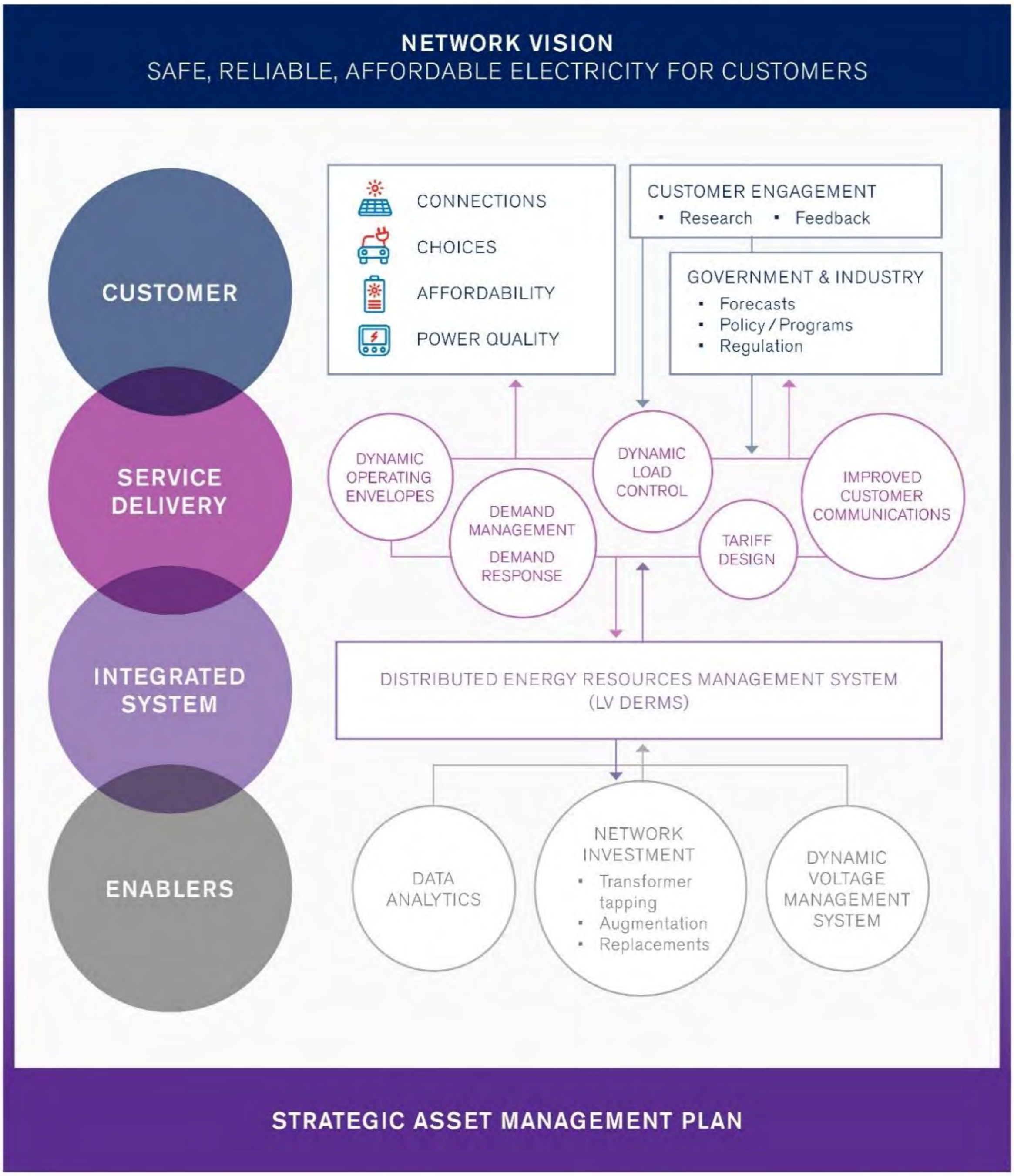
[15] UE RRP ATT06. slide 24
[16] UE RRP ATT06. slide 11

7. Capital investment

FUTURE NETWORK MODEL



Source: United Energy

7. Capital investment

Affordability

In our Future Network forum, we presented customers with an affordability / outcome trade-off in relation to the solar enablement program. Specifically, we demonstrated the solar outcomes (and the economic benefit associated with these outcomes) based on reducing our proposal by 50 per cent, 25 per cent or not at all. We asked our stakeholder to choose the level they felt most comfortable with.

Stakeholders did not end up specifically selecting a scenario. As Forethought noted: [17]

> *'Many stakeholders did not give a clear response to this prompt and instead questioned the modelling.'*

Additionally:[18]

> *'Stakeholders saw pursuing affordability as an important objective but disagreed on the trade-offs required to achieve affordable energy.*
>
> *Many did not see affordability and economic benefit to be a trade-off and instead saw economic benefit to be inherent flow-on value, which should therefore not be de-prioritised.'*

We are acutely aware that since our proposal was lodged, the COVID-19 pandemic has significantly impacted our customers. Some stakeholders considered the use of solar more important now than when we submitted our original proposal because customers are home more often. As Forethought noted:[19]

> *'Many also referenced the fact that due to higher levels of residential demand with Victorians working from home, networks should be cognisant that performance needs will increase as consumers expect that solar PV will work more efficiently.'*

Other stakeholders pointed to the costs of our program being paid for by all customers, some of whom will be having trouble paying their electricity and other utility bills.

While stakeholders did not select a specific level of solar investment, we consider a renewed focus on affordability is warranted, while still recognising the importance of transitioning to clean energy and the benefits from solar. This has directly led to our decision to accept the AER's decision to scale down our solar enablement program by 69 per cent.[20]

Communications

Stakeholders told us we need to play a more active role in communicating with customers and encouraging them to make the right energy choices. Forethought noted:[21]

> *'Stakeholders saw education and communication with customers as a key role in helping enable choices about the future of the networks and the future of energy. Instead of simply supplying energy, distributors were expected to provide the service of providing information and tools to consumers.'*

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[17] UE RRP ATT06. slide 21
[18] UE RRP ATT06. slide 21
[19] UE RRP ATT06. slide 22
[20] Reduction to network augmentation
[21] UE RRP ATT06. slide 11

7. Capital investment

To this end:

- we have launched a new website service called #lineylessons which aims to help customers feel confident in making decisions about their energy choices. This includes the checklist on our website to inform customer decision making on the size of solar system that is best suited to their needs
- our #lineylessons information is empowering customers to make sure their installers are using the right inverter settings as this is essential the capacity to host solar
- we have committed with the Victorian Government to developing a customer communication program that will notify customers of improvements to network conditions for those customers whose solar exports are either constrained or not permitted due to network issues
- we are in the process of establishing a dedicated embedded generation team within our Customer Group to be a single point of contact for solar customers.

AER's DER guideline

The AER is developing a guideline on Assessing DER Integration Expenditure. The AER has stated:

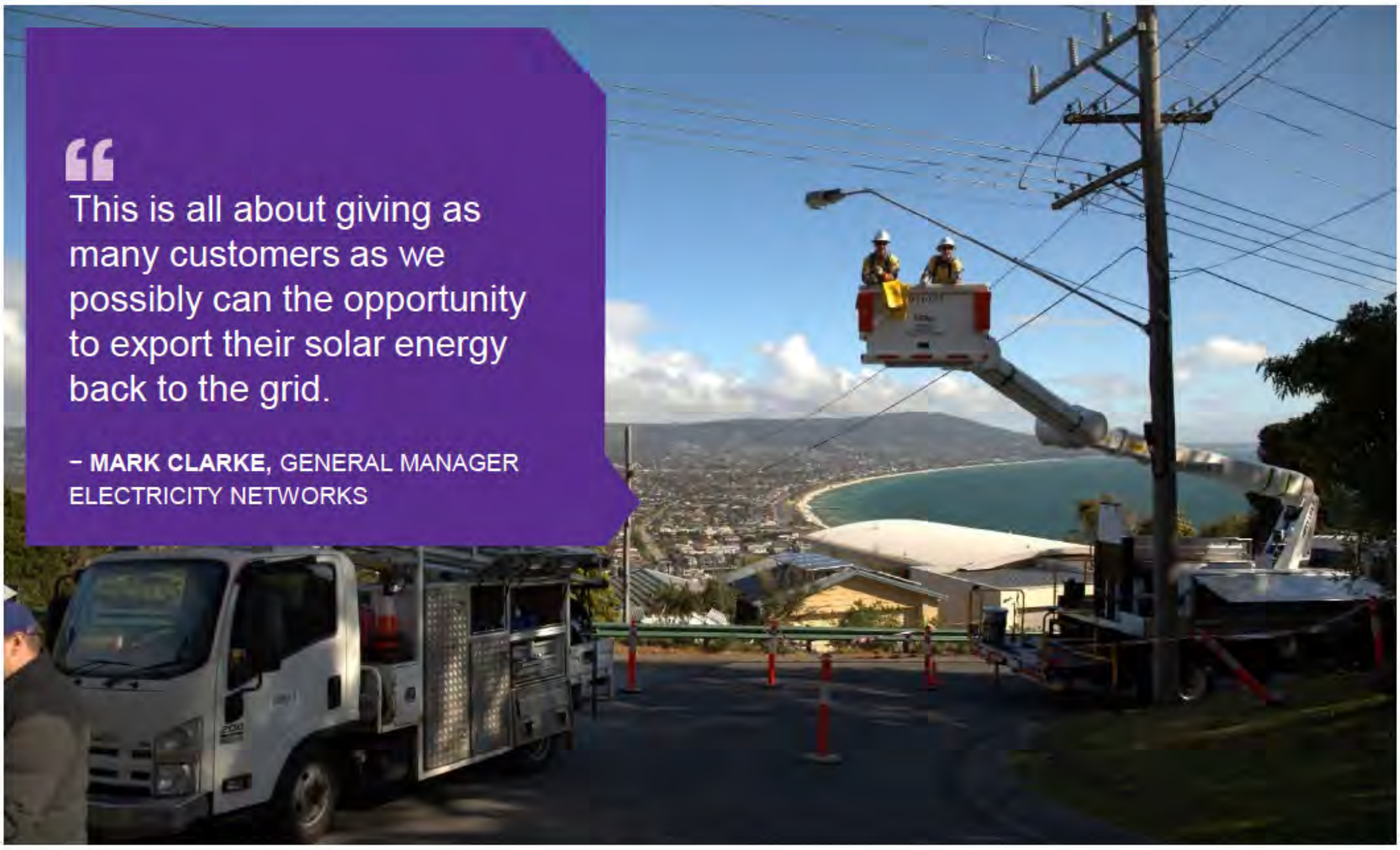
> *‘Given the extensive stakeholder engagement in forming the VaDER study's recommendations, we anticipate that consumers will expect Victorian distributors to prepare their revised proposals in the spirit of these recommendations.’*

This AER's guidance process began in November 2019. In November 2020 the AER published its consultant's report that the AER will use to inform its draft guideline. At this stage, there are no AER positions for us to seek to incorporate in our analysis. Further, the AER's consultant's report was only published three weeks before our revised proposal is due. We do not consider the AER has provided us with sufficient time to enable us to incorporate its consultant's recommendations into our revised proposal.

Nevertheless, consistent on the AER's consultant's report:

- our model base case allows for inverter systems to trip at times where solar production exceeds the networks' hosting capacity, rather than applying a static limit
- our value of DER benefits varies over time
- we have undertaken market modelling to determine wholesale market benefits and carbon emission reduction benefits from solar. This approach, and the benefits captured, are recognised as legitimate by the AER's consultant's report.

On this basis, we believe our analysis was conducted within the spirit of the recommendations.



> This is all about giving as many customers as we possibly can the opportunity to export their solar energy back to the grid.
>
> – **MARK CLARKE,** GENERAL MANAGER ELECTRICITY NETWORKS

SOLAR INSTALLATIONS ARE UP

As reported: Customer Consultative Committee Minutes, 10 June 2020

At the second meeting of United Energy's Customer Consultative Committee in 2020, guest presenter, Jonathan Leake, Director of Policy and Sector Development, Solar Victoria, reported there have been 80,000 new solar installations since the Solar Homes Victoria program was launched in 2018.

During 2020, the average number of applications monthly declined briefly in the early weeks of the COVID lockdown in March and then recovered to the usual 5,000 – 6,000 per month.

In response to questions from the Committee, Mr Leake indicated that solar customer research has found a high level of satisfaction with the benefits of solar installations equal to or better than expected. He said that even without direct education about energy efficiency, people are becoming a lot more conscious and engaged about it. It seemed that as more people were working from home, they have become more conscious of their energy usage.

These findings from the state-wide program were echoed in a report by United Energy to the next Committee meeting in September which showed solar panels being installed at a rapid rate in 2020.

The number of solar PV installations in the United Energy network increased by 8% from 77,463 on 1 January 2020 to 83,835 by 31 July, on pace with a 16% increase this year, the same rate as 2019.

The red-hot start to 2020 follows a blistering 2019, with postcode-level data painting a picture of how different suburbs are embracing solar. Huge increases in solar installations were seen in Dandenong from 2018 to 2019, with around 18% growth. Frankston saw a 15% increase in the same period, while Mornington had 13% growth.

7. Capital investment

7.5 Connections

When customers seek to connect to our network, or change their existing connection, we need to meet our customer's requirements. Connections capital expenditure should allow us to connect customers to the network, including to supply new residential customers and, assist industrial customers in expanding their operations.

NET CONNECTIONS AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26

Source: United Energy

7.5.1 Our revised connection forecast

The changes between our original proposal, the draft determination and our revised proposal are shown in the following table.

7. Capital investment

CONNECTIONS INVESTMENT ($MILLION, 2021)

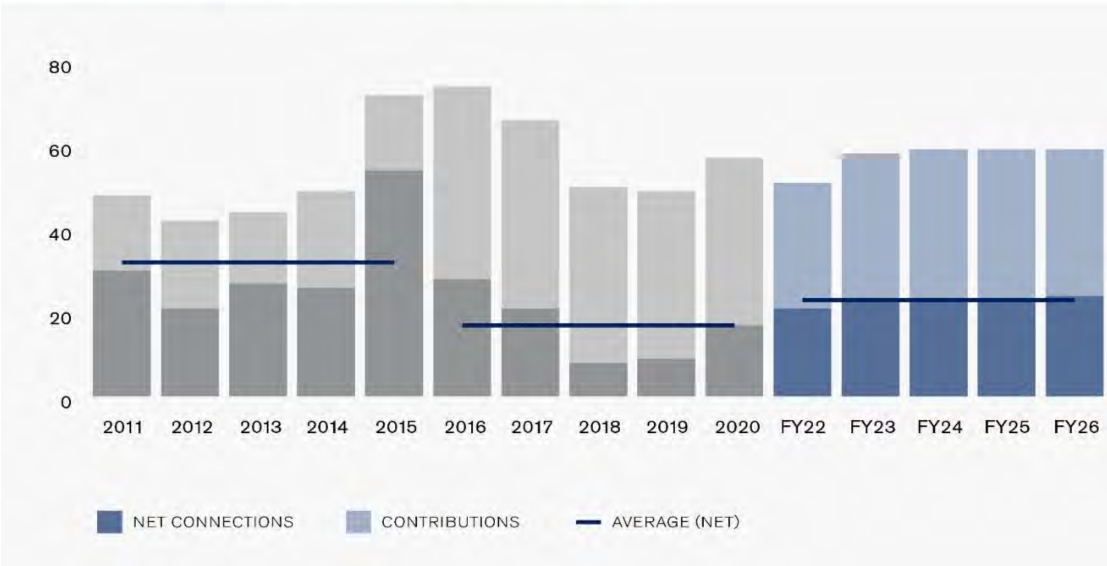
	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
GROSS CONNECTIONS	369.2	294.1	286.0
LESS CUSTOMER CONTRIBUTIONS	-240.0	-194.8	-171.9
NET CONNECTIONS	**129.3**	**99.3**	**114.2**

Source: United Energy
Notes: Forecasts contain real escalation

7.5.2 Trends in connections

Gross connections expenditure continues to increase over each regulatory period. The connections are typically driven by new business supply, dual and multiple occupancy residential housing developments and infrastructure projects.

CONNECTIONS INVESTMENT ($MILLION, 2021)



Source: United Energy
Notes: 2020 is the first forecast year. Forecast shown includes real escalation

Connections to the network remain strong. While residential connections expenditure this year is slightly lower in comparison to the expenditure to the end of September 2019, business and infrastructure connections are higher than at the same point in time last year. Overall, COVID-19 has not led to a reduction in connections expenditure.

7. Capital investment

While residential connections may slow in the near term, stimulus packages such as the Victorian Government's Big Housing Build[23] are likely to maintain construction activity in the sector.

For non-residential connections, we are expecting these to continue to increase going forward as State and Federal infrastructure projects continue. For example, the upgrade of Latham's road and suburban rail loop projects will continue and the recent Federal budget announced infrastructure funding of $1.1 billion for Victoria which included upgrade to roads in the Cranbourne area, and apartment buildings and social housing developments in Dandenong.

7.5.3 What we've heard and how we've responded

The table below shows our response to the feedback we have received from stakeholders.

	WHAT WE'VE HEARD	HOW WE'VE RESPONDED
IMPACT OF COVID-19 PANDEMIC	Customers expect us to adopt a conservative approach to forecasting connections as a result of COVID-19 and the expectation that: • residential connections will fall with the slowdown in net migration to Victoria • business connections will fall as the economy moves into recession. The AER amended our gross connections forecast in 2021/22 to reflect the impact of COVID-19.	We have listened to the feedback from our stakeholders and agree the COVID-19 pandemic may impact connections. However, the depth and duration of the impact is still unknown. Currently, our connections growth remains strong. We accept the AER amendment for COVID-19 pandemic using the Housing Industry Association (HIA) index for residential connections only. We have reviewed our forecasts to ensure the outcome is conservative.
FORECASTING METHODOLOGY	The AER raised concerns that our methodology had inconsistent years for calculating gross and net connections. The AER proposes an amended methodology based on historical expenditure. Consumers raised concerns that our connection forecasts in original proposal are now out-of-date.	We recognise the Australian Construction Industry Forum (ACIF) forecasts are no longer current, and an update has not been published since November 2019 due to the uncertainty regarding the COVID-19 pandemic. We agree that a forecasting approach based on historical expenditure would be appropriate given the current uncertainty.
CONNECTIONS POLICY	Customers have raised broad concerns around energy affordability, and generally do not support increases in the Regulatory Asset Base (RAB) and cost increases to cross-subsidise others' connection activities. The AER has raised concerns about the methodology for applying augmentation unit rates to customer contributions and other aspects of our connections policy.	New connections require a user-pays approach for some services, however this should be consistent with principles of fairness and equity for all customers. While we accept some methodological changes to our connection policy, we are concerned that other changes are not fairer for our customers compared to the current policy.

Source: United Energy

[22] UE RRP ATT45

7. Capital investment

7.5.4 Factors influencing our revised connection forecasts

This section sets out the changes in our revised proposal driven by:

- a recent court decision on the application of tax to customer contributions and consequential changes to the build-up of gross and net connections
- the COVID-19 adjustment should only be applied to residential connections
- acceptance of a methodological change for an input to calculating customer contributions in our connections policy, but we appropriately apply the change to both residential and non-residential customers
- rejection of amendment to our connections policy that could reduce customer contributions on the basis that it is not fair for all other customers.

Change to tax treatment of customer contributions impacts build-up of gross and net connections

On 21 October 2020, the Federal Court of Australia published a decision which impacts the tax treatment of customer contributions.[23] The decision confirms that cash contributions should be treated as assessable income for income tax purposes. Where assets are constructed and "gifted" to us they are no longer considered to result in derivation of income, but the associated rebate is now to be treated as a tax depreciating asset. Consequently, the build-up of gross and net connections changes:

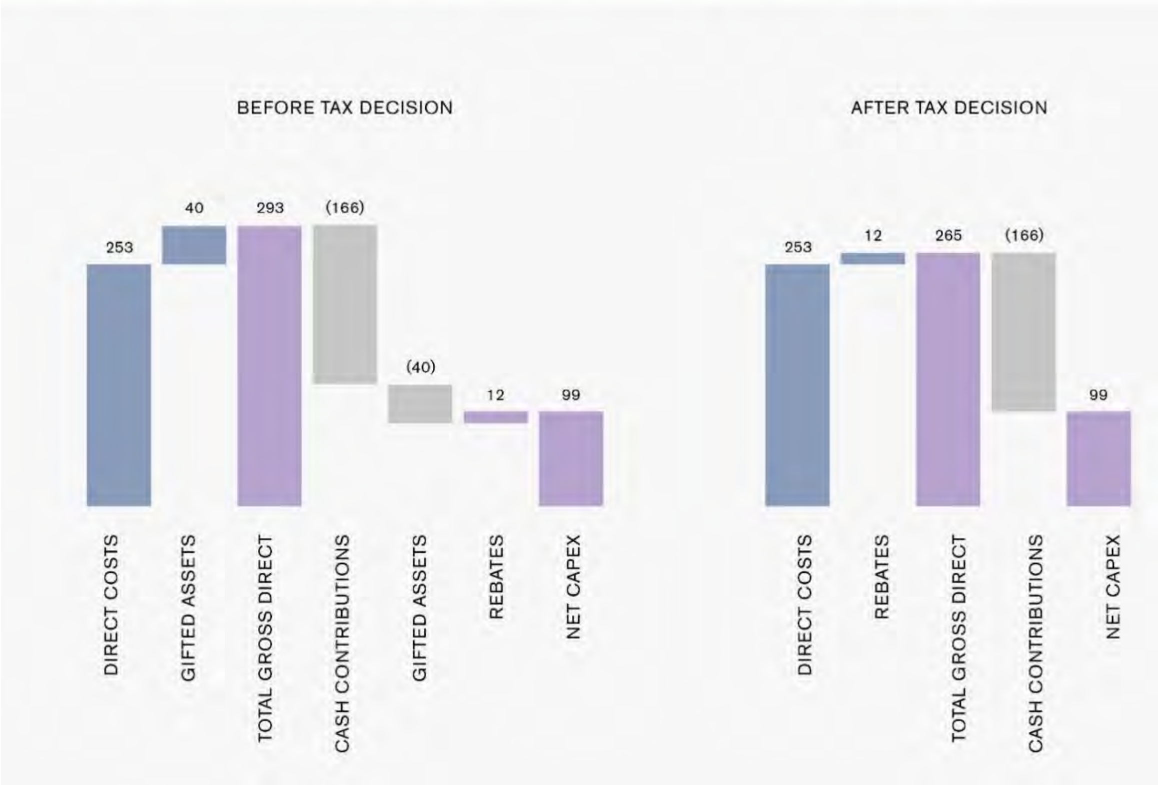
- original proposal:
  - gross capital expenditure = our cost of construction + estimated cost of construction of gifted assets
  - contributions = cash contributions – rebates + estimated cost of construction of gifted assets
  - net capital expenditure = (gross capital expenditure – contributions) = our cost of construction + rebates – cash contributions
- revised proposal:
  - gross capital expenditure = our cost of construction + rebates
  - contributions = cash contributions
  - net capital expenditure = (gross capital expenditure – contributions) = our cost of construction + rebates – cash contributions

The impact of this change on the draft determination is shown in the following figure.

[23] UE RRP ATT38

7. Capital investment

IMPACT OF TAX DECISION ON NET CONNECTIONS ($MILLION, 2021)



Source: United Energy
Notes: Figures do not contain real escalation

The above figure demonstrates that there is no change to the value of net connections expenditure. The gross expenditure differs by the removal of gifted assets and inclusion of rebates in the calculation. This amended methodology has been used in this revised proposal.[24]

The COVID-19 adjustment should only apply to residential connections

We have always intended to update our gross connections forecasts in our revised proposal based on updated the Australian Construction Industry Forum (**ACIF**) forecasts. However, at the time of preparing this revised proposal, the most current ACIF forecasts were published in November 2019 and thus out of date.

The draft determination rejected our forecasting approach using ACIF and substituted it with alterative numbers. The basis for rejecting our approach was:

- claims that our forecasting methodology involved ‘cherry picking’ of years
- uncertainty regarding the impacts of the COVID-19 pandemic.

We are unclear of the AER’s basis for claiming that our forecasting approach involved cherry-picking. We applied the same methodology for forecasting gross connections and customer contributions for CitiPower, Powercor and United Energy. The claims of cherry-picking were only made in respect of Powercor and United Energy’s forecasts.

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[24] UE RRP ATT39

7. Capital investment

In our original proposal, gross connections expenditure was calculated using 2015/16 to 2018/19 average volumes multiplied by ACIF growth rates and then multiplied by average unit costs. The average unit costs were calculated as expenditure divided by volumes for 2015/16 to 2018/19. Contributions were calculated as the average contributions for the 2016/17 to 2018/19 period, given inclusion of the 2015/16 year would have been inappropriate given the change in the capital contributions policy on 1 July 2016 following the adoption of Chapter 5A of the Rules in Victoria.

However, in the draft determination, the AER states:[25]

> *'For categories where historical unit rates and volumes are key inputs to a forecast, it is important to select appropriate years from which to calculate these averages. Generally, selecting a different range of years over which to calculate gross connections and customer contributions is unlikely to be appropriate, or at least requires justification. Otherwise, 'cherry picking' from different samples to arrive at a higher forecast is possible.'*

Our decision to limit the years used to calculate capital contributions until post the policy change was viewed by the AER as reasonable. The AER subsequently stated that we have not justified our decision not to use the same range of years to calculate average volumes and gross connections unit rates. As set out above, the same range of years were used to calculate volumes and unit rates for gross connections expenditure.

The AER substituted our approach with a revised methodology based on historical expenditure. It involved calculating the yearly average for gross connections and capital contributions for the 2016 to 2019 period, with the 2016 calendar year data weighted by half, and then applied to every year of the forecast period.

Given the uncertainty around the COVID-19 pandemic, we believe using historical expenditure as the basis for forecasting connections is a conservative, but appropriate approach, for the 2021–2026 regulatory period. As noted, our connections expenditure has continued to increase over time and therefore this approach is more likely to err on the side of under-forecasting the expected connection activity over the forward period.

We accept there is uncertainty regarding the impacts of the COVID-19 pandemic. The AER applied a COVID-19 adjustment of 0.58 to all expenditure in 2021/22 based on the Housing Industry Association (**HIA**) forecasts released in April 2020.

As the HIA forecasts relate solely to dwelling starts across Victoria, the COVID-19 adjustment should not be applied to non-residential connections. The AER notes that it reasonable to assume the effects of COVID-19 on construction will have ended by July 2022. Given the range of infrastructure projects being announced by governments to stimulate the economy, we consider these initiatives will negate any negative impact on the construction sector due to COVID-19.

For this revised proposal, we therefore accept the AER COVID-19 adjustment insofar as it only applies to residential connections.

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[25] AER, *United Energy distribution determination 2021-26*, Draft decision, p. 5-50.

7. Capital investment

Amendments to our connection policy

In our connections policy, the AER made two amendments which could impact the amount of customer contributions received from customers seeking a negotiated connection under Chapter 5A of the Rules. The changes relate to:

- reducing the unit rates for shared network augmentation that are used in calculating the contribution by the customer to upgrading the shared network
- increasing the shared network augmentation charge threshold, which is the minimum size of the connection to trigger the customer to make contributions to upgrading the shared network.

These are discussed in turn below.

Augmentation unit rate changes should be applied consistently

We accept the AER's change to discount our unit rates for shared network augmentation in our connections policy, however this will necessitate a change to our customer contributions forecast.

The AER amended the ‘diversification factors’ applied to the shared network augmentation unit rates for non-residential customers to reflect the period for which the connection will use the network. The AER considered the unit rates for new residential and non-residential customer's upstream contribution rates should be discounted to 75.4 per cent and 50.4 per cent of the full augmentation unit rates, based on an assumed 30 year and 15-year connection period respectively.[26]

We agree we should amend our methodology to align with the AER’s connection charge guideline, however that methodology should be appropriately applied to both residential and non-residential customers. The AER only amended the diversification factors for non-residential customers. In updating our approach and applying the AER’s percentages, we will remove our diversification factors and adopt the AER's discount factors. This will result in higher shared network unit rates for residential customers and lower rates for business customers. The resultant discounted shared network augmentation unit rates compare well with other distributors and will remain lower than those of AusNet Services, Jemena and the AER's own rates in the draft determination. [28]

Consequently, our customer contributions forecasts will need to be amended for the 2021–2026 regulatory period. Using offers made in 2018 and 2019, we have recalculated the contributions using the revised shared network unit rates which resulted in the following impacts on connection categories:

- -7.02 per cent to the contribution ratio for business (**CB**) projects
- +11.90 per cent to the contribution ratio for URD residential supplies (**CH**) projects
- +4.72 per cent to the contribution ratio for residential rural supply subdivision (**CS**) projects.

We have applied the amended contribution percentages in our revised proposal.

Threshold for contributing to the costs of upgrading the shared network

We do not agree with the AER proposal to increase the threshold where customers seeking a negotiated connection are required to contribute to the costs for upgrading the shared network. This threshold change will lower the amount of customer contributions received from larger residential customers and some business connections. This has not been factored into our revised proposal. If the AER persists with this matter in the final determination, the customer contributions forecast must be further lowered for the 2021–2026 regulatory period.

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[26] These figures align with the requirements in clause 5.2.11 of the AER’s connection charge guideline.
[27] AER, *United Energy distribution determination 2021-26, Draft decision*, p. 18-8.

7. Capital investment

Increasing the shared network augmentation charge threshold will result in an increase in the RAB and all other customers subsidising the costs of these connections. This is contrary to the principle of cost-reflective pricing and drives the wrong economic signals. The threshold is proposed to be increased from 100 Amperes (amps) to 100 amps single phase, or 100 amps per phase of a multi-phase supply. Customer contributions from some businesses and larger residential customer connections will be reduced, such as for premises seeking high electricity consumption to supply car lifts or in-home elevators.

The AER's position appears inconsistent with its own connection charge guidelines. That guideline sets out the principles for the shared network augmentation charge threshold, which notes that in most circumstances the following thresholds would be satisfactory: [28]

- 25 kVA on single wire earth return lines (**SWER**)
- the maximum capacity of a 100 Ampere 3 phase low voltage supply, elsewhere in the distribution network.

The AER has incorrectly misinterpreted the latter point to mean "100A 3-phase supply [a total of up to 300A]".

The AER change will be confusing for our customers as it is also contrary to our deemed distribution contracts approved by the Essential Services Commission.[29] Our deemed distribution contract stipulates that the maximum allocated supply capacity taken at a customer's premise is the lesser of:

- 100 amperes in aggregate across all phases elsewhere in the distribution network
- the rating of the smallest component of the distribution system used solely to supply electricity to your premises.

The shared network augmentation threshold is significantly above the needs of a standard residential or small business connection and we do not consider it appropriate or proportionate for the threshold to be raised. Our current thresholds are around 10 times the average residential maximum demand for residential customers, and three times for small business customers. As noted above, the impact of the threshold being raised is that all customers subsidise these non-standard connections.

7.5.5 Our revised connection forecasts are prudent and efficient

In this revised proposal, we have addressed the matters raised in the draft determination and the feedback from our customers and stakeholders. We consider our revised proposal forecasts are appropriate in the face of unprecedented uncertainty and better meet the requirements of the National Energy Objectives.

In preparing our revised connections forecasts we:

- have used accepted history as a predictor of the future for high volume connections
- accepted the AER's COVID-19 adjustment for residential connections
- continued to apply a bottom-up approach to low volume connections, however with the exception of discrete known projects that are certain to proceed, we have used history as the basis for these other forecasts
- updated the forecasts for customer contributions to reflect changes to the connection policy.

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[28] AER, *Connection charge guidelines for electricity retail customers*, June 2012, section 1.1.5.
[29] There is also no such threshold for customer contributions under Guideline 14 which still applies in Victoria.

7. Capital investment

7.6 Information and communication technology

7.6.1 Our revised ICT forecast

Our revised proposal includes information and communications technology (**ICT**) investments necessary to ensure we have the foundational capabilities to:

- support the delivery of a safe and reliable electricity network
- keep the network and our customer data protected from cyber security threats
- deliver new services for our customers and enable the evolving distributed energy resource market
- ensure we meet our regulatory obligations
- and achieve all of these outcomes at the lowest cost for our customers.

The figure below shows our revised proposal ICT capital expenditure as a proportion of our total revised capital expenditure proposal. ICT contributes 17 per cent of our total revised capital expenditure proposal.

IT AND COMMUNICATIONS AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26

Source: United Energy

7. Capital investment

The table below provides a summary of our ICT capital expenditure, the draft determination and our revised proposal, categorised by recurrent and non-recurrent ICT. Our revised proposal ICT expenditure is less than our original proposal but more than the draft determination.

IT AND COMMUNICATIONS INVESTMENT ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
RECURRENT	107.8	103.5	104.5
INTEGRATION OF DER (IT)	20.1	19.4	19.6
OTHER NON-RECURRENT	66.3	50.6	59.7
TOTAL IT	**194.3**	**173.5**	**183.8**

Source: United Energy
Notes: Forecast shown includes real escalation

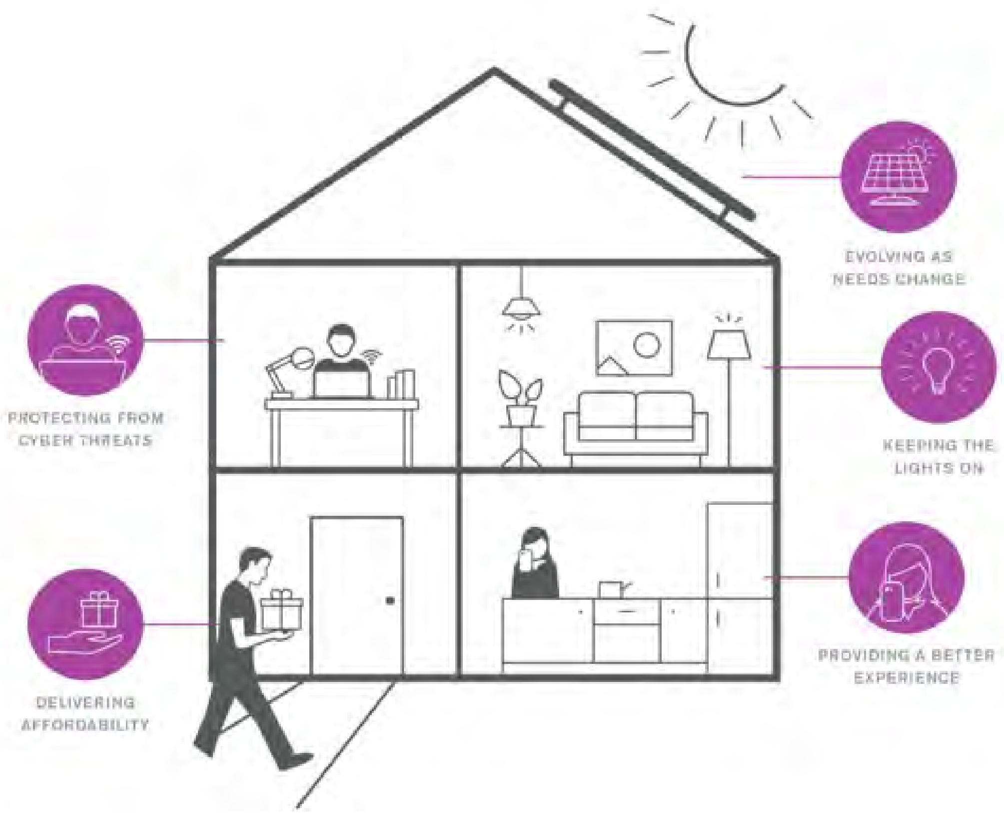
Our total ICT revised proposal reflects the prudent and efficient ICT investment needed to ensure a reliable, safe and low cost network for our customers over the long term.

7. Capital investment

7.6.2 How does our ICT investment assist customers?

Our ICT investment delivers benefits to customers by ensuring we deliver a safe and reliable electricity supply, which is resilient to cyber threats, low cost and an enabler of the future energy markets.

ICT INVESTMENTS



Source: United Energy

7.6.3 Trends in ICT

Our proposed ICT investment for 2021–2026 reflects the following key trends in ICT:

- **An increasingly digital world**—over time the opportunities to invest in digital technologies have grown exponentially presenting new and innovative ways to better manage the electricity network. During the current period we have made significant investments in the optimisation and automation in field operations and corporate processes which have delivered substantial cost savings for our customers. We have also invested in advanced analytics capabilities enabling us to analyse high frequency data from Advanced Metering Infrastructure (**AMI**) to improve safety and reliability outcomes for our customers. In the 2021–2026 period there are even more opportunities to leverage technology developments in the digital world to further improve our network operations, better manage the evolving energy market, deliver more customer benefits and improve the customer experience.

7. Capital investment

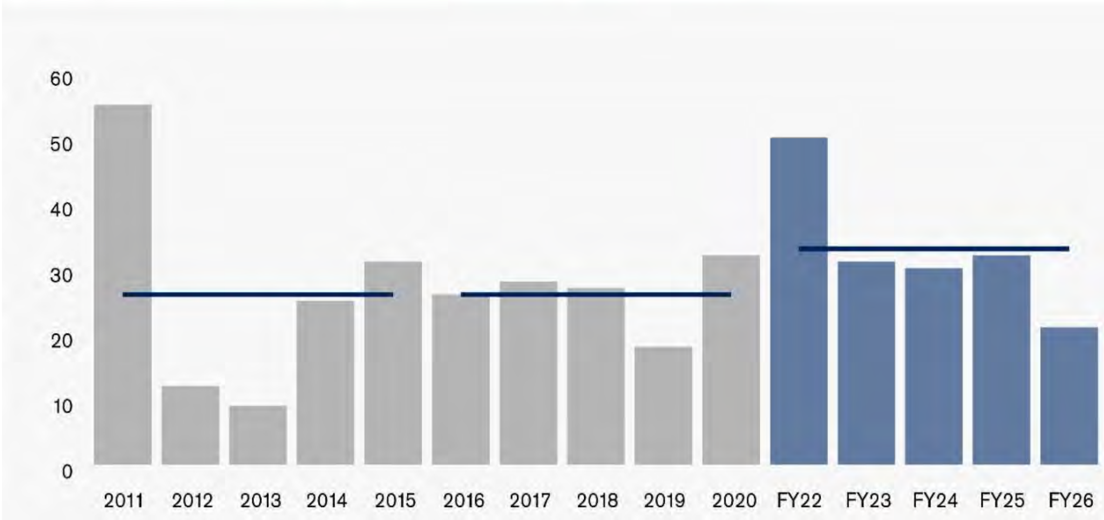
- **Enabling a network of the future**—the energy market is rapidly evolving with increased uptake of household solar, the growth in electricity vehicles and opportunities for battery storage—these new distributed energy technologies present opportunities for customers to more actively participate and have more control over their energy. At the same time the information and communications technology landscape continues to develop at rapid pace presenting opportunity to manage the network more dynamically. Our digital network program brings together these two developments to ensure we minimise costs to customers by using the least cost solution to manage the electricity network to enable the growth in distributed energy technologies.
- **More sophisticated cyber threat landscape**—the cyber threat landscape is becoming increasing sophisticated, with growing evidence of cyber threats and attacks globally and on Australian entities.[30] Cyber threats pose significant risks to our ability to maintain control of the electricity network and protect our customer and network data from unauthorised access. The risk to national sovereignty of cyber threats on Australian infrastructure is becoming an even higher priority for the Federal government, particularly in light of recent threats to Australian entities. Our proposed cyber security uplift ensures we will be well placed to mitigate cyber threats to our network or customer data.
- **Growing customer expectations**—our customers increasingly want to have greater knowledge and influence over their electricity. Customers experience far more enhanced digital service offerings from other service providers, such as airlines, banks, health providers, postal services etc. These digital channels save customers time and effort in sourcing information. Customers increasingly expect we adopt these simple tools to make it easier for them to engage in their electricity needs. Our revised customer enablement program will uplift the functionality of our customer facing services to reduce the time and effort our customers need to expend in their interactions with us.
- **Ensuring compliance with new obligations**—as a regulated electricity network we are required to comply with new rules and procedures. Over the 2021–2026 period, the largest known new compliance obligation impacting our ICT systems is the five minute settlement rule. The five minute settlement rule requires we receive, store, process and deliver energy data from meters every five minutes—a six-fold increase in the volume of data compared with today. Our five minute settlement project includes only the minimum necessary upgrades to our ICT systems to ensure we meet our compliance obligations.
- **Maintaining our existing ICT capabilities**—maintaining the existing services, functionalities and capabilities we have today is essential for ensuring our systems are free from bugs and security vulnerabilities which compromise the security, integrity and effectiveness of our systems. Failing to maintain the health of our existing ICT systems would result in higher costs for customers through lost productivity and rectification costs, compliance breaches and poorer less reliable electricity service.
- **Replace end of life systems**—during the 2021–2026 period our SAP ECC6 system will reach end of life due. Failing to replace or upgrade end of life systems would have significant detrimental impacts on our operations which would lead to higher costs to customers in both the immediate and long term.

[30] For example, in August 2020, the Department of Home Affairs published a consultation paper setting out its intention to further regulate critical infrastructure preparedness for cyber threats and to further enhance the cyber security obligations on the critical infrastructure of the highest importance to Australia.

7. Capital investment

The figure below presents our annual ICT investment from 2011 to 2025/26. Our proposal to invest more in ICT over 2021–2026 reflects the key trends in ICT discussed above.

IT AND COMMUNICATIONS INVESTMENT ($MILLION, 2021)



Source: United Energy

Notes: 2020 is the first forecast year. Forecast shown includes real escalation

7. Capital investment

7.6.4 What we've heard and how we've responded

The table below summarises the feedback received from stakeholders and the AER on our original proposal and sets out how we addressed these issues in our revised proposal.

	WHAT WE'VE HEARD	HOW WE'VE RESPONDED
CUSTOMER ENABLEMENT	AER/EMCa considered: • we are not best placed to provide improved availability and customer access to information as energy retailers already provide their customers with access to information on their energy usage. Retailers shared this view • the benefits of our program were likely to be lower than we estimated and the there is no benefit of providing customer data on a mobile app which is available on a webpage • there may be merit in a subset of proposed features such as creating a unified access point and contact centre artificial intelligence and automating connection and supply services Our CAP: • wanted to see the benefit to customers for each component of our program and to understand which customer groups benefit from each initiative, particularly the benefits to non-DER customers • raised concerns about the affordability of our proposal and questioned whether we had accounted for synergies in the delivery of the program across our networks The CCP: • was supportive of the development of seamless, modern web and mobile based tools to assist with customer-facing operations • were not supportive of the extension of the proposal to provide more frequent usage data.	To address AER and stakeholder concerns, we have engaged with our new CAP to re-scope our customer enablement program. We have targeted our revised proposal program to focus on a smaller set of key initiatives which bring the most benefit to the broadest range of customers. We have removed items which may in theory be supplied by third parties or are additional features which may only benefit some groups of customers. We have re-estimated the costs and benefits for the reduced scope of initiatives and assessed these over five years rather than ten. We have accounted for synergies in the implementation of the program across our three networks. Our revised customer enablement program, supported by our CAP, is a 32 per cent reduction on our original proposal. Details on our revised proposal are provided below.

Source: United Energy

7. Capital investment

	WHAT WE'VE HEARD	HOW WE'VE RESPONDED
INTELLIGENT ENGINEERING	The AER/EMCa supported our intelligent engineering program, however they did not consider the development of a mobile application for the dial-before-you dig service to be necessary and a duplication of an existing service. The CCP agreed the project would deliver more accurate and timely service but question whether we could demonstrate restraint by absorbing the costs The ECA questioned whether cost savings have been taken into account	In response to stakeholder feedback, we have accepted the draft determination to remove costs for the development of a dial-before-you-dig mobile application from our intelligent engineering program. While the project is of too significant uplift in capability to absorb within our business as usual, the reduced scope responds to stakeholder requests we demonstrate restraint. Our benefits analysis acknowledges cost savings are achievable following completion of the project in 2024/25. These savings will be passed through to customers through lower network charges from 2026.

Source: United Energy

7.6.5 Factors influencing our revised ICT forecasts

For our revised proposal, we have:

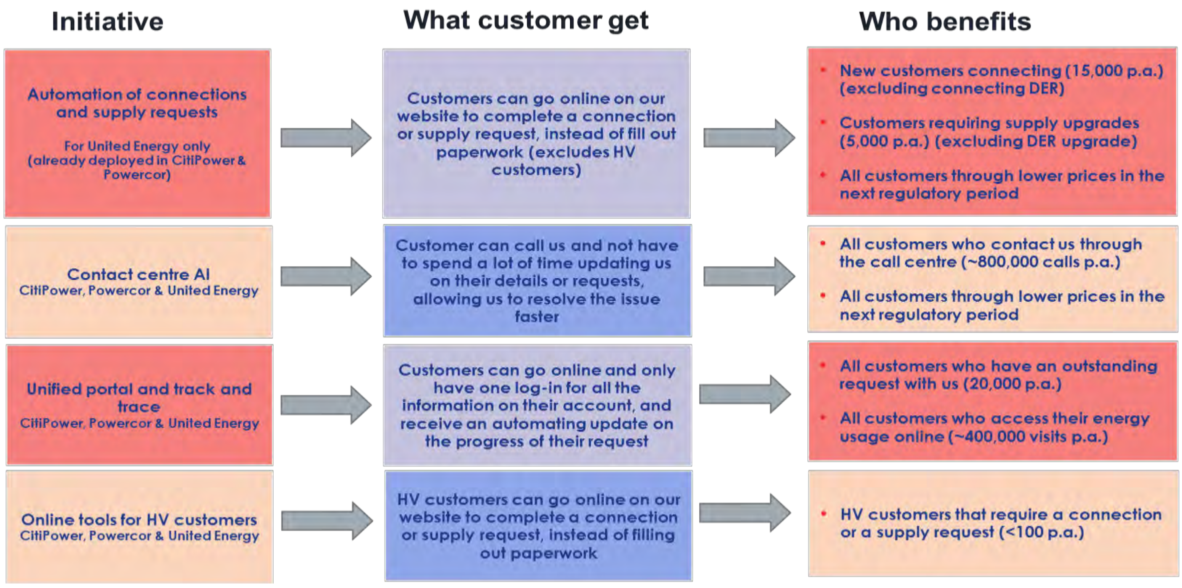
- reduced our customer enablement program to address the feedback from our stakeholders, including our Customer Advisory Panel, Energy Consumers Australia, the AER's Customer Challenge Panel, the AER and the AER's advisors EMCa. We propose a more targeted lower cost customer enablement program which focusses on automating customer
- accepted the draft determination decision to approve our non-recurrent projects which deliver new capabilities, including our proposed SAP S/4 Hana upgrade, digital network program, uplift in cyber security capabilities and ensuring compliance with the five minute settlement rule
- accepted the draft determination decision to reduce our intelligent engineering program to remove costs associated with the development of a dial-before-you-dig mobile phone application.

Targeted, lower cost customer enablement program

We are passionate about investing in ICT capabilities that will improve our customer experience and make it easier for our customers to engage with us.

We engaged with our newly formed CAP to develop our revised proposal customer enablement program which reflects feedback from our stakeholders. Our revised customer enablement program includes a targeted set of initiatives, as shown in the following figure.

7. Capital investment



Source: United Energy

Our revised program is also lower cost and captures synergies in project implementation across our three networks. Our revised customer enablement program is now only $8.6 million a reduction of 32 per cent over the five year period.

Initiatives no longer included in our revised customer enablement program will either be self-funded by us or no longer pursued over the 2021–2026 period.

Our CAP collectively supported our revised customer enablement program and found it to be good value for our customers. More detail on our revised program including our engagement process and revised initiatives, costs benefits is provided in the attached UE RRP BUS 7.02.

7.6.6 Our revised ICT forecasts are prudent and efficient

Our revised proposal addresses the matters raised in the draft determination and the associated EMCa report. Specifically, we have:

- revised our customer enablement program, with support from our Customer Advisory Panel, to focus on a targeted set of initiatives which deliver the greatest benefits to the broadest group of customers
- accepted the draft determination decision to accept our recurrent ICT and non-recurrent programs, SAP S/4 Hana upgrade, cyber security uplift, digital network and five minute settlement

Our overall revised ICT forecast is efficient and prudent for ensuring we deliver a safe, reliable and cost efficient network for our customers.

7. Capital investment

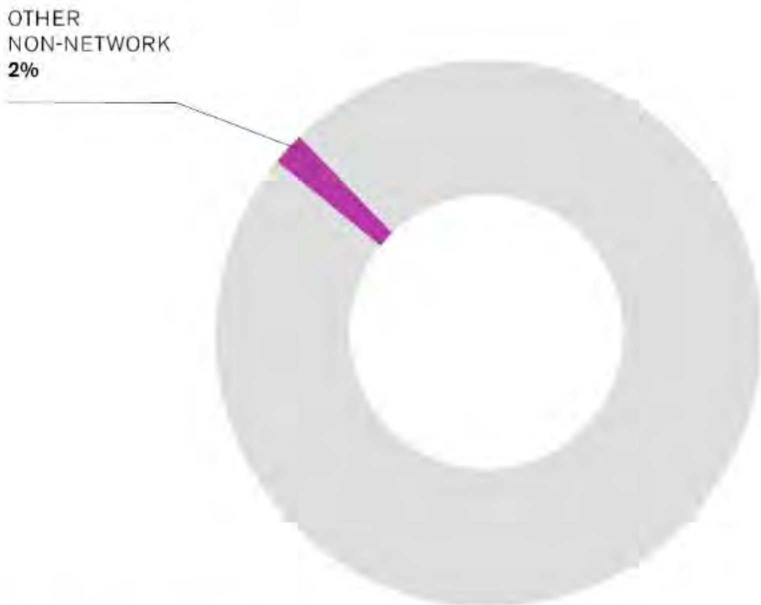
7.7 Other non-network

7.7.1 Our revised other non-network forecast

Our non-network assets support the safe and reliable delivery of electricity distribution services. They include property, fleet, tools and equipment.

The figure below shows our revised proposal other non-network capital expenditure as a proportion of our total revised capital expenditure proposal. Other non-network contributes 2 per cent of our total revised capital expenditure proposal.

OTHER NON-NETWORK AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26



Source: United Energy

Overall, our revised proposal is less than our original proposal, reflecting the prudent and efficient other non-network investment needed to ensure a reliable, safe and low-cost network for our customers over the long term. This is shown in the table below.

OTHER NON-NETWORK INVESTMENT EXCLUDING PROPERTY ($MILLION, 2021)

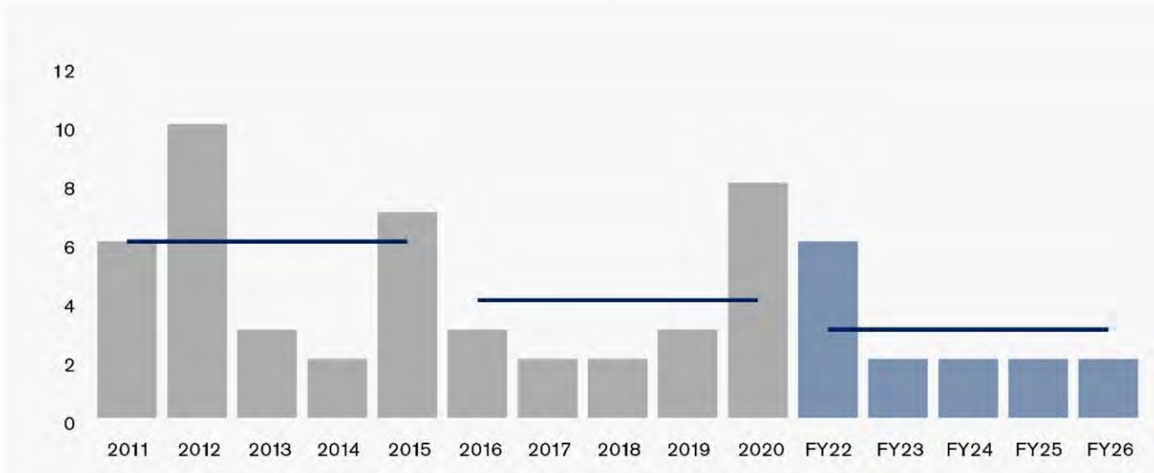
	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
OTHER NON-NETWORK	15.6	14.4	14.4

Source: United Energy
Note: Forecast shown includes real escalation

7. Capital investment

The figure below presents our annual other non-network investment from 2011 to 2025/26.

OTHER NON-NETWORK INVESTMENT (EXCLUDING PROPERTY) ($MILLION, 2021)



Source: United Energy
Note: Forecast shown includes real escalation

7.7.2 Overview of our revised property forecasts

Based on advice from EMCa, the draft determination accepts our Mornington depot upgrade and facilities security proposal. It however substituted our proposed upgrades to Burwood and Keysborough with minimum spend alternatives.

As a result of new information of the Burwood depot closing, we have reviewed our proposed property expenditure portfolio. We have changed our position on the Burwood depot upgrade to purchase a brownfield site, rather than the upgrade of the existing site.

We have retained our Keysborough depot upgrade and expansion given the existing depot requires significant upgrades due to the lack of adequate material storage, severely dated office buildings and poor traffic flow throughout the site. In addition, given the need to relocate the Burwood depot site, our Keysborough depot will increase in importance, as the number of customers being served from the depot and the number of operational and support staff housed at the site increases. We will also be required to relocate our back up control room from Burwood to Keysborough.

The table below provides a summary of our property capital expenditure for our original proposal, the draft determination and our revised proposal.

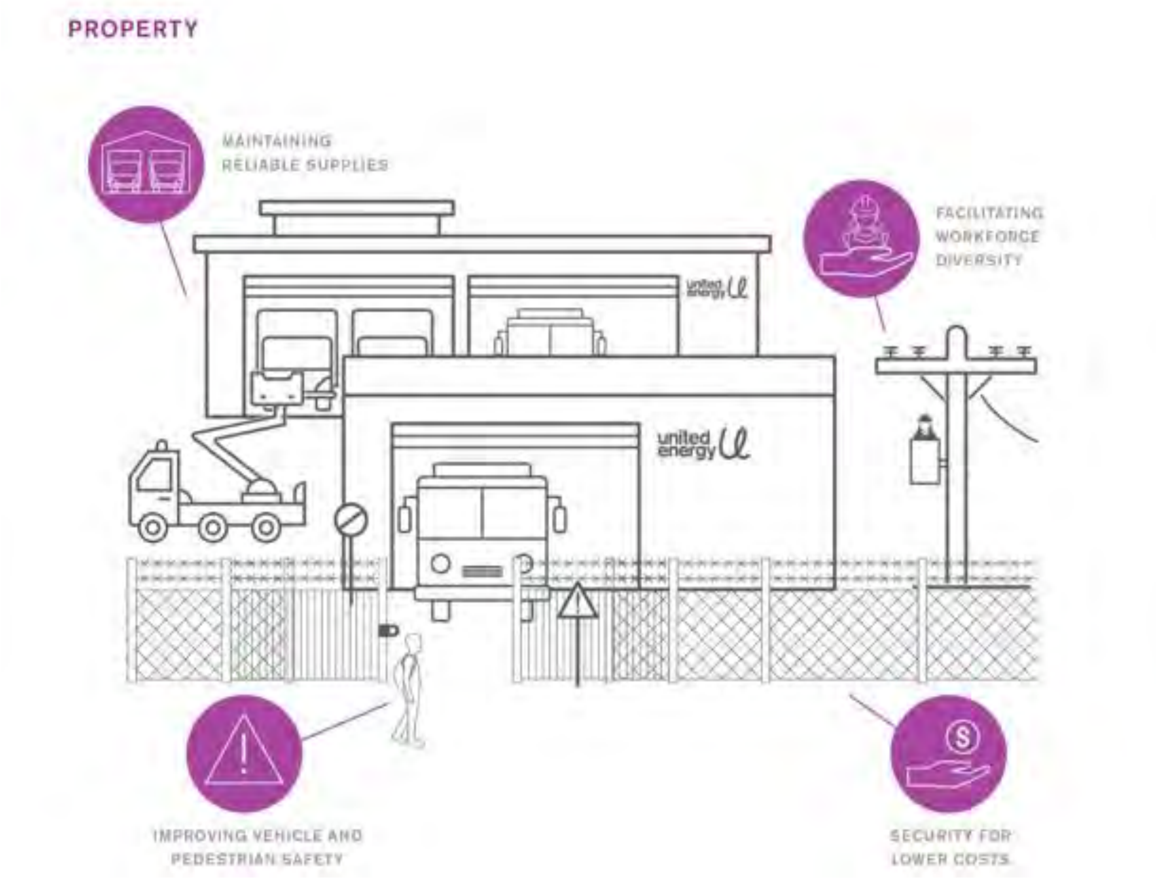
PROPERTY INVESTMENT ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
PROPERTY	69.8	47.2	67.9

Source: United Energy
Note: The AER's draft decision capital expenditure model appears to have shifted the Burwood and Keysborough depot minimum compliance costs to 2025/26 while the draft decision appendix states the AER accepted our proposed timing. Forecast shown includes real escalation.

7. Capital investment

7.7.3 How our property investments benefit customers



Source: United Energy

7.7.4 What we've heard and how we've responded

WHAT WE'VE HEARD	HOW WE'VE RESPONDED	HOW WILL CUSTOMERS BENEFIT
AER/EMCa noted concerns with our benefits assumptions including: • overstated and unsupported fatality risk assumptions • unsupported and double-counted productivity gains • reduced customer unserved energy costs are not supported by evidence	In light of new information, we have reviewed our depot portfolio against our network requirements. We have updated our benefits model to reflect a holistic view of our depot requirements and to reflect future depot zoning of customers and staff. We have responded to concerns raised by EMCa and revised our benefits assumptions. We have demonstrated the benefits to customers from our proposed portfolio of upgrades significantly outweigh the costs.	Our revised other non-network expenditure supports the operation of the network and helps us deliver a safe and reliable service for our customers. By investing now, we are ensuring we keep costs down over the long term for our customers. Our revised proposal also ensures we are meeting societal expectations to provide a safe workplace which caters for diversity.

Source: United Energy

7. Capital investment

7.7.5 Our revised property forecasts are prudent and efficient

Our revised other non-network property capital expenditure is prudent and efficient. It addresses the matters raised in the draft determination and the EMCa report. Our revised forecast also incorporates new information since our original proposal, ensuring we are proposing to maintain an optimised depot portfolio and are continuing to provide safe, reliable services for our customers.

Our revised property forecast includes updated independent cost quotes and updated benefits modelling. We have demonstrated that the benefits to customers outweigh the costs for our revised proposal.

7.7.6 Depots

Our Burwood depot is currently our key operational depot. It services the northern section of our distribution network, houses 160 operational employees and holds the backup control room for emergency and disaster recovery situations. Our Burwood depot is also our largest depot responsible for the largest number of maintenance and unplanned outage work. Our original proposal proposed to upgrade the depot on our existing Burwood site.

Following new information of Burwood's pending closure, we are proposing to construct a new depot on a brownfield site rather than upgrade the existing site. It is critical we replace our Burwood depot in an efficient and timely manner for us to continue to effectively service the northern section of our network. Failure to replace our Burwood depot would have a significant adverse impact on our network wide operating model, including network reliability, and result in increased costs for customers.

Our original proposal also proposed to expand and redevelop our Keysborough depot. This was due to the existing depot requiring significant upgrades due to lack of adequate material storage, severely dated office buildings and poor traffic flow throughout the site. The draft determination reduced our Keysborough upgrade to a minimum spend alternative based on substituting our benefit assumptions with EMCa's.

As a result of the need to relocate our Burwood site, the Keysborough site will become our main depot. This is because Burwood depot replacement will be a smaller parcel of land in a less optimal location and therefore:

- an increased number of customers will be served out of the Keysborough depot
- an increased number of employees will be housed out of the Keysborough depot
- the back-up control room currently housed at Burwood will need to be relocated to the Keysborough depot.

These increased operational requirements make the upgrade of the Keysborough depot even more central to ensuring it is a well-functioning operational depot of sufficient capacity to service our customers.

Given the need to vacate our Burwood depot, our priorities are therefore the Keysborough upgrade, the Burwood new build, and finally the Mornington upgrade.

7. Capital investment

We have updated our benefits model inputs for the changes in the customers served and employee per depot resulting from the rezoning of depot geographical catchments. We have also reviewed the assumptions in response to EMCa's views. We note that:

- given the indirect relationship between the condition of depot facilities and safety, reliability and productivity outcomes, it is unrealistic to presume a level of precision in the assumptions made. Our assumptions were based on our understanding of the likely impact poor depot facilities have on operational performance. As a sense check, we observed the relative performance of more modern depots in the Powercor network. On balance we are comfortable our assumptions are not unreasonable
- EMCa has made unsubstantiated judgement calls in significantly reducing or completely removing various benefits streams. EMCa's have not provided any evidence in support of its substitute assumptions and why they are any more reasonable than ours
- EMCa's approach involves piecemeal adjustments to specific assumptions. This presumes a level of precision which doesn't exist. Further, EMCa's conclusion that the minimum spend option is preferable is highly sensitive to its substitute assumptions
- a more reasonable approach is to apply sensitivity analysis on the set of assumptions. Reducing all our benefits assumptions by 50 per cent shows expanding and redeveloping the depot remains preferable to the minimum spend alternative.

More detailed information on our revised proposal for Burwood and Keysborough upgrades is provided in UE RRP BUS 8.01 and UE RRP BUS 8.02, including a network map which illustrates the geographical servicing zones for each depot across the network. We have also attached design works and updated cost quotes for the Keysborough depot, as well as evidence of the need to relocate the Burwood depot and updated cost quotes.

7.7.7 Facilities security

The draft determination considered our facilities security upgrades prudent and efficient. We accept the determination.

7.7.8 Our revised motor vehicle and tools forecasts

The draft determination considered our motor vehicle and tools capital expenditure prudent and efficient. We accept the determination.

The draft determination rejects our asset disposal forecast and included $2.8 million as a substitute estimate for our fleet disposals. This was based on applying a percentage of vehicle capital expenditure for Powercor (23 per cent, in turn based on SA Power Networks' disposals values) to United Energy's motor vehicle forecast.

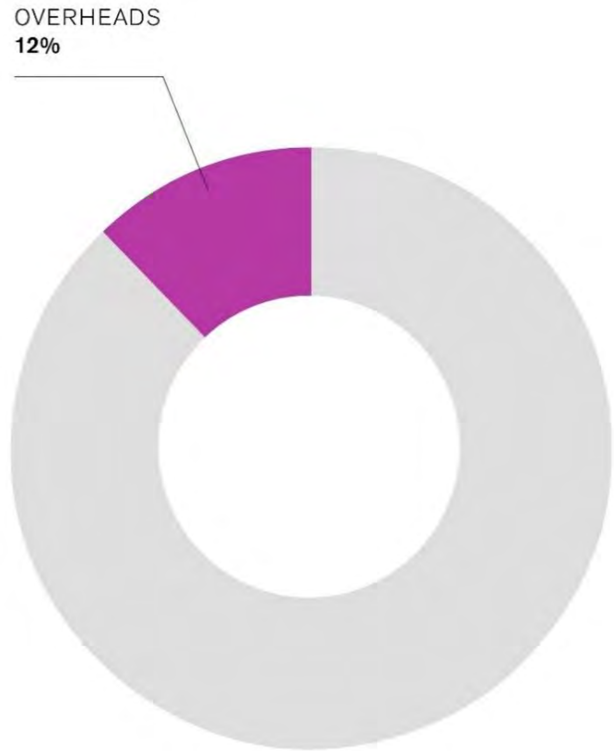
We do not accept the decision to reject our asset disposal forecast and substitute it with data from SA Power Networks. We agree fleet disposals should be accounted for and therefore, in our revised proposal, have used the historical average of asset disposals over the period 2016–2019. This approach captures all types of asset disposals, including fleet.

7. Capital investment

7.8 Network overheads

Our original proposal's capitalised network overheads were based on an estimate of the 2019 actuals. For our revised proposal, we have substituted our 2019 estimates with 2019 actual capitalised network overheads as reported in table 2.1.1 of the 2019 Category Analysis RIN.

OVERHEADS AS A PROPORTION OF TOTAL CAPITAL INVESTMENT PROGRAM FY22-FY26



Source: United Energy

The draft determination adjusts our proposed capitalised network overheads by assuming that the proposed network overheads are 25 per cent variable and 75 per cent fixed. In contrast, expensed overheads are assumed to simply scale with the rate of change. Thus, the draft determination has treated the one pool of overhead costs differently depending on whether they are expensed or capitalised. We believe capitalised overheads should be treated the same way as those expensed.

There is a further inconsistency in the draft determination. It reduces 25 per cent of proposed capitalised network overheads by the percentage reduction in our proposed capital expenditure.

Our original proposal included more capital expenditure than 2019. If we applied the 25 per cent variable rate of overheads used in the draft determination, we would have therefore included significantly more overhead in which case the AER cut would be relevant. Our capitalised overheads however instead took the same approach as expensed overheads. Therefore, the cuts for capitalised overheads were too severe (refer table below) and should be in line with historical spend.

7. Capital investment

The table below compares actual expensed and capitalised network overheads over 2016–2019 with the draft determination base for 2021–2026. It demonstrates the inconsistency in the draft determination which applies an annual base of $33.4 million for total network overheads compared to $36.3 million for 2019 and $39.1 million annual average for 2016-2019.

OVERHEADS ($MILLION, 2021)

	2016 ACTUAL	2017 ACTUAL	2018 ACTUAL	2019 ACTUAL	DRAFT DETERMINATION 2022-26 BASE
EXPENSED	21.0	25.2	15.9	15.3	15.3
CAPITALISED	20.5	15.7	21.9	21.0	18.2
TOTAL OVERHEAD POOL	41.5	40.9	37.8	36.3	33.5

Source: United Energy

Our revised proposal applies the base, step and trend approach to both expensed and capitalised network overheads. It therefore applies the 2019 base of $21.0 million for capitalised network overheads and scales it by the operating expenditure rate of change. United Energy forecasts $108.0 million of capitalised corporate overheads over 2021–2026 compared to the draft determination forecast of $91.6 million.

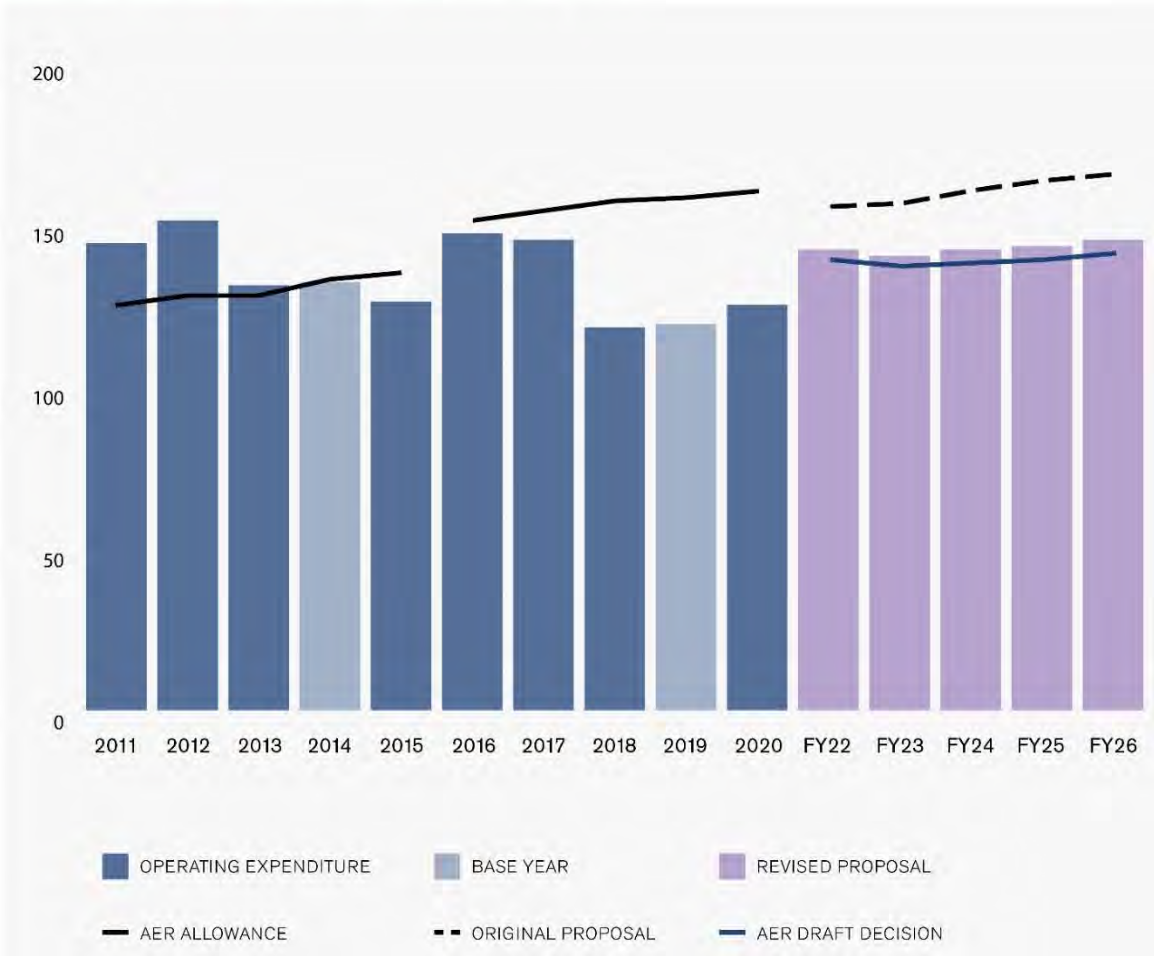
8

Operating expenditure

8. Operating expenditure

8.1 Introduction

OPERATING EXPENDITURE ($MILLION, 2021)



Source: United Energy
Notes: Forecast shown includes real escalation

Our revised proposal for operating expenditure reflects our commitment to remain among the most affordable and reliable distributors in Australia - our customers will continue to get the best deal in Victoria and Australia as we remain among the most efficient networks in the country

Chapter 8 photo: Network upgrades conducted in Dromana were conducted by a team of resource partners. During 2020, he Dromana community has been a focus of significant attention with he installation of a REFCL, early fault detection devices and upgrades to local substations.

8. Operating expenditure

OPERATING EXPENDITURE ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
BASE	616.6	598.8	598.8
FINAL YEAR INCREMENT	16.8	17.9	17.9
ADJUSTMENTS	32.0	19.9	11.3
OUTPUT GROWTH	25.3	15.3	15.3
PRICE ESCALATION	23.6	1.3	8.4
PRODUCTIVITY	-9.9	-8.7	-8.8
STEP CHANGES	73.8	40.6	58.2
GSLS	1.1	3.6	5.2
DEBT RAISING COSTS	6.5	5.9	6.1
TOTAL	**785.8**	**694.6**	**712.4**

Source: United Energy

As the figure shows, our forecasts embed the significant cost decreases we have achieved /through a merger of corporate services with CitiPower and Powercor and renegotiation of key service provider contracts, delivering ongoing savings of $39 million per year.

We have adjusted our original forecasts to include the expected impact of COVID-19 pandemic, resulting in conservative estimates that place affordability first. Our conservative approach is responsive to, and supported by, our Customer Advisory Panel (CAP) and wider industry stakeholders. The adjustment for COVID-19 pandemic means customers will pay $27 million less than we had anticipated in January 2020.

Workplace productivity has been impacted by the COVID-19 pandemic, changing how our people work, including restrictions on interactions between staff and customers, limitations on staff per vehicle and limitations on movements between depots. We expect many of these restrictions will remain in place over the medium term. This will make achievement of the 0.5 per cent annual productivity improvement target impossible. Nonetheless, we are committed to delivering for our customers and as such, have not sought for amendment of the productivity target.

As the most efficient network in the country with limited capacity to absorb costs and further reductions after we adjust for lower growth from COVID-19, it is especially important for us to ensure we are funded for our efficient and prudent costs. If this was not important before, it is now critical given we are absorbing a 0.5 per cent annual productivity improvement factor, estimated nationally across a number of utility sectors over a particularly buoyant period for the Australian economy. This contrasts with the structural break in productivity we are observing due to the COVID-19 pandemic and the proportionally greater impact the COVID-19 pandemic has had on Victoria.

Coupled with the pandemic, we face the lowest rate of change in Australian regulatory history. The draft determination assumes no demand growth, minimal energy growth and pessimistic customer forecasts. It also includes dire labour escalation forecasts, although we note the draft determination refers to taking an average in the final determination which will improve the situation.

8. Operating expenditure

Consequently, our revised proposal includes $58 million in step changes, $16 million lower than what we proposed in January 2020. Further, we are also accepting to absorb $3 million in increasing costs recognising the affordability challenges our customers face.

We have again sought to expense repair works and have provided further evidence to justify the transition.

We have reproposed allocating 88 per cent of our advanced metering infrastructure (**AMI**) communications operating expenditure from metering to standard control. The arguments advanced in the draft determination are not reflective of our current use of AMI data to better manage the distribution network and improve safety and reliability outcomes for our customers. To reinforce our position, our revised proposal presents independent analysis which demonstrates the extent to which we use AMI data to manage the distribution network and the safety and reliability consequences of adopting the AER's position that data from only 1 per cent of AMI meters is required.

Our revised proposal is $712 million, $74 million lower than our original proposal and $17 million higher than draft determination.

8.2 Our revised operating expenditure proposal

Our revised operating expenditure proposal is 9 per cent lower than our original proposal and 2 per cent higher than the draft determination.

FORECAST OPERATING EXPENDITURE ($MILLION, 2021)

	FY22	FY23	FY24	FY25	FY26	TOTAL
ORIGINAL PROPOSAL	152.0	153.5	157.3	160.2	162.8	**785.8**
DRAFT DETERMINATION	139.0	137.2	138.2	139.3	140.9	**694.6**
REVISED PROPOSAL	142.4	140.1	141.7	143.2	145.0	**712.4**

Source: United Energy
Note: Forecast shown includes real escalation

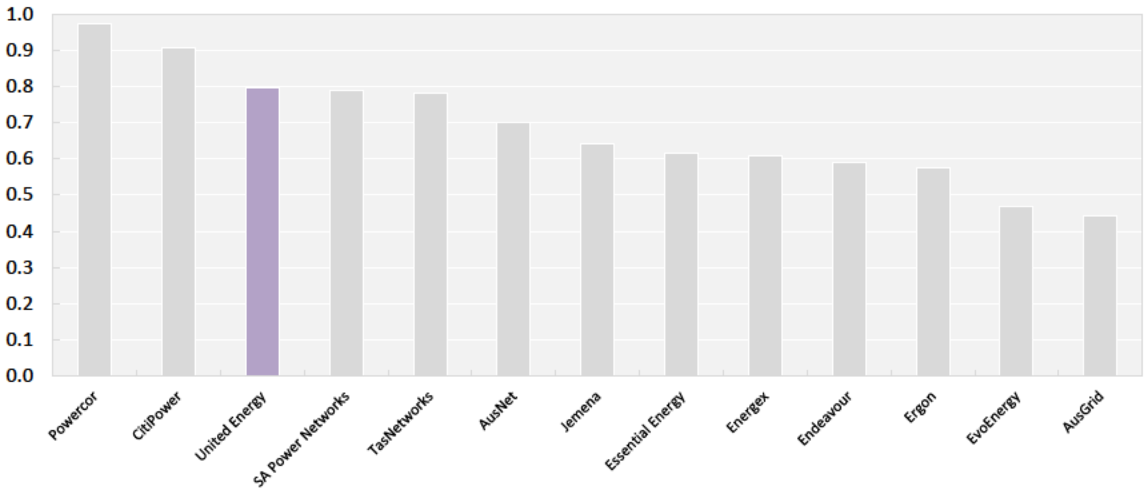
8.2.1 Our operating expenditure is prudent and efficient

Our operating expenditure is amongst the lowest in the country. Our customers have consistently received value for money through a safe, reliable and dependable network that meets our customers' expectations whilst being delivered at the lowest cost in Victoria and the country.

We comprise one of the four most efficient distributors in Australia—along with CitiPower and Powercor, distributors we also manage. Being on the efficiency frontier means we set the benchmark for the least-cost network operation—that is, our customers do not pay a $1 more than necessary.

8. Operating expenditure

OPERATING EXPENDITURE EFFICIENCY SCORES FROM COBB-DOUGLAS STOCHASTIC FRONTIER ANALYSIS (2006–2019)



Source: AER, Draft: Annual Benchmarking Report for electricity distribution network service providers, November 2020.

Being on the efficiency frontier, we don't have contingency to absorb increasing costs. This includes costs from new or modified regulatory and service obligations or material cost increases in delivering current obligations and services due to exogenous changes. Costs of these nature need to be recovered as step changes.

The draft determination repeatedly sought to dismiss step changes based on materiality or that they were recompensed through the rate of change. We do not accept these arguments. We now understand that materiality is being used as a proxy for negative step changes the AER considers we are not disclosing but must be present. The draft determination already imposes a negative step change of $9 million through the productivity adjustment. This adjustment is likely to double in size given the loss of productivity due to the COVID-19 pandemic and the disproportionate impact COVID-19 pandemic has had on Victoria. Further the productivity factor itself is arbitrary. We would argue any negative step changes the AER believes have not been disclosed are more than compensated for in the draft determination. There should also be an onus on the AER to identify and quantify the negative step changes it believes are present, the same way we are required to identify and justify positive step changes.

The second leg of the draft determination argument is based on step changes being compensated via the rate of change. The rate of change can only provide compensation if the step change in question is:

- correlated with demand, energy, customer numbers or circuit length. None of the step changes we have proposed are related to these variables
- a result of real labour price growth. while labour escalation is provided for, the draft determination provides no real price escalation for any non-labour costs. Again, our step changes are unrelated to labour escalation.

8. Operating expenditure

8.2.2 What we've heard and how we've responded

The table below summarises how we've addressed the draft determination and stakeholder feedback in each element of operating expenditure.

OPERATING EXPENDITURE ELEMENT	DRAFT DETERMINATION	WHAT OUR CUSTOMERS AND STAKEHOLDER HAVE TOLD US	HOW WE'VE RESPONDED IN OUR REVISED PROPOSAL
2019 BASE	Accepted as efficient	Accepted as efficient	Accepted AER's decision
BASE ADJUSTMENTS	• The AER accepted the reclassification of wasted truck visits • The AER reduced our proposed reclassification of AMI communications operating expenditure into standard control to 25 per cent • The AER accepted the reclassification of repair works from capital to operating expenditure albeit at a lower value	• Stakeholders in general support cost reflective allocation of costs between standard control and metering, if evidenced that all customer benefit from it • Stakeholders have questioned the merit of the reclassification of repairs to operating expenditure, as it is NPV neutral and there is no cost saving to customers	• We have accepted the AER's decision on wasted truck visits • We have re-proposed the higher share of 88 per cent of reclassification of costs of AMI communications, with further evidence of how we currently use AMI data to improve the safety and reliability of the distribution network • We have accepted the AER's decision on the reclassification of repairs • We have moved the cost recovery of Energy Safe Victoria (ESV) levy into the L factor of the price control formula, as a direct cost pass through is more suitable for these costs, like the distribution licence costs. We have made a negative base adjustment as a result

Source: United Energy

8. Operating expenditure

OPERATING EXPENDITURE ELEMENT	DRAFT DETERMINATION	WHAT OUR CUSTOMERS AND STAKEHOLDER HAVE TOLD US	HOW WE'VE RESPONDED IN OUR REVISED PROPOSAL
PRICE ESCALATION	• The AER has substituted our forecast with the single forecast from Deloitte Access Economics (DAE), which includes considerations of COVID-19 as well as assumptions around the increasing superannuation guarantee levy • The AER noted they were open to us providing updated BIS Oxford forecasts that include the same considerations, so that an average can be applied in the final decision • The AER substituted our actual labour and non-labour weights with industry averages • The AER accepted our 0% non-labour price forecast	• Stakeholders believe our labour price forecast is higher than the average and that we should be adjusting our forecasts to the all industry average • Stakeholders question whether the superannuation guarantee levy increase will result in higher or lower wages	• We have accepted the AER's substituted industry average weights for labour and non-labour price forecasts • We have accepted nil non-labour price escalation • We have sourced updated BIS Oxford labour forecasts that take account of COVID-19 and superannuation guarantee levy and applied an averaging approach with DAE. This has resulted in labour price growth rate that is less than half compared to our original proposal • Both the BIS and DAE forecasts assume a proportion of the superannuation guarantee levy increase will be absorbed by wages • We tested our approach with our CAP and it was broadly supported

Source: United Energy

8. Operating expenditure

OPERATING EXPENDITURE ELEMENT	DRAFT DETERMINATION	WHAT OUR CUSTOMERS AND STAKEHOLDER HAVE TOLD US	HOW WE'VE RESPONDED IN OUR REVISED PROPOSAL
OUTPUT GROWTH	• The AER have substituted our proposed output measures and weightings with the measures and weightings from the draft 2020 Benchmarking report • The AER have substituted our customer number growth forecast with a forecast from the Housing Industry Association (HIA) • The AER have substituted our ratcheted network-level maximum demand forecast with the Australian Energy Market Operator's (AEMO) forecast • The AER accepted our circuit length forecasting approach but substituted for 2019 actuals • The AER added energy to our output measures and substituted the value with 2011-2019 historical averages	• Stakeholders considered COVID-19 would have a material impact on our forecasts and expect us to adjust our forecasts • Our CAP and wider stakeholders want our forecasts to be conservatively low to minimise the risk of rewards for incorrect forecasts	• We accept the AER's decision on the output measures, the weights and the values • This results in the lowest output growth forecasts in recent history, and is reflective of the impact COVID-19 is likely to have in Victoria • These forecasts are conservatively low and mostly independently sourced and verified • We tested our approach with our CAP and it was broadly supported as a conservative approach that addresses stakeholder and CAP feedback

Source: United Energy

8. Operating expenditure

OPERATING EXPENDITURE ELEMENT	DRAFT DETERMINATION	WHAT OUR CUSTOMERS AND STAKEHOLDER HAVE TOLD US	HOW WE'VE RESPONDED IN OUR REVISED PROPOSAL
PRODUCTIVITY	• Accepted the 0.5 per cent annual pre-emptive adjustment	• Stakeholders want to see us and other distributors always aiming higher than 0.5 per cent	• We understand the need to always seek out productivity improvements, and as such we continue to forecast 0.5 per cent per annum • COVID-19 pandemic has resulted in a significant disruption to our productivity, with some restrictions likely to remain in place over the next regulatory period. This will make achieving the productivity target highly challenging, and force us to absorb costs if the target is not reached
STEP CHANGES	• The AER has accepted the Security of Critical Infrastructure step change (with an adjustment), the transition to Cloud services and the 5-minute settlement step change	• Overall, stakeholders wanted us to minimise step changes to the extent possible, but agree with some cost increases as necessary	• We accept the AER's decision on the 5-minute settlement and cloud transition step changes • We have provided an updated value for the security of critical Infrastructure step change relating to ICT through a market test. We have accepted the AER adjustments to our step change for back-office services. Our step change is $15 million lower than originally proposed. • We will absorb the financial year RIN step change and the new cost of regulation to licence engineers and field workers

Source: United Energy

8. Operating expenditure

OPERATING EXPENDITURE ELEMENT	DRAFT DETERMINATION	WHAT OUR CUSTOMERS AND STAKEHOLDER HAVE TOLD US	HOW WE'VE RESPONDED IN OUR REVISED PROPOSAL
STEP CHANGES	• The AER sought market testing of our costs for the Security of Critical Infrastructure step change • The AER rejected the solar enablement, ESV levy, financial year RIN, insurance premiums and demand management step changes as able to be recovered through the rate of change due to low materiality	• Stakeholders generally support an efficient low-cost operating expenditure solution as opposed to a capital solution that invests in long life assets • Stakeholders wanted project-type step changes to be treated as capital expenditure • Stakeholders wanted to see the concept of materiality applied to step changes	• We have re-proposed our solar enablement step change as the most efficient solution to integration of rooftop solar, and a necessary step to reducing investment in network assets. We disagree a materiality threshold and the operating expenditure solution is an efficient approach and reduces the need for capital expenditure • We have accepted the AER's decision on the demand management step change for the Cranbourne terminal station and high voltage feeders. We will continue to seek funding for the lower Mornington Peninsula demand management solution as the preferred and efficient solution to this investment. The same materiality argument applies as for the solar enablement step change. We have updated the value of this step change for the new market tested result
CATEGORY SPECIFIC EXPENDITURE	• The AER used its standard approach to forecast debt raising costs • The AER used its standard approach to forecast guaranteed service level (GSL) payments as category specific forecast	• Stakeholders did not consider debt raising costs to be a step change	• We accept the AER's decision on forecast debt raising costs • We have updated the GSLs category specific forecast with a placeholder value for the new Electricity Distribution Code requirements. Once we have modelled the impact of the final decision, we will update the AER with the actual adjustment values

Source: United Energy

8. Operating expenditure

8.2.3 We use AER's base-step-trend approach

We have applied the AER's base-step-trend approach to our revised proposal.

STEP	OUR APPROACH
1. START WITH THE 2019 BASE YEAR	We have updated the base year to our actual 2019. We consider this to be an efficient year, without non-recurrent expenditure. We then escalate in accordance with the AER's approach to 2020.
2. ADD BASE ADJUSTMENTS	Our base year operating expenditure does not include costs that: a) the AER has reclassified from alternative control to standard control (the cost of wasted truck visits if not distributor fault), b) our proposed reclassification of repairs from replacement expenditure and c) reclassification of some communications costs from metering expenditure. We have also made a negative adjustment for ESV levy costs. Base adjustments amount to $23 million which is added to the 2019 base before the trend is applied.
3. BASE YEAR	Base year that includes adjustments.
4. TREND THE BASE FORWARD USING THE RATE OF CHANGE	We trend base operating expenditure forward to account for expected growth in input prices, output drivers and productivity. Our forecast growth parameters have been reduced to account for the economic downturn from COVID-19. Forecast average real annual price growth is now 0.5 per cent and average real annual output growth is 0.9 per cent. We have maintained an average annual 0.5 per cent growth in productivity. This is consistent with the assumptions contained in the draft determination except for labour escalation, where the draft determination invited us to provide an update.
5. ADD STEP CHANGES	We add step changes to ensure we can meet new obligations, capture operating and capital expenditure trade-offs, or deliver more outcomes that are committed to. We have added $58 million for six step changes, which is 22 per cent less than the original proposal.
6. ADD DEBT RAISING AND GUARANTEED SERVICE LEVELS (GSLS) AS CATEGORY SPECIFIC EXPENDITURE FORECASTS	We have applied the AER's standard approach to forecasting debt raising costs and GSL payments. However, we have updated our GSL forecast with a placeholder value for the new Electricity Distribution Code requirements. Once we have modelled the final decision, we will update the AER with the actual adjustment values.
7. TOTAL	Total operating expenditure forecast.

Source: United Energy

8.2.4 Base adjustments in detail

We accept the draft determination decision on the reclassification of wasted truck visits. We also accept the decision on the reclassification of minor repairs.

We do not accept the draft determination assumption we only require 1 per cent of our smart meter data to safely and reliably manage the network. The draft determination assumption that only 25 per cent of AMI operating expenditure communication costs relates to standard control reflects a fundamental lack of understanding as to how modern networks operate. Meter data, such as power-quality data, is critical to the management of safety of the distribution network. For example, to identify neutral integrity faults. We already collect power-quality data from every meter multiple times per day and need to continue to do so to ensure the network safety issues are addressed efficiently and reliability is maintained at current levels.

8. Operating expenditure

To further reinforce our own experience, we engaged Operational Technology Solutions (**OTS**) to undertake an independent review of the use of our AMI data for network management purposes. OTS found that collecting data from 1 per cent of meters would have materially detrimental impacts on network safety (UE RRP ATT37). Our revised proposal therefore retains an 88 per cent reallocation of our communications costs from metering to standard control.

We have also made a negative adjustment for the ESV levy in our base year, as we are proposing to recover the levy through the price control formula. The table below summarises our revised base adjustment.

BASE ADJUSTMENTS ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
RECLASSIFICATION OF AMI COMMUNICATIONS OPERATING EXPENDITURE	4.7	1.3	4.6
BASE ADJUSTMENT FOR ESV LEVY	-	-	-11.9

Source: United Energy

8.2.5 Rate of change in detail

We accept the draft determination for output growth measures, values and weights. The draft determination does however result in a highly conservative estimate of the growth for our network. By accepting this highly conservative approach, we have put affordability first for our customers, in line with feedback from stakeholders and our CAP.

In accepting the draft determination, we continue to have grave concerns about the use of the multilateral partial factor productivity (**MPFP**) model in setting operating expenditure allowances. This is explained in our submission to the 2020 benchmarking review (UE RRP ATT04 and UE RRP ATT41). We accept that the draft determination is not the appropriate place to debate the approaches applied by the AER and Economic Insights but look forward to a constructive discussion on ensuring a more appropriate approach is taken to modelling operating expenditure in future resets.

Our customers and stakeholders want us to continue to aim high with regards to productivity. We therefore propose a 0.5 per cent annual productivity adjustment. This is despite the significant productivity losses that have occurred from the COVID-19 pandemic through changed work practices which are expected to have long lasting effects. Meeting the AER's productivity target will be extremely challenging and is likely to result in Victorian businesses recording negative efficiency carryover amounts, particularly in the early years of the next regulatory period.

Regarding the labour price escalation forecast, as per the draft determination, we have acquired an updated BIS Oxford forecast that incorporates the effects of COVID-19 pandemic. It also includes an adjustment for the legislated superannuation guarantee levy increase. The BIS Oxford methodology for capturing the effects of the superannuation guarantee levy is aligned with that of Deloitte Access Economics (**DAE**). That is, it includes an assumption that some of the legislated increase will be absorbed through lower wages. Our revised proposal uses an average of the DAE and BIS Oxford forecasts. Refer to UE RRP ATT42 and UE RRP ATT43 for the BIS Oxford report and an addendum.

8. Operating expenditure

RATE OF CHANGE PARAMETERS

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
PRICE ESCALATION	1.2%	0.2%	0.5%
OUTPUT GROWTH	1.3%	0.9%	0.9%
PRODUCTIVITY	0.5%	0.5%	0.5%
RATE OF CHANGE	1.9%	0.5%	0.9%
RATE OF CHANGE ($MILLION, 2021)	39.3	7.9	14.9

Source: United Energy

8.2.6 Step changes in detail

The draft determination accepted three of our proposed step changes. There was an expectation for the security of critical infrastructure step change we would update the value of the step change following market testing.

Most of our step changes were rejected on the assumption:

- they were immaterial, albeit without an establishment of a materiality threshold and despite a materiality threshold assessment not being required in the National Electricity Rules (**NER**)
- they are captured in the forecast rate of change, either through the forecast output growth or the forecast non-labour price escalation.

Considering each step change in isolation rather than in the broader context of ensuring we have reasonable opportunity to recover our efficient costs overall is guaranteed not to ensure we are funded for our efficient and prudent costs. Whilst we understand the need to avoid double counting, the step changes we proposed in our original proposal will not be covered by our base operating expenditure or accounted for in the rate of change, as:

- our base operating expenditure is highly efficient, and, unlike other networks, we have no capacity to absorb these step changes through the base
- the forecast rate of change is very conservative and lower than at any time in the last 20 years. Equally, the non-labour price growth has been determined by the AER to be zero. Therefore, our expenditure allowances will not capture in real non-labour price increases above CPI. Given the basket of goods used by our business is very different to CPI, this is of even greater concern
- the 0.5 per cent productivity adjustment will be virtually impossible to meet in the post COVID-19 environment in Victoria and will create further cost pressures and efficiency benefit penalties for us and ultimately customers.

The NER require the AER to accept our operating expenditure forecasts where they represent the prudent and efficient costs. The Rules do not stipulate a requirement for a materiality threshold in relation to step changes. We are concerned that introducing such a concept could create perverse outcomes where inefficient cost increases are rewarded as material, but efficient cost increases that do not meet a materiality threshold are not. Further, applying materiality thresholds on operating expenditure step changes such that involve capital -operating expenditure trade-offs, the AER is creating a bias against efficient operating expenditure solutions such as demand management.

8. Operating expenditure

Additionally, materiality assessments have been applied inconsistently across determinations. This has included approval of very minor step changes, including the recent SA Power Networks 2020–2026 final determination and in AusNet Services 2021–2026 draft determination (i.e. $1.2 million innovation fund step change).

Given these considerations, we have reproposed a number of step changes and we expect the AER will give full consideration to ensuring we can recover our efficient and prudent costs for these activities.

We understand that step changes add to the cost of our services and as such, we are aiming to ensure any cost increases are efficient, and are unable to be absorbed, without impacting our service offerings. To ensure we have sought no further funding than necessary:

- we only propose to recover our actual 2020/21 insurance premiums. This is despite strong evidence that premiums will continue to rise over the next regulatory period
- we market tested onshoring of services under the security of critical infrastructure step change. The step change is lower by $5.5 million
- we have reduced the value of the solar enablement step change using market tested unit rates acquired by our sister company reducing costs by $1.4 million
- we have reduced the value of the REFCL step change from the original proposal, by working with Energy Safe Victoria to better optimise testing requirements, and adjusting the calculation of the base operating expenditure. However, we don't accept the AER's approach to calculating the base expenditure and our revised proposal provides an alternative approach that is in line with how overall operating expenditure base is calculated.

Finally, we are absorbing the cost of the financial year RIN step change and the cost of licencing fees for engineers and field staff.

The detail of our step changes is provided in UE RRP BUS 9.01, UE RRP BUS 9.05, UE RRP BUS 9.06 and UE RRP MOD 9.01.

The table below summarises the step changes we are updating for the revised proposal.

UPDATED STEP CHANGES ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
SECURITY OF CRITICAL INFRASTRUCTURE	45.9	32.4	31.2
DEMAND MANAGEMENT PROGRAMS	8.6	-	3.1
SOLAR ENABLEMENT	4.2	-	3.9
INCREASING INSURANCE PREMIUMS	2.2	-	11.8

Source: United Energy

8. Operating expenditure

8.2.7 Category specific forecasts

The draft determination included debt raising costs and GSL payments as category specific forecasts.

The AER applied its standard approach to forecast debt raising costs in the draft determination. We accept the approach and forecast.

The draft determination adjusts our GSL payments forecast and moves it from the base adjustment to the category specific forecast. The draft determination also highlights the need to update the GSL forecasts for the Essential Service Commission of Victoria's (**ESCV**) review of the Electricity Distribution Code, which was finalised in late November 2020.

We accept the AER's approach to forecasting GSLs, however we have updated the forecast with a placeholder for the expected change in payments from the final decision on the Electricity Distribution Code review. Once we have modelled the impact of final Electricity Distribution Code review, we will provide the AER with an updated value of GSL forecasts.

CATEGORY SPECIFIC FORECASTS ($MILLION, 2021)

	ORIGINAL PROPOSAL	DRAFT DETERMINATION	REVISED PROPOSAL
DEBT RAISING COSTS	6.5	5.9	6.1
FORECAST GSLS	1.1	3.6	5.2

Source: United Energy

9

Alternative control services

9. Alternative control services

9.1 Our revised alternative control services proposal

Alternative control services (**ACS**) are our customer requested services that are directly recovered from customers seeking the service. They include network ancillary services, such as customer connections, as well as public lighting services. Metering provision services are also ACS and covered in this chapter.

We accept the vast majority of the draft determination with respect to public lighting, quoted services labour rates, fixed fee ACS charges, and metering services.

As requested, we have introduced two new charges to our fixed-fee services, and have provided a description of how we plan to charge for access to data where it is a cumbersome request.

Further, we have provided more evidence of how power quality data from smart meters is used in our daily operation of the distribution network, demonstrating the importance of communications costs being treated as an integral part of standard control services.

Finally, we have updated our service classifications to ensure we no longer require ring fencing waivers and included charges for the new services that have been added.

9.1.1 How our proposal responds to our customers and stakeholders

Affordability remains a key consideration for our customers and stakeholders, which is why we've accepted the AER's substituted labour rates and ancillary service charges. Effectively, we will be keeping our prices low and absorbing the actual costs not recovered through the approved charges.

Our stakeholders were broadly supportive of costs that benefit all customers being paid for by all customers. In response to draft determination on our reallocation of communications costs, we've provided further evidence of why a greater proportion of these costs should be shared among all customers of distribution services.

Our public lighting revised proposal assists with the transition to more energy efficient lights, which stakeholders have told us is a priority. In particular, councils have been very supportive of energy efficient public lighting.

Our metering proposal will continue to deliver and expand the benefits of smart meters to customers at lower cost.

9.2 Ancillary network services

We accept the draft determination and substituted quoted labour rates and fixed-fee business hours ancillary network services. We have also added two new charges as requested by the AER:

- failed field visit for lower cost services
- meter accuracy test - additional meters.

As requested, we have clarified where the access to meter data service would include a quoted charge.

We note the AER has largely accepted our proposed charges for fixed fee based after-hours ancillary network services.

Chapter 9 photo: Runners benefitting from environmentally-friendly LED lights which use 80% less energy than he older style they replaced, emit better light and help reduce carbon dioxide emissions.

9. Alternative control services

Our original proposal proposed to offer "access to meter data" for free, and to offer "access to meter data - cumbersome requests" as a quoted service. In response to this, the draft determination accepted this proposal, but sought clarity as to what constitutes a "cumbersome" request. We were therefore requested to provide parameters and definitions to distinguish between "access to meter data" services that are free and those which are cumbersome which will incur a quoted service charge.

We have also updated our service classifications to reflect the new services, and further to propose the reclassification of services that were under a ring-fencing waiver in the 2016–2020 regulatory period. We have added the two new services under network ancillary services ("failed field visit for lower cost services") and metering ancillary services ("meter accuracy test - additional meters"). Please refer to UE RRP APP09.

We have introduced charges for the services that were previously subject to a ring-fencing waiver, including:

- nightwatchman lights
- possum guards.

All the charges are listed in UE RRP APP09.

Our proposed approach to the development of the new charges, and the explanation of the access to meter data - cumbersome requests, is summarised in the table below.

SERVICE	OUR APPROACH
FAILED FIELD VISIT FOR LOWER COST SERVICES (FAILED FIELD VISIT - SIMPLE TASKS)	As per the draft determination, we propose the failed field visit fee for lower cost services to be equal to the full price for the "special meter read" service. Whether a failed field visit is a simple task (thereby only attracting the lower fee equal to the full price for the "special meter read" service) or a complex task (thereby attracting a higher fee) will depend what services the failed field visit was intended to provide. If a field visit requires two skilled field staff and a service truck, the failure of this field visit would attract the higher "complex tasks" fee. For our fee-based services, a failed field visit satisfies these criteria and therefore will attract the higher charge when the service is: • Basic connections • Meter/NMI/site investigation • Meter accuracy test • Isolation of supply or reconnection, excluding HV (single) • Isolation of supply and reconnection after isolation, excluding HV (same day) • Standard alteration, <60 minutes • Complex alteration, >60 minutes. As such, a failed field visit for any of these services will attract the charge for "failed field visit - complex tasks."
METER ACCURACY TEST - ADDITIONAL METERS	To calculate the meter accuracy test - additional meters charge, we have used a weighted average of the 2019 actual volumes of the meter accuracy test - single phase and the meter accuracy test - multi phase. This is similar to the approach taken to develop the meter accuracy test charge. We will only apply this fee where we have charged the "meter accuracy test" for the first meter tested and we are then testing additional meters at the site. We will apply this lower charge for each additional meter tested.

Source: United Energy

9. Alternative control services

SERVICE	OUR APPROACH
ACCESS TO METER DATA - CUMBERSOME REQUESTS	A non-cumbersome access to data request is one which involves only one meter, for example: • a customer requesting their own meter data • a customer requesting data relating to one of our zone substations that we are required to make available to them under the NER.[1] For these types of access to data requests, we will not charge. Any other data request which is going to require us to aggregate a combination of meters together using either the network or other geospatial information, and which takes more than 10 hours to complete, will be considered cumbersome. For these requests, we will apply the "access to data - cumbersome requests" charge.
NIGHTWATCHMAN LIGHTS	Nightwatchman lights were previously unclassified. During the 2016-2020 regulatory period we obtained a ring-fencing waiver to provide this service, with the understanding that it would be reclassified to ACS at the next regulatory determination. We are now proposing to introduce a fixed fee ancillary charge for installation of nightwatchman lights, which reflects the fixed fee we charge for the service today.
POSSUM GUARDS	We install these as a fixed fee ancillary service. During the 2016-2020 regulatory period, we obtained a ring-fencing waiver allowing us to provide this service. As of 1 July 2021, we propose to reclassify this service as ACS and continue to provide it as a fixed fee service.

Source: United Energy
Notes: (1) National Electricity Rules cl. 5.13A(d)

9.3 Public lighting

We largely accept the draft determination for public lighting. Our approach, as endorsed by the AER, reflects the right balance between a staged introduction of energy efficient lights and maintaining low prices for our customers.

We have updated the public lighting model for labour escalation consistent with our standard control models. We have retained the draft decision rate of return and inflation as a placeholder to be updated in the final determination consistent with the standard control values. Please refer to UE RRP MOD 13.01 for the updated public lighting model and UE RRP APP09 for the breakdown of the charges.

We have replaced the draft decision labour escalation rates with our revised proposal labour escalation rates. Further, we have corrected an error in the calculation of x-factors, have included the written down value price and x-factors, and have included avoided cost rebate price and x-factors.

Regarding the written down value, we plan to only have one written down value and avoided cost value irrespective of light type or wattage. These values would only apply when replacing non-energy efficient to energy efficient lights. These values are not applicable when replacing an energy efficient with a 'more' energy efficient light.

The AER asked for an explanation of why we use smart PE cells for Category V lights in our public lighting models. Our networks now have over 15,000 smart PE cells, the highest penetration of this technology in Victoria.

9. Alternative control services

Our use of this technology is guided by our stakeholders, including large public lighting customers such as City of Melbourne, City of Glen Eira, City of Wyndham and the Macedon Ranges Shire Council, which have all made significant investment in the adoption of smart PE cell technology. Failed units in these municipalities will need to be replaced, and failed lanterns also will need to be upgraded to smart PE cells. As part of our customer consultation process, all councils have requested that we adopt the use of smart PE cell technology in line with the intention of the Public Lighting Code.

Further, the draft determination accepts the unit price for smart PE cells, pending our explanation of how we arrived at this price. We arrived at the unit price by using the moving average price from our materials system for this asset category.

9.4 Metering services

In our original proposal, we sought to allocate from metering to standard control services (**SCS**) 88 per cent of the business as usual communication replacement costs and all the costs for upgrading AMI communications from 3G to 5G. This was based on a model of the use of data transported over the communication network, on the basis we collect data from every meter for network management purposes.

The draft determination rejected our proposed reallocation. The AER noted that while they have generally accepted that the underlying causal allocator identified by us may be an appropriate allocator for shared services, they disagree with the way that allocator has been calculated. The draft determination reallocated to standard control services 25 per cent of the business as usual AMI communication replacement costs and none of the 3G to 5G upgrade costs. This was on the basis we only need to collect data from 1 per cent of meters for network management purposes.

Meter data, such as power-quality data, is used for managing the safety of the distribution network, for example to identify neutral integrity faults. We already collect electricity network data from every meter and need to continue to do so to ensure network safety issues are addressed and we manage the network in the most efficient manner.

We engaged Operational Technology Solutions (**OTS**) to undertake an independent review of our use of AMI data for network management purposes to address the AER's concerns. OTS found that collecting data from less than 100 per cent of meters would have materially detrimental impacts on network safety.

OTS identified 15 use cases where we currently sample 100 per cent of AMI meters to manage the safety and reliability network. OTS quantified the impact of the most significant use case -the detection of faulty neutrals which cause electric chocks to customers. OTS found if we reduced the sampling of AMI from 100 per cent to 1 per cent it would result in an increase in electric shocks to customers of at least 50 per annum. Refer to UE RRP ATT37.

Given our duty under section 98 of the Electricity Safety Act to minimise safety hazards and risks to any person arising from the supply of electricity, we consider even just the one use case of neutral fault detection is sufficient to justify the sampling of 100 per cent of AMI meters.

Our revised proposal therefore retains the allocation from metering to standard control of 88 per cent of our business as usual replacement of communications devices and all the costs for upgrading communications devices from 3G to 5G.

We have updated our metering cost model for the labour escalation and different classification of operating and capital expenditure.

9. Alternative control services

We have also updated the post-tax revenue model (**PTRM**) and exit fee models to link capital and operating expenditure to the revised proposal cost model, recalculate metering revenue volumes based on draft determination customer number growth rates, re-solve equity raising costs and re-solve the revenue and pricing X factors. The tables below summarise metering revenue and X-factors and provide indicative metering charges.

METERING REVENUE AND X-FACTORS ($MILLION, 2021)

	2021/22	2022/23	2023/24	2024/25	2025/26	TOTAL
RETURN ON ASSETS	5.7	5.4	4.9	4.5	4.0	24.5
DEPRECIATION	14.1	15.5	16.7	18.1	19.5	83.9
OPERATING EXPENDITURE	5.9	6.1	6.4	6.6	6.9	32.0
TAX	1.4	1.3	1.5	1.6	1.7	7.5
UNSMOOTHED REVENUE	27.2	28.3	29.5	30.8	32.1	147.8
X-FACTOR	N/A	0%	0%	0%	0%	N/A
SMOOTHED REVENUE	28.1	28.8	29.5	30.2	30.9	147.6

Source: United Energy

INDICATIVE METERING CHARGES ($MILLION, 2021)

	2021/22	2022/23	2023/24	2024/25	2025/26
SINGLE PHASE SINGLE ELEMENT METER	37.84	37.20	36.59	36.02	35.48
SINGLE PHASE SINGLE ELEMENT METER WITH CONTACTOR	37.84	37.20	36.59	36.02	35.48
THREE PHASE DIRECT CONNECTED METER	42.67	41.95	41.27	40.62	40.01
THREE PHASE CURRENT TRANSFORMER CONNECTED METER	45.24	44.47	43.75	43.07	42.42

Source: United Energy

Please refer to UE RRP APP09 for the full list of metering charges and UE RRP MOD 11.02 and UE RRP MOD 11.04 for the updated metering models.

Additionally, we are re-proposing the manual meter read charge for the small number of remaining legacy meters on our network.

10

Managing uncertainty

10. Managing uncertainty

10.1 Introduction

The environment we operate within is inherently uncertain; events outside of our control can affect the quality, reliability and security of the services we provide our customers. This has never been more so than during 2020. Whilst our revised proposal has been prepared on the basis of the best information available to us, we cannot control for every eventuality.

This chapter sets out the nominated pass through events we need to ensure we can continue to guarantee the level of service our customers expect.

The uncertainty regime under the National Electricity Rules (**NER**) comprises pass-through events, capital expenditure reopeners and contingent projects. Both the nominated pass through event and contingent project mechanisms deal with expenditure that may be required during a regulatory period, but which is not able to be predicted with reasonable certainty at the time of preparing or submitting a regulatory proposal to the AER.

10.2 Pass through events

In providing for the pass-through mechanism, the Rules recognise that a prudent and efficient distributor 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.

In our original proposal, we proposed an insurer credit risk event, an insurance coverage event, a natural disaster event, a terrorism event, a retailer insolvency event, a major cyber event, an act of aggression event and an electric vehicle event.

In its draft determination, the AER accepted five of our proposed nominated pass through events, subject to amendments. The AER did not accept a major cyber, act of aggression or electric vehicle event.

10.2.1 Our response to the draft determination

Our revised proposal accepts the majority of the draft determination, save for proposing revisions to the definition of the insurance coverage event. The revisions we propose to our insurance coverage event are set out in the insurance business case (UE RRP BUS 9.05) submitted with this revised proposal.

In addition, we are also proposing three new nominated pass through events, being an insurance premiums event, an environment protection event and a poles management event.

Insurance premiums event

The past few years have seen a major withdrawal of insurance capacity globally for bushfire liability risks, due to a combination of insurer consolidation, appetite changes and (re)insurers being more selective in how they deploy their capacity.

The AER did not accept our forecast operating expenditure, including with respect to an insurance step change.[31] We have now locked in our 2020/21 insurance premiums. The new premiums are 2.5 times higher than our 2019 premiums used in the base operating expenditure and result in a step change of $12 million (10 per cent of 2019 operating expenditure) over the 2021–2026 period. It is likely that these increases will continue year on year. As such, we are proposing an insurance premium nominated pass through event in our revised proposal.

Chapter 10 photo: This pole mounted, 75kWh battery is one of two installed under United Energy's Bayside Battery Project and a first of its kind in Australia. This shared community infrastructure powers between 50 and 75 homes during peak periods on the network.

[31] AER, *Draft Decision United Energy Distribution Determination 2021-26*, 30 September 2020, pp. 6.58-6.59.

10. Managing uncertainty

The background to the insurance premiums pass through event, the reasons why it is required to ensure we are provided with the reasonable opportunity to recover our prudent and efficient costs and the reasons it delivers appropriate regulatory outcomes in the face of the uncertainty over insurance premiums in the next regulatory period, are discussed in the insurance business case UE RRP BUS 9.05 submitted with this revised proposal.

Environment protection event

We are subject to both Victorian and Commonwealth environmental obligations, including the *Environment Protection Act 1970* (Vic) and the State Environment Protection Policies for noise, land, groundwater, surface water and air quality.

Our original proposal included capital expenditure (and an operating expenditure step change) in respect of compliance with amended environmental protection legislation and associated subordinate instruments, which were due to commence in July 2020. After the deferral of the commencement of that legislation, and the delay in finalisation of the subordinate instruments, we withdrew our proposed capital and operating expenditure associated with the changes.[32] As a result, the AER did not include the expenditure proposed in respect of compliance with the updated environmental protection regime within its alternative estimate.[33]

Given that there is still considerable uncertainty with respect to the required capital expenditure we will incur in compliance with the new regulatory obligations, we consider that this capital expenditure is the proper subject of a nominated pass through event, rather than forming part of our capital expenditure forecast in our revised proposal.

Further information regarding our environment protection nominated pass through event is set out in our attached managing uncertainty appendix (UE RRP APP04).

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[32] CitiPower, Powercor and United Energy, *Amendments to operating expenditure step changes and capital programs*, 15 May 2020, pp. 1-2.

[33] AER, *Draft Decision Powercor Distribution Determination 2021-26*, 30 September 2020, pp. 6.50-6.51.

10. Managing uncertainty

Poles management event

Our original proposal proposed an increase in capital investment in poles, primarily driven by an improved wood pole management program. This reflected recent industry experience demonstrating heightened probabilities and consequences of failures with lower durability pole types, including Energy Safe Victoria (**ESV**)'s recent reviews of Powercor's wood pole management practices.

The draft determination did not accept our proposed increase in capital Investment in poles, reducing the forecast replacement expenditure from $94 million to $57 million on the basis of historical expenditure[34] .

In response to feedback from stakeholders, we have not included our incremental risk-driven wood pole replacement program in our revised capital investment forecast. We do however continue to propose increased condition-driven capital investment.[35] We understand that ESV has now accepted Powercor's pole management improvement plan and we expect ESV to commence a similar review of our own pole management practices in early-2021. Should ESV require further changes to our pole management practices, we need to ensure that we are able to recover our costs of compliance. As such, we are proposing a nominated pass through event to enable us to recover any additional pole management expenditure required following the conclusion of ESV's investigation of our pole management practices.

Further information regarding our proposed pole management event is set out in our attached managing uncertainty appendix.

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[34] AER, *Draft Decision United Energy Distribution Determination 2021-26*, 30 September 2020, pp. 5-22, 5-25.

[35] For more information, please see our revised Poles chapter.

11

Incentives

11. Incentives

This chapter outlines our revised proposal positions with regards to incentive schemes in response to the draft determination.

11.1 Capital expenditure sharing scheme

The capital expenditure sharing scheme (**CESS**) provides financial rewards for distributors whose capital investments becomes more efficient and financial penalties for those that become less efficient. The scheme ensures savings are shared between customers and distributors.

We accept the draft determination CESS calculations for the 2016–2020 regulatory period.

We accept the draft determination to apply the CESS in the 2021–2026 regulatory period in accordance with the CESS guideline.

11.2 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (**EBSS**) provides incentives for us to drive efficiencies in operating expenditure. The benefits of efficiency savings are shared between us and our customers.

We accept all points of the draft determination with regards to EBSS.

We further accept the draft determination to apply the EBSS in the 2021–2026 regulatory period with guaranteed service level payments and debt raising costs excluded from the calculation of the EBSS carryover amounts.

11.3 Demand management incentive scheme and 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 accept the draft determination to apply the new DMIS.

Under the DMIA, we are provided with an annual fixed allowance in the form of additional revenue for each regulatory year of the regulatory period. We have updated on DMIA allowance for our revised proposal revenue.

The table below provides our revised proposal DMIA.

DMIA AMOUNTS ($MILLION, 2021)

	FY22	FY23	FY24	FY25	FY26
DEMAND MANAGEMENT INCENTIVE ALLOWANCE	0.5	0.5	0.5	0.5	0.5

Source: UE RRP MOD 10.02

Chapter 11 photo: In August 2020, a storm cell carrying wind gusts up to 145km/hr hit the United Energy network and caused widespread damage with 59,000 customers off supply. More han 570 wire down, broken pole and cross arm events were reported over two days. Within 14 hours of the late afternoon event, all but 1,800 customers had been restored. The remainder were restored within 46 hours.

> While those who opt in are duly rewarded… their participation is a win for all, by helping to reduce the risk of network outages.
>
> – **SOPHIE VORRATH**, EDITOR, ONE STEP OFF THE GRID

VICTORIA SLASHES GRID OUTAGE RISK WITH RECORD DEMAND RESPONSE UPTAKE

As reported: Renew Economy, 20 January 2020

Record customer participation in electricity demand response initiatives has cut the risk of network outages in Victoria and delivered more than half a million dollars to those taking part, new data shows.

United Energy uses demand response to relieve pressure on the grid on those "few really hot days over summer" by getting customers to reduce or shift when they use electricity. Participating customers on constrained parts of the local network are financially rewarded every time they participate in an "event day" or a full three hours, as requested by the network.

United Energy's Summer Saver program has activated three times over the course of December, with results showing an amazing 97 per cent participation rate – well above the previously accepted average for the program over six years between 75-83 percent.

The program works by asking participating customers to reduce demand by taking simple measures like turning their air conditioners' temperature up and avoiding using high energy appliances like dishwashers and washing machines.

Over the first month of the Victorian summer alone, participating customers – most of them households – saved around 8.6MWh across the three events. More than $535,789 was awarded to participants.

"The great thing about Summer Saver is that, instead of conducting expensive upgrades to the network to accommodate just a handful of peak days, the program allows us to continue delivering a reliable power supply in an affordable way for customers," said United Energy's general manager of electricity networks, Mark Clarke.

But he said the key take-away from the new data was that customers were ready and willing – and even keen – to take part in network-led demand response programs.

11. Incentives

11.4 Service target performance incentive scheme

The service target performance incentive scheme (**STPIS**) provides incentives for us to improve network reliability and customer service when the benefits exceed the costs.

As requested in the draft determination, we have updated the STPIS targets for historical data over financial years 2015/16 to 2019/20.

We have also updated our proposed incentive rates for the updated targets and for our revised proposal average annual revenue over 2021–2026.

The draft determination approved the telephone answering parameter in the STPIS pending receipt and assessment of our proposed Customer Service Incentive Scheme (**CSIS**). For our revised proposal, we have therefore removed the telephone answering target and incentive rate and replaced it with our proposed CSIS.[36]

Our updated STPIS targets and incentive rates are shown in the table below.

STPIS TARGETS AND INCENTIVE RATES

	NETWORK SEGMENT	TARGET	INCENTIVE RATE
UNPLANNED SAIDI	URBAN RURAL SHORT	46.1 139.1	0.0916 0.0086
UNPLANNED SAIFI	URBAN RURAL SHORT	0.7 2.1	3.8479 0.3885
MAIFIe	URBAN RURAL SHORT	1.0 4.4	0.3078 0.0311
MED THRESHOLD	NETWORK	2.8	N/A

Source: UE RRP MOD 10.11

11.5 F-factor scheme

The F-factor scheme provides incentives for us to reduce the risk of fire starts from our assets.

We accept the draft determination to apply the F-factor scheme as set out in the AER's Victorian f-factor incentive scheme draft decision 2021–2026.

[36] Customer Service Incentive Scheme chapter.

Glossary

Term	Definition
2018 RORI	2018 Rate of Return Instrument
ACIF	Australian Construction Industry Forum
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
ARENA	Australian Renewable Energy Agency
BIS Oxford	BIS Oxford Economics
CAP	Customer Advisory Panel
CCC	Customer Consultative Committee
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
COVID-19	Coronavirus disease 2019
CPI	Consumer Price Index
CSIS	Customer Service Incentive Scheme
CSS	Customer Service Strategy
DAE	Deloitte Access Economics
DER	Distributed energy resources
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DVMS	Dynamic Management Voltage Systems
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EFCAP	Energy Futures Customer Advisory Panel
EP Act 1970	Environment Protection Act 1970
EP Amendment Act 2018	Environment Protection Amendment Act 2018
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EV	Electric vehicle
Frontier	Frontier Economics
GSL	Guaranteed service level
Guideline 14	Electricity Industry Guideline No 14 – Provision of Services by Electricity Distributors
HIA	Housing Industry Association
HV	High voltage
ICT	Information and communications technology
IT	Information technology
kV	Kilovolt
kVA	Kilovolt ampere
LV	Low-voltage
MAIFI(e)	Momentary average interruption frequency index (event)
MPFP	Multilateral Partial Factor Productivity
MVA	Megavolt ampere
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Industry and Economic Research
OTS	Operational Technology Solutions
PoE	Probability of Exceedance
PTRM	Post tax revenue model
PV	Photovoltaic
PVC	Polyvinyl chloride
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
REFCL	Rapid earth fault current limiter
Repex	Replacement expenditure
Reset RIN	Price Reset Regulatory Information Notice
RFM	Roll forward model
RIN	Regulatory information notice
RIS	Regulatory Impact Statement
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SARS-CoV-2	Severe Acute Respiratory Syndrome Coronavirus 2
SCADA	Supervisory control and data acquisition
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
SWER	Single wire earth return
VCR	Value of customer reliability

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