Regulatory proposal 2026–31

Part B: explanatory statement

Revenue and expenditure forecasts

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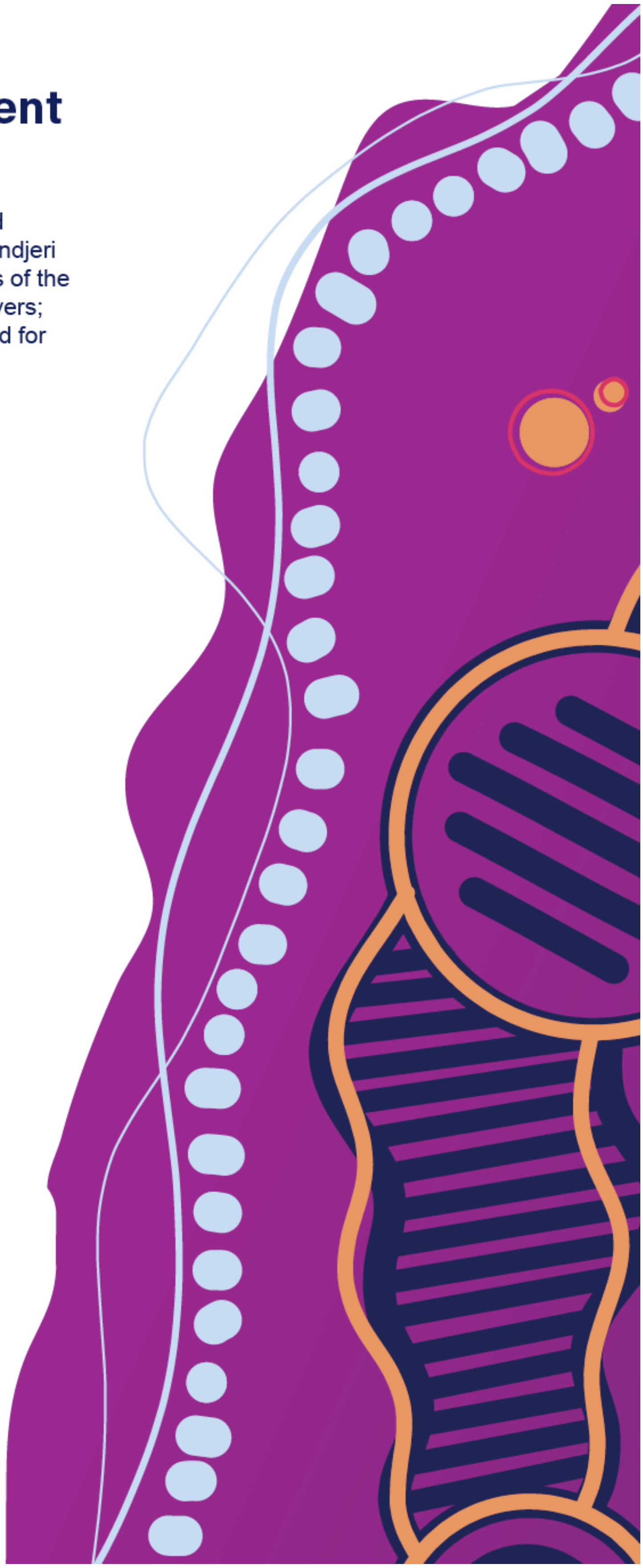
Acknowledgement of Country

United Energy acknowledges and respects the Bunurong and Wurundjeri People as the original Custodians of the lands and waters our network covers; lands First Peoples have occupied for tens of thousands of years.

United Energy pays our respects to Elders past and present and acknowledge their ancient and continuing connection to Country.



About this document

Every five years, the Australian Energy Regulator (AER) reviews our forecast plans for approval. This determines the services we deliver, and the revenue we recover from our customers.

In September 2024, we published a draft proposal setting out our preliminary plans for the 2026–31 regulatory period. This draft sought feedback from our customers and key stakeholders to further test or validate what we have heard from them throughout our extensive engagement program.

Our regulatory proposal builds on this draft, and represents our formal submission to the AER for the 2026–31 regulatory period. It comprises three separate parts that should be read together:

- part A – provides context for our proposal, outlines our engagement journey, and the service outcomes our customers expect us to deliver
- part B – sets out the revenue and expenditure required to deliver these service outcomes
- our tariff structure statement, which includes both our compliance documentation and explanatory statement setting out the reasons and derivation of our proposed tariffs.

Our regulatory proposal is also supported by a large volume of supplementary material, including revenue and expenditure modelling, business cases for key investments, and broader explanatory documentation.

This document represents part B of our regulatory proposal.

Table of contents

1. Overview

Our United Energy network supplies electricity to a 1,500km^2 area covering the east and south-east suburbs of Melbourne, and the Mornington Peninsula.

Households represent approximately 89 per cent of our 715,000 customers, with our broader community comprising a diverse range of interests. This includes many weekend households and a large population of seasonal tourists.

We have therefore become adept in managing growing variations in demand with technology and are proud to operate the smartest distribution network in Australia. This includes our use of smart meters and dynamic voltage management, and the deferral of major augmentation upgrades in the lower Mornington Peninsula through the adoption of non-network solutions.

As outlined in part A of our regulatory proposal, providing a safe, reliable, and resilient electricity supply is more important than ever before, and we are delivering this so our customers can have confidence in their electricity system to fully electrify their homes and lifestyles. For example:

- our network has benefited from sustained investment over multiple regulatory periods, with numerous zone substations having been upgraded or refurbished across a 15-year period. This has supported high levels of reliability, with our distribution network the second most reliable in Australia (i.e. our customers experience an average of just 33 minutes off supply per annum, which is almost 90 minutes lower than the National Electricity Market (NEM) average)
- our customers face the second lowest network charges in Victoria, and third lowest in Australia
- our network utilisation is greater than any other urban network, and around 13 percentage points above the overall National Electricity Market (NEM) average, reflecting the benefits of our many technology-focused solutions.

Significant growth, however, is expected in the future, including due to electrification associated with electric vehicles and the substitution of residential gas in Victoria. Major developments will also occur along the Suburban Rail Link East (which is entirely within our network boundaries), as well as from data centres and battery energy storage systems (BESS).

The extent of this electrification will quickly challenge our existing network. This means delivering on the priorities and service level expectations of our customers and key stakeholders requires a holistic investment program. This includes a combination of business-as-usual programs and targeted projects, recognising that many investments will support multiple service level outcomes.

We must also continue to meet our ongoing compliance and safety obligations. These non-discretionary programs and projects comprise the majority of our expenditure requirements.

In total, our investments will result in a nominal average annual estimated distribution bill increase of just $3 for residential customers, with no increase in corresponding metering charges.

1.1 Stakeholder feedback is reflected across our proposal

Our engagement program for our regulatory proposal commenced in 2022 and has reached more stakeholders and customers than ever before.

Initially, our engagement focused on exploring customer and community needs more broadly, followed by more targeted sessions on key themes. This included a range of engagement activities, from large-scale mass forums, community workshops, focus groups, in-depth interviews and quantitative surveys, and targeted bi-lateral meetings.

A fulsome overview of our stakeholder engagement program is set out in our engagement attachment and is summarised briefly below.[1] Key findings are also detailed in the corresponding expenditure chapters.

1.1.1 Customer service level outcomes

Throughout our regulatory proposal, we have sought to demonstrate where, how and why (or not) we have reflected stakeholder feedback in our decision-making. To do this, we first developed a set of service expectations based around the key themes identified by our customers as critical to their future energy supply.

In part A of our regulatory proposal, we mapped each of these key themes to our proposed service expectations and customer outcomes. As shown in figure 1.1, we also mapped our engagement forums directly to our expenditure categories, noting these typically reflect a one-to-many relationship.

In September 2024, we challenged the extent to which our proposed investments met customer and stakeholder expectations through the publication of our draft proposal and the 'test and validate' phase our engagement program. Our engagement mapping for test and validate is shown in figure 1.2.

Our draft proposal

Our draft proposal provided a transparent and comprehensive view of our preliminary plans for the 2026–31 regulatory period. Engagement from our customers and stakeholders on our draft proposal has been wide-reaching, with over 300,000 video views across social media, and an estimated total audience of over 900,000 customers.

In addition to stakeholder and customer feedback, the Customer Advisory Panel (CAP) provided a detailed report on their findings on our draft proposal. The CAP found there was much to commend in our extensive and sustained program of customer and stakeholder engagement (including initial steps taken to engage fully with First Peoples), and welcomed our emphasis on affordability. The CAP also provided further feedback on improvement opportunities.

A comprehensive set of recommendations from the CAP is set out in their report, and we have sought to address these throughout our regulatory proposal.

Fundamentally, the service level outcomes included in our regulatory proposal have remained consistent with those published in our draft proposal, as our 'test and validate' engagement largely supported our preliminary approach. However, we were strongly challenged to do more in some areas, including investing further in our vulnerable customer package to ensure it is effective.

In comparison to our draft, our regulatory proposal has also been updated to reflect more recently available data.

The 2026–31 regulatory period though remains one of considerable change, with cost drivers and growing customer needs that are beyond our capacity to control or manage with historical levels of investment. In total, our regulatory proposal represents an increase in our expenditure forecasts relative to our draft. The corresponding bill impacts, however, remain modest and consistent with our draft proposal.

[1] UE ATT SE.01 – Stakeholder engagement attachment – Jan2025 – Public.

FIGURE 1.1 STAKEHOLDER ENGAGEMENT MAPPING: DEEP AND NARROW

Key engagements	Electrification and CER integration	Augmentation	Replacement	Resilience	Connections	Information and communications technology	Property, fleet and other non-network	Operating expenditure	Metering	Public lighting	Tariffs and pricing
Customer Advisory Panel: Ensure the diverse and changing needs of our customers were properly understood, balanced and reflected in business plans	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Future Home Demand report: Ethnographic research process with Monash University to understand emerging energy trends in everyday household life	✓	✓	✓	✓	✓			✓			
Flexible services: Understand preferences and priorities for potential flexible service products	✓	✓			✓	✓		✓			✓
Community resilience workshops: Understand customer lived experiences during extreme weather, and challenge our proposed resilience solutions				✓		✓	✓	✓			
Government reviews: Outline our role in supporting customers and communities before, during and after extreme weather events				✓		✓	✓	✓			
Customer values research: Quantification of the relative importance that customers place on our services, and willingness-to-pay	✓	✓	✓	✓		✓	✓	✓			
Customer Service Incentive Scheme (CSIS) research: Quantitative survey measuring the relative importance that customers place on improvements in our services				✓				✓			
Vulnerable customer engagement: Exploring challenges facing customers experiencing (or at risk of) vulnerable circumstances, including during the energy transition	✓	✓	✓	✓		✓		✓	✓		✓
Energy transition summit and Future network forum: Identify service level expectations for management of emerging energy technologies, including rooftop solar and electric vehicles, and challenge future demand inputs	✓	✓	✓			✓		✓			✓
Customer energy futures: service level options paper: Customer expectations on service level outcomes for CER and electrification	✓	✓	✓			✓		✓			✓
Storage integration consultation paper: Outline and seek feedback on proposed approach to integrate storage connecting to our networks					✓						✓
Economic growth forum: Understand and identify key concerns for commercial and industrial customers, including tariff preferences	✓	✓	✓		✓						✓
Trade-off forums and quantitative surveys: Challenge customer willingness-to-pay or trade-off discretionary initiatives and service level outcomes, including overall bill impacts	✓	✓	✓	✓			✓	✓			✓
Joint distributor forums: Multiple forums to inform the development of tariff structures, resilience investment framework and how to best support customers experiencing vulnerability	✓			✓				✓			✓
Public lighting consultation paper: Test proposed public lighting service offerings and future investment plans										✓	✓

FIGURE 1.2 STAKEHOLDER ENGAGEMENT MAPPING: TEST AND VALIDATE

Key engagements	Electrification and CER integration	Augmentation	Replacement	Resilience	Connections	Information and communications technology	Property, fleet and other non-network	Operating expenditure	Metering	Public lighting	Incentives	Tariffs and pricing
Customer Advisory Panel: Ensure needs of our customers were understood, balanced and reflected in business plans	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Town hall: Provide an overview of our draft proposal and opportunity for customers to provide feedback directly to executive management	✓	✓	✓	✓		✓		✓	✓			
Community roundtable: Seek customer feedback on key draft proposal initiatives and level of investment	✓							✓	✓		✓	
First People's engagement: Attended BayMob Expo 2024 and VACSAL football and netball carnival to seek feedback on proposed First Peoples program	✓			✓				✓				✓
Energy Users Association of Australia (EUAA) engagement: Seek commercial and industrial customer feedback on key draft proposal initiatives and level of investment	✓	✓						✓				✓
Commercial and industrial interviews: Understand commercial and industrial customer concerns and support for draft proposal initiatives and tariff changes	✓	✓	✓					✓				✓
Quantitative study: Better understand customers' willingness to change consumption habits and understanding and support for tariffs, metering replacement and network control	✓								✓			✓

1.2 Our expenditure forecasts have been developed through a robust governance process

Our investment governance framework—which to date has delivered our customers amongst the lowest network charges in the National Electricity Market (NEM), while maintaining strong performance in safety and reliability—encompasses a set of principles, guidelines and controls that support planning, forecasting, decision-making, risk management and performance evaluation. This framework covers the capital and operating expenditure which directly relates to our network assets, as well as non-network investments that support the operation of our network.

As far as practicable, we have applied this governance framework in forecasting our expenditure needs for the 2026–31 regulatory period.[2]

For example, the investments included in our regulatory proposal are based on a consistent set of values applied through robust cost-benefit analysis and quantified risk-based assessments. These values align with standard AER assumptions (e.g. the value of customer reliability, customer export

[2] Our investment governance framework is set out in the attached: UE RIN 24 - Governance, forecasting and deliverability overview - Jan2025 – Public.

curtailment value and value of emissions reduction), or those determined through our quantified customer value analysis.

Development of our customer values

In 2021, we completed a significant body of work with our customers to develop an estimate of the value they place on various services, such as network resilience and enabling solar exports. These values were designed to be additive to other value measures, such as the AER's value of customer reliability (VCR).

We were the first network businesses in Australia to incorporate such values into our internal investment assessment approach. That is, these values are now contributing to the prioritisation of our capital program to support the likelihood that any investments align with our customers' expectations.

At the recommendation of the CAP, these values were re-tested and updated in 2024 to ensure they remain reflective of our customer's views. This reflected the view that the economic environment had changed materially, and the question of whether customer's preference had evolved as well.

The development of our expenditure forecasts also occurred through multiple expenditure iterations that progressively refined our investment portfolio. This process continually challenged and limited expenditure to those investments that deliver clear value for our customers.

In total, our iteration challenge process directly removed over $50 million of investments. It has also driven revisions in our demand forecast assumptions (to better align with customer and stakeholder feedback) that have further reduced our expenditure proposals.

The application of our governance framework has been further supplemented by challenges to our investment strategies and forecasts through input and oversight from the CAP. A key focus of the CAP has been on ensuring the diverse and changing needs of our customers are properly understood, balanced and reflected in business plans.

Another part of our expenditure challenge process included research to understand residential and small-medium business customers' willingness to pay for proposed initiatives, individually and collectively, through deliberative trade-off forums and quantitative surveys on key topics. In these sessions, customers were provided evidence of the expected outcomes and individual and cumulative bill impacts from different investment levels.

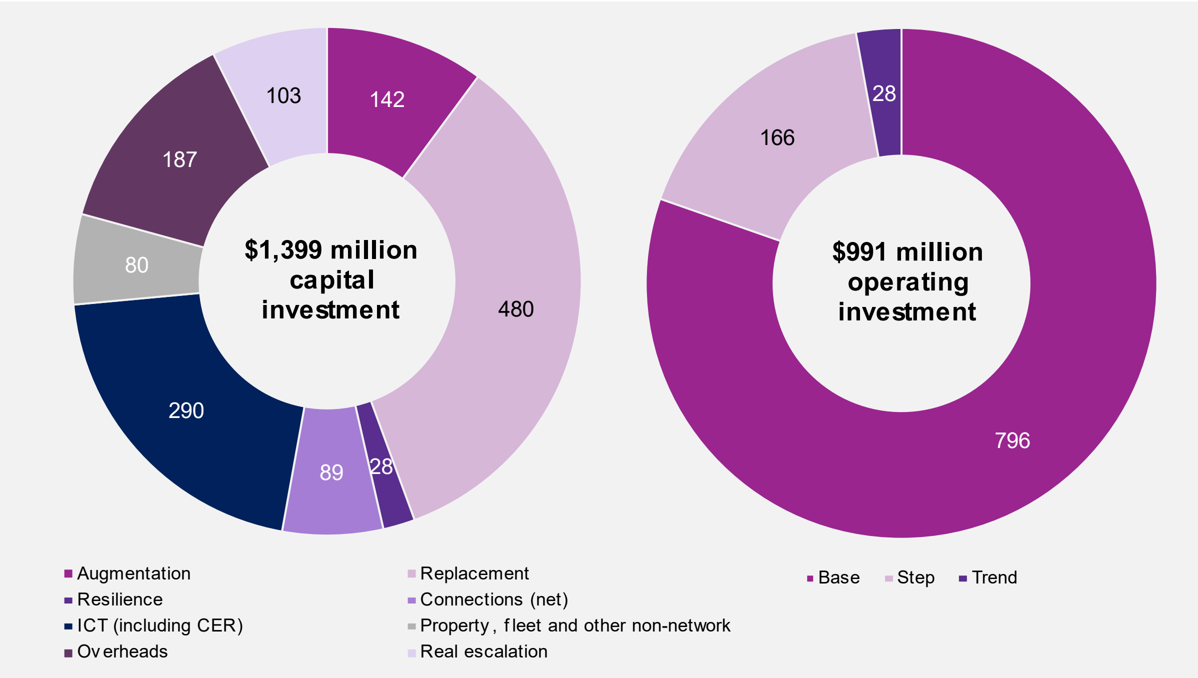
The outcomes of these customer trade-offs have been reflected in our expenditure forecasts.

1.2.1 Our expenditure forecasts

A summary of our proposed capital and operating expenditure forecasts for the 2026–31 regulatory period is set out in figure 1.3. As noted earlier, these forecasts were developed based on a robust governance framework.

Further detail on the basis of these forecasts is set out in the respective expenditure chapters.

FIGURE 1.3 CAPITAL AND OPERATING EXPENDITURE FORECASTS: 2026–31 ($M, 2026)



Note: Augmentation expenditure is net of disposals and the 'trend' component of operating expenditure is net of our productivity adjustment. Totals may not add due to rounding.

Proposed capital expenditure

Our net capital expenditure in the current regulatory period will marginally exceed the AER's allowance (but will further exceed this allowance after one-off asset disposals are excluded).

This overspend is driven by rising input costs that arose during the pandemic, and supply chain pressures that have not abated (as demand for labour and materials remains strong, both globally and domestically). This has impacted both distribution and zone substation projects.

Our augmentation spend, however, was lower due to efficient management of consumer energy resources (CER) following the stronger than expected performance of our dynamic voltage management system and other low cost interventions (like our industry leading work to identify and address incorrect customer solar settings with solar manufacturers). Actual net connections were also lower, driven by higher contributions.

For the 2026–31 regulatory period, our capital expenditure forecasts benefit from our relatively mature and stable investment profile over multiple regulatory periods. Our forecast, for example, is not dissimilar to investment levels observed previously, such as throughout the 2011–16 and 2021–26 regulatory periods.

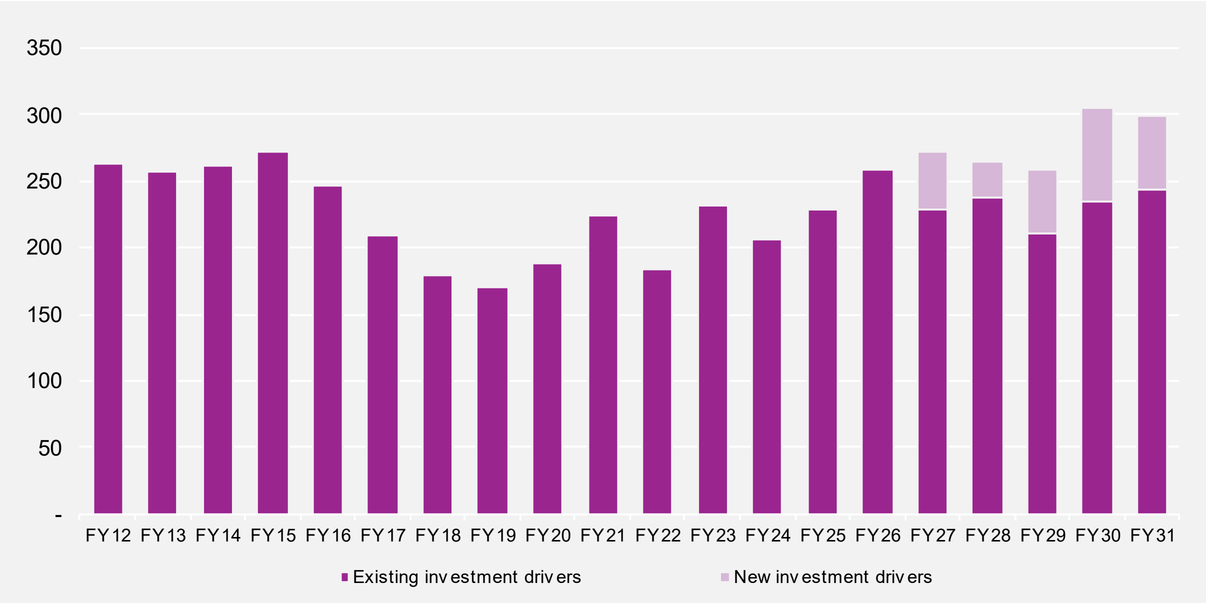
The drivers of our capital expenditure uplift for the 2026–31 regulatory period are discussed in detail further in this document. At a high level, these drivers include the following:

- we are one of the most highly utilised distribution networks in Australia, meaning the electrification of transport and gas, customer growth and CER integration are driving increasing augmentation. We have been a leader in utilising non-network solutions to manage steady growth historically, but this ongoing electrification will result in the construction of a new 66kV sub-transmission line in the lower Mornington Peninsula (following successful deferral in previous periods with non-network solutions)

- asset replacement forecasts are increasing to manage our aging distribution assets, including observed condition and defect trends. These forecasts are partially offset by a reduction in zone substation asset replacements following higher levels of investment in recent years
- new investments are required to strengthen our network and communities against increasing frequency and severity of extreme weather. Our resilience proposal implements the recommendations of two separate reviews undertaken by the Victorian Government
- our information and communications technology (ICT) portfolio includes upgrades to our cyber-security systems, replacement of our enterprise resource planning (ERP) and billing system, CER integration, and additional regulatory compliance associated with post-2025 NEM market reforms
- uplifts in connection activity, noting that our proposal does not include likely growth impacts from recent Victorian Government policy announcements regarding housing precincts along key rail corridors.[3]

Overall, our capital expenditure is forecast to increase in the 2026–31 regulatory period relative to recent periods, but is not dissimilar to our longer-term historic levels. A summary of our total capital investment over multiple regulatory periods is shown in figure 1.4, with the impact of new drivers in the 2026–31 regulatory period shown separately.

FIGURE 1.4 ANNUAL NET CAPITAL EXPENDITURE ($M, 2026)



Note: New investment drivers include, for example, customer-driven electrification and new CER investments (such as flexible services).

Proposed operating expenditure

Our operating expenditure forecast for the 2026–31 regulatory period has been developed using the AER's standard 'base-step-trend' approach.

As set out in our operating expenditure chapter, the key drivers of this forecast include our proposed step changes in vegetation management, ICT investments (including CER integration and reflecting the changing nature of IT solutions and market reforms), network and community resilience, and our

3 We have responded directly to stakeholder feedback and taken a cautious approach for large projects with uncertain timing. Pending further detail (and if required), we will reflect these works in our revised regulatory proposal, either as expenditure forecasts or through the existing uncertainty mechanisms.

program to better support customers experiencing or at-risk of experiencing vulnerable circumstances (including our First Nations customer package).

1.2.2 Our revenue forecast

Our expenditure forecasts are a direct input to our revenue building block approach, which consistent with the National Electricity Rules (the Rules), has been used to calculate our revenue requirement. This revenue requirement is summarised in table 1.1 and represents a 15 per cent uplift on the current regulatory period.

Our approach also uses the AER's roll forward model (RFM) and post-tax revenue model (PTRM), standard AER approaches for depreciation, asset lives and the rate of return, and has been prepared in accordance with our currently approved cost allocation method.

Further detail on these approaches is set out in our revenue and control mechanism attachment.[4]

TABLE 1.1 REVENUE REQUIREMENT ($M, NOMINAL)

BUILDING BLOCK	FY27	FY28	FY29	FY30	FY31
Return on assets	179	189	198	209	224
Regulatory depreciation	145	160	177	192	204
Operating expenditure	181	199	224	235	239
Incentives	43	4	-1	2	-3
Corporate income tax	3	4	4	6	6
Unsmoothed revenue requirement	552	556	602	644	671
Revenue X factor (%)	**-7.4%**	**-1.0%**	**-1.0%**	**-2.0%**	**-2.0%**

1.2.3 Customer bill impacts

Affordability was a key theme throughout our engagement program, recognising the prevailing cost of living challenges. In the context of the energy transition, however, customer sentiment was also focused on how our network can enable and unlock customer ‘value’ now and in the future—as noted by the Customer Advisory Panel, the big message on affordability from most, though not all customers, is about value rather than cost.[5]

This value recognises that in the longer-term, electrification is expected to deliver significant benefits for all customers. For example, recent research from the Australian Energy Market Commission (AEMC), Energy Consumers Australia (ECA) and other independent third parties have all outlined the long-term benefits of electrification.

For our regulatory proposal, the nominal average annual estimated distribution bill impact from our investments over the 2026–31 regulatory period, compared to 2025–26, is outlined in table 1.2

4 UE ATT 1.01 – SCS revenue and control mechanism – Jan2025 – Public.
5 UE ATT SE.30 – CAP - Report on Draft Proposal – Nov2024 – Public.

(calculated in accordance with the AER's bill impact template). These impacts are modest, and at the same time, our customers will receive no material increase in nominal meter charges.

TABLE 1.2 NOMINAL AVERAGE ESTIMATED BILL IMPACT

CUSTOMER TYPE	DISTRIBUTION CHARGES(1)	METERING CHARGES(2)
Residential	+$2.90	+$0.13
Small business	+$7.74	+$0.13

(1) Any final impact to customers will depend on factors such as the willingness of electricity retailers to reflect our price reductions in their pricing, actual energy consumption and the impacts of financial service performance incentive schemes.

(2) Metering charges are shown for a single-phase meter; if the customer has a three-phase meter, these savings will be greater.

2. Electrification and CER integration strategy

The 2026–31 regulatory period is one of critical change, as the pace and scale of electrification accelerates through the energy transition and customer behavioural preferences evolve.

The scale and scope of these changes—particularly in Victoria—mean that our energy system in the future will need to function very differently to the energy system we have now. Decisions made today need to be fit for purpose for tomorrow.

To better understand and plan for these changes, including the urgency of any potential response, we developed our electrification and CER integration strategy. Given the impact of electrification and greater uptake of CER, our strategy involves the following:

- using enhanced, industry-leading forecasting capabilities to better understand potential customer and network impacts (including capacity and voltage constraints)
- maximising utilisation of our existing infrastructure and exhausting all possible low-cost solutions
- optimising any remaining economic constraints and undertaking no-regrets investments that enable customers to derive value from their CER.

Importantly, while investment to support electrification and CER integration will come at some cost to customers, the long-term benefits will materially outweigh these to deliver overall value for customers, even customers who cannot fully electrify. For example, the AEMC recently projected electrification (including our draft proposal investments) to drive a 19 percent fall in Victorian electricity prices to 2031.[6]

Stated alternatively, the risks and consequences of not acting now will be a slower and more disruptive energy transition, including higher costs for customers, poorer service level outcomes and higher emissions that may fail to deliver on committed targets.

The components of our electrification and CER integration strategy are summarised below with each component discussed in further detail throughout this section. Customer and stakeholder feedback has played a key role in the development of this strategy.

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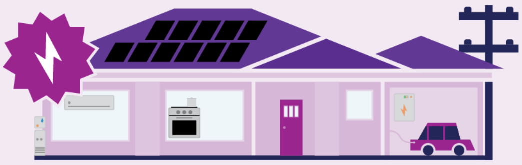
6 Australian Energy Market Commission, Residential electricity price trends, 2024, p. 32.

FIGURE 2.1 OVERVIEW: ELECTRIFICATION AND CER INTEGRATION STRATEGY

Customers are increasingly electrifying their homes to save money and look after the environment

All customers benefit from electrification through lower prices



We have developed industry leading forecasting capabilities to better meet customers' emerging energy needs

Inputs
Using smart meter data, customer insights and industry/government forecasts

HV forecast tool
Including **daily** minimum and maximum demand forecasts (**thermal**) for every **ZSS and HV feeder**

LV forecast tool
Including **30-minute** minimum and maximum demand forecasts (**thermal and voltage**) for every **LV and HV asset**

More accurate customer impacts quantified

We are maximising utilisation and exhausting all possible low-cost solutions

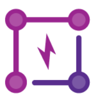
2021–26	2026–31	2031 onwards	Initiative type
		Cost-reflective tariffs	B
		Network optimisation (e.g. inverter compliance, hot water shifting)	B
Built		Dynamic voltage management system (DVMS)	B
Built		Victorian emergency backstop mechanism	E
	Semi-automated	Non-network marketplace	B
	Build	Enhanced data visibility	B
	Build	Flexible exports	E
	Build	Flexible load	L

B Both load initiative and export initiative E Export initiative L Load initiative

And optimising remaining augmentation

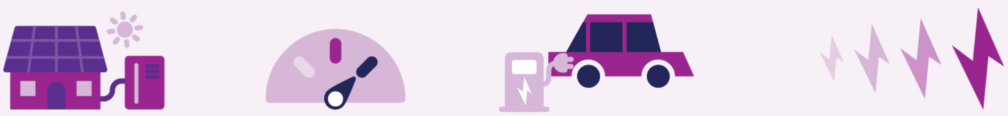
Identifying where single HV solutions can remove multiple LV constraints

Efficiently balancing proactive and reactive investments to deliver lowest long-term costs to customers



Assessing future replacement needs in augmentation planning to future-proof for electrification

Enabling customers to derive value



90% of customers can freely export 99% of the time

All customers can **export up to network limits**

All customers have **universal access to standard wall charging**

Maintain existing performance for all customers to provide confidence in the energy transition

2.1 What we've heard from our customers

The success of the energy transition, and broad-scale electrification, is deeply dependent on a positive customer experience. Our customers need confidence in their energy system to have confidence to fully electrify their homes and lifestyle.

To ensure our electrification and CER integration strategy is informed by these customer expectations, our engagement program included multiple energy transition and future-focused stakeholder summits, and our partnership with Monash University in the development of the Future Home Demand report.[7]

Energy transition summit and Future energy network forum

Recognising the fundamental changes that are occurring as part of the energy transition, we released an options paper and facilitated two separate forums to explore the priorities and expectations of customers and stakeholders on the utilisation and management of emerging energy technologies.

Focusing on rooftop solar, electric vehicles (EV) and electrification of gas, we sought preferences on service levels and investment options to better identify customer value propositions.

Participants were committed to greater equality, with a response to the climate emergency guiding their service level preferences, and highlighted the importance of capacity increases.

Stakeholders also supported a measured approach to EV charging enablement, and recognised that forecasts for electrification of gas were too conservative to achieve net zero by 2050 but the logistics of electrifying gas were challenging.

Monash University: Future Home Demand report

In 2023, we partnered with Monash University to better understand longer term behavioural trends to inform electricity sector planning. This involved research inside our customers' homes, with questions about their lifestyles, energy use practices and how they expected these to change in the future.

The study was a multi-staged research project with 36 households, supported by a survey of 1,325 customers. The study identified household implications for energy forecasting and generated insights for EV adoption, charging practices, demand management opportunities and future peak scenarios.

In addition to developing clear outcomes, our engagement focused on key input factors such as how customers expect to adopt and use CER and electrification technologies. These inputs are used in our demand forecasts, which underpin our entire regulatory proposal.

We also held mass market trade-off evaluation forums where customers chose between several costs and service levels for different initiatives. Customers at these forums supported investments to enable more solar export and improve stability of EV integration.

The key findings from our engagement around customer expectation and preferences on electrification and CER integration are summarised in table 2.1.

[7] UE ATT SE.10 – Monash University – Future home demand – Jul2023 – Public.

TABLE 2.1 KEY ENGAGEMENT FINDINGS

Solar export

Customers and stakeholders advocated for strategic investments in grid capacity, empowering consumers to make informed decisions and drive renewable energy integration while preventing anyone from being left behind.

Our customers echoed a commitment to equity for solar exports and felt strongly about responding to the climate emergency, which guided investment preferences. Stakeholders highlighted the importance of capacity increases to support positive flexible export outcomes and more hosting capacity.

Sentiment towards solar exports is positive with a focus on maximising solar energy output with smarter solutions. Customers prioritise self-consumption over export and strongly oppose export tariffs as they perceive them as additional costs.

Stakeholders expressed a collective belief in the benefits of flexible solar exports. Preferences for supporting solar-driven capacity improvements to avoid 'wastage' of renewable energy emerged, however latent concerns about non-solar customers bearing the cost of solar upgrades also emerged.

Electrification of gas

There were mixed views on the speed of electrification of gas, with some stakeholders suggesting forecasts were too conservative and that net-zero targets would be missed, where others suggested that cost and industry logistics to decarbonise were prohibitive.

New builds were considered the path of least resistance to electrify gas, whereas existing homes were seen as more challenging to electrify. Induction cooktops and space heating are the most likely household technologies to be electrified.

Customers expressed concern about the impact electrification may have on stability of the grid, particularly in the evening where induction cooktops would contribute to peak demand and in winter where heating has predominately been powered by gas.

Electrification of transport

Customers generally view EVs favourably, recognising their potential to support rapid decarbonisation and their economics due to rising fuel prices. Our customers prioritised reliable electricity supply and sought clear leadership through the energy transition.

However, some stakeholders expressed uncertainty about the speed of EV uptake, with remaining concerns about upfront cost (where government incentives are seen as a key requirement for uptake). Network reliability, range anxiety and availability of charging infrastructure were seen as barriers to overcome.

81 per cent of customers said they preferred to charge their EV at home, with 71 per cent of those customers preferring faster (level-two) charging and 29 per cent preferring slower (level-one) charging. Access to charging facilities continues to affect EV uptake.

Customers continue to have set views of how and when to charge electronic devices, which is likely to translate into EV charging and automation settings.

Customers generally support managed charging, however 96 per cent of customers require manual or override settings, indicating a strong preference to maintain control.

Stakeholders recognised the need for investment and a measured approach.

Commercial and industrial customers

Commercial and industrial customers consider power quality and network reliability as the most significant factors affecting their business operations. They experience a spectrum of problems related to interruptions, harmonics, power factor, voltage sags and surges.

Power disturbances, even if momentary, were reported to have material implications for these customers including substantial disruptions to production, loss of inventory, delays with cleaning and sterilising, and revenue loss. Power quality is seen as an increasing concern through the energy transition as more equipment becomes electrified.

Commercial and industrial customers shared concerns about access to future load and operational sustainability, and therefore prioritised unrestricted access to electrical supply and improvements to power quality that meet their operational needs as network demand continues to grow.

Energy storage was also assessed by customers as a viable option to support power quality improvements.

2.1.1 Test and validate

Our CER integration and electrification initiatives are highly tangible to customers because they contain several 'touch points' and deliver direct benefits for customers.

As part of our test and validate program, we endeavoured to understand more about the profiles, key motivators and barriers that influence consumer willingness to modify energy consumption habits. We also assessed consumer awareness, understanding and responsiveness to time-of-use energy tariffs, acceptance of network control and our overall program of investments.

Broadly, customers supported our proposed investments and our overall program of investments represented value for the services we delivered:

- 49 per cent of small and medium business customers and 55 per cent of residential customers were unfamiliar with the concept of time-of-use tariffs
- 54 per cent of small and medium business customers and 74 per cent of residential customers felt that lowering energy bills was the biggest motivator to shift energy usage to off-peak times
- 79 per cent of customers supported bill increases to enable more solar exports for all customers
- 72 per cent of small and medium business customers and 44 per cent of residential customers planned to replace their gas appliances with electric appliances over the next five years
- just 32 per cent of small and medium business customers and 19 per cent of residential customers felt that our proposed bill impacts did not represent value for the service that they received.

Customers also contributed their views on our programs related to CER integration and electrification. These findings are discussed in the context of our proposed investments below.

2.2 Customers are increasingly electrifying and investing in CER

The way our customers are using electricity is rapidly changing, with state and federal government policies influencing adoption of new technologies. This transformation of electricity needs is occurring at the same time as more typical network investment drivers like population growth, asset risk and safety persist and/or grow.

Considering all these factors holistically, annual consumption is expected to grow by 25 per cent, and peak demand by 5 per cent by the end of our 2026–31 regulatory period.

2.2.1 Net-zero commitments

The Victorian Government has a strong and enduring commitment to electrification, with a major focus on decarbonising the energy and transport sectors on its pathway to net-zero.

The pathway is supported by its objective of achieving net-zero by 2045. This commitment is further supported by legislated interim targets, including:

- 50 per cent reduction in carbon emissions by 2030 (below 2005 levels)
- 65 per cent of Victoria's electricity coming from renewable sources by 2030 (increasing to 95 per cent by 2035).

The achievement of these targets is driving new supply and demand-side interventions, and customer behavioural change.

2.2.2 Renewable generation and BESS deployment

To put the scale of the Victorian Government net-zero commitments into context, achieving 95 per cent of Victoria's electricity from renewable sources (by 2035) is expected to require around 30GW of wind and solar. This equates to more than two and a half times the renewable capacity that exists today.

Historically, this renewable generation has connected to the transmission network. However, over 830MW of renewables are connected directly to our distribution network, and this is expected to increase. There is also growing development activity in large scale BESS, such as the Springvale BESS project that recently was awarded a contract by the Commonwealth Government for the Capacity Investment Scheme.

Much of this renewable generation is provided by solar PV, with rooftop systems installed by over 19 per cent of our residential customers. The capacity of this rooftop solar connected to our network has doubled in the last five years alone, and is forecast to double again by the end of 2031.

While rooftop solar provides many benefits, including savings for customers and a reduction in Victoria's carbon emissions, high solar uptake can also lead to system security challenges such as minimum system load.[8] During December 2023, for example, Victoria set a record low for minimum operational demand.

Looking forward, the Australian Energy Market Operator (AEMO) are forecasting negative operational demand for Victoria in 2027.

2.2.3 Electrification of transport

EVs will transform our electricity grid, for both EV and non-EV owners, with increased consumption from wide-spread adoption having the ability to lower per-unit energy charges for all customers.

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[8] Minimum system load typically occurs when demand from the grid is low and the output from solar is high, and can lead to local or state-wide blackouts.

AEMO forecasts rapid growth in EV uptake, with 26 per cent of our customers expected to have an EV by 2031. This is almost 10 times the number of EVs on the road today.

AEMO's forecasts are consistent with existing Victorian Government policy, including its stated goal of a fully decarbonised road transport sector by 2045. This policy objective is supported by a target of 50 per cent of all new light vehicle sales to be zero emissions vehicles by 2030.

Collectively, the electrification of transport will increase Victoria's electricity usage by 5 per cent in 2031. Any impacts of EV charging on our network, however, will be heavily dependent on customer charging behaviour and geographic factors such as the localised concentration of EVs (including for our network, the need to support EV charging at major hubs, such as large shopping or tourism precincts).

2.2.4 Electrification of gas

Victoria has the highest percentage of gas connections in Australia, with around 80 per cent of residential homes connected to gas. We are more dependent on gas than any other jurisdiction, with triple the average annual consumption of New South Wales and South Australia customers, and seven-times that of Queensland. We also use over 40 per cent more than ACT and Tasmanian customers who live in similar cool climate zones.

In 2022, the Victorian Government published its Gas Substitution Roadmap.[9] This roadmap outlined the pathway to transition away from residential gas in Victoria, with the first key step being the ban on new residential gas connections from January 2024.

AEMO forecasts that the electrification of gas will result in an additional 2,600GWh of electricity being consumed per year by Victorians, primarily for space and water heating. This is expected to increase consumption by 7 per cent, improve utilisation and shift areas of our network to winter peaking.

2.2.5 Population growth

In 2023, Melbourne overtook Sydney as Australia’s largest city. This continued a trend of strong population growth across Victoria, including the south-east and across the Mornington Peninsula.

By 2031, AEMO forecast population growth of 13 per cent, or an additional 880,000 people calling our state home. In our network area, this is equivalent to an additional 100,000 people.

2.2.6 Behavioural change

In 2023, we partnered with Monash University to better understand longer term behavioural trends to inform electricity sector planning. This involved research inside our customers' homes, with questions about their lifestyles, energy use practices and how they expected these to change in the future.

The study identified household impacts and implications for energy forecasting. The research generated insights for EV's and charging practices, demand management opportunities and future peak scenarios.

Monash's findings support the view that working and studying from home will be a permanent feature. They also identified increasing trends towards greater in-home care, recreation and home automation. These trends all add to the increasing dependency on a reliable supply from the electrification of our energy system.

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9 Victorian Government, Gas Substitution Roadmap, 2022.

2.3 Enhanced forecasting capabilities allow us to better understand customer impacts

The changes above, both individually and collectively, are transforming our network. Our ability to forecast these changes, and understand their potential impacts on our network and customers, is fundamental to ensuring efficient outcomes and delivering desired customer experiences.

2.3.1 HV network

Our HV network forecasting tool is well established, and has been used and refined within our planning and asset management practices for multiple regulatory periods.

This tool generates detailed demand forecasts across our entire HV network, from our transmission connection to our distribution substations. It considers a wide range of information such as customer usage, customer insights, network topology, AEMO data, industry research, tariff impacts and weather to forecast probabilistic minimum and maximum demand through Monte Carlo simulation.

The tool accounts for all change drivers like residential and commercial gas electrification, EV growth and charging profiles, solar PV and batteries. This includes expected usage assumptions—for example, our HV forecasting tool weights EV adoption to dwellings that have a location to charge EVs (i.e. EVs are more likely to be adopted by a customer living in a house compared with a customer living in an apartment).

It also accounts for macroeconomic factors like energy efficiency, population growth, gross state product, income, home ownership and more to assess locational network impacts.

2.3.2 LV network

The uptake of new customer-centric loads is creating significant change and uncertainty on our LV network. These changes are impacting customers already.

To manage this increasing uncertainty, and more accurately assess the locational impacts of the energy transition, we developed new LV analysis and forecasting capability that significantly improves the sophistication and granularity of our forecasts.

This is a fundamental evolution in our forecasting capability, leveraging the extent of our smart meter population, and sets us apart from other distributors (who are typically required to rely on simplified archetype modelling).

Specifically, our LV forecasting tool uses power flow modelling to analyse the impacts of forecast energy use for every customer on our network. This analysis identifies the location and severity of both thermal and voltage impacts across our entire HV and LV network every 30 minutes. This power flow modelling incorporates real customer data as a starting point and considers the interconnected nature of electricity networks, where load on each asset has an impact on other interconnected assets—in total, it relies on over 800 billion data points through the computation process.

Our new LV forecasting and analysis capability builds on our HV forecasting tool and we can now assess the holistic impact of all change drivers (e.g. solar export, EV charging, electrified gas and general growth) simultaneously. The tool details the location, severity and impact of each constraint over time and we have developed economic assessments that leverage outputs from the tool.

We have also aligned our EV charging forecasting assumptions in our LV forecasting tool with the findings from Monash University's Future Home Demand report.

FIGURE 2.2 TIME-SERIES, CUSTOMER LEVEL THERMAL AND VOLTAGE FORECASTS

Traditional forecasting

Focussed on understanding single asset impacts where constraints are considered in isolation.

Key outputs:

- HV assets
- thermal constraints
- daily minimum and maximum demand
- LV assessments limited to direct impact on individual circuits

Enhanced forecasting

Our new approach considers our network as an interdependent system where constraints are considered holistically.

Key outputs:

- HV **and LV** assets
- thermal **and voltage** constraints
- forecasts demand in **30-minute intervals**
- LV assessments based on **power flow modelling** which considers **localised network** and **customer impacts**

Customer outcomes

Better network and customer visibility providing more accurate and granular forecasts, allowing us to better utilise existing network capacity and have better certainty on when and where to invest.

The criticality of accurate forecast tools is becoming further evident in predicting, and acting on, customer impacts. Today, we are observing in practice that a few EVs on a single residential street can be enough to create network constraints that severely impact customers.

For example, below is a case study on EV charging demonstrating some of the challenges our customers are experiencing now. This issue is not isolated; we have received numerous similar complaints from our customers where their EVs have not charged.

The prevalence and severity of undervoltage-driven constraints will grow over time as customers continue to electrify.

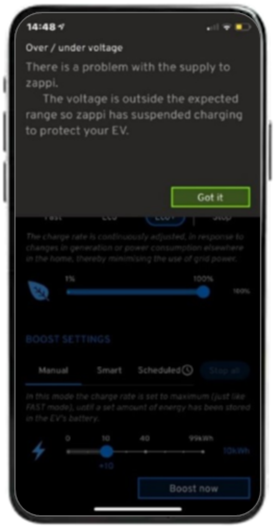
CASE STUDY: DAY-TO-DAY ACTIVITY IMPACTED BY UNDERVOLTAGE

A customer in Mount Eliza complained to us that their **EV was not charging, which impacted their day-to-day activities**.

The customer's phone application notified them that there was a problem with the voltage levels being supplied to charge their EV, and their EV charger had suspended charging.

We found that there was large voltage fluctuations, where voltage levels repeatedly dropped below 200V.

We installed a new substation and LV circuits to remediate the issue and ensure the customer was supplied with compliant voltage levels. The **total cost of remediation was $115,000**.



2.4 Exhausting all possible low-cost solutions to optimise outcomes

Throughout our current regulatory period, we have taken several steps to maximise the utilisation of our existing infrastructure to support electrification and CER. These low-cost solutions have delivered significant benefits for customers.

Examples of some of our low-cost approaches are outlined in table 2.2, with the impacts of these tools reflected in our revealed historical data (e.g. tap settings), and/or in our input assumptions (e.g. future tariffs). These low-cost approaches will be supported by the functional capabilities developed through our role as the distribution system operator, including our upgrades to our advanced distribution management system (ADMS) providing greater real-time visibility of customer behaviour.

For the 2026–31 regulatory period, we are building on this existing 'toolkit' to ensure we exhaust all possible low-cost solutions ahead of any augmentation. New low-cost solutions are a key feature of our electrification and CER integration strategy, and include wider testing of third-party capabilities, enhancing data visibility for stakeholders, maximising customers' ability to export to our network, and preparing for flexible load products.

A fulsome description of each of these proposed investments is provided in section 2.4.1.

TABLE 2.2 EXISTING LOW-COST SOLUTIONS

SOLUTION	DESCRIPTION
Cost-reflective tariffs	Implementing increasingly cost-reflective tariffs to incentivise consumption outside typical peak demand periods and increase network utilisation. For example, implementing a CER tariff that rewards customers for exporting during peak demand periods. Further information is available in our tariff structure statement
Adjusting asset settings	Low-cost augmentations that use existing capacity more effectively, for example, setting distribution transformers to different voltage set points (known as tapping) or balancing customer load across the three phases to stabilise power quality
Inverter compliance	Proactively identifying 40,000 non-compliant inverters in Victoria and working with installers and manufacturers to ensure compliance, improving local power quality and export outcomes for customers
Solar pre-approval	Implementing streamlined pre-approval for customer solar export connection requests in five minutes, based on local network power flow analysis
Dynamic voltage control	Optimising voltage levels across our HV network to maximise voltage compliance and power quality outcomes for customers
Victorian emergency backstop mechanism	Investment to meet the Victorian Government's legislation to maintain system security and limit the impact of minimum operating demand during peak solar generation periods by temporarily limiting generation or increasing demand
Hot water load shifting	We are also planning to build on our hot water load shifting trials to shift our controlled load hot water heating from overnight to the middle of the day. This will increase electricity demand in the middle of the day and support more solar export

2.4.1 Proposed non-network solutions: 2026–31 regulatory period

We are proposing to build on our existing low-cost solutions, with new capabilities in the 2026–31 expected to further exhaust all possible low-cost options. These capabilities include utilising new tariffs, offering flexible services for CER, improving data capture and availability, and increasing visibility for third-parties to remediate network constraints.

Collectively, we expect these solutions will create optionality, and will deliver improved services and lower prices for customers over the long term.

Cost reflective tariffs

We are proposing a suite of simple, efficient and adaptable tariffs for our 2026–31 regulatory period that are the most cost-reflective tariffs we have ever implemented. Our tariffs provide better pricing signals for customers to use and export electricity in ways that shift consumption away from peak periods and incentivise consumption during off-peak periods to increase network utilisation.

COST REFLECTIVE TARIFFS	COST
Our stakeholders expected that we introduce price signals for flexible resources, while maintaining simplicity and predictability across our tariff portfolio. We are proposing an opt-in two-way CER tariff that includes an export charge from 11am to 4pm and an export rebate from 4pm to 9pm. The tariff targets retailers and aggregators who can use flexible import and export devices such as home batteries and EVs with vehicle-to-grid capability to support the network. For commercial and industrial customers, we are implementing a winter incentive demand period and non-residential flexible connection tariffs. The non-residential flexible connection tariffs are largely targeted at integrating community batteries and grid-scale storage into our network, but also accommodate other potential flexible technologies such hydrogen production. EV charging stations will continue to be able to opt out of demand tariffs if they consume less than 160MWh per annum, and we plan to trial tariffs for dedicated low voltage EV charging sites, such as pole-mounted EV chargers.	-

Note: For further detail, refer to our tariff structure statement: United Energy Tariff Structure Statement 2026—31 – Explanatory Statement – Jan2025.

Network data visibility

We currently publish annual network and constraint data through our Rosetta network visualisation portal. However, with the growth in CER on the LV network, customers are seeking improved LV insights to make more informed decisions. We are observing an increasing amount of network data requests across a range of stakeholder such as, councils, market participants, customers, and Government.

NETWORK DATA VISIBILITY	COST
We are proposing to implement an improved customer portal presenting our physical network that will publish constraint and spare capacity data in a more usable, interactive, and timely way. This will enable more opportunities for a range of stakeholders to better understand connection opportunities as well as unlocking potential innovation. Our involvement in the AER and Victorian Government network data trial uncovered the ‘pain points’ that need to be improved including data timeliness, useability, and level of detail available. We are continuing our involvement in the network visibility program to incorporate the learnings into our proposed program. Customers through our test and validate program called for equitable access to data, ensuring all customers regardless of location or size could leverage this information. Customers supported our proposed data visibility program noting that equitable access to practical, timely and extensive data would be beneficial.	CAPEX $1M OPEX $2M

Note: For further detail, refer to our attached business case: UE BUS 2.03 – Network data visibility – Jan2025 – Public.

Non-network platform

In 2023, we partnered with the non-network solution platform, Piclo, to run a trial where we tendered our forecast network constraints. Non-network solutions have the potential to provide significant benefits for customers as third-parties may be able to address network constraints more efficiently than building more network.

Our current experience is that it takes time and commitment to successfully foster development of a third-party non-network solution market. A mature non-network marketplace has the potential to significantly improve network utilisation and lower costs for customers.

NON-NETWORK MARKETPLACE	COST
We are proposing to implement a procurement platform to create an automated marketplace where our constraints will be visible and actionable for third-parties to immediately resolve. Although expected uptake from third-party providers may be low initially (reflecting international experience, particularly that of the United Kingdom), encouraging market participation takes time to build and our platform will encourage market maturity. Notwithstanding this, we expect to defer $0.8m of augmentation in the 2026–31 regulatory period and have reduced our augmentation proposal accordingly. We will also absorb any operating expenditure costs associated with procuring these services. Through our test and validate program, stakeholders supported this innovative investment despite the current market for third-party suppliers being new.	CAPEX $2M OPEX $4M

Note: For further detail, refer to our attached business case: UE BUS 2.02 – Non-network marketplace – Jan2025 – Public.

Flexible exports

The capacity of rooftop solar is forecast to double by the end of 2031. This reflects the many benefits provided by rooftop solar, including savings for customers and a reduction in Victoria's carbon emissions.

Our networks' existing capacity to host solar exports (or our 'intrinsic hosting capacity') is being increasingly utilised as more solar connects. For example, 4 per cent of new solar customers in 2024 have been offered static zero export limits of less than 5kW because the available local intrinsic hosting capacity has been used by existing solar customers (who under existing standard connection agreements are provided static 5kW export limits if capacity is available). With the network quickly reaching its hosting capacity, and significantly more solar to be connected in the period, the proportion of export limited customers is expected to dramatically increase. Across Victoria, we are also facing imminent minimum demand issues from static uncontrolled PV exports, as evidenced by the Victorian Government's emergency backstop mechanism.

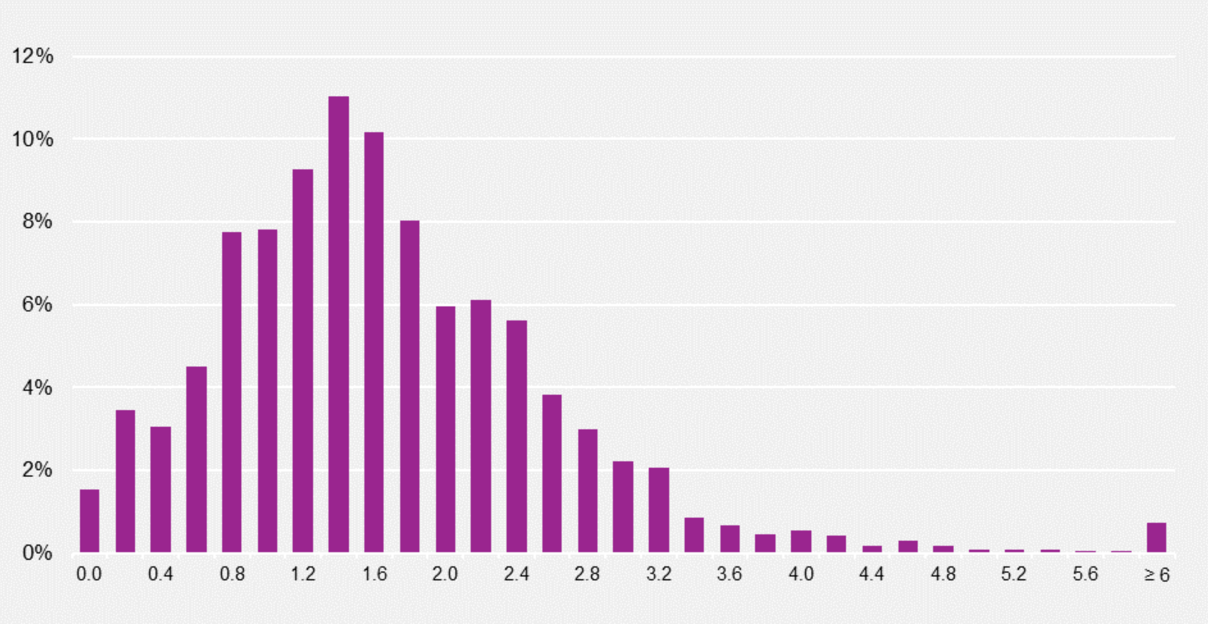
Intrinsic hosting capacity assessment

We used our LV forecast tool to assess the intrinsic hosting capacity at each customer connection point across our network.

Overall, and as shown in figure 2.3, we found that the median intrinsic hosting capacity to support exports is 1.5 kW per customer. This means that half of our network can support solar exports of 1.5 kW per customer and the other half would be constrained.

Our network's total intrinsic hosting capacity to support small-scale solar is 1,060 MW, which we expect to become more utilised over 2026–31, particularly in urban areas with high solar penetration.

FIGURE 2.3 PERCENTAGE OF CUSTOMERS WITH INTRINSIC HOSTING CAPACITY (KW)



FLEXIBLE EXPORTS	**COST**
Our customers have expressed expectations that we place more emphasis on fairness and equity for solar exports, prioritising long-term approaches and employing smarter solutions. To better use our existing hosting capacity, we are proposing to implement flexible export products that will vary customers' export limit through the day based on the available network capacity. This will utilise our existing infrastructure to enable an additional 180GWh of export for customers over 2026–31, equivalent to the total annual generation of 30,000 5kW solar systems, with even more future benefits. All solar customers will be offered a flexible export product, including existing export limited solar customers who will be eligible but may need inverter upgrades to support a flexible product depending on the age of their system. We are also planning to enable more equitable long-term access to exports for all customers, by reducing our standard static export limit from 5kW to 1.5kW because existing network intrinsic hosting capacity is being eroded and customers will have the option of a more efficient flexible export product. Customers and stakeholders at our energy transition summit expressed a collective belief in the benefits of flexible export products, stemming from economic considerations and a desire to support sustainable initiatives for future generations. 79 per cent of customers at our trade-off forum supported bill increases of $1.55 or more to support solar exports. Support for our flexible exports program was reinforced through our test and validate roundtables, where stakeholders preferred equal allocation of capacity across flexible customers and noted that sentiment focused on balancing fairness, network constraints and clear communication to foster realistic customer expectations. We are proposing no export-driven augmentation across our 2026–31 regulatory period. After accounting for the benefits of flexible exports, no efficient augmentation sites were identified using the AER's customer export curtailment value and value of emissions reduction. There was also limited support throughout our broader engagement program for network augmentation to enable more solar exports (in contrast to using smarter solutions such as flexible products).	CAPEX $11M OPEX $13M

Note: For further detail, refer to our attached business case: UE BUS 2.01 – Flexible services – Jan2025 – Public.

Flexible load

EV adoption will be a key driver of load growth on our network for many years to come, and as customer experience and confidence with EVs grows, flexible load products are likely to play a role in ensuring efficient investments. For example, EV charging is likely to be somewhat flexible for many customers.

Our research with Monash University indicates that over 50 per cent of customers may be amenable to automating some of their EV charging as long as they have the ability to override automated signals. Customers and stakeholders at our energy transition summit, however, shared mixed views about the necessity and customer appetite for flexible load products.

FLEXIBLE LOAD	COST
We are proposing to develop and refine the capability to implement flexible load products during the 2026–31 regulatory period, in preparation for scale implementation of flexible load products during our 2031–36 regulatory period. Developing this capability in 2026–31 will require us to build systems, ensure interoperability, iteratively learn from trials, and refine our understanding of how customers adopt and respond to flexible load products. Our approach recognises the mixed support from our customers and stakeholders and allows time for further engagement on design and implementation to ensure that customers are comfortable with flexible load products and they are not seen as a barrier to the energy transition.	CAPEX $2M

Note: For further detail, refer to our attached business case: UE BUS 2.01 – Flexible services – Jan2025 – Public.

2.5 Optimising the remaining augmentation portfolio with no-regrets investments

All else equal, our electrification and CER integration strategy prioritises low-cost solutions ahead of network investment.

Our low-cost solutions, however, will be supplemented by targeted no-regrets network upgrades in the 2026–31 regulatory period that improve capacity and provide customers with more ability to consume and export electricity. These investments include our customer-driven electrification program.

Importantly, these investments are also optimised. For example, our customer-driven electrification program minimises costs to customers by considering the following:

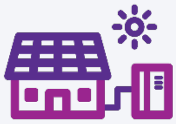
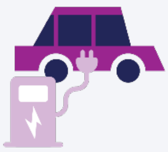
- HV solutions have been identified where these are more efficient than upgrading multiple LV sites in similar areas
- overlaps with our conductor replacement expenditure program have been identified and removed from our forecasts
- non-network solutions have been assumed to defer some LV augmentation, particularly late in the 2026–31 period, which has reduced our proposed electrification program.

As the nature of these investments are primarily adding capacity to our network, we consider these in more detail in our augmentation chapter.

2.6 Enabling customers to derive value from their CER investments

As a package, our proposal enables customers to derive more value from their investments and maintains strong quality of supply that enables EV charging and minimises reliability impacts. These outcomes are consistent with our key engagement findings.

TABLE 2.3 CUSTOMER SERVICE LEVEL COMMITMENTS

CUSTOMER SERVICE LEVEL		DESCRIPTION
	90 per cent of customers can freely export 99 per cent of the time	• 90 per cent of customers can export unconstrained 99 per cent of the time, meaning nearly all customers will have no export constraints most of the time • Although 10 per cent of customers will have partial constraints more than 1 per cent of the time, this is still more preferable than a static zero export limit
	All customers can export up to network limits	• All export customers can export using available network capacity rather than reserving capacity for some customers and using static zero export limits for other customers • We will ensure customers can export as much as possible while maintaining safety and reliability
	All customers have universal access to standard wall charging	• All customers can charge EVs using standard wall plugs • Availability to connect wall-mounted fast chargers at home (e.g. level-two chargers) remains dependent on network capacity • Flexible load products are expected to create future levers to facilitate more fast charging and shift charging away from peak periods
	Maintain existing performance for all customers to provide confidence in the energy transition	• Maintain existing voltage performance for customers to facilitate EV charging and minimise reliability impacts of EV charging on all nearby customers • Adhering to mandatory voltage compliance obligations will support customer service levels for export and load

3. Augmentation

Augmentation expenditure is investment to support capacity-driven reinforcement and expansion of our network footprint.

Additionally, augmentation can be driven by factors that are not related to demand, such as managing bushfire risk, maintaining adequate protections for system security and ensuring sufficient communications infrastructure to support network operations.

In the current regulatory period, we are expecting to underspend our augmentation allowance due to:

- better than expected performance from operational solutions to enable solar exports, including our DVMS and industry-leading work to identify and address incorrect customer solar inverter settings
- partially deferred augmentation works in the Doncaster area due to the impact of increased costs on revised benefits analysis
- general impacts associated with the pandemic, including the significant demand uncertainty and supply chain disruptions that impacted project timelines.

Looking forward, electrification of gas and transport are key drivers of demand-driven augmentation for the 2026–31 regulatory period. We forecast these holistically alongside macroeconomic growth factors, behavioural change and CER. These forecasts are underpinned by our demand forecasting tools, that as set out in our electrification and CER strategy, allow us to understand expected customer impacts in more detail than any other network in Australia.[10]

Accordingly, our proposal includes investment to facilitate growing demand across our network (including the Mornington Peninsula), enable customer electrification of gas and transport, and maintain system security.

Since our draft proposal, our augmentation forecasts have decreased, primarily driven by revised (lower) AEMO assumptions for both CER and electrification uptake.

A summary of our augmentation investment in the current and future regulatory period is shown below

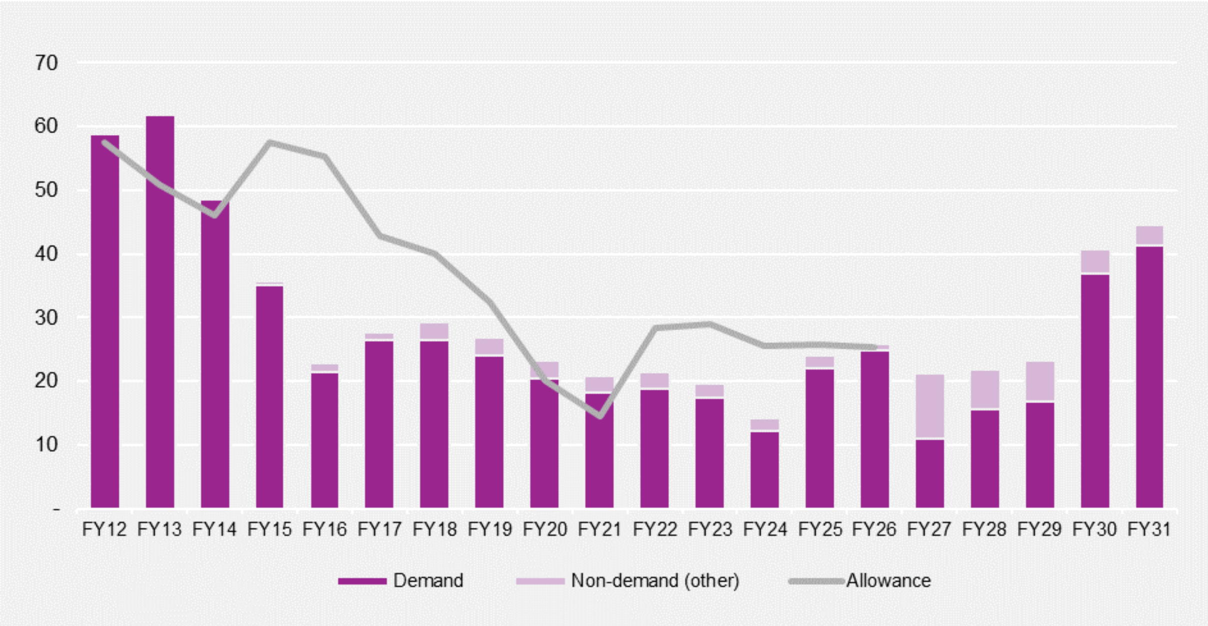
TABLE 3.1 TOTAL AUGMENTATION INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Augmentation	106	142

Note: Disposals have not been netted off.

10 Our forecasts (including for other expenditure categories) are based on the AER's 2019 VCR study, escalated in accordance with the AER's specified methodology. In late-December 2024, the AER published its new, 2024 VCR values. We are yet to assess the impact of these changes, but will consider these through the development of our revised regulatory proposal.

FIGURE 3.1 ANNUAL AUGMENTATION INVESTMENT ($M, 2026)



3.1 What we've heard

Our engagement program sought to understand customer expectations and preferences around the energy transition to inform the development of our proposal and ensure that it delivers value for customers. In particular we focused on customer preferences for CER and electrification rates.

Our electrification and CER integration strategy describes central themes identified through our engagement, including support for strategic investments to facilitate electrification of gas and transport.

TABLE 3.2 KEY ENGAGEMENT FINDINGS

Customers consistently highlighted the importance of a reliable energy supply, with the majority of customers having an appetite to maintain current reliability. Customers are becoming increasingly dependent on electricity given working from home trends and forecast electrification, and flagged a concern for reliability outcomes in their future[11]
Our customers echoed a commitment to equity for solar exports and felt strongly about responding to the climate emergency. They prioritised emissions reduction and the importance of capacity increases to support positive flexible export outcomes
Customers generally view EVs favourably, recognising their potential to support rapid decarbonisation. Customers see a future-ready network as tied to the widespread adoption of electric vehicles

11 This was both an output from customer engagement and observed on-the-ground via our Monash University Future Home Demand report. For further detail, refer to: Monash University, Future Home Demand, 2023.

There were mixed views on the speed of electrification of gas, with some stakeholders suggesting forecasts were too low and that net-zero targets would be missed, where others suggested that cost and industry logistics were prohibitive

Commercial and industrial customers prioritised unrestricted access to electrical supply and improvements to power quality that meet their operational needs as demand continues to grow on the network

3.1.1 Test and validate

Through our test and validate engagement, we sought to understand whether our customers supported our proposed programs of investment in our draft proposal.

During a series of roundtables, our customers affirmed support for investment to manage increasing load across our network, primarily driven by greater EV uptake.[12] Customers noted that the area our network covers has one of the highest proportions of EV ownership, and they expected this trend to continue.

Customers emphasised the need for strategic planning to manage the projected increase in energy usage, and expected that the network will be equipped to handle peak demand periods and growing number of EVs. Our customers noted that infrastructure to support EVs was most important for urban communities given the higher potential demand for EVs in these regions.

Our commercial and industrial customers expressed broad support for investments to maintain or improve power quality, citing this and reliability as their top priority. They conveyed a clear understanding that these investments were necessary to support growth, but expressed desire for more detail on how investments would lead to improvements in reliability and voltage management. Businesses intending to integrate renewable energy, including solar and battery storage, supported investments to address network constraints and improve overall electricity access.

Further detail on specific customer feedback is discussed with the relevant investments below.

3.2 Our proposed response

Our augmentation portfolio considers a range of network and non-network options to support the delivery of service level outcomes that our customers have identified as valuable to them.

3.2.1 Demand-driven augmentation program

Increases in localised peak demand are a major driver of our augmentation proposal.

We forecast that peak demand across our network in 2031 will be 5 per cent higher than it is today. This increase reflects the changes in customer technology adoption and use, described in more detail in our CER and electrification strategy, and increasing population.

Our network also supports key tourism and holiday destinations such as the Mornington Peninsula, meaning demand on our network can be highly seasonal and influenced by extreme weather events.

An overview of our key demand-driven augmentation projects proposed for the 2026–31 regulatory period is outlined below.

12 Forethought, Test and Validate Roundtables: Produced for CitiPower, Powercor and United Energy, 2024, pg. 36.

LOWER MORNINGTON PENINSULA SUPPLY AREA	COST
Demand across the Mornington Peninsula has been growing over time with increasing tourism and expansion. Our Summer Saver demand management program and contracted dispatchable generator fleet has, for the last decade, been the most efficient approach to manage increasing growth in the area. However, increasing demand and electrification are expected to outstrip the reliable capabilities of our Mornington Peninsula demand management program towards the end of the 2026–31 regulatory period. Investment in a new 66kV sub-transmission line is the most efficient solution to manage expected long-term demand growth on the peninsula. The 54km line and associated works at zone substations will add more than 110MW of capacity to the sub-transmission network by connecting Hastings to Rosebud and future-proofing growth and electrification of the peninsula.	$38M

Note: For further detail, refer to our attached business case: UE BUS 3.04 – Lower Mornington Peninsula supply area – Jan2025 – Public.

FEEDER UPGRADES	COST
Several HV feeders across our network are expected to require augmentation to maintain reliable electricity supply to customers. These works are driven by localised load growth leading to feeders exceeding their thermal rating (which places asset operation at risk).	$3M

Note: For further detail, refer to our attached business case: UE BUS 3.03 – Southern feeder thermal augmentation program – Jan2025 – Public.

3.2.2 Customer-driven electrification

As outlined previously, the electrification of gas and transport stands to increase consumption and peak demand across our network in the 2026–31 regulatory period (and beyond). Several independent bodies, including the AEMC, Energy Consumers Australia and the SEC have each found that all customers stand to benefit from electrification through lower household bills, even for customers who do not electrify themselves.

This electrification is typically occurring at the LV level of our network, with growing peak demand and increasing consumption from electrified homes and transport drawing more voltage, leading to lower voltage levels supplied to local customers. Lower voltage levels can cause unstable power quality, impact appliance function, lower appliance lifespan and reduce customers' ability to charge EVs.

To limit the impact that poor voltage levels can have on customers, we are obligated under jurisdictional regulatory instruments to maintain voltage levels between 216 and 253 volts at least 99 per cent of the time. Functional compliance is met if these limits are maintained across at least 95 per cent of our customers.[13]

[13] The Electricity Distribution Code of Practice is a jurisdictional instrument administered by the Essential Services Commission that regulates our activities to ensure they are undertaken in a safe, efficient and reliable manner. See, for example, Essential Services Commission, Electricity Distribution Code of Practice, May 2023, clause 20.4.2.

We achieved functional compliance within the current regulatory period (as shown in figure 3.2), due in large part to the performance of our DVMS and exhausting lower-cost investments such as addressing solar inverter settings, tap changes and phase balancing.

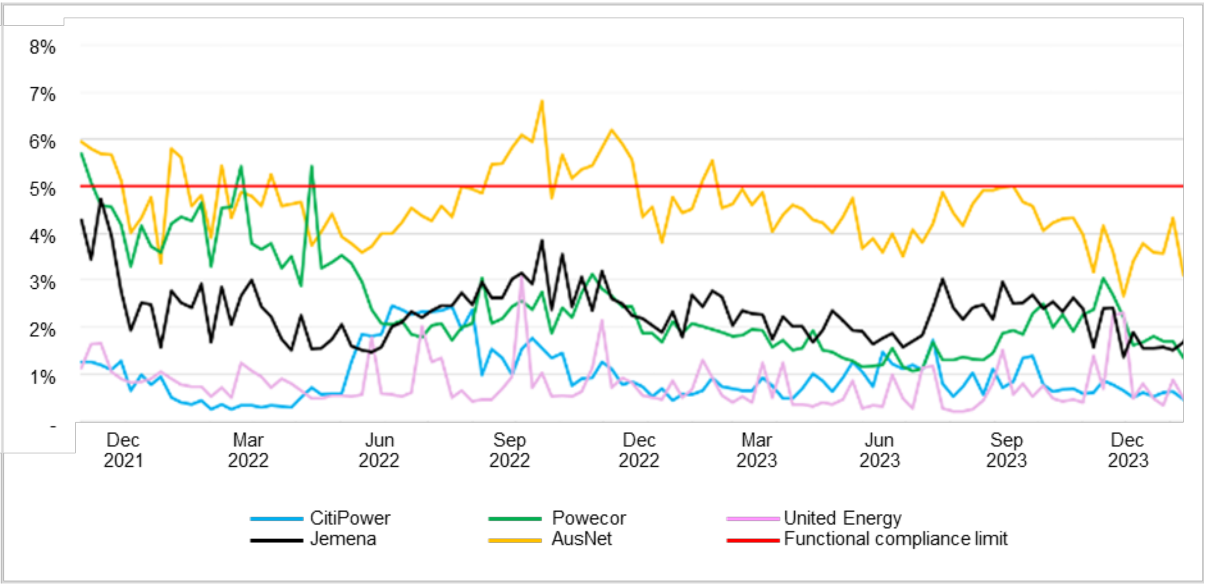
Case study: dynamic voltage management

We were the first network in the country to dynamically optimise voltage levels through our innovative dynamic voltage management system (DVMS). The DVMS uses our smart meter data readings to optimise voltage levels, considering our voltage compliance obligations to maintain voltage levels between 216 and 253 volts.

The DVMS sends a signal to each zone substation that specifies an optimal voltage set point level every 15 minutes. This maximises the number of customers who have compliant voltage levels as demand and localised voltage levels vary throughout the day.

Our network now provides amongst the most optimised and compliant voltage levels to customers in the country. DVMS will continue to be a key network management tool, however, further opportunities to improve voltage performance using DVMS are limited because all zone substations in our network are already optimised.

FIGURE 3.2 HISTORICAL OVERVOLTAGE NON-COMPLIANCE



Source: Essential Services Commission, Voltage performance data, 2024.

While we are functionally compliant today, some customers are still receiving poor voltage outcomes. When customers receiving non-compliant voltage outcomes complain to us, we are further obligated under jurisdictional instruments to resolve their voltage supply issues as soon as practicable.[14]

Through our engagement program, our customers have consistently demonstrated concern with the impact that electrification will have on the stability and power quality of the network, impacting their customer experience. Customers were also apprehensive of the network's capability to cope with increasing electricity use, particularly to facilitate electrification and net-zero technologies.

Additionally, more than 80 per cent of customers participating in our collaborative Future Home Demand study with Monash University preferred to charge electric vehicles at home, highlighting the importance of stable power quality at a customer level.

14 Essential Services Commission, Electricity Distribution Code of Practice, May 2023, clause 15.2.1.

CUSTOMER-DRIVEN ELECTRIFICATION	COST
To assess the value of options to support customer-driven electrification, we considered the optimal balance between proactive and reactive approaches. These options are summarised below in figure 3.3, with our preferred option to maintain service levels (consistent with option two). Proactive investment is more efficient than reactive investment because we can plan works in advance, target high-value sites, utilise efficiencies in service delivery and implement long-term efficient solutions such as tendering the constraint on our non-network procurement platform. In terms of customer outcomes, proactive investment will also allow more customers to charge EVs more often and reduce the power quality impacts of EV charging on other nearby customers. Our proposed customer-driven electrification program reflects a mostly proactive approach that maintains existing voltage performance levels. This program will ensure that an additional 6,500 non-compliant customers will improve their power quality to receive compliant voltage levels and enable more than 4GWh of additional compliant load. Our proposed investment comprises distribution substation upgrades, offloads and LV network reconductoring. These investments were further optimised, consistent with our electrification strategy (shown in figure 3.4). Customers have supported our electrification investment program. At our trade-off forums, 32 per cent of customers supported $45m of investment (with residential bill impacts of $0.86 p.a) and an additional 41 per cent supported $80m of investment (with residential bill impacts of $1.52 p.a) to facilitate increased EV charging and reduce EV-related outages. Customers at our test and validate forums typically supported our proposal, acknowledging growing demand and infrastructure challenges.	$66M

Note: For further detail, refer to our attached business case: UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public.

FIGURE 3.3 OPTIONS TO ADDRESS CUSTOMER ELECTRIFICATION

FIGURE 3.4 OPTIMISED AUGMENTATION SOLUTIONS

Identifying where single HV solutions can remove multiple LV constraints

- Where localised clusters of LV constraints were identified, we assessed whether a HV solution would be more economic
- HV solutions can be cheaper and more effective than several LV solutions because they improve capacity for more customers. This means HV solutions can future-proof a wider network area to support greater electrification and growth

Efficiently balancing proactive and reactive investments to deliver lowest long-term costs to customers

- Sites that are targeted for proactive investment deliver benefits for the greatest number of customers (i.e. least-regrets investment) and limits negative customer experiences
- Proactive investment reduces less efficient reactive investment (that we are obligated to deliver as soon as practicable following customers complaints), leading to more efficient service delivery outcomes
- Our balanced approach will build customer trust through the energy transition with better outcomes and lower long-term costs

Assessing future replacement needs in augmentation planning to future-proof for electrification

- As many of our existing assets are approaching their end-of-service life, we have considered any overlaps between forecast electrification needs and our replacement program
- It is more efficient to upgrade these assets once than it is to replace like-for-like now and upgrade again in the future
- This lowers costs for customers and is consistent with stakeholder feedback that we should be planning for a net-zero future

Electrification capex that delivers value for customers

- Our proposed augex portfolio comprises no-regrets projects that are expected to deliver materially higher benefits than costs valued under AER VCR frameworks
- Network upgrades will support growth and electrification while maintaining voltage compliance
- Our expenditure will enable all customers to charge electric vehicles and minimise customer impacts of localised EV charging

3.2.3 Non-demand augmentation

We must also manage our network to consider drivers that are not related to demand, but are vital to meeting compliance obligations, maintaining adequate protections for system security and ensuring safety and reliability for customers. Our non-demand investments relate to improving under-frequency load shedding and upgrades to communications infrastructure.

UNDER FREQUENCY LOAD SHEDDING	COST
An under-frequency event is when a large-scale transmission outage occurs, such as the trip of a large generator or a major transmission interconnector, and results in an under-supply of electricity to meet demand. If unaddressed this would pull system frequency down significantly, leading to broad scale blackout. UFLS is a scheme that sheds load instantaneously to maintain supply demand balance, frequency and system security. AEMO have increasingly raised concern at the load available under its UFLS scheme due to embedded generation in distribution networks and have recommended Victorian distributors explore options to address this risk.[15] Our proposed investment responds to AEMO's concerns through moving UFLS capability from our 66kV connection points at transmission terminal stations to the 22kV and 11kV feeder exits within our network at select zone substations, prioritising zone substations with large wind and solar farm connections. This will reduce the potential number of customers that would be load-shed in an emergency event and improves Victoria's system security (in line with other jurisdictions, who already have UFLS capability below the zone substation level).	$9M

Note: For further detail, refer to our attached business case: UE BUS 3.05 – Under frequency load shedding – Jan2025 – Public.

COMMUNICATIONS INFRASTRUCTURE	COST
Our communications infrastructure requires upgrades and expansion to manage increasing capacity constraints across our network. A key component of our program is fibre optic upgrades that connect key assets and support the reliable operation of centralised communication systems. Communication networks are an integral part of the electricity network as they support network visibility, remote automation, asset monitoring, network management and data acquisition. Existing capacity in our fibre optic communications network is highly utilised and there is little contingency to manage faults or failures. This expenditure is to improve the capacity of our fibre optic network to support customer growth and maintain reliable operation of our communications network.	$9M

Note: For further detail, refer to our attached business cases: UE BUS 3.06 – Fibre capacity upgrades – Jan2025 – Public.

[15] Australian Energy Market Operator, Under Frequency Load Shedding: exploring dynamic arming options for adapting to distributed PV, 2023, p. 12.

4. Replacement

The replacement of existing assets occurs as the condition of our network infrastructure deteriorates over time, and/or associated asset risks grow.

As assets deteriorate, they become less reliable, less safe, and more costly to maintain. At some point, intervention (e.g. replacement, refurbishment, or decommissioning) is required to maintain service levels and/or comply with regulatory obligations.

In the current period, we will materially exceed our regulatory allowance for replacement activities, particularly for poles and pole-top structures. This expenditure reflects rising input costs from the pandemic and ongoing global supply chain pressures, although our contract with our primary service provider muted some of these cost impacts.

Our expenditure in the current period also reflects our leading approach to managing zone substation risk. Our regulatory allowance provided funding for these works, particularly our extensive transformer replacement program, and we have substantively delivered on our forecast (notwithstanding rising input costs, as noted above).

Relocatable transformers and zone substation risk

In 2018, we started quantifying transformer failure risk based on the overall risk at the zone substation using joint and conditional probability modelling. Rather than focusing on single asset risks, our model considers the available redundancy and load transfer capability at the entire zone substation, response times for different investments, and the cost of multiple interventions that affect overall system reliability.

This approach is combined with the use of relocatable transformers to allow us to efficiently manage energy-at-risk across multiple sites with a single asset. By managing the consequence of failure, our relocatable transformers also allow us to make prudent investment decisions.

For example, where a zone substation has multiple transformers with poor condition history, or high conditional and joint probability failure risk, a relocatable transformer may allow us to replace just one or two transformers (and manage the other towards failure). To support the use of relocatable transformers, preparation works are undertaken at at-risk zone substations.

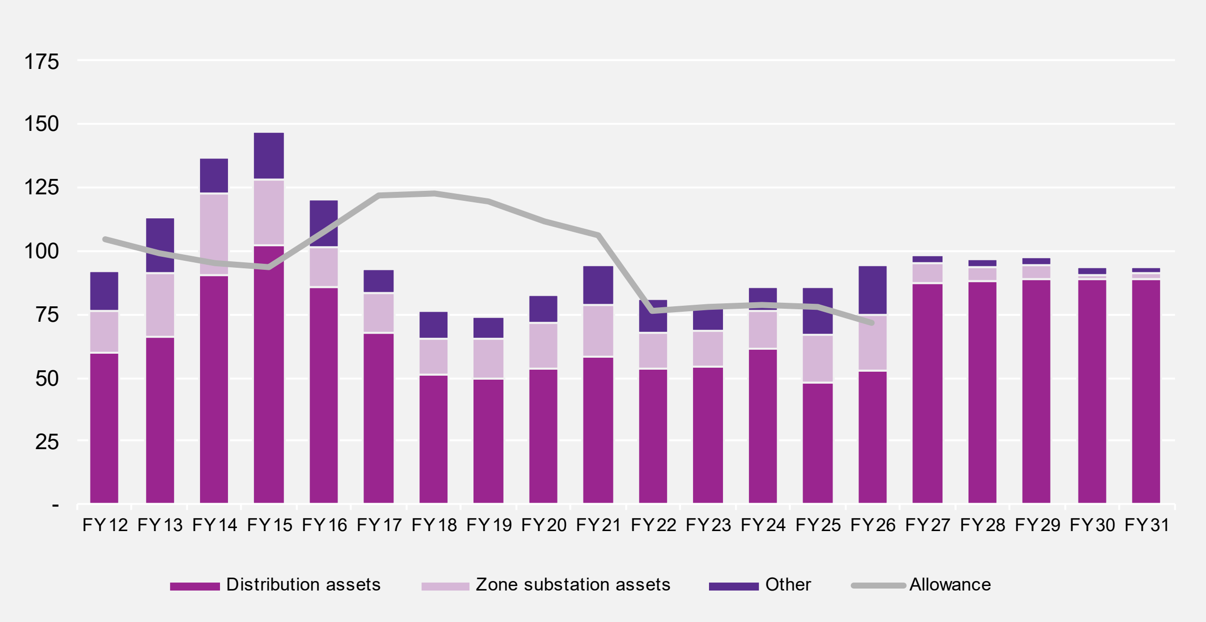
For the 2026–31 regulatory period, the key drivers of increasing replacement expenditure include uplifts in wood pole and risk-based overhead conductor replacements. These increases, however, are partially offset by a reduction in zone substation replacement works following significant investment in the current and previous regulatory periods.

A summary of our replacement investment in the current and future regulatory period is shown below.

TABLE 4.1 TOTAL REPLACEMENT INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Replacement	426	480

FIGURE 4.1 ANNUAL REPLACEMENT INVESTMENT ($M, 2026)



4.1 What we've heard

A central theme of our stakeholder engagement program was reliability, safety, and resilience. Broadly, our customers want to stay connected with a safe and uninterrupted electricity supply that can withstand both normal and extreme weather.

Our replacement program and asset management practices are critical to these outcomes, as well as to maintaining affordability and our position amongst the lowest cost distributors in Australia.

TABLE 4.2 KEY ENGAGEMENT FINDINGS

Customers value safety of their electricity network and community
Customers consistently highlighted the importance of a reliable energy supply, with majority of customers having an appetite to maintain current reliability
Customer are becoming increasingly dependent on electricity given working from home trends and forecast electrification.[16] Customers flagged a concern for reliability outcomes in their future
Customers continue to value affordability, particularly in times of high inflation. Customers expressed a strong preference for stable and predictable pricing structures, noting they are more comfortable with gradual increases rather than sudden step-ups

16 This was both an output from customer engagement and observed on-the-ground via our Monash University Future Home Demand report. For further detail, refer to: Monash University, Future Home Demand, 2023.

While we did not specifically engage on our detailed replacement program during the test and validate stage, we did further engage with customers on their electricity usage patterns. A high proportion of our customers indicated their preference for an electrified future to enable the energy transition, with significantly varied customer views on whether they would be willing to be flexible with their load.

Similarly, 72 per cent of small and medium business customers and 44 per cent of residential customers indicated plans to replace their gas appliances with electric appliances over the next five years. The substitution of gas will increase energy at risk from asset failures across our network.

4.2 Our proposed response

We take great pride in the role we play in providing an essential service for our communities. With increasing electrification, due to gas-substitution and transport needs, technology, and behavioural change, the consequence associated with outages is increasing; the impact of outages will be felt by customers more in the future than previously.

In the context of the electricity transition, our replacement program is therefore critical to ensure customers have trust in their energy system to have confidence to fully electrify their homes and lifestyle.

Accordingly, our replacement investment in the 2026–31 regulatory period will deliver on the following customer outcomes:

- maintain reliability outcomes for our customers in an electrified future by maintaining underlying asset condition for those with the highest risk and consequence, while safely managing an increase in reliability risk to balance affordability and reliability trade-offs
- only propose replacement based on risk or condition-based modelling to ensure assets are replaced only when benefit outweighs the costs, given affordability concerns
- gradually increasing replacement rates of asset classes (including poles, where a majority are deteriorating due to condition and load increases), to limit risks of deliverability constraints and price spikes in future years.

4.2.1 Our replacement forecast method

In considering our replacement needs, we monitor asset performance indicators, including asset failures, high priority defects, and asset condition. These indicators inform our underlying asset management response—for example:

- increasing asset failures indicates a likely need to act immediately and review asset management practices
- increasing high-priority defects indicates a likely need to act soon to increase interventions over time
- deteriorating condition indicates a likely need to act soon (relative to asset management thresholds), and/or undertake risk-based assessments.

The consideration of these indicators varies for different asset classes, recognising that managing lower-value distribution assets with large, aging populations requires different considerations to managing higher-value zone substation assets.

An overview of the different forecasting techniques that are applied across our asset categories is summarised in table 4.3.

TABLE 4.3 SUMMARY OF FORECASTING APPROACH

CATEGORY	SUMMARY
Fault or unplanned	Fault or unplanned forecasts are responses to asset failures that caused outages, including those due to external factors (such as third-party damage). It is based on our historical five-year average faut replacement volumes
Corrective	Corrective forecasts address conditional failure associated with deteriorated asset condition, defects, and non-compliances to legislated requirements or industry standards (such as Australian Standards): • condition-based forecasts are derived from asset condition models, which are used to predict future asset condition based on current measurable condition data and annual deterioration rates that have been informed by independent analysis. An increasing volume of assets in deteriorated condition indicates an increase in future interventions is required, regardless of the current asset performance • defect forecasts are based on the statistically best fit model for our recent historical high priority defects. A historical average model was adopted for the majority of our distribution assets' defect forecast • compliance forecasts are based on a least cost compliance basis
Risk-based	Risk-based forecasts are based on a quantitative cost benefit assessment of intervention costs compared with the risks of failure, where the risk reduction benefits outweigh the intervention costs. For risk-based assessments, asset interventions are informed by the following: • the probability of failure based on historical failures, asset condition and degradation information • the consequence of failure including cost to repair or unplanned replacement, decreased customer service levels, safety, and environmental hazards

Upon a decision to intervene on an asset, a range of options are also considered, particularly for our risk-based assessments. Within our cost-benefit analysis, we typically consider options to replace the asset, increase maintenance and/or life extension, retirement, or non-network solutions, with the aim to maximise community benefits from the analysis.

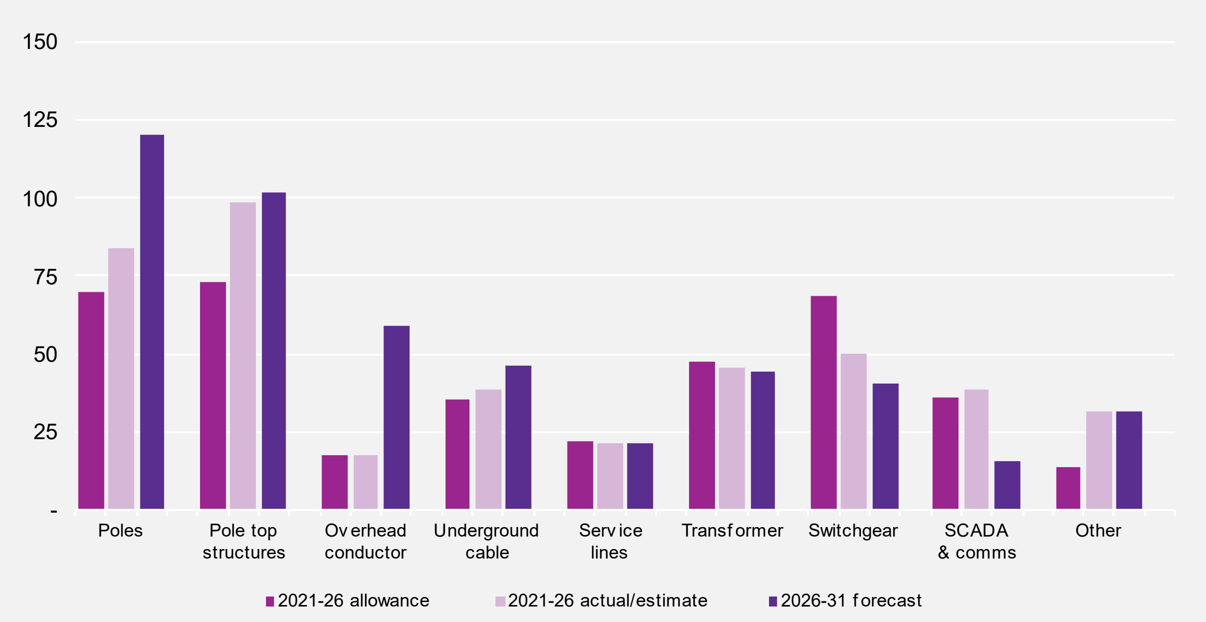
Increasingly, our asset management strategies are also needing to consider future electrification drivers (to avoid early replacement of assets due to increased capacity needs) and/or to meet longer-term deliverability challenges (particularly for high-volume assets).

4.2.2 Our replacement forecasts

Figure 4.2 presents our forecast investment for the 2026–31 regulatory proposal across our key asset categories.

Broadly, we are observing increases in distribution asset replacements, with reductions in zone substation works. The replacement drivers for each asset category are described in more detail below, and include a combination of volume increases (reflecting ongoing deterioration in the underlying asset populations) and unit rate pressures.

FIGURE 4.2 HISTORICAL AND FORECAST INVESTMENT BY ASSET CLASS ($M, 2026)



Note: Category totals shown above are consistent with our reset RIN. These may differ from category level forecasts shown below, as major plant replacement works (such as switchboard replacements) are allocated across multiple RIN categories to reflect the nature of the work undertaken.

4.2.3 Distribution assets

Distribution assets are our 'lower value, high volume' assets. This category includes poles, pole top structures, conductors, service lines, distribution switchgear and transformers, and underground cables.

The key areas of focus for our 2026–31 distribution asset portfolio include our wood pole and overhead conductor populations. We are forecasting increasing risk in these assets due to deteriorating condition.

While to date we have been able to limit customer impacts from deteriorating asset health via automation and sectionalisation of our network, there is only so much that can be done until asset failures result in negative customer impacts. In addition, given their underlying age and condition profile, increasing asset replacements now through a structured program is likely to represent no-regrets investments.

POLES	COST
We are observing an increasing proportion of wood poles being identified as limited life or unserviceable due to deterioration. Through cyclical inspection 'sound wood' is measured which determines the internal rot of wood poles, which is the main deterioration cause leading to pole failure. Our observed increasing volume of deteriorating poles has been corroborated against pole performance data. While pole failures have been relatively low, the failure rate has increased steadily since 2017.[17] In addition, wood pole defects have started to increase, noting that defects are a leading indicator of potential pole failures. In response to these indicators, we are proposing an uplift in our wood pole interventions in the 2026–31 regulatory period. Our condition-based wood pole intervention forecast is based on the measured condition of our poles and predicts the condition and serviceability of wood poles over time using an annual decay rate which was informed by independent analysis. A proportion of these poles will be staked, consistent with our historical staking ratio.	$120M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.01 – Poles – Jan2025 – Public.

POLE TOP STRUCTURES	COST
In the current regulatory period, our existing asset management approach for cross-arms has generally maintained network performance. Consistent with this, our forecast intervention volumes for the 2026–31 regulatory period are slightly lower with the corresponding replacements in the 2021–26 regulatory period. Our total forecast expenditure for the 2026–31 regulatory period, however, represents an minor increase on the current period driven by higher average units in the forecast period.	$102M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.02 – Pole top structures – Jan2025 – Public.

17 ESV, United Energy wood pole management: a review of sustainable wood pole safety outcomes, Public, June 2023, p. 10.

OVERHEAD CONDUCTORS	COST
Our proposal includes an increase in overhead conductor replacement expenditure, driven by a risk-based program to replace HV bare conductor. Since 2019, the number of HV conductor failures and high priority defects have been increasing. Further, our condition forecasts show that in the absence of any intervention before 2031, 44 per cent of our overhead conductor population (or approximately 1,585km) will have a modelled condition rating associated with higher risks of failure. This compares to only 10 per cent of the population today. Although we have been managing our overhead conductor performance to date, the scale of our conductor population and the ongoing deterioration in condition (as these assets continue to age) supports the need to move toward more sustainable intervention volumes.	$59M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.03 – Overhead conductors – Jan2025 – Public.

UNDERGROUND CABLES	COST
Our underground cables forecast is aligned with our forecast actuals in the current period and is based on the underlying defect and condition trends of these assets. Given the random nature of underground cable failures, including the variable length of any corresponding cable replacements, our fault and corrective forecasts are based on a simple average over the previous five-year period.	$45M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.04 – Underground cables – Jan2025 – Public.

DISTRIBUTION TRANSFORMERS	COST
Our distribution transformer forecast is largely aligned with our current period spend. Our replacements are forecast based on historical five-year replacement trends of distribution transformer types.	$41M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.06 – Distribution transformers – Jan2025 – Public.

DISTRIBUTION SWITCHGEAR	COST
Our proposal includes a slight decrease in distribution switchgear expenditure. Given the stable condition of our assets, we have forecast our fault and corrective based replacements using historical interventions. Further, our forecast replacement volumes are in line with our 2021–26 replacement volumes. This demonstrates the prudency of our forecast that reflects the effectiveness of our distribution switchgear asset management practice in maintaining reliability and minimise safety risks as far as practicable.	$40M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.07 – Distribution switchgear – Jan2025 – Public.

SERVICE LINES	COST
Our service line forecast is aligned with our forecast actuals in the current period. Our forecast is driven by defects and faults and are forecast based on historical annual defect rates and forecast asset inspections.	$21M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.05 – Services lines – Jan2025 – Public.

4.2.4 Zone substation assets

Zone substation assets are our 'higher value, low volume' assets. This category includes all the electrical assets within the zone substation, such as zone substation transformers, switchgear, relays, and communication assets.

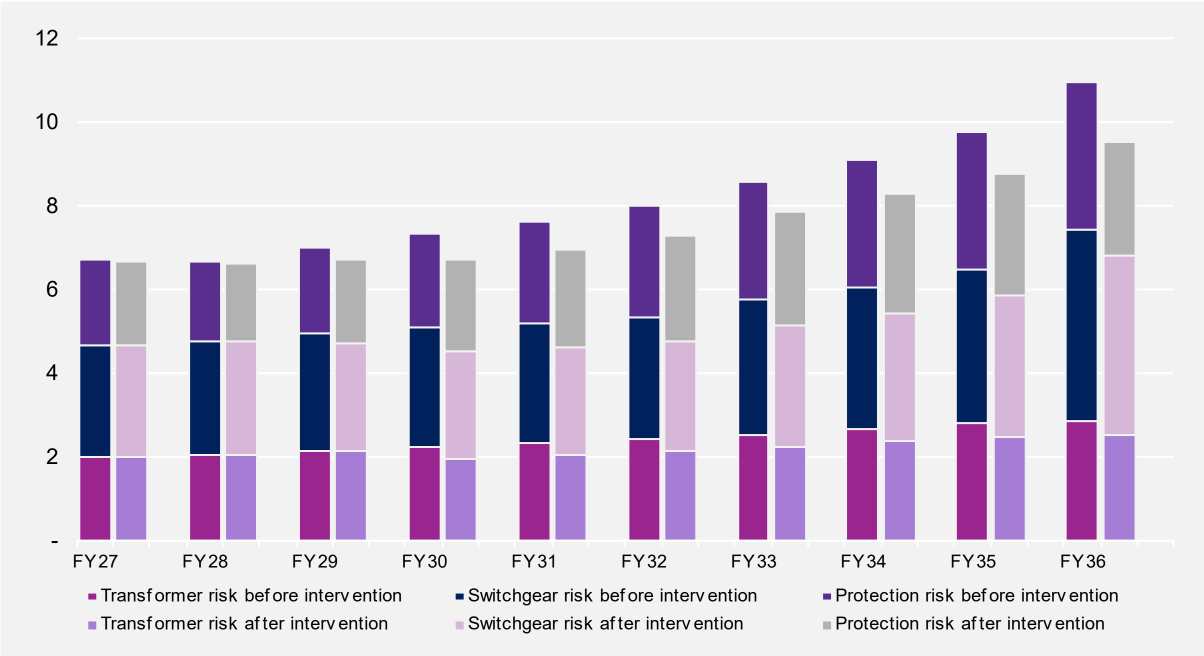
Our zone substation assets are managed based on the risk and condition of the asset. Our quantified risks include reliability risk for our customers, environmental risk, and safety risk.

As outlined previously, we forecast risk-based zone substation transformer and switchgear interventions by assessing the likelihood of asset failures against the consequence of the entire zone substation (instead of individual asset level impacts).[18] This approach has led to a more holistic asset management approach, allowing for greater consideration of the unique characteristics of each zone substation, including available redundancy and load transfer capability.

In practice, it means not all high-risk zone substation assets are targeted for intervention and this ensures our forecast replacements are only the most prudent and efficient. As shown in figure 4.3, however, our proposed zone substation replacement program will still result in overall zone substation risk increasing over the 2026–31 regulatory period. This is primarily driven by protection asset risks.

[18] Refer, for example, to our asset risk quantification guide: UE ATT 4.01 – Asset risk quantification guide – Jan2025 – Public.

FIGURE 4.3 COMBINED ZONE SUBSTATION ASSET RISK ($M, 2026)



This approach to risk-management, in combination with the use of relocatable transformers, has ensured prudent investment in zone substation assets, leading to a reduction in zone substation transformer and switchgear investment for the 2026–31 regulatory period .

ZONE SUBSTATION TRANSFORMERS	COST
Our zone substation transformer forecast represents a decrease in expenditure from the 2021–26 regulatory period. This forecast comprises the replacement of one transformer, as well as the continuation of an environmental refurbishment program to manage transformer oil leaks in accordance with regulatory requirements.	$8M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.08 – Zone substation transformers – Jan2025 – Public.

ZONE SUBSTATION SWITCHGEAR	COST
We are proposing a reduction in zone substation switchgear expenditure for the 2026–31 regulatory period, with major switchboard replacement works only forecast at our Elwood zone substation.	$6M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.09 – Zone substation switchgear – Jan2025 – Public.

PROTECTION	COST
We are proposing a reduction in protection replacement expenditure for the 2026–31 regulatory period. The key driver of our protection expenditure forecast is due to the switchboard replacement where it is prudent and economic to simultaneously replace the existing relays.	$13M

Note: For further detail, refer to our attached asset class overview: UE BUS 4.10 – Protection and control – Jan2025 – Public.

5. Resilience

Extreme weather events that cause impacts at scale are now occurring in Victoria nearly every year.[19] Since 2021, over 681,000 sustained outages due to extreme weather have impacted our customers.

Most recently, in February 2024, more than one million Victorian customers were off supply after a major storm front crossed Victoria. This storm was significant enough to damage transmission infrastructure, as well as distribution assets. The direct cost of this event on Victoria (excluding compensation payments) was estimated at $770 million.[20]

It is widely accepted that these sorts of extreme weather events will become more frequent and more severe over time.

Note: Emergency restoration works following extreme storms

5.1 What we've heard

To better understand the lived experience of our customers through these extreme events, we have engaged extensively with customers on network resilience. This involved community resilience roundtables, joint engagement with our Victorian distributors on resilience investment principles, and targeted conversations with key stakeholders through our broader regulatory reset engagement program.

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19 Department of Energy, Environment and Climate Action (DEECA), Network Outage Review Interim Report, 2024, p. 5.
20 DEECA, Network Outage Review Interim Report, 2024, p. 17.

TABLE 5.1 KEY ENGAGEMENT FINDINGS

	Communities consider resilience a vital element of the energy system
	Improving network resilience involves adapting to changing environmental and operational conditions
	Communities expect us to play a critical role in proactive and reactive disaster management and develop network resilience plans tailored to communities needs
	Transparent communication and education are critical, especially during crises, to stay informed about outage causes, recovery times, and preparedness measures

Our engagement also highlighted the increasing dependence of our communities on a resilient electricity supply. At the same time as our climate changes, the way we live our lives is changing too:

- critical infrastructure is increasingly reliant on electricity including water, sewerage, telecommunications and internet
- increases in remote work, school and other commitments which were once in-person
- a move away from the inner city to areas which are more prone to extreme weather and more reliant on community and individual preparedness
- with increasing take up of hybrid and electric vehicles, more people will begin to rely on electricity for their transportation needs over time
- as we move towards net-zero, electrification and the gas transition will increase and options for non-renewable services such as gas will decrease.

5.1.1 The Victorian Government has set clear expectations for distribution business to improve network resilience

Since 2021, the Victorian Government has initiated two separate reviews into network and community resilience. The recommendations from these reviews have strongly guided our approach to resilience.

Electricity distribution network resilience review

Following the extreme storm events in 2021, the Victorian Government engaged an expert panel to undertake an Electricity Distribution Network Resilience Review.[21]

The expert panel consulted broadly with local communities and stakeholders impacted by the extreme storms. It found loss of power caused ‘considerable distress’ and devastating consequences on people’s lives.[22] Customers told the panel of their reliance on power in all aspects of their lives including food, water, access to funds, caring for themselves and their family and their ability to work

[21] DEECA, Electricity Distribution Network Resilience Review, Final recommendations report.
[22] DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, pp. 4–5.

and communicate. The panel highlighted the significant risk vulnerable and life support customers are exposed to during prolonged outages.[23]

The outcomes from this review made clear the government's expectation that we reduce both the **likelihood** and **impact** of prolonged power outages by making investments in resilience. For example, specific recommendations included:

- distribution businesses should be required to take an all-hazards approach to risk mitigation for the purposes of safety, reliability, security and resilience of the electricity system. This should result in a regular assessment of the need for investments and solutions in the most high-risk locations, from 2025 onwards
- distribution businesses should be required to partner with communities and local councils in emergency planning and response
- distribution businesses should have new obligations to improve the prioritisation of the restoration of power following an outage, and improve their communication with customers before and after prolonged power outages.

Aa a result of the review, the Department of Energy, Environment and Climate Action (DEECA) is developing a proposal to enshrine resilience objectives explicitly in the National Electricity Rules.

Network outage review

This review has since been followed by a Network Outage Review (outage review) into the more recent February 2024 storm event.[24] The outage review highlighted that distribution businesses no longer operate in an environment which is ‘steady state’; we are now operating with real potential for frequent weather events that cause impacts at scale. As a result, the government expects a change in distribution businesses preparedness, response, and recovery from these events to protect the power Victorians value and the ecosystem of essential services that electricity distribution networks sustain.[25]

The outage review concluded in August 2024 with expectations that distribution businesses robustly plan for major events, align restoration with the Victorian Preparedness Framework and proactively address worst performing feeders to reduce the number and impact of outages.[26] It also highlighted the critical need for us to provide customers accurate and timely information and immediate local presence and support. The review emphasised the importance of alternative solutions on the ground, such as community hubs and alternative generation to support communities.[27]

5.2 Our proposed response

Our proposed response to meet government and community expectations for both network and community resilience is focused on how we can better prepare, adapt and respond to climate extremes. This approach represents a longer-term shift towards the proactive investment cycle required by the Victorian Government.

23 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, p. 9.
24 DEECA, Network Outage Review, Final report.
25 DEECA, Network Outage Review, Final report, p. 14.
26 DEECA, Network Outage Review, Final report, pp. 7-12.
27 DEECA, Network Outage Review, Final report, pp. 26-27.

TABLE 5.2 OUR APPROACH TO RESILIENCE INVESTMENTS

We **prepare** by hardening our network and working with communities to bolster their readiness.
We **adapt** by taking a future-proofed, no-regrets approach to our business-as-usual operations.
We **respond** by quickly mobilising when events occur to provide on the ground support to impacted communities.

We have also undertaken detailed climate modelling to best ensure any investments are evidence-based, and targeted at our highest-risk locations.

5.2.1 Identifying resilience options

We have undertaken detailed climate modelling to ensure all potential resilience investments are evidence-based, and targeted at our highest-risk locations.

With a changing climate giving rise to an increasing severity and frequency of extreme weather, history is no longer the best predictor of our future investment needs.

In this context, we engaged AECOM to undertake a climate impact assessment. This assessment used existing independent literature, including the Victorian Government's Climate Science Report and the Electricity Sector Climate Information, to identify and map climate risks and hazards against our network to assess our exposure to major climate risks and hazards.[28]

AECOM's report highlights our network area's exposure to extreme rainfall, bushfires and wind.

We have used to results of this work to identify where resilience expenditure will provide the greatest benefit to customers.

5.2.2 Proposed investments

Our proposed investments to support increased network and community resilience is summarised in figure 5.1, with further descriptions of our proposed investments provided below and in our attached business cases.[29]

At our trade-off forums we presented customers with a variety of options to better understand customer's willingness to pay for key resilience measures. The majority of customers—over 68 per cent—were willing to pay to improve network resilience through network hardening and community support.

28 DEECA, Victoria's Climate Science Report, 2024.
29 For further detail, refer to our attached business case: UE BUS 5.01 - Resilience - Jan2025 – Public.

FIGURE 5.1 NETWORK AND COMMUNITY INVESTMENTS

Our customers are experiencing the increasing risks and impacts of prolonged outages

In response to the increasing frequency and severity of extreme weather events, and our customers growing dependency on a reliable supply of electricity, we are proposing to harden the network and better support communities

		Prepare	Adapt	Respond
Network hardening	**New zone-substation at Shoreham** to improve resilience for customers on the lower-Mornington Peninsula	✓	✓	
Network hardening	**Enhanced climate modelling** to better forecast consequence and causality of extreme weather events	✓	✓	
Community support	**Additional mobile emergency response vehicles** to cater for multiple, concurrent outages			✓
Community support	**Community Support Officers**, who know and serve their communities	✓		✓
Community support	**Improved prioritisation tool** to manage risk and provide more relevant information during extreme events	✓		✓

Creating more resilient communities and networks by:

Strengthening and adapting our network to avoid time off supply

Reducing the impact of extreme weather events

Increasing on-the-ground support with people that know the local community

NETWORK HARDENING		COST
	By hardening our network we are able to reduce the likelihood of an outage by making our assets less prone to failure during extreme weather events. This will be increasingly important as the frequency and severity of extreme weather events continues to grow. As part of our network hardening program we are: • building a new zone substation at Shoreham to improve resilience for customers on the lower-Mornington Peninsula. Customers in this area are particularly exposed to outages due to the prevalence of long feeder lines. We considered a variety of options to address this resilience issue, including undergrounding select feeders, as well as developing alternative supply options that can continue to provide supply in the event of an outage. We consider that a new substation will best meet this exposure by diversifying the source of supply for customers and allow us to split customers onto smaller feeders which will reduce the number of customers impacted when an outage occurs. It will also halve the length of some of the longest and most exposed feeders on our network. The substation will be able to connect to the new sub-transmission line between Hastings and Rosebud that is due to be constructed in the 2026–31 regulatory period. This sub-transmission line has previously been deferred due to the use of non-network solutions, however these solutions are expected to become infeasible during the 2026–31 regulatory period • enhancing our climate modelling to better forecast the consequences and causality of extreme weather events. Demonstrating causality is currently challenging, particularly for storm-related events, and this proposal seeks to replicate the journey to increased maturity that has occurred successfully with fire consequence modelling. Expenditure related to climate modelling is included in our proposed innovation allowance.	$25M

Note: For further detail, refer to our attached business cases: UE BUS 5.01 – Resilience – Jan2025 – Public; and UE BUS 3.04 – Lower Mornington Peninsula supply upgrades – Jan2025 – Public.

COMMUNITY SUPPORT	COST
While we are seeking to prepare and adapt our network to limit the impact of extreme weather events, it is not possible to prevent all outages from occurring. We are proposing additional community support to help manage the response to these outages and minimise the impact of these outages on communities across our network. As part of our community support program we are: • deploying an additional mobile emergency response vehicle (MERV) to cater for situations where we have multiple, widespread, concurrent outages across our network • engaging two community support officers that have extensive knowledge of their own community and play a positive role in improving communication, empowerment, and collaboration with communities. These officers will be on the ground, represent the community and be a key point of contact for emergency management. This role was expected by government and essential to customers in our engagement, both in preparing for extreme weather events and responding to them. These officers will also allow us to meet stakeholders' growing expectations to expand our participation from state-wide engagement (today) to municipal and local council engagement. In addition to assisting communities in preparing and responding to extreme weather events, the community support officers will also assist in partnering on energy renewable projects, provide advice on optimal tariffs and settings for high voltage equipment and information on demand management options, and work with life support and other vulnerable customers in their communities amongst many other activities • developing improved systems to increase our situational awareness, supporting prioritisation and visualisation during wide-scale outages. This single view will allow the various groups within our business to all access the same information and see the decisions being undertaken, and to incorporate information from a wider range of sources. The single source of truth can then be shared with external stakeholders including government, emergency management and other critical infrastructure providers. Our customers identified a need for a public facing view during engagement which has been added to the proposal. A considered IT roadmap allows for improved prioritisation and visualisation during critical periods and improved information with all key stakeholders.	CAPEX $3M OPEX $4M

Note: For further detail, refer to our attached business case: UE BUS 5.01 – Resilience – Jan2025 – Public.

6. Connections

Connections expenditure supports the connection of new customers on our network. These connections can vary from residential houses to subdivisions, large residential/commercial properties, industrial sites and/or large-scale generation and storage.

Nearly all connections involve a customer contribution. Therefore, future connection investment requires an assessment of future customer contributions as well as underlying connection activity.

For the current regulatory period, actual connection activity is lower than the allowance provided in our final determination. The growing challenges and impacts of forecasting connections, however, has led to our proposal to exclude connections from future capital efficiency sharing schemes (CESS). This proposal is discussed in our managing uncertainty chapter, and reflects the non-discretionary nature of connections (i.e. we are obliged to facilitate all connection requests under our electricity distribution licence) and potential consequences on our entire network capital program.[30]

For the 2026–31 regulatory period, the key drivers of connections investment include the following:

- gross connection activity is forecast to be higher than the current regulatory period. The additional activity is underpinned by development to support the Suburban Rail Loop, including around Cheltenham, Clayton, Monash, Glen Waverly, Burwood and Box Hill
- at a segment level, growth in connection activity is forecast in all customer categories. Residential and subdivision growth is strong, driven by continuing shortages in housing across Victoria.

Notably, we have responded directly to stakeholder feedback and taken a cautious approach for large projects with uncertain timing. A key example of this is works associated with recent Victorian Government policy announcements regarding housing precincts along key rail corridors. These are likely to require major electrical infrastructure upgrades, but pending further detail on timing and locations, we have not included these directly in our regulatory proposal.[31]

A summary of our connection investments in the current and future regulatory periods is shown below.

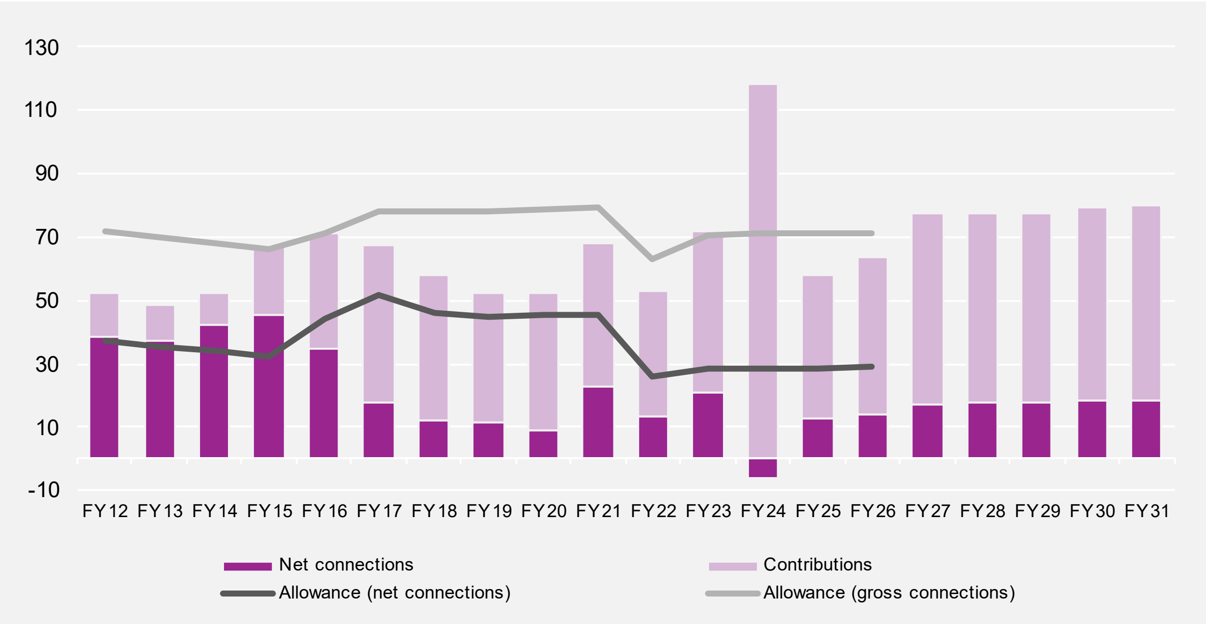
TABLE 6.1 TOTAL CONNECTIONS INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Connections (gross)	358	391
Customer contributions	303	302
Connections (net)	**55**	**89**

30 Essential Services Commission, Electricity distribution licence, United Energy Distribution Pty Ltd, as varied on 3 August 2022.

31 If required, we will reflect these works in our revised regulatory proposal, either as expenditure forecasts or through the existing uncertainty mechanisms.

FIGURE 6.1 ANNUAL CONNECTIONS INVESTMENT ($M, 2026)



6.1 What we've heard

As part of our engagement program, our discussions with customers and stakeholders focused on their perceptions of future connection activity and how that will intersect with the energy transition. We also asked them to consider any barriers that exist today, or may emerge, in connection processes.

Engagement with smaller customers primarily occurred through Monash University's Future Home Demand report and for larger customers (predominantly renewable energy proponents) through our Generator Steering Committee. Other stakeholders were engaged through our Future Energy Demand workshop, dedicated CAP workshop, bilateral discussions with intending connection applicants and meetings with the DEECA and real estate developers. [32]

We also published a consultation paper on integrating storage into our networks in February 2024 seeking comment and submissions from energy storage proponents. Feedback from that engagement has been incorporated.

32 See, for example: Forethought, Future Energy Network Forum, January 2024.

TABLE 6.2 KEY ENGAGEMENT FINDINGS

The cost of connections should not impede the energy transition. Consideration should be given to managing transition-based connection costs that may arise for customers who may face vulnerability
Access to new connections (and by extension, the right to an affordable and reliable supply) should be as equitable as possible
Whilst there were mixed responses to EV adoption, customers demonstrated no desire to cross subsidise their connection (public or private)
Grid scale renewable generators/loads sought more options for network access, less complexity and increased competitiveness of transmission markets (as many of these customers also require transmission augmentation to support their connection to the distribution network)
Large load customers wanted more options to preserve capacity on the grid (firmer access) and in some circumstances, greater opportunity to provide non-network solutions
The Victorian Government wanted barriers to residential CER adoption to be minimised. This included no up-front fees and consistency in the treatment of three-phase upgrades to support electrification

6.2 Our proposed response

The Electricity Distribution Code of Practice (EDCoP) requires us to make an offer to connect any customer seeking a connection to our network.[33] How these offers are calculated and presented is defined by the AER's service classification decisions, and our connection policy.

Our regulatory proposal includes a connection policy to govern connection charges for the 2026–31 regulatory period. Our connection policy is required to be consistent with the connection charge guideline for electricity customers and receive AER approval. Our connection policy is attached to this proposal and discussed further below.

Consistent with customer and stakeholder feedback, we have not proposed material changes to how we prepare customer connection offers. For example, we will continue to ensure the costs of the energy transition are collected where possible from those that benefit.[34]

We did not receive any further feedback from customers and stakeholders on connection investment following the release of our draft proposal. We have therefore maintained the approach adopted in our draft proposal (with many of these already underway in the current regulatory period). The approach includes:

[33] Essential Services Commission, Electricity Distribution Code of Practice, May 2023.

[34] For the avoidance of doubt, our connections policy will be expanded to accommodate other changes brought about by the energy transition. These include provisions related to static zero limits, stand-alone power networks and flexible export products.

- providing a wider range of service options for larger customers. This includes more optionality with respect to network tariffs, network access and accessibility to non-network markets through our demand management platform
- reforming how we apply alternative control charges in preparing connection offers
- working with regulators to tackle the behaviour of incumbent declared transmission network system operators that impacts larger connections.

Further detail on our demand management platform, and changes to our charges are set out respectively in our electrification and CER strategy and alternative control services chapters.

6.2.1 Forecasting connections activity

Developing robust forecast methods is critical to ensuring we are sufficiently funded to deliver a prudent and efficient capital program. For the 2026–31 regulatory period, our gross connections forecasts are based on the following:

- for most customer segments, connection activity projections were supplied by Macromonitor, a leading provider of economic forecasting and research services to the construction industry. The information sought from Macromonitor was customised to encompass the boundaries of our network.[35] These forecasts have been updated for this proposal reflecting the latest available macroeconomic data
- internal projections were also used to forecast grid-scale storage, based on our visible pipeline of registered projects. The pipeline information for this proposal has been updated since the draft proposal
- the above connection activity projections were applied to audited RIN data for the year 2022–23. Our most recent year of RIN data (2023–24) included connection works for several major hospital and infrastructure projects, making it an atypical (un)representative year for regular connection activities. For similar reasons, unit rates have also been based on 2022–23 RIN data
- further, a single year of data was used as the baseline given the impact the pandemic had on historical connection activity (i.e. where restrictions on construction distorted connection activity, making it less reliable as a basis for future forecasts).

6.2.2 Contribution rates

Forecasting contribution rates is complicated. Contribution rates are dependent on expected future revenue from each connection which is in turn a function of energy consumption patterns and network tariffs.

Since the draft proposal, network tariffs and the weighted average cost of capital (WACC) have been updated to reflect approved network tariffs for the financial year 2024–25 and changes in the cost of debt. Actual data on customer offers has also been updated to include a further five months of analysis.

Changes to the National Construction Code, energy efficiency requirements, growth in solar rooftop, electrification, changes in network tariffs and evolving customer trends are changing consumption behaviour.[36] For the draft proposal, a variety of forecast and actual information was applied to model future contribution rates including tariff projections, the Monash University Future Home Demand report and internal trial information. The consumption forecasts, however, were static. This assumption was highly unrealistic given the rapidly evolving energy landscape.

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35 Macromonitor, Forecasts by Region, Report prepared for CitiPower, Powercor and United Energy, August 2024.
36 Australian Building Codes Board, National Construction Code, 2022.

To have a more dynamic approach to consumption forecasts for this proposal, we engaged LEK to model the long-term consumption trends (2026–61).[37] Understanding longer term trends is essential given estimation of contributions required is subject to a 30-year analysis for residential connections.

LEK analysis considered future building standards, house size, solar uptake, EV uptake, behind the meter storage, energy efficiency (appliances), behavioural change and demand response. Each consideration was modelled for its impact on each tariff component (peak, off-peak and saver).

The impact of each consideration was varied, and multi directional. The largest impacts were EV uptake and behind the meter storage.

Further there was a shift in behaviour resulting in more consumption in saver periods and less during peak periods. Off peak consumption remained constant.

LEK's work was applied to historical residential contribution data retrieved over the period 2022–24.

Whilst the sophistication of modelling contribution rates for residential customers has improved, this has not been replicated for commercial and industrial customers. Commercial and industrial customers are highly heterogenous making the application of broad assumptions difficult. We have therefore maintained a static approach to their future consumption based on observed contribution rates over the period 2022–24.

6.2.3 Grid connected storage

We have included one additional connection category from those identified in the reset RIN—grid connected batteries. Based on forecasts prepared by our external demand forecast partner—Blunomy—298MW of grid connected storage is forecast to connect between 2026–2031.

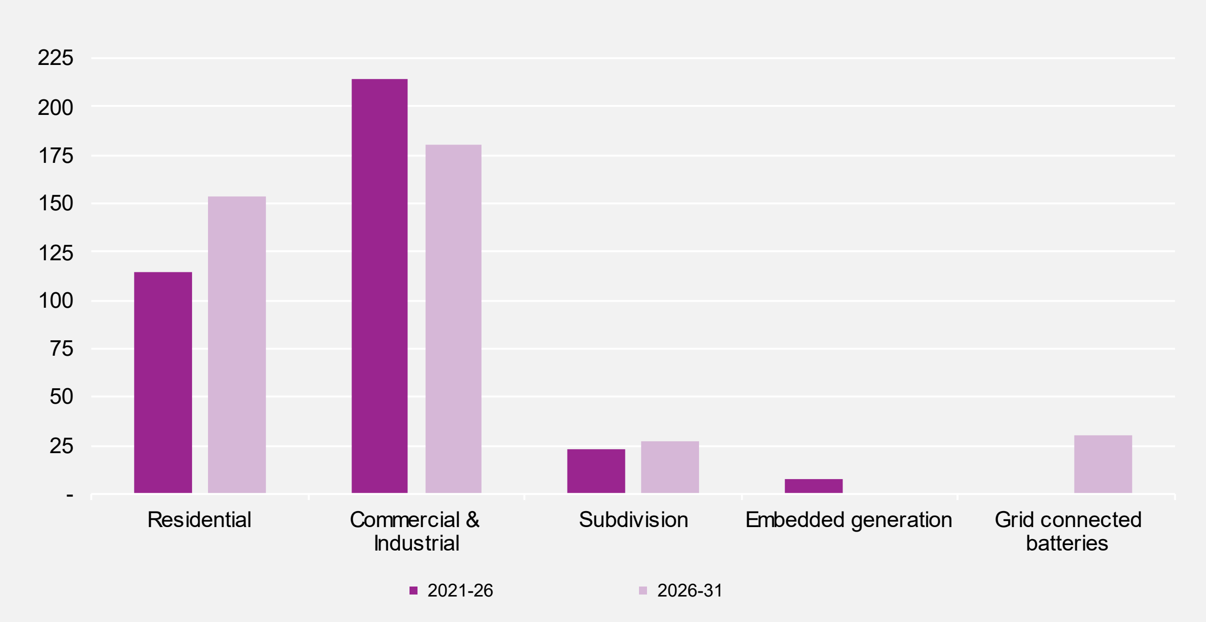
The absence of observable contribution rates for grid connected batteries made it challenging to estimate their future consumption. We have therefore applied internal estimates of incremental revenue and incremental costs for similar connected grid connected batteries. This resulted in an average contribution rate of 76 per cent.

6.2.4 Connections by segment

Figure 6.2 shows connection activity for the 2026–31 regulatory period by segment. Growth in connection activity is forecast in all customer categories except embedded generation. Commercial and industrial activity is mostly in line with the current regulatory period. Residential and subdivision growth remains strong, driven by the continuing housing shortages across Victoria, and especially Melbourne.

[37] LEK, Customer electricity use and data centre forecasts, Databook to supplement residential load forecasts, October 2024.

FIGURE 6.2 GROSS CONNECTION ACTIVITY BY SEGMENT ($M, 2026)



6.2.5 Connection policy

At the commencement of each regulatory period we are required to implement a new connection policy. The connection policy must comply with the AER's connection charge guideline and be approved as part of the final determination.[38]

As noted earlier, our connection policy remains largely the same as that in place over the current regulatory period. Several changes to the Rules, however, have necessitated the following new inclusions in the connection policy:

- changes to requirements for micro-embedded generation and storage connections to support the introduction of emergency backstop requirements
- introduction of an upfront fixed connection application fee payable by customers prior to receiving a connection offer
- a quoted service charge to support provision of a higher standard service should that be sought by a customer
- new provisions to support the introduction of export limits consistent with the AER's flexible exports guidance notice
- new provisions to support the introduction of regulated stand-alone power systems.

Further discussion on the new charges is available in the alternate control services chapter. The remaining changes related to minimum backstop, export limits and stand-alone power networks are consistent with required regulatory changes.

[38] AER, Connection charge guidelines for electricity customers, October 2024.

7. Information and communications technology

Information and communications technology (ICT) is integral to a modern electricity distribution network. ICT includes all the platforms, systems, databases and electronic devices we use to enable the delivery of our services, as well as all the underlying infrastructure required to run our ICT program.

Our reliance on ICT is increasing as a key means of managing and operating our network in smarter, more flexible and lower-cost ways. This reliance will continue to increase as the network and the services we provide undergo considerable change. For example, the successful delivery of our CER ICT investments, such as developing an ICT system to enable flexible exports, will allow us to defer or avoid future augmentation of the network. Similarly, the replacement of our billing system will enable the deployment of new dynamic tariffs in the future that will better reflect the benefits of consumer resources.

A summary of our ICT investment in the current and future regulatory period is shown below.[39] For the current period we are forecasting an ICT overspend. This overspend is driven by additional spending on our advanced distribution management system (ADMS) and AEMO NEM reforms, which are partially offset by the deferral of our enterprise resource planning (ERP) replacement project.

For the 2026–31 regulatory period, we are forecasting a step up in capital expenditure reflecting the following drivers:

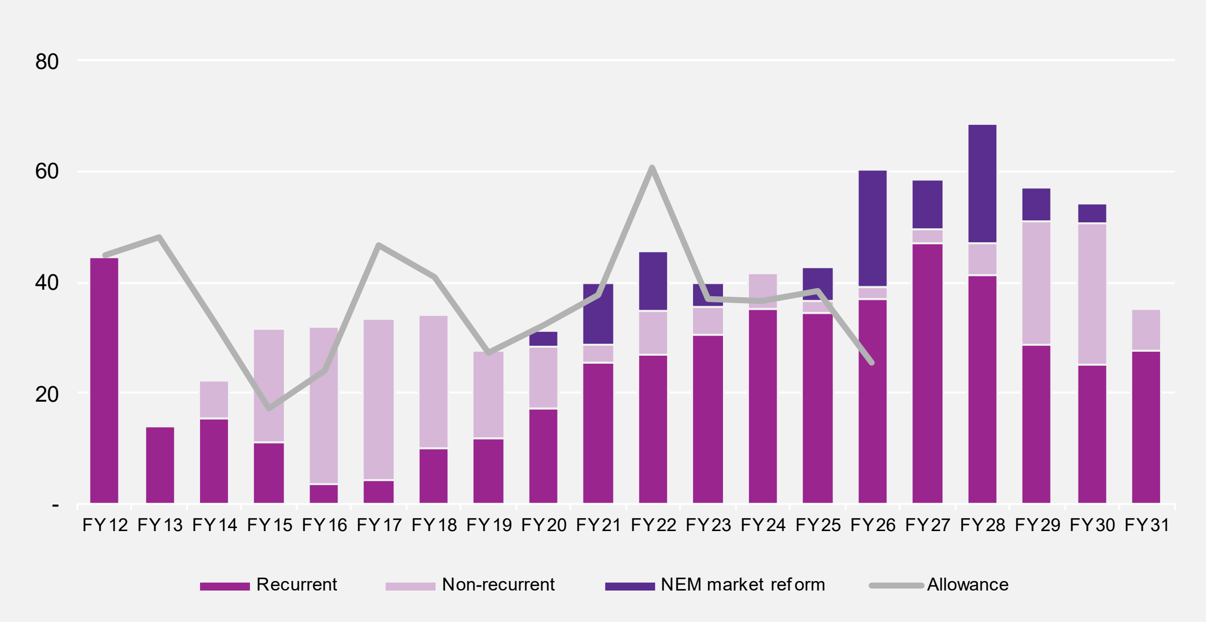
- a minor uplift in our recurrent investment program linked to a growing IT footprint
- an uplift in our non-recurrent ICT investment program, which includes upgrading our cyber-security position and the replacement of two of our core ICT systems that are critical to the energy transition
- new compliance requirements related to AEMO's NEM reform program, noting these have been updated since our draft proposal to reflect updated compliance timeframes that have brought forward investment into the 2021–26 regulatory period.

TABLE 7.1 TOTAL ICT INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Recurrent	165	170
Non-recurrent	23	63
Post-2025 NEM market reforms	43	41
Total	**231**	**274**

[39] Excluding CER, which is outlined in our electrification and CER integration strategy in chapter 2.

FIGURE 7.1 ANNUAL ICT INVESTMENT ($M, 2026)



7.1 What we've heard

For customers, ICT is a key enabler of the new services they increasingly want to access. For example, our customers want us to enable more rooftop solar exports, but are seeking lower cost solutions than traditional augmentation. As outlined previously in this document, our proposed flexible export services to enable this customer outcome will be delivered by an ICT solution.

Similarly, we've heard that customers want us to use innovation and technology to maintain a positive customer experience. They highlighted that efficient, easily accessible and responsive customer services were a priority.

We also tested customer expectations on cyber-security and ICT system replacement with our CAP, noting the technical nature of this issue. Recent large scale cyber breaches that have impacted some of Australian's largest companies demonstrate the growing cyber risks critical infrastructure providers face. These risks will continue to grow as we further digitalise and decentralise the electricity system. Similarly, our core ICT systems are now outdated and will be unable to provide the functionality required to meet the challenges of the energy transition.

TABLE 7.2 KEY ENGAGEMENT FINDINGS

Customers want us to enable more rooftop solar exports, but are seeking smarter solutions than traditional augmentation
Customers want us to use technology and innovation to maintain a positive customer experience
The CAP recognised the importance of improving our cyber security systems given recent large scale cyber breaches that have impacted some of Australia's largest critical infrastructure providers
The CAP supported replacing some of our key systems that have become outdated, ensuring we have the appropriate systems to meet the expected service levels of our customers now and into the future.

7.1.1 Test and validate

Following the release of our draft proposal, we also sought further feedback from the CAP as part of our test and validate engagement.

A key recommendation of the CAP was to continue, in partnership with the Victorian Government, to pursue tariff reform to enable all residential customers to have access to dynamic tariffs. Without investment in our ICT systems to enable dynamic distribution tariffs, we may act as a handbrake in delivering this reform.

7.2 Our proposed response

Our forecast ICT program for the 2026–31 regulatory period will allow us to maintain the currency of our existing ICT services and capabilities, unlock new benefits for our customers, and respond to changes in the energy market giving rise to new regulatory obligations.

Our ICT program will:

- continue to maintain and refresh our existing ICT investments
- enable the export of more solar through the development of flexible export services
- enable increased access to network data by digitalising our network
- ensure we are able to provide dynamic tariffs by upgrading our billing system
- enable a more data driven energy transition by modernising our core systems
- minimise the risk of a major cyber event by upgrading our cyber security
- ensure we comply with all new regulatory obligations stemming from the post-2025 NEM market reforms.

As part of our evaluation process, we engaged EY to undertake a review of our risk monetisation framework. As part of this review, we have developed clear guidelines on monetising a range of both business and IT specific risks. We have applied this guideline consistently across our ICT expenditure portfolio.[40]

7.2.1 Recurrent ICT investment

Recurrent ICT relates to maintaining and refreshing existing ICT services, functionalities and capabilities. Our forecast recurrent ICT investments are a small increase on current period expenditure.

Under our recurrent ICT investment program we will continue to refresh and update our IT systems prudently and efficiently to ensure we can provide the service levels expected by our customers. Below we outline some of our major recurrent expenditure categories.

NETWORK MANAGEMENT	COST
The network management systems comprise core operational systems that play a critical role in ensuring that we effectively and efficiently manage our network. These systems have a real-time 24/7 requirement to provide control and monitoring of customers' supply reliability and network performance, as well as providing tools to ensure network, employee and public safety is maintained. We need to invest in maintaining currency of critical system functionality that provides a key role in managing the electrical distribution network.	$54M

Note: For further detail, refer to our attached business case: UE BUS 7.05 - Network management systems - Jan2025 – Public.

INFRASTRUCTURE REFRESH	COST
There are a number of ageing assets (both hardware and software) that are being managed as part of their replacement cycle. As part of our infrastructure refresh, we will be moving some of our on premise infrastructure to cloud based solutions. Replacing and refreshing these assets will ensure that our infrastructure is maintained and that we have access to a variety of infrastructure solutions that best match our processes and systems.	CAPEX $31M OPEX $10M

Note: For further detail, refer to our attached business case: UE BUS 7.04 - Infrastructure refresh - Jan2025 – Public.

[40] For the full risk monetisation guideline refer to UE ATT 7.02 – EY - IT risk monetisation framework – Aug2024 - Public

MARKET COMPLIANCE — COST

$21M

The rules and obligations under which we operate often change to ensure the currency and relevance of the regulatory framework. While the AEMC and other government and regulatory bodies will continue to make structural changes to the Rules, smaller unidentified changes to regulated guidelines, procedures and obligations will also continue. These changes are needed to improve implementation of the Rules and deliver best-practices processes.

This investment is required to maintain compliance with all regulatory and market obligations, and is forecast based on historical costs.

Note: For further detail, refer to our attached business case: UE BUS 7.09 - Market compliance - Jan2025 – Public.

MARKET SYSTEMS — COST

$15M

Our Market Systems platform provides centralised storage and validation of meter reading data and manages market-compliant communications and customer requests both internally and with external participants of the NEM. Our Market Systems platform is essential for ensuring compliance with our regulatory obligations under the AEMO procedures, the Rules and Distribution Code.

This investment maintains the technical currency of our systems by prudently adopting software upgrades throughout the regulatory period.

Note: For further detail, refer to our attached business case: UE BUS 7.06 - Market systems - Jan2025 – Public.

OTHER RECURRENT CATEGORIES — COST

$30M

In addition to the four categories identified above we will also have recurrent investments linked to maintaining currency for:

- end user device management
- telephony
- enterprise management systems
- IT facilities
- customer enablement.

Recurrent investment is also required to support our ongoing cyber security and ERP and billing system needs, however recurrent expenditure associated with these two investments is included in our non-recurrent investments for these systems.

Note: For further detail, refer to our attached business cases: UE BUS 7.08 - End user device management - Jan2025 – Public; UE BUS 7.11 - Telephony - Jan2025 – Public; UE BUS 7.07 - Enterprise management systems - Jan2025 – Public; UE BUS 7.10 - Customer enablement - Jan2025 – Public; For IT facilities details see UE BUS 8.02 - Property recurrent expenditure - Jan2025 – Public.

7.2.2 Non-recurrent ICT investment

Non-recurrent ICT relates to ICT investments that unlock new benefits for customers. Our non-recurrent ICT investment program will ensure we continue to evolve our network capabilities to enable the services expected by our customers.

Our non-recurrent forecasts represent an uplift on current period expenditure, with this uplift driven by the replacement of two of our core ICT systems.

ERP AND BILLING SYSTEM REPLACEMENT	COST
We are upgrading two of our core systems; our ERP system and our billing system. Our ERP system is used for our core payroll, human resources, finance and assessment management systems. Our billing system is responsible for recording and issuing our network tariff bills and managing a range of market and customer data management processes. These core systems are ageing rapidly, with our billing system now over 25 years old. Both systems must be upgraded to modern standards as we will no longer receive vendor support to help us maintain and update these systems. We are now one of the last remaining customers worldwide who are using our current billing system. Continuing to use our old systems without the associated support will significantly increase the risks of system failures and will require a growing number of resources to keep the system running. The ageing systems are unlikely to meet changing customers' demands and will be unable to support our growing IT footprint. Moving to modern systems will ensure we continue to safely support and manage our assets. It will also provide us with core systems that are better able to integrate new and innovative services to customers. These services, such as new and dynamic tariffs, will be needed to support the energy transition and better maximise the value of CER. An upgraded billing system is also critical to allow for changes in future tariffs. Without investment in the 2026–31 regulatory period, we will be unable to provide dynamic tariffs until ~2035, well beyond when these tariffs will likely be required.	CAPEX $64M OPEX $22M

Note: For further detail, refer to our attached business case: UE BUS 7.01 - ERP & billing system replacement - Jan2025 – Public.

CYBER SECURITY	COST
As an essential service, our networks play a crucial role in providing safe and reliable electricity to our customers and communities, which can be put at risk by malicious cyber-attacks. Cyber-attacks include not just unauthorised access of IT systems or phishing of sensitive information, but malicious actors are increasingly targeting operational technology (OT systems), such as supervisory control and data acquisition (SCADA) systems. Any disruption to supply of electricity or the release of sensitive information due to a cyber-attack can have serious implications for customers, businesses, the government and communities. The increasing use of data and digitalisation across our network is creating a growing number of touchpoints that malicious actors may attempt to breach to gain access to our systems. To ensure our network remains safe and reliable and that network and customer data remains protected, we are upgrading our cyber security. Without improvements in cyber security we will have an increasing risk of a material cyber breach. Our proposed investment will reduce the risk of a material cyber breach of our network that could have the potential to lead to large-scale unplanned outages of our system. It will also strengthen the protection of our growing database of network and customer data. Our targeted cyber security investment will bring us to an SP2+ level under the Australian Energy Sector Cyber Security Framework (AESCSF), with a focus on practices and anti-patterns that provide the greatest level of benefit.	CAPEX $17M OPEX $17M

Note: For further detail, refer to our attached business case: UE BUS 7.02 - Cyber security - Jan2025 – Public.

7.2.3 AEMO NEM reform expenditure

The Energy Security Board (ESB), in collaboration with other key regulatory bodies, has set a pathway to modernise the NEM to better meet the community's evolving wants and needs and move towards a net-zero future. Known as the post-2025 NEM reforms, these changes are to accommodate the increasing uptake of new technologies, including CER.

Many of these reforms are being implemented through AEMO reviews, with implementation timeframes expected during the 2026–31 regulatory period. Each of these reforms will require significant changes to our IT systems and processes.

AEMO NEM REFORMS	COST
We have included two projects in our 2026–31 regulatory period that are driven by AEMO NEM reforms:	CAPEX $41M OPEX $3M

Flexible trading arrangements (FTA)

This investment links to the AEMC's rule change focused on unlocking CER benefits through flexible trading. It will:

- enable large customers to engage multiple energy service providers
- allow for the separation of flexible CER from passive loads leading to innovative products and services
- allow market participants to use in-built measurement capability in technology such as EV chargers and smart streetlights.

In order to meet updated AEMO compliance timelines, we have moved forward the timing of our FTA investments, with a significant portion of this investment now expected in the 2021–26 regulatory period. In November 2024, the AER approved an extension to the timeframe for submitting a cost pass-through application associated with these changes.

Market Interface Technology Enhancements (MITE)

This investment includes a number of foundational initiatives to enable the NEM reform program. It will support a single unique credential to access all AEMO hosted applications and create a unified stakeholder experience. This includes investments in:

- identity and access management
- portal consolidation.

Note: For further detail, refer to our attached business case: UE BUS 7.03 - AEMO NEM reforms - Jan2025 – Public.

In addition to the FTA and MITE investments, AEMO has also proposed changes to the industry data exchange. Improvements to the industry data exchange will create a national CER data exchange to better coordinate flexible CER.

At the time of writing this regulatory proposal we do not yet have enough information to develop expenditure related to this reform. Once these reform rule changes are final, we will review and update our proposed investments as part of our revised regulatory proposal.

8. Property, fleet, and other non-network

Our property and fleet portfolio includes buildings (including security, compliance, and sustainability), motor vehicle fleet, and tools and equipment.

Our property and fleet allow us to serve our communities by ensuring the appropriate people, resources and materials are located across our networks, so we can respond to outages, fix faults, maintain our network, and connect new customers. Our depots and fleet are also a key factor in the health and safety for our workers and staff.

For the current period, we are forecasting a property and fleet overspend. This overspend is driven by redevelopment of our Glen Waverley depot, as well as unit rate increases in fleet, and partial fleet insourcing due to external contract requirements.

For the 2026–31 regulatory period, the key drivers of investment include the following:

- a decrease in property expenditure, due to all depots having been redeveloped in the current regulatory period, with 2026–31 investment comprising head office redevelopment and prudent security investment
- an uplift in our fleet investments (including relative to our draft proposal) due to the insourcing of external contracts
- tools and equipment investment in line with current period expenditure.

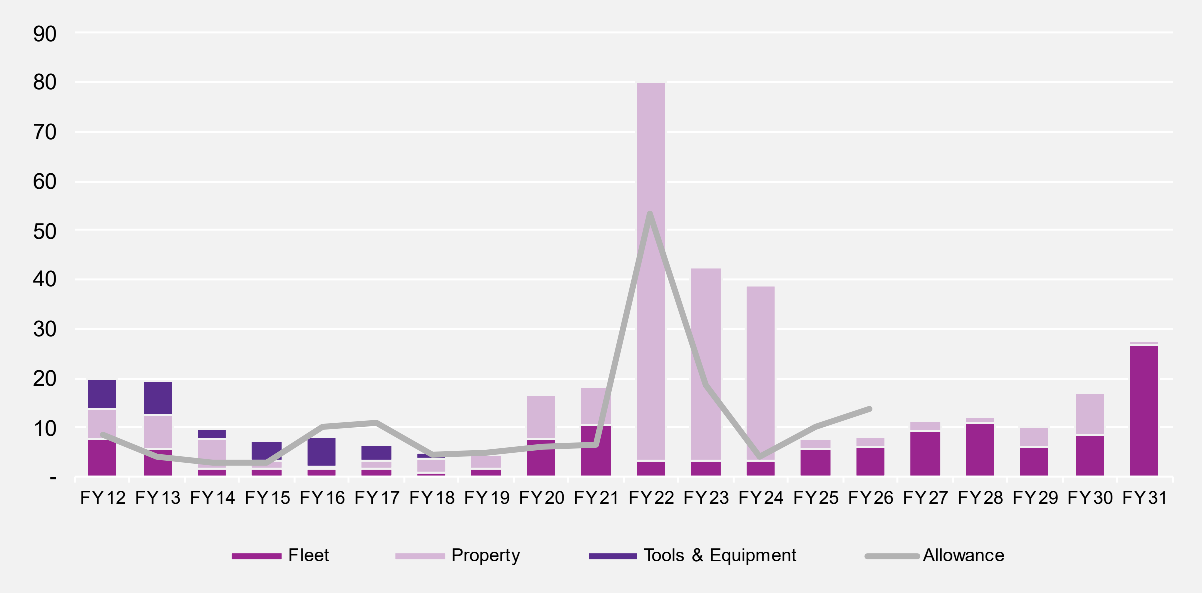
Our program also includes modest sustainability investments to meet community expectations regarding our environmental, sustainability and governance practices.

A summary of our fleet, property and other non-network investment in the current and future regulatory periods is shown below.

TABLE 8.1 TOTAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)

DESCRIPTION	2021–26	2026–31
Property	165	17
Fleet	21	62
Tools and equipment	1	1

FIGURE 8.1 ANNUAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)



8.1 What we've heard

Across our extensive stakeholder engagement program our customers consistently highlighted the importance of an affordable and reliable energy supply. As Victoria electrifies and demand increases, so too will the value of reliability and the consequence of time-off-supply. Our non-network (other) programs are critical to maintaining a reliable energy supply in our communities.

TABLE 8.2 KEY ENGAGEMENT FINDINGS

	Customers consistently highlighted the importance of a reliable energy supply, with most customers having an appetite to maintain current reliability
	Customers indicated a commitment to environmental sustainability and a moderate appetite to pay for emissions reductions
	Customers overwhelming see affordability as about value, rather than cost

8.2 Our proposed response

Our property and fleet investment in the 2026–31 regulatory period will deliver on the following customer outcomes:

- maintain safety for our workers and communities through prudent investments in building security
- improve environmental sustainability through a targeted program prioritising the least cost and highest impact investments to reduce emissions
- maintain efficient long-term operational deliverability and value throughout the energy transition via insourcing our fleet.

8.2.1 Property

Our buildings are vital to delivering the core operations of our network. Non-network property assets comprise depots, zone-substation control rooms, head office, contact centre, and network and security control rooms.

Our forecast property investments represent a step-down on current period expenditure. In the current regulatory period we upgraded all three of our existing depots (with Mornington due for completion in 2025), benefitting the communities we serve, the health and wellbeing of our workers, and the ability to undertake works in an efficient manner.

Other property works include prudent improvements to the security of our critical assets. Following customer engagement feedback, a sustainability program is also included.

HEAD OFFICE	COST
We are proposing to redevelop our head office at the expiration of our 15-year term lease, during the 2026–31 regulatory period. Our head office houses over 1,000 employees and contractors, playing a critical role for the business housing key corporate and network functions as well as the central control rooms. Fit-for-purpose facilities are essential in enabling the safe and continued operation of our network. Outdated facilities can lead to deterioration in productivity, staff retention and morale. Our current head office will require enhancements due to significant age and restricted flexibility in working arrangements and needs.	$10M

Note: For further detail, refer to our attached business case: UE BUS 8.01 – Head office refurbishment – Jan2025 – Public.

PHYSICAL SECURITY	COST
Our physical security program includes CCTV replacement and upgrades to enable integration with our security control room, and fencing at critical telco sites identified in accordance with the Security of Critical Infrastructure Act (2018). Physical security is crucial to maintain safety and security of supply of our network. In 2021–26 we have undertaken works to uplift the security of our assets, particularly the construction of a purpose-built control room. However, instances of security breaches, including attempted break-ins and copper theft, continue to rise. In accordance with industry best practice, we take a proactive approach to safety and security to support a safe and secure environment for customers, the public and our industry workers.	$4M

Note: For further detail, refer to our attached business case: UE BUS 8.02 – Property recurrent expenditure – Jan2025 – Public.

ENVIRONMENTAL SUSTAINABILITY	COST
Our customer engagement program evidenced that customers place value on reductions in emissions, however, there is a trade-off between sustainability and affordability. We engaged with the CAP on a framework to consider this balance. Our current program proposes a targeted sustainability approach prioritising the least cost and highest impact investments, to balance cost and value. This includes the installation of solar panels, battery storage, and EV charging infrastructure at our three depots to facilitate our roll-out of EVs.	$3M

Note: For further detail, refer to our attached business case: UE BUS 8.02 – Property recurrent expenditure– Jan2025 – Public.

8.2.2 Fleet

Fleet is an essential enabler in supporting the investment, maintenance, and operational activities of our network. Our fleet strategy and investment aim to align our asset management and acquisition with the business' current and evolving requirements to ensure good customer outcomes.

Our forecast fleet investment represents a step-up on current period expenditure, driven by the proposed insourcing of our fleet.

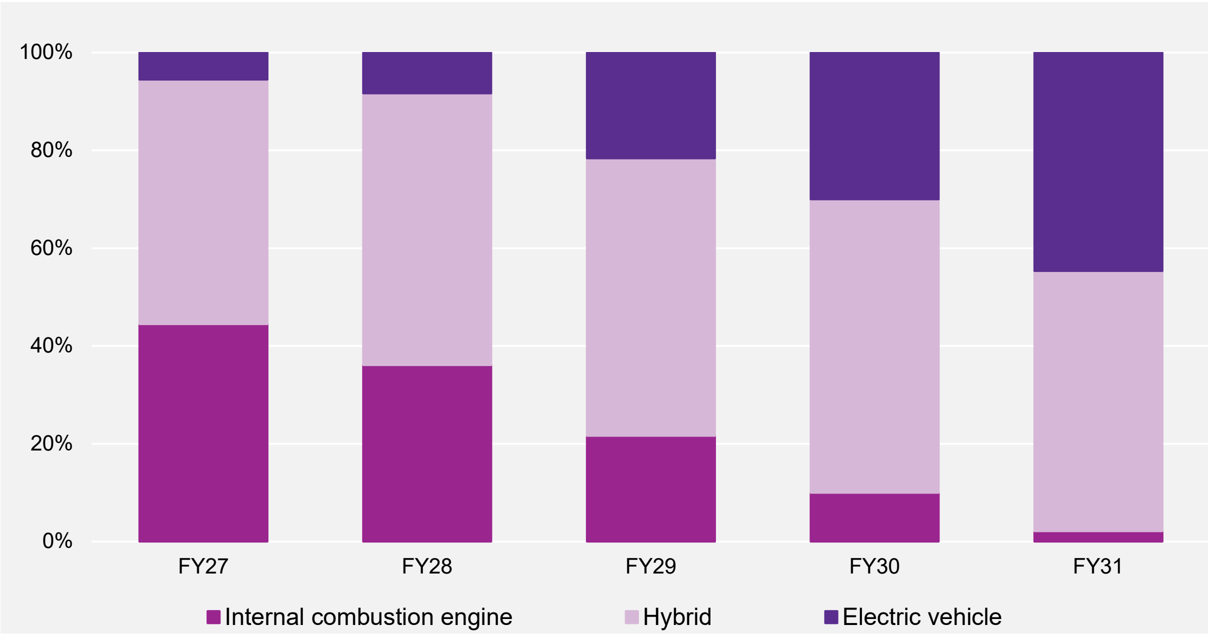
FLEET REPLACEMENT AND INSOURCING	COST
Our network currently operates under an outsourced field delivery model. Throughout the pandemic, this existing contract allowed us to manage some of the impacts of global supply chain cost impacts for our customers. As part of this outsourced model, ownership of fleet is currently split between United Energy and the incumbent service provider. This arrangement, however, may act as a barrier to entry for alternative service providers. In the 2026–31 regulatory period, we propose to insource the remaining proportion of fleet that we do not currently own. This will result in lower long-term fleet costs for our customers and provide greater competitive tension and bargaining power when re-negotiating future contracts (with either our incumbent service provider, or alternative competitors).	$61M

Note: For further detail, refer to our attached business case: UE BUS 8.03 – Fleet – Jan2025 – Public.

FLEET ELECTRIFICATION	COST
We worked with our stakeholders on determining the right level of EV uptake as well as considering the Victorian Government's Zero Emissions Vehicle Roadmap. Our fleet forecast includes modest additional capex for fleet electrification, with a focus on hybrid vehicle replacement to promote emissions reduction without compromising affordability, in line with our customers' preferences. Our assessment approach for fleet electrification also incorporates the AER's recently published value of emissions reduction. Our approach evaluates the total cost of ownership of vehicle electrification, including a negative operating expenditure step-change due to reduced operating costs of hybrid and electric vehicles. This represents an optimised hybrid/EV uptake rate that maximises economic efficiency and emissions reduction.	$1M

Note: For further detail, refer to our attached business case: UE BUS 8.03 – Fleet – Jan2025 – Public.

FIGURE 8.2 HYBRID AND ELECTRIC VEHICLE UPTAKE (%)



9. Operating expenditure

Operating expenditure is the day-to-day cost required to operate and maintain our distribution network. It covers our ongoing maintenance programs, vegetation management, fault responses, customer support services and corporate costs.

9.1 What we've heard

Throughout our engagement with customers and key stakeholders, a consistent theme has been the importance of an affordable electricity supply. This reflects the cost-of-living challenges we all face in today's economic environment, and the need to balance this against preferences for new services (such as those associated with the energy transition).

Our engagement program has also focused on testing our customers' willingness to pay for new services. The key findings from our engagement program, relevant to our operating expenditure forecasts, are summarised below.

TABLE 9.1 KEY ENGAGEMENT FINDINGS

Customers want us to ensure the cost of energy services is reasonable and affordable for all customers
Vulnerable customer advocates want us to ensure price sensitive vulnerable customers are empowered to manage their usage
Customers want value for money in their electricity services and want to ensure costs are invested in a meaningful way
Ensure our environment is protected from cyber security attacks
Commercial and industrial customers believe CER enables reliability

9.1.1 Test and validate

Our draft proposal set out our proposed customer assistance package to support customers who may be, or are at risk of, experiencing vulnerable circumstances. As part of our test and validate engagement at our roundtable discussions, our customers provided consistent feedback that reinforced the value of this assistance package.

Customers indicated they supported the package as it:

- highlights the importance of accountability tracking and communication of outcomes, especially as success was defined by the impact made
- builds strong partnerships in the community to deliver greater impact and ensure support is provided to vulnerable customers

- highlights the need to increase investment to assist other vulnerable groups facing energy poverty.

Our test and validate engagement phase also sought feedback on key CER integration programs that are reflected in our proposed operating expenditure step changes. For example:

- customers supported our proposed data visibility program, noting that equitable access to practical, timely and extensive data would be beneficial
- customers supported our flexible exports program, preferring equal allocation of capacity across flexible customers.

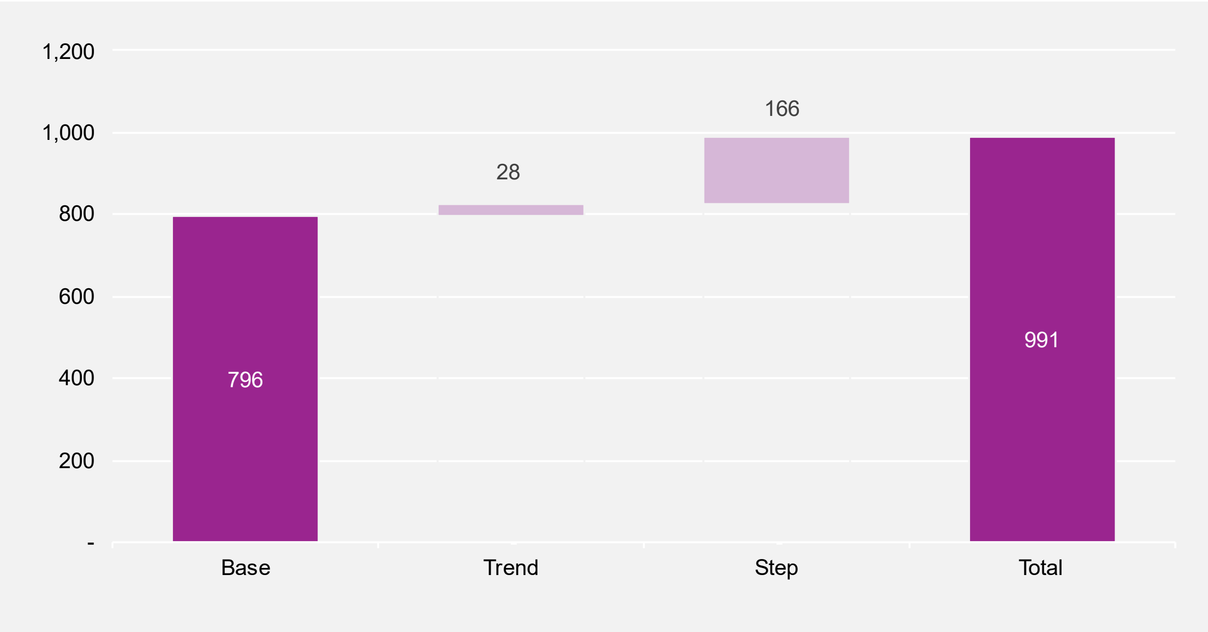
As outlined earlier in the respective CER chapter, our customers were supportive of our proposed investments.

9.2 Our proposed response

Consistent with the AER's preferred approach, as set out in its Better Resets Handbook, we have forecast operating expenditure using a 'base-step-trend' approach.

A summary of our proposed operating expenditure is shown in figure 9.1.

FIGURE 9.1 TOTAL OPERATING EXPENDITURE ($M, 2026)



Note: Totals may not add due to rounding.

9.2.1 Proposed base year

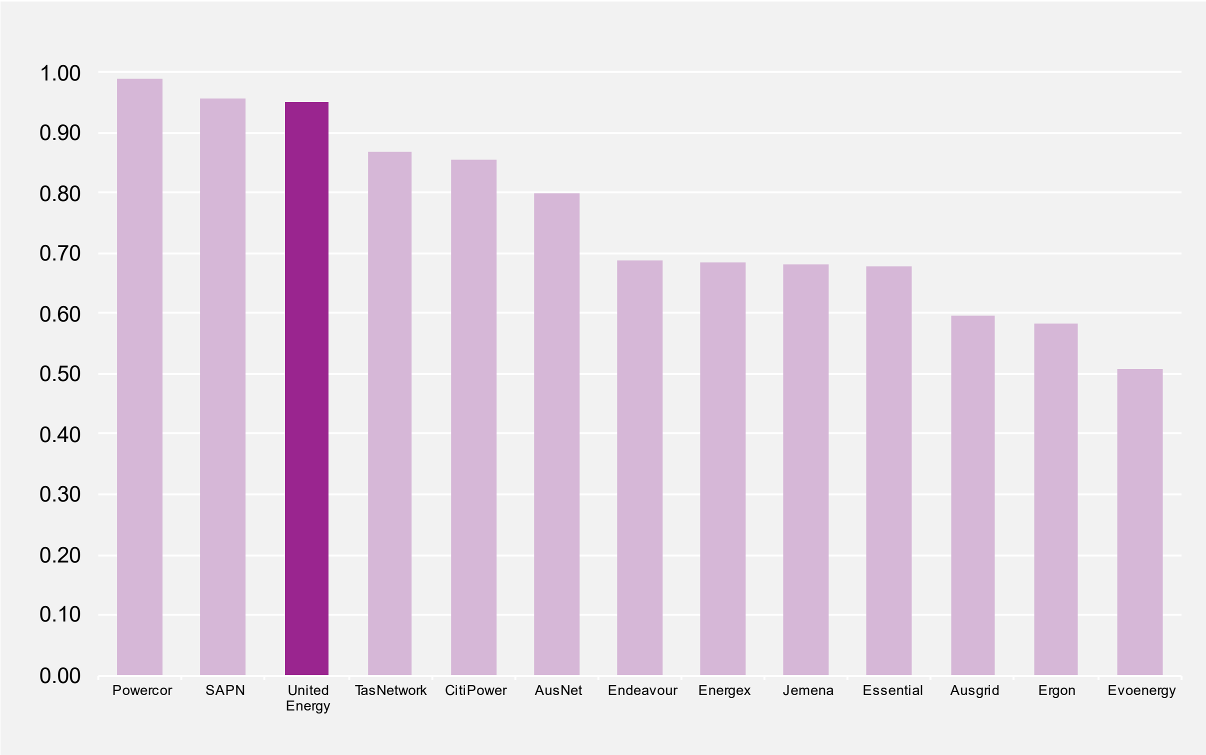
Under the AER's preferred forecasting approach, the first step is to determine the efficient revealed cost base year of expenditure. Where distributors are efficient, customers benefit through downward pressure on network charges and customer bills.

The AER reports annually on the productivity growth and efficiency of distributors, on both an individual network and industry level. They use economic benchmarking to measure how efficiently we deliver services over time and compared with our peers.

Specifically, the AER assesses whether distributors’ base year operating expenditure is efficient using its operating expenditure econometric modelling, which produces average operating expenditure efficiency scores over time. The AER considers that distributors with an efficiency score above 0.75 are 'benchmark comparators' that have had efficient operating expenditure over time.

Our average operating expenditure efficiency score in the AER's most recent benchmarking report is 0.95, indicating that we are a benchmark comparator with efficient operating expenditure. Customers benefit from this efficiency through lower network charges.

FIGURE 9.2 AER'S AVERAGE OPERATING EXPENDITURE EFFICIENCY SCORES



Source: AER, Annual Benchmarking Report, Electricity distribution network service providers, 2024, figure 14, p. 35.

For our regulatory proposal, therefore, our proposed base year is the penultimate year of the current regulatory period (i.e. FY25). We consider this is an appropriate reference point as it will be the most recent year where audited actual data will be available at the time of the AER's final decision.

Base year adjustments and category specific forecasts

A base year adjustment may be required to modify the base year to ensure it accurately reflects changes in the operating environment and ensures an accurate expenditure forecast.

Alternatively, a category specific cost is an operating expenditure forecast for specific categories of costs that are expected to vary significantly from that incurred in the base year, and therefore necessitate separate consideration.

We have identified the following three adjustments for the 2026–31 regulatory period:

- guaranteed service levels (GSL) – these are payments we make to customers who experience reliability less than the specified performance thresholds in the Electricity Distribution Code. These payments are volatile as they are based on a range of exogenous factors. We have therefore removed GSL payments from the base year, and replaced them with a new GSL payment rate with a placeholder increase of 15 per cent and volumes based on the average of the last three financial years (i.e. from 2021–22 to 2023–24)[41]

- licence fees – we must make payments to the Essential Services Commission (ESC) for our distribution licence. Licence fees have been increasing faster than forecast and given its variability and materiality, we removed licence fees from the base year. Consistent with the AER's final decision for jurisdictional schemes in our current regulatory period, we propose to recover actual licence fees from ESC through the price control mechanism over the 2021–26 regulatory period
- network innovation – we are seeking an innovation allowance that would allow us to research, test, and implement innovative ideas that have the potential to drive long-term value to customers but are not currently funded under the regulatory framework. Through our test and validate phase of customer engagement, we received strong customer support for our proposed innovation allowance, both in terms of the amount of expenditure and the key focus areas for investment.

9.2.2 Proposed trend forecast

Our base year operating expenditure is escalated by applying forecast trend growth. This trend adjusts for changes in services (output growth), real changes in output prices (price growth) and improvements in productivity (productivity growth).

Output growth

We have forecast output growth using inputs from a range of sources, including our smart meter data, and AEMO and Victorian Government forecasts. The output growth drivers we have used are those described in the 2024 AER annual benchmarking report, including customer numbers, circuit length and ratcheted maximum demand

We have weighted these growth drivers using output elasticities from the 2024 Quantonomics benchmarking report, as set in our operating expenditure model.[42] The forecast amounts for each growth driver are also described in our operating expenditure model.[43]

We have applied output growth as a percentage growth rate to our revealed base year, using the AER's four operating expenditure econometric benchmarking models.[44]

Price growth

Real price growth accounts for increases in prices that are expected to be over and above inflation. We consider real price growth separately for labour, and non-labour.

For labour growth, we used an average of independent forecasts for the utilities industry Wage Price Index growth in Victoria, plus the legislated 0.5 per cent increase for superannuation guarantee.[45]

Given the temporal nature of labour forecasts, we will update these for our revised regulatory proposals.

Our regulatory proposal also forecasts zero real non-labour price growth, notwithstanding there is evidence that material costs will continue to increase at a rate above inflation. This is particularly the case in the electricity sector, where both global and domestic demand associated with the energy

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[41] This placeholder will be updated in our revised proposal, following finalisation of the new rate that is expected to be available in 2025.

[42] See the input rate of change tab in: UE MOD 1.05 - Opex - Jan2025 – Public.

[43] See the input rate of change tab in: UE MOD 1.05 - Opex - Jan2025 – Public.

[44] Including Cobb-Douglas least squares, Translog least squares, Cobb-Douglas stochastic frontier analysis and Translog stochastic frontier analysis

[45] Specifically, see: AER, SA Power Networks Electricity Distribution Determination 2025 to 2030, Draft decision, and UE ATT 9.01 – Oxford Economics - Labour escalation – Jan2025 – Public.

transition remain high. We have recently been absorbing these costs in an effort to maintain customer affordability, however this is unlikely to be an appropriate long-term approach.

Consistent with the AER's previous regulation determination for our business, the relative weighting applied to labour and non-labour expenditure is 59.2 per cent labour and 40.8 per cent non-labour. Our actual labour and non-labour expenditure has a much greater weighting to labour, however, the AER has not previously countenanced our proposal to update these weights.

Productivity growth

We have applied a productivity growth forecast of 0.5 per cent, consistent with the AER’s preferred productivity growth forecast set out in its Better Resets Handbook. Productivity change has been applied as a negative percentage adjustment to the revealed cost base year of operating expenditure.

As a frontier firm on the AER’s benchmarking measures, these productivity targets are increasingly challenging to deliver. For example, the fundamentals of operating a network have changed considerably over the past 10 years, and many of our investment drivers are outside our control (such as the need to meet increasing compliance obligations arising from market reforms).

9.2.3 Step changes

Our step changes for the 2026–31 regulatory proposal include those required to meet new or changing compliance obligations, and deliver new services associated with the energy transition and network resilience. They also reflect the impacts of changing accounting treatments associated with software as a service, and the evolving nature of ICT solutions (which are now being delivered through cloud-based technologies, rather than on-premise capital alternatives).

As such our step changes are costs not accounted for in our base year expenditure, trend forecasts or productivity growth and are therefore forecast separately. Without these step changes, we will be unable to deliver efficient service outcomes for customers or meet our new regulatory obligations related to our step change proposals.

Each of our step changes is recurrent in nature. A summary of these step changes is included below, and where relevant, a fulsome justification is set out in the corresponding business cases.

TABLE 9.2 SUMMARY OF OPERATING EXPENDITURE STEP CHANGES ($M, 2026)

STEP CHANGE	AER CATEGORY	COST
Customer package	Major external factor	$15M
Vegetation management	Major external factor and regulatory obligation	$72M
CER integration	Major external factor	$19M
Cloud services	Capex / opex trade-off	$24M
ICT modernisation and new capability	Major external factor and capex / opex trade-off	$32M
Network and community resilience	Major external factor	$4M
Fleet electrification offset	Major external factor	-$0.2M

Customer package

The customer package combines several programs to improve services to our customers, especially those at risk of some form of energy poverty. These programs have been developed based on feedback from our customer engagements, and from the CAP.

As part of our process, and in response to a suggestion from the AER's Consumer Challenge Panel, we empowered the CAP to determine which customer programs were included in our draft proposal. The programs included are:

- energy care – a community outreach approach with in-person literacy programs to help interpret bills and understand energy consumption
- community energy fund – supporting inclusiveness and an equitable energy transition
- vulnerable customer assistance program – targeted at assisting customers and communities' transition away from gas-based appliances
- energy advisory services – enhance our data advisory program to support community information requests
- First Peoples program – the program aims to respond to community feedback with a strong focus on education, access to low energy appliances for vulnerable customers and energy audits. This program also aims to support First Peoples adoption of renewable energy both at a household and community level, as well as putting programs in place for climate emergencies.

Following our draft proposal, we incorporated feedback from our test and validate engagement, and updated our customer package (as attached).[46] Specifically, we made the following changes:

[46] For further detail, refer to our attached business case: UE BUS 9.02 – Customer assistance package – Jan2025 – Public.

- expenditure has been uplifted to reach a meaningful number of customers to provide tangible customer impact
- a vulnerable customer strategy is being developed, to further identify where we are uniquely well-placed to support customer in vulnerable circumstances. The CAP will be consulted in the development and implementation of this vulnerable customer strategy
- incorporated partnerships with organisations and community groups to deliver our programs
- established an internal working group to refine the principles, governance and operation of all elements of the customer assistance package.

Our revised customer package was then tested with both the CAP and FPAC. FPAC endorsed the First Peoples program, and the customer program in its entirety was endorsed by the CAP. Both the CAP and FPAC supported the business intent and value that this aims to bring to both First Peoples customers and customers at risk of vulnerable circumstances.

The CAP and FPAC articulated that appropriate governance and evaluation of the programs was a key requirement for successful program delivery.

Vegetation management

In Victoria, the Electricity Safety (Electric Line Clearance) Regulations (the Code) govern how we inspect and manage vegetation, and our Electric Line Clearance Management Plan (ELCMP) outlines our standards and practices for tree cutting or removal, including rectification timing.

Unlike our general safety obligations that require us to minimise risk as far as practicable, our vegetation clearance obligations are deterministic. That is, the Code requires that no vegetation enters the minimum clearance at any time (i.e. it is not a risk-based assessment).

In 2018, following a major review of our vegetation clearance management and contract arrangements, we introduced new technologies to provide faster and more accurate visibility of our network. Specifically, we commenced using light detection and ranging (LIDAR) technology to replace our ground-based vegetation inspection practices.

The application of LIDAR has improved across several years, with a steady-state level of maturity and confidence in the accuracy of the outputs being achieved from around 2022. We have also been on a continuous improvement journey through this time, including the procurement of additional infrastructure (e.g. our aerial fleet, as well as more mechanical cutting equipment), and providing longer-term contracts to our third-party providers to encourage growth in available labour resources.

The use of LIDAR, however, has naturally identified more 'known-unknowns' and technical non-compliances than we previously had the ability to identify. As a result, we have been prosecuted by ESV for failing to clear vegetation in accordance with the Code.

In effect, our regulatory obligation to comply with the Code has changed during the 2021–26 regulatory period. This is because, while the Code requirements are deterministic and have not themselves changed, the standard of compliance with these requirements required by law is informed by what is possible, having regard to industry best practice. As a result of our industry leading vegetation management program, industry best practice has evolved during the 2021–26 regulatory period, such that the standard of Code compliance that is possible has increased significantly. This new standard of compliance constitutes a change in a 'regulatory obligation or requirement' for the purposes of the National Electricity Law.

Our regulatory proposal, therefore, includes an operating expenditure step change reflecting the cost of achieving compliance with the Code at a point in time, and compliance with the ELCMP at all times. Following our draft proposal, we have updated our modelling so that we achieve this level of compliance in FY29. This better recognises the likely time required to build a resource pool capable of delivering the expected volume of works.

This incremental expenditure is to increase the volume of cutting undertaken, with further detail set out in our vegetation management attachment.[47]

At the same time, we have been engaging with ESV and the Victorian Government to seek amendments to the Code to better support the role of technology in managing vegetation clearance risks. The existing Code is due to sunset in mid-2025, with revisions subject to a public Regulatory Impact Statement (RIS).[48]

Cloud services

The changing nature of the ICT market offerings mean that many services are now offered as cloud-based solutions, rather than on-premises infrastructure. Cloud services are able to offer greater flexibility and scalability compared to tradition infrastructure solutions.

Following accounting rule clarification in early 2021, costs associated with the implemention of cloud services are now classified as operating expenditure. This is due to IT products transitioning from local data centres to cloud-based hosting. Prior to this, changes to these costs had been incurred as capital expenditure. To meet our accounting requirements for the 2026–31 regulatory period we have included our cloud implementation costs as an operating expenditure step change.

Further detail on the components of this step change are set out in the corresponding ICT business cases.[49]

ICT modernisation and new capability

Throughout the 2026–31 regulatory period we will be implementing a range of ICT modernisation and new capabilities to meet the needs and expectations of our customers. Once these new capabilities are established, we will require additional operating expenditure to run and maintain these capabilities. This includes supporting our new ERP and billing system, new enhancements associated with AEMO NEM reforms, as well as our new cyber capabilities that will improve threat prevention, monitoring and detection.

Further detail on the components of this step change are set out in the corresponding ICT business cases.[50]

Insurance premiums

The cost of insurance premiums has been increasing over time, driven by factors such as bushfire risk and other natural disasters. Our insurance premiums are expected to increase further in the short-term, however, there remains uncertainty about medium-term projections (particularly given recent events in California, and the international nature of the insurance market).

We have not included a step change for insurance premiums in our regulatory proposal, but plan to re-assess the insurance market at the time of our revised proposal.

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[47] UE ATT 9.02 – Vegetation management step change – Jan2025 – Public.

[48] We will consider the outcomes of this RIS in the development of our revised proposal.

[49] UE BUS 7.01 – ERP & billing system replacement – Jan2025 – Public; UE BUS 7.02 – Cyber security – Jan2025 – Public; UE BUS 7.04 – Infrastructure refresh – Jan2025 – Public.

[50] UE BUS 7.01 – ERP & billing system replacement – Jan2025 – Public; UE BUS 7.02 – Cyber security – Jan2025 – Public; UE BUS 7.04 – Infrastructure refresh – Jan2025 – Public; UE BUS 7.03 – AEMO NEM reforms – Jan2025 – Public.

10. Incentives

There are a number of mechanisms and schemes within the regulatory framework that incentivise us to continually improve our service levels to customers or maintain service levels efficiently.

For the 2026–31 regulatory period, we propose to continue the same incentives schemes as currently in place, with the addition of a new innovation allowance to deliver long-term benefits to customers through innovative projects beyond demand management. These schemes are outlined below.

TABLE 10.1 PROPOSED INCENTIVE SCHEMES FOR THE 2026–31 REGULATORY PERIOD

INCENTIVE SCHEME	SUMMARY
Capital Expenditure Sharing Scheme (CESS)	The CESS provides us with incentives to undertake efficient capital expenditure. Where we are able to make efficiency gains these are shared with customers, with customers receiving 70-80 per cent of these efficiencies
Efficiency Benefit Sharing Scheme (EBSS)	The EBSS provides us with incentives to undertake efficient operating expenditure. Where we are able to make efficiency gains these benefits remain with us for six years after which the full value of the benefit is passed onto customers
Service Target Performance Incentive Scheme (STPIS)	The STPIS incentivises us to maintain and improve network performance, and balances incentives in the EBSS and CESS to reduce expenditures. This ensures consumers receive benefits from genuine efficiency gains and not at the risk of a decrease in network performance
Customer Service Incentive Scheme (CSIS)	The CSIS is designed to incentivise customer services in accordance with customer preferences. It focuses on customer service levels in areas where customers value improvement
Demand Management Incentive Scheme (DMIS)	The DMIS provides us with financial incentives to undertake efficient expenditure on non-network solutions to manage peak electricity demand. This lowers the cost of managing peak electricity demand for customers
Demand Management Innovation Allowance Mechanism (DMIAM)	The DMIAM provides funding for research and development in demand management projects that have the potential to reduce long-term network costs. The DMIAM supports the development of ideas that may form part of the DMIS in the future
F-factor scheme	The F-factor scheme provides financial incentives to minimise the number of fire starts within high fire danger zones and times. This scheme is specific to Victoria
Innovation allowance	The innovation allowance is intended to support the broader development of research, trials and pilots, where such projects can provide long-term benefits to customers

The CESS, EBSS and STPIS have been part of the regulatory framework for a number of years, and we continue to respond strongly to the incentives provided by these schemes.

The AER recently conducted a review of these three schemes, noting that the CESS, EBSS and STPIS have ‘driven significant improvement in performance through efficiency gains’.[51] The review highlighted that together the schemes across the NEM had reduced revenue per customer by 35 per cent since 2014–15, while also improving the frequency and duration of outages by 20–30 per cent.

The AER further noted that ‘while the network service providers have been rewarded for the efficiency gains, the majority of benefits have gone to consumers.[52]

10.1 EBSS

We propose to continue to apply the EBSS to standard control operating expenditure over the 2026–31 regulatory period to ensure we have strong incentives to pursue efficiencies which deliver lower costs to customers over the long term. We propose to continue applying the EBSS in accordance with the AER's EBSS guideline and exclude the following costs from the 2026–31 carryover:

- debt raising costs,
- the demand management innovation allowance (DMIAM)
- GSL payments
- expenditure related to our proposed innovation allowance.

Applying the EBSS is consistent with the AER's framework and approach paper and our forecast operating expenditure for the 2026–31 regulatory period, which will be based on our actual efficient 2024–25 operating expenditure.

We have applied the AER's EBSS to calculate the revenue increments and decrements for the 2021–26 regulatory period, as outlined in the attached model and in table 10.2.[53]

The 2026–31 EBSS revenue adjustments will be updated with the latest available information for the purposes of the AER’s draft and final determinations.

51 AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
52 AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
53 UE MOD 1.06 – EBSS – Jan2025 – Public.

TABLE 10.2 EBSS CALCULATION ($M, 2026)

DESCRIPTION	FY22	FY23	FY24	FY25	FY26
Adjusted benchmark EBSS operating expenditure	176	175	179	183	186
Actual EBSS operating expenditure	158	152	162	156	-
Incremental efficiency	32	5	-3	4	-
Carry-over year	FY27	FY28	FY29	FY30	FY31
EBSS carry-over	**38**	**6**	**1**	**4**	**-**

10.2 CESS

We propose to continue applying the CESS to standard control expenditure in accordance with the AER's CESS guideline over the 2026–31 regulatory period. This ensures we have incentives to minimise project costs and pass on a proportion back to customers.

Consistent with the CESS guideline and the AER's framework and approach paper we propose using forecast depreciation to establish the opening RAB for the following regulatory period 2026–2031. However, we propose excluding connections expenditure from the CESS as this expenditure is broadly outside the control of network providers (see below). We also propose to exclude expenditure related to our innovation allowance.

We calculate the 2026–31 CESS revenue increment or decrement as follows:

- calculate the cumulative underspend or overspend for the current regulatory period in net present value terms
- apply the network sharing ratio of 30% to any underspend amount up to 10%
- apply the network sharing ratio of 20% to any underspend amount above 10%
- apply the network sharing ratio of 30% to any overspend
- deduct the 2021–26 financing benefit or cost of the underspends or overspends.

We have not adjusted the CESS calculation to exclude any deferred projects, as these do not meet the AER's requirements for exclusion from the CESS (e.g. we have not underspent our regulatory allowance for the 2021–26 regulatory period).[54]

Our detailed calculation of the 2026–31 CESS revenue adjustments arising from the true up for 2020 and the first half of 2021 actual net capital expenditure has been added into the attached model.[55] A summary of the CESS outcome is shown in table 10.3.

The 2026–31 CESS revenue adjustments will be updated with the latest available information for the purposes of the AER's draft and final determinations.

54 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023, p. 8.
55 UE MOD 1.07 – CESS – Jan2025 – Public.

TABLE 10.3 CESS CALCULATION ($M, 2026)

DESCRIPTION	PRESENT VALUE
Total efficiency gain	-3
Network service provider share	-1
Financing benefit	8
CESS payment in 2026–31	**-10**

10.2.1 Excluding connections expenditure from the CESS

While we agree that the CESS allows both distributors and customers to share the benefits of improved network performance, we propose that the CESS should be narrowed to only include capital expenditure that is within the control of network providers. For this reason, we consider the intent of the CESS would better align with the practical outcomes of the scheme if expenditure related to connections was excluded.

Connections expenditure is linked to the number of customers requesting connection to our network. The number of connection requests in any given regulatory period, both in terms of the nature and number of connections, is entirely outside of our control.

We must make an offer to any customer seeking a connection to our network, even when actual connection expenditure is already above our forecasts. This can place the overall capital program under significant pressure.

Given that connections expenditure is non-discretionary, we consider that applying a CESS penalty on top of the connections expenditure does not reflect the intent of the CESS, which is meant to incentivise efficiency gains.

The energy transition is also making it increasingly difficult to forecast connections expenditure due to:

- increased uncertainty of the number and nature of future connections
- recent emergence of new types of large connections such as data centres, batteries and EV charging stations
- difficulty of forecasting customer contributions.

Based on the increasing difficulty in accurately forecasting connections expenditure, we consider that the removal of connections expenditure from the CESS is appropriate.

10.3 STPIS

Over the 2026–31 regulatory period we propose calculating the STPIS targets, incentive rates and major event day (MED) threshold in accordance with the AER's 2018 STPIS guideline as follows:

- use historical performance data over the five-year period from 1 July 2021 to 30 June 2026
- apply the updated VCR as determined by the AER to determine the incentive rate
- calculate the MED using a beta of 2.5 consistent with the 2021–2026 application of the scheme.

We propose to not apply the GSL component of the STPIS scheme as we are subject to the Victorian jurisdictional GSL scheme. We also propose to not include the telephone answering component of the STPIS in favour of our proposed CSIS.

Our proposed STPIS targets, incentive rates and MED threshold are set out in table 10.4 with additional detail available in our incentives and targets models.[56]

TABLE 10.4 STPIS TARGETS AND INCENTIVE RATES FOR THE 2026–31 PERIOD

PARAMETER	NETWORK SEGMENT	TARGET	INCENTIVE RATE
Unplanned SAIDI	Urban	31.70	0.08
	Rural short	91.64	0.01
Unplanned SAIFI	Urban	0.43	3.86
	Rural short	1.35	0.36
MAIFIe	Urban	0.87	0.31
	Rural short	2.76	0.03
MED threshold	Network	2.05	

10.4 CSIS

The 2021–26 regulatory period was the first time we introduced an incentive scheme related to customer service levels. Over this period, we have exceeded our targets in all but one instance, delivering significant customer benefits. This was achieved through the continued investment in our people and processes.

For the 2026–31 regulatory period we again propose to include a CSIS in place of the telephone answering component of the STPIS. We have undertaken customer engagement to further understand what services customers value, and whether these have changed since the 2021–26 regulatory period.

We have also engaged with the CAP throughout our CSIS development. This has allowed us to incorporate the CAP's feedback on the design of the original customer engagement, the results of that engagement and on each potential CSIS measure. We also sought comprehensive feedback on our final proposed measures. Following these sessions, the CAP has provided its endorsement of our proposed CSIS.

We consider our current CSIS remains well aligned with our customer preferences. As such, our proposed CSIS for the 2026–31 regulatory period introduces only minor changes to our CSIS measures. Our proposed CSIS:

- maintains the SMS notification delivery measure, noting changes we have already made in relation to the structure of our SMS responses. These changes were made following customer feedback that our SMS's should provide additional information
- maintains the measures of SAIDI and SAIFI for planned outages, with an updated methodology to better align the SAIDI and SAIFI measures with productivity gains or losses for a given outage event (rather than varying based on the size of our works program)

[56] UE MOD 10.03 - STPIS targets - Jan2025 – Public; UE MOD 10.02 - STPIS incentives - Jan2025 – Public.

- expands our grade of service measure to capture both contact centre fault calls and general inquiries, which is reflective of feedback we have received from customers (who want our contact centre to be responsive to all customer calls). We have also increased the revenue at risk associated with this measure to better align our CSIS with potential investment opportunities.

The total value of the revenue we will risk is +/- 0.5 per cent of our annual revenue for the 2026–31 regulatory period. This equates to approximately $2.8 million per year.

Table 10.5 sets out our proposed CSIS measures with the relevant revenue at risk, baseline target and incentive rate. Our full CSIS proposal for the 2026–31 regulatory period is attached to this regulatory proposal.[57]

TABLE 10.5 PROPOSED CSIS FOR THE 2026–31 PERIOD

CSIS MEASURE	REVENUE AT RISK	BASELINE TARGET	INCENTIVE RATE
SMS notification	0.10%	67.3%	0.04
Planned outages	0.15%	SAIDI: 62.38 SAIFI: 0.21	SAIDI: -0.05 SAIFI: -9.35
Grade of service	0.25%	66.7%	0.04

10.5 DMIS and DMIAM

We propose to include the DMIS and DMIAM in the 2026–31 regulatory period, consistent with our current regulatory period. Applying these satisfies the requirements of the National Electricity Law (NEL) by providing an incentive to use more demand management, which can defer augmentation and create option value, potentially lowering costs in the long term.

The demand management projects we have undertaken through the DMIAM during the 2021–26 regulatory period are set out in table 10.4.

[57] UE ATT 10.01 - CSIS - Jan2025 – Public.

TABLE 10.6 DMIAM PROJECTS: 2021–26 REGULATORY PERIOD

PROJECT/PROGRAM	SUMMARY
Trial tariff project	We trialled new network tariffs from 1 July 2022 which could shift demand away from peak demand times to minimum demand times
Electric vehicle hotspots trial	This project looked at demand management capabilities through research and smart algorithms to identify and understand the impact of EV charging on our network, gaining insights into the EV load and how we can manage it both now and into the future
Pole top batteries	Investigated the technical and commercial feasibility of using pole-mounted batteries connecting to the low voltage network to manage constraints and increase the hosting capacity of rooftop solar

Table 10.7 provides our proposed DMIAM allowance for the 2026–31 regulatory period, calculated in accordance with the AER's guidelines.[58]

TABLE 10.7 DMIAM ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31
DMIAM	0.67	0.67	0.67	0.68	0.69

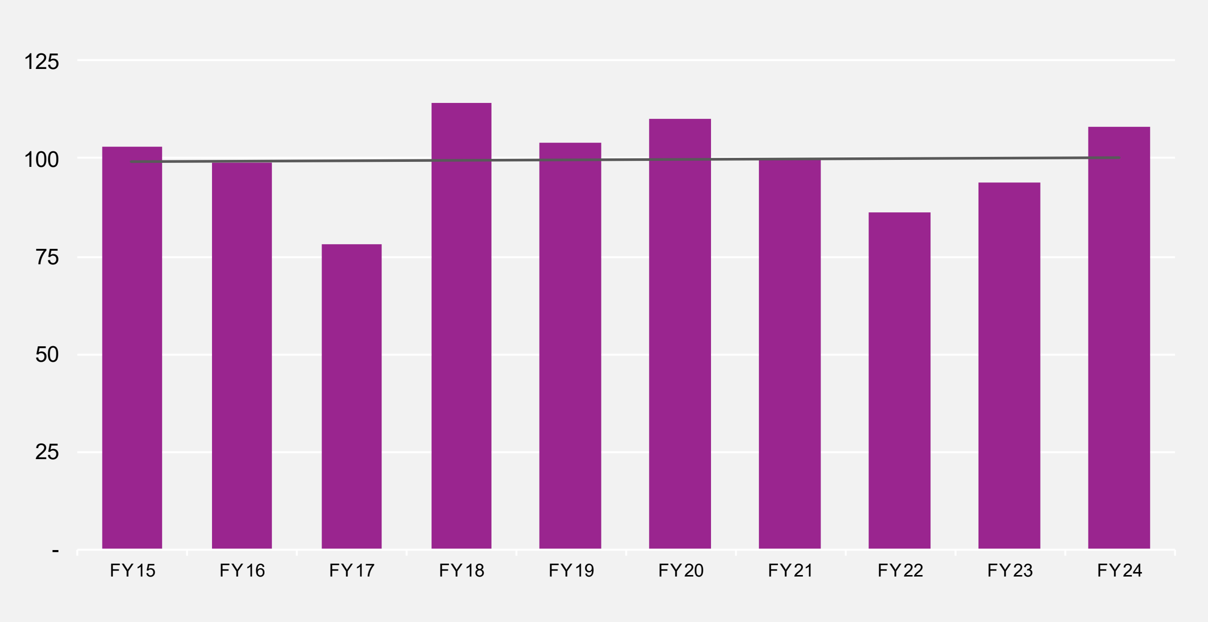
10.6 F-factor scheme

We propose to continue to apply the F-factor scheme during the 2026–31 regulatory period, consistent with the AER's framework and approach paper. The F-factor scheme is a Victorian Government scheme introduced following the 2009 Black Saturday bushfires that provides incentives to limit powerline ignitions.

Figure 10.1 demonstrates historical fire starts on our network. Fire starts on our network have, on average, been relatively stable since the introduction of the F-factor scheme.

58 AER, Demand management innovation allowance mechanism, December 2017, p. 8.

FIGURE 10.1 NUMBER OF FIRE STARTS



10.7 Innovation allowance

We are seeking an innovation allowance that would allow us to research, test and implement innovative ideas that have the potential to drive long-term value to customers, but are not currently funded under the regulatory framework. Through our test and validate phase of our customer engagement we received strong customer support to our proposed innovation allowance both in terms of the amount of expenditure and the key focus areas for investment.

The current innovation incentive framework is narrow in scope and is mostly limited to innovation in demand management through the DMIS and DMIAM. While these two schemes have been successful in delivering innovation to demand management, there are a broader range of innovation opportunities that can provide long-term benefits to customers.

Innovation, by definition, involves developing and testing new processes and technologies, where the scope may not yet be clearly defined and the potential benefits uncertain. These types of projects do not lend themselves to the AER's current regulatory process (which requires a higher level of certainty around the costs and benefits of a project, i.e. projects must be set out 5–7 years in advance, with associated business cases and cost benefit models). Having funding linked only to the innovative projects identifiable so far in advance runs the risk that highly innovative opportunities that may only be identified during the regulatory period are unable to be undertaken.

Our current approach to innovation internally is based on a two-year lifecycle that includes a 'fail fast' mentality.[59] This makes it difficult to forecast the exact projects that would be undertaken over the full five-year regulatory period. This same difficulty occurs when thinking about customer focussed innovation.

Due to these practicalities, our preference would be for an innovation allowance that is agreed upon at the beginning of the regulatory period but does not require specifying each of the individual innovation projects throughout the regulatory period. We consider that such an allowance would also lead to the better utilisation of the AER's regulatory sandbox(see below) by providing the desired level of funding

59 For clarity, our internal innovation focus is on productivity enhancement initiatives. These are already incentivised under the CESS and EBSS, and accordingly, would not be the focus of this innovation allowance.

in relation to innovation more broadly, rather than the level of innovation funding associated with projects that can be demonstrably proven prior to the regulatory period.

Regulatory sandbox

In 2023 the AER established a regulatory sandbox function that enables the trial of new innovative products and services. The sandbox facilitates trials by granting trial waivers, which temporarily exempts an innovator from having to comply with specific rules that may be creating a barrier to the trial proceeding.

Given the fast paced and dynamic nature of innovation, the sandbox is an important development to assist businesses quickly and efficiently trial innovative solutions that have the potential to deliver long-term customer benefits.

We understand that currently the sandbox is being underutilised, which is likely linked to the limited funding options available for innovation projects outside of demand management innovation. Providing distributors with an innovation allowance linked to the desired level of innovation customers are willing to fund, will provide the funding businesses require to invest in innovation more broadly. In this environment, the sandbox will be a key complementary tool that will allow distribution networks to trial innovative solutions that may deliver long-term customer benefits.

We propose to include an innovation allowance of $15M, that would be drawn upon across the regulatory period. We have set out our proposed innovation projects for the initial two years of the regulatory period which equates to approximately 50 per cent of our proposed allowance. We will then seek to provide specific innovation projects for the remaining three years during the regulatory period.

In recent AER decisions, the AER has approved innovation expenditure for some distributors as part of their capital expenditure forecasts. We have included our proposed innovation expenditure in our capital and operating expenditure forecasts consistent with this approach, however we consider an innovation incentive framework similar to the DMIAM but with a broader scope of innovation opportunities would better align with how innovation is treated in practice.

The innovation allowance will focus on four key areas:

- **assisting the energy transition** – innovation to support industry to electrify hard to abate areas and new arrangements and technologies to support community uptake of appropriate energy solutions
- **building network resilience** – innovation to support our deployment of SAPS and microgrids by trialling new processes and technologies
- **improving customer experiences** – innovation to improve power quality issues for sensitive industry processes, provide more localised real time information to customers and undertake tariff optimisation trials
- **developing sustainable networks** – innovation to improve performance and capacity for renewable energy, increasing grid stability and developing new technologies to support localised climate modelling and forecasting.

Further details on our innovation expenditure, including the projects we propose to undertake during the initial two years of the 2026–31 regulatory period and proposed governance arrangements are set out in our innovation allowance business case.[60]

[60] UE BUS 10.01 - Innovation allowance - Jan2025.

11. Uncertainty framework

Historically, changes in consumer demand have been gradual, allowing for relatively stable and predictable growth. However, the ongoing energy transition is dramatically changing how customers interact with the energy network, impacting both the amount and timing of electricity consumption.

This section sets out our proposed approach to managing this uncertainty, including the use of nominated pass-through events and contingent projects.

11.1 The energy transition is bringing greater uncertainty

The current regulatory framework is not fully equipped to handle the fast-moving and significant changes brought about by the energy transition. The current uncertainty mechanisms within the regulatory framework do not provide adequate flexibility to account for potential changes in electricity consumption and demand during a regulatory period. Instead, the framework relies predominately on forecasts made prior to the start of the regulatory period.

Without greater ability to account for uncertainties in future electricity demand, we may not have sufficient funding to deliver the network services that customers expect and value. Without the necessary infrastructure in place, customers are likely to experience lower service levels, including:

- additional capacity constraints and more frequent low voltage events: policy initiatives driving the shift from gas and internal combustion engines to electric options will increase electricity demand and without timely investment will exacerbate maximum and minimum demand events. This will limit customer's ability to benefit from their own CER
- poorer reliability: such as outages caused by overloaded circuits from increasing demand on the LV network
- reduced power quality: the integration of more renewable energy sources, rooftop solar, batteries, and EV chargers will complicate maintaining consistent power quality. This can be particularly damaging for our large commercial and industrial customers whose machinery can be damaged, or operations disrupted (at significant cost), by fluctuations in power quality.

Additionally, delivering infrastructure investments reactively, at a later date than prudent, and within a compressed timeframe will inefficiently drive-up long-term costs for customers.

Government policies are expected to bridge the gap between current emissions and emission reduction targets

Victoria has a number of emission reduction targets on its pathway to net zero, as shown in table 11.1.

TABLE 11.1 VICTORIAN EMISSION REDUCTION TARGETS

DESCRIPTION	2030	2035	2045	2050
Emissions target	45-50% reduction	75-80% reduction	Committed net-zero	Legislated net-zero

Source: DEECA, Victoria's Climate Change Strategy.

The Victorian Government will likely need to introduce new policies to ensure that Victoria is able to meet its emission reduction targets. For example, in its zero emissions vehicle (ZEV) roadmap, the Victorian Government has set a target of 50 per cent of new light vehicle sales to be zero emissions vehicles by 2030.[61] Strong EV uptake is needed to reach 50 per cent market share by 2030 and an even faster uptake is required to meet emissions targets. It is therefore reasonable to expect that the Victorian Government will introduce new initiatives to incentivise the uptake of EVs to meet its announced targets.

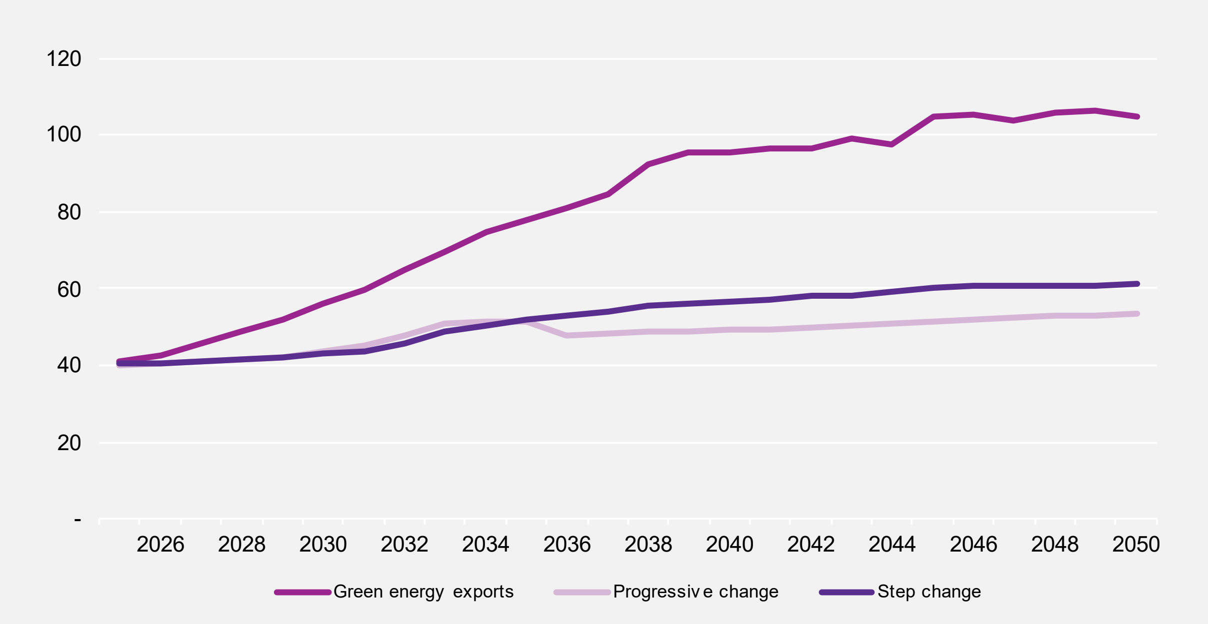
While any increase in expenditure required to deliver these government policies may be accounted for under the uncertainty framework (e.g. as a regulatory change, under the pass-through mechanism), any complementary or subsequent increase in electricity consumption beyond the government policy will not. For example, a household may decide to purchase an EV based on a government incentive. This may then accelerate additional electrification within a household to maximise the benefits of full electrification. It is important that an uncertainty framework captures the additional consumption that may occur due to future government policies, ensuring that distribution networks can accommodate all increases in electricity consumption and demand.

There is considerable uncertainty with the path the energy transition will take

In developing its system plan, AEMO includes a number of different scenarios based on how the energy transition may take shape. While AEMO considers the step change scenario to be the most likely pathway for the energy transition, it acknowledges that the transition is far from certain. The rate at which EVs replace internal combustion engine vehicles, the adoption of rooftop solar and batteries, and the speed at which households move away from gas are subject to a range of factors that are closely tied to government policies.

Due to the extent of these uncertainties, AEMO's long-term plans encompass multiple scenarios to account for different transition paths. One of these paths is the green energy exports scenario. In this scenario, Australia's development of an energy export industry through increased renewable energy, coupled with a faster electrification process, would lead to a substantial increase in energy consumption in Victoria. By 2030, operational consumption (i.e. consumption after accounting for household rooftop solar and batteries) under the green energy exports scenario would be 30 per cent higher than AEMO's step change estimates.

FIGURE 11.1 VICTORIAN OPERATIONAL CONSUMPTION FORECASTS (TWH)



Source: Australian Energy Market Operator, Electricity Statement of Opportunities, 2024.

[61] DEECA, Victoria's Zero Emissions Vehicle Roadmap, 2021.

Given the Victorian Government's commitment to drive electrification of homes and businesses, there is a high likelihood that electricity consumption may exceed the step change scenario in the 2026–31 regulatory period. It is therefore prudent that the regulatory framework also accounts for the potential for consumption to be higher than the step change scenario predicts.

11.2 Our proposed response

The uncertainty regime under the Rules comprises pass-through events, capital expenditure reopeners and contingent projects. These mechanisms deal with expenditure that may be required during a regulatory period, but which is not able to be predicted, or predicted with reasonable certainty, at the time of preparing or submitting a regulatory proposal to the AER. Given the high level of uncertainty associated with the energy transition and customer affordability concerns, we consider the uncertainty framework can be utilised to ensure customers are not required to fund investments as they are needed.

This is also consistent with feedback we have received from the CAP. In its report on our draft proposal, the CAP highlighted the growing need to address and better plan for uncertainty given the likely changes of the energy transition, while also considering that one of the key messages from customers was ensuring affordability.[62]

Rather than building up our expenditure forecasts to cover every possible eventuality, we therefore propose nominated pass-through events in this regulatory proposal to enable us to request additional funding from the AER during the regulatory period if the future state of the distribution network is materially different from forecast. The exclusion of the costs of these uncertain events from our regulatory proposal ensures our customers face the lowest possible prices.

Table 11.2 summarises our proposed nominated pass-through events for the 2026–31 regulatory period. The majority of our nominated pass-through events are events that have previously been accepted by the AER, and we do not propose any changes to these definitions.

We are also proposing three new pass-through events. Further details around each of the nominated pass-through events, including proposed triggers, are set out in our uncertainty attachment.[63]

We have not included any contingent projects in this regulatory proposal.

[62] UE ATT SE.30 – CAP - Report on Draft Proposal – Nov2024 – Public.
[63] UE ATT 11.01 - Managing uncertainty - Jan2025 – Public.

TABLE 11.2 NOMINATED PASS-THROUGH EVENTS

TYPE OF EVENT	CHANGES FROM CURRENT DEFINITION
Insurer credit risk event	No changes proposed from current definition
Insurance coverage event	No changes proposed from current definition
Natural disaster event	No changes proposed from current definition
Terrorism event	No changes proposed from current definition
Retailer insolvency event	No changes proposed from current definition
Fault level event	Additional event to address the risk that a part or parts of the distribution network will exceed fault level limitations and require upgrades to comply with relevant safety, contractual and regulatory obligations
Electrification event	Additional event to address the uncertainty around the pace of electrification, as electrification requires additional investment in the network
AEMO participant fee event	Additional event to address the potential for AEMO to alter its electricity market participant fees leading to a material increase in the costs to us in providing direct control services

12. Alternative control services

Alternative control services (ACS) are a set of specific services provided by networks that are not covered by standard network tariffs but are available on request.

12.1 Metering

In 2009, the Victorian Government mandated the Victorian distributors to roll-out advanced metering infrastructure (AMI) meters in residential and small commercial premises consuming up to 160MWh per annum. As we provide metering services, we therefore act as both the electricity distributor and the metering coordinator for those properties.

Our initial meter roll-out was completed between 2010–2014, and as such, the existing meter population is reaching the end of its economic life.

For the 2026–31 regulatory period, the key driver of our forecast metering investment is the proposed proactive replacement of 34 per cent of the total meter population. As discussed below, this represents a reduction in the speed of our proposed roll-out relative to our draft proposal (and corresponding expenditure).

Our proposed program will reduce the risk of high failure rates requiring disruptive and expensive reactive replacements. It will also better smooth customer meter charges, with efficiencies due to the bulk purchase of meters and lower labour installation costs from a coordinated approach.

12.1.1 What we've heard

Our engagement with our customers and the CAP discussed alternative meter replacement programs, and their corresponding customer benefits, expectations and affordability impacts.

TABLE 12.1 KEY ENGAGEMENT FINDINGS

We are expected to effectively manage the risk of significant meter failures which will result in customer disruptions and high reactive replacement costs. Customers consistently highlighted the importance of a reliable energy supply, with the majority of customers having no appetite for a deterioration in reliability performance
Customers see innovation and technology as essential drivers of an enhanced customer experience, and in particular, the potential of new technologies like smart meters and digital applications. We should address how we add value with the replacement program, making sure new meters provide additional benefits
We need to ensure there is no overlap between our forecasts for new connections, proactive replacements, and reactive replacements

Test and validate

As part of our test and validate engagement, we undertook a quantitative survey across a number of key issues outlined in our draft proposal. This included our proposed proactive metering program.

In this engagement, customers were asked to consider alternative options regarding meter replacements:

- the first option was to commence proactive meter replacements starting in 2026 while maintaining the current meter charges, which would help prevent potential failures in the coming years
- the second option was to delay proactive replacements until after 2031, resulting in decreased meter charges from 2026 to 2031, but potentially increasing charges from 2031 onwards. This delay may lead to an increased likelihood of meter failures in the future.

This discussion resulted in over two thirds of residential and SMB customers preferring us to start proactively replacing meters to prevent failures.

Through our customer engagement at the roundtable session, customers also expressed strong support for the proactive meter replacement program. Their feedback included the following:

- participants agreed on the importance of upgrading meters without interruptions
- a targeted rollout approach was wanted to optimise the rollout effectiveness without compromising the meter benefits
- a proactive rollout approach was considered reasonable noting that there would be immediate benefits, such as reliability of meter performance, as well as long-term visibility benefits
- communication and transparency was desired — participants wanted clear communications with customers on the purpose and benefits of the rollout
- customers required confidence that their privacy would be maintained
- enhanced data and monitoring capabilities were wanted in the new meter assets.

12.1.2 Our proposed response

Since the draft proposal, we have undertaken further analysis and research to refine our understanding of potential future failure rates of the meter fleet and the associated uncertainties. This has allowed us to make informed adjustments to the pace of the rollout, ensuring it reflects the latest insights and aligns with the anticipated needs of the network.

Our approach aims to balance operational efficiency, cost-effectiveness, and the delivery of reliable service to customers and results in the proposed proactive replacement of 34 per cent of the total meter population.

The primary reasons for adopting a proactive replacement strategy include the following:

- our aging meter population poses an increasing risk of reactive failure replacements
- the large-scale AMI roll-out necessitates a structured, proactive replacement approach
- enabling customers to benefit from increased data visibility, behind the meter energy management solutions and the next wave of energy efficiency initiatives that customers will leverage
- ensuring more stable and consistent meter charges is beneficial for customers.

We expand on these reasons below and in our attached metering business case.[64] In total, our proposed expenditure relating to our meter replacement program is shown below.

[64] UE BUS 12.01 – Metering – Jan2025 – Public.

TABLE 12.2 TOTAL METERING INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	50	243

While existing failure rates are low, there is a growing risk of an increase in reactive failure replacements

Our initial AMI roll-out population was completed in a concentrated four-year period, and these meters will all be reaching 16 to 20 years of age by 2031. At the time of installation, their expected service life was around 15 years (consistent with expected life of the underlying componentry).

To date, the actual engineering life of these meters remains uncertain. These are the oldest and earliest forms of smart meters in service in Australia, and some of the oldest in the world.

The nature of these meters functionality and componentry is that they are less likely to fail due to metrology errors (i.e. being inaccurate) and more likely to fail due to an electronic component coming to end-of-life and taking out major functionality like onboard power-supply, communication, display, memory storage and time keeping. Electronic components age through ongoing use, exposure to excessive heat or cold, voltage spikes, moisture/corrosion and even insect infestation.

This means it is reasonably expected that our metering population begins failing soon, and that we need to manage this fleet to avoid a systemic failure of large volumes of aged meters. The risk of reactive failure replacement increases the longer proactive measures are delayed, and reactive failures tend to be significantly more costly and disruptive than planned proactive replacements.

A structured approach is prudent and efficient given the scale of the program

Given the substantial volume of the AMI roll-out population—our initial roll-out comprised close to 600,000 meters—a proactive approach to meter replacement is both prudent and more efficient, and will minimise disruptions for customers. In contrast, reactive replacements (following a failure that leads to functional loss) will increase customer inconvenience, and incur delivery inefficiencies that drive up costs, ultimately burdening customers with higher bills.

We propose to commence our proactive meter replacement in 2026–27, and replace one third of the total initial meter roll-out population over the 2026–31 regulatory period. A 12-year proactive meter replacement program will reduce risks associated with wide-scale failures and expensive reactive replacements.

To deliver this program, we ran an expression of interest in 2024 and will tender for AMI meters in the first half of 2025. The expression of interest provided us with technology capability and indicative pricing based on both business-as-usual volumes and proactive replacement program volumes.

Current AMI meters are from a technology stack developed 20 years ago. It is important to ensure that whatever meter technology we decide to use is a robust technology that will serve our needs for the next 20 years, to avoid functional or technical obsolescence. In this context, we intend to use new AMI 2.0 meters that are distributed intelligence (DI) meters with a co-processor on the meter for real time data analytics on the meter, without interrupting the metrology processor and its energy data measurement and processing.

Our approach will smooth metering prices over time

Our proposed approach of spreading proactive replacements over 12 years will also have the advantage of avoiding volatile metering charges.

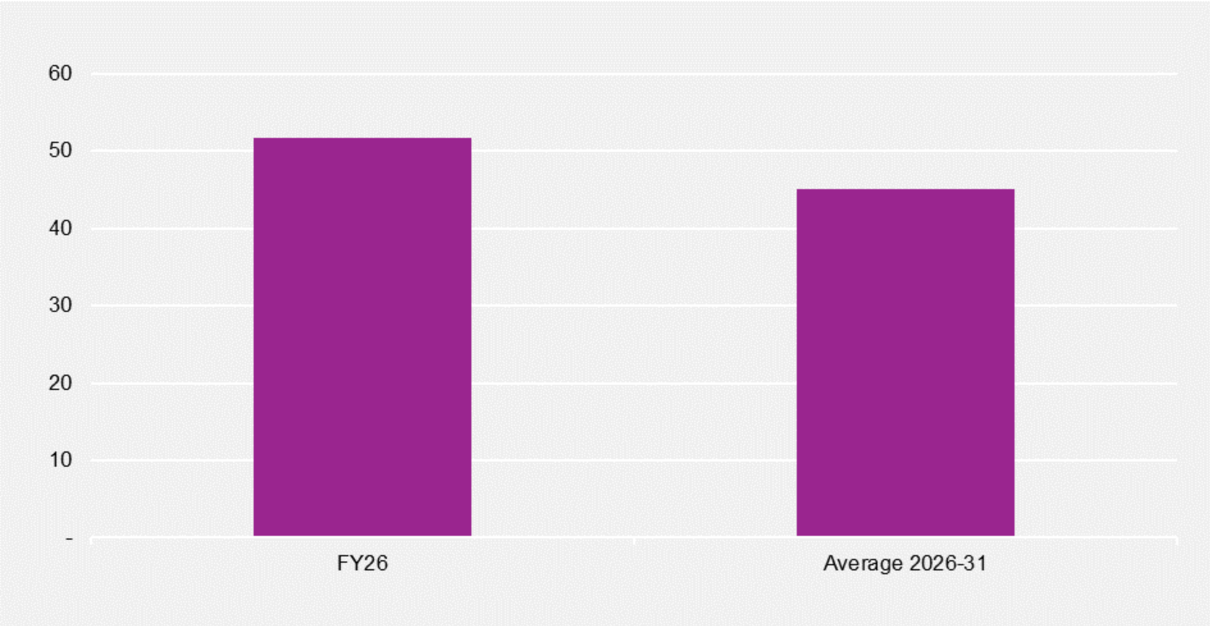
Our metering revenue forecast for the 2026–31 regulatory period is shown below. Notwithstanding the expenditure increase associated with a replacement roll-out, metering revenue will remain relatively stable due to the impact of lower depreciation (as existing meters become fully written down).

TABLE 12.3 TOTAL METERING REVENUE ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	178	177

This revenue outcome will be reflected in the expected average charge for single-phase meters over the 2026–31 regulatory period, relative to the final year of this regulatory period (as shown below).

FIGURE 12.1 SINGLE-PHASE METER CHARGE ($, 2026)



12.1.3 We address the impact of electrification and EV fast charging on our connections and additions profile

On 1 January 2024, new gas connections for new dwellings, apartment buildings, and residential subdivisions requiring planning permits were phased out. As a result, we expect to see a significant increase in the following:

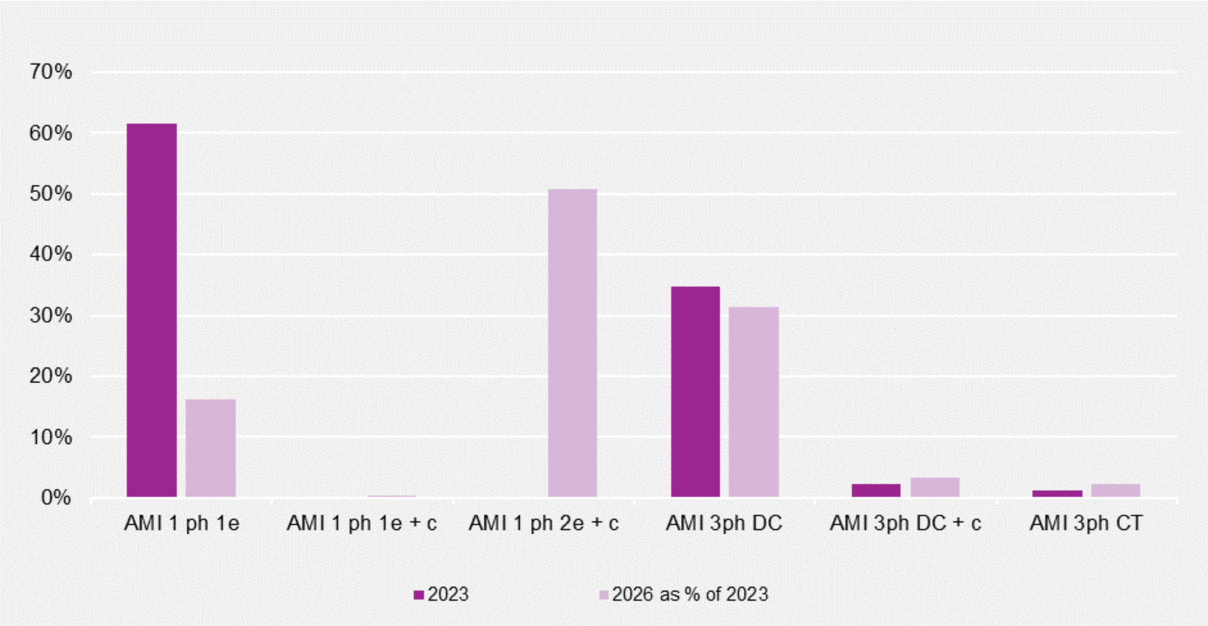
- single-phase two element connections due to heat pump electric hot water systems displacing existing gas hot water systems (under the Victorian Government subsidies)
- a move to three-phase new connections and requested upgrades due to both gas space heating being replaced by electric space heating, and uptake of EV fast charging.

Today, we are seeing growth in three-phase installations year-on-year and these are expected to continue to increase. Our forecast of new connections will include a substantial reduction in one-phase single element meter installations, and a corresponding increase in one-phase two element and three-phase meters.

The number of supply alterations and metering alterations are also forecast to increase as gas hot water and gas space heating customers move to electricity.

Our expectation is that demand for single-phase two element and three-phase meters will increase in the 2026–31 regulatory period as shown in figure 12.2.

FIGURE 12.2 NEW CONNECTIONS



12.2 Public lighting

We provide public lighting services to 15 local councils and the Department of Transport and Planning (DTP). The provision of public lighting services and the respective obligations of our business and public lighting customers are regulated by the Victorian Public Lighting Code.

There are approximately 122,000 public lights installed across our network. Of these, 75,000 (61 per cent) have been upgraded to Light Emitting Diodes (LEDs), providing improved energy efficiency and maintenance outcomes for our customers.

The cost of these services is charged to customers through an operation, maintenance, repair and replacement (OM&R) charge per light. All other public lighting services are treated as quoted services.

12.2.1 What we've heard and our proposed response

In July 2024, we conducted a structured stakeholder consultation session with representatives from local councils and the DTP. This session identified key topics for the public lighting sector in the 2026–31 period.

The following sections outline what we heard from local councils and the DTP in more detail, and our proposed response. Further details are provided in our public lighting attachment.[65]

Transition to LED public lighting

During our consultation process, councils supported the proactive replacement of non-LED residential lighting that will be banned in the next regulatory period.

Councils further indicated interest in the introduction of standard lanterns with a warmer colour temperature (2700k/3000k). We consider this as a future offering in our standard material list. We have already approved some non-standard lanterns with 2700k/3000k.

65 UE ATT 12.01 – Public lighting – Jan2025 – Public.

In response to council feedback, and for the following reasons, we plan to convert all public lighting to LED over time to:

- meet Australia’s commitments in the Minamata Convention in 2021 to eliminate the use of mercury vapour (MV) in lamps and more recently to also prohibit the use of compact fluorescent lamps (CFL) from the end of 2026 and T5 fluorescent lamps from end of 2027
- respond to customer expectations regarding energy cost savings
- support both Victorian and Commonwealth Governments’ commitment to lower carbon emissions, through lower energy consumption
- provide further energy efficiency opportunities when combining LED lights with smart control devices.

There was also interest from some councils to proactively replace non-LED major road lighting. We acknowledge the outstanding efforts made by some councils in proactively replacing these lights, however, we wish to affirm that lantern replacements for non-banned light types will be undertaken upon reaching the end of their operational life.

Implementation of a central management system

We propose to introduce a basic central management system (CMS), together with the development of an agreed smart PE cell operation protocol, prior to the start of the 2026–31 regulatory period.

We propose to spread the operating cost of the CMS across all light types, incurring a minimal incremental charge on a per light basis.

Councils have shown support for a CMS to be established in order to enable dimming, constant light output and improve fault restoration.

LED lamps in decorative lanterns

We propose to continue retrofitting LED lamps to existing non-standard decorative lanterns.

This allows councils to navigate the discontinuation of mercury vapour and compact fluorescent lamps effectively and enables the continuation of the functional and aesthetic benefits of these fixtures while embracing modern, energy-efficient, and environmentally friendly lighting solutions.

Solar powered lights

Councils indicated interest in solar lighting as a potential OM&R service. We will continue to complete current trials to be in a position to include this service in our 2031–36 price period.

Transitioning legacy lighting schemes

We propose to give councils management and control of public lighting in non-trafficable parks, gardens and laneways to help ensure safety and access.

This decision stems from increasing challenges in accessing public lighting infrastructure in these areas. These difficulties are largely due to elevated service expectations imposed by park managers, typically the councils themselves.

Further, many larger councils have expressed support for this initiative, particularly if financial assistance is provided to facilitate the transition.

Additionally, the growing use of laneways as active spaces, featuring awnings, tables, chairs, and bollards, has further restricted access for maintenance and service activities.

We appreciate the challenges to transition existing lighting back to councils located in parks, gardens, walkways and laneways. We are hopeful that council's undertaking capital works can potentially assist in this transition.

12.2.2 Tariff changes

Our prices for public lighting services are regulated by the AER separately from our distribution network tariffs. However, our network operations facilitate the provision of these services, affording us the opportunity to leverage economies of scale in the planning, delivery and administration.

Our current public lighting tariffs are developed to reflect the type of technology in use (LED or conventional) and road type (major or minor).

This approach ensures charges are consistent and stable over time and easy to understand.

When the impact of reduced energy consumption is considered, we expect the transition to LED lighting will ultimately reduce the overall cost of public lighting for councils and the DTP.

We propose to apply the same weighted average price increase across all light types.

We are forecasting moderate real price increases mainly driven by:

- dedicated public lighting poles are reaching end of serviceable life that will require replacement or staking resulting in increased capital spending
- replacement of non-LED lights with LED lights will continue to reduce OM&R spending
- increases in the regulated rate of return.

12.3 Re-classification or modification of existing services

12.3.1 Reserve feeder maintenance

Reserve feeder maintenance costs are currently classified as an ACS quoted service.

The administrative cost of calculating a reserve feeder maintenance charge for each reserve feeder, every year, does not justify the small amount of revenue that is collected from this charge.

Furthermore, the charge is more readily calculated as an average per kVA cost at each voltage level.

We propose to re-classify reserve feeder charges as an ACS fixed-fee service with fixed fees per kVA of reserve feeder capacity approved by the AER.

12.3.2 Provision of data

The AER’s framework and approach paper:

- classifies the provision of basic network data, such as visibility maps and data portals, as a standard control service
- classifies the provision of data beyond basic data as an ACS and therefore the cost would be recovered from the party requesting the data

We already have an approved ACS service ‘access to network data – cumbersome requests’ the description of which will be modified to ‘customer and third-party requests for the provision of electricity network data, or consumption data outside legislative obligations, or requests for assistance to understand or interpret data, or to identify the data they require to meet their needs’.

12.4 New services

12.4.1 Enhanced connection service

The AER's framework and approach paper approved a new enhanced connection service which would provide a requesting customer with greater network capacity than they would otherwise be eligible for.

We propose to introduce a new alternative control service: management of export and load at a customer site that provides the customer greater network capacity than they would otherwise be eligible for.

12.4.2 Reversion of embedded networks

The Victorian Government has clamped down on new residential apartment embedded networks and is considering a new licencing regime for embedded networks. We anticipate an increase in the number of embedded networks reverting to no longer being an embedded network. Our basic connection charge will recover the cost of assigning NMIs and installing meters for individual units. However, we will also incur other costs such as for project management, communication, inspection of wiring and meter boards, and abolishment of meters.

We propose a new ACS quoted service 'reversion of embedded networks' to cover network costs which are not covered by the basic connection service.

12.4.3 Embedded generator control equipment

We need to install control equipment at embedded generation sites to enable compliance with the Victorian Government mandatory Essential System Service.

We propose a new ACS quoted service 'embedded generator control equipment' to cover the installation of control equipment at embedded generation sites to enable compliance with the Victorian Government mandatory Essential System Service.

12.4.4 Bulk conversion to 5-minute meter data

A retailer could request us to bulk convert all meters to 5-minute data. While a meter reconfiguration fee can cover a single meter request, there is no appropriate charge for a bulk request.

We propose a new ACS quoted service for requests for bulk conversion to 5-minute meter data.

For further information visit:

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