Jemena Electricity Networks

JEN 2026-31 REVISED PROPOSAL

1 December 2025

Acknowledgement of Country

We acknowledge the many Traditional Owners across this Great Southern Land on which our Group employees and contractors live, work, volunteer, and play.

We pay our respect to the oldest continuing cultures on this planet by way of acknowledging Elders past and present.

We recognise that the First Peoples have lived, travelled on and cared for this Country for thousands of years. Without hesitation, we acknowledge First Peoples connections to the lands and waters of this Country including those relationships with all that is on, above, in, and under the waterways, seascapes, and landscapes.

With an open heart and mind, we are committed to listening and learning from the experiences, traditions, stories, customs, and practices of Australia's First Nations Peoples as we bring our projects to life in many communities where we work. We remain committed to working with First Peoples in co-creating shared futures and building energy infrastructure, maintenance, and services for new and existing communities.

We honour and pay tribute to the legacy gifts of knowledge, experience and wisdom born from thousands of First Nations generations associated with the lands and waters.

We will work collaboratively with First Nations employees, Elders and Communities to preserve and grow the legacies of the past for the generations to come.

"Wurru Wurru Biik Djirringu – Sky Country of Lightning" by Simone Thomson

Wurru Wurru Biik Djirringu – Sky Country of Lightning

The traditional language of the Wurundjeri People is Woi-Wurrung. In the Woi-Wurrung language, the name Wurundjeri is in two parts. 'Wurun' meaning the manna gum tree, and 'djeri', the white grub that lives in the tree – the witchetty grub. Manna gum leaves float across the sky symbolising deep respects to the traditional custodians of the lands and waterways in which Jemena operates – Wurundjeri Country.

Birrarung, the majestic river of mist and shadows weaves gently across country from its birthplace at the foothills of the Great Dividing Range, to the saltwater Bay of Naarm, the place known as Melbourne. This significant and sacred waterway was a vital food source and means of travel, and the meeting place for inter-clan trade and ceremonies. The flowing water represents our connection to energy and mother earth and the relationship we all have with this vital resource.

Campsites are depicted along the river; they are the arced shaped mounds representing the customer homes within the region that Jemena services. Trees along the waterways represent the growing strength of Jemena and symbolise the intricate root system beneath country linking its customers. A burst of lightning strikes from the sky above, a flicker of light represents its relationship to power and its likeness to the extensive network of tree roots symbolising the distribution of power.

Bunjil the Wedgetail Eagle is the great and mighty creator spirit for the Wurundjeri People and all the Kulin Tribes. He created the lands and sacred waterways and all the flowers, trees and animals. After his creation he took the clay from the earth and moulded it into his people.

He took the string from the stringy bark tree and used it for their hair, then he blew into their mouths so they could breathe. After this, Bunjil was tired. So, he asked Waa the Crow, the Keeper of the Wind and Water if he could open up his bag of wind, he was too tired to use his wings to fly.

Waa did as he was asked and opened up his bag, but the wind was small. Bunjil asked him to open wider for a bigger wind, so Waa did as he was asked and opened his bag wider creating a mighty and powerful whirly wind. It lifted Bunjil into the air and carried him high into the sky right up into the heavens where he became the stars. This is where he remains today watching over his beautiful creation.

In the Aboriginal way, a person is represented by the 'U' and 'n' symbol. From the bird's eye view, this is the shape a person makes whilst sitting on the ground, knees crossed. People are shown around the interconnecting circles representing the many communities across Wurundjeri Country who are customers of Jemena. White dots around these circles symbolise Bunjil's stars in the sky country representing light and power distributed by Jemena.

The large Gathering Circle along Birrarung is the meeting place of Jemena. This is the place where its community gather symbolising the commitment they share in delivering power to its customers, the broader community. It is the place where Bunjil circles from above in his sky country of lightning – *wurru wurru biik djirringu.*

— Simone Thomson, a proud Wurundjeri and Yorta-Yorta woman

The Artist

Simone is a Melbourne based Aboriginal artist and Traditional Owner of Victoria's Woi-Wurrung Wurundjeri and Yorta-Yorta language groups through her mother. Simone also has Irish and Scottish heritage from her father. Simone draws inspiration for her art from the abundant textures and colours of this beautiful land, along with the ancestral bonds she has to the Birrarung (Yarra River) and Dhungala (the Murray River).

The origin of the name Jemena is from the Wagiman people in the Northern Territory (spelt Jemenna in the Wagiman language).

It means “to hear, to listen, to think”.

We have been operating with permission from the Wagiman people under the variant name Jemena since 2008.

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Summary

Highlights

- Building on extensive customer engagement and a comprehensive program of work, we have developed this revised 2026-31 regulatory proposal in response to the AER's draft decision. Our proposal seeks to maintain electricity reliability, leverage scale to drive cost reductions, and deliver distribution charge savings to all of our customers.
- We do not agree with several aspects of the AER's decision and believe the regulatory allowance provided is insufficient for operating and investing in the electricity distribution network to meet the expectations of our customers.
- Our customers support our proposal. In developing our 2026-31 regulatory proposal, we undertook an award-winning customer and stakeholder engagement program to ensure we heard from our customers, including those customers whose voices, without specialist engagement, would not typically be heard. We captured those sentiments in our initial and revised proposals.
- The energy transition is fundamentally changing the structure and function of the electricity system and is rapidly transforming the way that we need to plan, manage and operate our network. Our 2026-31 revised proposal continues this theme as outlined in our initial regulatory proposal and includes several initiatives that will enable us to pre-empt the transformation, mitigate potential negative impacts of disruption, and embrace the opportunities it presents to our customers.
- Key drivers of our expenditure over the 2026-31 regulatory period include connecting new customers and catering to growth, maintaining network reliability, and accommodating the development of customer energy resources (such as rooftop solar, electric vehicles and storage batteries) through digitisation and automation.
- To deliver our plans, we forecast that we will need $1,868 million ($Real 2026) in revenue over the next regulatory period, a 20% increase from our revenue requirement for the current regulatory period.[1]
- As part of the revised proposal, the distribution charges in a typical residential customer's annual electricity bill will be $94 lower by the end of the next period compared to an annual bill in 2025-26. This price is enabled by increased load across our network, driven by data centres and major connections, and by increased utilisation by existing customers as they switch from gas to electricity to heat their homes and cook their meals.

Jemena Electricity Networks (Vic) Ltd (JEN) is an electricity distribution network service provider (DNSP). Every day we help deliver electricity to over 387,000 homes and businesses across north and western Melbourne. We are subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER). Our network prices are approved by the AER for the period 1 July 2026 to 30 June 2031 (the next regulatory period). Before each new cycle, we submit a proposal to the AER that outlines our plans for the five-year period and how we expect to fund them.

As a part of the review process, the AER considers our proposal and makes a draft determination. This submission—our 2026-31 revised regulatory proposal (revised regulatory proposal)—contains updates to our 2026-31 regulatory proposal (initial 2026-31 regulatory proposal) and responds to the AER's draft decision.

All dollar values in this document are expressed in $Real 2026 unless stated otherwise.

1 The revenue requirement for the current regulatory period includes JEN's reopener application, which we provide more details in Attachment 08-01.

The AER's Draft Decision

In January 2025, we submitted our initial regulatory proposal to the AER for consideration and assessment of our plans for operating and investing in JEN's electricity distribution network over the next regulatory period. These plans were created with the latest policies, technologies, and macro trends in mind. They were also developed in collaboration with our customers, who shared their views on what is important to them when it comes to providing electricity distribution services.

The AER considered our plans against the NER, the Better Resets Handbook, and other regulatory and legal frameworks that play an essential role in shaping the National Electricity Market (NEM). On 30 September 2025, the AER published its draft decision outlining its view on our proposal and the regulatory allowances it considers efficient for operating and investing in the JEN electricity network. A summary of the key aspects of the AER's draft decision on standard control services is provided in the table below.

Table S.1: Key elements of the AER's standard control service draft decision, Real $2026, millions

Category	Proposed Amount	Draft Decision	Variance	Variance (%)
Revenue Requirement	$1,846	$1,602	-$244	-13.2%
Net Capital Expenditure Allowance	$1,366	$843	-$523	-38.3%
Operating Expenditure Allowance	$615	$565	-$50	-8.2%

Similarly, the AER made a decision on our Advanced Metering Infrastructure (AMI) services that also resulted in significant reductions in our expected revenue requirements and operating expenditure, somewhat offset by an increase in capital expenditure allowance as outlined in the table below.

Table S.2: Key elements of the AER's AMI services draft decision, Real $2026, millions

Category	Proposed Amount	Draft Decision	Variance	Variance (%)
Revenue Requirement	$139	$117	-$22	-15.9%
Net Capital Expenditure Allowance	$105	$113	$8	7.7%
Operating Expenditure Allowance	$77	$56	-$21	-27.3%

While the draft decision presents the AER's view on an efficient regulatory allowance, however, this is significantly below the view put forward by JEN in its initial regulatory proposal.

Overall, we do not agree with the AER's views. We believe the funds sought in our initial regulatory proposal is the minimum required to deliver efficient electricity distribution services to our customers and to prudently operate our network.

Our customer's views

We shared the outcomes of the AER's draft decision with our Energy Reference Group (ERG). They identified several areas of concern with the draft decision, including:

- Potential impact of capital (and operating) expenditure reductions on future network reliability
- The role of distributors in the energy transition
- Public lighting
- Tariff structures
- Metering
- Customer Incentive Schemes
- Innovation Funding

The ERG has advised us that it will collate its views and make its own submission on these items to the AER's engagement process.

We also presented the draft decision to our JEN customer council. Our customer council includes several members of our People's Panel and Customer Voice groups, which provides a continuity of feedback from customers who have been on our engagement journey since we started developing our regulatory proposal.

Our customer council understands the AER's draft decision and appreciates the complexities involved in making it.

Our Revised Proposal

We have considered the AER's draft decision in depth and have taken on board its feedback to develop a revised regulatory proposal that addresses the AER's concerns. We have re-evaluated business cases, customer requirements and risk and take account of the latest policy developments. The additional analysis and review confirms the prudence and efficiency of the regulatory allowances we proposed in January 2025, albeit with some minor variations in costs between categories, as outlined in the table below.

Table S.3: Revised Proposal requirements for standard control services in the next regulatory period, Real $2026, millions

Category	Proposed Amount	Revised Proposal	Variance	Variance (%)
Revenue Requirement	$1,846	$1,868	$22	1.2%
Net Capital Expenditure Allowance	$1,366	$1,335	-$31	-2.3%
Operating Expenditure Allowance	$615	$641	$26	4.2%

For our AMI services, we have responded to the AER's views by offsetting meter inspections with meter replacements; however, to avoid inspection costs in the longer term, we require a much higher meter replacement rate than allowed for in the draft decision. As a result, our program of work in the next regulatory period will require a further uplift in the regulatory allowance than our initial regulatory proposal sought. We outline this in the table below.

Table S.4: Revised Proposal requirements for AMI services in the next regulatory period, Real $2026, millions

Category	Proposed Amount	Revised Proposal	Variance	Variance (%)
Revenue Requirement	$139	$148	$9	6.4%
Net Capital Expenditure Allowance	$105	$201	$96	91.9%
Operating Expenditure Allowance	$77	$65	-$12	16.5%

This submission (our revised regulatory proposal) outlines our revenue requirement for the next regulatory period. It provides a more detailed rationale of our forecasts of capital and operating expenditure, along with reasoning for other elements of the building block model, such as revenue adjustments and ex-ante incentives.

Our revised regulatory proposal responds to a rapidly changing energy market

In planning for the next regulatory period, we have considered and addressed challenges associated with climate change, policy changes, and the rapid development of technology, all of which have accelerated the rapid transformation of the Australian energy market. We also need to cater for significant growth across our network. Current cost-of-living pressures are a concern for all the customers we engaged with—maintaining affordability alongside reliability was considered essential for equitable energy access. Our network must adapt to these challenges in the long-term interests of our customers.

Paving the way for a technology-driven, dynamic future energy market remains a strong theme in our revised regulatory proposal. Our revised regulatory proposal seeks to ensure we can continue to play our role in supporting the transformation of the energy system whilst meeting the needs of our customers and our community.

Our customers' expectations

Our initial regulatory proposal was shaped by our customers' expectations and regulatory obligations regarding the safety, reliability, and security of the network as the energy market transitions.

We continue to represent our customers' views in our revised regulatory proposal. Recognising our role as an essential service provider, we are driven to continuously improve our customer-centric culture and strive to understand customer needs and expectations.

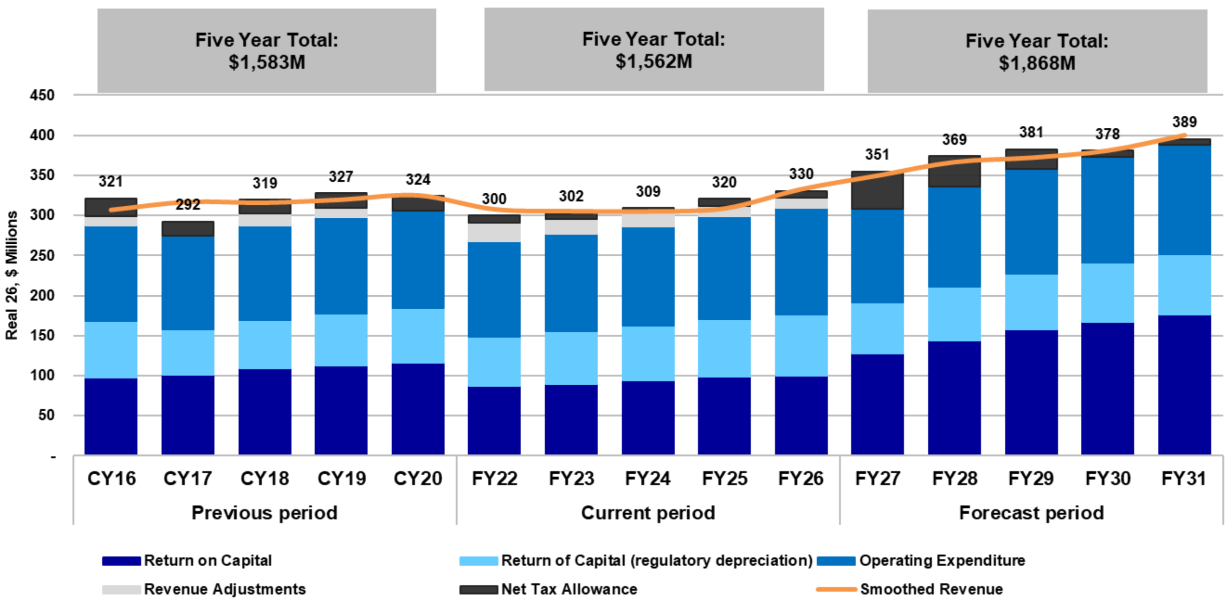
In preparing this submission, JEN has kept customer objectives at the forefront, and we have respected our customers' decisions. We have focused on several key themes when developing our revised proposal, which our customers have told us are important to them:

- **Maintaining reliability:** Ensuring backbone infrastructure is resilient against climate volatility and electrification.
- **Managing the energy transition:** Supporting flexible exports, equitable tariffs, and inclusive innovation.
- **Delivering services efficiently:** Streamlining operations, accelerating smart meter deployment, and enhancing customer communications.

Our required revenue to deliver the Revised Regulatory Proposal

We forecast that we will need $1,868 million in revenue over the next regulatory period, a 20% increase from our revenue requirement for the current regulatory period (see Figure S.1). Key drivers for the increase are our proposed investments to connect new customers, maintain network reliability and improve resilience, accommodate Customer Energy Resources (CER) (including, rooftop solar, EVs and batteries), digitise and automate and provide ongoing service excellence to our customers. These initiatives are consistent with and in response to our customers' feedback and recommendations.

Figure S.1: Total revenue requirement – network distribution services, Real $2026, millions

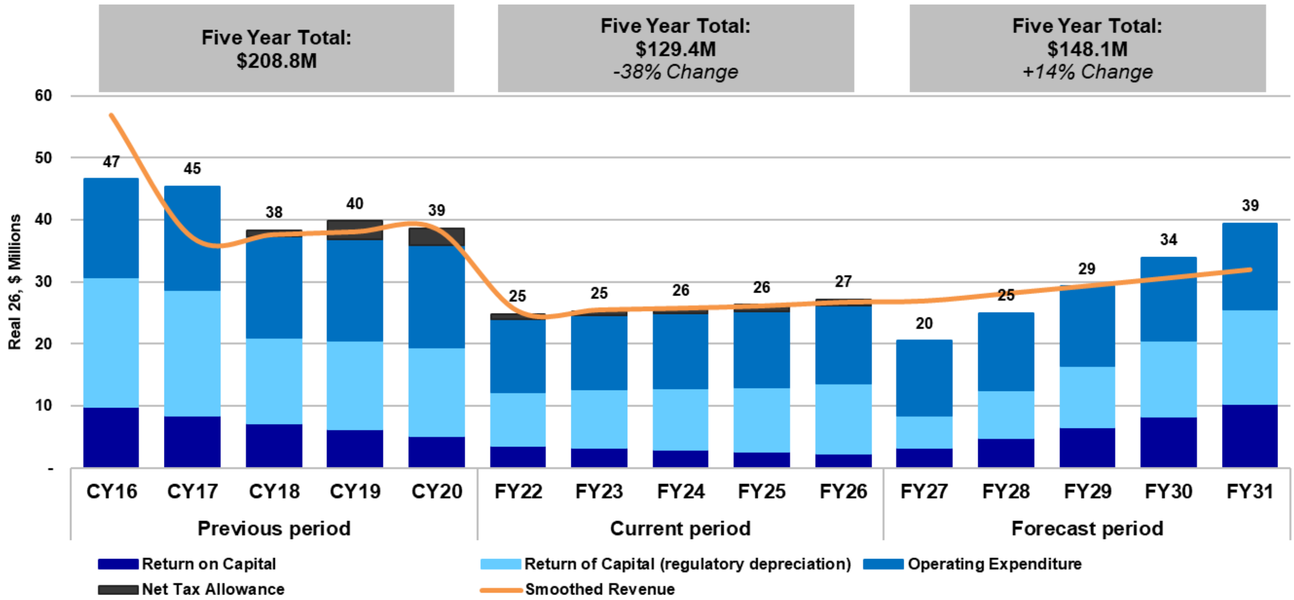


We also seek $148 million in revenue over the next regulatory period to deliver AMI services to our residential and small business customers, which represents a 14% increase from the current regulatory period (see Figure S.2). Key drivers for our proposed revenue requirement for AMI services include:

- replacement of smart meters that have reached their 15-year technical lifespan, and

– minimising in-person inspections of meters as part of our new regulatory obligations.

Figure S.2: Revenue requirement for AMI services, Real $2026, millions

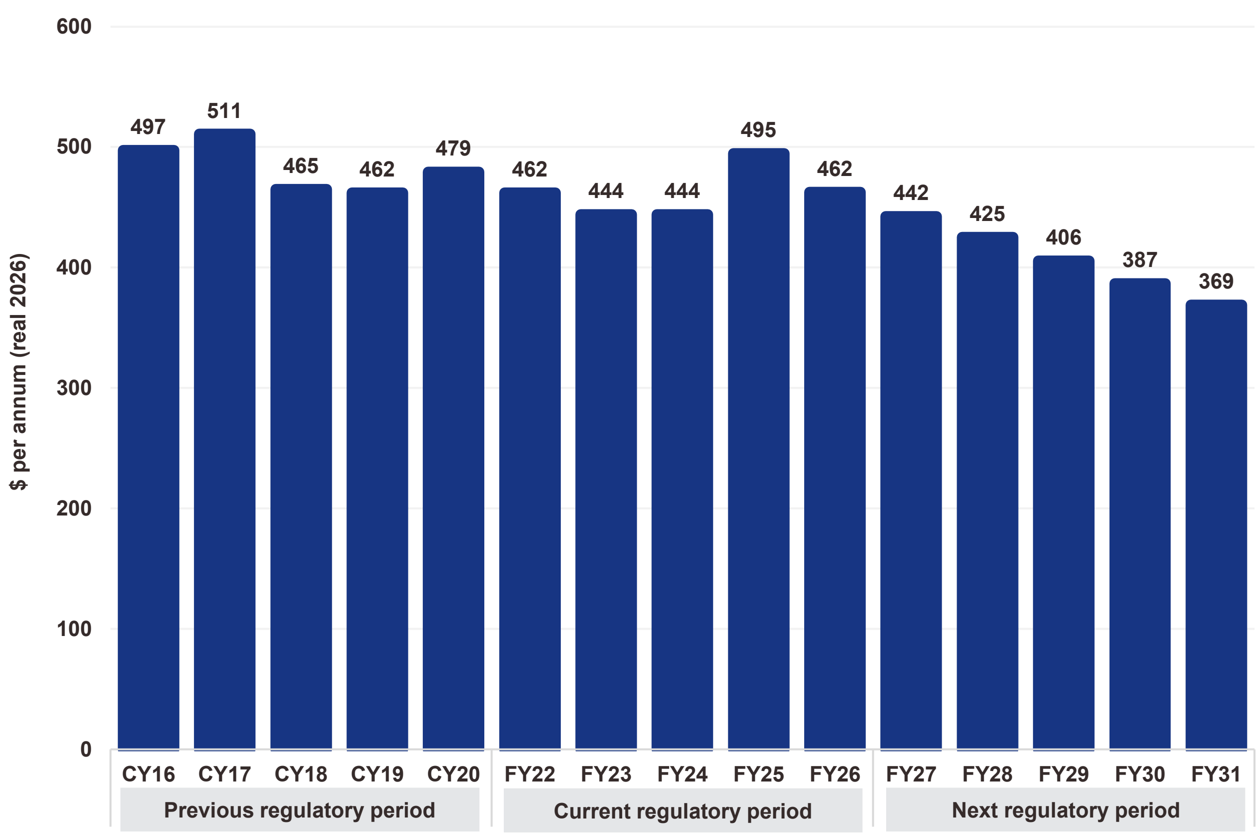


Customer bill impacts

Affordability remains our customers' top concern. We propose to deliver a significant reduction in distribution charges. The distribution charges in a typical residential customer's annual electricity bill will be $94 lower by the end of the next period compared to an annual bill in 2025-26.

Our proposed price reduction continues the theme from our initial regulatory proposal which was enabled by an increase in load from data centres, major connections and increased utilisation from existing customers as they move from using gas to electricity to heat their homes and cook their meals. Network distribution costs represent around 35% of a typical residential customer's electricity bills. Figure S.3 shows the historical and forecast distribution charges for a typical residential customer. A typical residential customer's average annual bill is expected to decrease from $462 in the current period to $406 in the next period, which represents a 12% saving in real terms.

Figure S.3: Historical and forecast residential distribution charges per year, Real $2026

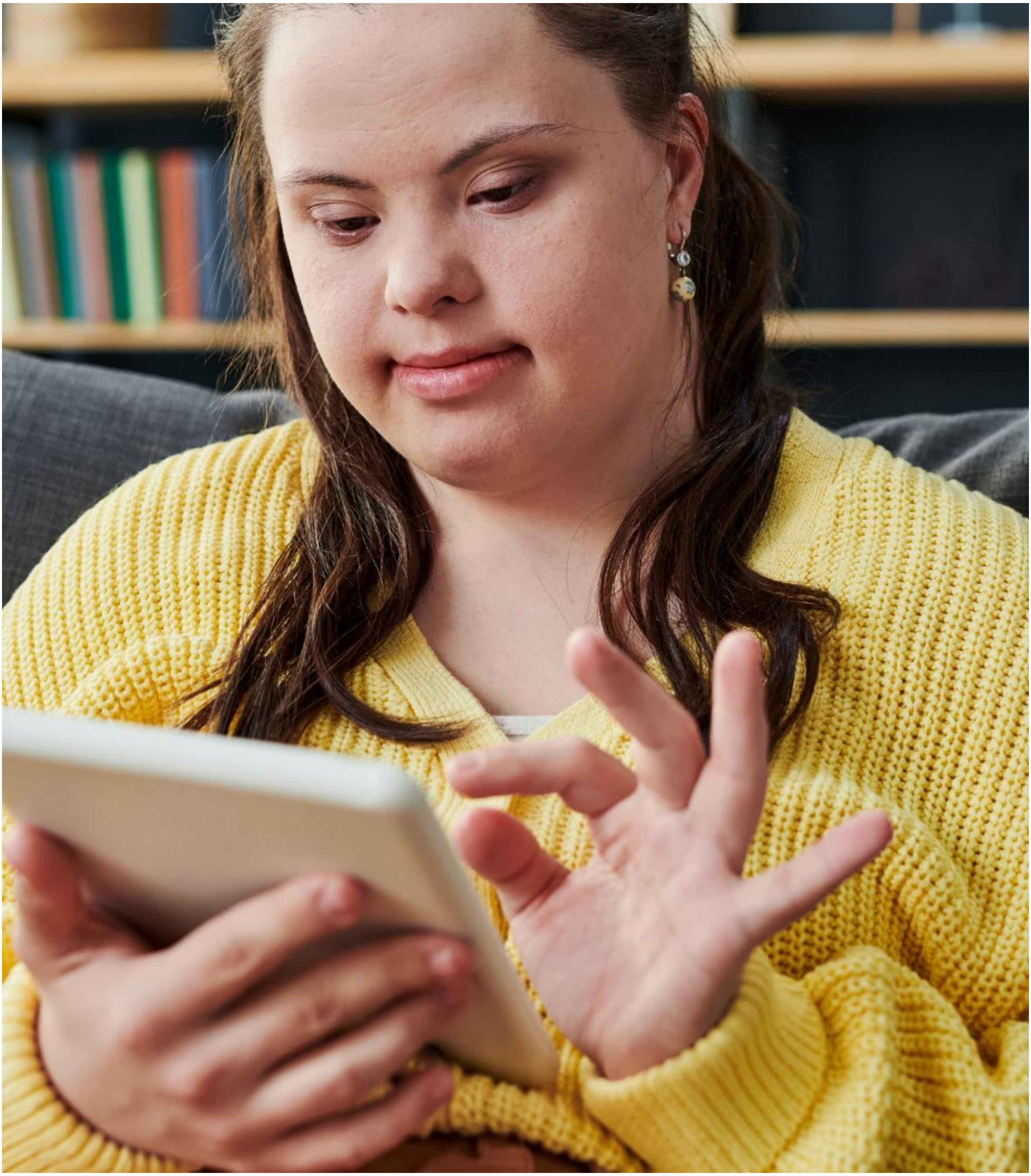


Note: for residential customers consuming around 4300kWh per annum

We provide further information on our revised regulatory proposal in the remainder of this document and in the attachments and supporting materials attached to this submission.


Safety First

1. Background



1.1 About Jemena Electricity Networks

Our electricity network is one of five licenced electricity distribution networks operating in Victoria. We are the sole distributor of electricity in north-west greater Melbourne. Every day we help deliver electricity to over 387,000 homes and businesses across north and western Melbourne.

We build and manage the infrastructure that transports electricity across a 950 square kilometre area and provide energy to support businesses and critical infrastructure such as Melbourne Airport, which sits in the middle of our distribution area.

1.2 Operating environment

The distribution area we manage covers a mix of industrial, commercial and residential customers, including established inner suburbs, some major transport routes and Melbourne Airport. Our network covers semi-rural areas around Sydenham, Sunbury and Coolaroo, some of which have a high bushfire risk.

Our network environment is mainly flat land with a few exceptions, such as Greenvale and Reservoir, which have minor undulations. It includes Maribyrnong River, Merri Creek, Darebin Creek, and Steele Creek as waterways and is bordered by the Yarra River in the east and Port Phillip Bay in the south. Underground, we encounter a diverse mix of ground types, ranging from soft sand to hardened basalt rock.

Our total distribution area covers approximately 12% of the Victorian population.

1.3 Our role as an electricity distribution network

As our society increases its reliance on electricity for day-to-day life and we progress towards a decarbonised future, the electricity system will change and continue to change. As it transforms, so too does our role as an electricity distribution network provider. We also see an evolution in our workforce and the technologies we procure to support this change.

Customers want to connect to and interact with the electricity system in many ways this includes using new technologies such as EVs and community batteries. They also want to generate electricity that can be exported back into the electricity network from rooftop solar. As we move to more electricity use and small-scale generation, we need to manage the congestion of the network and the electricity that flows back to the electricity network.

We are also seeing emerging market trends with new products and services coming online such as virtual power plants where customers can benefit from aggregating exported energy or orchestrating customer electricity usage; we also play a part in transporting electricity with these emerging products and services.

The transition to this new role will be heavily influenced by customers, governments and regulators, as well as other changes in the broader electricity market. With a changing role, we need to pre-empt the transformation, minimise the impact, and embrace the opportunities it presents. We see that greater dependence on data and communications will be necessary, and our interactions with markets, new market players and customers will increase which we need to prepare for.

1.4 Our customers

As a provider of essential services, we have an important relationship with our customers and local communities. Customers are at the heart of our commitment to deliver electricity safely, reliably, and affordably.

Apart from a few very large customers, anyone currently connected to JEN's electricity distribution network is a customer of ours. We also connect new customers and provide distribution services to other groups like property developers, landlords and businesses of all sizes, from sole traders through to large energy consumers, including Melbourne and Essendon airports, industrial customers and hospitals.

1.4.1 Residential customers

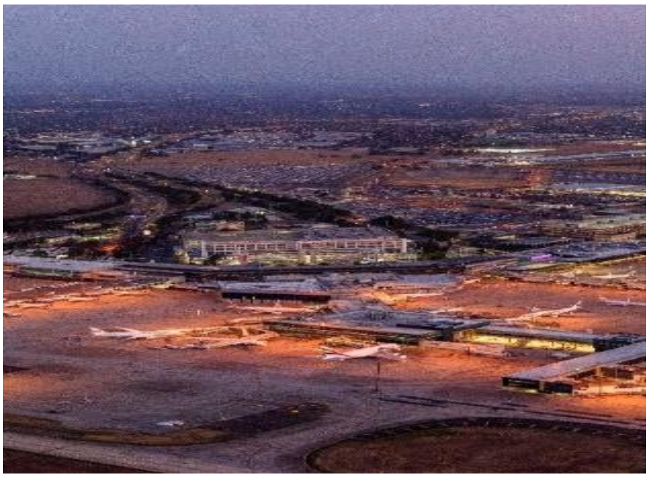
We are the sole electricity distributor in northwest greater Melbourne, servicing more than 387,000 households. Our network area's residential customers and communities are diverse, spanning some of Victoria's fastest-growing Local Government Areas including Hume, Merri-bek, Maribyrnong and Moonee Valley.

Our residential customers are made up of diverse households that include:

- Households with solar
- Households with electric vehicles
- Households with batteries
- Dual fuel households with gas and electricity
- Households with electricity only
- Renters and homeowners
- Households of different densities (low, medium and high)
- Households with different socio-economic status
- Customers with lived experience of disability and mental health difficulties
- First Nations peoples
- Seniors
- Young People
- Multicultural households.

1.4.2 Large customers

Our large commercial and industrial customers—made up of over 2,700 customers in north and western Melbourne—consume more than 50% of the electricity that flows through our network. Large customers come from a range of industries, including:



- aviation
- transport
- data centres and high-tech industries
- property development
- health and medical
- education
- local councils
- logistics
- food manufacturing
- telecommunications
- other utilities.

Each large customer has different energy priorities that reflect the realities of their industries and the customers they serve.

1.4.3 Small and medium business customers

Small to medium-sized businesses in our network are a vital part of our rich and vibrant communities. Our small- to medium-sized business customers number over 32,300 and span north and western Melbourne. Each small and medium business has unique circumstances and ways of operating, including different working environments, retail spaces and office locations.

Small to medium-sized businesses include a large mix of sectors and professions, for example:

- accommodation and hotels
- florists
- agriculture
- furniture building and restoration
- bars, clubs and breweries.
- printing and design
- cafes, food stalls and restaurants
- real estate
- clothing
- retail
- consultancies
- small goods, delicatessens and butchers.
- entertainment and music.

1.5 Purpose of this revised regulatory proposal

As an electricity distribution network service provider, we are subject to economic regulation overseen by the AER under the NER. A key function of the AER is to set maximum prices for the services we provide to customers.

The cost of distributing energy across the electricity network is covered by network charges included in customers' electricity bills. Typically, network and metering charges make up approximately 35% of a household customer's total bill.

The AER approves our prices in five-year cycles. In the build-up to each new term, we submit a regulatory proposal to the AER that outlines our plans for the next regulatory control period and how we expect to fund them.

The regulatory proposal must outline:

- the services we will offer
- the costs we are likely to incur in providing these services
- the prices we propose to charge during the next regulatory period.

The AER only approves the proposal if it complies with the NER and promotes the long-term interests of our customers.

As a part of the NER requirements, our regulatory proposal undergoes two rounds of review by the AER to ensure it captures the prudent and efficient expenditures required to maintain the electricity distribution network. Our initial regulatory proposal was submitted to the AER in January 2025; since then, the AER has released its draft decision.

This submission, our revised regulatory proposal, is developed in response to changes in circumstances since developing our initial regulatory proposal and in response to the AER's draft decision.

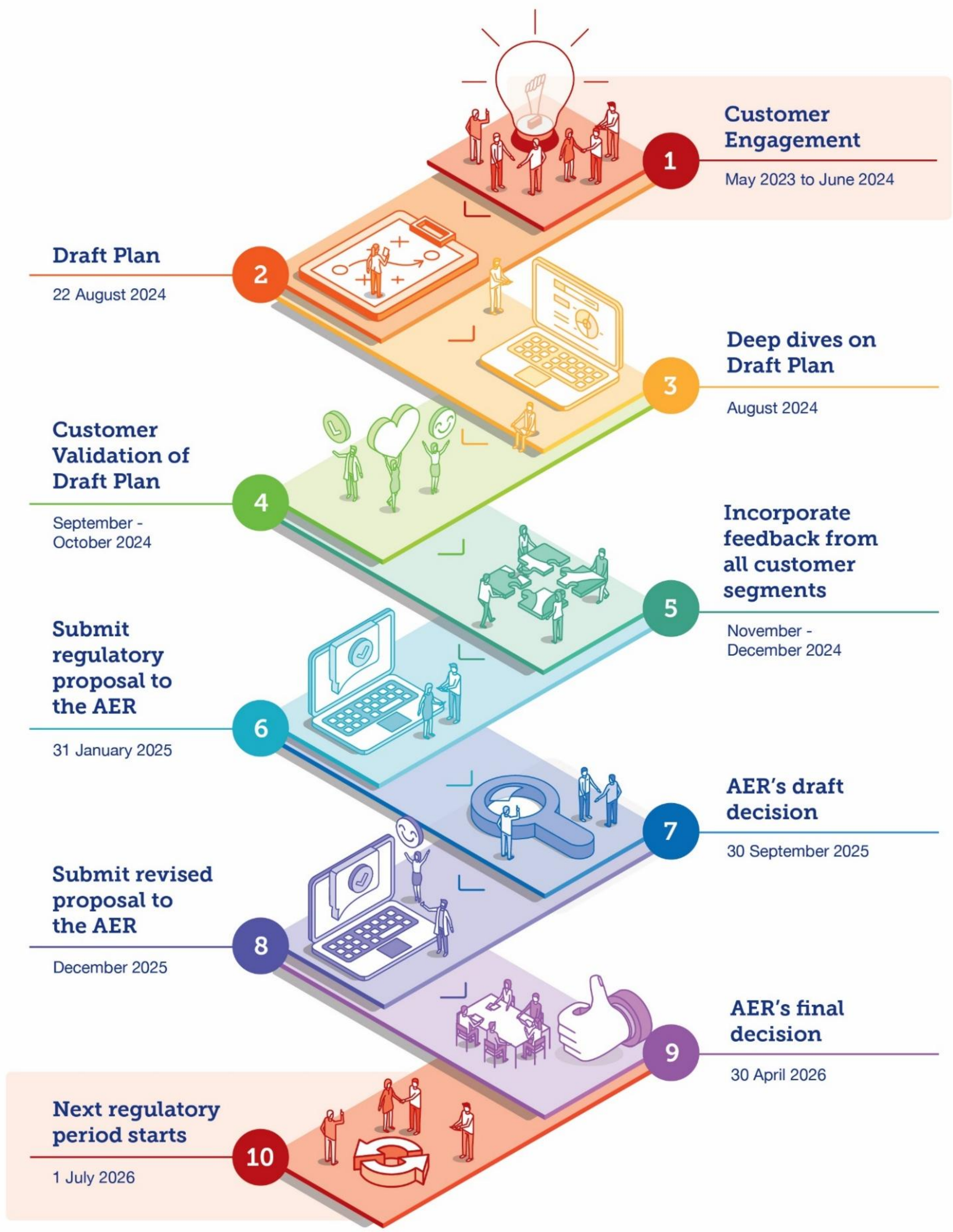
1.6 Customer-centric regulation

The AER regulates energy networks and must ensure that its decisions promote customers' long-term interests.

As part of its five-yearly assessment of regulatory proposals from each electricity distribution network service provider, the AER considers, among other factors, the extent and quality of consumer engagement we have undertaken during the development of this draft proposal. It also looks for evidence that our regulatory proposal reflects the outcomes of that process.

Customers and their interests were at the forefront of developing our initial regulatory proposal and we continue this theme as we developed this revised regulatory proposal.

1.7 The journey to approval



2. Engagement with our customers

2 ENGAGEMENT WITH OUR CUSTOMERS

Highlights

- Our customers helped shape our proposal; they expressed their views, and we captured them in our proposal.
- We have developed an award-winning engagement program, giving confidence that the approach we undertook is credible and can be relied upon for informing regulatory decisions.

2.1 Our customers are key

Our customers have been critical partners in shaping this proposal. From the People's Panel and Customer Voice Groups (CVGs) through to local councils, retailers, and large businesses, their voices have guided our priorities. Members of these groups have continued their involvement by joining JEN's Customer Council, ensuring continuity and accountability in representing customer perspectives.

Insights from these groups highlighted priorities such as affordability, equity, reliability, and inclusive communication.

The ERG has provided profound insights throughout the engagement process, and more recently when considering the AER's draft decision. In their deliberation, the ERG members focused on several key areas of concern:

- **Reliability and resilience:** Concerns about AER's proposed cuts to replacement (-38%) and augmentation (-34%) capex, particularly for substations such as Coburg North, Coburg South, and North Heidelberg.
- **Role in the energy transition:** Recognition that distributors are enablers of household and SME decarbonisation, requiring flexible exports, dynamic operating envelopes, and equitable tariff reform.
- **Public lighting:** Strong support for modern, efficient lighting as a community safety and sustainability priority.
- **Tariff structures:** Calls for transparent modelling of cross-subsidies and equitable tariff pathways.
- **Metering:** Endorsement of smart meter upgrades as a foundation technology.
- **Customer incentive schemes:** Advocacy for evidence-led, inclusive incentives that do not exclude small customers.
- **Innovation funding:** Support for JEN's Innovation Fund to enable agile, customer-focused trials beyond the limitations of federal grants.

We respect the insights from these groups—and in particular the recent considerations of the ERG following its review of the draft decision—and have sought to incorporate them into our revised regulatory proposal.

2.2 Addressing AER Concerns

The AER's draft decision raised several questions about whether JEN's engagement was sufficiently representative and whether customer insights were fully integrated into the proposal.[2]

We note that JEN's engagement program directly addresses these concerns:

- **Breadth and inclusivity:** Engagement spanned residential, business, multicultural, First Nations, seniors, and vulnerable cohorts.
- **Independent facilitation:** MosaicLab, Gauge Consulting, Sagacity Research, and RPS ensured transparent, robust processes.
- **Integration of feedback:** Customer priorities are explicitly linked to expenditure, tariff design, and innovation initiatives.
- **Independent validation:** The newDemocracy Foundation confirmed JEN's engagement met best-practice standards and aligned with the AER's *Better Resets Handbook*.

Further, in its submission to the price reset consultation process, the ERG noted that JEN's customer engagement is exemplary and class-leading[3] while the AER's Consumer Challenge Panel (CCP32) has observed that JEN has met, and in many areas exceeded, the expectations set out in the AER's Better Resets Handbook, and has significantly 'raised the bar' on our successful 2021-26 engagement program.[4]

2.3 Award-winning engagement

Our customer and stakeholder engagement for the 2026–31 price reset proposal is award-winning. JEN was named the Energy Category winner in the Engagement Institute's Core Values Awards, announced in November 2025.[5] The Engagement Institute (formerly IAP2) is Australasia's peak body for promoting customer and community engagement, reviewing hundreds of applications each year to recognise excellence.

This achievement reflects the passionate work of our staff and engagement partners, and most importantly, the commitment of our customers through the People's Panel and Customer Voice Group processes, as well as energy experts through the ERG.

The Core Values Awards celebrate engagement processes that align with the principles of public participation, as defined by the Engagement Institute:

- Those affected by a decision have a right to be involved in the decision-making process.
- Public participation includes the promise that the public's contribution will influence the decision.
- Sustainable decisions recognise and communicate the needs and interests of all participants, including decision makers.
- Engagement seeks out and facilitates the involvement of those potentially affected or interested.
- Participants help design how they participate.
- Participants receive the information they need to engage meaningfully.
- Participants are informed how their input influenced the decision.

2 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 9 – Customer service incentive scheme, September 2025, pp. 3-5. AER, Draft determination, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 14 – Alternative control services, September 2025, p.14.

3 ERG, Feedback on AER's issues paper for Jemena Electricity Network's distribution determination 2026-31, p.5.

4 CCP32, CCP32 Advice to the Australian Energy Regulator on the 2026 31 Regulatory Proposal for Jemena Electricity Distribution Network, May 2025, p.9.

5 https://engagementinstitute.org.au/core-values-awards/winners/ (cited 20-Nov-2025).

We are proud to receive this recognition, which affirms that our 2026–31 price reset proposal is built on genuine, inclusive, and transparent engagement. It demonstrates our commitment to listening to our customers and stakeholders and ensuring their voices truly shape our decisions.

Photo shows members of JEN's team involved in customer engagement, along with People's Panel and Customer Voice Group members who continue to collaborate with us through JEN's Customer Council.

JEN has also been recognised as having *Exceptional Impact* by Democracy R&D,[6] a European Agency with a mandate for global promotion of democratic participation processes.

6 https://democracyrd.org/

2.4 The AER draft decision and our response

The AER considered that JEN has met the expectations for genuine consumer engagement regarding our capital expenditure proposal.[7] In its draft decision, the AER also noted the CCP32's views on our engagement in that JEN has met, and in many areas exceeded, the expectations set out in the AER's Better Resets Handbook, and has significantly 'raised the bar' on our successful 2021-26 engagement program.[8] The AER encouraged JEN to continue with our high standard of consumer engagement to ensure that our customers' preferences are considered in our revised regulatory proposal.

Further, the AER has encouraged JEN to engage more with our customers and stakeholders across several areas in our revised regulatory proposal. In response, we further engaged with JEN's ERG and the Victorian Greenhouse Alliances (VGA). We summarise in Table 2.1 the AER's suggested areas for further engagement and our response.

Table 2.1: AER suggested areas for further engagement

Topic	AER draft decision – areas for further engagement	JEN response
Tax treatment of forecast capital contributions from large customer connections	The AER noted that its assessment remains ongoing and noted that JEN has indicated it will engage further with its stakeholders ahead of lodging its revised regulatory proposal.[9] As part of the revised regulatory proposal process, the AER expects broader engagement on the topic and further information on why the 22kV voltage level is the most suitable threshold at which to charge the net tax liability directly to the connecting customer.[10]	In our July 2025 engagement with ERG on who should pay the net tax on capital contribution, the ERG advised that the connecting customer should cover the tax cost proportionate to their specific connection request and the benefits they receive. The ERG also said that this arrangement should apply to data centres and other large customers, limited to the connection component of the contract. During our 15 October 2025 engagement with the ERG, we discussed the AER's draft decision, including that the large customers (not existing customers) should pay the net tax on the capital contribution. The ERG did not provide any further feedback on this draft decision.
Network resilience proposal	The AER considered that JEN has only partly satisfied the network resilience guidance note criteria – Genuine customer engagement. It noted the CCP32's observation that we have engaged with our People's Panel, but it is not clear whether we have sought feedback in other consumer forums other than the People's Panel.[11]	We did not undertake further engagement with our customers regarding our network resilience proposal because we are not pursuing our main network resilience project (the Relocation of assets in flood-risk areas) in the next regulatory period. Due to time constraints, we are unable to complete the AER-required risk assessment model, options analysis, historical flood data review, and climate modelling ahead of the revised regulatory proposal.

7 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.7.

8 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Overview, September 2025, p.8.

9 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 1 – Annual revenue requirements, September 2025, p.38.

10 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 16 – Connection policy, September 2025, p.16.

11 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.24.

Topic	AER draft decision – areas for further engagement	JEN response
Customer service incentive scheme (CSIS)	JEN's proposed CSIS is not compliant with the requirements of the scheme.[12] Specific issues with JEN's CSIS include: – insufficient evidence that customers strongly support the adoption of the scheme or attribute value to the service improvements proposed, and – JEN's limited application of its expert panel's feedback on additional CSIS parameters.	In our October–November 2025 meetings with the ERG, we presented the AER's draft decision on CSIS. On both occasions, the panel confirmed their support for the scheme and encouraged JEN to advocate for its inclusion. While the ERG noted that there are additional CSIS metrics they would like to see included in future regulatory control periods, they reiterated their support for the scheme despite any perceived limitations. In addition to their support for the CSIS, the ERG also shared their views that relying on the STPIS, particularly the new connections metric would be 'a missed opportunity to foster engagement, build trust, and encourage positive behaviour across the network'. The ERG identified CSIS as a key area for its submission to the AER.
Tariff structure statement (TSS)	The AER encouraged JEN to engage: – with stakeholders, including with retailers, to encourage take up of cost reflective tariffs and improve understanding of how tariff reform can complement our proposal expenditure[13] – with our larger customers to inform our revised tariff structure statement[14] – with retailers and the Victorian Government on the benefits to the network of smart meter customers facing cost reflective tariffs[15] – with stakeholders on whether a new controlled load tariff could be expanded to include other flexible loads, and in consideration of AGL's submission, also encouraged JEN to explore retailer-led control for any new controlled load tariffs[16] – and respond to the ERG's suggested changes to our large customer tariffs. The AER noted that JEN is considering whether to include a winter demand incentive charge in the next regulatory period and has already committed to engaging with the AER and stakeholders on this.[17]	Throughout the next regulatory period, we will continue to engage with key stakeholders, including retailers, about our ongoing tariff reform approach and customer transition to more cost-reflective tariffs. Our revised TSS includes the following tariffs and trial tariffs that will provide pricing incentives for customers with flexible loads, including EVs and batteries: – residential daytime saver tariff (A130) – residential export tariff (A10E) – small business kerbside EV charging trial tariff (A20E) – low-voltage large business storage tariff (A30B) – high-voltage large business storage trial tariff (A40B). We will also consider introducing a new controlled load trial tariff during the next regulatory period. As part of these trials, we capture customer and broader stakeholder feedback so we can incorporate it into our future tariff reform. Further, in our October–November 2025 meetings with the ERG, we presented the AER's draft decision on TSS and our proposed approach for the revised regulatory proposal. The ERG identified tariffs as a key area for its submission to the AER.

12 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 9 – Customer service incentive scheme, September 2025, p.1.

13 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 13 – Tariff Structure Statement, September 2025, p.1.

14 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 13 – Tariff Structure Statement, September 2025, p.15.

15 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 13 – Tariff Structure Statement, September 2025, p.16.

16 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 13 – Tariff Structure Statement, September 2025, p.26.

17 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 13 – Tariff Structure Statement, September 2025, p.37.

Topic	AER draft decision – areas for further engagement	JEN response
Public lighting	The AER encouraged JEN to engage with its stakeholders: – to accurately reflect customers' interest in funding the accelerated LED rollout – to confirm the volume of the smart lighting control devices to be installed.[18]	We further engaged with our public lighting customers through the VGA about these two key matters.[19] The VGA confirmed councils' preference for JEN to fund the accelerated LED rollout and that smart lighting control devices should be installed in major roads and 10% of residential customers in the next regulatory period. Our revised regulatory proposal reflects this feedback. We set out the details of our engagement with councils through the VGA in *JEN – RP – Att 11-01 Alternative control services*. Further, in our October–November 2025 meetings with the ERG, we presented the AER's draft decision on public lighting and our revised regulatory proposal. The ERG identified public lighting services as a key area for its submission to the AER.
Metering	The AER is seeking feedback from stakeholders on whether it is appropriate to smooth the metering services price path in years 2-5, similar to the AER's smoothing approach for metering revenues.[20] The AER also encouraged JEN to consider this approach as part of our revised regulatory proposal.	In our October–November 2025 meetings with the ERG, we presented the AER's draft decision on metering and our revised regulatory proposal. The ERG identified metering services as a key area for its submission to the AER

2.5 Further engagements with ERG

Since submitting our initial regulatory proposal to the AER, we have met with and engaged our ERG five times. We summarised these engagements in Table 2.2.

Table 2.2: JEN's further engagements with the ERG, February 2025 to November 2025

Date	Agenda	Comment
26 February 2025	Summary of initial regulatory proposal	For information
30 April 2025	Summary of AER's issues paper and stakeholder submissions	For information
11 July 2025	Tax on connection offers	The ERG was convened in response to an AER information request. The AER asked whether the current practice of recovering tax from connecting data centres across the broader customer base should continue. The AER enquired whether JEN had consulted on the tax treatment of capital contributions for data centres (and large customers) in developing its regulatory proposal. It encouraged it to do so if it had not.

18 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 14 – Alternative control services, September 2025, pp. 14, 16-17.

19 Through several meetings and emails from September 2025 to November 2025. See Table 2-1 of *JEN – RP – Att – 11-01 Alternative control services*.

20 AER, Draft decision, Jemena electricity distribution determination 1 July 2026-30 June 2031, Attachment 14 – Alternative control services, September 2025, pp. 14, 16-17.

2 ENGAGEMENT WITH OUR CUSTOMERS

Date	Agenda	Comment
15 October 2025	Summary of AER's draft decision Key response strategies for JEN's revised regulatory proposal	After this meeting, the ERG sent their key areas of interest to JEN and requested that we present our revised regulatory proposal for those areas during the next meeting.
11 November 2025	JEN's revised regulatory proposal specific to key areas of interest to the ERG which includes the following: – impact of capital and operational expenditure reductions on network reliability – the role of distributors in the energy transition – reducing the smart lighting volumes could hinder the shift to modern, low emission infrastructure – tariff structures and cost allocations – metering – customer incentive schemes – innovation funding – additional governance and strategic considerations.	During this meeting, we discussed our revised regulatory proposal for their specific areas of interest to enable them to form a view and finalise their submission to the AER in December 2025.

2.6 Revised regulatory proposal focus

In preparing this submission, JEN has kept customer objectives at the forefront, and we have respected our customers' decisions.

When considering the feedback from customers on the draft decision, we have focused on several key themes when developing our revised proposals, focusing on:

- **Maintaining reliability:** Ensuring backbone infrastructure is resilient against climate volatility and electrification.
- **Managing the energy transition:** Supporting flexible exports, equitable tariffs, and inclusive innovation.
- **Delivering services efficiently:** Streamlining operations, accelerating smart meter deployment, and enhancing customer communications.

3. The Energy Transition

Highlights

- Supported by government policies, more and more households and businesses are transitioning towards full electrification and are investing in Consumer Energy Resources.
- These factors will place a higher priority on achieving network reliability that meets community and policy expectations in an operating environment that is expected to become more complex and challenging to manage over time.
- To ensure the efficient operation of this increasingly complex environment, governments, the Australian Energy Market Commission (AEMC) and other Government agencies are consulting on changes to the rules and regulatory obligations to continue to support the energy transition.
- Distribution Network Services Providers—like JEN—will play a crucial role in transitioning the energy system to a decarbonised future, and investment is needed to support this change.

3.1 Energy transition overview

3.1.1 Leaving the steady state

The laws, rules and objectives that underpin the NEM operations have historically incentivised the efficient delivery of electricity to customers in a steady-state environment. This involves balancing affordability and efficient investment, with customer expectations around reliability and quality of service.

However, in recent years, consumer preferences, policy changes, and the rapid development of technology have led to changes in how JEN's customers interact with our network and, in some instances, have increased their reliance on the electricity network.

Our customers have told us they expect JEN to seamlessly meet the challenges of the energy transition in an equitable, cost-effective and timely manner while still providing reliable service amid increasing climate pressures. How the market continues to evolve over the next two decades—including the cost of energy, developments in technology, customer needs and expectations, and the regulatory and policy responses—remains unclear; however, what is clear is that the energy system in the long term will be vastly different from that of today. For example, new technologies like battery storage, EVs and home energy management systems to manage their usage and lower their bills. Also, with the cost of solar photovoltaic electricity systems becoming cheaper, it is becoming more common for energy consumers to generate their own energy 'behind the meter'.

Ruchika Deora, Energy Reference Group member said, "The biggest challenge for Jemena I think facing the future, is actually becoming a technology agnostic enabler of what could look like multiple markets, multiple energy flows and we need to ensure that Jemena is really set up to enable those outcomes in the best interests of consumers."

Our customers told us they want us to continue providing affordable, reliable electricity while empowering and supporting customers to take up and utilise more CER.

For the next regulatory period, we aim to continue providing a reliable energy network while developing and deploying digital initiatives that encourage innovation and support customers' choices in managing their energy needs.

3.1.2 Policy and regulatory changes

Policies and regulations are also rapidly changing to support and foster this transition. There are several projects included in our revised regulatory proposal that relate to this changing governance landscape, which require us to begin investment and change before the next regulatory period commences. These include:

- ICT: Victorian Emergency Backstop Mechanism Stage 2 (VEBM)[21]
- ICT: Flexible Trading Arrangements (FTA),[22] and
- ICT: Market Interface Technology Enhancements (MITE)[23]

These projects are examples that set the scene for how rapidly the reform agenda is upon us, and how quickly we must respond.

In the ten months since submitting our regulatory proposal, we have gained further clarity on the impacts of these programs on our business procedures and ICT systems. This has allowed us to refine the scope and cost of the programs. JEN has also chosen to withdraw one initiative, *ICT Outage Preparedness and Response,* due to the delays in the consultation process and the increasing likelihood that the requirements of the final rule change may differ significantly from what we initially estimated.[24]

In addition to these rule changes, numerous consultations on potential rule changes and policy directions have commenced since we prepared our initial regulatory proposal, as shown in Figure 3.1 below.

Figure 3.1: Rule changes and consultations since our initial submission

30 Rule changes initiated by the AEMC

19 Final decisions made by the AEMC

3 Consultations initiated by the ESC

3 Consultations on CER Roadmap initiatives

2 Consultations initiated by DECCA

The enormous reform agenda exacerbates the work we must do and the investments we must undertake to support policy objectives. Whilst not all changes impact JEN or our customers directly, we will keep a 'watching brief' of these consultations. We will ensure that we represent our customers' interests and preferences in any submissions we make.

21 DECCA, Victoria's Emergency Backstop Mechanism for Solar
22 The AEMC, Unlocking CER Benefits Through Flexible Trading
23 AEMO, Market Interface Technology Enhancements
24 Further details are included in JEN – RP – Att 05-01A - Technology Expenditure - 20251201 – Public

3.2 Demand forecasts

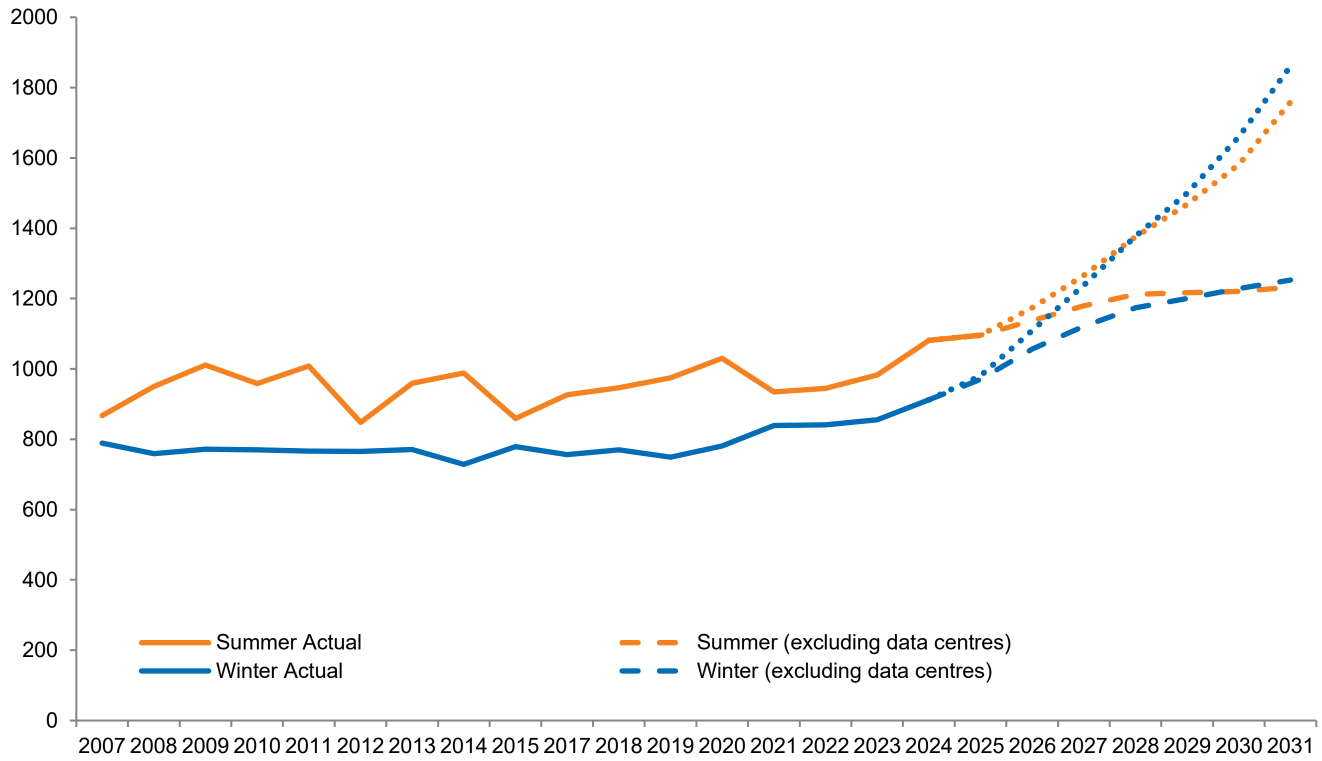
Highlights

- Our forecast demand is grounded in independent inputs, developed using leading techniques and validated using alternative methods.
- We have sought to address the AER's concerns with our demand forecasts as presented in our initial proposal and align them to the methods used by other DNSPs that the AER has approved.
- JEN continues to anticipate that organic growth, policy drivers and data centre growth will increase demand, creating a once-in-a-generation opportunity for substantial scale efficiency to be passed onto our customers.

In our initial regulatory proposal, we forecast unprecedented levels of peak demand growth on our electricity distribution network. This growth is driven by new customer developments in the distribution network area, policy initiatives by the Victorian Government (in particular the gas substitution policy) and unprecedented growth in data centre customers. Around 12 months after developing this forecast, we continue to forecast strong growth based on these same key drivers; however, data centre demand drivers have continued to increase further.

Forecast system peak demand, including and excluding data centre loads, is shown in Figure 3.2 below. We note that the demand forecast, which underpins our augmentation forecast, excludes data centre loads.

Figure 3.2: Forecast system peak demand (POE50, MW)



3.2.1 We have responded to the AER's concerns

In our initial regulatory proposal, we developed peak demand forecasts using Blunomy's top-down forecast and relying on our own bottom-up (spatial) forecasts. In its draft decision for JEN, the AER did not agree with our forecast; the AER considered that we had not provided compelling evidence of an uplift in demand, although it recognised that maximum demand on our network would increase. The AER and Baringa,[25] were concerned about how we:

- Developed button-up (spatial) forecasts
- Included large data centre connections in our peak demand forecast.

To address the AER's feedback, we:

1. Moved to entirely rely on the Blunomy forecast, consistent with the approach adopted by other Victorian DNSPs and accepted by the AER. We no longer prepare an internal bottom-up forecast or undertake any reconciliations or adjustments – the primary issue raised with our demand forecast.
2. Forecast all data centre loads consistent with the approach outlined in the AER's draft decision, which is to include only those connections that are signed or have firm offers in place.

We have also updated our forecast with the latest inputs from the Australian Energy Market Operator (AEMO)'s Inputs, Assumptions and Scenarios (IASR) and other macroeconomic indicators.

The changes we have made to our demand forecast fully address the AER's concerns, and we now apply a methodology that the AER considers produces a realistic expectation of demand.[26]

We recognise the complexities of forecasting demand and have sought a further independent forecast from an alternative forecasting agency (End Game Analytics) to cross-check those produced by Blunomy. Overall, the forecast is similar, but there are differences at the spatial level. Applying Endgame Analytics' demand forecast yields an even higher augmentation forecast than we are proposing. This suggests that our forecast is reasonable.

While we are proposing an uplift in augmentation relative to the current regulatory period spend, the need for an increase is not surprising given our history of constrained investment over the long term, the material increase in demand we (and AEMO are forecasting), the need to support an increase in housing supply and our network's increasing levels of utilisation.

3.2.2 We have responded to the AER's concerns

The AER raised concerns that our forecast was opaque, difficult to replicate and not well evidenced. To respond to the AER's concerns with our demand forecast, we have made the three main changes:

1. **Transparency** – We have improved the transparency of our forecasting approach by simplifying our forecasting approach and updating our demand forecast documentation. We have also created a separate independent forecast to verify the Blunomy forecast.
2. **Bottom-up and top-down reconciliation** – We have changed our methodology to rely on Blunomy's spatial and system-level forecasts. This brings us into line with other Victorian DNSPs, removes the need for any reconciliation adjustment (which drove the majority of the concerns related to transparency), and ensures that CER is modelled spatially.
3. **Data centre loads** – We have only incorporated contracted and firm data centre loads in our demand forecast.

With these actions complete, we believe our updated forecast should satisfy the AER's concerns about our demand forecasts.

25 The consultant to the AER.

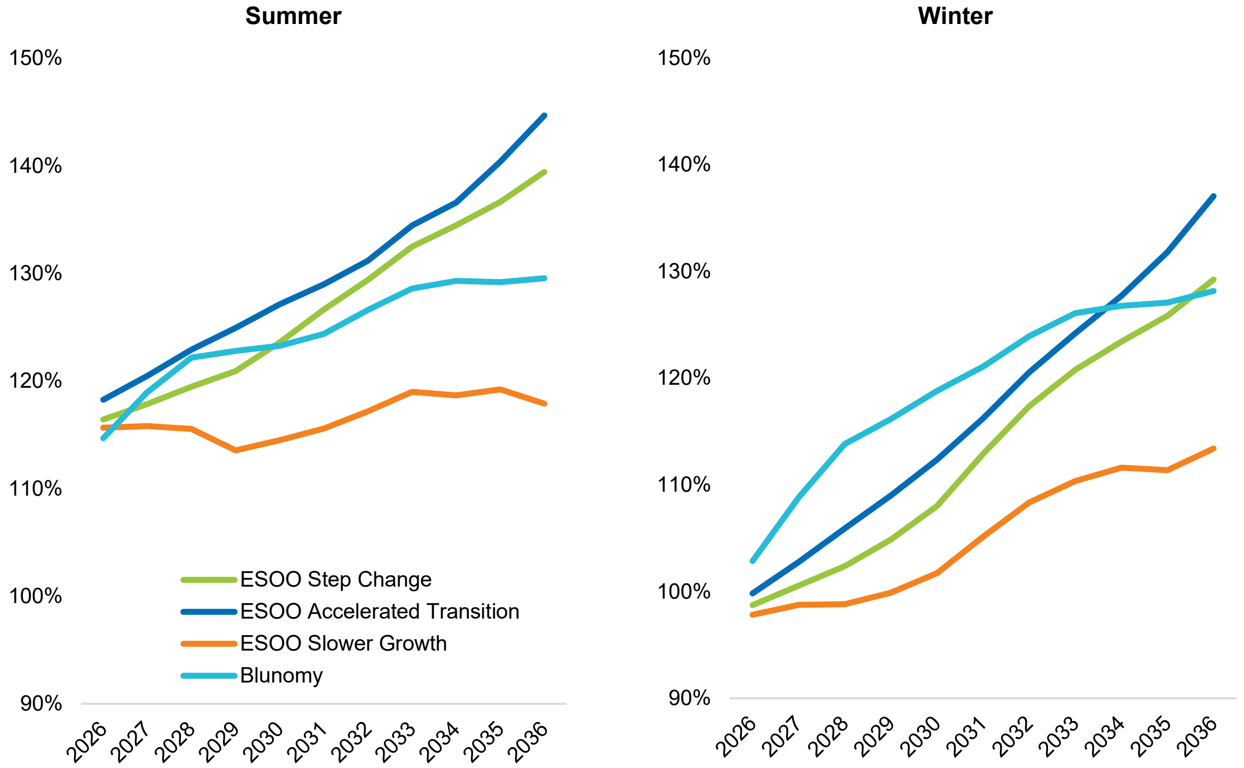
26 As evidenced by the AER's acceptance of the demand forecasting methodology applied by other Victorian DNSPs.

3.2.3 Comparing and cross-checking our demand forecasts

We compared Blunomy's forecast for our network against the forecasts in AEMO's three most likely scenarios (Step change, Accelerated Transition and Slower Growth) for Victoria as a reasonableness check. As shown in the chart below, forecast demand is presented relative to 2024 summer peak demand to ensure we compare the forecasts on a consistent basis.

We found that Blunomy is forecasting lower summer peak demand growth (what drives our augmentation forecast) than AEMO in both the Step Change and Accelerated Transition scenarios. The gap is 2.3% - 4.6% percentage points by the end of the next regulatory period and 9.9% - 15% too low by the end of the following 2031-36 regulatory control period. This indicates that it is unlikely there is any systemic upward bias in Blunomy's demand forecast. This indicates that it is unlikely there is any systemic upward bias in Blunomy's demand forecast, and that there is a high likelihood our forecast understates demand.

Figure 3.3: Comparison of Blunomy's forecast versus AEMO's 2025 ESOO (POE10, MW)



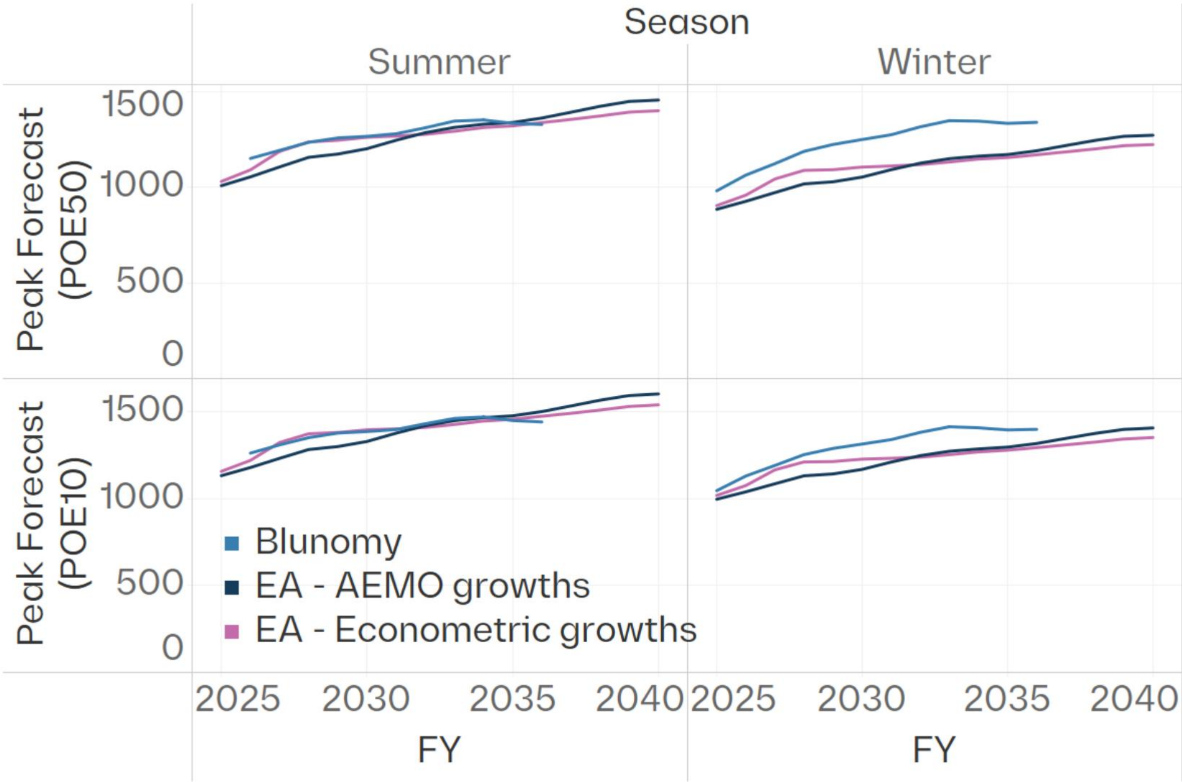
We note that in winter, Blunomy is forecasting higher peak demand growth than AEMO is forecasting for the whole of Victoria in the Step Change scenario. However, currently, winter peak demand growth is not a material driver of our augmentation forecast.

3.2.4 Alternative forecast cross checks

Given the AER's concerns about our demand forecast and the criticality of our augmentation forecast, we commissioned an alternative forecast from Endgame Analytics as a cross-check of the Blunomy forecast. Endgame Analytics applied a component-based framework which – given the AER's feedback to date – focused on simplicity, explainability and reproducibility. The forecast spatially allocated CER and did not include any large industrial loads.

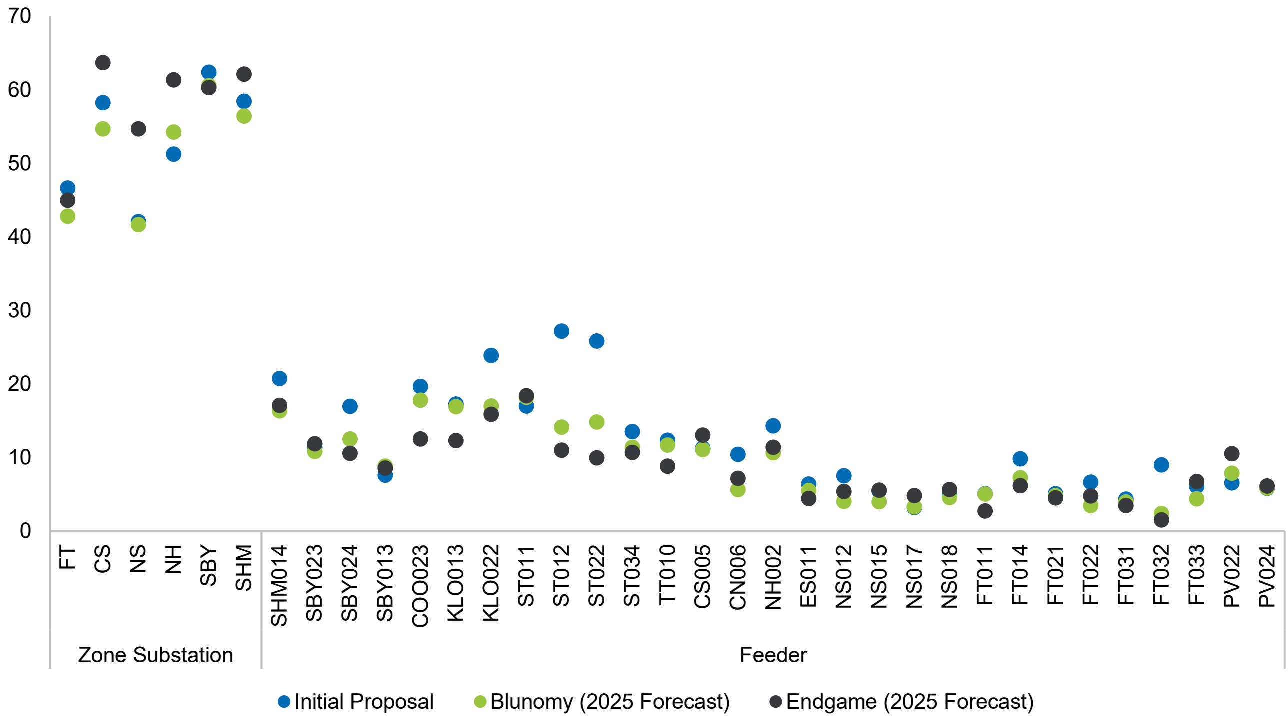
Even though a different methodology was applied, Endgame Analytics' system-level summer forecast is close to those prepared by Blunomy (The results at the system level are shown in Figure 3.4 below). As with the comparison to AEMO, Blunomy's winter forecast is higher than Endgame Analytics' forecast. This difference has no impact on our augmentation forecast as it is driven by summer, not winter, demand. Noting that over winter our network asset ratings are also higher, meaning there is less stress on the network during the colder months, and the need for investment in this season is lower.

Figure 3.4 Comparison of system peak demand forecast by source, season and POE (MW)



While the forecasts are similar at the system level, our augmentation requirements are based on a spatial view of demand. The difference in load forecasts (POE50, 2031, summer) is shown in Figure 3.5: below. Broadly, Endgame Analytics forecasts higher demand for our Zone Substations but lower demand for feeders.

Figure 3.5: Maximum demand constrained zone substations and feeders (POE0, 2031, Summer) MVA



3 THE ENERGY TRANSITION

Overall, the outcomes of our revised work on demand forecasting—both top down and spatial—meet best practice standards and support the proposal capital expenditure program over the next regulatory period.

4. Our services

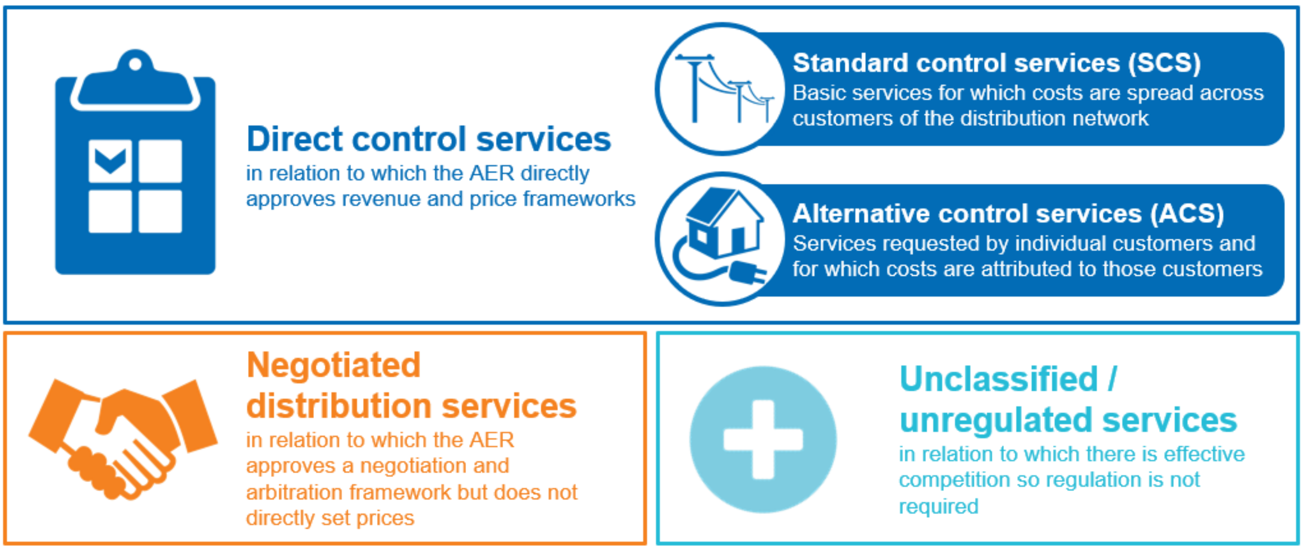
Highlights

- The AER has adopted the classification of services as outlined in its Framework and Approach (F&A) paper. JEN agrees with the classification decision.
- The AER has also identified a material change that warrants classifying other services. This is *Distribution asset rental: Rental of distribution assets (e.g. poles) to third parties for the installation of electric vehicle (EV) chargers or associated hardware*, which the AER consider should be classified as a negotiated service.
- JEN supports the innovation and classification of new services; however, we are concerned about whether a negotiation service is the best classification.

4.1 Overview

We provide different types of electricity distribution services. The classification of distribution services determines the economic regulation that the AER will apply to the services we provide. The NER set out how the AER is to classify distribution services, as shown in Figure 4.1.

Figure 4.1: Distribution service classifications



The AER publishes an F&A paper ahead of making its ex-ante price reset determination for a DNSP. In this paper, the AER classifies the services after consulting with customers and other stakeholders.

4.2 JEN's initial regulatory proposal

The proposed services classification in our initial regulatory proposal is consistent with the distribution services classification outlined in the AER's Final F&A. We outline our approach to classifying services in *JEN – RP – Att 04-01 – Classification of services.*

4.3 Draft decision

The AER must accept the service classification as outlined in the F&A and can only depart if it identifies a material change. In its draft decision, the AER adopted the service classification from the F&A and identified one material change warranting a variation to the service classification for the next regulatory period.[27]

4.3.1 Additional Service Classification

In its draft decision, the AER identified a material change warranting the classification of a new service. This service is:

> *Distribution asset rental: Rental of distribution assets (e.g. poles) to third parties for the installation of electric vehicle (EV) chargers or associated hardware*

In determining the materiality of events, the AER note:

> *we have seen widespread emergence of third-party interest in using DNSP-owned infrastructure as a host for non-DNSP equipment. Particular concerns have been raised by prospective providers of commercial kerbside EV chargers with their ability to rent DNSPs' kerbside poles as a 'host' for EV charging infrastructure. These include the variability, transparency and fairness of access pricing and other terms of pole leasing arrangements. Together these have created a step change in the materiality and relevance of accessing distribution asset rental services*

JEN anticipates strong growth in electric vehicle uptake—as depicted in our demand forecast—and may result in a considerable rise in kerbside charging infrastructure.

In the draft decision, the AER has classified the new *Distribution asset rental* service as a negotiated service.

4.4 Revised regulatory proposal

JEN accepts the AER's service classification in the draft decision. However, we are concerned about classifying the *Distribution asset rental* as a negotiated service on the grounds that JEN—as a Distribution Network Service Provider—is unable to provide negotiated services due to ring-fencing constraints.

In the draft decision, the AER notes that the service:

> *can be provided by part of the DNSP's business that is classified as a related electricity service provider*

However, negotiated services under the Negotiation Framework are provided by the DNSP and not the Related Electricity Service Provider.

We seek further clarity on this point and ring-fencing obligations in the AER's final decision.

27 AER - Attachment 11 - Service classification - Draft decision - AusNet Services, Jemena, CitiPower, Powercor and United Energy distribution determinations 2026-31 - September 2025.

5. Our capital investment

Highlights

- We propose a revised capital expenditure (net of customer contributions) of $1.3B, which is $31 million or 2% lower than the forecast expenditure in our initial regulatory proposal.
- Our revised regulatory proposal is supported by new or enhanced business cases and updated demand forecasts, which demonstrate that our forecast capital expenditure is prudent and efficient.
- We have addressed the feedback provided by the AER in its draft decision in relation to the additional support it requires to accept our forecast capital expenditure.
- The AER's draft decision to limit expenditure to historical trends will compromise our ability to comply with reliability standards and the NEO, and slowing progress toward Australia's energy transition goals.

5.1 Overview

We welcome the AER's draft decision, particularly when acknowledging that several elements of our proposed capital expenditure for Standard Control Services (SCS) are prudent and efficient. In response to the AER's feedback encouraging JEN to provide additional support where allowances have not been approved, we have carefully considered this advice and developed new business cases and enhanced existing ones to strengthen the rationale for our proposed investments. We have also reviewed the scope of some of our proposed projects, gaining greater clarity on the impacts of the rule and procedural changes on our systems and business processes, and have revised our forecast accordingly.

We forecast a lower net capital expenditure of $1,335 million under our revised regulatory proposal for the next regulatory period. There are increases or decreases in forecasts between the different types of capital expenditure; however, overall, our revised forecast is $31 million lower than our forecast capital expenditure in the initial regulatory proposal (refer to Figure 5.1).

Our revised forecast capital expenditure (net of customer contributions) is 58% higher than the AER's draft decision of $843 million. We do not consider that the AER's draft decision, which aligns closely with historical capital expenditure levels, adequately reflects the evolving obligations and customer expectations of DNSPs.

Our forecast expenditure is necessary to ensure that JEN can meet the following critical challenges in the next regulatory period:

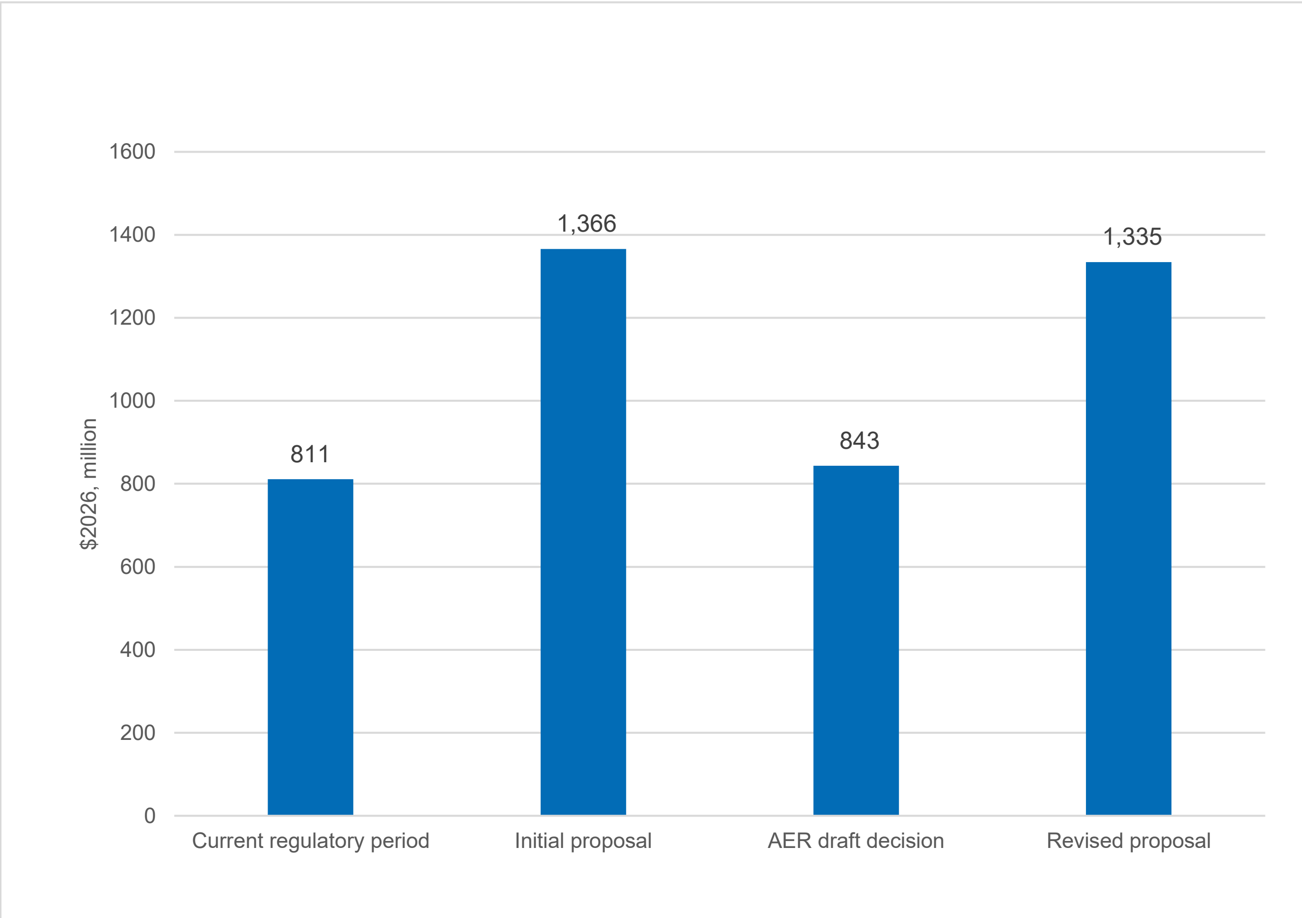
- **Network Reliability**. Aging infrastructure and increased demand variability require us to invest in asset replacement and augmentation to maintain reliability standards. Deferring or underfunding these programs risks higher outage rates and customer dissatisfaction.

5 OUR CAPITAL INVESTMENT

- **Energy Transition Requirements**. The rapid integration of customer energy resources/distributed energy resources (CER/DER), electrification, and decarbonisation targets necessitate upgrades to accommodate two-way power flows, advanced voltage management, and system security. These changes require substantial capital investment in new technologies, ICT systems, and grid reinforcement—far beyond historical norms.
- **Ongoing greenfield and infill development**. We must augment our already highly utilised network to support new housing supply across our network area. This requires an uplift in augmentation spend to avoid either development moratoriums or widespread outages.
- **Large customer connections such as data centres**. Connection expenditure relates to the costs we incur in connecting new customers to our network. Connections are not discretionary or within our control. Various regulatory instruments require us to offer connection services to customers.[28]

Limiting expenditure to historical trends ignores these forward-looking risks and obligations and could compromise compliance with reliability standards and the National Electricity Objective (NEO), while slowing progress toward Australia's energy transition goals.

Figure 5.1: Comparison of actual and forecast net SCS capital expenditure, $2026, million



28 Such as Chapter 5A of the NER and the Essential Services Commission Electricity Distribution Code of Practice.

5.2 AER's draft decision and our response

We summarise in Table 5.1 the AER's draft decision, including how we have responded to it.

Table 5.1: Key elements of the AER's draft decision and our response

Capital expenditure	AER draft decision[29]	Adopted AER recommendations?
Connections	The AER accepted our business-as-usual connection forecast but removed major and data-centre connections where there was any material uncertainty on whether a connection would occur. This reduced our net connections forecast capital expenditure from $366.4M to $211M. The biggest change related to data centre connection forecast capital expenditure where the AER accept 100% of inflight projects (where a Connection Works Agreement (CWA) has been signed) and 50% of 'Enquiry to Offer' projects. The AER requested additional evidence, beyond what we have already provided, on the likelihood that each connection will progress to a CWA.	✓ Our revised regulatory proposal mostly applies the AER's draft decision preferred approach. For data centres, we only include expenditure where a Connection Works Agreement has been signed (in-flight) or will soon be signed (firm offer). Our revised regulatory proposal net connection forecast is $349M, higher than the AER's draft decision of $211M, largely due to projects progressing through the connection process. If we had included all data centre projects in our pipeline as well as those we anticipate given broader trends, our forecast would be $231M higher. We have been able to reduce our forecast to include only projects with no uncertainty, following the AER's decision to allow ex post adjustments for higher-than-forecast connections. Whilst we align our revised regulatory proposal with the AER's approach, we do not believe this is the best forecast in the circumstances. We do this on the basis that the new criteria for acceptance, as outlined in the draft decision, involve levels of certainty not available at this stage of forecasting.

29 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025.

Capital expenditure	AER draft decision[29]	Adopted AER recommendations?
Augmentation	The AER did not accept JEN's augmentation capital expenditure forecast of $270M. The draft decision included $150M in augmentation capital expenditure, which is 44% lower than JEN's proposal. The AER expressed concerns with JEN's demand forecasts and, therefore, with JEN's demand-driven augmentation expenditure of $165M. It has included a placeholder of $100M which is based on JEN's demand driven historical augmentation expenditure. The AER has not accepted our proposed non-demand-driven augmentation capital expenditure of $59M and has included an alternate forecast of $48M. The AER has accepted our forecast expenditure for the final 2 stages of the East Preston Conversion Program.	✓ On demand-driven augmentation, we have addressed the AER's concerns by updating our forecasting approach. After we made these changes, we re-evaluated our augmentation program. Other than the removing projects driven by data centres we found that there was no material change in our augmentation program. We also asked Endgame Analytics to review our demand forecast to ensure we had addressed the AER's issues and to produce an alternative forecast as a cross-check. Applying this forecast results in a $17M *higher* augmentation forecast, indicating that our forecast is conservative. We have retained the majority of our forecast and excluded data centre driven augmentation to produce a revised demand-driven augmentation forecast of $143M. ✓ In respect of our operational communications network project, we revised our economic analysis, taking into account the AER's feedback. We found that our preferred solution remains the most economic option and have retained the project in our forecast.
Replacement	The AER did not accept JEN's replacement expenditure forecast of $380M (net of customer contribution and the Maribyrnong project[30]). It included a substitute estimate of $230M, which is 40% lower than JEN's forecast.	✓ Our revised regulatory proposal addresses the AER's concerns and recommendations. Supported by new or enhanced business cases, our revised regulatory proposal net replacement expenditure forecast is $390M (or $419M gross). The $10M increase in forecast from the initial regulatory proposal is due to our revised regulatory proposal to expand the scope of the upgrade to substation locks and security systems. This will enable us to meet our regulatory obligations.
Network resilience	The AER did not accept JEN's network resilience capital expenditure of $20M (including the Maribyrnong project) and instead provided an alternative estimate of $1M. The main driver of the decrease is the AER's rejection of JEN's proposed Maribyrnong project for insufficient justification. The AER has accepted our proposed capital expenditure for the Mobile emergency response vehicle and mobile generators as prudent and efficient.	✓ We welcome the AER's draft decision to accept our proposed capital expenditure for the Mobile emergency response vehicle and mobile generators. We acknowledge the AER's re-categorisation of the Maribyrnong project as a network resilience initiative. However, due to time constraints, we are unable to complete the AER-required risk assessment model, options analysis, historical flood data review, and climate modelling ahead of the revised regulatory proposal.

30 Also referred to as Relocating assets that are in high-flood risk zones which the AER has re-categorised as a network resilience project in its draft decision.

Capital expenditure	AER draft decision[29]	Adopted AER recommendations?
Innovation	The AER did not accept JEN's capital expenditure forecast of $4 million for network innovation and has included an alternative forecast of $2M.	✓ Our revised regulatory proposal accepts the AER's feedback. We reassessed and refined our innovation program for the next regulatory period. We forecast capital expenditure of $3M ($2024) for our innovation program for the next regulatory period.
CER	The AER did not accept JEN's CER forecast of $85M capital expenditure and has included a substitute forecast of $18M, which is 79% lower than JEN's capital expenditure proposal.	✓ We have not adopted the AER's proposed re-categorisation of this expenditure. However, our revised proposal addresses the AER's feedback. We have reduced the scope of the three initiatives that the AER has re-categorised as CER. These projects are discussed as part of our forecast capital expenditure for augmentation and ICT. The projects are now categorised under network augmentation and ICT.
Non-network - ICT	The AER did not accept JEN's information and communications technologies (ICT) capital expenditure forecast of $153M (including CER). It included $104M ICT capital expenditure which is lower than JEN's proposal. The draft decision included an alternative forecast of $29.7 million for recurrent ICT capital expenditure, which is based on the past 4.5 years of actual data. It accepted the drivers behind 9 of our 13 proposed non-recurrent ICT capital expenditure (net of CER) as prudent and efficient.	✓ Our revised regulatory proposal applies the AER's approach for setting the recurrent ICT capital expenditure. We have provided additional justification documents to support some of the non-recurrent capital expenditure projects, for which the AER has included an alternative estimate of $0 or partial capital expenditure. We propose two new non-recurrent capital expenditures: the cyber security program and the Victorian Emergency Backstop Mechanism (VEBM2), with a total forecast expenditure of $7M. This is to address recently identified risks and regulatory obligations that were unknown/uncertain at the time of the initial regulatory proposal. Our revised regulatory proposal is $133M which is $20M lower than our forecast spend under the initial regulatory proposal.
Non-network– Other	The AER has accepted our forecast capital expenditure for fleet replacements and property as prudent and efficient. The AER's draft decision is silent on our proposed capital expenditure for fleet growth, which was submitted to the AER as part of our response to information request#5 in April 2025.	✓ We welcome the AER's decision to accept our proposed expenditure for fleet replacements and property in the next regulatory period. For the revised regulatory proposal, we seek additional capital expenditure to address fleet-growth requirements that are essential to delivering our expanded replacement and augmentation capital works program.

5 OUR CAPITAL INVESTMENT

Capital expenditure	AER draft decision[29]	Adopted AER recommendations?
Capitalised overheads	The AER did not accept JEN's proposed overhead amount of $128M (net) or $222M (gross) and substituted $98M and $159M, respectively. The AER did not accept JEN's approach of using a single-year base (2023–24) to forecast overhead compared with the AER's standard approach of using a 3-year average of historical actual overhead.	✓ Our forecast capitalised overheads partially adopt the AER's draft decision. Our revised regulatory proposal adopts the 4-year 2021–25 period, which adds the 2024-25 year to the 3-year average adopted in the draft decision. However, based on Farrier Swier's analysis, we propose updating the fixed/variable split to 50%/50% (compared with the AER's draft decision of 70%/30% split). Applying a 50%/50% fixed/variable split is consistent with empirical evidence that suggests that the variable weight is noticeably higher.

5.3 Revised capital expenditure forecast

Table 5.2 and Table 5.3 show our revised forecast of gross and net capital expenditure for each type of expenditure compared with our initial regulatory proposal and the AER's draft decision.

Table 5.2: Comparison of forecast net SCS capital expenditure ($2026, million)

Capital expenditure	Initial regulatory proposal (Re-categorised)	AER draft decision	Revised regulatory proposal
Replacement	380.1	229.8	390.5
Augmentation	269.5	150.1	235.2
Connections	366.4	211.0	348.8
ICT	153.6	103.7	133.1
Property	17.4	17.0	17.4
Fleet	30.8	30.7	45.1
CER integration	0.0	n/a	n/a[31]
Resilience	19.8	1.3	19.8
Non-network – Other	1.4	1.4	1.4
Capitalised overheads	127.5	98.2	143.4
Total net capital expenditure	**1,366.3**	**843.3**	**1,334.7**

Notes: The initial regulatory proposal categorisation has been restated to align with the revised regulatory proposal mapping. The draft decision categorisation has been restated to allocate the modelling adjustments to their respective categories. The total capital expenditures for the initial regulatory proposal and draft decision have not changed.

[31] These projects are now categorised under network augmentation and ICT.

Table 5.3: Forecast gross capital expenditure ($2026, million)

Capital expenditure	Initial regulatory proposal (Re-categorised)	AER draft decision	Revised regulatory proposal
Replacement	408.9	247.3	419.3
Augmentation	269.5	150.1	235.2
Connections	1,102.6	562.5	1,067.6
ICT	153.5	103.7	133.1
Property	17.4	17.0	17.4
Fleet	33.6	33.5	47.9
CER integration	0.0	0.0	n/a
Resilience	19.8	1.3	19.8
Non-network – Other	1.4	1.4	1.4
Capitalised overheads	222.2	159.5	244.8
Gross capital expenditure	**2,228.8**	**1,276.3**	**2,186.5**
Less capital contributions	859.7	430.2	849.1
Less asset disposals	2.8	2.8	2.8
Net capital expenditure	**1,366.3**	**843.3**	**1,334.7**

Notes: The initial regulatory proposal categorisation has been restated to align with the revised regulatory proposal mapping. The draft decision categorisation has been restated to allocate the modelling adjustments to their respective categories. The total capital expenditures for the initial regulatory proposal and draft decision have not changed.

5.4 Supporting attachments

The revised capital expenditure forecast outlined in this section is supported by a body of materials, forecasts and models as outlined in *JEN – RP – Att 05-01 Capital expenditure.*

6. Our operating expenditure

Highlights

- With significant efficiencies realised through our 2019 operational transformation program, we expect to underspend our current regulatory period allowance. Our customers will benefit from these efficiencies through lower forecast operating expenditure in the long term.
- We operate efficiently and benchmark well amongst our peers. Our 2024-25 base year operating expenditure is below the efficient level estimated using the AER's benchmarking approach.
- We largely accept the AER's draft decision on our operating expenditure, other than its proposed treatment of insurance premium underspends in the current regulatory period and its decision on our ICT step changes.
- Our revised forecast operating expenditure for the next regulatory period is $640.9 million, which is -0.4% lower than our allowance for the current regulatory period in real terms, and $76M higher, or 13.5%, than the AER's draft decision. This difference is mainly due to a higher trend escalation, reflecting updated demand forecasts and expected growth in data centre load over the next regulatory period and higher ICT step changes of $34.1 million.
- Our revised ICT step changes reflect the inclusion of our project implementation costs, and costs for new energy reform obligations, which were uncertain at the time of our initial regulatory proposal.

6.1 Overview

Our revised regulatory proposal operating expenditure forecast for our SCS over the next regulatory period, compared with our initial regulatory proposal and the AER's draft decision, is shown in Table 6.1. The forecast operating expenditure model is provided in *JEN - RP - Att 06-03M SCS opex model – 20251201*.

Table 6.1: Forecast SCS operating expenditure for 2026–31 period ($2026, million)

Description - operating expenditure ($M)	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
Establish efficient base year	479	475	486
Base year adjustments	23	44	28
Estimate trend	60	52	75
Develop category specific forecasts	12	8	10
Forecast step changes	41	-14	42
Total SCS operating expenditure	**615**	**565**	**641**

6 OUR OPERATING EXPENDITURE

The AER's draft decision of $564.7 million over the next regulatory period is 8.2% ($50.4 million) lower than our initial regulatory proposal of $615.2 million. Our revised regulatory proposal is $640.9 million, 13.5% higher than the AER's draft decision and 4.2% above our initial regulatory proposal. The increase in the AER's draft decision allowance is primarily driven by:

- a higher trend, reflecting updated demand forecasts and expected growth in data centre load over the next regulatory period
- higher ICT operating expenditure step change of $34.1M compared with the AER's draft decision of $8.1 million.

In developing our revised regulatory proposal, we have made the following updates:

- Replaced the estimated 2024-25 base year operating expenditure with audited actuals, which are $3 million higher than the initial regulatory proposal estimates.
- Removed the AER's adjustment for bushfire insurance underspend, including both the non-recurrent efficiency gain in the base year and the associated negative step change. This is because our underspend reflects genuine and ongoing efficiency improvements and is therefore recurrent in nature. We also consider that the adjustment is inconsistent with the NEL and NER. Refer to section 6.3.4 for more details.
- Updated the ICT step change to include project implementation costs and reflect revised cost estimates. Refer to section 6.3.3 for more details.
- Updated our demand forecast to align with the latest AEMO projections and increased data centre activity. Refer to section 3.2 for more details.
- Adjusted our forecast for the inclusion of new cost passthrough applications, which increases our operating expenditure by $6 million over the next regulatory period. Refer to Table 6.2, ICT services for more details.

6.2 Draft decision

Our revised regulatory proposal addresses the key issues raised by the AER in its draft decision and demonstrates that our operating expenditure forecast represents the best forecast in the circumstances. Table 6.2 summarises the key elements of our response to the AER's draft decision on our operating expenditure. More detailed responses are contained within *JEN - RP - Att 06-01 Operating expenditure – 20251201* and *JEN - RP - Att 05-01A Technology expenditure addendum - 20251201*.

Table 6.2: JEN: response to the AER's draft decision on operating expenditure

Initial regulatory proposal	AER draft decision[32]	JEN response – revised regulatory proposal
Base year		
Selection of base year	The AER concluded that our 2024-25 base year operating expenditure is not materially inefficient. Given this, the AER relied on our revealed costs and used our estimated 2024–25 operating expenditure as the basis of its alternative estimate of total operating expenditure. The AER modified our forecast base year operating expenditure from $478.9M to $475.2M over the next regulatory period based on different inflation numbers to convert nominal amounts in real terms for the 2024-25 base year estimate.	We have submitted our audited 2024-25 total operating expenditure excluding category specific forecasts of $97.3M for the AER's consideration, which is $1.5M higher than our estimated operating expenditure submitted in our initial regulatory proposal. Our 2024-25 base year operating expenditure is below the efficient level estimated using the AER's benchmarking approach. See section 2.1 of *JEN - RP - Att 06-01 Operating expenditure – 20251201* for more details.

32 AER, Attachment 3 – Operating expenditure \| Draft decision – Jemena distribution determination 2026-31, September 2025.

Initial regulatory proposal	AER draft decision[32]	JEN response – revised regulatory proposal
Base year adjustments		
Software as a Service (SaaS)	Accepted our adjustment of $8.9M for SaaS costs in the base year.	We accept the AER's draft decision on the treatment of SaaS costs and have updated our adjustment to $9.1M based on our audited 2024-25 results.
Incremental ICT project implementation costs	Rejected our proposed $4M adjustment ($0.8M per year) over the next regulatory period on the basis that incremental ICT base adjustment was not prudent, and it risks double counting costs already provided through the base-trend-step operating expenditure forecasting approach.	We do not agree with the AER's draft decision on our incremental ICT project implementation costs. However, consistent with the AER's preferred approach, in our revised regulatory proposal, we have treated our ICT project implementation costs as part of our total ICT step change (see below and section 6.3.3 for more detail).
ESC licence fee	Made a $2.2M negative adjustment for ESC licence fees on the basis that the costs will be recovered as a jurisdictional scheme from 2025–26.	We agree with the removal of the ESC licence fee from our operating expenditure and its recovery as a jurisdictional scheme. However, license fees are not included in our 2024-25 base year actual operating expenditure. Therefore, no adjustment to our base year is required.
Non-recurrent efficiency gain	The AER stated that an adjustment was required for our insurance premium underspends to ensure that our total forecast operating expenditure is prudent and efficient, and to treat the significant insurance premium underspends in the current regulatory period as non-recurrent efficiency gains.	We do not agree with the AER's proposed treatment of the bushfire insurance premium underspends and have not adjusted both the non-recurrent efficiency gain in the base year and the associated negative step change. This is because our underspend reflects a genuine and ongoing efficiency improvement, and therefore, is recurrent in nature. We also consider that the adjustment is inconsistent with the NEL and NER. See section 6.3.4 for more details.
2024-25 to 2025-26 final year increment	Modified our adjustment from $13.0M to $12.9M.	We have updated our adjustment to $19.2M to reflect our actual audited 2024-25 results.
Forecast trend		
Output growth	Adopted the AER's output growth forecast, resulting in modifying our proposed output growth from $58.8M to $50.4M.	We have updated our output growth inputs to reflect the latest available information, including our best estimate of growth in data centre load over the period. This results in revised output growth of $73.8M.
Price growth	Adopted the latest data for the Wage Price Index (WPI) and inflation, resulting in modifying our proposed price growth from $8.8M to $9.6M.	We have updated our price growth inputs for the latest available information, which results in an average annual price growth of 0.6%, increasing our total operating expenditure forecast by $9.1M over the next regulatory period.
Productivity growth	Adopted our proposed productivity growth rate of 0.5%, which decreased the AER's alternative operating expenditure estimate by $7.9M over the next regulatory period.	We accept the AER's draft decision and have applied the annual 0.5% productivity rate to our revised operating expenditure forecasts, resulting in a $7.8M adjustment over the next regulatory period.

Initial regulatory proposal	AER draft decision[32]	JEN response – revised regulatory proposal
Step changes		
ICT services	We proposed a total of $21.6M for ICT services step changes over the next regulatory period. The AER rejected $13.6M of our proposed ICT service step changes on the basis that the costs were: - double-counted in the base / trend approach - covered by efficiencies, and/or - subject to further information. The AER consequently approved an alternative estimate of $8.1M over the next regulatory period. As mentioned above, the AER rejected our proposed $4M adjustment for project implementation costs over the next regulatory period on the basis that incremental ICT base adjustment was not prudent, and it risks double-counting costs already provided through the base-trend-step operating expenditure forecasting approach.	We do not accept the AER's draft decision on our ICT step changes and project implementation costs. Our revised ICT services step changes are $34.1M over the next regulatory period for our project implementation costs and incremental ongoing operating expenditure. We have updated our project implementation costs and have accepted some of the AER's draft decision on parts of our ICT step changes. We have also updated our estimates to comply with new energy reform obligations for Flexible Trading Arrangement reforms (FTA), Market Interface Technology Enhancements (MITE) initiatives and the Victorian Emergency Backstop Mechanism No.2 (VEBM2), consistent with our cost pass through applications for these reforms. The step changes associated with the reforms make up $13.5M of the difference between our revised regulatory proposal forecast and the AER's draft decision. See section 6.3.3 for more details.
CER integration – grid stability; voltage and Power quality management; and data visibility and analytics	The AER rejected the expenditure on the basis that it was not satisfied that these costs represent prudent and efficient expenditure, that the costs are already in JEN's operating expenditure, and that they are covered by trend component.	We withdraw our proposed step change.
New REFCL obligations	The AER accepted as a placeholder our proposed $4.9M step change over the next regulatory period, subject to review of the actual costs incurred by JEN in preparation for the 2025–26 bushfire season.	We accept the AER's draft decision and provide details of our actual costs incurred and revised forecast over the next regulatory period in preparation for the 2025–26 bushfire season.
Outage preparation and response	The AER rejected our proposed $4.9M step change over the next regulatory period on the basis that it is business as usual activity and covered by the output factor.	We withdraw our proposed step change.
LBRA hazard trees management program	The AER rejected our proposed $2.6M step change over the next regulatory period on the basis that we did not provide sufficient information to demonstrate prudency and efficiency, and that it is business as usual activity and covered by the output factor.	We provide additional information to demonstrate the prudency and efficiency of our Resilience – LBRA hazard trees management program. We have included $2.6M over the next period.
Deploying mobile vehicle response	The AER rejected our proposed $0.4M step change over the next regulatory period on the basis that it is business as usual activity and covered by the output factor.	We accept the AER's draft decision.

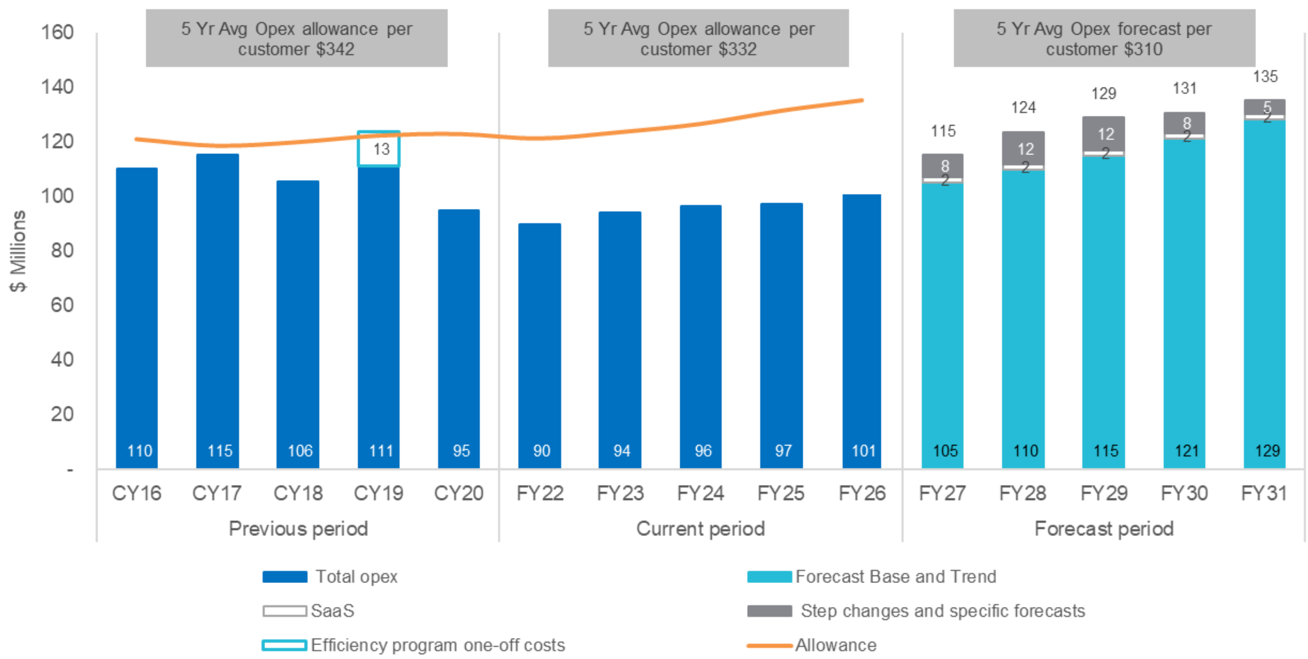
Initial regulatory proposal	AER draft decision[32]	JEN response – revised regulatory proposal
Customer education	The AER rejected our proposed $4.3M step change over the next regulatory period on the basis that we have not demonstrated that the step up in expenditure is justified against the AER's step change criteria.	Whilst our customers supported the expenditure through engagement, we withdraw our proposed step change. The AER's draft decision on our Tariff Structure Statement noted the importance of customer education programs in supporting tariff reform and encouraging demand response, thereby contributing to lower prices over time. However, by rejecting our proposed step change, the AER has constrained our ability to deliver these programs.
Insurance adjustment	The AER has included a negative step change adjustment of $27.2M over the next regulatory period for insurance adjustment. The AER stated that the adjustment is required to ensure that our total forecast operating expenditure is prudent and efficient and to treat the significant insurance premium underspends in the current regulatory period as non-recurrent efficiency gains.	As noted above, we do not agree with the AER's proposed treatment of insurance premium underspends and have not adjusted both the non-recurrent efficiency gain in the base year and the associated negative step change. See section 6.3.4 for more details.
Category specific forecasts		
GSL	Modified our forecast GSL costs from $1.3M to $1M over the next regulatory period to account for the double-counting of costs in our forecast.	We modified our proposed GSL to correct the historical data to remove double-counting identified by the AER in its draft decision. We have also updated the forecast to include the actual 2024-25 costs in the averaging calculation, resulting in $1.2M of GSL costs over the next regulatory period.
Innovation fund	The AER is not satisfied that we have provided sufficient information in support of the proposed costs and innovation fund projects. Therefore, the AER modified our forecast from $4.2M to $1M over the over the next regulatory period	We do not accept the AER's draft decision and have modified our proposed funding for the innovation fund to $2M over the next regulatory period to reflect the three projects approved by the AER in its draft decision, and the addition of one new project.
Debt raising costs	Modified our forecast debt raising costs from $6.7M to $5.9M over the over the next regulatory period.	We have updated our forecast debt raising costs to reflect revised regulatory proposal forecasts, resulting in debt raising costs of $6.7M.

6.3 JEN's revised operating expenditure

In its draft decision, the AER approved $564.7 million in SCS operating expenditure for the next regulatory period, which is 8.2% ($50.4 million) lower than our initial regulatory proposal of $615.2 million. Our revised regulatory proposal is $640.9 million, 13.5% higher than the draft decision and 4.2% above our initial regulatory proposal. The increase in our revised regulatory proposal compared with the AER's draft decision is primarily driven by an increase in trend of $23 million, reflecting updated demand forecasts and expected growth in data centre load over the period, and increased ICT step changes of $26M (see section 6.3.3).

Figure 6.1 shows our total SCS operating expenditure over the previous regulatory period and the current regulatory period, along with the total operating expenditure allowance for the previous and current regulatory periods. Through deliberate action, we managed to reduce our expenditure below our allowance for the current regulatory period. Our proposed allowance for the next regulatory period builds on this success and delivers lower prices to our customers.

Figure 6.1: Historical and forecast operating expenditure, Real $2026, millions



Note: HY21 (Jan to Jun 2021) is not included for visualisation purposes. It does not impact the operating expenditure forecast.

We undertook a thorough assessment to determine that our revised regulatory proposal forecast operating expenditure represents the amount required to meet our obligations and customers' expectations efficiently and to promote the long-term interests of our customers.

6.3.1 Selection of base year - benchmarking

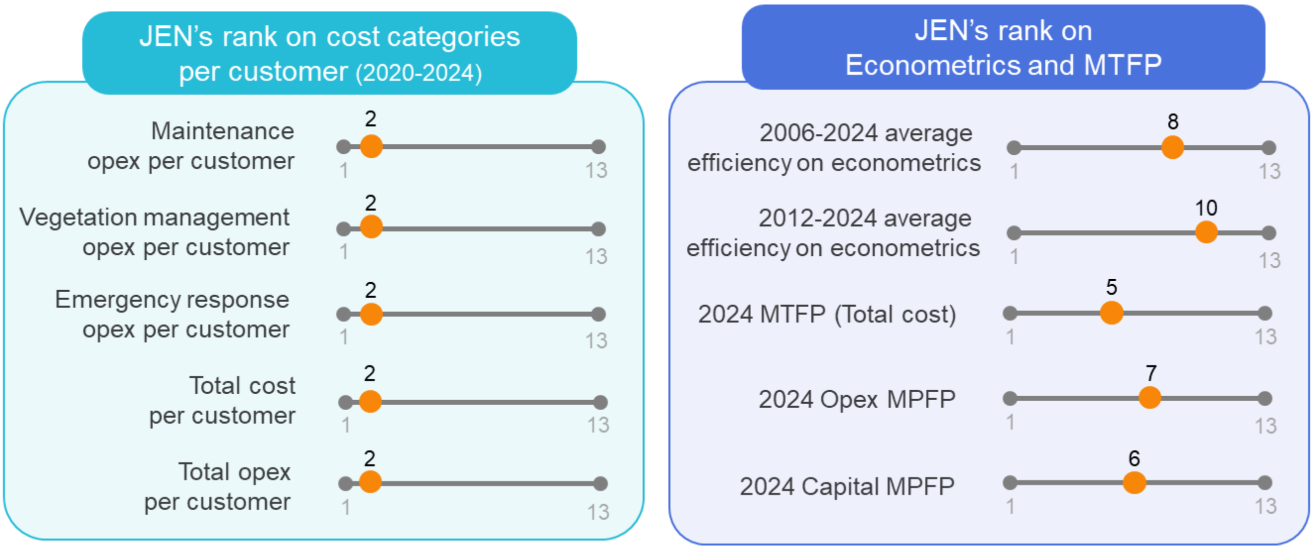
The AER's draft decision accepted the efficiency of JEN's proposed base year, using an estimated 2024–25 operating expenditure of $95.8 million.[33] Since then, three key updates have occurred:

- Our audited actual operating expenditure for 2024–25 is approximately $3 million higher than our estimate in our initial regulatory proposal.
- Draft 2025 benchmarking results have become available.
- Output weights used in the multilateral total factor productivity (**MTFP**) approach have been updated to reflect more recent data and revised treatment of capitalised corporate overheads, which impacts the relative performance between DNSPs.

After accounting for these updates, JEN continues to perform well across all benchmarking measures based on the latest benchmarking analysis as shown in Figure 6.2 which summarises JEN's positions across various benchmarking methods based on the latest 2025 draft benchmarking results.

33 AER draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031, Attachment 3 – operating expenditure, September 2025, p8.

Figure 6.2: JEN's benchmark position against our peers



Source: Quantonomics Economic Benchmarking Results for the AER's 2025 DNSP Annual Benchmarking Report (draft) – August 2025

6.3.2 Step changes

We accept the AER's draft decision on our proposed customer communications and education, CER Integration Strategy Initiatives, and Network resilience initiatives step changes. We also accept the AER's placeholder decision on the new REFCL obligations. We do not accept the AER's draft decision on our ICT services, the safety initiatives for LBRA hazard trees management program and the negative step change for the insurance adjustment.

Table 6.3 sets out our revised regulatory proposal, operating expenditure step changes compared with our initial regulatory proposal and the AER's draft decision.

Table 6.3: Forecast SCS operating expenditure step changes for 2026–31 period ($2026, million)

Description	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
Customer communications and education	4.3	-	-
ICT services	21.6	8.1	34.1
CER Integration Strategy Initiatives	3.0	-	-
New REFCL	4.9	4.9	4.9
Network resilience initiatives	4.9	-	-
Safety initiatives - LBRA hazard trees management program	2.6	-	2.6
Negative step change for insurance adjustment	-	-27.2	-
Total	**41.4**	**-14.3**	**41.6**

6.3.3 ICT step changes

In its draft decision, the AER rejected several of our proposed ICT operating expenditure step changes on the basis that the step changes 'double counts costs provided through the trend component of our base-step-trend forecasting approach.' We do not agree with this approach to setting these regulatory allowances. We consider that the intent of the trend allowance is driven by increased demand and general network growth more broadly and enabling us to maintain our services. Given the scale of the expected ongoing structural changes in the ICT

6 OUR OPERATING EXPENDITURE

industry (discussed below) over the next regulatory period, we consider the associated step changes to be outside the trend allowance.

Also, in response to the AER's draft decision:

- Consistent with the draft decision and further feedback from the AER, we have now included our ICT project implementation costs with our incremental ICT ongoing operating expenses as ICT step changes.
- Compared with the AER's decision for the current regulatory period, a change in accounting treatment, coupled with ICT vendors increasingly moving towards recurring subscription services that are cloud-based, means that a significant portion of our ICT costs previously recorded as capital expenditure is now recorded as operating expenditure. The operating expenditure relates to project implementation costs and incremental ongoing operating expenditure. We expect industry structure changes to continue into the next regulatory period, leading to further ICT step changes. In addition, our total ICT spend within the business is increasing as a proportion of total expenditure, as we rely more on technical support to deliver our services. Therefore, we consider that several ICT step changes rejected by the AER in its draft decision are best regarded as a capital-to-operating expenditure trade-off. This also means that our base-year costs do not cover our proposed ICT step changes; they reflect step changes associated with implementing new systems and ongoing costs for new subscription services.
- In the context of the ICT industry structural change, we consider that the AER's top-down assessment approach of our ICT step changes may not be appropriate for new cloud-based technology solutions in an environment where significant change is occurring, and that alternative assessment efficiency techniques may be more suitable (such as a bottom-up forecast of ICT step changes).
- We believe that in deciding on our proposed ICT step changes, the AER needs to consider the financial impact of our step changes individually and in aggregate and should be consistent in the treatment of materiality of the step changes with its recent decisions.
- We have updated two of our reform projects, Market Interface Technology Enhancements (MITE) initiatives and the Flexible Trading Arrangements (FTA), based on new information and included forecast expenditure for a new regulatory obligation for the Victorian Government's Emergency Backstop Mechanism no. 2 (VEBM2). We also consider that the AER's reliance on benchmarking for MITE operating expenditure is inappropriate because of likely differences in ICT environments, including system maturity, automation, and adaptability.
- We have included the three enterprise initiatives that the AER did not approve for JEN, but it did in its recent decision on the Jemena Gas Networks Access Arrangement for the 2025-30 period.
- Our ICT step changes are net of the project implementation costs in our base year operating expenditure and the associated trend allowance.

Our revised ICT step changes

Our revised ICT operating expenditure step change forecast is $34.1M per annum over the next regulatory period, as shown in Table 6.4.

Table 6.4: JEN ICT operating expenditure step change for 2026–31 period ($2026, million)

	FY27	FY28	FY29	FY30	FY31	Total
Project implementation costs	7.6	10.1	9.9	4.5	1.4	33.5
Ongoing operating expenditure	2.8	4.1	4.7	6.0	6.8	24.5
Less base year project implementation costs and trend	-4.3	-4.5	-4.7	-5.0	-5.3	-23.8
Total ICT step change	**6.0**	**9.7**	**9.9**	**5.5**	**2.9**	**34.1**

We note that much of our proposed ICT step changes are driven by new regulatory obligations, and / or capital to operating expenditure trade-offs resulting from ICT vendors moving to a subscription-based service model.

6.3.4 Insurance premium underspends

In its draft decision, the AER adjusted our operating expenditure by:

- adding the underspend against our bushfire insurance step change in the base year 2024-25, classifying it as a non-recurrent efficiency gain
- subtracting the estimated underspend in the final year 2025-26 as a negative step change over the next regulatory period.
- adjusting the calculation of the EBSS carryover amounts arising from the application of the EBSS during the current regulatory period to reflect the non-recurrent efficiency gain adjustment made to base operating expenditure.

We do not agree with the characterisation of insurance underspend as a non-recurrent efficiency gain in the base year. Instead, we retain the approach to determining forecast operating expenditure in our initial regulatory proposal, using a standard base-step-trend approach, and remove the adjustment for non-recurrent efficiency gains from both operating expenditure and EBSS.

We consider the underspend reflects a genuine and ongoing efficiency improvement, and therefore a recurrent saving. We consider that the adjustment does not align with the NEO or the NER. The following independent expert advice supports this position:

1. A legal opinion provided by the Hon. John Middleton AM KC, Senior Advisor at DLA Piper and former judge of the Federal Court and President of the Australian Competition Tribunal, in which he concludes that the AER's draft decision is contrary to law, as follows:[34]

    a) The AER does not have the power to make the adjustments set out in its draft decision.

    b) The AER's draft decision, which affects a clawback of our underspend on insurance premiums in the current regulatory period, is contrary to the scheme of Chapter 6 of the NER.

    c) The AER's draft decision contravenes section 16(1) of the National Electricity Law (**NEL**). The AER is not exercising its economic regulatory function or power in a manner that will or is likely to contribute to achieving the NEO.

    d) The reasoning of, and rationale for, the AER's draft decisions are unreasonable.

2. Brendan Quach, Senior Economist at HoustonKemp, states that AER's draft decision creates perverse incentives for DNSPs and undermines the objectives and intent of the NEL/NER economic regulatory regime:[35]

    a) the approach taken in the draft decision undermines the objectives and intent of the total operating expenditure regime, the EBSS and the NEL/NER economic regulatory regime; and

    b) aside from the merits and legality of the AER's approach, the revenue outcomes that occur under the AER's draft decision are not consistent with its stated intention in the draft decision.

We agree with the expert reports, and consequently, we have removed the draft decision non-recurrent efficiency gain and the associated negative step change from our revised operating expenditure proposal. Our response to the AER's draft decision is discussed in further detail in *JEN – RP - Att 06-05 Insurance operating expenditure.*

6.4 Supporting attachments

The revised operating expenditure forecast outlined in this section is supported by a body of materials, forecasts and models as outlined in *JEN - RP - Att 06-01 Operating expenditure - 20251201*.

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[34] *JEN - DLA Piper - RP - Att 06-06 John Middleton Legal Opinion for Victorian DNSP Insurance Opex – 20251128.*

[35] *JEN – HoustonKemp - RP - Att 06-07 Victorian DNSP insurance premiums – 20251128.*

7. Incentive schemes

Highlights

- Efficiently designed financial incentives for distribution network service providers are in the long-term interests of our customers. They encourage us to be innovative and to find ways to spend within our regulatory allowances, leading to lower prices for customers in the long term.
- We do not agree with the AER's EBSS adjustment to treat our current period insurance underspend as a non-recurrent efficiency gain. It incorrectly characterised our efforts to manage costs within a total allowance as a windfall gain from external factors. We propose to remove this adjustment in our revised regulatory proposal.
- We have updated the EBSS and CESS revenue to reflect actual costs in 2024-25 and updated capital contributions for 2021-22 to 2023-24. This results in -$34.5 million in CESS and $13.2 million in EBSS.
- We accept the AER's draft decision for the application of EBSS and an updated CESS for the next period.
- We do not accept the AER's draft decision on the STPIS & CSIS for the coming regulatory control period.

The AER applies a range of incentive schemes to electricity DNSPs. These schemes incentivise us to operate efficiently, reduce costs, innovate and improve service outcomes for our customers. The incentive schemes are set in a way to balance the tensions between service levels and reduce expenditure.

We propose the following incentive schemes to be applied in the next regulatory period:

1. **The capital expenditure sharing scheme** (CESS) incentivises us to be more efficient by rewarding us when we underspend capital expenditure allowances and penalising us when we overspend. The rewards or penalties are shared with our customers:
   a) For underspending, 30% benefit up to 10% underspent of capital expenditure allowance, and then 20% benefit thereafter
   b) For overspending, distribution network service providers will incur a 30% penalty.

   Our consumers benefit from improved efficiencies through a lower regulatory asset base, which is reflected in lower network prices in subsequent regulatory periods. In addition to applying the CESS scheme, we propose adjusting net connection capital expenditure from its calculation—in both the next regulatory period—to account for non-controllable expenditure.
2. **The efficiency benefit sharing scheme** (EBSS) incentivises us to deliver ongoing improvements to operating expenditure efficiencies relative to the regulatory allowance in each regulatory period. Any savings we make are shared with our customers; the sharing ratio varies depending on a range of technical factors. However, it is approximately 70% (customers), 30% (JEN) and are broadly in line with the rewards and penalties under the CESS. Our customers benefit from improved efficiencies through lower operating expenditure in subsequent regulatory periods.
3. **The customer service incentive scheme** (CSIS) incentivises us to provide holistic customer service at a level consistent with their customers' preferences.

4. **The service target performance incentive scheme** (STPIS) incentivises us to maintain and improve network reliability performance to the extent that our customers are willing to pay for such improvements. It seeks to ensure that our service levels do not deteriorate because of incentive rewards to pursue efficiency gains under the CESS and EBSS.
5. **The demand management incentive scheme** (DMIS) provides a financial incentive to undertake efficient expenditure on non-network solutions to manage peak electricity demand. Reduced peak demand may defer investments in network solutions, leading to lower electricity bills for consumers.
6. **The demand management innovation allowance mechanism** (DMIAM) complements the DMIS by providing an annual allowance for research and development in demand management projects that may reduce long-term network costs.

7.1 CESS

In our initial regulatory proposal, we estimated a CESS revenue of $3 million, based on actual forecast capital expenditure data to 2023–24 and forecast data for 2024–25 and 2025–26. This estimate also assumed that our re-opener application[36] for unforeseen large customer connections was approved.

The AER's draft decision instead calculated a CESS penalty of $26 million. This reflects the withdrawal of our reopener application, along with updated inflation and weighted average cost of capital (WACC) assumptions.

In this revised regulatory proposal, we have updated the CESS calculation to reflect updated capital expenditure for 2024–25 and 2025–26, capital contributions on an as-incurred basis for 2021–22 to 2023–24 and the inclusion of four new cost pass-through applications we recently submitted to the AER.[37]

Table 7.1 below provides a comparison of CESS outcomes across the initial regulatory proposal, draft decision, and revised regulatory proposal.

Table 7.1: CESS revenue between the initial regulatory proposal and the draft decision and revised regulatory proposal ($2026, millions)

Description	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
CESS revenue	3.1	-25.5	-34.5

For the next regulatory period, the AER has accepted the continuation of CESS and noted that the updated CESS guideline,[38] published in August 2025, will apply to JEN. The revised guideline introduces two key changes:

- Volumetric adjustments for business-as-usual (**BAU**) connections
- Ex-post exclusions for large bespoke connection projects

7.2 EBSS

In our initial regulatory proposal, we estimated an EBSS carryover amount of $21 million, based on actual operating expenditure data to 2023–24 and forecast data for 2024–25. The AER's draft decision calculated an EBSS carryover amount of -$4 million, primarily due to its adjustment for a non-recurrent efficiency gain in relation to JEN's bushfire insurance step change in the current regulatory period. The AER stated this adjustment was necessary to meet the operating expenditure criteria, noting that without it, the EBSS would treat the underspend as a recurrent saving and provide JEN with a windfall gain unrelated to efficiency improvements. We do not agree with the AER's draft decision.

36 In October 2024, JEN submitted an application to the AER to reopen its 2021-26 price rest determination to account for unforeseen expenditures. This application was subsequently withdrawn.

37 JEN – RP – Support – FTA pass through application – 20251104, JEN – RP – Support – MITE pass through application – 20251030, JEN – RP – Support – VEBM2 pass through application – 20251105, JEN – RP – Support – ASMR pass through application – 20251113

38 AER, Capital Expenditure Incentives Guideline v4 – August 2025

In this revised regulatory proposal, we have updated the EBSS to reflect actual audited costs for 2024–25, removal of the non-recurrent efficiency gain adjustment and inclusion of new cost pass-through applications we recently submitted to the AER.[39]

Table 7.2 below provides a comparison of EBSS outcomes across the initial regulatory proposal, draft decision, and revised regulatory proposal.

Table 7.2: EBSS revenue between initial regulatory proposal, draft decision and revised regulatory proposal ($2026, millions)

Description	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
EBSS carryover amount	21.0	-4.4	13.2

For the next regulatory period, JEN accepts the AER's draft decision and the proposed application of Version 2 EBSS.

7.3 CSIS & STPIS

Following engagement with our customers and stakeholders, JEN proposed removing the telephone answering component of the STPIS and instead introducing a CSIS for the coming regulatory control period. In its draft decision the AER did not accept this proposal and instead suggested JEN should retain the telephone answering component of the STPIS and introduce the 'new connections' component.

JEN does not accept this decision due to:

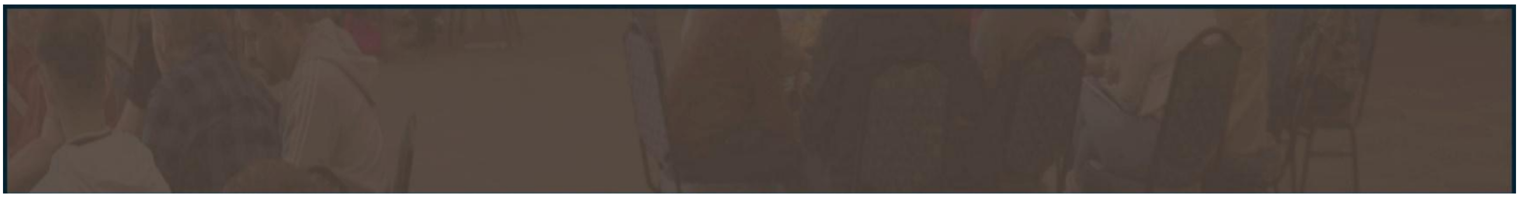
- Feedback from our ERG (following the AER's release of the draft decision) in support of the proposed CSIS
- The limited application of the 'new connections' aspect of the STPIS. As the scheme does not include alternative control services (ACS) customer connections, it would not apply to the majority of residential and small business customers.

Given the above, JEN's revised regulatory proposal includes the CSIS and STPIS reliability metrics which we had initially proposed as we believe this is the long-term interest of all our customers.

7.4 Supporting attachments

The revised incentive scheme revenue forecast outlined in this section is supported by a body of materials, forecasts and models as outlined in *JEN - RP - Att 07-01 Incentive mechanisms – 20251201.*

39 JEN – RP – Support – FTA pass through application – 20251104, JEN – RP – Support – MITE pass through application – 20251030, JEN – RP – Support – VEBM2 pass through application – 20251105, JEN – RP – Support – ASMD pass through application – 20251113



8. Our revenue requirement and what it means for our customers

Highlights

- The AER's draft decision on our SCS building block revenue is $1,602 million ($Real 2026). This is a reduction of $244 million from our initial regulatory proposal and is largely driven by reductions to our proposed capital expenditure and operating expenditure forecast and incentive scheme revenue.
- In our revised regulatory proposal, we forecast a total building block revenue requirement for our standard control services of $1,868 million ($Real 2026) over the next regulatory period, a 19.6% increase from the current regulatory period. This reflects a higher capital and operating expenditure forecast compared to the AER's draft decision.
- Despite the increase in our forecast revenue requirements, prices are forecast to decrease due to an increase in forecast energy demand for the next regulatory period.
- The distribution charges in a typical residential customers' annual electricity bill are forecast to be $94 lower by the end of the next period compared to an annual bill in 2025-26 (in real terms).
- Our forecast revenue requirements reflect our customers' expectations on affordability, network reliability, digitisation and automation, sustainable future, accessible communication and fairness.

8.1 Our revenue requirement and price impacts

Table 8.1 details the revised regulatory proposal, unsmoothed and smoothed revenue for the next regulatory period.

Table 8.1: Total revenue requirement revised regulatory proposal, Real $2026, millions

	FY27	FY28	FY29	FY30	FY31	Total
Return on capital	128.3	143.4	157.4	167.0	176.1	772.3
Regulatory depreciation	63.4	67.4	70.2	73.7	75.2	349.9
Operating expenditure	116.4	124.9	130.4	132.2	136.9	640.9
Revenue adjustments	-3.7	-4.4	-1.6	-2.4	-6.4	-18.6
Cost of corporate income tax	46.4	37.9	24.5	7.9	6.7	123.4
Annual revenue requirement (unsmoothed)	350.7	369.3	380.9	378.4	388.6	1,867.9
Annual expected revenue (smoothed)	**349.6**	**366.5**	**371.9**	**380.9**	**400.0**	**1,868.9**
Revenue path	n/a (or 6.1%)	4.8%	1.5%	2.5%	5.0%	n/a

Despite the increase in revenue requirement, the distribution charges in a typical residential customers' annual electricity bill are forecast to be $94 lower by the end of the next period compared to an annual bill in 2025-26 (in real terms). This is primarily due to higher electricity demand and volumes expected from data centres customers absorbing the increases in costs (and revenue requirement) to support their needs. Our revised regulatory proposal Attachment 09-01 on Pricing, details bill impacts on our customers and the new innovative tariffs that JEN is introducing to align with greater uptake and use of solar energy and batteries.

8.2 Regulated Asset Base

8.2.1 AER draft decision

The value of the assets we use in providing our services is known as our capital base, or regulated asset base (RAB). This represents the unrecovered capital expenditure we have incurred to provide services to our customers.

In its draft decision, the AER has determined an opening value of our capital base of $2.124 billion ($ nominal) as at 1 July 2026, which is forecasted to increase to $2.719 billion by 30 June 2031. This is $571.7 million lower than our initial regulatory proposal due to AER approving lower capital expenditure for the next regulatory period.

8.2.2 JEN's response to draft decision

JEN has proposed a closing RAB of $3.285 billion ($ nominal) based on –

- A higher starting RAB as at 1 July 2026 as a result of higher actual net capital expenditure for 2024-25, updated capital contributions on an 'as incurred' basis for 2021-22 to 2023-24, and revised forecast net capital expenditure for 2025-26.
- Higher net capital expenditure forecast for the next regulatory period due to higher expected data centre connections, replacement and non-network expenditure
- Higher placeholder inflation forecast of 2.66% compared to draft decision forecast of 2.55% that will be updated as part of AER's final decision once Reserve Bank of Australia's (RBA) February 2026 Monetary Policy Statement (MPS) is published. JEN's inflation forecast is based on AER's approach of using two years of forecasts from the latest available MPS and applying a glide path approach. Since the latest MPS did not have two years of June forecasts inflation JEN has used the December forecasts as placeholder estimates.
- Regulatory depreciation of $379.6 million ($ nominal) compared to $331.2 million in the draft decision

8.2.3 Revised regulatory proposal RAB forecast

Table 8.2 below provides an overview of our initial regulatory proposal RAB, the AER's draft decision, and our revised regulatory proposal forecast.[40]

Table 8.2: JEN SCS RAB between initial regulatory proposal, draft decision and revised regulatory proposal (Nominal, $millions)

	Initial regulatory proposal	AER Draft Decision	Revised regulatory proposal
Opening RAB at 1 July 2026	2,132.3	2,124.4	2,188.1
Net Capex	1,512.7	925.9	1,476.5
Inflation on opening RAB	331.4	308.1	361.5

40 We note that our actual 2024-25 costs and recast 2021-22 to 2023-24 capital contributions on 'as incurred' basis are currently undergoing audit as part of the 2024–25 Annual Regulatory Information Order (RIO) process, due for submission to the AER on 30 November 2025. As this revised regulatory proposal is due on 1 December 2025, we have used unaudited numbers as placeholders. We expect the AER will update these values to reflect audited actuals in its final determination, once the RIO audit is complete.

	Initial regulatory proposal	AER Draft Decision	Revised regulatory proposal
Straight-line depreciation	-685.6	-639.3	-741.2
Closing RAB at 30 June 2031	3,290.7	2,719.1	3,284.9

8.3 Rate of return

In its draft decision, the AER accepted our method for calculating the WACC but revised our estimate using updated market data and inflation assumptions. The AER also accepted our proposed averaging periods.

8.3.1 AER's draft decision

The AER used a placeholder risk-free rate of 4.25% to estimate the return on equity based on the latest market data. For inflation it used 2.55% as a placeholder estimate.

8.3.2 JEN's response to draft decision

JEN has retained the AER's draft decision rate of return placeholder estimates for its revised regulatory proposal, as JEN's approved averaging period has not concluded at the time of submitting the revised regulatory proposal. The rate of return will be updated in the AER's final decision using observations in our approved averaging periods.

8.3.3 Revised regulatory proposal rate of return

Table 8.1 below sets out the placeholder rate of return in our initial regulatory proposal, the AER's draft decision, and our revised regulatory proposal.

Table 8.1: Rate of return parameters between initial regulatory proposal, draft decision and revised regulatory proposal (per cent)

	Initial regulatory proposal	AER Draft Decision	Revised regulatory proposal
Return on Equity	7.67%	7.97%	7.97%
Return on Debt (5 year average)	5.05%	4.95%	4.95%
Inflation forecast	2.50%	2.55%	2.66%
Leverage	60%	60%	60%
Gamma	57%	57%	57%
Corporate tax rate	30%	30%	30%
Nominal vanilla WACC (% year average)	6.10%	6.16%	6.16%

8.4 Corporate income tax

Corporate income tax is a cost for all companies. The regulatory framework enables network companies to recover efficient tax costs from customers as this cost is necessary to ensure sufficient funds are available to meet our corporate tax obligations.

8 OUR REVENUE REQUIREMENT AND WHAT IT MEANS FOR OUR CUSTOMERS

8.4.1 AER's draft decision

In the draft decision the AER approved $71 million ($Real 2026) in corporate income tax allowance. This is $55 million lower than our initial regulatory proposal and is largely driven by AER rejecting our capital contribution forecast.

8.4.2 JEN's response to the draft decision

In JEN's revised regulatory proposal, we estimate our capital contributions at $849.1 million ($Real 2026), $418.9 million higher than the AER's draft decision. This is primarily driven by a higher connection capital expenditure forecast.

We note that we have reflected the impact of the new Connection Policy, which has been approved by the AER in its draft decision and is effective from 1 July 2026, in our revised capital contribution forecast. Under the revised Connection Policy, JEN will recover tax on capital contributions directly from connecting customers, rather than through the building block revenue allowance, for connections above 22 kV where the projects have not been included in the regulatory allowance.

Accordingly, our revised regulatory proposal includes only those data centre projects expected to reach the contract or firm offer stage by December 2025. For all other data centre connections, we have assumed the new policy will apply and have not included these projects in the building block calculation. We expect to recover tax for these projects directly from the connecting customers.

8.4.3 Revised regulatory proposal tax

Our revised regulatory proposal We have updated our corporate income tax forecast to reflect our revised building block revenue for the next regulatory period. Table 8.2 sets out the tax forecast in our revised regulatory proposal.

Table 8.2: Forecast tax building block for JEN's revised regulatory proposal ($2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Taxable income	359.6	294.1	189.9	61.1	52.0	956.8
Corporate income tax	107.9	88.2	57.0	18.3	15.6	287.0
Less: imputation credits	61.5	50.3	32.5	10.4	8.9	163.6
Tax forecast	46.4	37.9	24.5	7.9	6.7	123.4

8.5 Revenue adjustments

Revenue adjustments are made to building block costs to account for incentive schemes and other adjustments needed to give effect to rule requirements. For the next regulatory period, these primarily reflect the application of two incentive schemes— EBSS and CESS.

8.5.1 AER's draft decision

In the draft decision the AER approved a penalty of $29.9 million in EBSS and CESS outcome. This is $54.0 million lower compared to our initial regulatory proposal and is largely driven by JEN's withdrawing its reopener application that impacts CESS outcome, and AER's applying an ex-post adjustment to EBSS for insurance cost savings.

8.5.2 JEN's response to draft decision

JEN has updated its CESS forecast to reflect the withdrawal of the re-opener application and updated its estimate of 2025-26 capital expenditure based on the latest information. We have also accounted for four new cost passthrough applications that we submitted to the AER in November 2025. This results in a further reduction in CESS outcome from the draft decision of $9.0 million. However, on EBSS, we do not agree with the AER's ex-post adjustment for insurance cost savings.

8.5.3 Revised regulatory proposal revenue adjustment

Table 8.3 sets out the incentive scheme forecasts in our initial regulatory proposal, the AER's draft decision, and our revised regulatory proposal.

Table 8.3: JEN SCS Incentive scheme forecasts ($2026, millions)

	Initial regulatory proposal	AER Draft Decision	Revised regulatory proposal
EBSS	21.0	-4.4	13.2
CESS	3.1	-25.5	-34.5
Net incentive schemes	**24.1**	**-29.9**	**-21.3**

Numbers may not add due to rounding.

8.6 Price control mechanism

Price control mechanisms set limits on the prices that we, as an electricity distribution network, can recover from customers for direct control services. For standard control services, the NER require a prospective CPI–X form or similar incentive-based approach. In its draft decision, the AER sets the price control mechanism and formulae for:

- standard control services under a revenue cap.
- alternative control services – metering services under a revenue cap.
- all other alternative control services under a price cap.

We accept the AER's draft decision on price control mechanisms.

9. Our tariffs and charges

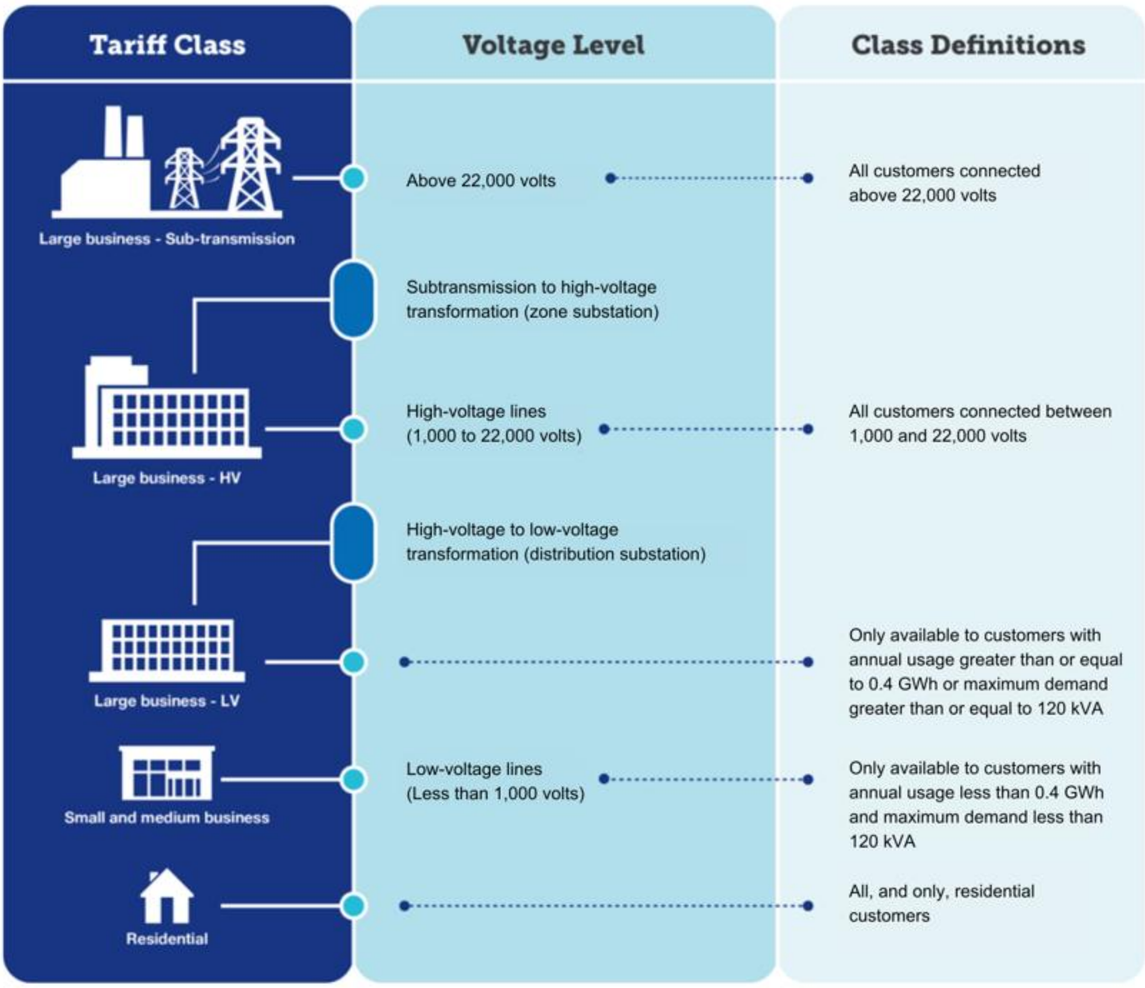
Tariffs are the fees and structures we use to pass pricing signals and to recover our costs from customers. We recover our allowed efficient costs from electricity retailers through network tariffs, and electricity retailers recover these costs through the charges they levy on customers through retail bills. To a large extent, our tariff strategy relies on retailers passing on our pricing signals in their customer charges.

9.1 Our tariff structures

We offer Standard Control Services tariffs to our customers through five tariff classes which correspond with our five major customer segments.

Figure 9.1 shows these tariff classes and their respective definitions:

Figure 9.1: Current regulatory period tariff classes



9.2 AER draft decision and JEN response

The AER's draft decision on our proposed Tariff Structure Statement (**TSS**) and our revised regulatory proposal response are summarised in Table 9.1 below.

Table 9.1: Summary of the AER's draft decision and JEN's response

Topic	AER draft decision	JEN response	Further information
Price control mechanisms	The AER's draft decision confirmed its preferred approach to continue to apply the same control mechanisms that applied to JEN in the 2021-26 regulatory period:[41] – a revenue cap for standard control services – a revenue cap for metering services (as alternative control services) – a price cap for ancillary network services, public lighting and metering exit fees (as alternative control services).	We accept the AER's draft decision on price control mechanisms.	n/a
Kerbside electric vehicle (EV) charging	The AER stated that we have a role to play in enabling and supporting the roll out of new technologies, including kerbside EV charging.[42]	We are proposing a trial tariff specifically for kerbside EV charging operators in our revised regulatory proposal given the potential for demand for such charging to grow significantly in the coming years.	Section 6.4.1 of our revised regulatory proposal TSS.
Integrate tariff strategy into broader regulatory proposal	The AER stated that we should further integrate our tariff strategy into our broader regulatory proposal.[43]	We have considered our tariff strategy when preparing our broader regulatory proposal, including when developing our capital program and demand forecasts for the next regulatory period. We want to see customers change their behaviour in response to the price signals we provide, especially where this helps to mitigate the need for further investment. However, we have not observed a discernible change in response to our efforts to date.	Refer to section 4.3 of JEN's revised regulatory proposal TSS and section 3 of *JEN - RP - Att 05-01 Capital expenditure*.

41 AER, Jemena 2026-31 electricity distribution determination – Overview, September 2025, p. 30.
42 AER, Jemena 2026-31 electricity distribution determination – Overview, September 2025, p. viii.
43 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 1.

Topic	AER draft decision	JEN response	Further information
Further stakeholder engagement	The AER stated that we should engage further with stakeholders, including retailers, to encourage the take up of cost-reflective tariffs and improve understanding of how tariff reform can complement (mitigate) our proposed expenditure.[44]	Throughout the next regulatory period, we will continue to engage with key stakeholders, including retailers, about our ongoing tariff reform approach and customer transition to more cost-reflective tariffs. Our revised TSS includes a range of tariffs and trial tariffs that will provide pricing incentives for customers with flexible loads, including EVs and batteries.	Section 3.3 of our revised regulatory proposal TSS explanatory statement.
Long-run marginal cost (**LRMC**)	The AER was not satisfied that our use of five-year demand driven capital expenditure forecasts to estimate long-run marginal costs was compliant with the pricing principles.[45]	We have updated our import and export long-run marginal cost methodology, calculations and model from a five-year horizon to a ten-year horizon to meet the AER's expectations. We have also provided further information regarding the proposed expenditure and underlying demand driving our LRMC calculations.	Sections 3.2, 3.3 and 3.4 of our revised regulatory proposal TSS and Att 09-03 Long run marginal cost model - 20251201.
Proposed basic export level (**BEL**) for export tariffs	The AER was not satisfied that we adequately justified the basic export level for our proposed export tariffs.[46]	We have provided further information in our revised regulatory proposal TSS, including information related to the intrinsic hosting capacity of our network, consistent with section 6.2 of the AER's Export Tariff Guidelines. We have proposed our BEL after considering our intrinsic hosting capacity. For our LV large business storage tariff, we have not proposed an export charge and therefore do not require a BEL.	Section 6.2 of our revised regulatory proposal TSS.
Flexible tariffs and shifting future demand growth out of peak periods and tariff communication campaign	The AER encouraged us to seek avenues to make more progressive tariffs attractive to small customers who are better able to respond to price signals. This includes consumers with more flexible loads, like electric vehicles (EVs) or home batteries, whose response to network price signals could help mitigate the need for network investment in future regulatory periods.[47]	Our revised TSS includes a range of tariffs and trial tariffs that will provide pricing incentives for customers with flexible loads, including EVs and batteries.	Section 3.3 of our revised regulatory proposal TSS explanatory statement.

44 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 1.
45 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 1.
46 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 1.
47 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 32.

9 OUR TARIFFS AND CHARGES

Topic	AER draft decision	JEN response	Further information
Further network bill impact analysis	The AER required us to provide additional network bill impact analysis for small customers moving from withdrawn tariffs to standard tariffs.[48]	We have provided this additional bill impact analysis in our revised regulatory proposal.	Sections 5.3.3 and 7.2 of our revised regulatory proposal TSS explanatory statement.
Changes to small customer demand tariffs	The AER did not approve our proposed changes to small business tariff assignment, because the tariff assignment policies were not clear.[49]	Customers on tariff A20D will be moved to our default small business tariff, A210. While small businesses (except those with dedicated EV chargers) can opt out of our single-rate tariff (A200), our small business time-of-use tariff (A210) is the default tariff for customers with smart meters. A200 is the default tariff only for customers with accumulation meters.	Section 4.3 of our revised regulatory proposal TSS and section 7.2 of our revised regulatory proposal TSS explanatory statement.
Tariff discounting	The AER required additional information on our proposal to continue discounting our residential time-of-use tariff relative to our single-rate tariff.[50]	We propose to continue our 1 per cent per year discount of our new daytime saver tariff (A130) relative to our flat-rate tariff (A100).	Section 5.3.1 of our revised regulatory proposal TSS explanatory statement.
Low-voltage large business storage tariff	The AER required additional information regarding our proposed low-voltage large business storage tariff, A30B.[51]	We include the structure, charging periods and assignment policies for our proposed Large Business storage tariff, A30B, in our revised TSS. We have also provided indicative prices for the forecast regulatory period for this tariff, as well as additional information on our connection processes for customers on this tariff. We are not proposing an export charge component and therefore do not require a BEL for this tariff.	Section 6.3.1 of our revised regulatory proposal TSS.
Site-specific tariffs	The AER required additional information regarding our proposed site-specific tariffs.[52]	We propose that site-specific tariffs will be available upon request for large customers (22kV and above) seeking new connections or undertaking a significant upgrade to an existing connection.	Section 8.2.2 of our revised regulatory proposal TSS explanatory statement.

48 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 8.
49 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 8.
50 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 15.
51 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 9.
52 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 9.

Topic	AER draft decision	JEN response	Further information
Unmetered tariffs and type 9 metering	The AER required us to give further consideration of unmetered tariffs to account for future type 9-meter loads.[53]	We have updated the name of our 'unmetered supply' tariff (A290) to 'Public lighting and street furniture' to address the AER's draft decision. From a network tariff perspective: – larger type 9 metered loads, such as public lighting and street furniture, will be assigned to network tariff A290 – kerbside EV chargers, whether metered by type 5 or type 9 meters, will be assigned to network trial tariff A20E.	Sections 4.3 and 6.3.1 of our revised regulatory proposal TSS and Attachment 11-01 - Alternative control services of our revised regulatory proposal.
Tariff assignment	The AER required us to provide more information regarding our small business customer assignment policies[54] and encouraged us to make other elements of our tariff assignment clearer.[55]	Customers on tariff A20D will be moved to our default small business tariff, A210. Tariff A270 is closed to new entrants, meaning new customers cannot be assigned to it, but existing customers can remain on it. For low-voltage and high-voltage large business customers, tariffs A34T, A37T and A40T will be closed to new entrants.	Sections 4.3 and 4.4 of our revised proposal TSS, and sections 7.2 and 8.2 of our revised regulatory proposal TSS explanatory statement.
Controlled-load tariff	The AER encouraged us to consider developing a controlled load tariff for new residential customers.[56]	We will consider introducing a controlled-load trial tariff during the next regulatory period. In years two to five of a regulatory period, we can propose in-period trial tariffs in our annual pricing proposals that are submitted to the AER in March.	Section 4.6.1 of our revised regulatory proposal TSS.
Locational tariffs	The AER encouraged us to consider in future resets or tariff trials, locational tariffs that provide solar soak periods to small businesses located in areas with minimum demand issues.[57]	We may consider locational trial tariffs over the next regulatory period where appropriate. This trial tariff approach could help to address locational minimum demand issues. In addition, our proposed site-specific tariffs for large business customers introduce some elements of these more bespoke pricing arrangements.	Section 4.6.2 of our revised regulatory proposal TSS.

53 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 9.
54 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 16.
55 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 18.
56 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 10.
57 AER, Jemena 2026-31 electricity distribution determination – Attachment 13 – Tariff structure statement, September 2025, p. 10.

9.3 Supporting attachments

Refer to the following supporting attachments for further information:

- *JEN - RP - Att 09-01 Tariff structure statement - 20251201*
- *JEN - RP - Att 09-02 Tariff structure statement explanatory statement - 20251201*
- *JEN - RP - Att 09-03 Long run marginal cost model - 20251201*
- *JEN - RP - Att 09-04 SCS indicative pricing schedule – 20251201.*

10. AMI Metering Services

10 AMI METERING SERVICES

Highlights

- For the next regulatory period, we will provide AMI services to approximately 387,000 customers.
- Our revised regulatory proposal not only means our customers will receive compliant and reliable AMI services but also means 166,354 existing customers will gain access to the benefits of the current generation of AMI meters.
- We forecast a total revenue requirement of $148 million ($Real 2026) for our AMI services in the next regulatory period. This is 6% higher than our forecast revenue requirement under our initial regulatory proposal.
- Our revised regulatory proposal means our customers will pay higher ACS AMI charges than in our initial regulatory proposal, with most customers' bills increasing by under $10 (or about $2 per year) in real terms over the five years to FY31.

10.1 Overview

The AER accepted some of the elements we put forward in our initial regulatory proposal; however, it did not accept all of them. The AER's draft decision led to a total annual revenue requirement (ARR) for JEN's metering services of $117 million ($Real 2026) for the next regulatory period, which is 16% lower than our proposed ARR under our initial regulatory proposal.

For our revised regulatory proposal, we are proposing a higher ARR of $148 million ($Real 2026). This is $9 million or 6% higher than our forecast AAR in the initial regulatory proposal. Our revised regulatory proposal means that most customers' bills will be increasing by under $10 (or about $2 per year) in real terms over the five years to FY31.

10.2 AER draft decision and JEN response

Our revised regulatory proposal accepts most aspects of the AER's draft decision. We welcome the AER's draft decision on:

- the need for proactive replacement of end-of-life meters, and that replacement is preferable to conducting physical inspections in line with our age-based inspection obligations in our metering asset management strategy (**MAMS**)
- our ability to source meters and scale up to deliver the replacement program
- our meter unit rates
- our projected volumes of new meter installations (growth), reactive replacements, and customer-initiated replacements
- our efficient operating expenditure base year costs, meter disposal step change and IT enhancements step change.

However, after further assessments of our proposal and the AER's draft decision, we are making some changes in some of the elements of our metering services proposal. We summarised in Table 10.1 the AER's draft decision on these key elements and our response. These key changes impact our forecast capital expenditure, with proactive meter replacement having the most influence.

Table 10.1: Key elements of JEN's AMI services: AER's draft decision and JEN response

Issue	AER draft decision	JEN response
Capital expenditure		
Proactive meter replacement	Increased JEN's ~20% proactive replacement, substituting higher 33% replacement forecast on the basis that it considered replacements more efficient than physical inspections	Accept the decision not to conduct physical inspections and instead, increase our proactive replacement volumes to 43%[58] to avoid needing any physical inspection obligations in the subsequent regulatory control period (that is, 2031-36).
Meter installation – labour costs	Accepted JEN's labour rate which was benchmarked using 2024-25 Hayes data and found to be: — the lowest of the Victorian distribution networks, and — lower than the maximum efficient labour rate for a field worker that the AER draft decision approved for ancillary network services	Update JEN's labour rate to the maximum efficient labour rate for a field worker that the AER draft decision approved for ancillary network services (adjusted to remove overheads).
Other meter-related capex	Accepted JEN's proposal to not forecast 2026-31 legacy meter replacement costs, with these being incurred by 30 June 2026	Accept the draft decision and reflect JEN's costs of delivering its approved legacy meter retirement plan by 30 June 2026 in the opening RAB.
Communications capex	Reduced JEN's forecast capital expenditure by 41.4%	Update JEN's forecast capital expenditure to reflect JEN's lifecycle replacement of communications assets installed initially during the 2009-13 AMI rollout that have exceeded their design life and do not comply with current data security standards.
Information technology capex	Reduced JEN's forecast capital expenditure by 53.6%	Update JEN's forecast IT capital expenditure for AER feedback and to reflect the scale of our updated AMI meter replacement program
Required revenues		
Annual revenue requirement	Applied a flat real revenue path for years 2–5 by applying 0% X factors in these years, with any real revenue movement in 2026–27	Update to a 4.4% increase in real revenue path for each year over the 5 years.

58 Calculated as 166,000 over an AMI metering base of 386,000.

10.3 JEN's revised regulatory proposal

The revised annual revenue requirement has slightly increased

Table 10.2 outlines our revised ARR and price path for the next regulatory period compared with the AAR in JEN's initial regulatory proposal and the AER draft decision.

Our revised regulatory proposal has not accepted the AER's draft decision revenue path which applied a flat real revenue path for years 2–5 by applying 0% X-factors in these years with an initial P0 adjustment. Instead, JEN has applied a smooth revenue path involving a 4.4% increase in real revenue for each year over the five years. This smooths the price impacts on our customers and better aligns our revenues with our required revenues in each year of the period. JEN notes that the effect of growth in our meter customer base means the annual price increase is less than the annual revenue increase, as discussed below.

Table 10.2: Revised proposed revenue requirement and price path, Real $2026, millions

	FY27	FY28	FY29	FY30	FY31	NPV
Initial regulatory proposal						
Unsmoothed revenue requirement	22.4	24.6	28.3	30.8	33.2	125.0
Smoothed revenue requirement	25.0	25.5	27.4	29.4	31.6	125.0
Revenue path change (% pa) (1)	**1.7%**	**1.8%**	**7.5%**	**7.4%**	**7.4%**	**N/A**
Draft decision						
Unsmoothed revenue requirement	18.7	20.7	22.7	25.5	29.4	105.0
Smoothed revenue requirement	23.2	23.2	23.2	23.2	23.2	105.0
Revenue path change (% pa) (1)	**14.0%**	**-**	**-**	**-**	**-**	**N/A**
Revised regulatory proposal						
Unsmoothed revenue requirement	20.5	25.0	29.3	33.9	39.4	132.9
Smoothed revenue requirement	26.9	28.1	29.3	30.6	32.0	132.9
Revenue path change (% pa) (1)	**4.43%**	**4.41%**	**4.40%**	**4.38%**	**4.37%**	**N/A**

Revised capital expenditure is higher, but operating expenditure is lower

We forecast a revised total capital expenditure for AMI metering services of $202 million for the next regulatory period. This is $96 million or 92% above our initial regulatory proposal and $88 million or 78% higher than the AER's draft decision. However, we forecast a lower revised operating expenditure of $65 million, which is $13 million or 16% below our initial regulatory proposal (Table 10.1). The key driver for the change in our capital and operating expenditure forecasts is the proposed proactive meter replacement volumes for the next regulatory period.

Our revised regulatory proposal reflects the AER's draft decision which rejected our proposed physical meter inspection and substituted it with replacements instead. We welcome the AER's draft decision that increasing our proactive end-of-life AMI meter replacement is preferable to our proposal of having a hybrid of age-based physical meter inspections and a smaller proactive replacement program. This pragmatic approach recognises that all first-generation AMI meters will eventually need to be replaced, and their failure rate increases over time. It also ensures more of our customers can access the enhanced benefits of the current generation of AMI meters, including 5-minute interval data capable of supporting both enhanced market participation options and Type 8 metering, and improved cyber security.

However, at the replacement volumes provided for in the draft decision, this approach creates an imprudent and likely unachievable peak in required meter inspections during the next regulatory period. To allow JEN to replace meters in a profile that avoids inefficient peaks in activities and the need for the prescribed age-based physical inspections, in line with the AER's draft decision logic, JEN proposes that a total of 166,354 meters (43%) be replaced in the next regulatory period. This profile involves an additional 36,000 meters of replacements beyond the AER's draft decision and provides for a more sustainable level of required inspections or proactive replacements in the 2031-36 regulatory period.

Our proposed profile:

- avoids the costly physical inspection peak the AER's draft decision would have caused in the 2031-36 regulatory period
- smooths the future end-of-life AMI replacement profile, and thereby efficiently helps overcome the cyclical asset management challenge created through the original mandated 4-year Victorian advanced interval meter rollout (**AIMRO**)
- supports efficient minimisation of meter installation program and labour resources.

Table 10.3: How our revised regulatory proposal expenditure forecasts compare (5 years), $2026, million

Expenditure category	Initial regulatory proposal	Draft decision	Revised regulatory proposal
Capital			
Proactive replacement	43.9	62.4	124.3
Growth	19.4	19.3	20.3
Reactive replacement	8.6	8.5	9.3
Communications	15.1	11.5	17.7
IT	7.4	5.7	23.5
Other	10.1	5.3	5.7
Equity raising costs	0.4	0.6	1.2
Total capital expenditure	**105.1**	**113.3**	**202.0**
Operating			
Base year total operating expenditure (excluding debt raising costs)	47.9	47.6	54.0
Price growth	1.2	2.1	2.3
Output growth	3.4	3.4	2.9
Productivity growth	-	-	-
Step changes	24.5	2.9	5.1
Debt raising costs	0.2	0.2	0.3
Total operating expenditure	**77.2**	**56.2**	**64.6**

10.4 Supporting attachments

For a detailed discussion of the AER's draft decision, our response and revised regulatory proposal for metering services, refer to *JEN – RP – Att 10-01 Advanced Metering Infrastructure*.

11. Other services

Highlights

- Other services include public lighting and ancillary services.
- Under our revised regulatory proposal, the price we charge for Operation, Maintenance and Replacement (OMR) for public lighting is proposed to increase by 78.6% for both legacy lights and energy efficient lights. This reflects our customers' preference:
  - that smart lighting control devices should be installed in major roads and 10% of residential customers, and
  - for JEN to fund the accelerated LED rollout in the next regulatory period.
- We have generally accepted the AER's draft decision on ancillary network services, except that we have updated our proposed labour rates.

In this chapter we give an overview of the AER's draft decision on our initial regulatory proposal for public lighting and ancillary network and our revised regulatory proposal. Ancillary network services include basic connection services and connection management services, among other services that we charge on a per-request basis.

11.1 Public lighting services

The AER did not accept JEN's public lighting proposal as submitted; however, it has accepted our proposed labour rates for public lighting. The AER considers that while some of the key drivers behind our proposal are reasonable, there are some inputs where adjustments are necessary. The AER encouraged us to engage further with JEN's public lighting customers on some specific areas of our proposal.

Our approach to public lighting is customer-driven. We further engaged with our public lighting customers through the Victorian Greenhouse Alliances (VGA) about the appropriate volume of smart lighting control devices to be installed in the next regulatory period, who will fund the accelerated LED rollout and other matters raised in the AER's draft decision.[59]

The price we charge for OMR for public lighting is proposed to increase by 78.6% for both legacy lights and energy-efficient lights. The key drivers of the price increase are the accelerated LED rollout (funded by JEN) and the deployment of 33,454 smart lighting control devices across JEN's major roads and 10% of residential customers. These drivers are consistent with our customers' feedback through the VGA.

11.2 Ancillary network services

We have generally accepted the AER's draft decision on our proposed prices for ancillary network services. Most of the changes the AER has adopted are based on the responses we have provided them during the information process.

The main change to our revised regulatory proposal is that we have updated our labour rates to reflect the most recent escalation rates and to include the base salary of Glove and Barrier (G&B) line workers in our Field Worker labour rate calculation.

Where the JEN updated calculated labour rate is greater than the AER Maximum labour rate, we have adopted the AER maximum labour rate. Where our updated calculated labour rate is lower than the AER's maximum labour rate, we have adopted our updated calculated labour rate.

Our approach means that our revised regulatory proposal rates are within or equal to the AER's maximum thresholds and therefore provide a more accurate reflection of the efficient costs associated with delivering these services, supporting the sustainable provision of high-quality outcomes for customers.

11.3 Supporting attachments

Refer to *JEN – RP – 11-01 Alternative control services* for a more detailed discussion on our revised regulatory proposal for public and ancillary services including the schedule of prices for the next regulatory period.

59 Through several meetings and emails from September 2025 to November 2025. See Table 2-1 of *JEN – RP – Att – 11-01 Alternative control services.*

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