Final Decision

AusNet Services Electricity Distribution Determination (1 July 2026 to 30 June 2031)

Overview

April 2026

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	30 April 2026	56

List of attachments

This Overview forms part of the Australian Energy Regulator’s (AER's) final decision on the distribution determination that will apply to AusNet for the 2026–31 period. It should be read with all other parts of the final decision.

A number of issues were settled at the draft decision stage or required only minor updates so that detailed attachments to this final decision are not needed. Where this is the case, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Overview

1. Building block approach: Annual revenue requirement, Regulatory asset base, Regulatory depreciation and Corporate income tax

2. Capital expenditure

3. Operating expenditure

4. Pass through events

5. Efficiency benefit sharing scheme

6. Capital expenditure sharing scheme

7. Service target performance incentive scheme

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12. Control mechanisms

13. Tariff structure statement

14. Alternative control services

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Executive Summary

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution and transmission systems in all states and territories except Western Australia.

We exist to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions.

A regulated electricity distribution network service provider (DNSP) must periodically apply to us to determine the maximum allowed revenue it can recover from consumers for using its network.

On 31 January 2025, we received regulatory proposals from 5 Victorian DNSPs for the period 1 July 2026 to 30 June 2031 (2026–31 period).

This is our final decision for AusNet Electricity Services Pty Ltd [ABN 91 064 651 118] (AusNet). It is predicated on a series of constituent decisions summarised in section 5 of this Overview.[1]

The final decision will be implemented from 1 July 2026 and reflected in 2026–27 prices.

The regulatory framework guides our decisions in the long-term interests of consumers

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we determine the revenue requirement for distribution and transmission businesses.

We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of the price, quality, safety, reliability and security of electricity supply that will benefit consumers in the long term. Our decision must also consider targets for reducing Australia's greenhouse gas emissions, as required under the National Electricity Objective (NEO).

The central component of AusNet's proposal is the revenue that it recovers from consumers over the 2026–31 period. We have assessed this by considering the constituent components of AusNet's proposal, including capital expenditure (capex), operating expenditure (opex) and the tariff structure statement (TSS), to ensure that they comply with the NER and, in turn, further the NEO.

Our final decision allows AusNet to recover $4,740.8 million ($nominal, smoothed) in revenue from its consumers in the upcoming 2026–31 period. This is $198.2 million (4.0%) less than AusNet's revised proposal, but $312.5 million (7.1%) more than our draft decision. It is $1,151.0 million (or 32.1%) higher than the revenue we approved for AusNet in the current 2021–26 period.

1 NER, cl 6.12.1.

Market factors, specifically rising inflation and interest rates, are driving higher revenues. In this final decision we estimate 50% of the increase in revenue from period to period can be attributed to these factors.

Our final decision also approves continued investment in AusNet's network to support its prudent and efficient delivery of the reliability and resilience outcomes its consumers have identified as most important.

We are focused on efficient investment to deliver a safe, reliable and resilient network that meets consumer needs

Networks have a vital role in delivering a system that serves consumers now and into the future.

In Victoria, the energy market is undergoing a complex transition. Emissions reduction targets, now reflected in the NEO, are driving changes in household and commercial energy use. An increasing number of consumers are responding to incentives to move away from gas appliances. Electrification, for example movement from gas to electric heating in the home and electrification of transport, is changing patterns in demand on the network. We continue to see high maximum electricity demand across the state. On 27 January 2026, the Australian Energy Market Operator (AEMO) reported an all-time operational demand record of 10,736 MW in Victoria.[2]

At the same time, prolonged outages following severe weather events and bushfires continue to increase focus on the reliability and resilience of the electricity networks. Regional reliability and differences in performance between, and even within, network areas are also front of mind for many communities.

Network costs are rising across the National Electricity Market (NEM), driven by a range of factors that affect reliability, security, and safety. The network is getting older, input costs are rising, and digitalisation is increasing the risk of cyber-attacks. The system is adapting to integrate Consumer Energy Resources (CER) and connect large, new loads such as data centres.

Proposals from Victorian DNSPs included significant uplifts in expenditure relative to the current period and to decisions we have made in recent years for other DNSPs. However, any new network infrastructure will be paid for by consumers. It is therefore important that businesses effectively utilise their existing infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment. New investment needs to clearly target where and how demand on the network is changing.

Network tariff reform enables DNSPs to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use consumers and can support the energy transition currently underway. Where price signals are passed through by retailers, and consumers are well placed to respond to these price signals, appropriately structured tariffs can enable growth in the value consumers derive from their CER, and in the number of consumers with CER. At the same time, this response to price signals can reduce

2 AEMO, 'Victoria's electricity demand reached a new milestone', *LinkedIn*, 28 January 2026, accessed 1 March 2026.

network constraints and minimum load issues and therefore reduce the level of network investment required, resulting in lower prices for all consumers.

Broader cost of living pressures mean that many households are facing difficult choices about whether to heat, cool, or power their homes in the ways they want and need, emphasising the importance of balancing affordability with the urgency of the transition to protect consumers from avoidable long-term costs.

Our final decision focuses on the outcomes that are important to consumers

Where DNSPs have engaged with consumers to identify the outcomes that are most important to them, our role is to carefully assess whether the revenue, expenditure and tariff structures a DNSP has submitted are necessary to deliver those outcomes prudently and efficiently so that expenditure over the period under review will serve the long term interests of consumers.

When we undertake our assessment, we must consider whether we are satisfied that the expenditure proposed by the DNSP reasonably reflects prudent and efficient costs and a realistic expectation of future network demand and cost inputs. To do this, we scrutinise the DNSP's proposed business cases and supporting information, consider advice from our expert consultants, and apply our various analytical tools, such as the replacement capex (repex) model and economic benchmarking for opex.

We consider proposed tariff structures have been integrated into forecast demand and proposed spending as retailers respond to the price signals in cost reflective tariffs and consumers may change their behaviour.

We carefully balance incentives so that our decisions drive continued efficiency without compromising performance and service quality.

With the benefit of further and better supporting information requested in our draft decision, we have arrived at a total opex forecast that is in line with AusNet's, but we have found only 76% of its revised capex forecast to be prudent and efficient. Our final decision now approves increases of $164.1 million, or 11.2% ($2025–26) in opex, and $357.0 million, or 16.0% ($2025–26) in capex relative to AusNet's expected actual expenditure in the current period.

The quality of supporting information and analysis that accompanied AusNet's initial proposal was not proportionate to the uplifts in expenditure proposed. We were not satisfied that the magnitude of increases in expenditure AusNet had proposed were in line with prudent and efficient decision making. Our draft decision underscored the need for further work by AusNet to ensure its expenditure proposals met these objectives. Our final decision to reduce AusNet's forecast capex by 24.0% is materially different from our draft decision reduction of 51.3%. This reflects AusNet accepting some of the lower forecasts in our draft decision and our acceptance in this final decision of a higher forecast for some programs because of additional supporting information.

AusNet's revised capex proposal represented an increase in forecast capex compared to our draft decision, driven by factors such as an increase in the demand forecast, as well as higher unit rates for labour and materials. The revised proposal also included $441.2 million in new projects which were not included in its initial proposal, including additional replacements, augmentations, connections and property improvements.

Our expectation is that DNSPs submit comprehensive and well-considered initial proposals at the start of the determination process. Initial proposals should not be considered drafts or works in progress.

The quality of proposals is even more critical when, as here, a revised proposal seeks to introduce material new expenditure that has not been subject to the same extensive period of assessment and consultation as initial proposals. Revised proposals are intended only as an opportunity for DNSPs to incorporate the substance of any changes required to address matters raised by our draft decision and our reasons for it. Any new or revised projects in their revised proposals must be equally well-considered and justified with supporting information.

Consumer support alone does not guarantee any one or more of the assessment criteria have been met in respect of a DNSP's total capex or opex forecast, or of any individual projects or programs that have informed those forecasts. In developing proposals to address consumers' concerns, we expect DNSPs to identify, test (including through engagement), and choose from credible options and solutions that it can satisfy us will—when included in a total capex or opex forecast—reasonably reflect the expenditure criteria.

Where we are satisfied that a DNSP has achieved this, its forecasts of capex and opex for proposed options and solutions will form part of the total expenditure we approve.

Consumers are not well served by engagement that focuses on solutions that do not reflect those criteria, or by proposals that are not supported by rigorous and robust analysis, and which do not demonstrate that proffered options are prudent and efficient.

Where we are not satisfied, we must look to alternative options and solutions in order to approve total expenditure forecasts that will address consumers' concerns and deliver their preferred outcomes in a way that *is* prudent and efficient.

This is how we ensure that consumers are paying no more than necessary for safe, secure and reliable energy supply and a resilient network that meets their needs and delivers their preferred outcomes.

We make decisions on the total capex and total opex that DNSPs can recover from consumers for the 2026–31 period. While a proposal may be informed by a series of potential projects, we are not required to consider and individually approve the potential projects that have informed a DNSP's total capex or opex forecast. Ultimately, the DNSP will decide what projects it considers prudent and efficient to proceed with in the 2026–31 period.

Resilience

Resilience is the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events.[3] Submissions have emphasised the impact of prolonged outages following extreme weather events and the importance consumers place on addressing this.[4] They have also highlighted the importance of ensuring any increase in investment is prudent and efficient.[5]

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3 AER*, Network Resilience – A note on key issues,* April 2022, p 6.

4 Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026–31*, January 2026.

5 Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026–31*, January 2026.

The total capex forecast in our final decision includes $73.6 million ($2025–26) of expenditure to improve the resilience of AusNet's network, including capex for all the resilience projects in AusNet's revised proposal:

- $61.9 million for asset hardening and vegetation management, which will strengthen the network's ability to withstand weather events
- $7.1 million for stand-alone power systems, which will reduce some customers' exposure to weather events
- $3.5 million for mobile generation, which will allow AusNet to supply power to consumers while network restoration is ongoing. This would also contribute to addressing some of the recommendations from the Victorian Network Outage Review.
- $1.1 million for emergency vehicles, which will provide communication support and safety provisions to affected customers during an outage, including rural and remote areas with limited accessibility.

We recognise the work that AusNet has done in attempting to model the increasing climate risk to its network. We understand that this is a difficult but important process, a view shared by the Victorian Government[6] and CCP32.[7] However, we consider AusNet has—through a combination of modeling errors and unsubstantiated assumptions—overestimated the improved resilience and network performance that its proposed network hardening program could deliver for consumers. When we adjust for these, it results in a reduction of $81.9 million to this component of AusNet's proposal.

Our alternative forecast ensures that resilience expenditure is being targeted to the rural areas that face the most climate risk and provide value to all AusNet consumers. The focus on rural areas is an approach supported by stakeholder groups, such as Sandy Point Community Power Inc.[8]

Integration of consumer energy resources

CER include rooftop solar, energy storage devices, electric vehicles and other consumer appliances that can respond to demand or pricing signals. For distribution networks, CER integration expenditure is primarily for the purpose of accommodating the connection of additional rooftop solar to the network and maintaining the export service for rooftop solar customers.

Our final decision recognises that distribution networks play an important role in the facilitation and management of CER connected to their networks. Actions taken by distribution networks to support CER can benefit consumers, including through lower wholesale costs, lower network costs, and lower carbon emissions. We support AusNet's intentions to undertake beneficial CER expenditure.

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6 Hon Lily D'Ambrosio MP, *Response to AER draft decisions for the Victorian Electricity Distribution Determination 2026–31*, 28 January 2026, p 1.

7 Consumer Challenge Panel 32, *CCP32 Advice to the Australian Energy Regulator on the AusNet Services electricity distribution network AER Draft Decision & Revised Revenue Proposal (2026–31)*, 19 January 2026, p 18.

8 Sandy Power Community Power Inc, *Submission: AusNet Services - Determination 2026–31*, 19 January 2026, pp 2–3.

We appreciate that this is a new and uncertain area where the quantification of costs and benefits is not straightforward. Our final decision includes $38.2 million for CER integration, informed by AusNet's proposed delivery of distribution system operator expenditure, CER enablement and supply improvement:

- $21.1 million to allow for network data visibility and a non-network market platform. This expenditure has the potential to defer network augmentation through procuring flexible services and improving net data visibility
- $8.7 million for CER enablement for dynamic voltage management activities
- $8.4 million for the supply improvement program to respond to quality of supply issues on the network.

Regional reliability improvements

Reliability refers to the continuous adequate supply of electricity under different conditions—effectively, that the electricity consumers want is available when they need it.[9]

Submissions have made it clear that consumers are unhappy with current levels of reliability in some of the worst-served areas of AusNet's network and want to see improvements.[10] However, it is critical that before DNSPs seek to recover costs from consumers, they must provide robust, quantitative cost-benefit analyses to demonstrate the prudency and efficiency of the solutions they include in forecast expenditure.

We have approved $7.2 million in new expenditure to improve regional reliability. This includes all $1.7 million of AusNet's revised worst served customer program and $5.6 million for the Benalla to Euroa reliability improvement program.

In considering the Euroa reliability improvement program, we heard from the community on the need to address the poor performance of that part of the network. We agree. However, we consider there are options that better target the root cause of reliability issues on the Benalla to Euroa line and do so at a significantly lower cost.

AusNet's proposed solution was a $38.1 million express feeder that would run between Benalla and Euroa along a similar path to the existing feeder. This construction does not provide significant route diversity, and the express feeder will remain exposed to similar risks that the current line faces. Further, this solution would only affect outages that are upstream of Euroa as it is expected to connect back into the existing network prior to the township. AusNet's own modelling demonstrated that the express feeder is not expected to reduce the number of outages by addressing the root cause of reliability issues. Rather, it will provide backup supply when there is a fault on the line between Benalla and Euroa.

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9 AER, *Network Resilience – A note on key issues,* April 2022, p 6.

10 Annabelle Cleeland MP, *Submission - AusNet electricity distribution proposal 2026–31*, January 2026; Member for Indi Dr Helen Haines MP, *Letter of Support - AusNet Revised Regulatory Proposal 2026-2031 BN11 Express Feeder Upgrade*, January 2026; Strathbogie Shire Council, *Submission - AusNet electricity distribution proposal 2026–31*, January 2026; Kristy Hourigan, *Submission - AusNet electricity distribution revised proposal 2026–31*, December 2025; RDA Hume, *Submission - AusNet electricity distribution proposal 2026–31*, January 2026; Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026–31*, January 2026; Chris Harvey, *Submission - AusNet electricity distribution proposals 2026–31*, January 2026; John Mumford, *Submission - AusNet electricity distribution proposal 2026–31*, January 2026.

AusNet presented a partial rollout of covered conductors as an alternative option to its proposed express feeder, at a total investment of $2.4 million. This would reduce the number of outages customers face and improve the customer minutes interrupted. However, given the poor performance experienced by consumers as expressed in submissions, our final decision includes a larger $5.7 million in funding for a more extensive roll out of covered conductors. An extensive rollout of covered conductors on the Benalla to Euroa line will directly address the root cause of the poor reliability that Euroa has been experiencing. This delivers the outcome that AusNet and its stakeholders have expressed support for, while ensuring that consumers pay no more than necessary for reliable supply. Our decision ensures that consumers are only asked to pay for AusNet's forecast programs where they are demonstrably in the long-term interests of consumers.

Tariff structure statement

Network tariffs allow distributors to recover their approved revenue. Most customers pay network costs through network tariffs passed on to them through their electricity retailer.

Victorian distributors' tariff structure statements reflect an evolving tariff landscape and have responded to jurisdictional preferences, stakeholder consultation, and recent rule changes, such as the *Access, pricing and incentive arrangements for distributed energy resources rule change* (August 2021) that provided for two-way pricing. For example, the tariff structure statements include:

- new time-of-use tariffs for residential customers that include low network cost recovery during the middle of the day (solar soak tariffs) to incentivise and reward electricity use when there is generally abundant solar on the grid
- withdrawal of opt-in demand tariffs for residential customers in recognition that retailers and small consumers generally find demand tariffs overly complex
- optional two-way tariffs for residential customers with CER that encourage export at times that benefit the grid
- innovative tariffs and tariff trials that send signals and rewards to large and flexible load/supply, including storage customers and kerbside electric vehicle charging.

The network tariff structures we have approved provide opportunities for consumers to benefit from using the network in ways that support efficient network outcomes and reduce network costs. They align with the Victorian Government's preference for cost reflective tariffs to remain optional. We also support AusNet's offer of tariffs to small customers that encourage them to opt-in to more cost-reflective options through their retailer.

DNSPs are incentivised to manage cost pressures without sacrificing performance

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for a 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. By only allowing efficient costs in our approved revenues, we promote achievement of the NEO and revenue and pricing principles and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

We strengthen and balance those incentives by putting targeted incentive schemes in place at the start of each period. Our final decision is that in 2026–31 an opex Efficiency Benefit

Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) will apply to encourage businesses to pursue expenditure efficiencies. At the same time, a Service Target Performance Incentive Scheme (STPIS) will provide financial incentives to maintain and improve reliability and customer service performance, so that costs are not reduced at the expense of service quality.

Feedback on our draft decisions highlighted strong support for AusNet's proposed Customer Service Incentive Scheme (CSIS), and the value of the CSIS in providing consumers with agency in identifying services that are most important to them. However, since its inception in our last determinations for Victorian DNSPs, the CSIS has been subject to significant compliance issues, including multiple suspensions and transitional arrangements since scheme implementation, as well as an observable decrease in the quality of proposals. As a result, the CSIS has attracted criticism from consumer representatives, DNSPs, and customers voicing concerns regarding redundancy, duplication of Service Target Performance Incentive Scheme (STPIS) functions, and suggestions that the scheme might be replaced by non-incentivised reporting.

To deliver the intended benefits of a CSIS, its design must be robust, its intentions clear and its performance parameters measurable. We were not satisfied that AusNet's initial proposal was fit for purpose.

AusNet's revised proposal has not addressed the concerns our draft decision raised with its proposed CSIS. Our final decision will therefore not apply a CSIS in the 2026–31 period. While not a long-term solution, our final decision delivers some incentivised customer service benefits in the absence of a CSIS by applying the customer service (telephone answering) component of the STPIS. Looking forward, the AEMC's Electricity Network Regulation Review is one opportunity for consideration of the role of incentive schemes in our distribution determinations and how the challenges encountered with the CSIS can be addressed.

Contents

1 Our final decision

Our final decision allows AusNet to recover a total revenue of $4,740.8 million ($nominal, smoothed) from its consumers from 1 July 2026 to 30 June 2031.

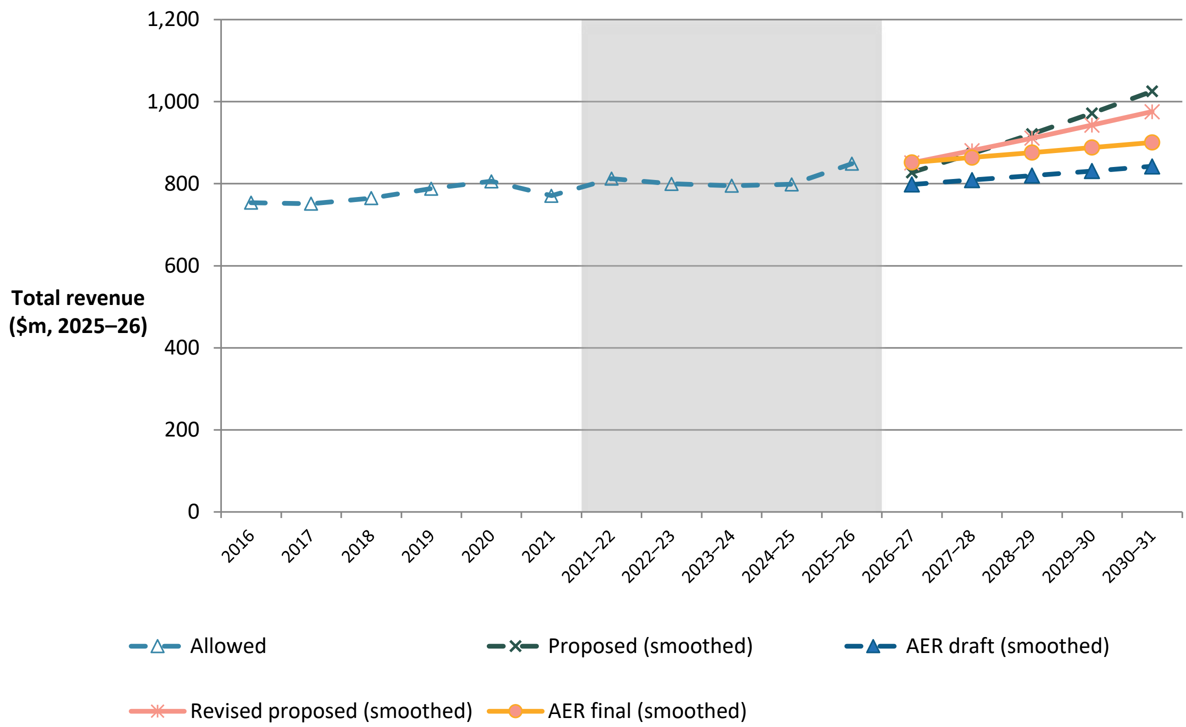
Our final decision revenue is $1,151.0 million (32.1%) more than AusNet's allowed revenue in the 2021–26 period in nominal terms. In the sections below, we briefly outline what is driving AusNet's revenue.

1.1 What is driving revenue

Revenue is driven by changes in real costs and inflation. In this section we use 'real' values that have been adjusted for the impact of inflation to compare revenue from one period to the next on a like-for-like basis.

In real terms, this final decision would allow AusNet to recover $4,380.8 million ($2025–26, smoothed) over the 2026–31 period. This is $325.6 million (8.0%) higher than the revenue we approved for AusNet in the current 2021–26 period. AusNet's revenue over time is shown in Figure 1.

Figure 1 Changes in regulated revenue over time ($ million, 2025–26)

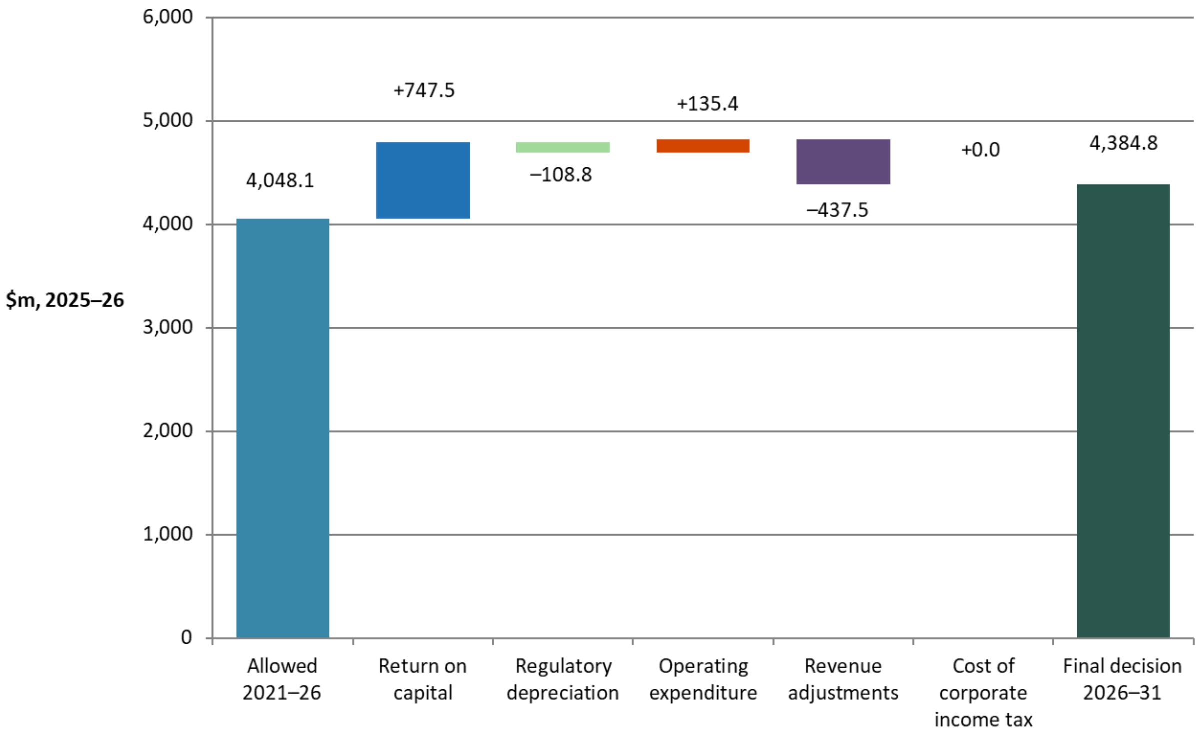


Source: AER analysis.
Note: For presentational purposes, the revenue for the half-year 2021 extension period has been doubled.

Figure 2 highlights the key drivers of the change between the revenue approved for AusNet for the 2021–26 period and in this final decision for the 2026–31 period. It shows that our final decision provides for:

- A return on capital which is $747.5 million (55.2%) higher than the 2021–26 period, driven by:
  - a higher rate of return being applied in the 2026–31 period, reflecting changes in financial market data, observed in accordance with the 2022 *Rate of Return Instrument*
  - actual regulatory asset base (RAB) growth in the current 2021–26 period due in part to higher actual inflation
  - higher forecast net capex in the 2026–31 period compared to the 2021–26 period, which is contributing to growth in AusNet's forecast RAB over the 2026–31 period.
- A return of capital (regulatory depreciation), which is $108.8 million (11.2%) lower than the 2021–26 period. This is due to higher indexation of the RAB, mainly driven by a higher expected inflation rate, which has more than offset the increase in the straight line depreciation in the 2026–31 period.
- Forecast opex which is $135.4 million (9.0%) higher than the forecast we approved for the 2021–26 period.
- Revenue adjustments under AER expenditure incentive schemes, which are $437.5 million lower than the 2021–26 period, mainly due to a change from EBSS and CESS benefits to penalties in the 2026–31 period.
- A zero-forecast cost of corporate income tax, which is the same as the 2021–26 period, as we expect AusNet to continue incurring tax losses.

Figure 2 Changes in total revenue between 2021–26 period and 2026–31 period ($million, 2025-26 unsmoothed)



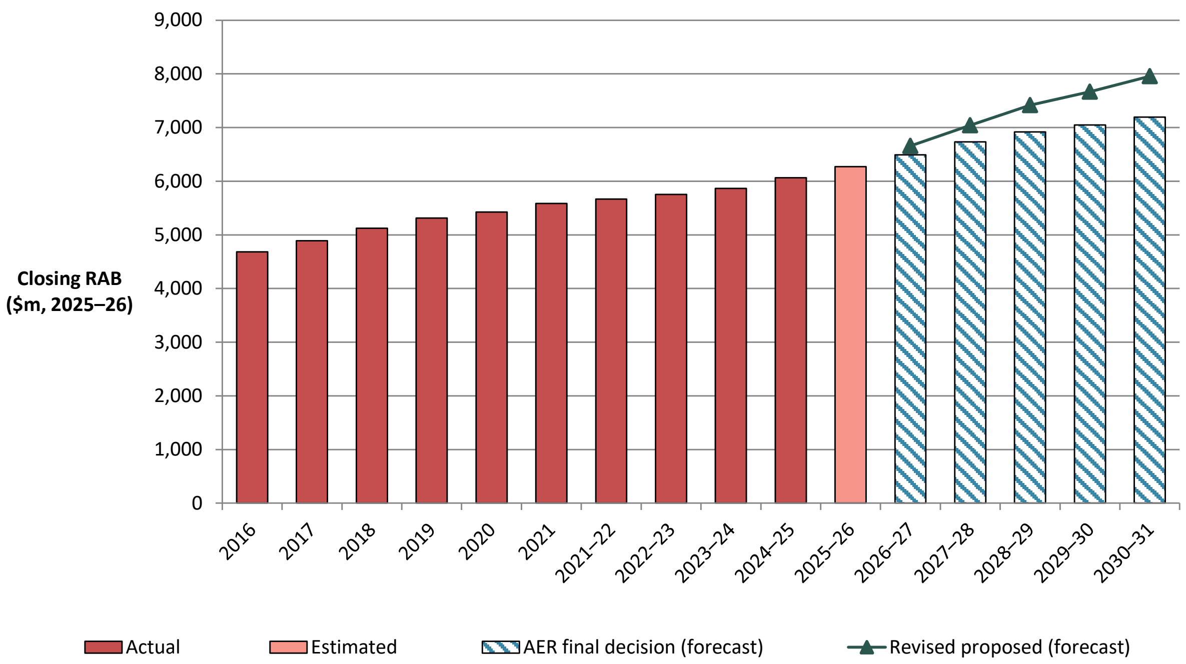
Source: AER analysis.

Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI). The 2021–26 building blocks and allowed revenue also excludes cost pass through amounts recovered through a C-factor mechanism as part of the annual pricing process.

Figure 3 shows the value of AusNet's RAB over time in real terms. After a RAB increase of 12.3% over the 2021–26 period, our final decision forecasts a RAB increase of $921.9 million (14.7%) over the 2026–31 period. This increase in the RAB is driven by a higher forecast capex over the 2026–31 period compared to the 2021–26 period. However, this increase is lower than what AusNet proposed, reflecting our final decision to reduce AusNet's revised proposed forecast capex.

RAB values substantially affect a network business's revenue requirements, and the total costs customers ultimately pay. We expect RABs to change over time, as capital investment will depend on the network's age and technology, load characteristics, the levels of new connections, and reliability and safety requirements.

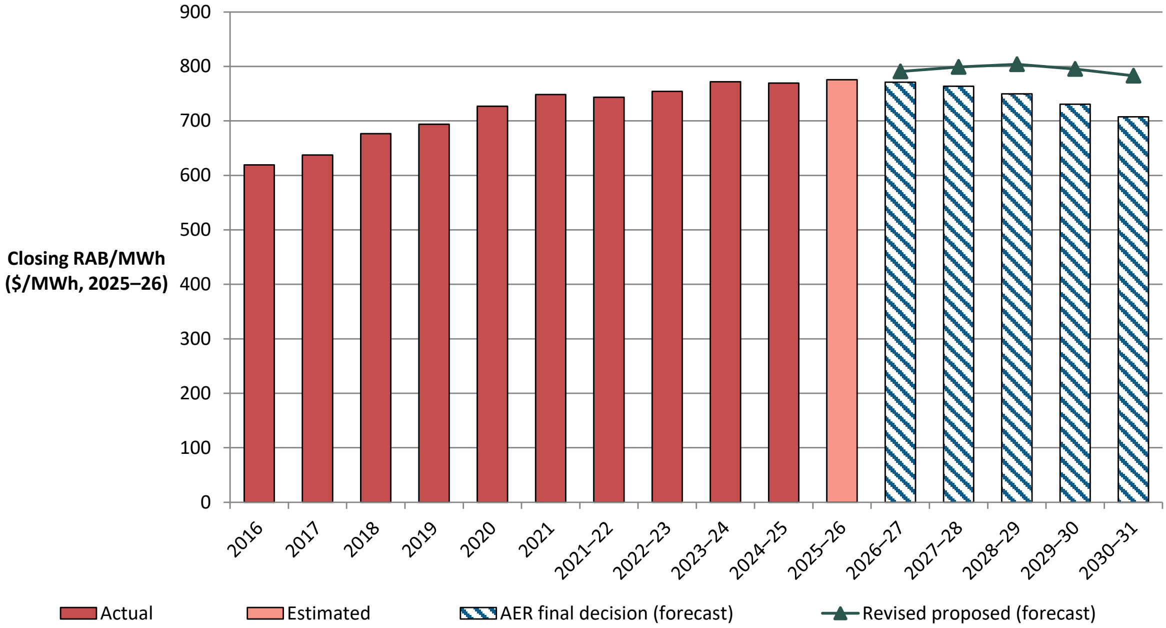
Figure 3 AusNet's RAB value over time ($ million, 2025–26)



Source: AER analysis.

We consider efficient investment in, and efficient operation and use of, electricity services are important to minimise the required capex and the RAB. In real terms, AusNet's RAB per unit of energy consumption (MWh) has historically been the highest of the Victorian DNSPs and, as can be seen in Figure 4, has increased steadily over the past 2 periods. This measure has started to decline in 2024–25 based on consumption growth which has offset a moderate increase in the RAB in real terms. Over the 2026–31 period, AusNet's RAB per MWh continues to show a forecast decline, driven by an increased rate of forecast energy consumption, which more than offsets the projected growth to the RAB. This is based on AusNet's forecast energy delivered and could change depending on the actual volume of energy delivered.

Figure 4 AusNet's RAB per energy consumption over time ($/MWh, 2025–26)



Source: AER analysis.

1.2 Expected impact of our final decision on electricity bills

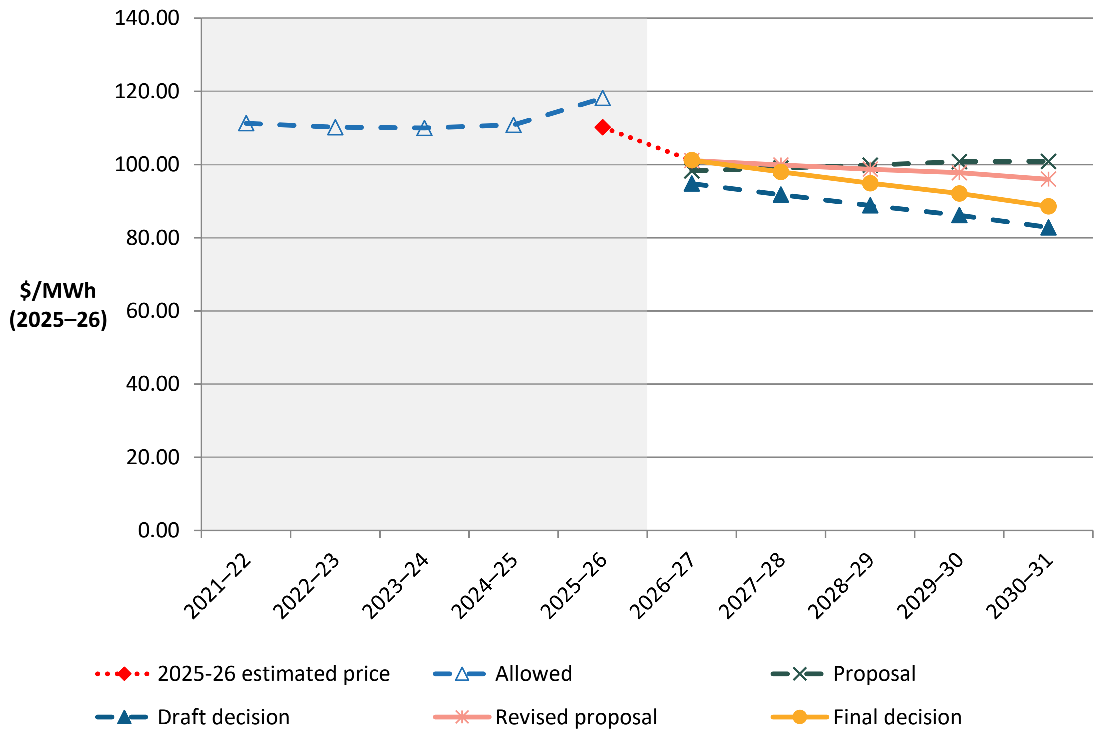
Our decision on AusNet's revised proposal sets the revenue allowance that forms the major component of its network charges for the next 5 years.

AusNet recovers its regulated revenue through distribution charges, set annually by reference to the TSS and pricing formulae approved by us as part of this decision.

For illustrative purposes only, we estimate the impact of this final decision would be a total reduction to AusNet's distribution charges of around 19.6% in real terms by 2030–31 compared to current, 2025–26 levels, or an average reduction of 4.3% per annum.[11] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption during the 2026–31 period. Figure 5 compares this indicative price path for the 2026–31 period to the 2021–26 period.

[11] The average decrease to indicative network charges of 4.3% ($2025–26) per annum reflects 2 components: 1) The final decision smoothed revenue average increase of 0.2% per annum ($2025–26); and 2) AusNet's proposed forecast energy delivered in its distribution network area, which is expected to increase on average by 4.7% per annum.

Figure 5 Change in indicative charges for 2021–26 to 2025–30 ($2025–26, $/MWh)



Source: AER analysis.

1.2.1 Potential bill impact

AusNet's distribution charges make up around 35% of its residential customers' electricity bills and 45% of its small business consumers' electricity bills.[12] Our final decision also covers charges for revenue-capped metering services (that form part of alternative control services) and these costs are included in this estimated bill impact analysis. Other components of the electricity supply chain also contribute to the prices ultimately paid by consumers. These are the cost of purchasing energy from the wholesale market, core transmission network charges, environmental scheme costs and the costs and margins applied by electricity retailers.[13] These components of the bill sit outside the decision we are making here and will also continue to change throughout the period.

In nominal terms, which include the effect of expected inflation, the impact of this final decision would be a reduction to the distribution component of consumers' electricity bills. For illustrative purposes only, we estimate the impact of our final decision on the average annual electricity bill for a typical customer in AusNet's network area, as it is today ($nominal), would be:[14]

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12 Based on Victorian Default Offer, for a small business with a total annual use of 10,000 kWh per year.

13 AEMC, *Data Portal*, *Trends in VIC supply chain components 2023/24*.

14 Our estimated bill impact is based on the typical annual electricity usage of 4,000 kWh and 10,000 kWh for residential and small business customers in AusNet's network area, respectively. Essential Services Commission, *Victorian Default Offer 2025–26, Final Decision Paper*, 21 May 2025, p 5.

- a reduction of $91 (4.8%) by 2030–31, or an average reduction of $18 per annum for a residential customer. This reflects:
  - a $57 reduction for distribution standard control service charges
  - a $34 reduction for metering.
- a reduction of $214 (4.9%) by 2030–31, or an average reduction of $43 per annum for a small business customer. This reflects:
  - a $170 reduction for distribution standard control service charges
  - a $44 reduction for metering.

We discuss the sensitivity of employing alternative forecasts of energy throughput and its impact on indicative bills below.

Sensitivity of forecast energy delivered on bills

The impact of our final decision on consumer bills is likely to change over the 2026–31 period. AusNet forecast the amount of annual energy delivered through its network to increase from 8,084 GWh in 2025–26 to 10,165 GWh in 2030–31, an increase of 2,081 GWh, or 25.7% over the period. This is the forecast that has informed the illustrative estimates of tariff and bill impacts in this final decision. A variance in energy consumption compared to that forecast by AusNet would lead to bill impacts that are higher or lower than what we have estimated. This is because AusNet operates under a revenue cap and is therefore entitled to recover the revenue we determine, regardless of the actual energy delivered.

For example, if energy delivered were to increase over the period at only 40% of the rate forecast by AusNet, the modelled impact on average annual bills would be: [15]

- a smaller nominal reduction of $5 (0.3%) by 2030–31 for a residential consumer[16]
- a nominal increase of $42 (1.0%) by 2030–31 for a small business consumer.[17]

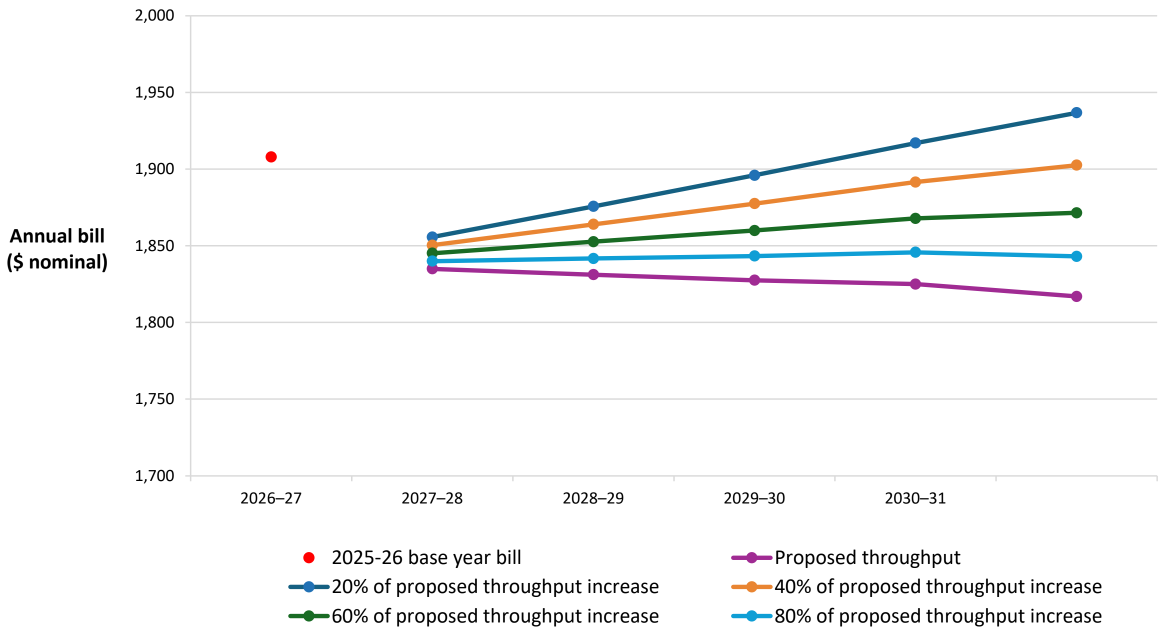
Figure 6 shows the average annual bill for a residential consumer for a range of alternative energy delivered forecasts.

15 This would therefore reflect energy throughput of 8,917 GWh in 2030–31, or an increase in energy throughput over the period of 10.3% compared to the 25.7% increase proposed by AusNet.

16 This reflects an increase of $29 for distribution standard control services, and a reduction of $34 for metering.

17 This reflects an increase of $86 for distribution standard control services, and a reduction of $44 for metering.

Figure 6 Sensitivity of energy delivered on annual residential bills



Source: AER analysis.

1.3 Consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations.

AusNet's Coordination Group has expressed comfort that, in principle, AusNet's proposal addresses the issues most important to customers: reliability and resilience. However, it noted that affordability remains a key issue and may become more of an issue in the future as networks seek to recover the costs of the recent bushfires and floods through cost pass through applications.[18]

Feedback on our draft decision sought clarity as to the impact that engagement has had on our decision making, and in particular our draft decisions to reduce proposed expenditure in areas that were of key interest to consumers.

Where consumers have been engaged on the outcomes a DNSP should seek to achieve, our role is to carefully assess the prudency and efficiency of the expenditure the DNSP has submitted is necessary to deliver them.

The framework under which we must assess forecast expenditure is set out in the NER.

A DNSP must, in its proposal to the AER, include the total forecast opex and capex it considers is required to achieve the opex and capex objectives:[19] These objectives include meeting or managing expected demand for services over the relevant period. They also

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18 AusNet Coordination Group, *Submission - AusNet electricity distribution proposal 2026–31*, January 2026, p 15.

19 NER, cls 6.5.6(a), 6.5.7(a).

include complying with all applicable regulatory obligations or requirements, including any service standards applicable to quality, reliability and security of supply. To the extent that there is no applicable regulatory obligation or requirement in relation to the quality, reliability or security of supply, the objectives require that quality, reliability or security of supply are maintained over time.

We must accept the DNSP's proposed forecast if we are satisfied that, in total, it reasonably reflects each of the opex and capex criteria:[20]

1. the efficient costs of achieving the opex and capex objectives; and
2. the costs that a prudent operator would require to achieve opex and capex objectives; and
3. a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the opex and capex objectives.

These criteria reflect and serve to support the NEO, to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity, and the reliability, safety and security of the national electricity system.[21]

All 3 criteria must be satisfied before we accept a proposal.

If we are not satisfied that the proposed forecast reasonably reflects costs that are efficient, and prudent, and a realistic expectation of forecast demand, cost and other inputs required to achieve the opex and capex objectives, we must not approve it.[22]

Consumer engagement and support is valuable both to DNSPs in the development of their proposals, and to us in assessing them and making decisions that are in consumers' long-term interests. The extent to which a proposed forecast of capex or opex "includes expenditure to address the concerns of consumers as identified by the DNSP in the course of its engagement with distribution service end users or groups representing them" is one of 12 non-exhaustive factors to which the AER must have regard in making the required assessment against the opex and capex criteria.[23]

Requirements for prudency and efficiency are not at odds with the intention that proposals include expenditure to address consumers' concerns. However, consumer support alone does not guarantee any one or more of the assessment criteria have been met in respect of a DNSP's total capex or opex forecast, or of any individual projects or programs that have informed those forecasts.

When considering the outcomes of a DNSP's consumer engagement, and consumers' responses to our decisions, we have regard to the consumer concerns the DNSP seeks to address (as put in our Better Resets Handbook, the outcomes consumers are seeking).

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20 NER, cls 6.5.6(c), 6.5.7(c)(1).

21 NEL, s 7.

22 NER, cls 6.5.6(d), 6.5.7(d).

23 NER, cls 6.5.6(e)(8), 6.5.7(e)(3).

In developing proposals to address those concerns, and achieve those outcomes, we expect a DNSP to identify, test (including through engagement), and choose from credible options and solutions it considers will achieve the opex and capex objectives, and that it can satisfy us will reasonably reflect the opex and capex criteria.

Where we are satisfied that a DNSP has achieved this, its proposed options and solutions will form part of the total opex and capex we approve.

Where we are not satisfied, we must look to alternative forecasts of capex or opex in order to approve total expenditure forecasts that will address consumers' concerns and deliver their preferred outcomes in a way that does achieve the opex and capex objectives and satisfy the opex and capex criteria.

That may mean our total opex and capex forecasts assume the same (or similar) options or solutions that a DNSP has engaged on and subsequently proposed but at a more efficient cost, or at a volume that better reflects a realistic expectation of demand forecasts.

It may mean that our total forecast defers, or does not include for the period under assessment, expenditure on an option or solution we are not satisfied is needed at the time the DNSP has proposed, and which could instead occur later so that it is not necessary or appropriate to recover the costs from consumers yet.

It may mean that we do not include the option or solution the DNSP has proposed, in which case our total expenditure forecasts will be informed by alternative options we consider would address consumer concerns, and ultimately support the same outcomes in way that we are satisfied is prudent, and reflects a realistic expectation of demand forecasts and cost and other inputs.

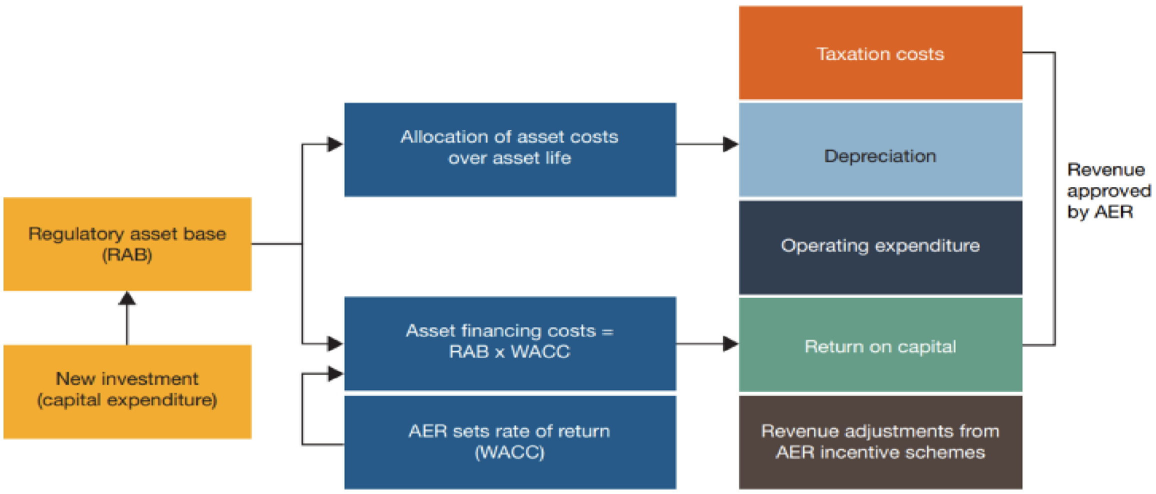
This is how we ensure that consumers are paying no more than necessary for safe, secure and reliable energy supply and a resilient network that meets their needs and delivers their preferred outcomes.

2 Key components of our final decision on revenue

AusNet's proposed revenue reflects its forecast of the efficient cost of providing distribution network services over the 2026–31 period. Its revenue proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach which looks at 5 cost components (see Figure 7):

- return on the RAB – or return on capital, to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the RAB – or return of capital, to return the initial investment cost to investors over time
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements – resulting from the application of incentive schemes, such as the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS)
- estimated cost of corporate income tax.

Figure 7 The building block model to forecast network revenue



Source: AER.

Revenue smoothing

Our final decision incudes a determination of AusNet's annual revenue requirement (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2026–31 period. The smoothed revenues we set in this final decision are the amounts that AusNet will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2026–31 period.[24]

The annual revenue requirement is the sum of the various building block costs for each year of the regulatory control period, which can be lumpy over the period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. As such, revenue smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period.

For this final decision, we have approved lower revenues than AusNet's revised proposal. This is mainly driven by increased negative revenue adjustments and our reduction to AusNet's forecast capex. Further reductions to revenues are due to our updates for external economic factors including a higher expected inflation rate, which reduces the regulatory depreciation building block.

However, our final decision allows for higher revenues than those determined in the 2021–26 period. In nominal terms, AusNet's unsmoothed revenue for the first year of the 2026–31 period (2026–27) is about 4.5% lower than its approved revenue for the last year of the 2021–26 period (2025–26). It then increases by an average of 5.6% per annum over the remaining 4 years of the period.

We are mindful of the impact this revenue increase over the final 4 years of the period could have on network charges for AusNet's consumers (in the event forecast energy growth is lower than expected). Consequently, our smoothed revenue profile reduces these increases and passes on an appropriate reduction in 2026–27.

Our final decision smoothed revenue is for an initial revenue reduction of 1.9% ($ nominal) in 2026–27, followed by constant annual increases of 4.1% for the remaining 4 years (2027–28 to 2030–31). This smoothing profile results in a divergence between smoothed and unsmoothed revenue for 2030–31 of –3%, which is within our preferred range.

We consider our final decision smoothing path is more stable and reasonably provides for a reduction in the first year of the period, resulting in smaller revenue increases for years 2 to 5. This approach is consistent with our draft decision and AusNet's revised proposal.

2.1 Regulatory asset base

The RAB accounts for the value of regulated assets over time. To set the revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the RAB at the end of each year of the regulatory period. The value of the RAB is used to determine the return on capital and regulatory depreciation building blocks. It substantially impacts AusNet's revenue requirement, and the price consumers ultimately pay. Other things

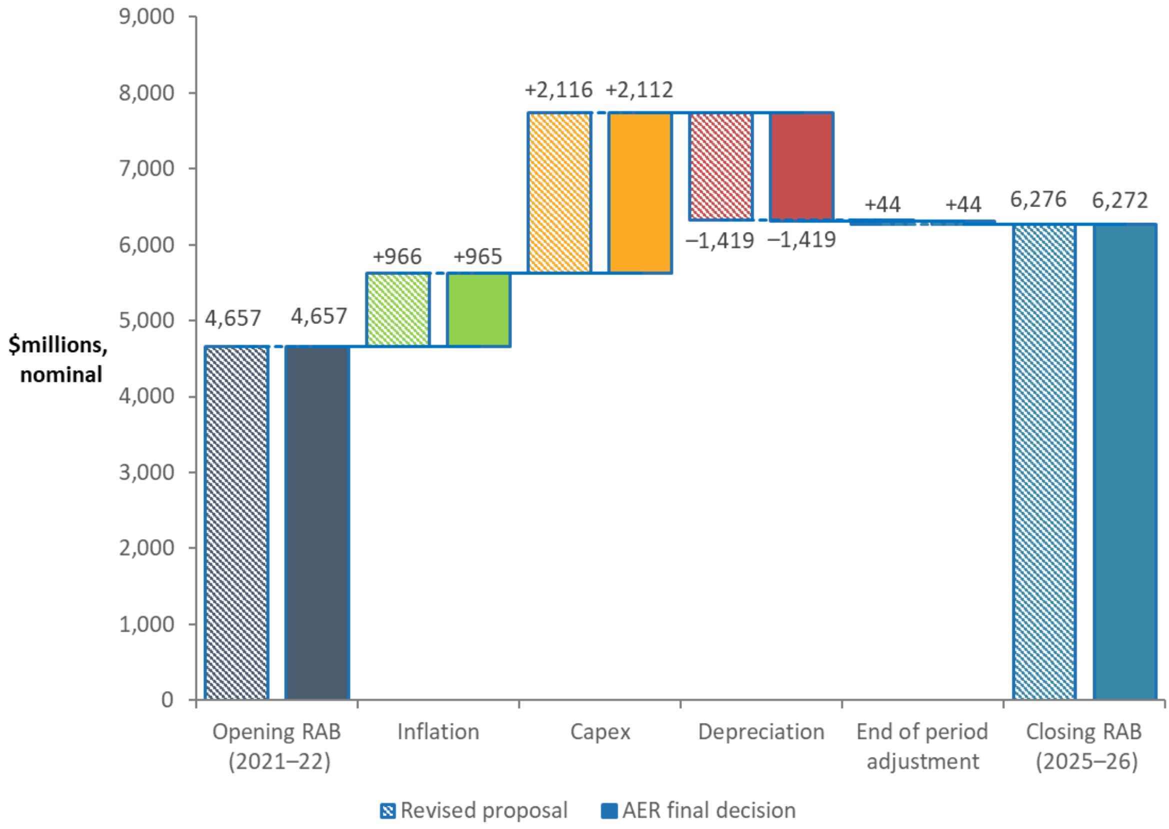
24 Our final decision expected revenues have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

being equal, a higher RAB would increase both the return on capital and regulatory depreciation components of the revenue determination.

For this final decision, we have determined an opening RAB value of $6272.0 million ($ nominal) as at 1 July 2026. This value is $3.9 million (0.1%) lower than AusNet's revised proposed opening RAB value of $6,276.0 million. This reduction is mainly due to our minor adjustments to capex inputs to be consistent with the annual reporting regulatory information notices (RINs) and the annual information orders (AIOs).

Figure 8 shows the key drivers of change in AusNet's RAB over the 2021–26 period compared to its revised proposal.

Figure 8 Key drivers of change in the RAB over the 2021–26 period – revised proposal compared with AER's final decision ($million, nominal)

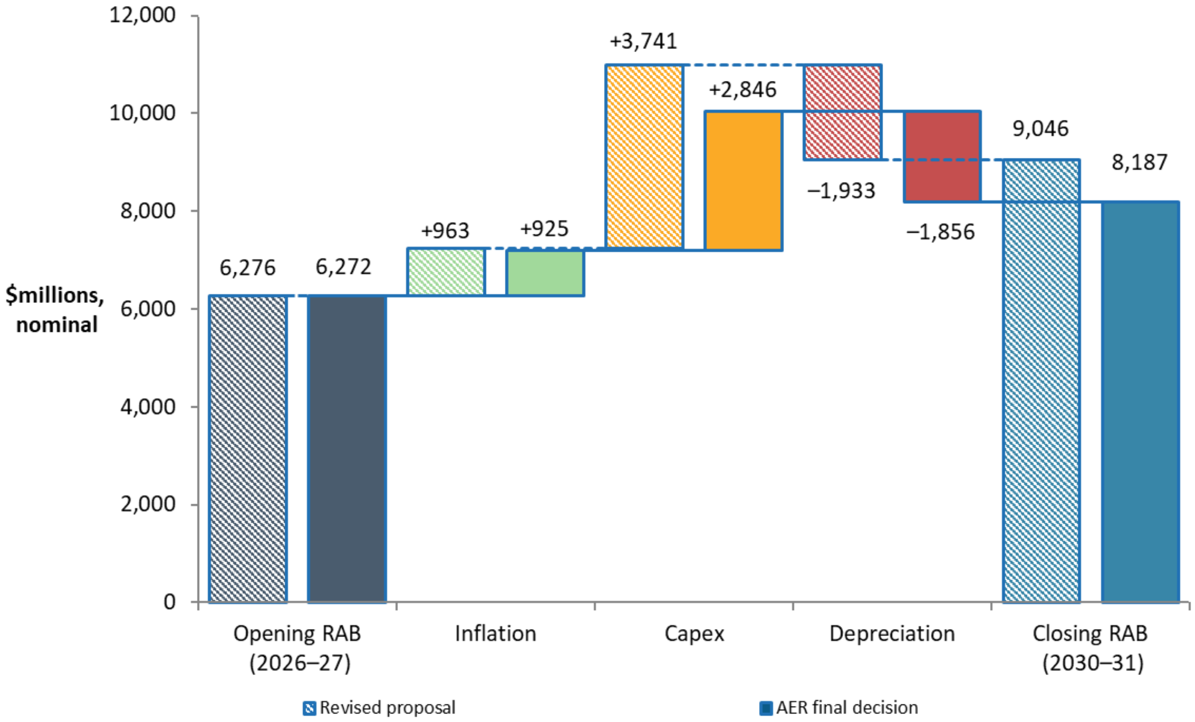


Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for timing assumptions in the roll forward model.

Figure 9, likewise shows the key drivers ($ nominal) of the change in AusNet's forecast RAB over the 2026–31 period compared to its revised proposal. Our final decision projects an increase of $1,915.0 million (30.5%) to the RAB by the end of the 2026–31 period compared to the $2,770.4 million (44.1%) increase in AusNet's revised proposal. We have determined a projected closing RAB of $8,187.0 million ($ nominal) as at 30 June 2031, which is $859.4 million (9.5%) lower than AusNet's revised proposal of $9,046.4 million. This lower value is mainly due to our final decision to reduce AusNet's forecast capex (section 2.4). It also reflects our final decisions on the opening RAB as at 1 July 2026, expected inflation (section

2.2) and forecast depreciation (section 2.3). The reasons for our final decisions are discussed in Attachment 1.

Figure 9 Key drivers of change in the RAB over the 2026–31 period – revised proposal compared with AER's final decision ($million, nominal)



Source: AER analysis.
Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for timing assumptions in the PTRM.

2.2 Rate of return and value of imputation credits

The AER's 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[25]

The return each business is to receive on its RAB, known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of 2 sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and

25 AER, *Rate of Return Instrument (Version 1.2),* March 2024.

reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much, and consumers will pay inefficiently high tariffs.

We are required by the NEL to apply the RORI to estimate an allowed rate of return.[26] For this final decision, we have applied the 2022 RORI.[27]

AusNet's revised proposal adopted the 2022 RORI.[28] Our final decision rate of return of 6.29% (nominal vanilla) is higher than the 6.07% placeholder in the revised proposal, principally due to an increase in the risk-free rate.

Our calculated rate of return in Table 1 applies to the first regulatory year of the 2026–31 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our final decision accepts AusNet's proposed risk-free rate[29] and debt averaging periods[30] because they are consistent with the 2022 RORI.[31]

Table 1 Final decision on AusNet's rate of return (nominal)

	AER's draft decision (2026–31)	AusNet's revised proposal (2026–31)	AER's final decision (2026–31)	Allowed return over the regulatory control period
Nominal risk-free rate	4.25%	4.25%	4.82%[a]	Constant (%)
Market risk premium	6.20%	6.20%	6.20%	Constant (%)
Equity beta	0.6	0.6	0.6	Constant
Return on equity (nominal post-tax)	7.97%	7.97%	8.54%	Constant (%)
Return on debt (nominal pre-tax)	4.79%	4.79%	4.79%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.06%	6.07%	6.29%[c]	Updated annually for return on debt

26 NEL, section 18H.

27 AER, *Rate of Return Instrument (Version 1.2),* March 2024.

28 AusNet, *ASD - AusNet - EDPR Revised Proposal 2026–31*, December 2025, pp 238–240.

29 AusNet, *ASD - AusNet - Appendix 11A Rate of return averaging period 310125 – CONF*, 31 January 2025, p 2.

30 AusNet, *ASD - AusNet - Appendix 11A Rate of return averaging period 310125 – CONF*, 31 January 2025, p 3.

31 AER, *Rate of return Instrument (version 1.2),* March 2024, cl 7–8, pp 23–25.

	AER's draft decision (2026–31)	AusNet's revised proposal (2026–31)	AER's final decision (2026–31)	Allowed return over the regulatory control period
Expected inflation	2.55%	2.60%	2.62%	Constant (%)

Source: AER analysis; AER, *Overview - Draft decision - AusNet Services distribution determination 2026–31*, September 2025, p 13; AusNet, *ASD - AusNet - EDPR Revised Proposal 2026–31*, December 2025, pp 238–239.

(a) Calculated using AusNet's risk-free rate averaging period of 20 business days ending 27 February 2026.

(b) Calculated using AusNet's actual nominated return on debt averaging period.

(c) Applied to the first year of the 2026–31 regulatory control period.

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the operating expenditure (opex) forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in previous AER revenue determinations (for example, see our 2025–30 Directlink Electricity Transmission Determination final decision).[32] AusNet has proposed to use our approach to estimate debt and equity raising costs.[33]

Our final decision is to apply a debt raising cost of 8.51 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex.

We have updated our estimate for the 2026–31 period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 RORI. AusNet's revised proposal also adopted this value.[34]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.62%. It is an estimate of the average annual rate of inflation expected over a 5-year period based on the outcome of our 2020 inflation review. AusNet's revised proposal also adopted our approach.[35]

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32 AER, *Final decision - Attachment 3 - Rate of Return - Directlink Electricity Transmission Determination 2025 to 2030*, September 2024, pp 4–6.

33 AusNet, *ASD - AusNet - EDPR Revised Proposal 2026–31*, December 2025, p. 240.

34 AusNet, *ASD - AusNet - EDPR Revised Proposal 2026–31*, December 2025, p. 240.

35 AusNet, *ASD - AusNet - EDPR Revised Proposal 2026–31*, December 2025, pp. 240–241.

Table 2 Final decision on AusNet's forecast inflation (%)

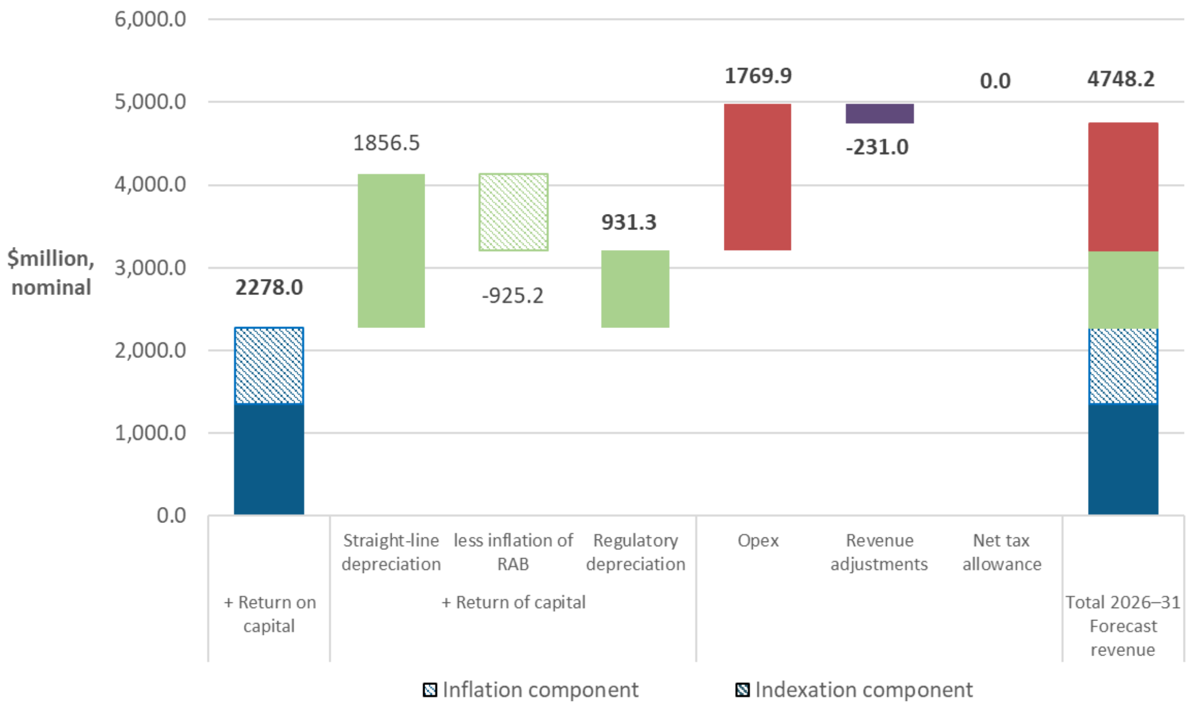
	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	2.90%	2.60%	2.57%	2.53%	2.50%	2.62%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, February 2026, Table 3.1: Detailed Forecast Table. See the *Statement on Monetary Policy*.

Our final decision uses the Reserve Bank of Australia's (RBA) February 2026 Statement on Monetary Policy which contains a consumer price index (CPI) forecast for the financial years ending 30 June 2027 and 30 June 2028. This means the first 2 years of the 2026–31 period are based on RBA forecasts and, thereafter, a linear glide path from year 3 to the mid-point of the RBA's inflation target band of 2.5% in year 5.

Figure 10 isolates the impact of expected inflation from other parts of our final decision to illustrate its effect on the return on capital and regulatory depreciation building blocks, and the total revenue allowance. Where all other elements are held constant, lower expected inflation reduces the return on capital but increases regulatory depreciation.

Figure 10 Inflation components in final decision revenue building blocks ($ million, nominal)



Source: AER analysis.

2.3 Regulatory depreciation (return of capital)

Depreciation is a method used in our decision to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining total revenue, we include an amount for the depreciation of the projected RAB. The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our final decision determines a regulatory depreciation amount of $931.3 million ($ nominal) for the 2026–31 period. This is a reduction of $39.5 million (4.1%) from AusNet's revised proposal of $970.8 million.

This reduction is primarily due to our final decision to reduce AusNet's forecast capex, which has reduced straight-line depreciation in the 2026–31 period. Our final decision to apply a lower opening RAB as at 1 July 2026, and a higher expected inflation rate for the 2026–31 period, has further reduced the regulatory depreciation building block.[36]

2.4 Capital expenditure

Our final decision is to not accept the total forecast capex of $3,408.1 million ($2025–26) in AusNet's revised proposal. Our alternative forecast is $2,590.5 million, which is 24.0% below AusNet's forecast.

Our decision is based on a balanced consideration of various factors, including the revised capex proposal from AusNet, stakeholder submissions, investment need and service reliability performance. We consider our alternative forecast will sufficiently allow a prudent and efficient service provider in AusNet's circumstances to meet the capex objectives.

Table 3 compares our alternative estimate of forecast capex to AusNet's revised proposal.

Table 3 AER's final decision on AusNet's total net capex forecast ($ million, 2025–26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
AusNet's revised proposal	703.0	720.8	731.3	611.9	641.1	3,408.1
AER's final decision	542.2	572.5	528.3	473.9	473.6	2,590.5
Difference ($)	**-160.8**	**-148.2**	**-203.0**	**-138.0**	**-167.5**	**-817.6**
Difference (%)	**22.9%**	**20.6%**	**27.8%**	**22.6%**	**26.1%**	**24.0%**

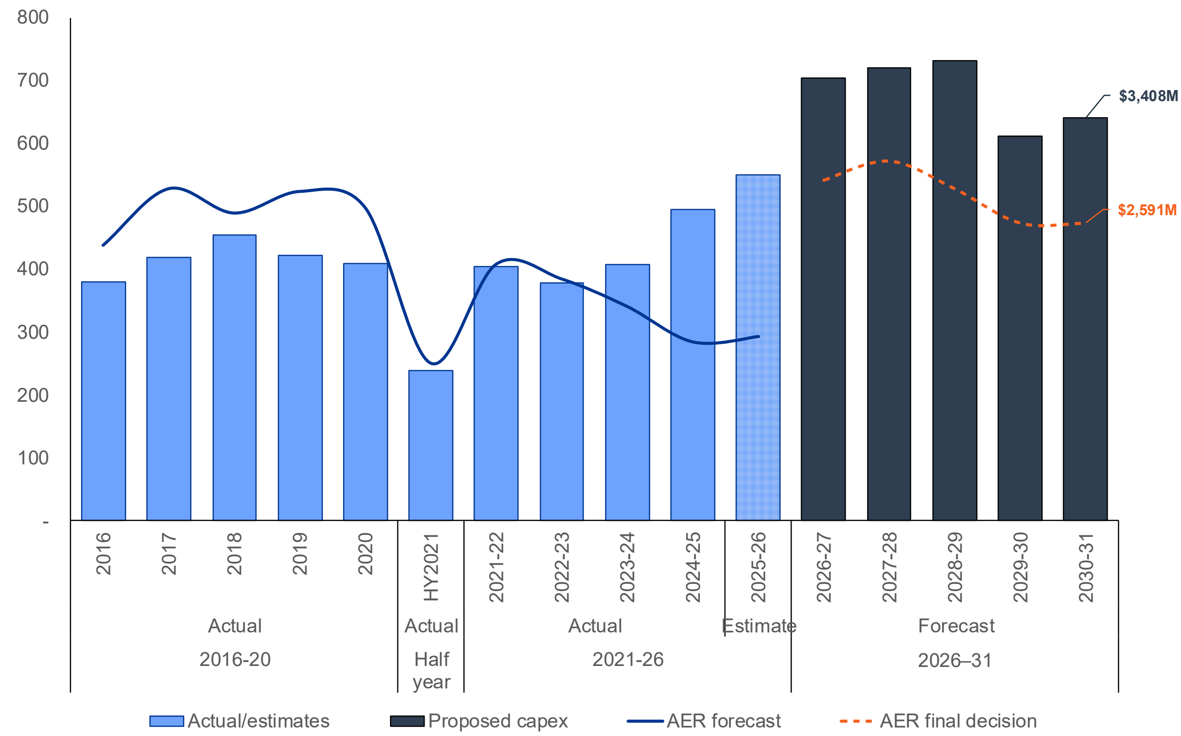
Source: AER analysis and AusNet's revised proposal.
Note: Numbers may not add up due to rounding. The final decision includes modelling adjustments relating to updates to CPI and real cost escalation assumptions.

Figure 11 places our final decision capex forecast of $2,590.5 million in the context of historical capex. Our final decision capex forecast is:

- $882.0 million, or 51.6% higher than the capex forecast we approved in our final decision for the 2021–26 regulatory control period
- $357.0 million, or 16.0% higher than AusNet's actual (and estimated) capex for the 2021–26 regulatory control period.

[36] Since RAB indexation is deducted from straight-line depreciation, a higher value of expected inflation also results in a lower regulatory depreciation.

Figure 11 AusNet's historical and forecast capex ($million, 2025–26)



Source: AER RIN Database, AER Analysis.
Note: Nominal figures converted to real dollars 2025–2026.

AusNet's revised proposal forecast $3,408.1 million ($2025–26) of capex over the 2026–31 regulatory control period. This represented an increase of 52.6% compared to its actual and expected expenditure over the 2021–26 period.

AusNet's revised capex proposal represented an increase in forecast capex compared to our draft decision, driven by factors such as an increase in the demand forecast, as well as higher unit rates for labour and materials. The revised proposal also included $441.2 million in new projects which were not in its initial proposal, including additional replacements, augmentations, connections and property improvements.

In our draft decision, we asked AusNet to provide more information and evidence to justify the proposed expenditure and address our concerns on the quality of the business cases, supporting models, options analysis and lack of information for some proposals. We also raised concerns that although consumer support was an important factor in our consideration, it should not be the only factor supporting proposed expenditure.

In responding to our draft decision, AusNet:

- provided additional information where requested including an updated demand forecast based on the latest available information, revised business cases and models for replacement and augmentation expenditure
- adopted the AER's value of customer reliability in economic assessments and business cases to estimate benefits of avoiding unserved energy

- undertook root cause analysis for its proposed reliability expenditure and reflecting this in the options for worst served feeders
- provided detailed mapping of its risks, benefits and costs for its cyber security
- revised its risk allowance methodology and justification.

For this final decision, our assessment focused on the key issues from the revised proposal including replacement capex, augmentation, connections, information and communication technology (ICT), fleet and CER integration expenditure.

We have included AusNet's proposed property, non-network other, capitalised overheads and innovation expenditures in the total capex forecast. We have also accepted AusNet's demand forecast.

The categories of expenditure where we have not included all of AusNet's proposed expenditure are:

- Replacement capex – we have made material adjustments to 14 repex programs, which were driven by overestimated modelling inputs and cost estimates. Further, we have removed the risk allowance applied across replacement, augmentation and connections expenditure. We consider the proposed risk allowance is generic in nature and not specific to the individual projects.
- Resilience – we have adjusted the network hardening and vegetation management programs. We consider that AusNet overestimated the benefits and the effectiveness of some of its proposed solutions.
- Connections – we have adjusted AusNet's programs where we considered a number of projects were presented without justification and with high unit rates.
- Augmentation capex – we have adjusted expenditure for demand-driven, reliability, safety and compliance augmentation. These adjustments are driven by our engineering and economic assessments, as well as community support considerations.
- ICT – we have accepted AusNet's recurrent ICT program but have adjusted some non-recurrent projects where we consider that benefits were too high and the scope was not adequately justified. Further, we have adjusted the cybersecurity forecast with updated costs and removed initiatives we considered were not justified or duplicative.
- Fleet – our forecast is based on continuing to lease all currently leased vehicles at existing rates, with the currently owned vehicles replaced at the cost AusNet proposed. There have been no changes to proposed volumes, and we have allowed for AusNet's growth in fleet.
- CER integration – our forecast allows AusNet to implement measures to facilitate and manage CER, such as flexible export limits, and dynamic voltage management. The funding enables AusNet to undertake cost effective measures to manage incoming CER volumes on the network including flexible export limits. We have also removed duplication within some initiatives.

Table 4 sets out our final decision for AusNet by capex category. Further detail and reasons for our final decision on forecast capex are set out in Attachment 2.

Table 4 AER final decision by capex category ($million, 2025–26)

Category	AusNet's revised proposal	AER's final decision	Difference ($/%)	
Replacement	1,218.8	979.9	-238.9	-19.6%
Augmentation	881.8	638.5	-243.4	-27.6%
Connections	793.3	528.1	-265.2	-33.4%
ICT	349.8	282.5	-67.3	-19.2%
Property	145.7	145.7	-	-
Fleet	173.5	102.9	-70.6	-40.7%
CER integration	92.1	38.2	-54.0	-58.6%
Non-network - other	4.5	4.5	-	-
Capitalised overheads	204.9	204.9	-	-
Gross total	**3,864.5**	**2,925.1**	**-939.4**	**-24.3%**
Less customer contributions	420.0	209.8	-210.2	-50.0%
Less disposals	36.4	36.4	-	-
Modelling adjustments		-88.4		
Net total	**3,408.1**	**2,590.5**	**-817.6**	**-24.0%**

Source: AER analysis, AusNet revised proposal. Numbers may not sum due to rounding.
Note: Within these categories:

- Resilience: Our forecast includes $73.6 million for network and community resilience, spread between replacement, augmentation and fleet expenditure. This is $81.9 million (52.7%) less than AusNet's proposal.
- Innovation: Our forecast includes a $3.7 million innovation allowance, spread between augmentation and ICT expenditure.
- Cyber security: Our forecast includes $20.0 million cyber security within ICT expenditure. This is $7.5 million (27.3%) less than AusNet's proposal.

2.5 Operating expenditure

Our final decision is to not accept AusNet's total opex forecast of $1623.9 million[37], including debt raising costs, for the 2026–31 regulatory control period.[38] We consider that AusNet's total forecast opex does not reasonably reflect the opex criteria, having regard to the opex factors, including consistency with the incentive schemes applying to AusNet.[39]

37 All dollar values are in $2025-26 terms unless stated.

38 AusNet, *ASD – AusNet – EDPR Revised Proposal 2026-31*, December 2025, p. 183.

39 NER, cl. 6.5.6(e).

Our alternative estimate of $1,634.9 million is $11 million higher than AusNet's proposal. The difference is primarily driven by AusNet's selection of 2022–23 as the base year.

We consider that AusNet's actual expenditure in its selected 2022–23 base year does not provide a sufficient level of expenditure that reasonably reflects the opex criteria. AusNet has then included 10 step changes to make up the shortfall. The selection of base year also impacts the application of the Efficiency Benefit Sharing Scheme (EBSS) (November 2013). The EBSS provides for the same base year to be used for both calculating efficiency carryover amounts and forecasting opex.

Our alternative estimate of $1,634.9 million has been forecast using a different base year (2024–25). This provides AusNet with sufficient forecast opex to satisfy the opex criteria and is consistent with our top down approach to forecasting. This is in contrast to AusNet's approach of selecting a low base year that is not reflective of ongoing efficient costs, and using step changes to make up the shortfall, which is reflective of a bottom up build.

Using 2024-25 as a base year to forecast opex also provides consistency with the EBSS. We consider that our estimate of $1,634.9 million reasonably reflects the opex criteria, including the efficient and prudent costs to achieve the opex objectives over the 2026–31 regulatory control period, having regard to the opex factors including consistency with the EBSS.[40]

Our decision is based on a balanced consideration of various factors, including the revised opex proposal from AusNet, stakeholder submissions and our assessment against our guidelines and the NER and the national electricity objective and revenue and pricing principles in the National Electricity Law (NEL). We consider our alternative forecast will sufficiently allow a prudent and efficient service provider in AusNet's circumstances to meet the opex objectives.

Table 5 compares our final decision on AusNet's total forecast opex for the 2026–31 period to its revised proposal.

Table 5 AusNet opex for the period 2026–31 ($million, 2025–26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
AusNet's revised proposal	309.7	316.9	324.8	331.0	341.5	1,623.9
AER's final decision	314.5	319.6	326.5	332.5	341.8	1,634.9
Difference ($)	**4.8**	**2.7**	**1.7**	**1.5**	**0.3**	**11.0**
Difference (%)	**1.6%**	**0.9%**	**0.5%**	**0.5%**	**0.1%**	**0.7%**

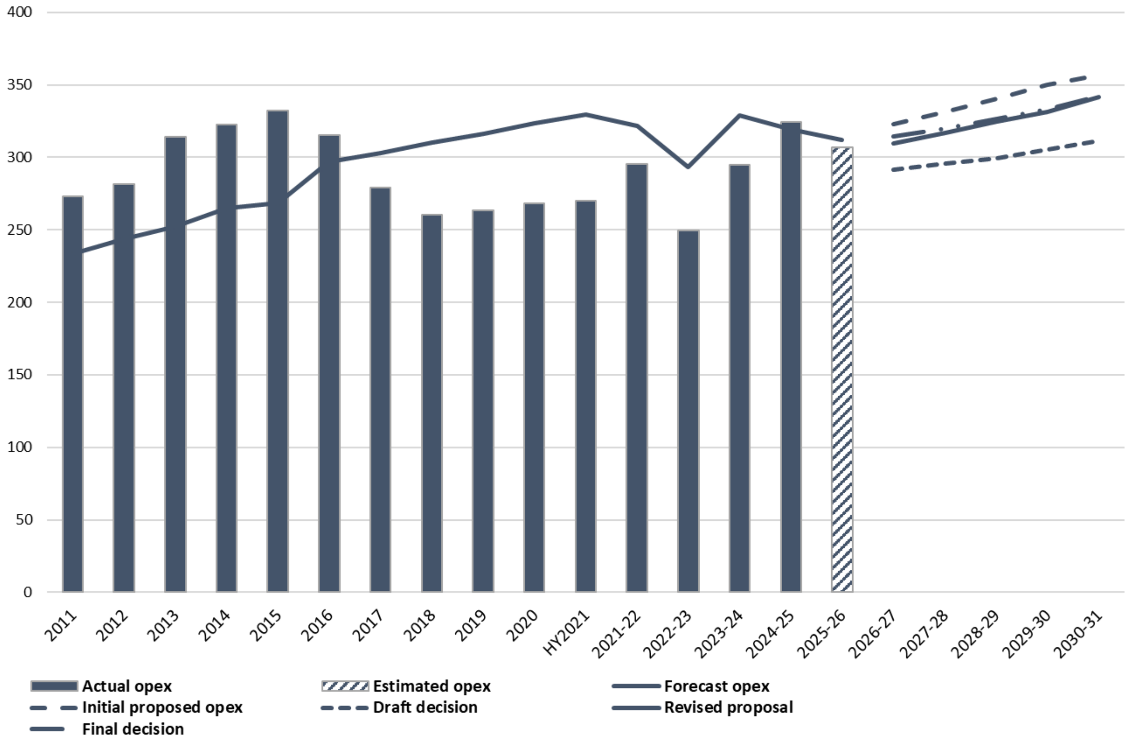
Source: AusNet, *ASD - AusNet EDPR 2026–31 - Opex Model,* December 2025; AER analysis.

Figure 12 places our final decision opex forecast of $1,634.9 million in the context of historical opex. Our final decision opex forecast is:

40 NER, cl. 6.5.6(c)-(e).

- $60.0 million, or 3.8% higher than the opex forecast we approved in our final decision for the 2021–26 regulatory control period
- $164.1 million, or 11.2% higher than AusNet's actual (and estimated) opex for the 2021–26 regulatory control period.

Figure 12 AusNet's historical and forecast opex ($million, 2025–26)



Source: AER RIN Database, AER Analysis.
Note: Nominal figures converted to real dollars 2025–2026.

AusNet's revised proposal included forecast opex of $1,623.9 million ($2025–26) over the 2026–31 regulatory control period. This represented an increase of 10.4% compared to its actual and expected expenditure over the 2021–26 period.

AusNet's revised opex proposal is an increase in forecast opex compared to our draft decision, driven mainly by higher forecast trend growth, especially output growth, and materially higher net step changes. Notable opex step changes include increased expenditure for digital activities, preparedness and response, more frequent pole inspections, resilience measures (such as the hazard tree program), the integrated distribution system planning rule change, sustainability reporting, and customer engagement and communication. It also includes a category specific forecast for customer engagement and communications.

The difference between our alternative estimate of total opex forecast and AusNet's revised proposal is due to our final decision using 2024–25 as the base year, providing AusNet with sufficient forecast opex to satisfy the opex criteria and is consistent with our top down approach to forecasting and the EBSS.

Our final decision also includes a negative insurance step change (–$23.3 million) to ensure that forecast opex reflects the premiums AusNet will pay in 2025–26 (plus an amount for the rate of change) and meets the opex criteria. However, we note that we have changed our approach from the one we adopted in the draft decision in response to stakeholder feedback and further consideration of the regulatory framework.

Further detail and reasons for our final decision are set out in Attachment 3.

2.6 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2026–31 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our post-tax revenue model (PTRM).

Our final decision determines an estimated cost of corporate income tax amount of zero for AusNet over the 2026–31 period, consistent with our draft decision and AusNet's revised proposal. This is because we expect AusNet to incur a forecast tax loss in each year of the 2026–31 period.[41] We have determined that $469.9 million in tax losses as at 30 June 2031 will be carried forward to the 2031–36 period where it can be used to offset future tax liabilities. The forecast tax loss arises mainly because of the carry forward of AusNet's accumulated tax loss at 30 June 2026.

Our final decision is to accept AusNet's revised proposal to change the tax treatment for type 1 capital contributions (cash) from large customer connections for the 2026–31 period. As discussed in section 4.4, we consider the change in tax treatment would apply to load customers connecting at 22 kV and above. This would mean that the net tax liability from these connections would be added to the capital contribution amount paid by the connecting customer for the 2026–31 period. The net tax liability would, therefore, be borne by the connecting customer.

2.7 Revenue adjustments

Our calculation of AusNet's total revenue includes adjustments for incentive schemes that applied in its determination for the current period, such as the EBSS and CESS. These mechanisms provide a continuous incentive for AusNet to pursue efficiency improvements in opex and capex, and a fair sharing of these between AusNet and its users.

Our final decision includes:

- A revenue adjustment of -$51.2 million from the application of the EBSS in the 2021–26 period. This represents a -$90.0 million difference from AusNet's proposed carryover amount of $38.8 million. This reflects that our final decision:
  - uses 2024–25 base year to calculate carryovers consistent with base year used to forecast total opex
  - updates actual and forecast inflation and real vanilla WACC input for 2026–27.

41 A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to future regulatory control periods to offset future taxable income until the tax loss is fully exhausted.

- A revenue adjustment of -$167.3 million from the application of CESS in the 2021–26 period. This represents a -$29.9 million difference from AusNet's proposed revenue decrement of -$137.4 million. This reflects that our final decision:
  - updates capex inputs to reflect actual expenditure and changes to forecast
  - updates actual and forecast inflation and WACC inputs.

Our final decision also includes an allowance of $4.57 million ($2025–26) for the Demand Management Innovation Allowance Mechanism (DMIAM), which comprises a fixed allowance of $0.2 million ($2017), plus 0.075% of the annual revenue requirement for each regulatory year, as set out in our PTRM. AusNet will submit demand management projects for approval under the DMIAM. This allowance is included as a positive adjustment to revenue, and not as capex or opex. This allows any part of the total allowance that is not spent on an approved project to be returned to consumers in the subsequent period.

2.8 Uncertainty mechanisms

Our distribution determination for AusNet will set the revenue allowance that forms the major component of its network charges for the next 5 years. It provides a baseline or starting point for that period. Over the 2026–31 period there are several additional mechanisms under the NER that may operate to increase or decrease those charges.

A distribution business may apply to us seeking the recovery of additional costs incurred during a regulatory period, if certain predefined exogenous events occur as specified in either the NER or in its respective revenue determination.

2.8.1 Cost pass through events

There are 3 prescribed cost pass through events (regulatory change event, service standard event and tax change event) that apply to all Victorian DNSPs under the NER.

In addition to the NER prescribed pass through events, AusNet proposed 6 nominated pass through events. Of these, 5 were approved as part of our determination for the current period (an insurance coverage event; insurer credit risk event; terrorism event; natural disaster event; and retailer insolvency event) and will continue to apply in 2026–31.

While we recognise the important role of pass through events as one element of the framework for managing uncertainty, we are also careful to ensure new nominated events are included only where they reflect an appropriate allocation of risk and are clearly justified with regard to the nominated pass through event considerations in the NER. In this context, we have not accepted the new cost pass through event for electrification AusNet proposed for the 2026–31 period. Among other things, we do not consider the proposed event is clearly defined or measurable, and consider it is manageable by means other than a cost pass through. Full details of our assessment can be found in Attachment 4 to this final decision.

2.8.2 Contingent projects

Contingent projects are usually significant network augmentation projects that are reasonably required to be undertaken to achieve the capex objectives. However, unlike other proposed capex projects, the need for the project within the regulatory control period and the associated costs are not sufficiently certain. Consequently, expenditure for such projects does not form a part of the total forecast capex that we approve in this determination. Such projects are linked to unique investment drivers and are triggered by defined events. The occurrence of the trigger event must be probable during the relevant regulatory control period. The cost of the projects may ultimately be recovered from consumers in the future if certain predefined conditions or ‘trigger events’ are met.

AusNet proposed 2 load-driven augmentation expenditure projects as contingent projects in its revised proposal:

- Cranbourne Zone Substation ($53.9 million ($2024)): this involves installing a third 20/33MVA transformer, switch room, busbar and new 22kV distribution feeder(s) at the zone substation to accommodate growing demand and enable transfer of load from constrained neighbouring substations to maintain supply during peak periods.
- Wodonga-Barnawartha Area Augmentation ($59.3 million ($2024)): this involves adding a new 66kV line and upgrading low-capacity sections of existing lines between Wodonga Transmission Terminal Substation and Barnawartha zone substation.

We consider AusNet has justified the need for these contingent projects and shown they are reasonably necessary to meet the localised demand in Cranbourne and Wodonga-Barnawartha Areas associated with the development of specific commercial projects. However, we had concerns with the proposed trigger events and have worked with AusNet to develop appropriate trigger events, which we consider meet the NER requirements for contingent projects.

Our final decision on AusNet’s proposed contingent projects for the 2026–31 period is set out in Attachment 2.

3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. They provide important balancing incentives under network determinations, encouraging businesses to pursue expenditure efficiencies while maintaining the reliability and overall performance of the network.

Our final decision on the incentive schemes that will apply to AusNet in the 2026–31 period is as follows.

3.1 Capital Expenditure Sharing Scheme

Our final decision is that the CESS will continue to apply to AusNet in 2026–31. This incentivises efficient capex throughout the period by rewarding efficiency gains and penalising efficiency losses, each measured by reference to the difference between forecast and actual capex. Consumers benefit from improved efficiencies through a lower RAB, which is reflected in regulated revenues for future periods.

We updated the CESS in August 2025 and introduced a mechanism which takes the potential for change in forecast connections volumes into account. We also updated the guidelines to allow adjustments to CESS penalties following an ex post review for any additional large bespoke connections, including data centres, that have not been included in a network's proposal. As these adjustments are new additions to the CESS, we sought AusNet's views in its revised proposal on how this adjustment can be applied.

AusNet proposed excluding capex under the volumetric adjustment and for the following new large bespoke connections:

- data centres
- grid scale batteries and renewable generator hybrids
- community batteries
- other bespoke large commercial connections.

We consider that community batteries are not large bespoke connections as per our guideline, because expenditure is forecast based on standardised unit rates. Given this, we have classified them as business-as-usual connections, and they will be subject to the volumetric adjustment.

We consider the volumetric adjustments and ex post adjustment mechanisms are in the long-term interest of consumers as they reduce any windfall gains and losses associated with forecasting error. Therefore, consistent with our draft decision, we will apply the CESS as set out in the Capital Expenditure Incentives Guidelines (version 4) to AusNet in the 2026–31 regulatory control period.

AusNet also proposed that its innovation capex be excluded from the CESS in the 2026–31 period We have maintained our position to not have category specific exclusions beyond the volumetric adjustment for connections. However, we note that AusNet may choose not to recover a CESS reward if it does not undertake innovation capex.

3.2 Efficiency Benefit Sharing Scheme

Our final decision is that the EBSS will continue to apply to AusNet in 2026–31. This provides a continuous incentive to pursue efficiency improvements in main standard control services opex and provide for a fair sharing of these between networks and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods.

3.3 Customer Service Incentive Scheme

Our draft decision was to reject AusNet's proposed CSIS for the following reasons:

- the lack of baseline data and targets
- the proposal to apply a +/-1% revenue at risk, and
- the potential risk of interrelationship with the STPIS.

In lieu of applying the CSIS, our draft decision was to apply the customer service (telephone answering and new connections) parameters of the Service Target Performance Incentive Scheme.

AusNet's revised proposal accepted our draft decision that its proposed revenue at risk was inconsistent with the CSIS. However, it did not accept our arguments regarding the potential overlap with the STPIS, lack of baseline data and targets, and our proposal to apply the new connections parameter of the STPIS.

Our final decision is not to apply the CSIS presented in AusNet's revised proposal, as it has not addressed the concerns raised. While we agree with AusNet's argument in its revised proposal that its proposed CSIS does not overlap with the STPIS, we do not consider 12 months of data to be sufficient to establish meaningful baseline data and targets.

Instead, we will apply the telephone answering component of the STPIS, but not the new connections parameter for reasons explained in detail in Attachment 9. While the revised proposal confirmed some of our original assumptions when raising this parameter, based on stakeholder feedback, we will not activate the new connections parameter of the STPIS in the 2026–31 period.

3.4 Service Target Performance Incentive Scheme

AusNet accepted our draft decision to apply the version 2.0 of the STPIS for the 2026–31 regulatory control period.[42]

In accordance with the STPIS,[43] our final decision is to set AusNet's performance targets based on average performance over the past 5 regulatory years with adjustments to account for expected reliability improvements associated with expenditure programs.[44]

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42 AusNet, *Electricity Distribution Price Review - 2026–31 Regulatory Proposal*, December 2025, pp 252–253.

43 STPIS Version 2.0, cl 3.2.1.

44 The expenditure programs are 10 WSF & BN11 (reliability) and Covered conductor & ACR (resilience). Our reasons for accepting the reliability and resilience programs are outlined in Attachment 2.

Attachment 7 outlines the reasons for our final decision.

3.5 Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

Our final decision is to apply the DMIS and DMIAM to AusNet in the 2026–31 regulatory control period. The DMIS provides network service providers with financial incentives for undertaking efficient demand management activities. The DMIAM funds research and development in demand management projects that have the potential to reduce long-term network costs. This approach is consistent with AusNet's revised proposal,[45] and our draft decision on DMIS and DMIAM.[46]

3.6 Victorian F-Factor incentive scheme

The F-factor scheme is prescribed by the Victorian Government's 'F-factor scheme order 2016' to reduce the risk of fire starts by network assets.[47] We will continue to adopt our current approach to give effect of the outcomes of the scheme as an 'I-factor' component within the price control formula.

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[45] AusNet Services, *AusNet Electricity Distribution Price Review 2026–31 Revised Regulatory Proposal*, December 2025, p 248.

[46] AER, *Attachment 8 - DMIS and DMIAM - Draft decision – AusNet Services distribution determination 2026–31,* September 2025.

[47] Victoria, *Gazette: General*, No G 51, 22 December 2016, p 3239.

4 Network pricing

4.1 Service classification

Our determination for AusNet separates the regulated distribution services it provides into different classifications, which determines how it will recover the cost of providing those services through network prices. We set out our proposed approach to the classification of distribution services to be provided by AusNet in 2026–31 in our Framework and Approach paper in July 2024, at which time services were classified as either:

- Standard control services: those that can only be provided by the relevant DNSP, and are common to most, if not all, of a DNSP's customers. The costs of providing these services are captured in the building block revenue determination discussed in the previous sections of this Overview and shared between all consumers.
- Alternative control services: those that can only be provided by the relevant DNSP but will only be required by some of its customers, some of the time; or services that can be purchased from the relevant DNSP, but which can also—or have the potential to be—purchased from a competing provider. The cost of providing alternative control services is recovered from users of those services only.

In recognition of material changes in circumstances since the Framework and Approach paper was published, our final decision makes the following changes to the service classifications set out in the Framework and Approach:

- Type 9 metering services, if required to be provided by a Victorian DNSP upon request by a public lighting customer in relation to a public lighting asset pursuant to an Order made under sections 15A and 46D of the Victorian *Electricity Industry Act 2000*[48] as in force from time to time, will be classified as direct control services and then as alternative control services within the existing public lighting service group.
- Distribution asset rental for electric vehicle charging infrastructure, and the facilitation of distribution asset rental for this infrastructure, will be classified as negotiated distribution services. Facilitation of this new, negotiated distribution service will be excluded from the existing shared asset facilitation service that forms part of the standard control, common distribution service.

We do not directly regulate the prices, terms and conditions of access to negotiated distribution services. The effect of a negotiated service classification is that, for the 2026–31 period, negotiations between AusNet and parties seeking access to distribution asset rental for electric vehicle charging infrastructure will be subject to:

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48 Consultation by the Victorian Department of Energy, Environment and Climate Action (DEECA) on amendments to the *Advanced Metering Infrastructure (Obligations to Install Meters) Order 2017* (made under sections 15A and 46D of the *Electricity Industry Act 2000*, gazetted on 10 October 2017) closed in February 2026. Publication of the *Advanced Metering Infrastructure (Obligations to Install Meters) Order 2026* is expected to occur in May 2026.

- a Negotiating Framework, which sets out the procedure to be followed during negotiations between the DNSP and any person who wishes to receive a negotiated distribution service, as to the terms and conditions of access to the service, and
- Negotiated Distribution Service Criteria (NDSC), setting out the principles that guide negotiations and outcomes, and must be applied by DNSPs in negotiating terms and conditions of access, including prices and access charges.

We will apply those same principles in arbitration of access dispute between a DNSP and a service applicant as to the terms and conditions of access to a direct control service or to a negotiated distribution service.

The Negotiating Framework and NDSC for the 2026–31 period are discussed in Attachment 17 to this final decision.

4.2 Tariff structure statement

Our final decision is to approve AusNet's revised TSS. In making our final decision, we considered the late amendment AusNet proposed to its revised TSS to replace tariff codes for its default small residential time-of-use and time-of-use feed in tariffs. We have amended AusNet's revised TSS to give effect to those changes. We are satisfied that AusNet's TSS complies with the pricing principles for direct control services and other applicable requirements of the NER.

AusNet's revised TSS for the 2026–31 period is its third since the AEMC's *Distribution Network Pricing Arrangements* rule change in 2014 that introduced the tariff structure statement framework.[49] This TSS is also AusNet's first since the AEMC's 2021 *Access, pricing and incentive arrangements* rule change that allowed for two-way pricing.[50] Together these rule determinations introduced several reforms to distribution pricing, including to progress cost reflective pricing and to support more CER onto the network. AusNet's 2026–31 TSS will apply from 1 July 2026 and remain in effect until the end of the regulatory period.

We assess TSSs against the requirements of the NER and NEL, including the pricing principles and other applicable requirements of the NER. The assessment includes whether the network tariffs progress towards better reflecting network costs,[51] or progress network tariff reform. Network tariff reform enables distributors to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use consumers and can support the energy transition currently underway. Where price signals are passed through by retailers, and consumers are well placed to respond to these price signals, appropriately structured tariffs can enable growth in the value consumers derive from their CER, and in the number of consumers with CER. At the same time, this response to price signals can reduce network constraints and minimum load issues and therefore reduce the level of network investment required, resulting in lower prices for all consumers.

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49 AEMC, *Rule Determination – National Electricity Amendment (Distribution Network Pricing) rule 2014*, November 2014.

50 AEMC, *Rule Determination – National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Resources) rule 2021*, August 2021.

51 NER, cl 6.18.5(a).

Our draft decision emphasised that AusNet should consider the extent that well-designed network tariffs can shift future demand growth out of peak periods and into low/minimum demand periods. Our final decision also flags that we expect AusNet to continue to consider the links between TSSs, expenditure and the capacity of network tariffs, along with non-network strategies like demand management and control, to permanently shape customer load and support efficient use of the network in its fourth TSS.

In making our final decision, we have considered that under the pricing principles, tariffs may vary from those complying with the economic pricing principles to the extent permitted by the NER.[52] That is, to consider the pricing principles relating to customer impacts and retailer ability to incorporate tariffs in a retail offer and/or customer understandability. Such tariffs comply with the NER and other applicable regulatory instruments. We are also required to make our decisions in a manner that will or is likely to contribute to the achievement of the NEO.

While an indicative pricing schedule must accompany the TSS, the price levels for each tariff for each year of the 2026–31 period are not set as part of this determination. Annual prices are subject to a separate, annual pricing process each year of the regulatory period.

4.2.1 Our final decision and its context

We approved many elements of AusNet's initial TSS in our draft decision. This included the introduction of a solar soak tariff for residential customers (a time-of-use tariff with very low consumption charges between 11am and 4pm) to replace its existing default time-of-use tariff, introduction of an individually calculated tariff, and refinements to critical peak charging tariffs for medium and large customers. Attachment 13 of our draft decision sets out our reasons for approving those elements. We do not repeat them in our final decision. Rather, our final decision focuses on:

- AusNet's response our draft decision – for example, we required AusNet's revised TSS to include better supporting information for its proposed 1kWh/day basic export levels and LRMC input forecasts based on at least a 10-year period
- any changes between AusNet's initial TSS and its revised TSS
- submissions in response to our draft decision and/or AusNet's revised TSS.

Our final decision is to approve AusNet's revised TSS. AusNet's revised tariff structure statement addressed key elements of our draft decision. These elements included:

- providing additional information on how it had regard to network intrinsic hosting capacity in proposing 1 kWh/day basic export levels for its proposed two-way tariff
- extending the LRMC input forecasts to 10 years and providing further explanation of forecast demand driving expenditure
- clarifying that its dedicated circuit tariff will include 6 to 8 hours of supply

52 NER, cl 6.18.5(c).

- including network bill impact analysis for large customers affected from being reassigned from legacy tariffs to default tariffs, and residential customers affected from being assigned from the withdrawn optional demand tariff to the default time-of-use tariff
- changing the name of its unmetered supply tariff to 'public lighting and street furniture' and clarifying that this tariff would be available to type 7, type 8 and type 9 metered load that is considered public lighting or street furniture.

AusNet proposed the following additional changes in its revised TSS (ones not in response to our draft decision) that complement the changes it made in response to our draft decision:

- a new site-specific tariff for new sub-transmission customers
- changes to its methodology for calculating network support exemptions for storage customers.

In addition, AusNet made a late amendment to its revised TSS, via a letter to the AER, to revise the tariff codes for its default time-of-use tariff.[53] We have amended AusNet's revised TSS to reflect these changes. Changes to AusNet's tariff codes were initiated by AusNet, in response to a retailer preference for new tariffs to have new tariff codes (the approach taken by other Victorian distributors). Red Energy and Lumo Energy recommended that AusNet adopt the same approach to applying new tariff codes to new tariff structures as Jemena and CitiPower, Powercor and United Energy (CPU), because a consistent approach simplifies the retail process and reduces costs.[54]

Submissions covered a range of views on specific network tariff structures, assignment policies and progress on network tariff reform. Submissions generally supported the progress of network tariff reform in Victoria (including introduction of solar soak periods and optional two-way tariffs, noting that some submissions supported further consistency between the Victorian distributors' two-way pricing tariffs.[55] Additionally, the Victorian Government supported AusNet increasing the level of its two-way tariff reward.[56] However, multiple submissions also noted that Victorian distributors are somewhat constrained in progressing tariff reform because the Victorian Government does not support the mandatory assignment of small customers to cost reflective tariffs.

A number of submissions highlighted the need for considered and coordinated education on tariffs in the context of an evolving tariff environment in Victoria. For example, the CCP32's feedback supported a joint tariff information campaign between Victorian distributors,

53 AusNet, *Revision to TSS tariff codes*, February 2026, p 1.

54 Red Energy and Lumo Energy, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 1.

55 AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 1; Hon Lily D'Ambrosio MP, *Submissions on Victorian electricity distribution proposals 2026–31*, January 2026, pp 1–2.

56 Hon Lily D'Ambrosio MP, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, pp 1–2.

retailers and the Government.[57] Similarly, Jemena's Energy Reference Group (ERG) noted and urged the AER to clarify who is responsible for this education.[58] While these submissions related to Jemena and AusNet's revised proposals, we consider that customer engagement is relevant to all Victorian distributors. This is discussed further in section 13.1.3 of our final decision Attachment 13.

There were also multiple submissions that commented on the Victorian distributors' kerbside EV tariff trials which they will run over the 2026–31 period. The submissions generally supported EV tariff trials but advocated for eligibility for the trials to be broadened, for example, submissions from Nexa Advisory, Evie Networks, AGL and the Victorian Government.[59] The Victorian Government also emphasised that any such trials should still be cost reflective.

While we do not have a role in approving or assessing tariff trials, our final decision Attachment 13 notes that if the Victorian distributors were to propose these trials as full tariffs in their TSSs for the 2031–36 period, we would then assess them against the pricing principles and other applicable requirements of the NER. We would only approve tariffs that complied with the NER's distribution pricing principles and other NER requirements. This is discussed in Appendix A of our final decision Attachment 13.

In consideration of submissions, our final decision:

- approves AusNet's proposed two-way tariff, with higher export rewards than proposed by AusNet in its initial TSS. We have not required further consistency between the Victorian distributors' two-way tariffs, for example requiring Jemena and AusNet to introduce seasonal components in their tariffs to match CPU's. We consider that the distributors have achieved *some* consistency by having the same basic export levels of 1/kWh per day and solar soak windows. However, we acknowledge that they have maintained differences to reflect differences in their networks
- encourages AusNet to engage with the other Victorian distributors, retailers and the Victorian government to undertake communication and engagement to build customers' understanding of tariffs. However, we consider that any joint engagement or communication should focus on how customers can understand, respond to and benefit from *retail* tariffs and signals, rather than network tariffs. This is because customers are not directly exposed to network tariffs, and it is the retail offer that customers can see and potentially respond to.

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57 CCP32, *AusNet Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, pp 22–23; CCP32, *Jemena Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 11; CCP32, *CitiPower Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 20; CCP32, *Powercor Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 22; CCP32, *United Energy Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 22.

58 Jemena Energy Reference Group, *Feedback to AER on Jemena Electricity Networks electricity distribution proposals 2026–31*, January 2026, p 5.

59 Nexa Advisory, *Submission on Victorian Electricity distribution proposals 2026–31,* January 2026, pp 7–10; Evie Networks, *Submission on Victorian Electricity distribution proposals 2026–31,* January 2026, pp 3–6; AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 3; Hon. Lily D'Ambrosio MP, *Submission on Victorian electricity distribution proposals 2026–31*, February 2026, pp 6–7.

- explains the trial tariff framework, and encourages the Victorian distributors to engage in tariff trials for a broader range of EV charging load during the 2026–31 period
- accepts AusNet's late amendment request to change tariff codes.

In our final decision Attachment 13 we describe our assessment of AusNet's proposed revised TSS. Attachment 13 of our final decision is to be read alongside Attachment 13 of our draft decision, in which we approved (and explained the reasons for the approval of) many elements of AusNet's initial proposed tariff structure statement. Alongside Attachment 13, we publish marked up and clean versions of AusNet's revised tariff structure statement, schedule of tariff structures and charging parameters and its revised indicative price schedule to reflect the amendment to its tariff codes.

4.3 Alternative control services

4.3.1 Public lighting

Public lighting services include the provision, construction and maintenance of public lighting assets. This includes technologies such as energy-efficient light emitting diode (LED) luminaires and emerging public lighting technologies such as smart-enabled luminaires.

Our draft decision did not accept AusNet's public lighting proposal. We made several adjustments, including for replacement cycles, inflation and labour price growth. We also encouraged AusNet to consult further with stakeholders on its accelerated LED rollout and smart lighting services.

In its revised proposal, AusNet proposed to accelerate its LED rollout, replacing all non-LED lights by the end of the 2026–31 period, and introduce smart lighting services. It did this in simplified public lighting models that recognised previously council-funded LED lights in order to avoid / minimise the cross subsidisation between councils who have already upgraded their LED lights and the councils who are yet to upgrade.

The Victorian Greenhouse Alliance's submission stated it broadly supported the revised public lighting proposals of the 5 Victorian DNSPs, particularly the accelerated LED rollouts. It considered this investment will deliver significant energy savings and emissions reductions for councils and communities.[60]

Our final decision is to not accept AusNet's public lighting proposal, although its revised proposal was largely reasonable. This is because in our final decision we have made several mechanical changes related to update inflation, the weighted average cost of capital and labour price growth. In addition, our final decision to classify type 9 metering services as alternative control services means that the costs as proposed by AusNet are included in public lighting prices.

Our final decision public lighting prices for 2026–27 are on average 1.1% higher compared to AusNet's revised proposal.

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60 VGA, *Victorian Greenhouse Alliances - Submission - Victorian electricity distribution proposals 2026–31 - January 2026*, p 1.

The reasoning behind our final decision is outlined in further detail in Attachment 14.

4.3.2 Metering services

Metering services include maintenance, reading, data services, and the recovery of capex related to metering assets. Unlike other jurisdictions in the NEM, Victorian DNSPs are the monopoly providers of most metering services to small customers. This includes smart meters which are a part of regulated alternative control services.

Our draft decision did not accept AusNet's metering proposal. We made several adjustments to its forecast metering capex and encouraged AusNet to consider and respond to these in its revised proposal.

In its revised proposal AusNet accepted most parts of our draft decision on metering services, updating for the latest information on inputs such as inflation, the rate of return and labour escalation inputs, as well as updating inputs related to the 2024–25 year which are now known. AusNet also revised the historical capex allocations for the 2021–26 regulatory period, as requested in our draft decision.

We received submissions from CCP32 supporting AusNet's acceptance of our draft decision on metering services.

Our final decision is to not accept AusNet's revised proposal on metering services. This is because our final decision makes mechanical changes related to updated inflation, the rate of return and labour escalation inputs, as well as implementing updates on revised 2021–26 historical capex that AusNet provided subsequent to its revised proposal.

Our final decision on metering services is discussed further in Attachment 15.

4.4 Connection policy

As detailed in our draft decisions Victorian DNSPs' connection policies generally aligned with the requirements of the NER, with all DNSPs adopting enhancements following engagement on their initial proposals.

Our draft decisions recognised that the continued strong growth in data centre connections could lead to a growing cross subsidy of the tax costs associated with type 1 capital contributions from very large customers. We asked DNSPs to consider whether the net tax liability arising from type 1 capital contributions could be included as part of the upfront connection cost paid directly by the customer, rather than recovered from all customers through distribution use of system charges.

In response to our draft decisions all 5 Victorian DNSPs agreed to recover tax associated with type 1 capital contributions upfront but considered it should apply to all customers above a defined threshold, not just data centres.

All DNSPs proposed the application of upfront tax recovery to all large customers above a given threshold. However, each proposed different thresholds above which a newly connecting customer would, in addition to its upfront capital contribution, be charged upfront the tax costs associated with the capital contribution.

Our final decisions adopt a consistent threshold of ≥22 kV for load customers. This threshold limits the currently tax cross subsidy that occurs when large connections, like data centres, connect to the distribution network. The threshold is fair, provides certainty and ensures alignment across Victorian DNSPs.

For consistency and neutrality between DNSPs we considered a threshold of 1.5MW should apply to embedded generators for upfront recovery of tax costs associated with type 1 capital contributions. This is consistent with our decision on AusNet's Connection Policy for the current, 2021–26 period.

5 Constituent decisions

In accordance with clause 6.12.1 of the NER, this final decision on the distribution determination that will apply to AusNet for the 2026–31 period is predicated on the following constituent decisions.

Table 6 Constituent decisions

NER cl 6.12.1	Constituent decision
6.12.1(a)	The AER's final decision is that the classification of services set out in Attachment 11 to this final decision will apply for the 2026–31 regulatory control period.
6.12.1(b)(1)	The AER's final decision is not to approve the annual revenue requirement as set out in the building block proposal for each regulatory year of the 2026–31 regulatory control period. The AER’s final decision on the annual revenue requirement for each regulatory year of the 2026–31 regulatory control period is set out in Attachment 1 to this final decision.
6.12.1(b)(2)	The AER's final decision is to approve the commencement and length of the regulatory control period as proposed in the building block proposal. The AER’s final decision is that the regulatory control period will commence on 1 July 2026, and that the length of the regulatory control period will be 5 years (concluding 30 June 2031).
6.12.1(b1)	The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) of the NER and therefore has not made a decision in accordance with clause 6.12.1(b1).
6.12.1(c)	Acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is not to accept the total of the forecast capital expenditure for the 2026–31 regulatory control period that is included in the current building block proposal. The AER’s final decision therefore sets out an alternative estimate of the total of the required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, of $2,590.5 million ($2025–26), and reasons for that decision, in Attachment 2 to this final decision.
6.12.1(c1)	The AER’s estimate of the total of the required capital expenditure under cl. 6.12.1(c) (above) does not include expenditure for a restricted asset.
6.12.1(d)	Acting in accordance with clause 6.5.6(d) of the NER, the AER's final decision is not to accept the total of the forecast operating expenditure for the 2026–31 regulatory control period that is included in the current building block proposal. The AER’s final decision therefore sets out an alternative estimate of the total of the required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors, of $1,635.5 million ($2026-27), and reasons for that decision, in Attachment 3 to this final decision.

NER cl 6.12.1	Constituent decision
6.12.1(d1)(1)-(3)	The AER's final decision is that the following proposed contingent projects described in the current regulatory proposal are contingent projects for the purposes of the distribution determination: • Cranbourne Zone Substation ($53.9 million ($2024)) • Wodonga-Barnawartha Area Augmentation ($59.3 million ($2024)). The AER's final decision is that the capital expenditure for each of the above contingent projects reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, as set out in Attachment 2. The AER's final decision is that the trigger event in relation to each of the above contingent projects is as set out in Attachment 2.
6.12.1(e)	The AER's final decision on the allowed rate of return for the 2026–27 regulatory year is 6.29% (nominal vanilla). The rate of return for the remaining regulatory years of the 2026–31 period will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
6.12.1(e1)	The AER's final decision on the allowed imputation credits for each regulatory year or the 2026–31 regulatory control period is 0.57.
6.12.1(f)	The AER's final decision on the regulatory asset base as at the commencement of the 2026–31 regulatory control period, in accordance with clause 6.5.1 and schedule 6.2 of the NER, is $6,272.0 million ($nominal). The reasons for the AER's decision are set out in Attachment 1 to this final decision.
6.12.1(g)	The AER's final decision on the estimated cost of corporate income tax to AusNet for each regulatory year of the 2026–31 regulatory control period is zero dollars, in accordance with clause 6.5.3 of the NER. The reasons for the AER's decision are set out in Attachment 1 to this final decision.
6.12.1(h)	The AER's final decision is not to approve the depreciation schedules submitted by AusNet. The AER has therefore determined depreciation schedules in accordance with clause 6.5.5(b) of the NER, as set out in Attachment 1 to this final decision.
6.12.1(i)	The AER's final decision on how applicable incentive schemes are to apply to AusNet in the 2026–31 regulatory control period is: • Version 2 of the Efficiency Benefit Sharing Scheme will apply, for the reasons set out in Attachment 5 to this final decision. • Version 4 of the Capital Expenditure Sharing Scheme will apply, for the reasons set out in Attachment 6 to this final decision. • Version 2 of the Service Target Performance Incentive Scheme (including the customer service component) will apply, for the reasons set out in Attachment 7 to this final decision. • Version 1 of the Demand Management Incentive Scheme will apply, for the reasons set out in Attachment 8 to our draft decision.

NER cl 6.12.1	Constituent decision
	• Version 1.01 of the Demand Management Innovation Allowance Mechanism will apply, for the reasons set out in Attachment 8 to our draft decision. • A small scale incentive scheme (Customer Service Incentive Scheme) will not apply, for the reasons set out in Attachment 9 to this final decision.
6.12.1(j)	The AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final decision, including in supporting models and attachments.
6.12.1(k)	The AER's final decision on the form of the control mechanism (including the X factor) for standard control services is, in accordance with the Framework and Approach Paper, a revenue cap. The AER's final decision on the formulae that give effect to those control mechanisms is set out in Attachment 12 to this final decision.
6.12.1(l)	The AER's final decision on the form of the control mechanism(s) for alternative control services is, in accordance with the Framework and Approach Paper: • For metering services – a revenue cap. • For ancillary network services public lighting, and metering exit fees – a price cap. The AER's final decision on the formulae that give effect to those control mechanisms is set out in Attachment 12 to this final decision.
6.12.1(m)	The AER's final decision on how AusNet is to demonstrate compliance with the control mechanisms above is: • For Standard Control Services: maintain distribution unders and overs mechanisms through the annual pricing model templates. • For Alternative Control Services – metering services revenue cap: maintain metering services unders and overs account through the annual pricing model templates. • For Alternative Control Services – price caps: demonstration that proposed prices are compliant with price caps through the annual pricing model templates. These mechanisms and processes to demonstrate compliance are set out in Attachment 12 to this final decision.
6.12.1(n)	The AER's final decision is that the following additional pass through events are to apply for the 2026–31 regulatory control period in accordance with clause 6.5.10: • insurance coverage event • insurer credit risk event • terrorism event • natural disaster event • retailer insolvency event

NER cl 6.12.1	Constituent decision
	These events have the definitions set out in Attachment 4 of our draft decision.
6.12.1(n1)	The AER's final decision is to approve the tariff structure statement proposed by AusNet. The reasons for our final decision are set out in Attachment 1 to this final decision.
6.12.1(o)	The AER's final decision is that a variant of the negotiating framework as proposed by AusNet, as set out in Attachment 17 to this final decision, is to apply to AusNet for the 2026–31 regulatory control period.
6.12.1(p)	The AER's final decision is that the Negotiated Distribution Service Criteria set out in Attachment 17 to this final decision will apply to AusNet for the 2026–31 regulatory control period.
6.12.1(q)	The AER's final decision on the policies and procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another, is set out in Attachment 13 of our draft decision.
6.12.1(r)	The AER's final decision is that depreciation for establishing the regulatory asset base as at the commencement of the following 2026–31 regulatory control period (as at 1 July 2031) is to be based on forecast capital expenditure. The reasons for the AER's decision are set out in Attachment 1 to this final decision.
6.12.1(s)	The AER's final decision on how AusNet is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 2026–31 regulatory control period, and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges, is through the unders and overs mechanism. This is to be demonstrated through the use of the annual pricing model templates and is set out in Attachment 12 to this final decision.
6.12.1(t)	The AER's final decision on how AusNet is to report to the AER on its recovery of jurisdictional scheme amounts and pass through of jurisdictional scheme refund amounts for each regulatory year of the 2026–31 regulatory control period, and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those amounts, is through the unders and overs mechanism. This is to be demonstrated through the use of the annual pricing model templates and is set out in Attachment 12 to this final decision. This final decision applies to each jurisdictional scheme under which AusNet has jurisdictional scheme obligations at the time of this final decision.
6.12.1(u)	The AER's final decision is that a variant of the connection policy as proposed by AusNet, set out in Attachment 16 to this final decision, is to apply to AusNet for the 2026–31 regulatory control period.
Other constituent decisions	
	In accordance with section 16C of the *National Electricity (Victoria) Act 2005*, the NEL, the NER and the 'f-factor scheme order 2016',[61] the AER's final decision is to apply the f-factor incentive payments/penalties as a part of the 'I-factor'

[61] Victoria, *Gazette: General*, No G 51, 22 December 2016, p 3239.

NER cl 6.12.1	Constituent decision
	adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 12 to this final decision.

6 List of submissions

We received 19 submissions in response to our draft decision and AusNet's 2026–31 revised proposal.

	Date
AER Consumer Challenge Panel (CCP32)	January 2026
AGL	January 2026
Ausgrid	January 2026
AusNet Coordination Group	January 2026
Emerald Village Association	January 2026
Evie Networks	January 2026
Hon Annabelle Cleeland MP	January 2026
Hon Dr Helen Haines MP	January 2026
Hon Lily D'Ambrosio MP	January 2026
IND Technology	January 2026
John Mumford	January 2026
Kristy Hourigan	December 2025
Nexa Advisory	January 2026
RDA Hume	January 2026
Red Energy and Lumo Energy	January 2026
Sandy Point Community Power	January 2026
Save our Surroundings Riverina	January 2026
Strathbogie Shire Council	December 2025; January 2026
Victorian Greenhouse Alliances	January 2026

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	consumer energy resources
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
CPU	CitiPower, Powercor and United Energy (collectively)
CSIS	Customer Service Incentive Scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EV	electric vehicle
GWh	gigawatt hour
ICT	information and communication technology
LED	light emitting diode
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia

Term	Definition
repex	replacement expenditure
RORI	rate of return instrument
SCS	standard control services
STPIS	Service Target Performance Incentive Scheme
TSS	tariff structure statement
WACC	weighted average cost of capital