Final Decision

CitiPower 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	55

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 CitiPower 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

6. Capital expenditure sharing scheme

7. Service target performance incentive scheme

9. Customer service incentive scheme

11. Classification of 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 CitiPower Pty Ltd [ABN 76 064 651 056] (CitiPower). It is predicated on a series of constituent decisions summarised in section 5 of this Overview.[1]

This 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 CitiPower'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 CitiPower'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 CitiPower to recover $2,039.0 million ($nominal, smoothed) in revenue from consumers in the upcoming 2026–31 period. This is $4.1 million (0.2%) more than CitiPower's revised proposal. It is $515.8 million (or 33.9%) higher than the revenue we approved for CitiPower in the current, 2021–26 period.

Market factors, specifically rising inflation and interest rates, are driving higher revenues (in this case producing final decision revenues that are slightly above those proposed). In this final decision we estimate 51% of the increase in revenue from period to period can be attributed to these external factors.

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1 NER, cl 6.12.1.

Our final decision also approves continued investment in CitiPower's network to support its prudent and efficient delivery of the outcomes its consumers have identified as most important: a reliable, safe, and resilient network that delivers in line with existing service levels and supports electrification at the lowest cost.[2]

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.[3]

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 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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2 Customer Advisory Panel, *Submission - CitiPower electricity distribution proposal 2026-31*, January 2026, p 55.

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

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 and provided in CitiPower's revised proposal, we have accepted CitiPower's revised opex forecast in full, and 94.7% of CitiPower's revised capex forecast. Our final decision now approves increases of $81.5 million, or 17.2% ($2025–26) in opex, and $361.7 million, or 56.2% ($2025–26) in capex, relative to CitiPower's expected actual expenditure in the current period.

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 they 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.

Network augmentation and customer driven electrification

Augmentation (augex) is capital expenditure required to build or upgrade the network to address system constraints driven by changes in demand and network utilisation, to enable the DNSP to comply with quality, safety, reliability, security of supply and greenhouse gas emission reduction target requirements.

The total forecast capex in our final decision includes the vast majority of CitiPower's proposed augex, including its revised Brunswick modernisation program, zone substation capacity upgrades, asset relocations, CBD security of supply and HV feeder programs. The difference between the $221.1 million in augex included in our final decision and CitiPower's proposed $242 million is in our assessment of the prudent and efficient expenditure required for its customer driven electrification program.

Customer driven electrification was a key element of CitiPower's augex proposal. CitiPower proposed it to improve its steady-state voltage compliance by investing in proactive and reactive network augmentation. Consumer and stakeholder feedback on CitiPower's revised proposal emphasised the scale and pace of electrification in Victoria[4] and raised concern that electrification is outpacing the capability of the existing network, leading to undervoltage and a lowering of service levels.[5] Submissions expressed support for investment to address these issues,[6] but emphasised that utilisation of the existing network should be prioritised and proposals for expenditure uplifts carefully tested.[7]

Our final decision approves $23.4 million for CitiPower's customer driven electrification program, including $9.5 million for reactive works, and a further $13.5 million for proactive works. This is a reduction from the proposed $44.2 million in CitiPower's revised proposal, which reflects our concerns with CitiPower's economic modelling of the required expenditure (for example, the inclusion of works in areas that were not exhibiting increases in undervoltage over the 2026–31 period, and its assumptions as to major vs minor complaints). We are satisfied that our lower forecast is a prudent and efficient amount based on the available data, and one which provides a reasonable amount for CitiPower to manage the issues of undervoltage and service levels consumers have raised, at the same time allowing for some proactive investment.

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4 Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026-31*, January 2026, p 2.

5 Customer Advisory Panel, *Submission – CitiPower electricity distribution proposal – 2026-31*, January 2026, p 6.

6 CCP32, *Submission – CitiPower electricity distribution proposal – 2026-31*, January 2026.

7 Nexa Advisory, *Submission – CitiPower electricity distribution proposal 2026-31*, January 2026, p 5.

Our final decision also recognises the challenges in connecting new, large loads like data centres to the shared distribution networks. Our decision helps to ensure large customers like data centres are paying their own way when connecting to the distribution network. This includes paying for both the direct cost of connection that is only used by the data centre and a fair portion of the shared distribution network costs (the part of the network that consumers and data centres share).

We have carefully scrutinised demand forecasts, and targeted forecasting methodologies so that only net capex for data centre connections that are likely required in the forecast period are included in our decisions. We have also removed cross subsidisation of tax liability for these capital contributions by small customers. This helps ensure that the tax liability created by data centre and other large user contributions will not be unfairly subsided by small customers.

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 CitiPower's intentions to undertake beneficial CER expenditure.

We have accepted CitiPower's CER integration forecast in full. Our final decision includes a combined $23.7 million in capex and opex for CER integration, informed by CitiPower's proposed delivery of:

- A flexible services program that will support a transition from static CER import and export limits to a flexible approach to CER operation and management. This program is intended to address increasing curtailment of exports driven by CER and potentially constrained import capacity driven by electrification over the 2026–31 period.
- A non-network marketplace program, which provides non-network service providers the opportunity to provide solutions to network constraints. This program will support the development of a platform that will allow for easier interaction and access to non-network service opportunities. We agree with stakeholders that "… [non-network] platforms are a necessary foundation for procuring network support services and demand response at scale and are necessary to drive market maturity." [8]
- A data visibility program, in recognition that consistent, accessible and timely information on low-voltage network data would provide additional certainty for stakeholders which would encourage CER-related investments. Like stakeholders, we see merit in strengthening the businesses' CER capability in the immediate term given the longer-term benefits. [9] Given the forecast associated with this program is a relatively small

[8] Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026-31*, January 2026.

[9] Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026-31*, January 2026.

component of total capex, we also see low risk for consumers if these benefits take some time to be realised.

We appreciate that this is a new and uncertain area where the quantification of costs and benefits is not straightforward. While we identified some information gaps in CitiPower's proposal, on balance we see merit in strengthening CitiPower's CER capability in the immediate term given the longer-term benefits to consumers.

Vegetation management

Overgrown branches near powerlines can pose risks such as power outages or fires, especially during severe weather conditions.

In the current period CitiPower introduced helicopter mounted light detection and ranging (LiDAR) technology to inspect its electricity lines for compliance against its vegetation management obligations under the Electricity Safety (Electric Line Clearance) Regulations 2025 (Victoria). Using LiDAR provides increased accuracy and precision compared to previous, visual inspections and has helped CitiPower to better understand previously unidentified non-compliance with its vegetation management obligations.

Our final decision includes a step change of $3.5 million in opex that will allow CitiPower to address these issues. This step change provides CitiPower 28.2% more per year in vegetation management opex than it spent in 2024–25 (our most recent year of actual data) to meet safety obligations and manage risk on its network.

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 Government 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 CitiPower's offer of tariffs to small customers that encourage them to opt into 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 CitiPower'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 CitiPower's initial proposal was fit for purpose.

CitiPower's revised proposal did not include a CSIS, and our final decision will 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 CitiPower to recover a total revenue of $2,039.0 million ($ nominal, smoothed) from its consumers from 1 July 2026 to 30 June 2031.

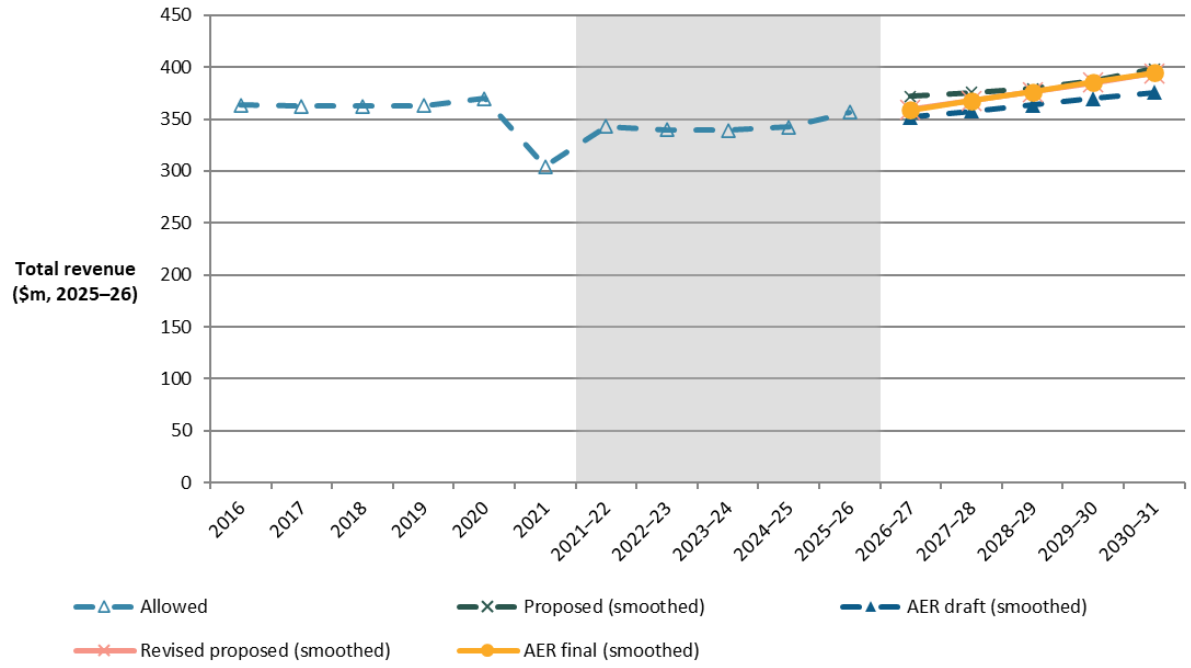
Our final decision revenue is $515.8 million (33.9%) more than CitiPower's allowed revenue in the 2021–26 period in nominal terms. In the sections below we briefly outline what is driving CitiPower's revenue.

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 CitiPower to recover $1,883.2 million ($2025–26, smoothed) over the 2026–31 period. This is $162.6 million (9.4%) higher than the revenue we approved for CitiPower in the current 2021–26 period. CitiPower's revenue over time is shown in Figure 1.

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



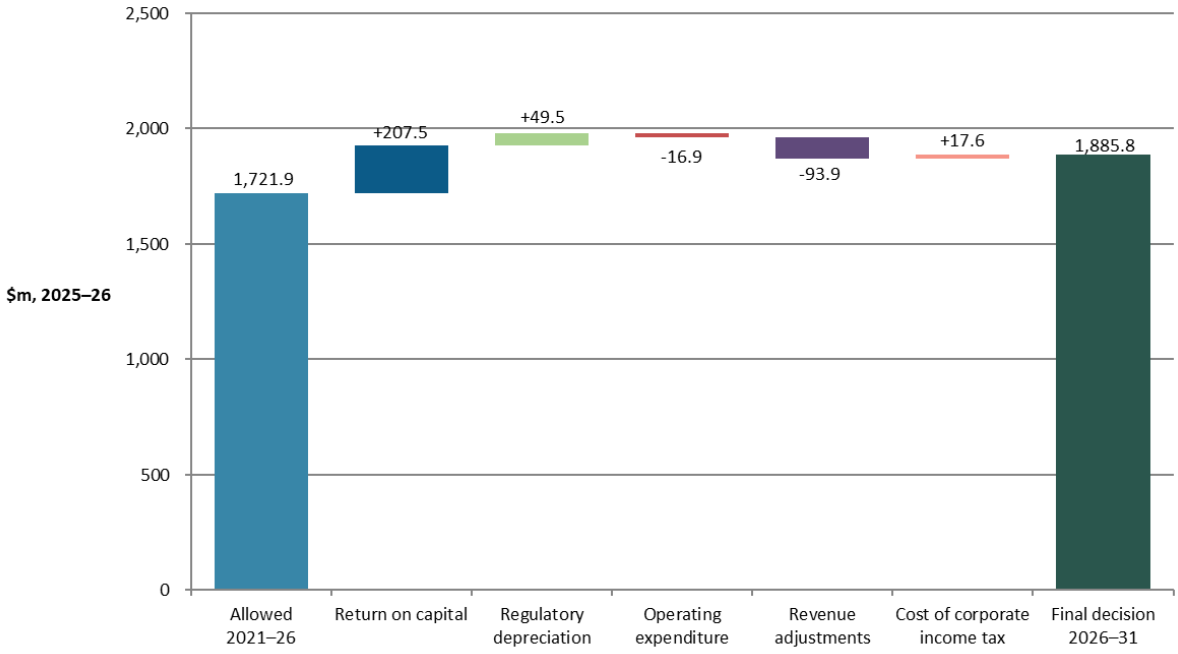
Source: AER analysis.
Note: For presentational purposes, the revenue for the half-year 2021 extension period has been doubled.

Figure 2 highlights the key drivers of the change between the revenue approved for CitiPower 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 $207.5 million (37.6%) 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 CitiPower's forecast RAB over the 2026–31 period.
- A return of capital (regulatory depreciation), which is $49.5 million (10.5%) higher than the 2021–26 period. This is caused by an increase to straight-line depreciation due to higher forecast capex in the 2026–31 period, which is partly offset by higher indexation of the RAB, mainly driven by a higher expected inflation value in the 2026–31 period.
- Forecast opex which, while higher than CitiPower's actual opex in 2021–26, is $16.9 million (2.9%) lower than the forecast we approved for the 2021–26 period.
- Revenue adjustments under AER expenditure incentive schemes, which are $93.9 million lower than the 2021–26 period, mainly due to a larger EBSS penalty and a lower CESS benefit.
- A forecast cost of corporate income tax which is $17.6 million (42.8%) higher than the 2021–26 period. This is due to a higher return on equity and a projected increase in capital contributions compared to the 2021–26 period.

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



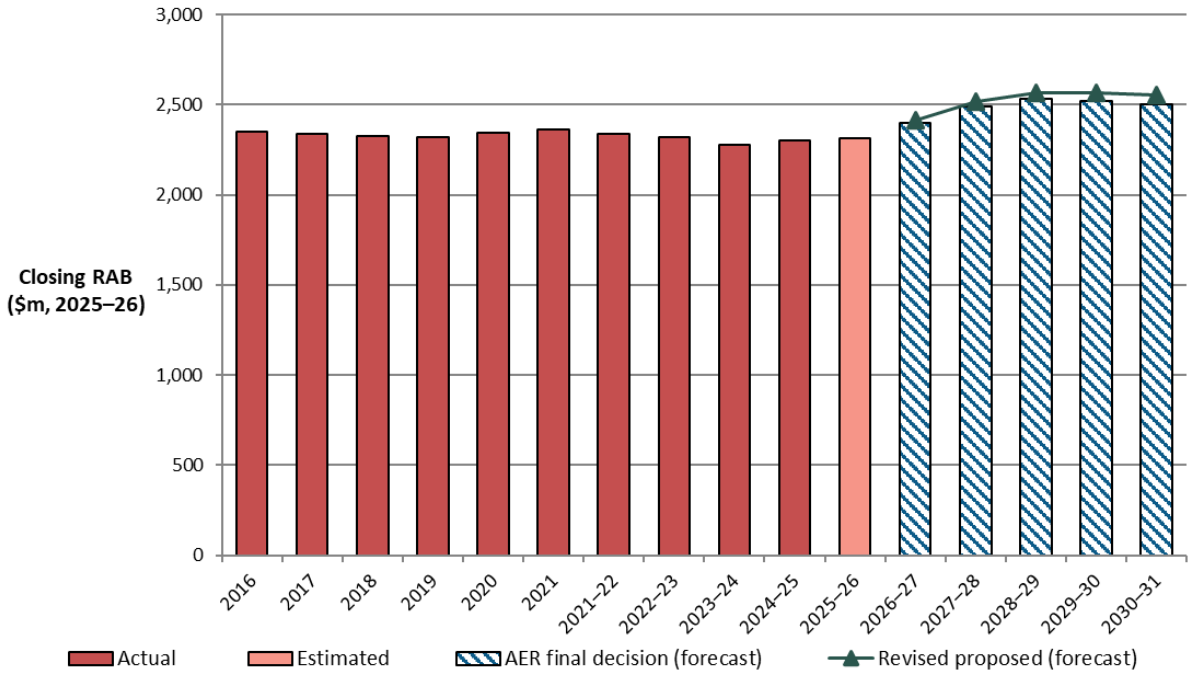
Source: AER analysis.
Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI). The 2021–26 building blocks and allowed revenue also excludes cost pass through amounts recovered through a C-factor mechanism as part of the annual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

Figure 3 shows the value of CitiPower's RAB over time in real terms. After a RAB reduction of 1.4% over the 2021–26 period, our final decision forecasts a RAB increase of $192.6

million (8.3%) 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 CitiPower proposed, reflecting our final decision to reduce CitiPower's revised proposed forecast capex.

RAB values substantially affect a network business's revenue requirements, and the total costs consumers 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.

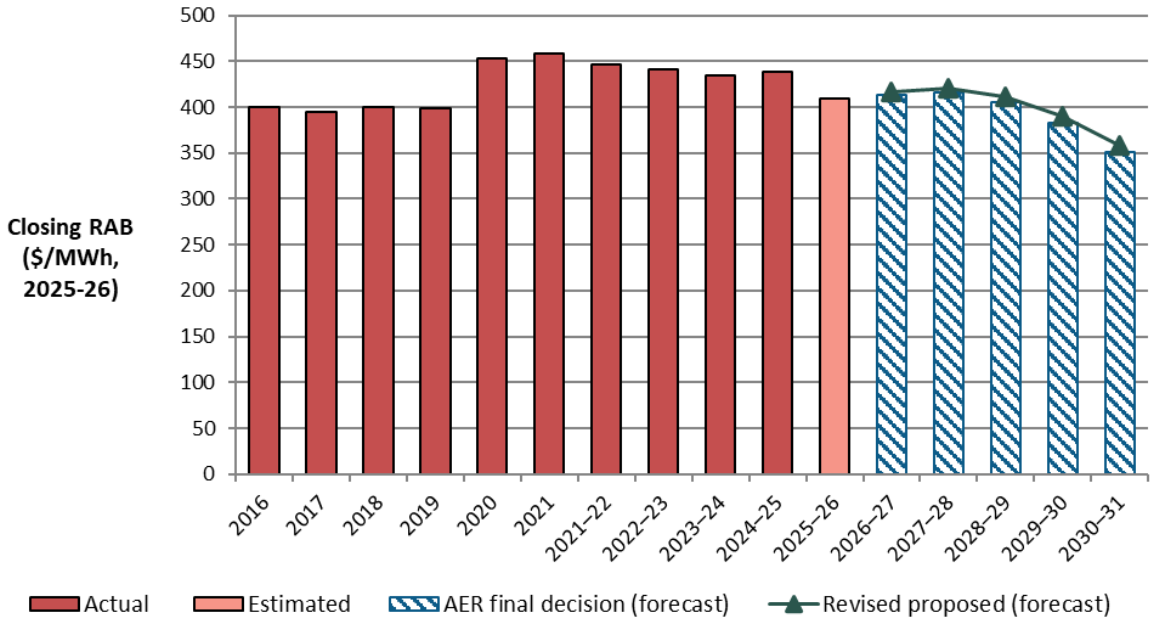
Figure 3 CitiPower's RAB value over time ($ million, 2025–26)



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, CitiPower's RAB per unit of energy consumption (MWh) has declined since the start of the 2021–26 period and is expected to decline further. As can be seen in Figure 4, over the 2026–31 period, CitiPower'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 in the RAB. This is based on CitiPower's forecast energy delivered (MWh) and could change depending on the actual volume of energy delivered.

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



Source: AER analysis.

1.2 Expected impact of our final decision on electricity bills

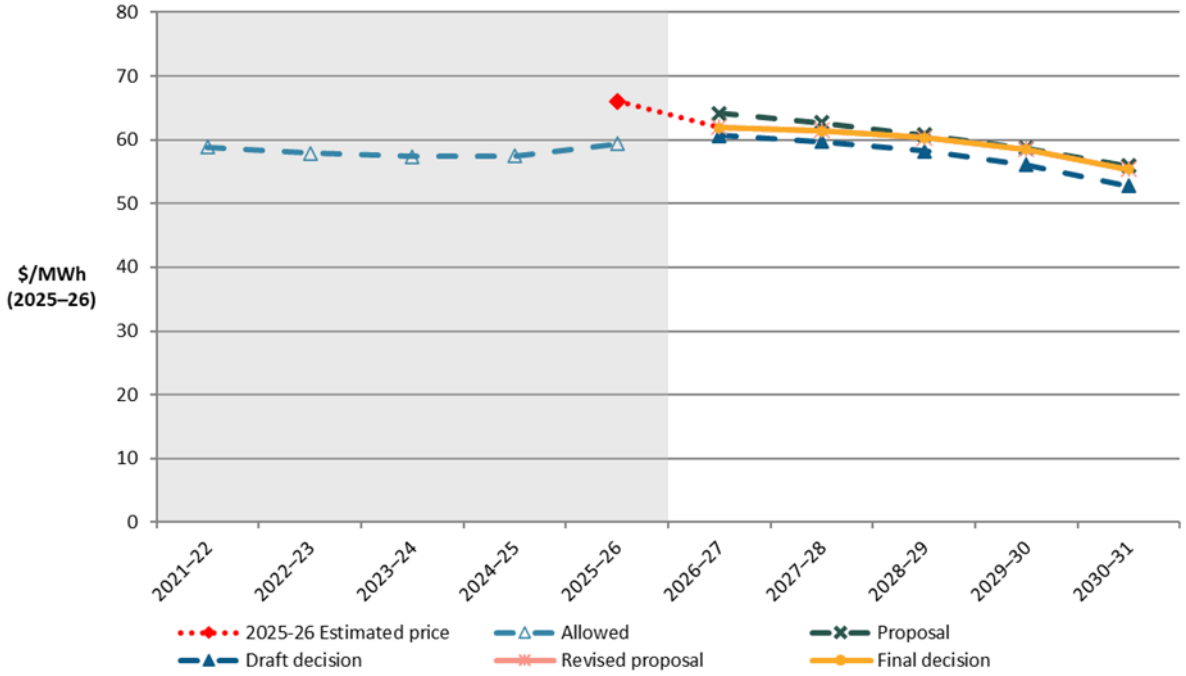
Our decision on CitiPower's revised proposal sets the revenue allowance that forms the major component of its network charges for the next 5 years.

CitiPower 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 CitiPower's distribution charges of around 16.1% in real terms by 2030–31 compared to current, 2025–26 levels, or an average reduction of 3.4% per annum.[10] 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.

[10] The average decrease to indicative network charges of 3.4% ($2025–26) per annum reflects 2 components: 1) The final decision smoothed revenue average increase of 1.2% per annum ($2025–26); and 2) CitiPower's proposed forecast energy delivered in its distribution network area, which is expected to increase on average by 4.8% per annum.

Figure 5 Change in indicative charges for 2021–26 to 2026–31 ($2025–26, $/MWh)



Source: AER analysis.

1.2.1 Potential bill impact

CitiPower's distribution charges make up around 28% of its residential customers' electricity bills and 31% of small business customers' electricity bills.[11] 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.[12] 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 CitiPower's network area, as it is today ($ nominal), would be:[13]

- a reduction of $40 (2.6%) by 2030–31, or an average reduction of $8 per annum for a residential customer. This reflects:
  - a $19 reduction for distribution standard control service charges

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

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

13 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 CitiPower's network area, respectively. Essential Services Commission, *Victorian Default Offer 2025–26, Final Decision Paper*, 21 May 2025, p 5.

  - a $21 reduction for metering.
- a reduction of $69 (2.2%) by 2030–31, or an average reduction of $14 per annum for a small business customer
  - a $44 reduction for distribution standard control services charges
  - a $25 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. CitiPower forecast the amount of annual energy delivered through its network to increase from 5,639 GWh in 2025–26 to 7,125 GWh in 2030–31, an increase of 1,486 GWh, or 26.3% 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 CitiPower would lead to bill impacts that are higher or lower than what we have estimated. This is because CitiPower 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 CitiPower, the modelled impact on average annual bills would be: [14]

- a nominal increase of $19 (1.2%) by 2030–31 for a residential consumer[15]
- a nominal increase of $64 (2.0%) by 2030–31 for a small business consumer.[16]

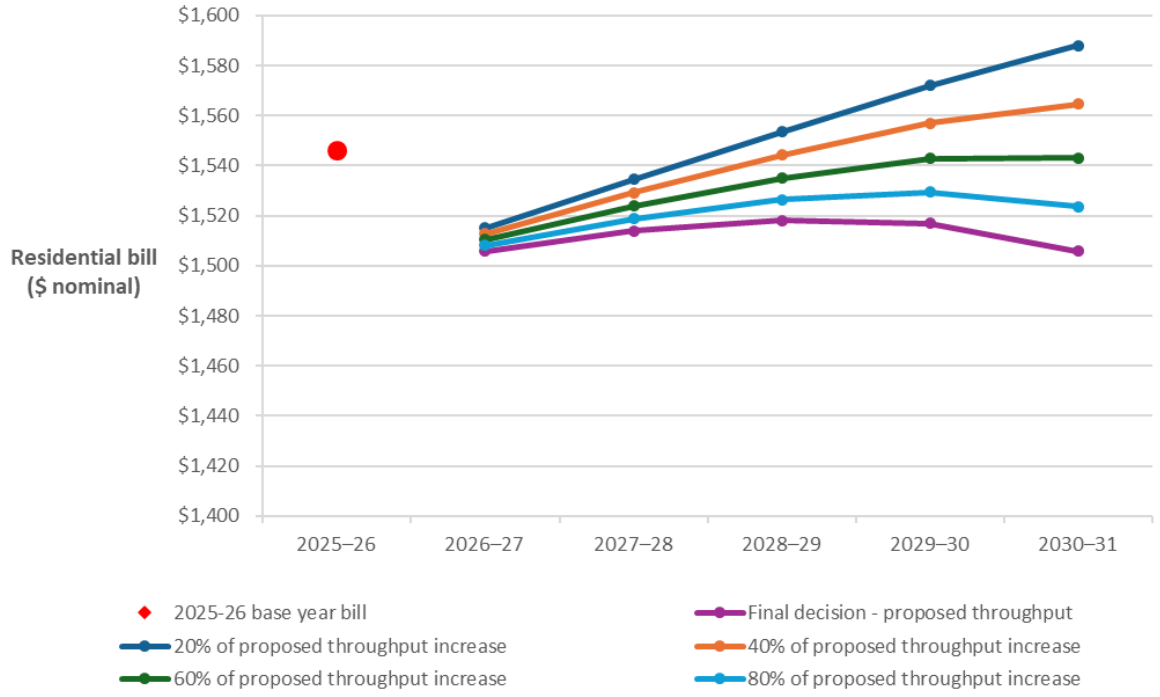
Figure 6 shows the average annual bill for a residential consumer for a range of alternative energy delivered forecasts.

[14] This would therefore reflect energy throughput of 6,233 GWh in 2030–31, or an increase in energy throughput over the period of 10.5% compared to the 26.3% increase proposed by CitiPower.

[15] This reflects an increase of $40 for distribution standard control services, and a reduction of $21 for metering.

[16] This reflects an increase of $89 for distribution standard control services, and a reduction of $25 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.

CitiPower's Customer Advisory Panel commended the nature and extent of its customer engagement. We have heard that CitiPower's consumers expect their electricity supply to be reliable, safe, and resilient in line with existing service levels and for CitiPower to support electrification at the lowest cost.[17] While it welcomed our regard for affordability, the Customer Advisory Panel also encouraged us to focus closely on customer perspectives and interests in our consideration of what is prudent and efficient.[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.

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17 Customer Advisory Panel, *Submission - CitiPower electricity distribution proposal 2026-31*, January 2026, p 5.

18 Customer Advisory Panel, *Submission - CitiPower electricity distribution proposal 2026-31*, January 2026, p 10.

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 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

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

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).

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).

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.

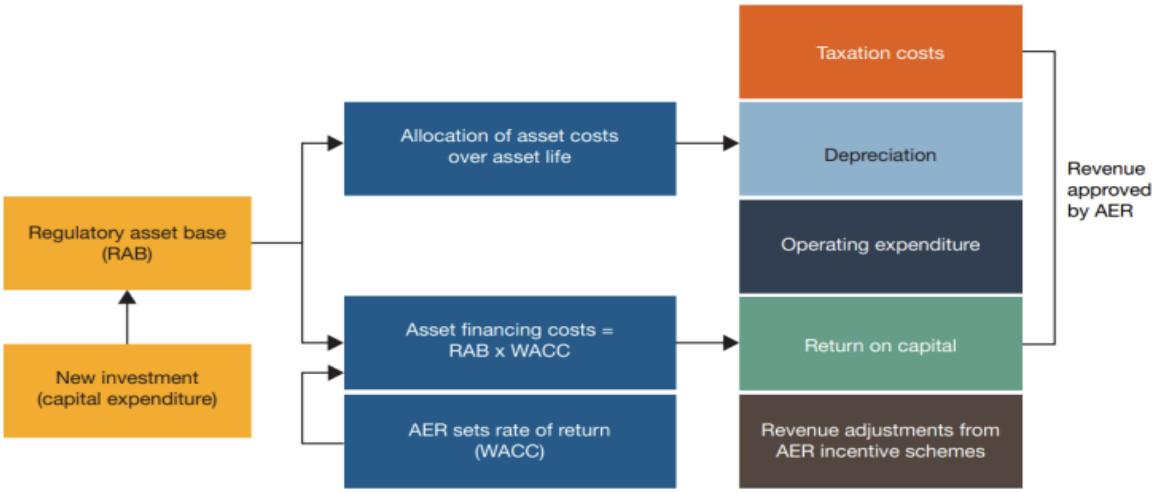
This is how we ensure that consumers are paying no more than necessary for safe, secure and reliable energy supply and a resilient network that meets their needs and delivers their preferred outcomes.

2 Key components of our final decision on revenue

CitiPower'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 CitiPower'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

CitiPower 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 slightly higher revenues than those in CitiPower's revised proposal. This is mainly driven by a higher rate of return, which increases the return on capital. The increase in revenue has been partially offset by our decision to reduce CitiPower's forecast capex, and our determinations on incentive scheme outcomes, which impact the revenue adjustments building block.

Our final decision also allows for higher revenues than those determined in the 2021–26 period. In nominal terms, CitiPower's unsmoothed revenue for the first year of the 2026–31 period (2026–27) is about 4.7% lower than its approved revenue for the last year of the 2021–26 period (2025–26). It then increases by an average of 6.9% 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 CitiPower'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 decrease of 1.1% ($ nominal) in 2026–27, followed by constant annual increases of 5.1% 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 CitiPower'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 CitiPower's revenue requirement, and the price consumers ultimately pay. Other

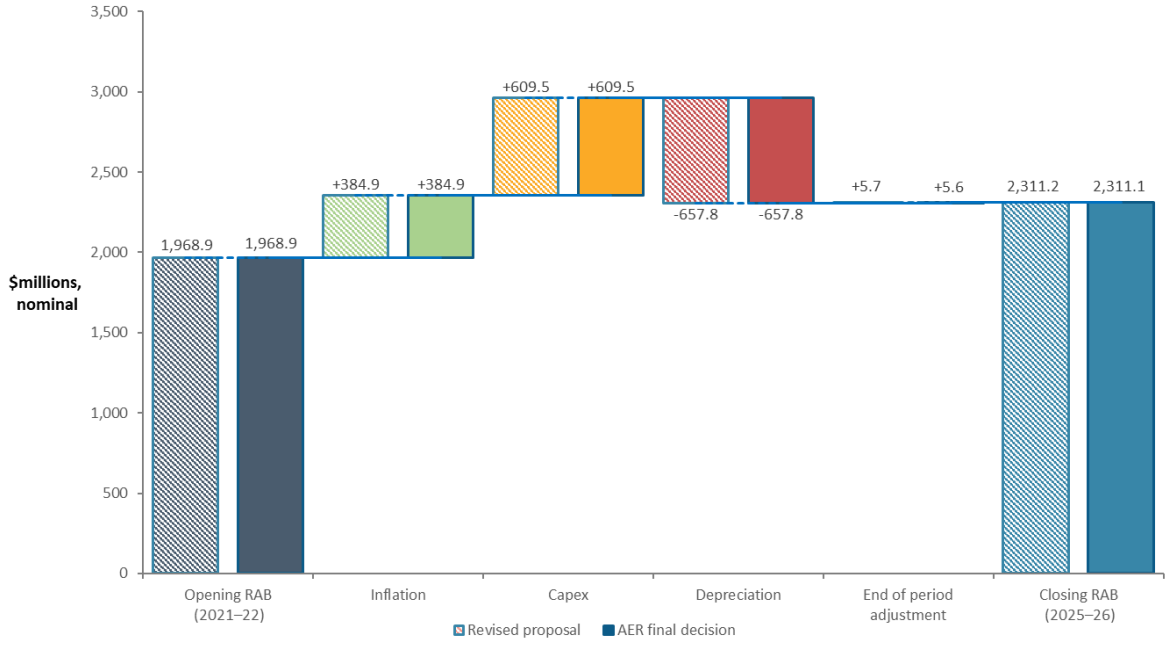
[24] Our final decision expected revenues have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

things 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 $2,311.1 million ($ nominal) as at 1 July 2026. This value is less than $0.1 million lower than CitiPower's revised proposed opening RAB value of $2,311.2. This reduction is due to minor input updates to the roll forward model.

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

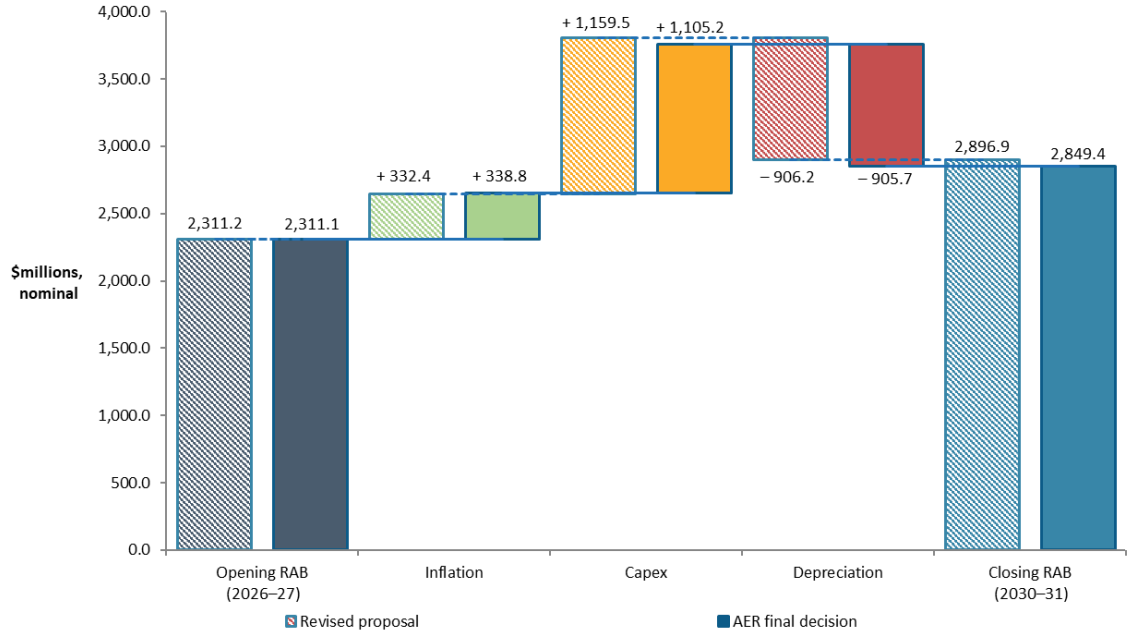
Figure 8 Key drivers of change in the RAB over the 2021–26 period – revised proposal compared with AER's final decision ($million, nominal)



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 CitiPower's forecast RAB over the 2026–31 period compared to its revised proposal. Our final decision projects an increase of $538.2 million (23.3%) to the RAB by the end of the 2026–31 period compared to the $585.7 million (25.3%) increase in CitiPower's revised proposal. We have determined a projected closing RAB of $2,849.4 million ($ nominal) as at 30 June 2031, which is $47.5 million (1.6%) lower than CitiPower's revised proposal of $2,896.9 million. This lower value is mainly due to our final decision to reduce CitiPower'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 decision 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 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]

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

26 NEL, section 18H.

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

CitiPower's revised proposal adopted the 2022 RORI.[28] Our final decision rate of return of 6.14% (nominal vanilla) is higher than the 5.93% 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 CitiPower'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 CitiPower's rate of return (nominal)

	AER's draft decision (2026–31)	CitiPower'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%	4.69%[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%	8.41%	Constant (%)
Return on debt (nominal pre-tax)	4.58%	4.58%	4.62%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	5.93%	5.93%	6.14%[c]	Updated annually for return on debt
Expected inflation	2.55%	2.55%	2.62%	Constant (%)

Source: AER analysis; AER, *Draft decision – CitiPower distribution determination 2026–31*, September 2025, p 13; CitiPower, *RRP MOD 2.01 – SCS PTRM,* December 2025.
(a) Calculated using CitiPower's actual risk-free rate averaging period of 60 business days ending 30 January 2026.
(b) Calculated using CitiPower's actual nominated return on debt averaging period.
(c) Applied to the first year of the 2026–31 regulatory control period.

28 CitiPower, *Revised Proposal 2026–31 – Revenue and Expenditure Forecasts,* December 2025*,* p 18.

29 CitiPower, *ATT 1.02: Averaging periods for returns on equity and debt – Confidential*, 30 June 2025, p 2.

30 CitiPower, *ATT 1.02: Averaging periods for returns on equity and debt – Confidential*, 30 June 2025, p 3.

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

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] CitiPower has proposed to use our approach to estimate debt and equity raising costs.[33]

Our final decision accepts CitiPower's proposed opex including debt raising costs.

We have updated our estimate for the 2026–31 period based on the benchmark approach using updated inputs. This results in equity raising costs of $2.2 million.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 RORI.[34] CitiPower's revised proposal also adopted this value.[35]

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. CitiPower's revised proposal also adopted our approach.[36]

Table 2 Final decision on CitiPower'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 of 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 year ending June 2027 and 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.

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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 CitiPower, *RRP MOD 2.01 – SCS PTRM,* December 2025.

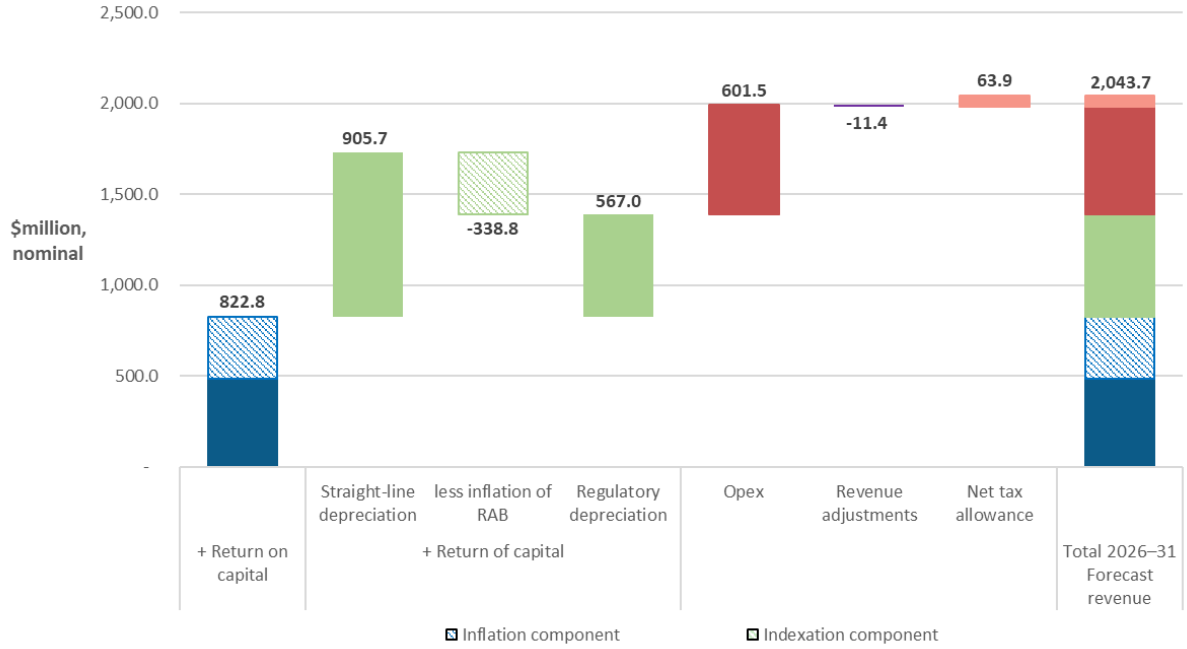
34 AER, *Rate of return Instrument (version 1.2),* March 2024, cl 27.

35 CitiPower, *RRP MOD 2.01 – SCS PTRM,* December 2025.

36 CitiPower, *Revised Proposal 2026–31: Revenue and Expenditure Forecasts,* December 2025, p 18.

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 $567.0 million ($ nominal) for the 2026–31 period. This is a reduction of $6.8 million (1.2%) from CitiPower's revised proposal of $573.7 million.

This reduction is primarily due to our final decision to apply a higher expected inflation rate for the 2026–31 period compared to CitiPower's revised proposal, which has increased the indexation of the RAB and in turn reduced the regulatory depreciation building block.[37]

[37] Since RAB indexation is deducted from straight-line depreciation, the higher RAB indexation results in lower regulatory depreciation.

2.4 Capital expenditure

Our final decision is to not accept the total forecast capex of $1,060.9 million ($2025–26) in CitiPower's revised proposal. Our alternative forecast is $1,005.0 million, which is 5.3% below CitiPower's forecast.

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

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

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

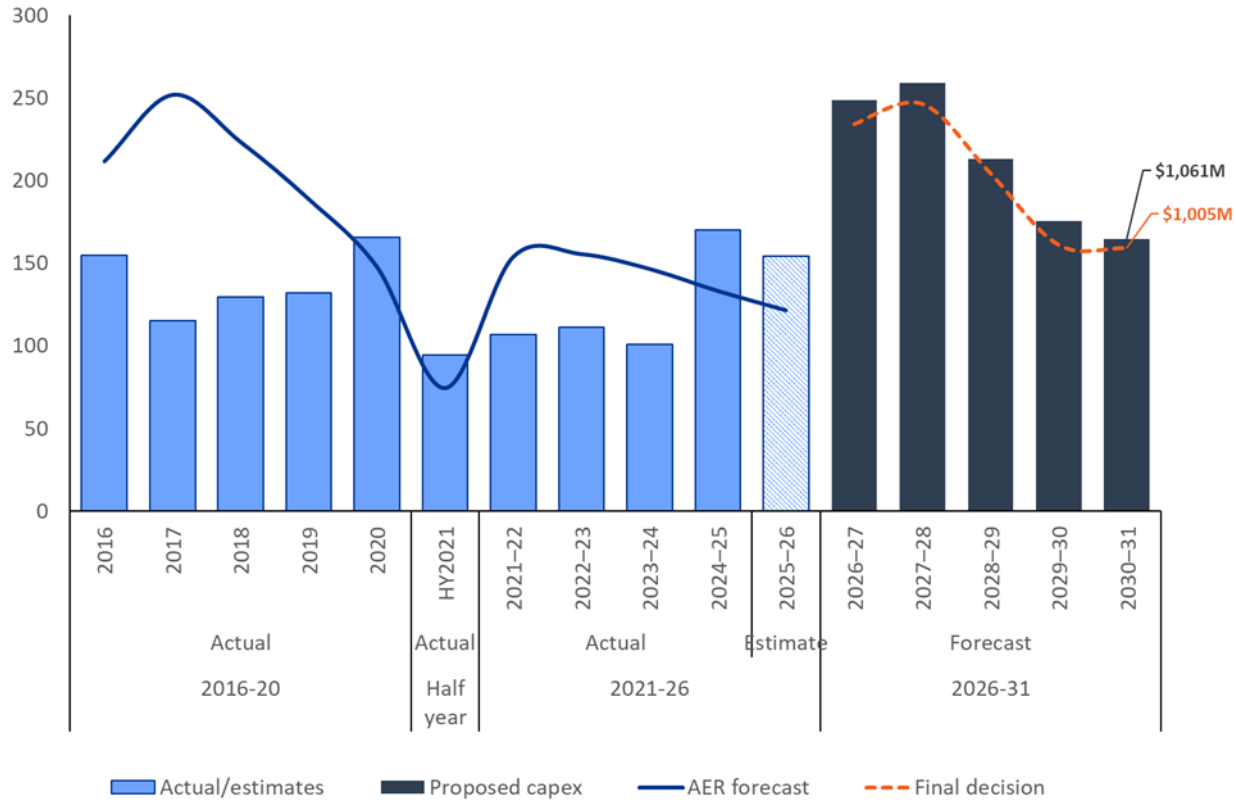
	2026-27	2027-28	2028-29	2029-30	2030-31	Total
CitiPower's revised proposal	248.4	259.2	213.3	175.6	164.5	1,060.9
AER's final decision	234.2	246.3	204.2	161.0	159.2	1,005.0
Difference ($)	**-14.2**	**-12.8**	**-9.0**	**-14.5**	**-5.3**	**-55.9**
Difference (%)	**-5.7%**	**-5.0%**	**-4.2%**	**-8.3%**	**-3.2%**	**-5.3%**

Source: CitiPower's revised proposal and AER analysis.
Note: Numbers may not sum due to rounding.

Figure 11 places our final decision capex forecast of $1,005.0 million in the context of historical capex. Our final decision capex forecast is:

- $297.3 million, or 42.0% higher than the capex forecast we approved in our final decision for the 2021–26 regulatory control period
- $361.7 million, or 56.2% higher than CitiPower's actual (and estimated) capex for the 2021–26 regulatory control period.

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



Source: CitiPower's revised proposal and AER analysis.
Note: Capex is net of disposals and capital contributions.

CitiPower's revised proposal forecast $1,060.9 million ($2025–26) of capex over the 2026–31 regulatory control period. This represented an increase of 64.9% compared to its actual and expected expenditure over the 2021–26 period.

CitiPower's revised capex proposal represented an increase in forecast capex compared to our draft decision, driven by factors including replacement and augmentation expenditure. The revised proposal also included a large proportion of connections capex representing almost 60% of its total forecast capex. CitiPower also proposed 2 contingent projects.

In our draft decision, we asked CitiPower to address the information gaps and lack of supporting information in its initial proposal as well as engage its customers about its revised proposal. One area we asked CitiPower to focus on was providing further justification for its economic modelling, in particular its optimal timing and costs relating for several augex programs. We invited CitiPower to reconsider these programs in its revised proposal while taking into account our concerns. We also asked CitiPower to provide additional evidence to support the uncertainty of its contingent projects. For data centres, as this was a relatively new type of capex, we provided guidance on the information we required to assess data centre capex.

In responding to our draft decision, CitiPower:

- accepted our draft decision on fleet, property, cyber-security expenditure, flexible services CER program, non-network (other), and some programs in replacement and augmentation capex where we accepted CitiPower's forecast; and
- accepted our lower forecasts in Information and Communications Technology (ICT), and some programs for replacement and augmentation.

For this final decision, our assessment focused on the following unresolved issues:

- remaining replacement and augmentation programs
- connections capex
- CER programs for data visibility and non-network marketplace platform
- innovation expenditure, and
- 2 contingent projects.

In this final decision, we have not included all of CitiPower's forecast repex because we found for a number of larger repex programs CitiPower's preferred investment option was not optimal especially given the alternative was an effective lower cost option. For augex, we have included an alternative forecast for the customer driven electrification program, as we found that CitiPower had not justified its economic modelling. For connections capex we found that CitiPower had not sufficiently justified the volumes of data centres, and we have included a reduced forecast.

We also made reductions to CitiPower's forecast in other categories (innovation expenditure and escalations applied to contract labour) because we were not provided with sufficient evidence that its forecast was prudent and efficient.

Table 4 sets out our final decision for CitiPower 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	CitiPower's revised proposal	AER final decision	Difference ($/%)	
Replacement	252.6	223.5	-29.0	-11.5%
Augmentation	242.0	221.1	-20.9	-8.6%
Connections	635.1	654.1	19.0	3.0%
ICT	110.8	110.8	-	-
Property	83.5	83.5	-	-
Fleet	21.0	21.0	-	-
CER integration	11.5	11.5	-	-
Non-network - other	7.0	7.0	-	-
Capitalised overheads	144.6	143.3	-1.3	-0.9%

Category	CitiPower's revised proposal	AER final decision	Difference ($/%)	
Gross total	**1,508.0**	**1,475.7**	**-32.2**	**-2.1%**
Less customer contributions	446.4	467.1	20.7	4.6%
Less disposals	0.7	0.7	-	-
Modelling adjustments		-3.0		
Net total	**1,060.9**	**1,005.0**	**-55.9**	**-5.3%**

Source: CitiPower's revised proposal, AER analysis.
Note: Numbers may not sum due to rounding.
Within these capex categories contains innovation and cyber security, which we assess separately:

- Innovation: Our forecast includes a $2.4 million capex innovation allowance, spread between repex and augex. This is $0.3 million (11.1%) lower than CitiPower's revised proposal.
- Cyber security: Our forecast includes CitiPower's proposed $5.4 million of cyber security, which sits within the ICT expenditure. CitiPower accepted our draft decision for cyber security.

CitiPower updated its proposed connections forecast to $655.8 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.[38]
Our final decision net capex of $1,005.0 million does not include forecast capex approved separately in our determination for CitiPower's *Unlocking CER benefits through flexible trading* cost pass through of $3.2 million. This cost pass through capex is included in CitiPower's final decision Post Tax Revenue Model.[39]

2.5 Operating expenditure

Our final decision is to accept CitiPower's revised total forecast opex of $555.8 million ($2025–26), including debt raising costs, for the 2026–31 period.

Our alternative estimate of $551.1 million, including debt raising costs, is $4.7 million or –0.9% lower than CitiPower's revised proposal total forecast opex. We consider this is not materially different to CitiPower's revised proposal. Consequently, we consider that CitiPower's total forecast opex reasonably reflects the opex criteria.

Our decision is based on a balanced consideration of various factors, including the revised opex proposal from CitiPower, stakeholder submissions and our own analysis and assessment. We consider this forecast will sufficiently allow a prudent and efficient service provider in CitiPower's circumstances to meet the opex objectives.

Table 5 compares our alternative estimate of CitiPower's total forecast opex for 2026–31 compared to its revised proposal (which we have accepted).

38 CitiPower, *IR#095 Connection policy upfront tax recovery - Public*, March 2026.

39 AER Determination - CitiPower, Powercor and United Energy - Unlocking CER benefits through flexible trading cost pass throughs, April 2026.

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

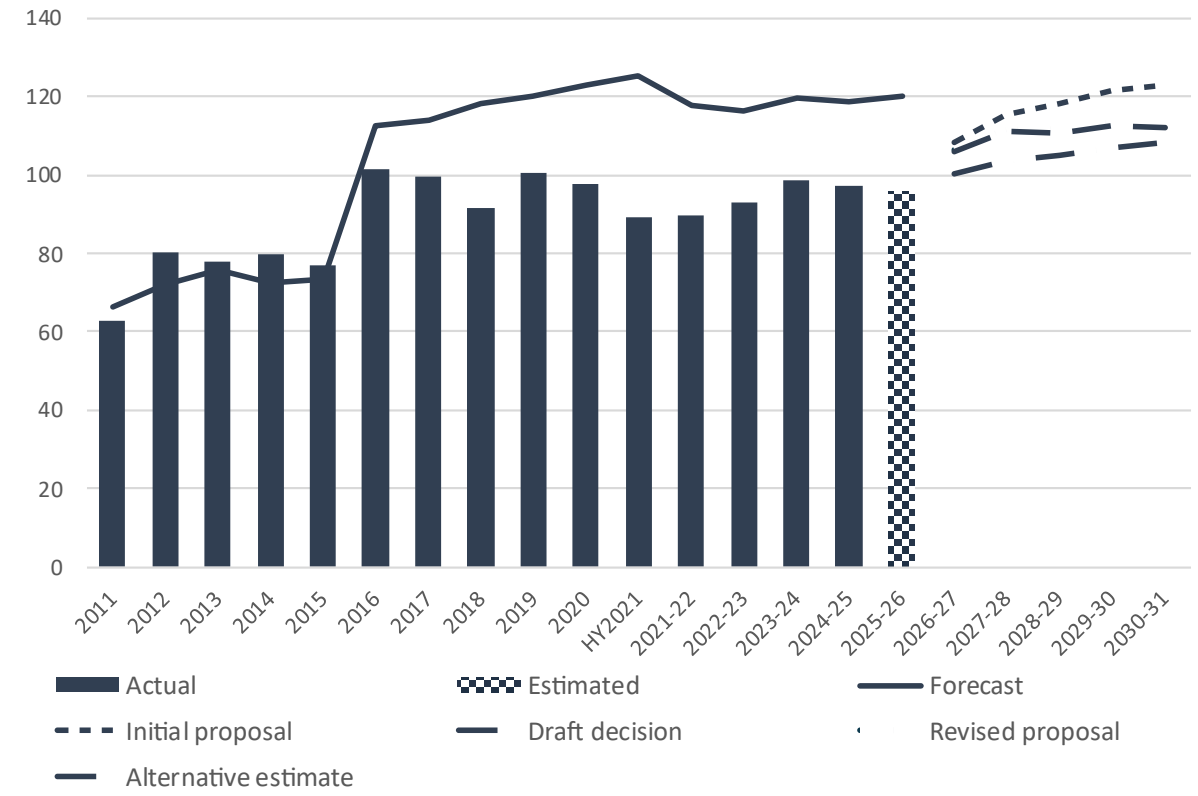
	2026-27	2027-28	2028-29	2029-30	2030-31	Total
CitiPower's revised proposal	106.2	111.6	111.5	113.4	113.1	555.8
AER's alternative estimate	105.8	110.7	110.5	112.2	111.9	551.1
Difference ($)	-0.4	-0.9	-1.0	-1.2	-1.2	-4.7
Difference (%)	-0.4	-0.8	-0.9	-1.1	-1.1	-0.9

Source: CitiPower, *CP RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Figure 12 places our final decision opex forecast (CitiPower's revised proposal) of $555.8 in the context of historical opex. Our final decision opex forecast is:

- $36.7 million (-6.2%) lower than the opex forecast we approved for the 2021–26 period
- $81.5 million (17.2%) higher than CitiPower's actual (and estimated) opex in the 2021–26 period.

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



Source: CitiPower, *Economic benchmarking – Regulatory Information Notice response 2010–24*; AER, *Final decision PTRM 2010–2015*; AER, *Final decision PTRM 2015–20*; AER, *Final decision 2021–26 PTRM*; CitiPower, *CP RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower's revised proposal included forecast opex of $555.8 million ($2025–26) over the 2026–31 period. This represented an increase of 17.2% compared to its actual and expected expenditure over the 2021–26 period.

CitiPower's revised proposal represented an increase in forecast opex compared to our draft decision. In its revised proposal, CitiPower included:

- higher forecast output growth ($12.8 million)
- higher step change estimates for:
  - vegetation management ($14.7 million)
  - CER integration ($12.2 million), and
  - cloud services ($10.9 million).

The difference between our alternative total opex forecast and CitiPower's revised proposal is largely due to us:

- including a lower estimate for the vegetation management step change (-$11.1 million or -2.0% lower)
- including a lower estimate for forecast output growth (-$4.5 million or -0.8% lower)
- including a slightly lower estimate for CitiPower's proposed innovation fund
- updating inputs for inflation and base year opex.

Further detail and reasons for our final decision are contained 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 $63.9 million ($ nominal) for CitiPower over the 2026–31 period. This is an increase of $9.2 million (16.7%) from CitiPower's revised proposal of $54.7 million. This increase is primarily due to our final decision on a higher return on equity, lower tax depreciation, and higher forecast capital contribution (Attachment 2), which is a component of taxable income.

Our final decision is to accept CitiPower'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 CitiPower'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 CitiPower to pursue efficiency improvements in opex and capex, and a fair sharing of these between CitiPower and its users.

Our final decision includes:

- A revenue adjustment of –$14.4 million from the application of the EBSS in the 2021–26 period. This represents a –$7.4 million difference from CitiPower's proposed carryover amount of –$6.9 million. This reflects that our final decision:
  - updates forecast inflation for 2025–26 and real vanilla WACC for 2026–27
  - updates actual Guaranteed Service Level payments and total opex for 2024–25, to reflect the opex reported in CitiPower's 2024–25 Regulatory Information Order
  - updates forecast total opex for 2024–25 and 2025–26 to add the opex approved for CitiPower's *Unlocking CER benefits through flexible trading* cost pass through (see Attachment 3 for further detail)
  - updates movements in provisions in actual opex for 2021–22 and 2023–24 to reflect the amounts CitiPower reported in its resubmitted response to Economic Benchmarking Regulatory Information Notices for those years and in 2024–25 to reflect the amount reported in its Regulatory Information Order.
- A revenue adjustment of $3.1 million from the application of CESS in the 2021–26 period. This represents a $16.8 million difference from CitiPower's proposed revenue increment of $19.9 million. This reflects that our final decision:
  - updates capex inputs to reflect actual expenditure and changes to forecast
  - includes adjustment to account for the deferral of capex
  - updates actual and forecast inflation and WACC inputs.

Our final decision also includes:

- An allowance of $2.7 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. CitiPower 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.
- A revenue adjustment of –$2.2 million ($2025–26), consistent with CitiPower's revised proposal, which returns a portion of the unregulated revenue that CitiPower earns using shared assets to its consumers.

2.8 Uncertainty mechanisms

Our distribution determination for CitiPower 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, CitiPower's revised proposal included 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.

CitiPower reproposed a new fault level pass through event in its revised proposal, which we did not accept as part of our draft decision.

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. For this final decision, we have not accepted CitiPower's reproposed fault level event for the 2026–31 period as we are not satisfied that CitiPower is unable to prevent or substantially mitigate the impact of this event through effective joint planning. Full details of our assessment can be found in attachment 4 of 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 (trigger events) are met.

Our final decision is to accept CitiPower's proposed Laurens Street Zone Substation and Richmond Zone Substation contingent projects for the 2026–31 regulatory control period. We have concluded that CitiPower's $54 million and $65 million ($2026 unescalated), respectively, for these contingent projects may be reasonably required to be undertaken in order to achieve the capex objectives over the 2026–31 period.

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 CitiPower 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 CitiPower 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 CitiPower's views in its revised proposal on how this adjustment can be applied.

CitiPower instead proposed to opt out of the volumetric adjustment for business-as-usual connection and ex post adjustments for large bespoke connections. It considered that its reported volume data would not be accurate for the purposes of the volumetric adjustment. We do not agree, as its data issue is not material and the volumetric adjustment can be accounted for. For large bespoke connections, we consider there is no reason to not apply an ex post CESS adjustment if it is required.

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 CitiPower in the 2026–31 regulatory control period.

3.2 Efficiency Benefit Sharing Scheme

Our final decision is that the EBSS will continue to apply to CitiPower in 2026–31. This provides a continuous incentive to pursue efficiency improvements in 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 CitiPower's proposed CSIS for the following reasons:

- inadequate consultation on scheme design
- merging performance targets for general and fault calls within the grade of service parameter into a single target which does not incentivise genuine improvement, and
- targets which do not incentivise genuine improvement or are commensurate with service improvements or degradations.

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. While CitiPower accepted our draft decision to not apply the CSIS and to instead apply the telephone answering component of the STPIS, it did not accept our draft decision to apply the new connections parameter.

CitiPower's revised proposal did not include a CSIS for the 2026–31 regulatory control period. Instead, we will apply the telephone answering component of the STPIS, but not the new connections parameter. 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 (STPIS)

CitiPower accepted our draft decision to apply version 2.0 of the STPIS for the 2026–31 regulatory control period.[40]

However, our final decision is to not accept CitiPower's proposed modifications to the telephone answering parameter.

In accordance with the STPIS,[41] our final decision is to set CitiPower's performance targets based on average performance over the past 5 regulatory years.

Attachment 7 outlines the reasons for our final decision.

3.5 Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM)

Our final decision is to apply the DMIS and DMIAM to CitiPower 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 CitiPower's revised proposal[42] and our draft decision on DMIS and DMIAM. [43]

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40 CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts,* December 2025, p 61.

41 STPIS Version 2.0 clause 3.2.1.

42 CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts,* December 2025, p 59.

43 AER, *Attachment 8 - DMIS and DMIAM - Draft decision - CitiPower distribution determination 2026-31,* September 2025.

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.[44] 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.

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

4 Network pricing

4.1 Service classification

Our determination for CitiPower 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 CitiPower 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*[45] 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. (CitiPower is also subject to a number of conditions relevant to this

[45] 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.

service under a ring-fencing waiver granted in October 2025 enabling it to conduct a kerbside EV charging trial.[46])

- The new Hot Water Switching Service proposed by CitiPower, Powercor and United Energy (CPU) will, for CPU only, be classified as a negotiated 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 CitiPower and parties seeking access to distribution asset rental for electric vehicle charging infrastructure or the new Hot Water Switching Service will be subject to:

- 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 any 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 make 4 amendments to CitiPower's revised TSS: 2 amendments to make it compliant with the NER[47] and 2 amendments at CitiPower's request. One of the requested amendments is on how its billing systems administer its two-way residential tariff/basic export level and the second is to clarify off-peak charges for flexible connection tariffs. We are satisfied that, with these amendments, CitiPower's TSS complies with the pricing principles for direct control services and other applicable requirements of the NER.

CitiPower'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.[48] This TSS is also CitiPower's first since the AEMC's 2021 *Access,*

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46 On 22 October 2025, the AER granted a time-bound, limited scope ring-fencing waiver to CPU, to enable CPU to conduct a kerbside EV charging trial at sites that meet specific criteria in Victoria until mid-2031, with strict conditions to safeguard market competition. The waiver, from clauses 3.1(b) and 4.2 of the guideline, will allow CPU to install up to 100 EV chargers (which must include at least 5% vehicle-to-grid chargers) to test, analyse and publicly report on how EV charging can be used to manage local network constraints, improve voltage stability, and shift demand away from peak periods. The AER has imposed 9 waiver conditions, including obligations for CPU to ensure an even playing field for third-parties. The waiver will expire on 30 June 2031, unless varied or revoked sooner.

47 NER, cl 6.12.3(l)(2).

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

pricing and incentive arrangements rule change that allowed for two-way pricing.[49] Together these rule determinations introduced several reforms to distribution pricing, including to progress cost reflective pricing and to support more CER onto the network. CitiPower'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,[50] 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.

Our draft decision emphasised that CitiPower 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 CitiPower 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.[51] 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 CitiPower'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, and the structures of CitiPower's 3 proposed flexible connection tariffs. Attachment 13

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

50 NER, cl 6.18.5(a).

51 NER, cl 6.18.5(c).

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:

- CitiPower's response to our draft decision – for example, we required CitiPower'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 CitiPower's initial TSS and its revised TSS
- submissions in response to our draft decision and/or CitiPower's revised TSS.

We consider that CitiPower has largely responded to our draft decision. Our final decision is to amend CitiPower's revised TSS only to the extent necessary to make it compliant with the NER.[52] We are satisfied that, with the following amendments, CitiPower's TSS complies with the requirements of the NER, the NEL and contributes to achieving the NEO:[53]

- better explain the available supply for dedicated circuit tariffs
- remove the 120kVA (kilovolt-amperes) minimum chargeable demand charge that applies for the rolling demand component of CitiPower's large LV (low voltage) business tariffs.

We have also made 2 amendments to CitiPower's revised tariff structure statement at its request. The first is to further explain how it will bill its basic export level. In March 2026 CPU explained to us that CitiPower's and Powercor's billing systems did not support implementation of the basic export level on a daily basis. The amendment explains that CPU will administer the basic export level over a 31 day period (consistently across the 3 networks), such that unused exports under the daily limit will roll over within a billing period. The basic export level and how it will be administered by CPU is discussed further in the final decision Attachment 13.

The second amendment requested by CPU is to clarify that customers on the Small Flexible and Large Flexible tariff will face off-peak charges at all times other than during the peak period of 4pm – 9pm. This is an editorial change intended to improve understanding.

These amendments complement the changes CitiPower made in its revised TSS in response to our draft decision. The changes 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 and flexible connection tariffs
- including bill impact analysis for residential customers affected by removing residential demand tariffs and those moving from the existing default time-of-use tariff to the new solar soak time-of-use tariff
- including further explanation and bill impact analysis of its proposal to increase fixed charge cost recovery from small business customers
- including some further information about the supply time availability for controlled load/dedicated circuit tariffs

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52 NER, cl 6.12.3(l)(2).

53 NER, cl 6.12.3(k) and NEL, s 7.

- extending the LRMC input forecasts to 10 years and providing further explanation of forecast demand driving expenditure
- including further information on eligibility, CitiPower's discretion, and flexible connection processes and fees for flexible connection tariffs
- clarifying that its type 7 and type 9 meter tariff would only be available to type 7 metered load, public lighting and type 9 metered load that consumes <5MWh per annum.

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.[54] Additionally, the Victorian Government supported the seasonal components of CitiPower's two-way tariff.[55] However, multiple submissions 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.

One stakeholder submitted that retaining a minimum chargeable demand of 120kVA in the rolling demand component of CitiPower's large LV tariff, despite removing the 120kVA demand threshold to access the tariff, could negatively impact customers with supply capacity lower than 120kVA.[56]

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, 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.

AGL's submission encouraged CitiPower to move from year-round capacity charges to fixed charges, similar to Jemena's storage tariff. AGL considered that larger battery systems

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54 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.

55 Hon Lily D'Ambrosio MP, *Submissions on Victorian electricity distribution proposals 2026-31*, January 2026, pp 6–7.

56 Barwon Water, *Submission on Powercor electricity distribution proposal 2026-31*, January 2025, p 1. The Barwon Water submission referred to Powercor's proposed Large LV tariff changes, but is relevant across CitiPower, Powercor and United Energy.

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.

connecting to CitiPower's proposed flexible connection tariffs would be subject to a higher annual network charge in Victoria than in other jurisdictions, regardless of their behaviour.[59]

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.[60]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 CitiPower's proposed two-way tariff. 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
- approves the supporting information CitiPower provided on its flexible connection tariffs. However, we have not required it to move from capacity charges to fixed charges. We consider that rolling demand / capacity charges are an accepted charging parameter for scaling recovery of residual costs in business tariffs, and are used by other jurisdictions
- amends CitiPower's revised TSS statement to remove the 120kVA minimum chargeable demand charge from the large low voltage tariffs
- encourages CitiPower 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.
- 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.

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59 AGL, *Submission on Victorian electricity distribution proposals 2026-31*, January 2026, p 2.

60 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.

In our final decision Attachment 13 we describe our assessment of CitiPower's 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 CitiPower's initial TSS. Alongside Attachment 13, we have published marked up and clean versions of CitiPower's revised tariff structure statement. We note that we have one final decision tariff structure attachment covering CitiPower, Powercor and United Energy.

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 CitiPower's public lighting proposal. We made several adjustments, including for replacement cycles, labour rates, inflation and labour escalators. We also encouraged CitiPower to consult further with stakeholders on an accelerated LED rollout and smart lighting services.

In its revised proposal, CitiPower accepted most of the adjustments in our draft decision. In response to its further stakeholder consultation, CitiPower proposed to replace all non-LED major road lights with LED lights by the end of the 2026–31 period. CitiPower proposed to recover the costs of the accelerated LED rollout through an 'Accelerated Replacement Charge'.

The Victorian Greenhouse Alliances' 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.[61]

Our final decision is to not accept CitiPower's public lighting proposal. This is because in our final decision, we have made mechanical updates to inflation, labour price growth, and the weighted average cost of capital. This results in final decision prices for public lighting services that are 0.4% higher compared to CitiPower's revised proposal prices for most light types. Our final decision accepts CitiPower's Accelerated Replacement Charge for LED lights. While the approach to determining this charge is novel, our decision reflects that it has high level customer support and avoids any cross subsidisation by councils who have already funded LED replacements.

In addition, our final decision to classify type 9 metering services requested by public lighting customers as alternative control services (discussed earlier) differs from CitiPower's revised proposal classification as negotiated services. Hence, CitiPower did not include these costs (and therefore the recovery mechanism) in its revised proposal. Following further

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

consultation with CitiPower, we have included a new price to enable it to recover the costs of testing type 9 metering services.

Our final decision on public lighting is discussed further 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 CitiPower's metering proposal. We made several adjustments to its forecast metering capex and encouraged CitiPower to consider and respond to these in its revised proposal.

In its revised proposal CitiPower 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. CitiPower also revised the historical capex allocations for the 2021–26 regulatory period, as requested in our draft decision.

We received submissions from Green Metering and Flow Power. These submissions questioned the AER's draft decision and CitiPower's revised proposal relating to proactive replacement of metering services on the basis it prevented future potential for a competitive market for metering services. We note at the time of our final decision that there is no competitive market for metering services in Victoria, nor is there any indication that a competitive market is being considered in the future. Therefore, our final decision is made accounting for the Victorian DNSPs, including CitiPower, being monopoly providers of most metering services.

Our final decision is to not accept CitiPower'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.

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 CitiPower 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 $1,005.0 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(c) of the NER, the AER's final decision is to accept the total of the forecast operating expenditure for the 2026–31 regulatory control period of $555.8 million ($2025–26) that is included in the current building block proposal, as set out in Attachment 3 to this final 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:

NER cl 6.12.1	Constituent decision
	• Laurens Street Zone Substation • Richmond Zone Substation 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 to this final decision.
6.12.1(e)	The AER's final decision on the allowed rate of return for the 2026–27 regulatory year is 6.14% (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 $2,311.1 million ($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 CitiPower for each regulatory year of the 2026–31 regulatory control period, in accordance with clause 6.5.3 of the NER, is 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 CitiPower. 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 CitiPower 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. • 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.

NER cl 6.12.1	Constituent 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 CitiPower 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 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 refuse to approve the tariff structure statement proposed by CitiPower.

NER cl 6.12.1	Constituent decision
	In accordance with cl 6.12.3(l) our final decision therefore includes an amended tariff structure statement. Amendments and reasons for our final decision are set out in Attachment 13 of this final decision.
6.12.1(o)	The AER's final decision is that the negotiating framework as proposed by CitiPower, as set out in Attachment 17 to this final decision**,** is to apply to CitiPower 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 CitiPower 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 CitiPower 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 CitiPower 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 CitiPower 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 CitiPower, set out in Attachment 16 to this final decision, is to apply to CitiPower for the 2026–31 regulatory control period. is to apply to CitiPower for the 2026–31 regulatory control period.
	In accordance with section 16C of the *National Electricity (Victoria) Act 2005*, the NEL, the NER and the 'f-factor scheme order 2016',[62] the AER's final decision is to apply the f-factor incentive payments/penalties as a part of the 'I-

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

NER cl 6.12.1	Constituent decision
	factor' 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 12 submissions in response to our draft decision and CitiPower's 2026–31 revised proposal.

	Date
AER Consumer Challenge Panel (CCP32)	January 2026
AGL	January 2026
Ausgrid	January 2026
CPU Customer Advisory Panel	January 2026
Evie Networks	January 2026
Flow Power	March 2026
Green Metering	February 2026
Hon Lily D'Ambrosio MP	January 2026
Nexa Advisory	January 2026
Red Energy and Lumo Energy	January 2026
Save our Surroundings Riverina	January 2026
Victorian Greenhouse Alliances	January 2026

7 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
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
repex	replacement expenditure

Term	Definition
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