Draft decision

CitiPower electricity distribution determination
1 July 2026 – 30 June 2031

Overview

September 2025

AUSTRALIAN ENERGY REGULATOR

Important notice

The information in this publication is for general guidance only. It does not constitute legal or other professional advice. You should seek legal advice or other professional advice in relation to your particular circumstances.

The AER has made every reasonable effort to provide current and accurate information, but it does not warrant or make any guarantees about the accuracy, currency or completeness of information in this publication.

Parties who wish to re-publish or otherwise use the information in this publication should check the information for currency and accuracy prior to publication.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

AER reference: AER23008247

Amendment record

Version	Date	Pages
1	30 September 2025	53

Invitation for submissions

CitiPower has the opportunity to submit a revised proposal in response to this draft decision by 1 December 2025.

Interested stakeholders are invited to make a submission on both our draft decision and CitiPower's revised proposal (once submitted) by Monday, 19 January 2026.

Submissions should be sent to: Vic2026@aer.gov.au and addressed to Dr Kris Funston, Executive General Manager.

Alternatively, you can mail submissions to GPO Box 3131, Canberra ACT 2601.

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

Parties wishing to submit confidential information should:

1. Clearly identify the information that is the subject of the confidential claim.
2. Provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be published on our website.

Pre-determination conference

Your engagement is a valuable input to our determination. We encourage all interested stakeholders to join us at our Pre-determination conference on Tuesday, 14 October 2025.

Details of how to register for this forum are available on our website and through Eventbrite.

List of attachments

This document forms part of the AER's draft decision on CitiPower's electricity distribution determination for the 2026-31 regulatory control period.

A full list of attachments is provided below.

Overview

1) Annual revenue requirement
2) Capital expenditure
3) Operating expenditure
4) Pass through events
5) Efficiency benefit sharing scheme
6) Capital expenditure sharing scheme
7) Service target performance incentive scheme
8) Demand management incentive scheme and Demand management innovation allowance mechanism
9) Customer service incentive scheme
10) Victorian F-factor incentive scheme
11) Classification of services
12) Control mechanisms
13) Tariff structure statement
14) Alternative control services
15) Metering Services
16) Connection policy
17) Negotiated services framework and criteria

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. 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 draft decision for CitiPower Pty Ltd [ABN 76 064 651 056] (CitiPower), for the period 1 July 2026 to 30 June 2031 (2026–31 period). It is predicated on a series of constituent decisions summarised in section 5 of this Overview.[1]

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).

When we undertake our assessments, we consider whether we are satisfied that the proposed expenditure by the DNSP reasonably reflects prudent and efficient costs and a realistic expectation of future network demand and cost inputs.

Consumer support is an important part of this assessment. However, even where it is possible to say that a proposal is reflective of consumer views and preferences, this does not displace the AER's role in carefully testing and assessing the prudency and efficiency of proposed expenditure. Submissions have emphasised the importance of this scrutiny in ensuring desired outcomes are delivered at the lowest sustainable cost.[2]

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

1 NER, cl. 6.12.1

2 Hon Lily D'Ambrosio MP - *Submission - Victorian electricity distribution proposals 2026-31* - June 2025; Origin Energy - *Submission - Victorian electricity distribution proposals 2026-31* - May 2025.

the replacement capital expenditure (repex) model and economic benchmarking for operating expenditure.

In addition, we are informed by stakeholder submissions and consumer preferences and priorities elicited through the DNSP's consumer engagement processes, and from our own Consumer Challenge Panel.

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

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 it complies with the NER.

CitiPower put forward its proposal at a time when network costs are rising across the National Energy Market (NEM), driven by a range of factors that affect reliability, security, and safety. The network is getting older, input costs are rising, digitalisation is increasing the risk of cyber-attacks, and the system is adapting to climate change, more rooftop solar, batteries, electric vehicle charging and large, new loads such as data centres.

On top of that, broader economic pressures like higher interest rates and inflation are also pushing costs up compared with the last 5-year period.

In Victoria, the energy market is undergoing a complex transition. Emissions reduction targets and the transition to net zero, 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, and the electricity grid is now a two-way system as rooftop solar and batteries play a larger role in supply and demand.

These shifts are changing the way consumers are seeking to use electricity, and their expectations of electricity distribution networks. In turn, they are impacting how CitiPower and other electricity distribution networks operate and invest in their networks.

At the same time, recent severe weather events have put resilience in the spotlight. Many Victorian consumers experienced extended outages. Victorian government reviews into electricity distribution network resilience, outage planning and operational responses have made several recommendations. Differences in performance between and within networks are also front of mind for many – equally important both in terms of service levels and access to the opportunities transition provides.

Safety and reliability are enshrined in the NEO and are key components of our decision making. We expect DNSPs to submit proposals that meet their obligations in these areas in a way that is prudent and efficient. Our draft decision underscores the need for CitiPower to do further work to ensure capex and opex proposals meet these objectives.

Network utilisation is in the mid-to-high range in Victoria compared with elsewhere in the NEM. However, we want to see a commitment by networks towards network pricing structures aimed at reducing the amount of network investment required to provide sufficient network capacity and stability during peak demand and export periods.

We encourage network businesses to utilise the revenue determination process to propose tariff design, incentive structures and efficient and prudent expenditure that contributes to achieving the NEO.

A DNSP's revenue proposal must have robust demand forecasts and clear evidence for increased investment in network augmentation in the 2026-31 period. We expect to see business cases that are well supported by analysis.

As any new network infrastructure will be paid for by consumers, it is important that businesses effectively utilise their existing infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment.

This is the challenging environment in which CitiPower has put forward its forecast plans and revenues for the upcoming regulatory control period. This draft decision sets out our assessment of CitiPower's proposal and the further work we now encourage it to undertake in its revised proposal to achieve the best possible outcomes for consumers.

Our draft decision

Our draft decision allows CitiPower to recover $1,964.9 million ($nominal, smoothed) in revenue from consumers in the upcoming 2026–31 period. This is $112.7 million (or 5.4%) less than the $2,077.6 million that CitiPower proposed. It is $441.8 million (or 29.0%) higher than the revenue we approved for CitiPower in the current, 2021–26 period.[3]

Market factors, specifically rising inflation and interest rates, are driving higher revenues. In this draft decision we estimate 53% of the increase in revenue from period to period can be attributed to these external factors.

Our draft decision differs from CitiPower's proposal in our assessment of the prudent and efficient capex and opex it will require in 2026–31 to continue to operate its network, and meet expected demand for its services, in accordance with its regulatory obligations. Based on the information before us, we are not satisfied that the magnitude of increases in expenditure CitiPower has proposed are in line with prudent and efficient decision making. Our draft decision identifies areas in which further work by CitiPower is needed to ensure its expenditure proposals meet these objectives. Our draft decisions on forecast expenditure are therefore subject to further supporting information being provided.

In this draft decision, we have not accepted CitiPower's proposed net capex of $1,216.3 million ($2025–26) and have substituted it with an alternative estimate of $882.2 million (a 27.5% reduction). We have accepted CitiPower's forecast where it has provided sufficient evidence to support its prudency and efficiency. This is the case for its forecast for property, fleet, cyber security and other non-network capex. However, in this draft decision we have not accepted other elements of its proposed capex for which we found its proposal did not include sufficient quantitative evidence to support its forecasts.

We recognise CitiPower is responding to a rapidly evolving energy system with growing demand from both traditional and large customer connections. However, for several projects and programs, we found the optimal timing for investment is likely to be beyond 2026-31. Our assessment of CitiPower's proposal also found concerns with its input assumptions and

3 In $2025–26 terms this is $98.6 million (or 5.7%) higher than the revenue we approved for CitiPower in the 2021–26 period.

options across several capex categories. These include CitiPower's proposed uplifts in replacement capex (the largest single contributor to its capex forecast), where we consider CitiPower could have explored lower, cost-effective options such as refurbishment instead of more expensive options. Our draft decision also reduces CitiPower's repex forecast where we have found insufficient evidence to support its proposed step up in volumes relative to the current period. Our draft decision includes guidance to CitiPower on the additional detail, support and justification that it should provide in its revised proposal if a further uplift in capex is to be approved.

Our draft decision does not accept CitiPower's $586.1 million ($2025-26) opex forecast and substitutes it with an alternative estimate of $524.4 million (a 10.5% reduction). This is in part due to our adoption of a lower forecast of output growth. Our draft decision also includes lower estimates of efficient opex for each of CitiPower's proposed step changes. While we consider these step changes to be prudent, we are not satisfied that the amounts CitiPower has proposed reflect an efficient level of expenditure.

One key area of difference is CitiPower's proposed step increase in vegetation management expenditure. While we are satisfied that CitiPower has justified the need for a step up in expenditure relative to the current, 2021-26 period to achieve regulatory compliance, we consider it has overestimated the efficient amount required to do so.

In looking beyond expenditure based solutions for the 2026-31 period, we encourage CitiPower to do more to integrate its tariff strategy into its proposal. That is, it should include in its broader proposal (for example its forecast demand and proposed expenditure), further consideration of small consumers responding to the incentives for behaviour change provided by its tariffs.

CitiPower's proposed TSS makes some progress on sending cost reflective price signals through retailers to shift usage out of peak times and into low-cost periods of the day. This includes proposing a solar soak (very low priced) period in the middle of the day for residential consumers. However, CitiPower assumed limited consumer response to its small customer tariffs in its demand forecasts (other than, for example, responses implicit through AEMO's electric vehicle charging forecasts). We are therefore not convinced that CitiPower has done all it can to utilise tariffs to encourage efficient use of the network.

It is imperative for CitiPower to use all the levers available to it, particularly tariffs, to optimise network utilisation. We consider that CitiPower should engage further with stakeholders, including with retailers, to encourage take up of cost reflective tariffs and improve understanding of how tariff reform can complement (or mitigate) its proposed expenditure. It should look to develop tariff trials aimed at managing flexible load and improve its long-run marginal cost calculations.

CitiPower also has a role to play in enabling and supporting the roll out of new technologies, including kerbside electric vehicle (EV) charging. While most EV charging occurs at home, kerbside AC chargers are seen by many stakeholders as a practical and cost-effective solution for high-density areas without off-street parking, offering convenience similar to home charging, and avoiding major grid upgrades. Third-party interest in using DNSP-owned infrastructure as a host for non-DNSP equipment is growing, and kerbside power poles owned by DNSPs have been identified as a potential host location for commercially provided EV charging infrastructure that will allow off peak charging of vehicles near the home. Commercial proponents of kerbside EV charging infrastructure are seeking to rent the use of DNSPs' kerbside poles for this purpose. Our draft decision is to classify a new, negotiated distribution asset rental service to support negotiation of access to Victorian DNSPs' kerbside poles for that purpose on terms that are fair, reasonable and cost reflective.

In this Overview and the accompanying detailed attachments, we have set out the assessment approaches applied, and enquiries made as part of our review, which have enabled us to arrive at this draft decision. This draft decision is the mid-point in our assessment of CitiPower's proposal. CitiPower can respond in a revised proposal that incorporates the substance of the changes required by, and addresses matters raised in, this draft decision.

Contents

1 Our draft decision

Our draft decision allows CitiPower to recover total revenue of $1,964.8 million ($ nominal, smoothed) from its consumers from 1 July 2026 to 30 June 2031. This is $441.8 million more than CitiPower's allowed revenue in the 2021–26 period in nominal terms. In the sections below, we briefly outline what is driving this increase in CitiPower's revenue.

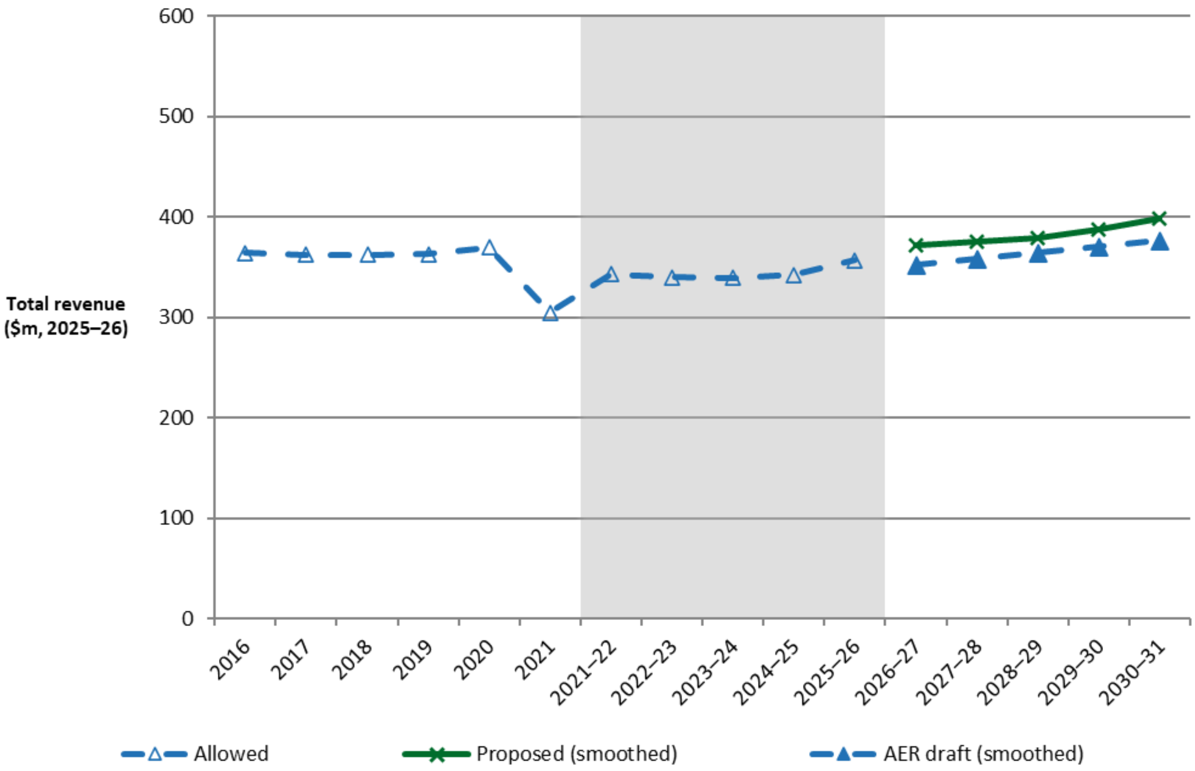
Our draft decision is $112.7 million lower than CitiPower's proposal of $2,077.6 million in nominal terms. While a slight increase in the rate of return and a small decrease in expected inflation have had some impact, the largest contributors to this difference are our draft decisions to reduce CitiPower's proposed forecasts of capex and opex (by 27.5% and 10.5%, respectively). This reflects that we are not yet satisfied that all its projected increases are prudent, efficient and reflective of realistic expectations of demand. CitiPower will have the opportunity in its revised proposal to address our concerns with its expenditure forecasts and, where it does so, final decision outcomes are likely to be different to those presented here. We discuss this further in section 2.

1.1 What is driving revenue?

Revenue is driven by changes in real costs and inflation. To compare revenue from one period to the next on a like-for-like basis in this section, we use 'real' values based on a common year (2025–26) that have been adjusted for the impact of inflation.

In real terms, this draft decision would allow CitiPower to recover $1,819.3 million ($2025–26, smoothed) from consumers over the 2026–31 period. This is 5.7% higher than our decision for the current (2021–26) period. Changes in CitiPower's revenue over time are shown in Figure 1, along with our draft decision smoothed revenue for the 2026–31 period compared to what CitiPower proposed.

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



Source: AER analysis.

Figure 2 highlights the key drivers of the change in real terms between the revenue approved for CitiPower for the current, 2021–26 period and in this draft decision for the 2026–31 period.

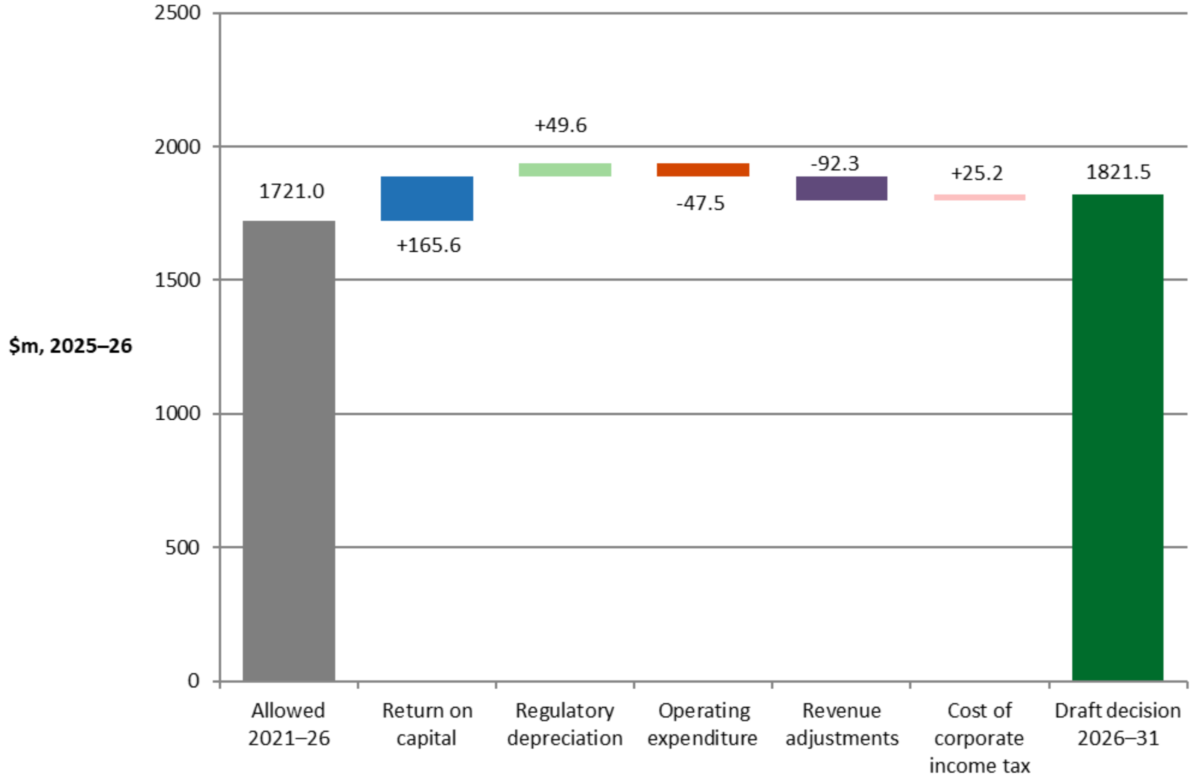
Our draft decision would provide for a return on capital that is $165.6 million (30.0%) higher than the 2021–26 period. Higher actual inflation for the current 2021–26 period and higher interest rates for the 2026–31 period would increase CitiPower's return on its regulatory asset base (RAB) which, at the start of the 2026–31 period will be higher than anticipated in our last determination. Our draft decision also projects further RAB growth over the 2026–31 period driven by forecast capex, which in turn is increasing the return on capital.

The higher opening RAB and forecast capex increases are also producing a higher return of capital (regulatory depreciation).

Our draft decision also includes a higher net tax amount in total revenue, driven by a higher return on equity and a projected increase in capital contributions paid to CitiPower by new, large connecting customers to its network compared to the 2021–26 period.

Offsetting these to an extent are our forecast of opex for 2026–31, which is lower than the opex forecast we approved in the 2021–26 period. Revenue decrements in 2026–31 for incentive schemes that applied to CitiPower's 2021-–26 expenditure have also reduced revenue.

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



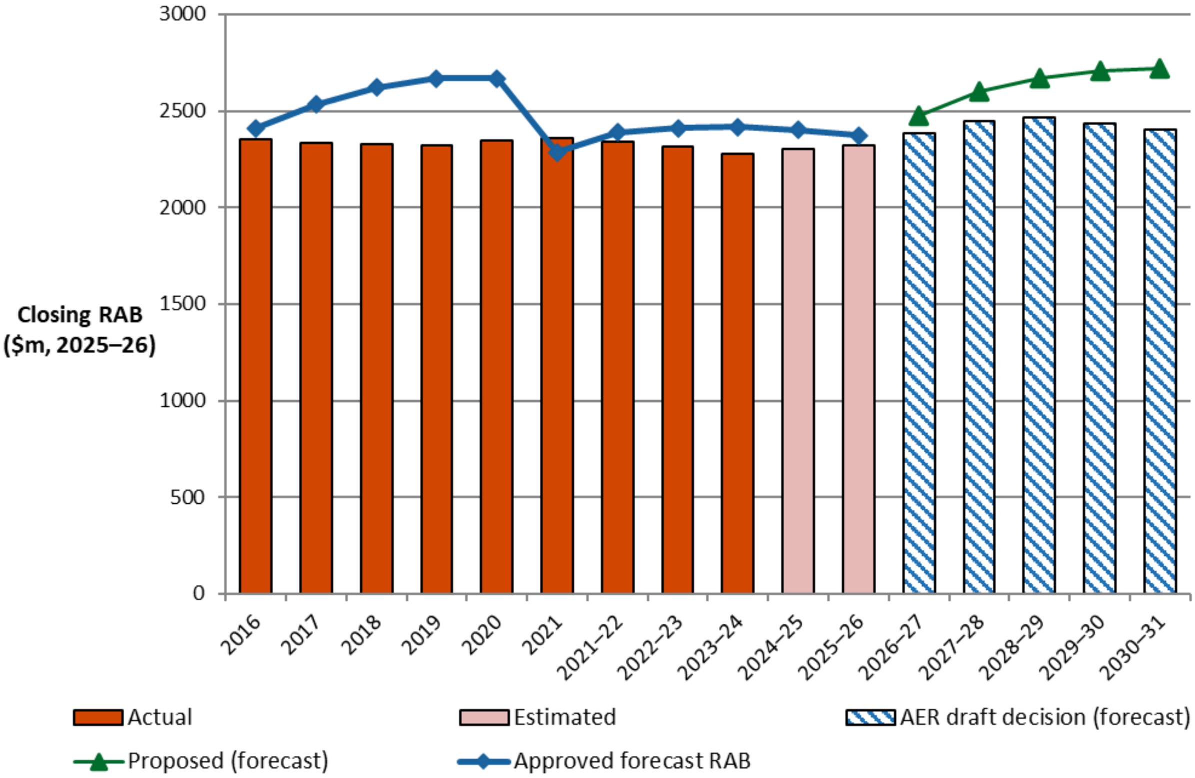
Source: AER analysis

Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI).

RAB values substantially affect a network businesses' 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 shows the value of CitiPower's RAB over time in real terms. After a reduction of 1.6% over the 2021–26 period, our draft decision results in a forecast increase to the RAB of $77.5 million ($2025–26) or 3.3% over the 2026–31 period. This increase in the RAB is driven by higher forecast capex. However, as shown in Figure 3, this increase is significantly lower than what CitiPower proposed, reflecting our draft decision to reduce CitiPower's proposed forecast capex.

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

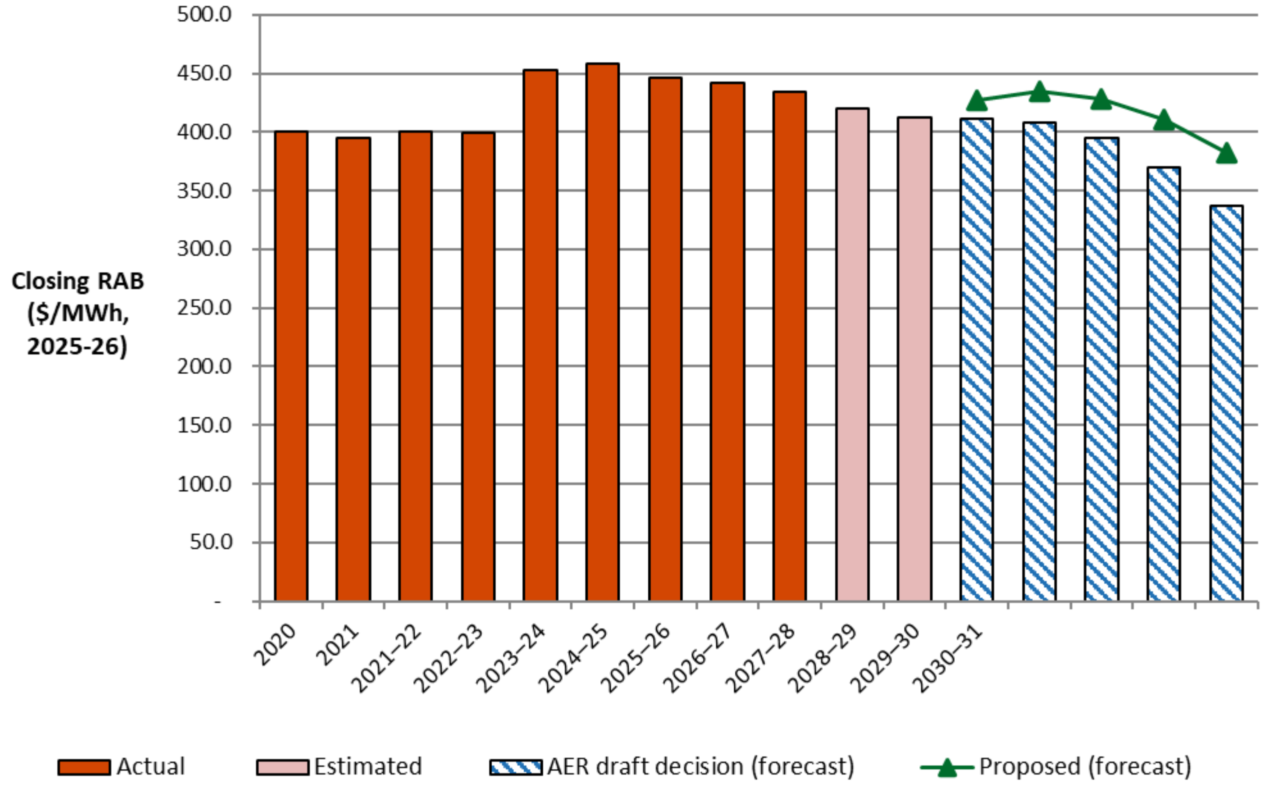


Source: AER analysis.

CitiPower's RAB per MWh is forecast to decline significantly over 2026–31 compared to the final year of the 2021–26 period, as can be seen in Figure 4. This is based on CitiPower's forecast energy delivered (MWh) and could change depending on the actual volume of energy delivered.

CitiPower's RAB per energy consumption measure in real terms has declined since 2024–25. This reflects growth in actual energy consumption and moderate decline in the inflation adjusted real RAB ($2025–26) to 2025–26. Over the 2026–31 period, CitiPower's RAB per unit of energy consumption continues to show a forecast decline driven by an increased rate of forecast energy consumption. We consider efficient investment in, and efficient operation and use of electricity services are important to minimise required capital expenditure and the RAB.

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



Source: AER analysis.

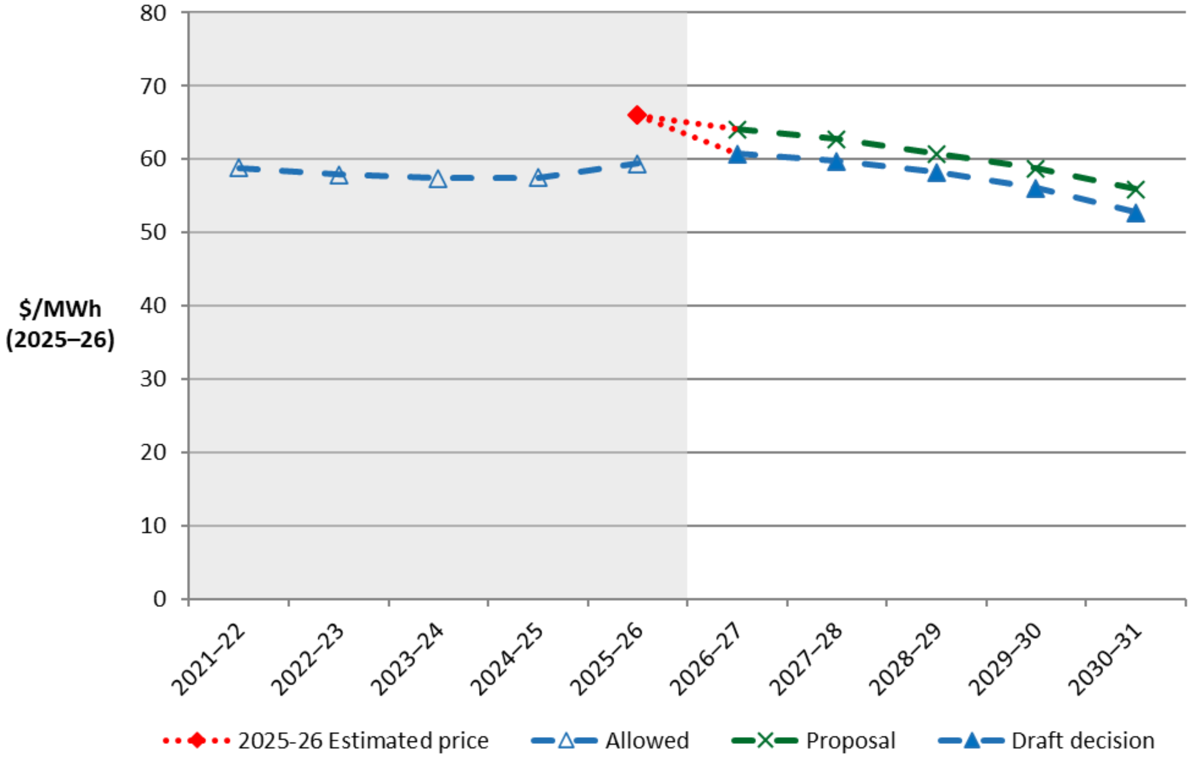
1.2 Expected impact of our draft decision on electricity bills

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 modelled impact of this draft decision would be a total decrease to average distribution charges of around 20.1% in real terms by 2030–31 compared to 2025–26 levels, or an average real decrease of 4.4% per annum.[4] This estimate is subject to ongoing revenue adjustments and changes in consumer energy consumption in the 2026–31 period. Figure 5 compares this indicative draft decision price path for the 2026–31 period to the 2021–26 period, and what CitiPower proposed.

4 The average decrease to indicative network charges of 4.4% ($2025–26) per annum reflects 2 components: 1) The draft decision smoothed revenue average increase of 0.2% 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 distribution charges for 2021–26 to 2026–31 ($2025–26, $/MWh)



Source: AER analysis.

Potential bill impact

CitiPower's network charges make up around 28% of its residential consumers' electricity bills and 31% of its small business consumers' electricity bills.[5] Our draft 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—the cost of purchasing energy from the wholesale market, transmission network charges, environmental schemes and the costs and margins applied by electricity retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers.[6] These sit outside the decision we are making here but will also continue to change throughout the period.

At the time of making this draft decision, we have used placeholder values for certain components of revenue such as the rate of return, expected inflation and some expenditure forecasts. We will make further updates for these values as part of our final decision. It is for this reason that we expect the total expected revenues approved in our final decision and resulting bill impacts to be different to this draft decision.

In nominal terms, which include the effect of expected inflation, the impact of this draft decision would be a decrease to the distribution component of consumers' electricity bills.

---

5 Based on Victorian Default Offer, for a small business with a total annual use of 10,0000 kWh per year.

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

We estimate that the modelled impact of our draft decision on the average annual electricity bill for a retail consumer in CitiPower's network area, as it is today, would be:[7]

- a nominal reduction of $59 (3.8%) by 2030–31, or an average of $12 per annum for a residential consumer. This reflects:
  - a $41 reduction for distribution SCS charges
  - a $18 reduction for metering.
- a nominal reduction of $114 (3.6%) by 2030–31, or an average of $23 per annum for a small business consumer. This reflects:
  - a $92 reduction for distribution standard control services (SCS) charges
  - a $22 reduction for metering.

For our draft decision, we have adopted CitiPower's proposed forecasts of annual energy throughput to estimate the bill impacts, noting that if the actual energy delivered over the 2026–31 period is lower than forecast, it will result in higher bills, all else being equal, as CitiPower is under a revenue cap. 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 draft decision and 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. This is a significant increase of 1,486 GWh or 26.3%. CitiPower's forecast energy delivered has informed the illustrative example of tariff and bill impacts in this draft 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.

Stakeholders have highlighted the degree of uncertainty and risk around the demand forecasts proposed by CitiPower, noting that if actual energy delivered over the 2026–31 period is less than forecast, distribution network tariffs and consumer bills would be higher, all else being equal.[8] 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 40% of the rate forecast by CitiPower, the modelled impact on average annual bills would be:[9]

- a nominal reduction of $3 (–0.2%) by 2030–31 for a residential consumer[10]

---

[7] 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.

[8] Sensitivity of energy delivered on bills was also discussed in our issues paper. AER, *Issues paper CitiPower, Powercor and United Energy electricity distribution determination 2026-31*, pp 9-13, March 2025.

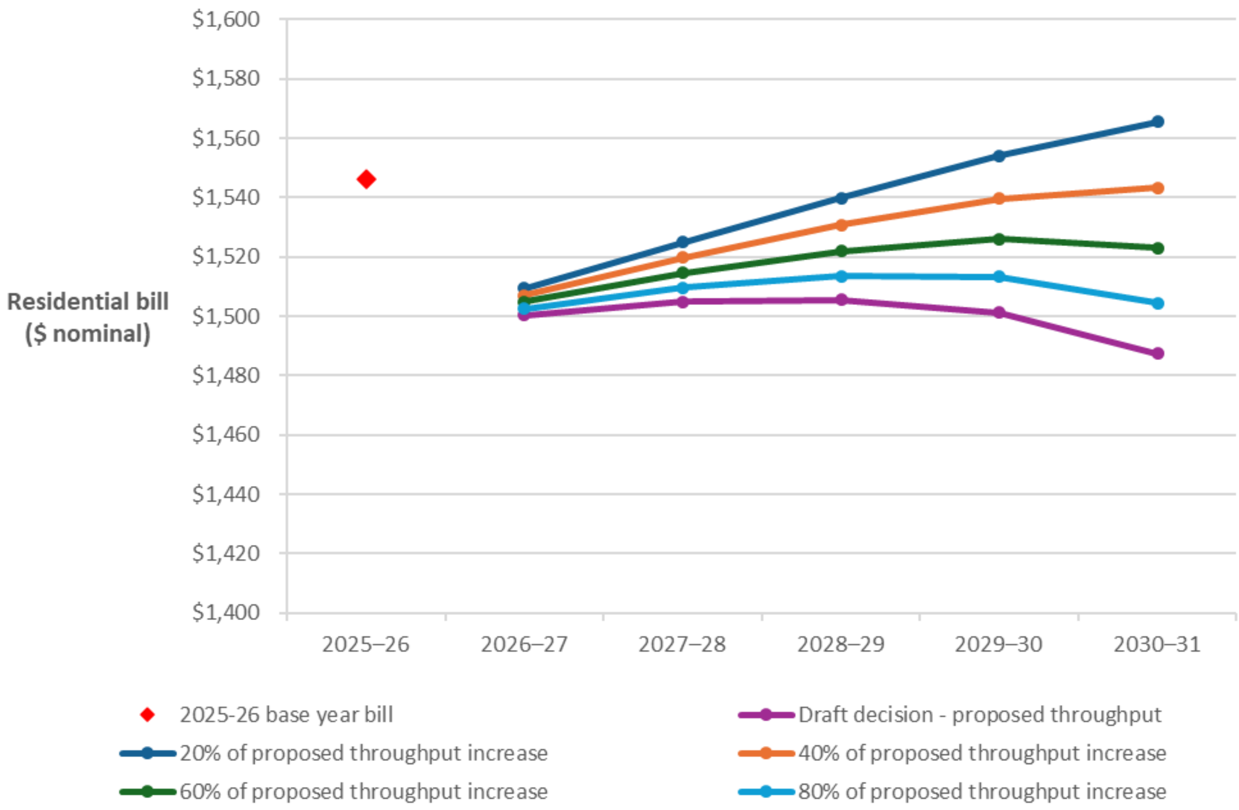
[9] This would therefore reflect energy throughput of 6,803 GWh in 2030–31, or an increase in energy throughput over the period of 20.7% compared to the 26.3% increase proposed by CitiPower.

[10] This reflects an increase of $15 for distribution SCS, and a reduction of $18 for metering.

- a nominal increase of $13 (–0.4%) by 2030–31 for a small business consumer.[11]

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

Figure 6 Sensitivity of energy delivered on annual residential bills ($ nominal)



Source: AER analysis.

1.3 Consumer engagement

High quality consumer engagement is critical to development of a proposal that supports delivery of services and outcomes that reflect consumers' needs and preferences. Experience shows that proposals that genuinely reflect consumer preferences, and which also meet our expectations for assessing capex, opex, depreciation and tariff structure statements, are more likely to be largely or wholly accepted at the draft decision stage, creating a more effective and efficient regulatory process for all stakeholders.

CitiPower began its engagement for the 2026-31 regulatory period early, keen to learn from feedback relating to engagement on its proposal for the current, 2021-26 period. Its Customer Advisory Panel found much to commend in CitiPower's sincerity, its extensive and sustained program of consumer and stakeholder engagement on a range of key issues, and its involvement of diverse consumer groups and other stakeholders.[12]

---

11 This reflects an increase of $35 for distribution SCS, and a reduction of $22 for metering.

12 CPU Customer Advisory Panel - *Submission - CitiPower electricity distribution proposal 2026-31* - April 2025.

Where consumers have been engaged on the outcomes CitiPower seeks to achieve, our role is to now carefully assess the prudency and efficiency of the expenditure CitiPower has submitted is necessary to deliver them.

The NER require us to consider the extent to which CitiPower's proposed forecasts of opex and capex include expenditure to address the concerns of its end users, as identified by CitiPower in the course of its engagement with end users or groups representing them. This is one of several factors to which we must have regard in determining whether the total forecasts of opex and capex CitiPower has proposed reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs. [13]

We have heard that CitiPower's consumers want clear value from their network, and for everyone to have access to the electricity supply they value regardless of where they live or work. They want existing service levels maintained and to stay connected with reliable and safe supply, and a network that is resilient to extreme weather. As the market shifts towards more sustainable energy sources and practices for a cleaner future, consumers want greater energy supply independence and expect CitiPower to manage additional capacity requirements on its network and to support electrification at the lowest possible cost.

CitiPower has proposed significant uplifts in capex and opex relative to previous periods. Even where it is possible to say that its proposal is reflective of consumer views and preferences, this does not displace the AER's role in carefully testing and assessing the prudency and efficiency of proposed expenditure. Submissions have emphasised the importance of this scrutiny in ensuring desired outcomes are delivered at the lowest sustainable cost. [14]

Similarly, the effectiveness and outcomes of CitiPower's engagement on its TSS, including its export tariff transition strategy[15], informed our assessment of proposed tariff structures. For example, we have had regard to information exchanged and feedback provided as part of consumer engagement when considering whether the structure of a tariff is reasonably capable of being understood by retail consumers, *or* of being directly or indirectly incorporated by retailers or intermediaries into contract terms offered to those consumers. [16]

[13] NER, cll. 6.5.6(c), 6.5.7(c)(1).

[14] Hon Lily D'Ambrosio MP - *Submission - Victorian electricity distribution proposals 2026-31* - June 2025; Origin Energy - *Submission - Victorian electricity distribution proposals 2026-31* - May 2025.

[15] NER, cl. 6.8.2(c1)(2).

[16] NER, cl. 6.18.5(i).

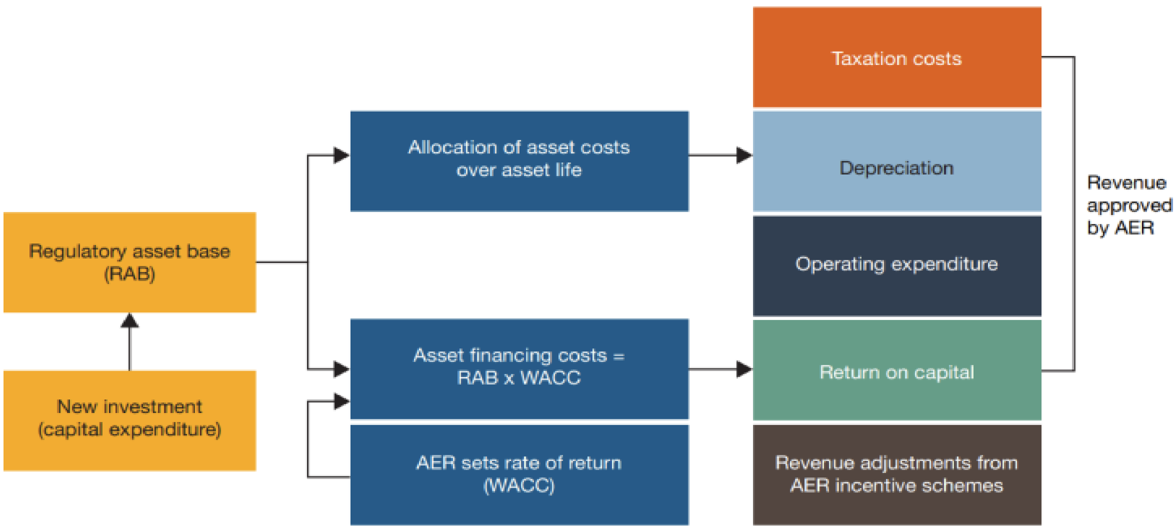
2 Key components of our draft decision on revenue

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. It delivers benefits to consumers as efficient costs are revealed and drives lower cost benchmarks in subsequent regulatory periods. By only allowing efficient costs in our approved revenues, we promote achievement of the NEO and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

Under the NEL and NER, revenue is calculated using 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 EBSS and CESS
- estimated cost of corporate income tax.

Figure 7 The building block model to forecast network revenue



Source: AER.

Revenue smoothing

Our draft decision incudes a determination of CitiPower's annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2026–31 period. The smoothed revenues we set in this draft decision are the amounts that CitiPower will target for its annual pricing purposes and recover from its consumers for the provision of SCS for each year of the 2026–31 period.

The ARR 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 draft decision, we have approved lower revenues than CitiPower's proposal. This is mainly driven by our reductions to CitiPower's forecast capex and opex, and its opening RAB as at 1 July 2026. Further reductions to revenues are due to our determinations on incentive scheme outcomes, which impacted the revenue adjustments building block.

Our draft decision allows for higher revenues than those determined in the 2021–26 period for the reasons discussed in section 1.1 of this Overview. In nominal terms, CitiPower's unsmoothed revenue for the first year of the 2026–31 period (2026–27) is 6.1% lower than the approved revenue for the last year of the 2021–26 period (2025–26). It then increases by an average of 4.7% 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. Consequently, our smoothed revenue profile reduces these increases and passes on the optimal reduction in 2026–27.

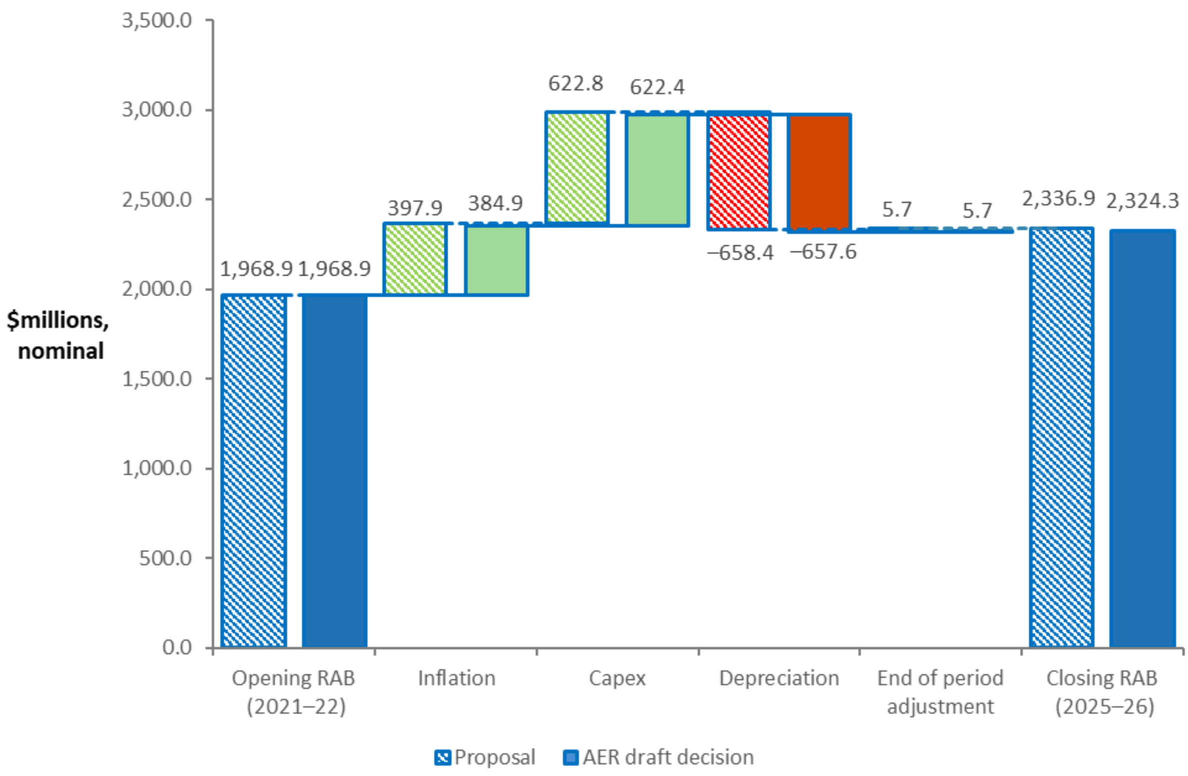
Our draft decision smoothed revenue is for an initial reduction of 3.0% ($ nominal) in 2026–27, followed by constant annual increases of 4.2% for the remaining 4 years (2027–28 to 2030–31). This smoothing profile results in a divergence between smoothed and unsmoothed revenue for 2030–31 of –3%, which is within our preferred range.

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

For this draft decision, we have determined an opening RAB value of $2,324.3 million ($ nominal) as at 1 July 2026. This value is $12.6 million (0.5%) lower than CitiPower's proposed opening RAB value of $2,336.9 million. This reduction is largely due to the update we made to the consumer price index (CPI) input for 2025–26 to reflect the actual outcome in the roll forward model (RFM). Figure 8 shows the key drivers of change in CitiPower's RAB over the 2021–26 period compared to its proposal.

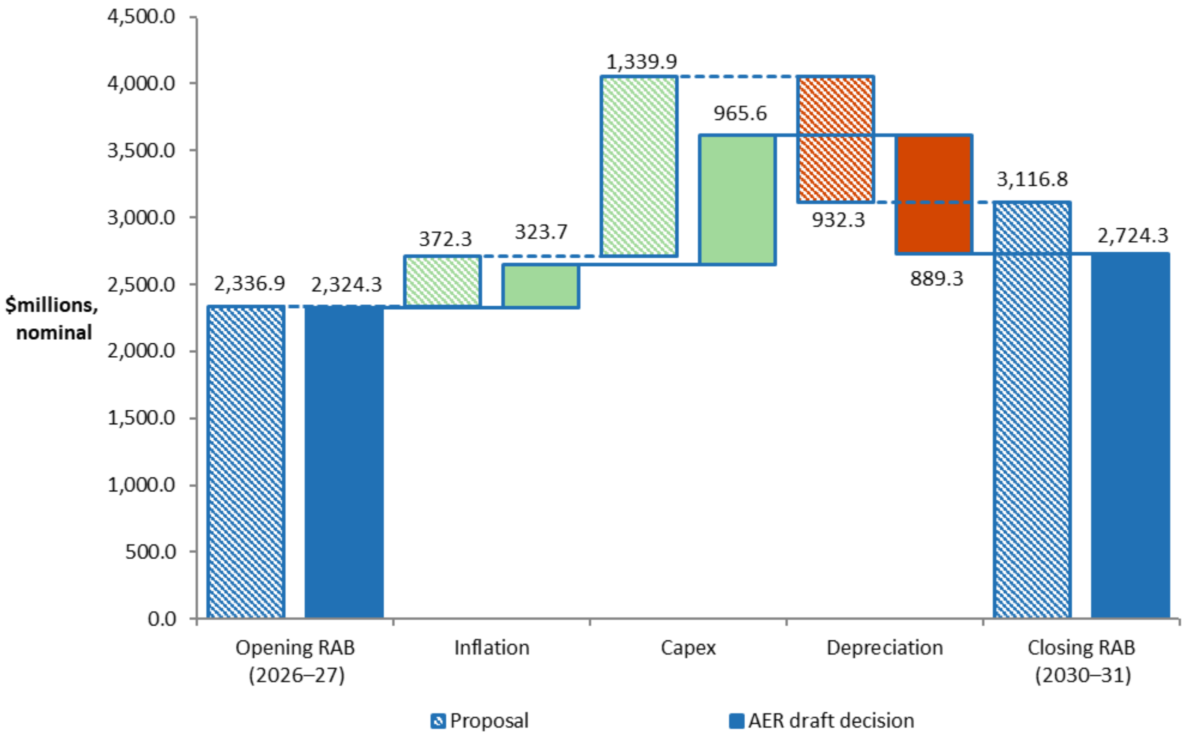
Figure 8 Key drivers of change in the RAB over the 2021–26 period – proposal compared to AER's draft decision ($million, nominal)



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

Figure 9 likewise shows the key drivers ($ nominal) of the change in CitiPower's RAB over the 2026–31 period compared to its proposal. Our draft decision projects an increase of $399.8 million (17.2%) to the RAB by the end of the 2026–31 period compared to the $779.9 million (33.4%) increase in CitiPower's proposal. We have determined a projected closing RAB of $2,724.1 million ($ nominal) as at 30 June 2031, which is $392.7 million (12.6%) lower than CitiPower' proposal of $3,116.8 million. This lower value is mainly due to our draft decision to reduce CitiPower's forecast capex (section 2.4). It also reflects our draft 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 draft decision are discussed in Attachment 1.

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



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

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.[17]

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 prices.

[17] AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

We are required by the NEL and NER to apply the RORI to estimate an allowed rate of return. For this draft decision, we have applied the 2022 RORI.[18]

CitiPower's proposal adopted the 2022 RORI.[19] The 5.93% (nominal vanilla) rate of return in this draft decision is slightly higher than the 5.84% placeholder in the proposal, reflecting the net effect of a higher risk-free rate and a lower cost of debt.

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 draft decision accepts CitiPower's proposed risk-free rate and debt averaging periods because they are consistent with the 2022 RORI.[20]

Table 1 Draft decision on CitiPower's rate of return (nominal)

	AER's previous decision (2021–26)	CitiPower's proposal (2026–31)	AER's draft decision (2026–31)	Allowed return over the regulatory control period
Nominal risk-free rate	1.38%	3.96%	4.25%[a]	
Market risk premium	6.10%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	5.04%	7.68%	7.97%	Constant (%)
Return on debt (nominal pre-tax)	4.52%[c]	4.62%	4.58%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.73%[c]	5.84%	5.93%	Updated annually for return on debt
Expected inflation	2.00%	2.75%	2.55%	Constant (%)

Source: AER analysis; AER, *Final decision – CitiPower distribution determination 2021-26 – Attachment 3 – Rate of return*, 30 April 2021, p. 5; CitiPower, *MOD 1.08 - Rate of return - Jan2025*, 31 January 2025.

(a) Calculated using a placeholder averaging period of 20 business days ending 30 June 2025, which will be updated for the final decision.

(b) Calculated using a placeholder averaging period of 20 business days ending 30 June 2025, which will be updated for the final decision.

(c) Applied to the first year of the 2021–26 regulatory control period.

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

19 CitiPower, *SCS Revenue and control mechanism*, 31 January 2024, p 5.

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

Debt and equity raising costs

In addition to compensating 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 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 capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our past determinations.[21] CitiPower has proposed to use our approach to estimate debt and equity raising costs.[22]

Our draft decision is to apply a debt raising cost of 8.55 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex (see section 2.5).

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 $2.78 million.

Imputation credits

Our draft decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[23] CitiPower's proposal also adopted this value.[24]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.55%. 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.[25] CitiPower's proposal also adopted our approach.[26]

Table 2 Draft decision on CitiPower's forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	2.60%	2.58%	2.55%	2.53%	2.50%	2.55%

Source: AER Analysis; RBA, *Statement on Monetary Policy Table 3.1: Detailed Forecast Table*, August 2025, accessed 1 September 2025.

Our draft decision uses the Reserve Bank of Australia's (RBA) August 2025 Statement on Monetary Policy (SMP) which contains a consumer price index (CPI) forecast for the year-ending June 2027. This means the first year of the 2026–31 period is based on RBA forecasts and, thereafter, a linear glide-path from year 2 to the mid-point of the RBA's inflation target band of 2.5% in year 5.

21 AER, *AER - Draft Decision Attachment 3 - Rate of return - Ergon Energy - 2025-30 Distribution revenue proposal,* 23 September 2024, pp 4–6.

22 CitiPower, *MOD 1.01 - SCS PTRM - Jan2025,* 31 January 2025.

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

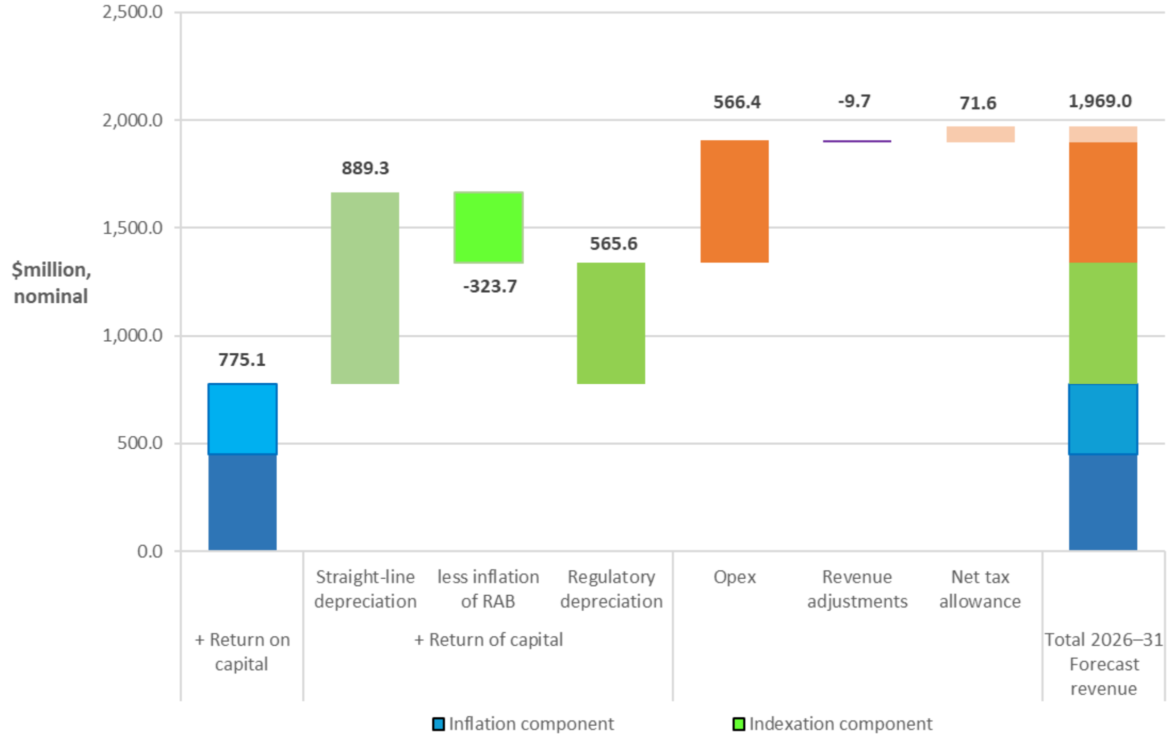
24 CitiPower, *SCS Revenue and control mechanism*, 31 January 2025, p 8.

25 AER, *Final position, Regulatory treatment of inflation*, December 2020.

26 CitiPower, *SCS Revenue and control mechanism*, 31 January 2025, p 6.

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

Figure 10 Inflation components in the draft 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 draft decision determines a regulatory depreciation amount of $565.6 million ($ nominal) for the 2026–31 period. This is an increase of $5.6 million (1.0%) from CitiPower's proposal of $560.0 million. This increase in regulatory depreciation is primarily due to a lower expected inflation rate in our draft decision compared to CitiPower's proposal, which has reduced the indexation of the RAB.[27] This increase is partially offset by our draft decisions to reduce the proposed forecast capex and the opening RAB as at 1 July 2026, which have reduced straight-line depreciation over the 2026–31 period.

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

2.4 Capital expenditure

Capital expenditure (the capital costs and expenditure incurred to provide network services) mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Capex is added to CitiPower's RAB, which is used to determine the return on capital and return of capital (also known as regulatory depreciation) building block allowances. All else being equal, a higher capex forecast will lead to higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision is to not accept CitiPower's total forecast capex of $1,216.3 million ($2025–26) for the 2026–31 period. Our alternative forecast is $882.2 million, which is 27.5% lower than CitiPower's forecast. Table 3 sets out our draft decision for CitiPower's forecast capex by capex category.

Table 3 AER's draft decision by capex category ($ million, $2025–26)

Capex category	CitiPower's proposal	AER's draft decision	Difference over capex category ($/%)	
Replacement	351.6	194.1	-157.5	-44.8%
Innovation	4.8	0.9	-3.9	-81.9%
Augmentation	212.6	130.6	-82.0	-38.6%
Connections	236.7	209.7	-27.0	-11.4%
ICT	119.5	108.5	-11.0	-9.2%
Property	84.3	84.3	0.0	0.0%
Fleet	21.1	21.1	0.0	0.0%
CER integration	11.8	9.8	-2.0	-16.9%
Cyber security	5.6	5.6	0.0	0.0%
Non-network capex – other	7.0	7.0	0.0	0.0%
Capitalised overheads	162.1	144.1	-18.0	-11.1%
Total capex (less capital contributions)	**1217.1**	**915.6**	**-301.5**	**-24.8%**
less Disposals	-0.7	-0.7	0.0	0.0%
Modelling adjustments		-32.7	-32.7	
Net capex	**1216.3**	**882.2**	**-334.1**	**-27.5%**

Source: CitiPower and AER analysis.

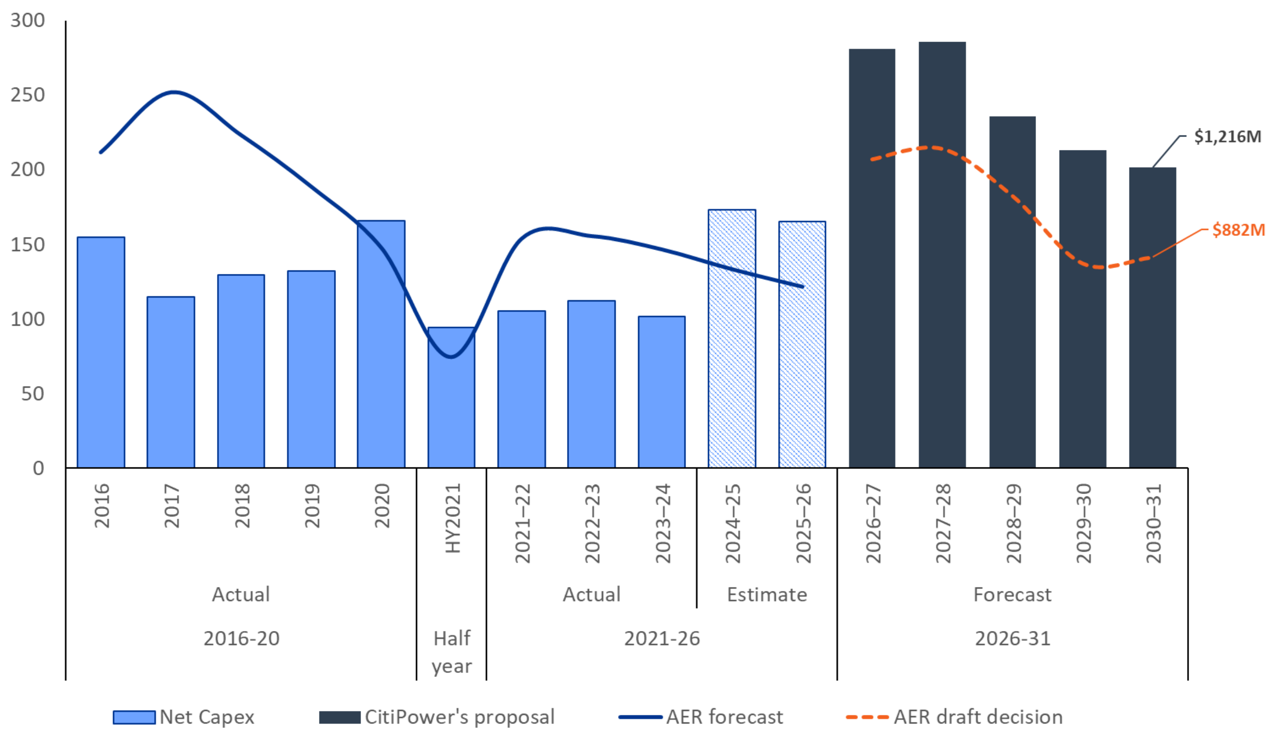
Notes: Numbers may not sum due to rounding. For CitiPower's proposal, we re-categorised capex to align with how we assessed each category. We re-categorised $5.6 million of ICT to cyber security, $2.4 million of augex to innovation and $2.4 million of repex to innovation. CitiPower did not propose resilience capex.

Figure 11 shows CitiPower's historical capex trend, its proposed forecast for the 2026–31 regulatory control period, and our draft decision. As can be seen, CitiPower proposed a material step up in the forecast period relative to the current period. We also observe material underspends in actual capex in the current and previous periods. The main driver of the underspend in the current period is due to asset disposals, where there is a large increase in actual asset disposals compared to the forecast asset disposals in the 2021–26 period.[28]

Figure 11 also shows that while our draft decision is a reduction to CitiPower's forecast, it is also a step up from CitiPower's current period actual/estimates. We note that some of this step up is because:

- For connections, there was a temporary decrease in volumes in the current period due to COVID. The forecast reflects volumes which are consistent with expected economic activity and pre COVID levels.
- There was a significant increase in CitiPower's property forecast relative to the current period, which is mainly driven by its Burnley depot upgrades. We found expenditure for these upgrades to be prudent and efficient.

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



Source: CitiPower and AER analysis.
Note: Capex is net of asset disposals and capital contributions.

Based on the information before us, we have reviewed CitiPower's total capex forecast from a top-down and bottom-up perspective.

---

28 Capex is assessed on a net capex basis (gross capex minus asset disposals). While we also saw a large increase in actual asset disposals in Ausgrid's 2024-29 proposal as a result of a compulsory acquisition in the Sydney CBD, this is not a type of underspend we typically see.

Our top-down testing of CitiPower's forecast capex informed the scope of our bottom-up review. We observe the following about CitiPower's forecast capex at the top-down level:

- Its proposed total capex forecast is materially above (84.4%) current period actual/estimates.
- It proposed a step up in the forecast for almost all capex categories, with a material step up in the largest components of capex.
- The repex modelling results indicate that CitiPower has higher unit rates and shorter replacement lives compared to the median of the other 13 NEM DNSPs.
- There is a decreasing trend in the whole of network System Average Interruption Frequency Index (SAIFI) from 2015 to 2024, suggesting that reliability of its network is generally improving overtime.

Given these top-down findings, we have undertaken a bottom-up review on most capex categories.

We note that we have accepted CitiPower's forecast where it has provided sufficient evidence to support its prudency and efficiency. This is the case for its forecast for property, fleet, cyber security and other non-network.

However, we have not accepted CitiPower's forecast in full, reducing it by 27.5%, because we found that it did not provide sufficient quantitative evidence to support the material step up in the forecast.

For several projects and programs, we found the optimal timing for investment is beyond 2026-31. We note a pattern of underspending across the previous and current period. During this time, CitiPower has deferred some capex, and we have adjusted the CESS payment accordingly to address deferrals in augex and ICT. In other cases, we have made reductions to CitiPower's repex forecast (such as its substation switchgears) as we consider that the more expensive option of a substation re-build is not optimal in this regulatory period. More generally, we note that the pattern of deferral of capex projects reduces our confidence in CitiPower's proposed timing of its capex investments especially as it has discretion in delivering these projects. While we appreciate that there are uncertainties associated with the scheduling of projects, it is not in consumers' interests to pay for projects that are not required where the optimal timing is beyond 2026-31.

In some cases, such as for poles and distribution switchgear programs, CitiPower did not provide cost benefit analysis to demonstrate that its preferred higher cost option is prudent and efficient. In other cases, such as the Brunswick modernisation program and customer driven electrification augex projects, we found overstated costs and/or benefits in its economic analysis. Its preferred investments were found to not have positive net benefit once more reasonable assumptions are applied.

Our draft decision sets out reasons for our position including information gaps and/or lack of supporting information. We invite CitiPower to address these issues in its revised proposal. We would also encourage CitiPower to engage with its consumers about its revised proposal. We acknowledge the extensive consumer engagement that CitiPower undertook on its capex proposal and would encourage it to continue to ensure that its consumers' preferences are considered in its revised proposal.

In summary, our bottom-up review found that CitiPower provided sufficient evidence to support the forecast for some capex categories, namely in property, fleet, cyber security and other non-network. However, for the other areas of capex, CitiPower did not demonstrate the prudency and efficiency of its forecast, and we came to the following findings:

- *Repex* – Our bottom-up review confirmed concerns we found at the top-down level. Our reductions are mainly driven by a reduction to CitiPower's forecast volumes in several programs. Our largest reduction has been to CitiPower's forecast for its high value, low volume assets (substation switchgears and substation transformer programs) which are the main drivers of CitiPower's proposed material step up in forecast repex. We also have concerns with the reasonableness of inputs and assumptions in its economic analysis. We found that CitiPower could have explored lower cost-effective options, such as refurbishment, instead of more expensive options. Other reductions to CitiPower's repex forecast relate to insufficient evidence to support the step up in volumes relative to the current period.
- *Augex* – We have not accepted the forecasts for several of CitiPower's augmentation projects. We have considered EMCa's advice and agree that some of CitiPower's forecast at the project level is not prudent and efficient. While we made no changes to the demand forecast, we found issues in CitiPower's cost benefit analysis including issues with overestimated benefits, high costs and incorrect use of the Value of Customer Reliability (VCR). Our largest reduction has been to CitiPower's demand driven augex which was the main driver of CitiPower's proposed material step up in forecast augex. We also have concerns with the optimal timing of several projects which we consider should be deferred beyond the 2026–31 regulatory control period.
- *Connections* – We have not accepted CitiPower's forecast unit rates for its connections. We considered CitiPower's use of a single year unit rate was not reasonable and we have applied an average unit rate based on current period unit rates. We broadly accept CitiPower's forecast volumes for BAU connection types. However, we do not consider CitiPower's data centre forecast, which is based on forecast capacity, is reasonable as its methodology is not an accurate reflection of the likely volume of data centre connections to be constructed in the forecast period. It is our understanding that CitiPower will be revising its data centre forecast for our consideration in its revised proposal.
- *ICT* – We have not accepted the forecasts for the 9 recurrent projects proposed by CitiPower in full. We have considered EMCa's advice and agree that CitiPower did not provide sufficient evidence to support the uplift compared to historical current period spend. For non-recurrent expenditure, we concur with EMCa that while these projects are prudent, when benchmarked against other DNSPs some projects were not efficient. For one project, CitiPower did not take account of net opex benefits, which we have netted off in our alternative forecast.
- *CER* – We have considered EMCa's findings and agree that CitiPower's proposal to introduce flexible service offerings to address increasing curtailment of exports is prudent and efficient. For the non-network marketplace platform, our assessment concurs with EMCa's findings that there is a lack of evidence of the need for the investment, and there are issues with CitiPower's cost benefit analysis, with benefits arising long after CitiPower proposes to invest. For its network data visibility project

which allows users to obtain data on constraints and spare capacity, our assessment concurs with EMCa's finding that there was no quantitative evidence to support the investment. We encourage CitiPower to provide a cost benefit analysis in its revised proposal to quantify this investment.

- *Innovation* – We recognise the importance of innovation investment in supporting the energy transition and protecting consumers. There is a need for trials and pilots to test and explore new ideas, concepts and technology before committing to implementation of solutions and rolling these into business-as-usual activities. We also recognise CitiPower's consumer engagement on innovation-related expenditure. However, we have not accepted CitiPower's forecast in full. We have accepted the forecast for some projects as we found that these projects align with the criteria for ex-ante innovative projects. However, we found that most projects did not satisfy the ex-ante innovation criteria; especially the criteria that the project be innovative.

Our draft decision on CitiPower's capital expenditure is set out in Attachment 2.

2.5 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services. Forecast opex is one of the building blocks we use to determine CitiPower's total regulated revenue requirement.

Our draft decision is to not accept CitiPower's total opex forecast of $586.1 million,[29] including debt raising costs, for the 2026–31 period. This is because our alternative estimate of $524.4 million is materially different ($61.7 million, or 10.5% lower) than CitiPower's total opex forecast proposal.[30] Therefore, we consider that CitiPower's total opex forecast does not reasonably reflect the opex criteria.[31]

Our draft decision, which is less than CitiPower's proposed total opex forecast, is:

- $61.9 million (10.6%) lower than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $55.3 million (11.8%) higher than CitiPower's actual (and estimated) opex in the 2021–26 period.

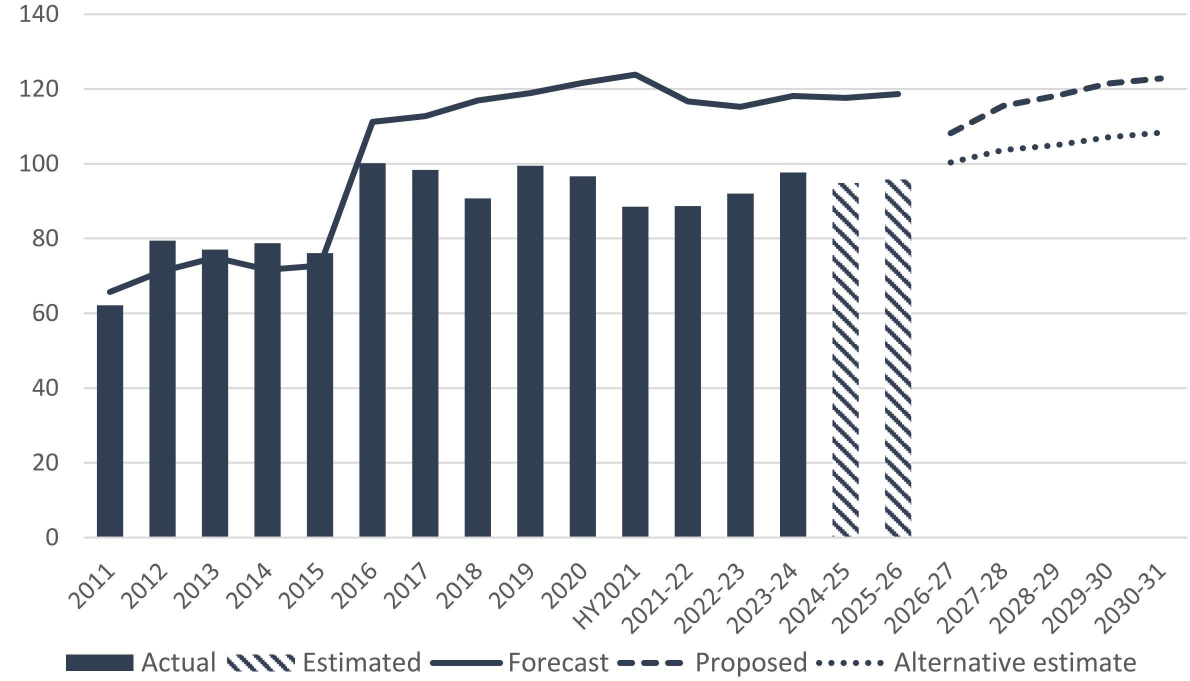
In Figure 12, we compare our alternative estimate of opex to CitiPower's proposal for the next regulatory control period. We also show the forecasts we approved for the last 2 regulatory control periods and CitiPower's actual and estimated opex over these periods.

[29] All dollars are in $2025-26 terms unless otherwise stated.

[30] CitiPower, *Regulatory Proposal 2026-31 – Part B – Explanatory Statement*, January 2025, p. 74.

[31] NER, cl. 6.5.6(c)-(e).

Figure 12 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 MOD 1.05 – opex*, January 2025; AER analysis.

The key differences between CitiPower's opex proposal are primarily driven by our lower alternative estimates of efficient costs for CitiPower's proposed step changes. In our alternative estimate we have:

- included a lower alternative estimate for the vegetation management step change ($24.9 million lower)
- included a lower alternative estimate for the CER integration step change ($2.9 million lower)
- included lower alternative estimates for the cloud services ($10.0 million lower) and ICT modernisation ($3.0 million lower) step changes
- reclassified the customer assistance package step change as a category specific forecast and included a lower alternative estimate ($2.8 million lower).
- used our output growth forecast, reducing forecast opex by $12.6 million.

The largest adjustment to our alternative estimate is our lower forecast for CitiPower's proposed vegetation management step change. We consider that while CitiPower has justified the need for a step change in costs to comply with its electric line clearance obligations in the 2026–31 period, the available evidence suggests the efficient amount required is less than proposed by CitiPower due to errors in its input assumptions and forecasting methodology.

We discuss the differences between our alternative estimate and CitiPower's proposal in more detail 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 PTRM.

Our draft decision determines an estimated cost of corporate income tax amount of $71.6 million ($ nominal) for CitiPower over the 2026–31 period. This is an increase of $7.3 million (11.3%) from CitiPower's proposal of $64.3 million. This increase is primarily due to our draft decision on a lower tax depreciation and higher regulatory depreciation. Regulatory depreciation is a component of revenue for tax purposes. Tax depreciation is a component of tax expense. Therefore, higher regulatory depreciation and lower tax depreciation will increase the estimated taxable income for CitiPower, thereby increasing the estimated cost of corporate income tax.

Proposals from Victorian DNSPs have brought into focus the impact that the tax treatment of large customer capital contributions, paid in respect of new, large customer connections, has on the revenue recovered from all consumers. We have identified a potential alternative approach drawing on our determinations for the current period. This relates to the DNSPs' proposals that net tax liability arising from capital contribution from large, embedded generators be included in connection charges payable by the generator itself. This approach was proposed to reduce the cross-subsidy paid by the wider consumer base to large, embedded generator connections, and to reduce exposure to forecasting risk associated with these connections. Our draft decisions encourage Victorian DNSPs to consider the possibility of extending of this model to other large connecting customers (e.g. data centres) in their revised proposals.

2.7 Revenue adjustments

Our calculation of total revenue for 2026–31 will include adjustments for the expenditure incentive schemes that were applied to CitiPower as part of our determination for the current, 2021-26 period.

These include:

- an EBSS revenue decrement of $5.0 million,[32] from the application of the EBSS in the 2021–2026 regulatory control period.[33] This represents a -$2.7 million difference from CitiPower's proposed carryover amount of -$2.3 million.[34]
- a CESS revenue decrement of $3.9 million which is $17.2 million lower than CitiPower's forecast CESS revenue increment of $13.3 million. This reflects updates to inflation, WACC, 2020 true-up and an adjustment for deferred capex.

Our draft decision on the application of the CESS and EBSS to CitiPower's expenditure in the new, 2026-31 period is discussed in section 3.

32 All dollars in this document are in $2025–26 terms unless otherwise stated.

33 NER, cl. 6.4.3(a)(5).

34 CitiPower, CP MOD 1.06 – EBSS, January 2025.

Our draft decision also includes an allowance of $2.6 million ($2025-26) under the Demand Management Innovation Allowance Mechanism (DMIAM), to fund research and development in innovative demand management projects that have the potential to reduce long-term network costs.[35] Consistent with the design of the DMIAM, this allowance is included in CitiPower's total revenue as a positive revenue adjustment rather than as part of forecast opex or capex. Any unspent portion of the allowance can therefore be returned to consumers as one of the permitted adjustments to revenue under the NER.[36] This is not the case for unspent capex or opex, as CitiPower has suggested for example in the case of its proposed innovation allowance and community energy fund for the 2026-31 period. We consider the NER only allows for adjustments in limited circumstances[37] and we do not accept that the businesses can apply a 'use it or loss it' mechanism to select elements of their capex and opex proposals.

Our draft decision also includes a revenue adjustment (reduction) of –$2.9 million ($2025–26), to return a share of the unregulated revenue 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 their 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.

Cost pass through events

There are 3 prescribed cost pass through events (regulatory change event, service standard event and tax change event) which apply to all Victorian DNSPs under the NER. In addition to the NER prescribed pass through events, CitiPower proposed 8 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). Our draft decision is to accept these again.

While we recognise the important role of pass through events as one element of the framework for managing uncertainty, we are also careful to ensure new nominated events are included only where they reflect an appropriate allocation of risk and are clearly justified with regard to the nominated pass through event considerations in the NER. In this context, we have not accepted the following new cost pass through events proposed for the 2026–31 period by CitiPower, Powercor and United Energy (CPU):

---

35 We developed and implemented the DMIAM under cl. 6.6.3A of the NER: AER - Demand management innovation allowance mechanism - 14 December 2017.

36 NER, cl. 6.4.3(a)(5).

37 NER, cl. 6.4.3(a)(6).

- **Fault level event**: the risk of CPU exceeding its prescribed fault levels due to potential new generation assets added to the upstream transmission network by AEMO. We consider it unlikely that any transmission project would have the effect of raising fault levels above their specified limits for CPU over the 2026–31 period, and that if such a project were to occur, any impact (including cost) on the DNSP's fault levels could be largely or entirely mitigated through joint planning with the TNSP, AEMO and other stakeholders.

- **Electrification event**: the risk of CPU incurring potential costs due to increased demand on its network if the State or Federal government announces new electrification policies. We do not consider this event to be clearly defined and measurable. We also consider that any potential cost impact of electrification could be largely mitigated by prudent planning, including through CPU's augex and demand forecasts, and joint planning and consultation with government and other relevant stakeholders. We also consider any sudden, unexpected and material cost impacts arising from an electrification policy announcement to be unlikely over 2026–31. These considerations align with similar AER decisions in the past.

- **AEMO participant fee event**: the potential for CPU to be charged Participant Fees by AEMO after its current fee structure review. We have not accepted this event at this time. We recommend CPU have regard to AEMO's draft fee structure released in September 2025, and factor this into its revised proposal (due in December 2025). If AEMO's draft decision is to charge participant fees to DNSPs in the 2026–31 period, CPU should include these forecast fees in its revised revenue proposal, rather than recovering costs through the pass through mechanism.

We discuss our assessment on the new nominated pass through events in more detail in Attachment 4.

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.

CitiPower proposed 3 contingent project the LS Zone Substation, J Zone Substation and R Zone Substation as part of its regulatory proposal for the 2026–31 regulatory control period. Our draft decision does not accept these.

We do not consider the LS Zone Substation and J Zone Substation contingent projects meet the requirements in the NER to be included as contingent project, as the expenditure is sufficiently certain enough to be included in forecast capex. We recommend that CitiPower either provides additional evidence to support why these projects are reasonably uncertain or include this expenditure in its revised capex forecast.

We do not consider the R Zone Substation project meets the requirements in the NER to be included as a contingent project because part of the expenditure is already accounted for in the forecast capital expenditure in the regulatory control period. We recommend CitiPower provide addition information in its revised proposal to demonstrate the repex included for the R Zone Substation does not address the same need (in whole or in part) as this proposed contingent project. Alternatively, if the repex included for the R Zone Substation does address the same need we request CitiPower resubmits its contingent project application without the component that is already accounted for.

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 draft decision on the incentive schemes that will apply to CitiPower in the 2026–31 period is as follows.

Efficiency benefit sharing scheme

Our draft decision is that the efficiency benefit sharing scheme (EBSS) will continue to apply to CitiPower in 2026–31. This provides a continuous incentive to pursue efficiency improvements in main standard control services opex and provide for a fair sharing of these between networks and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods. Our draft decision on the EBSS is set out in Attachment 5.

Capital expenditure sharing scheme

Our draft decision is that the capital expenditure sharing scheme (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. CitiPower proposed excluding connections and innovation capex from the CESS in the 2026-31 period.

We updated the CESS in August 2025 and introduced a mechanism which takes into account the change in volumes of connections. As the volumetric adjustment is a new addition to the CESS, we are seeking CitiPower's views in the revised proposal on how this adjustment can be applied. The full detail on our draft decision for the CESS is in Attachment 6.

We have maintained our position to not have category specific exclusions beyond the volumetric adjustment for connections. However, we note that CitiPower may voluntarily reduce its CESS reward if it does not undertake innovation capex.

Customer service incentive scheme (CSIS)

Our draft decision is to not apply a customer service incentive scheme (CSIS) to CitiPower in 2026–31.

The CSIS is designed to encourage electricity DNSPs to engage with their consumers, identify (through consumer engagement) the customer services their consumers want improved, and then set targets to improve those services based on their consumers' preferences. We identified issues with CitiPower's consultation and performance targets and found that CitiPower's proposed CSIS is not compliant with the requirements of the scheme. Our draft decision on the CSIS is set out in Attachment 9.

We will instead apply the telephone answering parameter and introduce the new connections parameter of the customer service component of the service target performance incentive scheme (STPIS). We have observed that CSIS proposals are becoming increasingly homogenised, static, and informed by diminished consumer engagement. While our assessment of the new connections parameter is ongoing, we consider that formalising customer service incentive parameters under the STPIS could be a better outcome for consumers. A new connections parameter in the STPIS aligns with our focus on ensuring that network service providers comply with their obligations to provide timely and transparent connections and reflects consumers' apparent willingness to pay for the improved services relating to connections.

Service target performance incentive scheme

Our draft decision is that the STPIS will continue to apply to CitiPower in 2026-31. The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance, and not to reduce costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years. Our draft decision on the STPIS is set out in Attachment 7.

Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

Our draft decision is that both the Demand Management Incentive Scheme (DMIS) and DMIAM will continue to apply to CitiPower in 2026–31. 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. Our draft decisions on the DMIS and DMIAM are set out in Attachment 8.

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:[38] 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. Our draft decision on the Victorian F-factor incentive scheme is set out in Attachment 10.

---

[38] Victoria Government Gazette, G 51, 22 December 2016, p. 3239

4 Network pricing

Our determination for CitiPower separates the regulated direct control 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 Victorian DNSPs in 2026–31 in our Framework and Approach paper in July 2024,[39] 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 consumers, 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.

However, since the Framework and Approach was published[40] we consider a material change of circumstances has arisen that justifies the classification of a new, negotiated distribution service.

DNSPs can rent their assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.) for use separately or in addition to essential electricity connection and supply services. These distribution asset rental services are currently not classified (i.e. unregulated), meaning the AER has no role in setting the price or non-price terms offered to customers. When a DNSP's annual unregulated revenues from shared assets are expected to be greater than 1% of its total smoothed annual revenue requirement for that regulatory year, a portion of any revenue earned by a DNSP from distribution asset rental is returned to consumers in accordance with the Shared Asset Guideline (as noted in section 2.7).

Our Framework and Approach paper for Victorian DNSPs for the 2026–31 regulatory control period did not classify, or mention, distribution asset rental services in any form.

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

---

39 AER – *Final Framework and Approach – Victorian electricity distribution determinations 2026-31* – July 2024, Appendix A.

40 AER - Final Framework and Approach - Victorian electricity distribution determinations 2026-31 - July 2024

regulated connection or metering services) for use by third parties as a host for EV charging infrastructure, and competitive delivery of kerbside EV charging in particular.

Our draft decision is to classify the following new negotiated distribution service, to support negotiation of access to Victorian DNSPs' kerbside poles for that purpose on terms that are fair, reasonable and cost reflective:

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

The effect of the negotiated service classification for this service would be that, for the 2026-31 period, negotiations between CitiPower and parties seeking access to this new distribution service would 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, setting out the principles that guide negotiations,

both of which will be approved as part of our distribution determination for that period.

We received no submissions on proposed Negotiating frameworks or our proposed Negotiated distribution service criteria in our consultation on these earlier this year. We are mindful, however, that service classifications at the time of that consultation did not include any negotiated services. We therefore welcome any new submissions on the proposed frameworks and criteria now that this has changed. We discuss this further in Attachment 17 to this draft decision.

4.1 Control mechanisms for standard and alternative control services

In our Framework and Approach paper for the 2026–31 period, our proposed approach was to continue to apply the same control mechanisms as we applied in the current, 2021–26 period:

- a revenue cap for standard control services
- a revenue cap for metering services (as alternative control services)
- a price cap for ancillary network services, public lighting and metering exit fees (as alternative control services).

Our draft decision confirms this approach.

In our issues paper, we requested feedback on whether the current form of control mechanism for standard control services remained appropriate, and whether criteria for a change to the control mechanism had been satisfied. Our draft decision is that the above control mechanisms will continue to apply in the 2026-31 period. We discuss this further in Attachment 12 to this draft decision.

4.2 Tariff structure statement

Our draft decision is to not approve CitiPower's proposed TSS. We consider CitiPower is making some progress on network tariff reform within the constraint of aligning with Victorian Government preferences that customers move only gradually to cost reflective tariffs over the 2026–31 regulatory period. However, we encourage CitiPower to further consider how well-designed network tariffs charged to retailers can shift future demand growth out of peak periods and into low/minimum demand periods.

CitiPower's proposed TSS for the 2026–31 period is its third TSS since the Australian Energy Market Commission's (AEMC's) *Distribution Network Pricing Arrangements* rule change in 2014 that introduced the TSS framework.[41] The TSS is also CitiPower's first since the AEMC's 2021 *Access, pricing and incentive arrangements* rule change that allowed for two-way pricing.[42] Together these rule determinations introduced several reforms to distribution pricing, including to progress cost reflective pricing and to support more CER into the network.

Principally, we assess TSSs against the requirements of the NER and NEL, including the pricing principles and other applicable requirements of the NER.[43] We are also required to make our decisions in a manner that will or is likely to contribute to the achievement of the NEO.[44] For TSSs, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant.

With each TSS, we also look at how a DNSP has responded to the reforms mentioned above. A TSS informs use of the network by:

- providing clear price signals of what it costs to use the network at different times, allowing consumers (or their retailers) to make informed decisions to better manage bills
- transitioning tariffs to greater cost reflectivity while requiring DNSPs to explicitly consider the impacts on retail customers, by engaging with consumers, consumer representatives and retailers in developing network tariff proposals
- managing future expectations by setting out the DNSP's tariff approaches for a set period.

A TSS must set out several matters. These include tariff classes, proposed tariffs and the structures and charging parameters, the strategy for introduction of export tariffs, and the approach to setting tariff levels in each year of the regulatory control period.[45] The policies and procedures that will be used to assign customers to tariffs or reassign customers from one tariff to another must also be outlined.

---

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

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

43 NEL, s. 16(2). The national electricity objective is in NEL, s. 7.

44 NEL, s. 16(1)(a).

45 NER, cl. 6.18.1A(a).

While an indicative pricing schedule must accompany the TSS, the tariff levels for each tariff for each year of the 2026–31 period are not set as part of this determination.[46] Tariff levels for the regulatory year commencing 1 July 2026 will be subject to a separate, annual approval process beginning in May 2026, after we have made our final revenue determination in April 2026.[47]

4.2.1 Our draft decision and its context

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 customers and can support the energy transition currently underway. Where price signals are passed through, 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 does not approve CitiPower's proposed TSS. We accept that some individual elements comply with the pricing principles and contribute to achievement of the NEO. However, we strongly encourage CitiPower to reflect further on its assumption of no consumer response to its small customer tariffs in its demand forecasts[48] (other than those implicit through CitiPower's use of the Australian Energy Market Operator's (AEMO's) EV charging forecasts and use of specific battery profiles). Our draft decision emphasises the capacity for well-designed network tariffs to shift future demand growth out of peak periods and into low/minimum demand periods. We have provided examples in Attachment 13 of consumers responding to price signals. We therefore consider CitiPower should engage further with its stakeholders, including retailers, on the benefits of assigning small customers to cost reflective tariffs in the 2026–31 period where they can benefit from low off-peak rates, and should further explain the interrelationship between its tariff strategy and its wider proposal (including demand forecasts and proposed expenditure) in its revised proposal overview.[49]

CitiPower is also required to make the following changes in its revised TSS for the elements that we do not approve in this draft decision. These changes are required for CitiPower's TSS to achieve compliance with the NER pricing principles and contribute to the achievement of the NEO:

- calculate long-run marginal costs for both import and export services using forecasts based on at least a 10-year period
- include further information to justify the proposed basic export level[50] of 1 kWh/day for the CER tariff, small flexible connection tariff and TUOS pass-through tariff

46 NER, cl. 6.8.2(d1).
47 This will occur pursuant to obligations in cl. 6.18.2 and cl. 6.18.8 of the NER.
48 CitiPower, *Information Request CitiPower #020 – TSS*, May 2025, pp 1–2.
49 NER, cl 6.8.2(c1)(1)(v).
50 The basic export level is the amount of electricity that a customer will be able to export to the grid at no cost (NER cl. 11.141.12). The basic export level must apply for a 10-year period (that is, for 2 regulatory periods). This may be adjusted within the 10-year period.

- include network bill impact analysis for all customer types and tariff changes
- provide further information, including bill impact analysis, to support proposed changes to small business fixed charge recovery or reconsider the increase
- clarify the supply times available to controlled load tariffs
- include more transparent information on flexible connections agreements and fees
- include further consideration of type 7 and type 9 metered tariffs / unmetered tariffs.

We note that CitiPower, along with the other Victorian DNSPs, also retained its opt-out assignment to cost reflective tariffs for new small customers with smart meters, and its largely opt-in assignments to cost reflective tariffs for existing small customers. For example, CitiPower will not assign existing small customers to cost-reflective tariffs except in limited circumstances. This includes if they own EV fast chargers or upgrade to 3-phase. Customers with EV fast chargers will not be able to opt-out to single rate tariffs. CitiPower's assignment policies align with the Victorian Government's preference that customers move only gradually to cost reflective tariffs over the 2026–31 regulatory period.[51] This means that despite having near-universal smart meter penetration in Victoria since 2013, the proportion of consumers in Victoria on cost reflective pricing is low compared to other jurisdictions in the NEM.

Encouraging opt-in to, and a response to, cost reflective tariffs is particularly important for CitiPower given the significant demand-driven augmentation expenditure proposed by the Victorian DNSPs. CitiPower's (and the other Victorian DNSPs') view that small consumers are not responding to price signals warrants further consideration and response by CitiPower. It does not align with outcomes from trial tariffs or experience emerging from other DNSPs. We continue to consider that tariffs are an important, low-cost tool DNSPs can use to mitigate expenditure in the 2026–31 period and future periods by incentivising use of existing network capacity.

To progress tariff reform under its assignment polices and encourage customers to opt-in to a more cost reflective tariff, CitiPower proposed to continue to discount its residential and small business time-of-use tariffs by 1% each year. This would mean that by 2031 these tariffs would be on average 10% cheaper than CitiPower's non-cost reflective single rate/flat residential and small business tariffs. CitiPower also progressed tariff reform by proposing a solar soak (low priced) period in the middle of the day for the residential time-of-use tariff, opt-in CER (two-way) tariff, 3 flexible connection tariffs for storage and generation customers and a winter incentive demand charge for the large customers.

However, we are not convinced that CitiPower has done all it can to utilise and/or encourage take-up of cost reflective tariffs to encourage efficient use of the network. We therefore encourage CitiPower to develop a tariff trial aimed at more flexible load, like EVs or home batteries, whose response to network price signals could help mitigate the need for network investment. We also consider that improved calculations of long-run marginal costs will assist CitiPower's tariffs to better reflect efficient costs and improve the accuracy (and therefore effectiveness) of its price signals, particularly to manage flexible loads. Given the changes

51 Hon. Lily D'Ambrosio MP, *Submission on Victorian Electricity Distribution Proposals 2026-31*, June 2025.

currently taking place in the energy sector there exists opportunity for CitiPower (and other DNSPs) to further refine and develop their long-run marginal cost methodologies.

In addition to the required changes, we encourage CitiPower to consider making minor improvements in its revised TSS. This includes by providing clarity on which customers can access controlled load tariffs.

In Attachment 13, we describe in further detail the reasons for our decision and the changes that we consider necessary for us to approve CitiPower's TSS proposal, as well as the changes we encourage CitiPower to make. We note that we have one draft decision tariff structure attachment for 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 is to not accept CitiPower's public lighting proposal, although we consider it is largely reasonable. For the draft decision we have made several updates to the public lighting model inputs, including to decrease certain hourly rate inputs and for more mechanical changes related to updated inflation and labour escalators inputs. This results in prices for 2026–27 that are approximately 1.9% lower when compared to CitiPower's proposal for most light types.

We also encourage CitiPower to consult further with its stakeholders to inform its revised proposal. This consultation should include matters such as an accelerated LED rollout, smart lighting services and funding options for this rollout. These issues reflect those raised in a submission to our issues paper from the Victorian Greenhouse Alliances.

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 is not to accept CitiPower's metering proposal. For the draft decision we have made several adjustments to the forecast capex. This includes lower labour costs associated with the reactive replacement of meters upon fault or failure in line with our labour rate benchmarks and reduced equipment and installation costs of some communications equipment that we do not consider are justified. We have also made more mechanical changes related to updated inflation, rate of return and labour escalators inputs. Overall, this results in a decrease of $8.3 million ($nominal) or 7.8% from CitiPower's proposed total revenue requirement for metering of $105.7 million ($nominal, smoothed) for the 2026–31 period.

We encourage CitiPower to consider the metering adjustments that we have made in this draft decision and respond to these in its revised proposal and to incorporate the outcomes of any further stakeholder engagement it undertakes.

The reasoning behind our draft decision is outlined further detail in Attachment 15.

5 Constituent decisions

In accordance with clause 6.12.1 of the NER, this draft decision on the distribution determination that will apply to CitiPower for the 2026-31 period is predicated on the following constituent decisions:

Table 4 Constituent decisions

NER cl. 6.12.1	Constituent decision
6.12.1(a)	The AER's draft decision is that the classification of services set out in Attachment 11 will apply for the 2026–31 regulatory control period.
6.12.1(b)(1)	The AER's draft 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 draft decision on the annual revenue requirement for each regulatory year of the 2026–31 regulatory control period is set out in Attachment 1.
6.12.1(b)(2)	The AER's draft decision is to approve the commencement and length of the regulatory control period as proposed in the building block proposal. The AER’s draft decision is that the regulatory control period will commence on 1 July 2026 and 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 draft decision is not to accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal. The AER’s draft decision therefore sets out an alternative estimate of the total of the required net capital expenditure of $882.2 million ($2025–26). The reasons for the AER’s decision are set out in Attachment 2.
6.12.1(c1)	The AER’s estimate of the total of the required capital expenditure under cl. 6.12.1(c) (above) does not include expenditure for a restricted asset.
6.12.1(d)	Acting in accordance with clause 6.5.6(d) of the NER, the AER's draft decision is not to accept the total of the forecast operating expenditure for the regulatory control period that is included in the current building block proposal. The AER’s draft decision therefore sets out an alternative estimate of the total of the required operating expenditure of $524.4 million ($2025–26). The reasons for the AER’s decision are set out in Attachment 3.
6.12.1(d1)(1)	The AER’s draft decision is that the following proposed contingent projects described in the current regulatory proposal are not contingent projects for the purposes of the distribution determination: • LS Zone Substation • R Zone Substation

<table>
<tr><th>NER cl. 6.12.1</th><th>Constituent decision</th></tr>
<tr><td></td><td>

- J Zone Substation

The AER has therefore not made decisions under clauses 6.12.1(d1)(2) and 6.12.1(d1)(3) for these proposed contingent projects.

The reasons for the AER's decision are set out in Attachment 3.</td></tr>
<tr><td>6.12.1(e)</td><td>The AER's draft decision on the allowed rate of return for the 2026–27 regulatory year is 5.93% (nominal vanilla) for the reasons set out in Section 2.2 of this Overview. 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.</td></tr>
<tr><td>6.12.1(e1)</td><td>The AER's draft decision on the allowed imputation credits for each regulatory year or the regulatory control period is 0.57.</td></tr>
<tr><td>6.12.1(f)</td><td>The AER's draft 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 $2,324.3 million ($nominal). The reasons for the AER's decision are set out in Attachment 1.</td></tr>
<tr><td>6.12.1(g)</td><td>The AER's draft decision on the estimated cost of corporate income tax for the 2026–31 regulatory control period, in accordance with clause 6.5.3, is $71.6 million ($nominal). The reasons for the AER's decision are set out in Attachment 1 and the amount for each regulatory year of the 2026–31 regulatory control period is set out in the table below:
<table>
<tr><th>($million, nominal)</th><th>2026–27</th><th>2027–28</th><th>2028–29</th><th>2029–30</th><th>2030–31</th><th>Total</th></tr>
<tr><td>Tax payable</td><td>31.6</td><td>30.7</td><td>32.9</td><td>34.3</td><td>37.0</td><td>166.5</td></tr>
<tr><td>Less: value of imputation credits</td><td>–18.0</td><td>–17.5</td><td>–18.8</td><td>–19.6</td><td>–21.1</td><td>–94.9</td></tr>
<tr><td>Net cost of corporate income tax</td><td>13.6</td><td>13.2</td><td>14.2</td><td>14.8</td><td>15.9</td><td>71.6</td></tr>
</table></td></tr>
<tr><td>6.12.1(h)</td><td>The AER's draft decision is not to approve the depreciation schedules submitted by CitiPower. The AER has therefore determined depreciation schedules in accordance with cl. 6.5.5(b). The regulatory depreciation amount approved in this draft decision is $565.6 million ($ nominal) for the 2026–31 regulatory control period. The reasons for the AER's decision are set out in Attachment 1.</td></tr>
<tr><td>6.12.1(i)</td><td>The AER's draft decision on how applicable incentive schemes are to apply to CitiPower in the 2026-31 period is:

- Version 2 of the Efficiency Benefit Sharing Scheme will apply. Our reasons are set out in Attachment 5.
- Version 4 of the Capital Expenditure Sharing Scheme will apply. Our reasons are set out in Attachment 6.</td></tr>
</table>

<table>
<tr><th>NER cl. 6.12.1</th><th>Constituent decision</th></tr>
<tr><td></td><td>Version 2.0 of the Service Target Performance Incentive Scheme (including the customer service component) will apply. Our reasons are set out in Attachment 7.
the Demand Management Incentive Scheme will apply. Our reasons are set out in Attachment 8.
the Demand Management Innovation Allowance Mechanism will apply. Our reasons are set out in Attachment 8.
the Customer Service Incentive Scheme will not apply. Our reasons are set out in Attachment 9.</td></tr>
<tr><td>6.12.1(j)</td><td>The AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft decision, including in supporting models and attachments.</td></tr>
<tr><td>6.12.1(k)</td><td>The AER’s draft decision on the form of the control mechanism(s) (including the X factor) for standard control services is, in accordance with the Framework and Approach Paper, a revenue cap.
The AER’s draft decision on the formulae that give effect to the revenue cap form of control mechanisms is set out in Attachment 12.</td></tr>
<tr><td>6.12.1(l)</td><td>The AER’s draft 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 draft decision on the formulae that give effect to those control mechanisms is set out in Attachment 12.</td></tr>
<tr><td>6.12.1(m)</td><td>The AER’s draft 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.</td></tr>
<tr><td>6.12.1(n)</td><td>The AER’s draft decision is that the following additional pass through events are to apply for the regulatory control period in accordance with clause 6.5.10:
an insurance coverage event;
insurer credit risk event;</td></tr>
</table>

NER cl. 6.12.1	Constituent decision
	• terrorism event; • natural disaster event • retailer insolvency event. These events have the definitions set out in Attachment 4.
6.12.1(n1)	The AER's draft decision is not to approve the tariff structure statement proposed by CitiPower. The reasons for our draft decision are set out in Attachment 13.
6.12.1(o)	The AER's draft decision is that the negotiating framework as proposed by CitiPower is to apply to for the regulatory control period The reasons for the AER's decision are set out in Attachment 17.
6.12.1(p)	The AER's draft decision is that the Negotiated Distribution Service Criteria set out in Attachment 17 will apply to CitiPower for the regulatory control period. The reasons for the AER's decision are set out in Attachment 17.
6.12.1(q)	The AER's draft 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.
6.12.1(r)	The AER's draft decision is that depreciation for establishing the regulatory asset base as at the commencement of the following 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.
6.12.1(s)	The AER's draft decision on how CitiPower is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 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. This is discussed in Attachment 12.
6.12.1(t)	The AER's draft 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 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. This draft decision applies to each jurisdictional scheme under which CitiPower has jurisdictional scheme obligations within the operation of this draft decision.
6.12.1(u)	The AER's draft decision is that a variant of the connection policy as proposed by CitiPower, set out in Attachment 16, is to apply to CitiPower for the regulatory control period. The reasons for the AER's decision are set out in Attachment 16.

NER cl. 6.12.1	Constituent decision
Other constituent decisions	
	In accordance with section 16C of the *National Electricity (Victoria) Act 2005*, the NEL, the NER and the 'f-factor scheme order 2016',[52] the AER's draft decision is to apply the f-factor incentive payments/penalties as a part of the 'I-factor' adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 12.

Notes: In this table, 'regulatory control period' means the period 1 July 2026 to 30 June 2031 determined in accordance with clause 6.12.1(b)(ii).
References in this table to 'the current proposal', 'the building block proposal', 'the current building block proposal' and to documents submitted or matters proposed by CitiPower are to the regulatory proposal and tariff structure statement submitted by CitiPower on 31 January 2025.
References in this table to 'the Framework and Approach Paper' are to AER – *Final Framework and Approach – Victorian electricity distribution determinations 2026-31* – July 2024, published by the AER on 31 July 2024.

Source: References in this table to where detailed constituent decisions can be found are to documents and models published on the AER's website.

52 http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf, Victoria Government Gazette, G 51 22 December 2016, p. 323

6 List of submissions

	Date
AGL	June 2025
AER Consumer Challenge Panel (CCP32)	May 2025
CPU Customer Advisory Panel	May 2025
Electric Vehicle Council	May 2025
Hon Lily D'Ambrosio MP	June 2025
Origin Energy	May 2025
Save Our Surroundings Riverina	May 2025
Victorian electricity distribution businesses	May 2025
Victorian Greenhouse Alliances	May 2025

7 Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual revenue requirement
Augex	Augmentation expenditure
BAU	Business as usual
CAP	Community Advisory Panel
Capex	Capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	Consumer Energy Resources
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
CPU	CitiPower, Powercor and United Energy
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

Term	Definition
PTRM	Post-tax revenue model
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement expenditure
RFM	Roll forward model
RORI	Rate of return instrument
SCS	Standard control services
SMP	Statement on monetary policy
STPIS	Service target performance incentive scheme
TOU	Time-of-use
TSS	Tariff structure statement
TUOS	Transmission use of system charges
VCR	Value of customer reliability
WACC	Weighted average cost of capital
WPI	Wage price index