Issues paper

CitiPower, Powercor and United Energy
Electricity distribution determinations 2026-31

March 2025

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
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Contents

1 Introduction

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a safe, secure, reliable, and affordable energy future for Australia as it transitions to net zero emissions.

A regulated network business 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 revenue proposals from Victorian electricity distributors CitiPower, Powercor, United Energy, AusNet Services (AusNet), and Jemena Electricity Networks (Jemena) for the period 1 July 2026 to 30 June 2031 (2026–31 period). In assessing these proposals, it is our role to ensure that consumers pay no more than is necessary for an energy system that delivers safe, reliable, secure energy that contributes to the reduction of greenhouse gas emissions.

This Issues paper focusses on the proposals for the distribution network and services provided to consumers by:[1]

- CitiPower, in the city of Melbourne and its inner suburbs
- Powercor, in the western suburbs of Melbourne and western Victoria
- United Energy, in the southern suburbs of Melbourne and the Mornington Peninsula.

It identifies preliminary issues we consider are likely to be relevant to our assessment of the proposals.

You can read more about proposals from other Victorian distributors in our Issues papers for AusNet and Jemena.

1.1 Our process

This Issues paper is the first stage in our consultation on these proposals. Submissions and views shared with us in this stage of consultation will help to inform our draft decisions on the proposals later this year. CitiPower, Powercor and United Energy will then have the opportunity to respond to any concerns raised in our draft decisions in revised proposals. We will seek further submissions on both the draft decisions and revised proposals before making our final decisions in April 2026.

An indicative timeline for this process is provided below.

1 Victorian consumers can find out who their electricity distributor is by visiting: https://www.energy.vic.gov.au/households/find-your-energy-distributor

Table 1-1 Indicative timeline

Milestone	(Indicative) timeline
Regulatory proposals submitted to AER	31 January 2025
AER Issues paper	28 March 2025
AER Public forum	1 April 2025
Submissions on proposals and issues paper close	14 May 2025
AER draft decisions	(September 2025)
Revised proposals submitted to AER	(December 2025)
Submissions on draft decisions and revised proposals close	(January 2026)
Final decisions	(April 2026)

1.2 Have your say

Interested stakeholders are invited to make submissions on the proposals by Wednesday, 14 May 2025.

Submissions should be sent to: vic2026@aer.gov.au and addressed to Kris Funston, Executive General Manager Network Regulation.

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 confidentiality claim.
2. Provide a non-confidential version of the submission in a form suitable for publication.

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

1.2.1 Public forum

Please join us at an online public forum on Tuesday, 1 April 2025 to learn more about our process, and the proposals CitiPower, Powercor, United Energy and other Victorian electricity distributors (AusNet and Jemena) have submitted for the 2026-31 regulatory control period.

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

2 Initial observations

CitiPower, Powercor and United Energy's proposals, and our assessments of them, come at a time of significant change. Emissions reduction targets and the transition to net zero, now reflected in the National Electricity Objective (NEO), are driving changes in household and commercial energy use. In Victoria we are starting to see the impacts of increasing electrification and uptake of Consumer Energy Resources on the way that energy networks operate and invest in order to continue delivering safe, reliable and secure supply of essential services.

In recent years we have also seen a number of severe weather events, with storms in 2021 and 2024 resulting in prolonged power outages for hundreds of thousands of Victorian customers. Victorian Government reviews into electricity distribution network resilience, outage planning and operational responses have made a number of recommendations, some already in train.

These changes are shaping proposed increases across operating and capital expenditure over the next five years, including in evolving approaches to meeting and managing demand and maintaining quality, reliability and security of supply.

All three proposals are responding to these challenges with significant increases in operating and capital expenditure, which will require close examination. Investment in the distribution networks over the next 5 years will have long term impacts on energy costs. We need to be satisfied that the proposals reflect prudent and efficient investment to maintain the networks and prepare them to support the energy transition. We need to balance that assessment with ongoing cost-of-living pressures so that consumers pay no more than is necessary—in the 2026-31 period and beyond it—for an energy system that delivers safe, reliable, secure energy that contributes to the reduction of greenhouse gas emissions.

In the sections below we explore the key drivers of CitiPower, Powercor and United Energy's proposed revenue for the 2026-31 period, and the preliminary issues we consider are likely to be relevant to our assessment of their proposals.

2.1 Key drivers of proposed revenue

The proposed total revenue to be recovered from electricity customers over the 2026–31 period is:

- $2,077.6 million ($nominal, smoothed) for CitiPower. This is 37.9% higher than what we approved for the 2021–26 period.
- $5,495.9 million ($nominal, smoothed) for Powercor. This is 55.8% higher than what we approved for the 2021–26 period.
- $3,020.7 million ($nominal, smoothed) for United Energy. This is 42.7% higher than what we approved for the 2021–26 period.

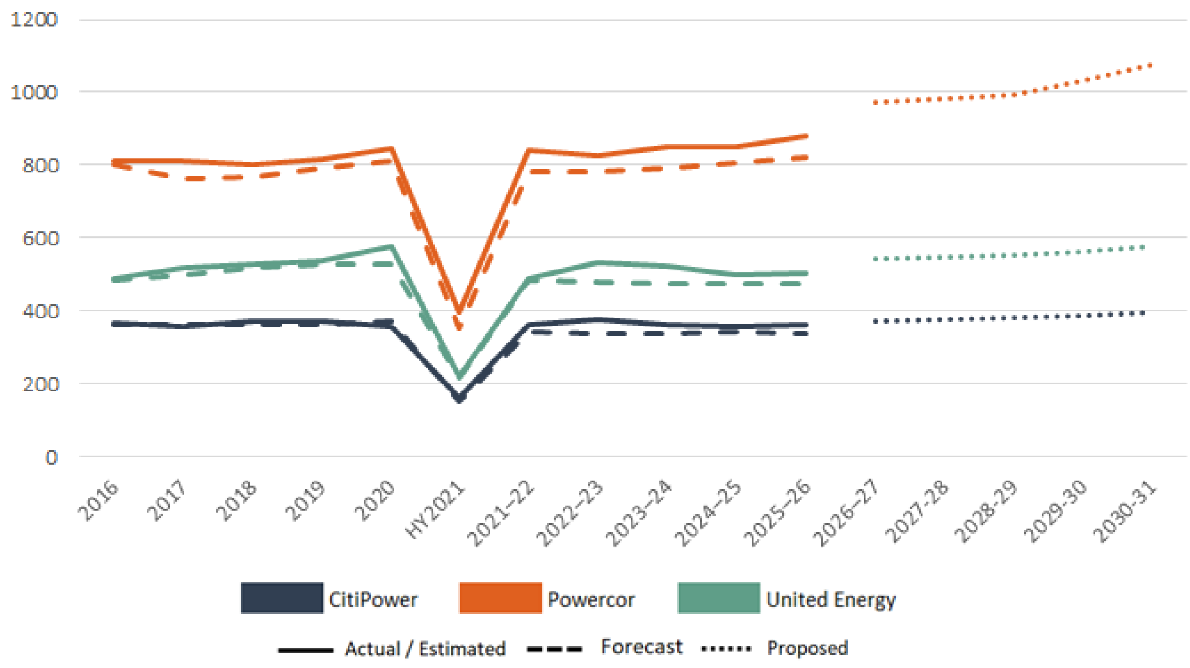
To compare revenue from one period to the next on a like-for-like basis, we make an adjustment for the impact of inflation. To do this, we use 'real' values based on a common year (2025–26) that have been adjusted to remove the impact of inflation.

Changes in regulated revenue for CitiPower, Powercor and United Energy over time are shown in Figure 2-1. In real terms:

- CitiPower's proposal would allow it to recover $1,917.0 million ($2025–26, unsmoothed) from consumers over the 2026–31 period. This is $213.6 million (12.5%) higher than our decision for the current (2021–26) period.
- Powercor's proposal would allow it to recover $5,070.9 million ($2025–26, smoothed) from consumers over the 2026–31 period. This is $1,084.1 million (27.2%) higher than our decision for the current (2021–26) period.
- United Energy's proposal would allow it to recover $2,782.4 million ($2025–26, smoothed) from consumers over the 2026–31 period. This is $389.5 million (16.3%) higher than our decision for the current (2021–26) period.

We estimate that approximately 29% to 41% of the increases from the 2021–26 period is driven by market factors including higher inflation and interest rates. The other 59% to 71% of the increases is mainly driven by increases in capital and operating expenditure.[2]

Figure 2-1 Changes in regulated revenue over time ($ million, 2025–26)



Source: AER analysis.

Note: 'HY2021' in the chart refers to the half-year extension period of 1 January 2021 to 30 June 2021 due to the transition from a calendar year regulatory period to a financial year basis that occurred in 2021.

Figure 2-2 to Figure 2-4 highlight changes in each network's proposal at the 'building block' level to illustrate what is driving the proposed increases in real revenue from the 2021–26 period to the 2026–31 period.

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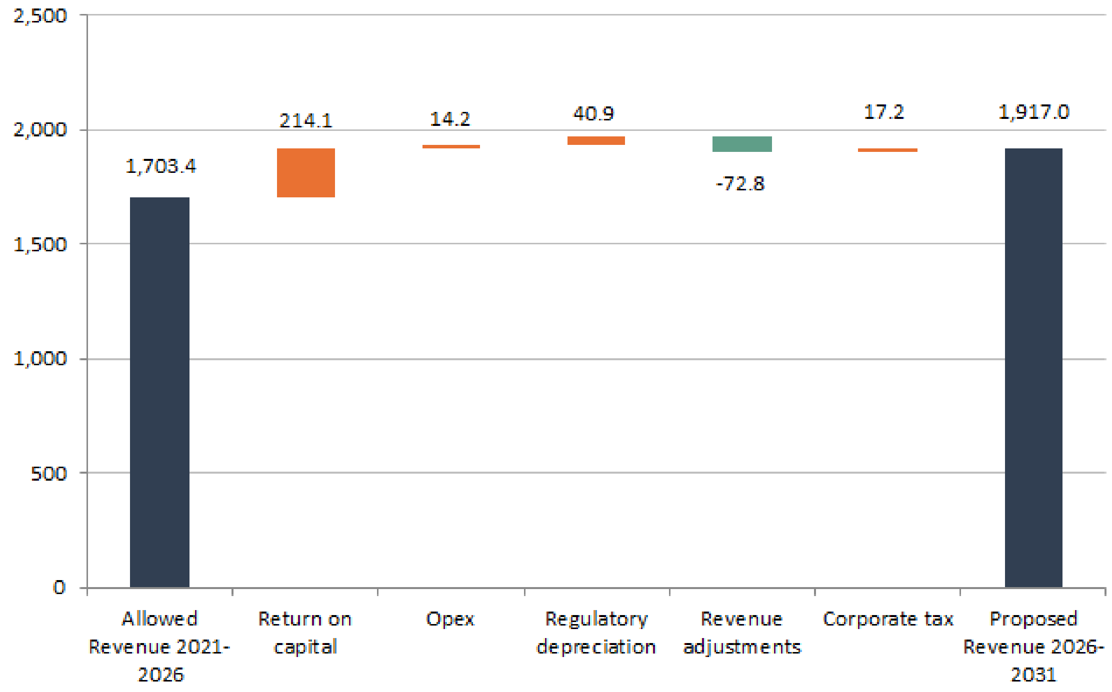
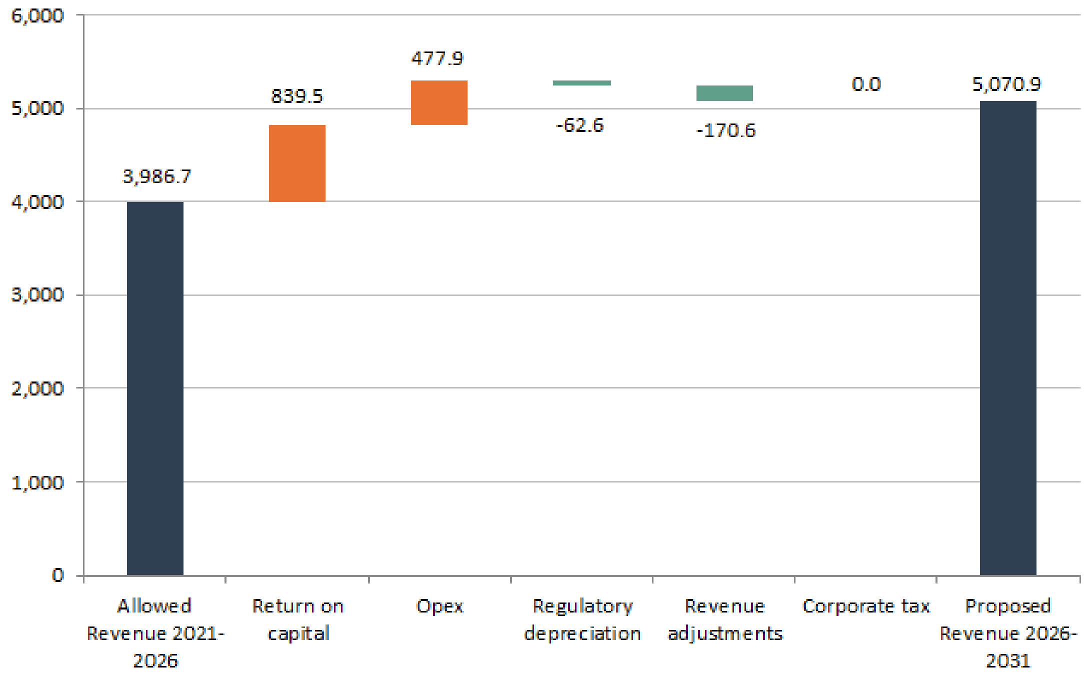
2 The proportion of the respective increases driven by market factors are 41% for CitiPower, 29% for Powercor, 33% for United Energy.

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



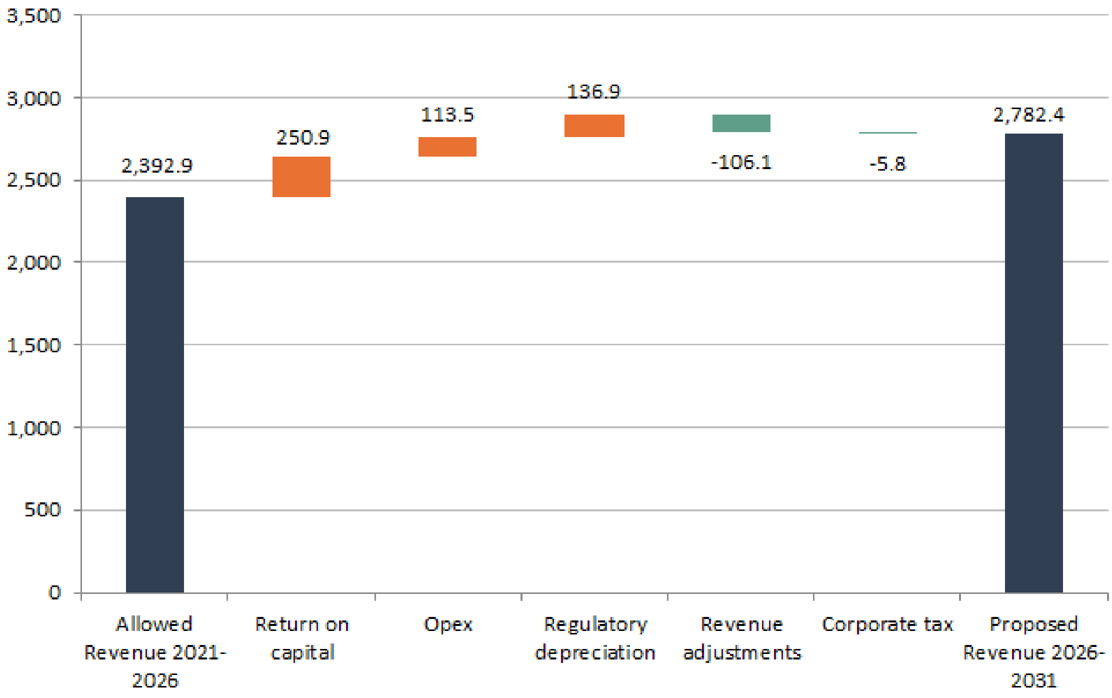
Source: AER analysis.
Note: This comparison is based on converting 2021–26 allowed revenue for inflation to 2025–26 dollar terms using lagged CPI.

Figure 2-3 Powercor – 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 2021–26 allowed revenue for inflation to 2025–26 dollar terms using lagged CPI.

Figure 2-4 United Energy – 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 2021–26 allowed revenue for inflation to 2025–26 dollar terms using lagged CPI.

For each network, the overall upward trend in revenue is driven primarily by a higher return on capital. One reason for this is that we have seen higher inflation over the 2021-26 period than forecast at the time of our last determination. The other is that proposals for 2026-31 include significantly higher capex forecasts than approved for the 2021-26 period.

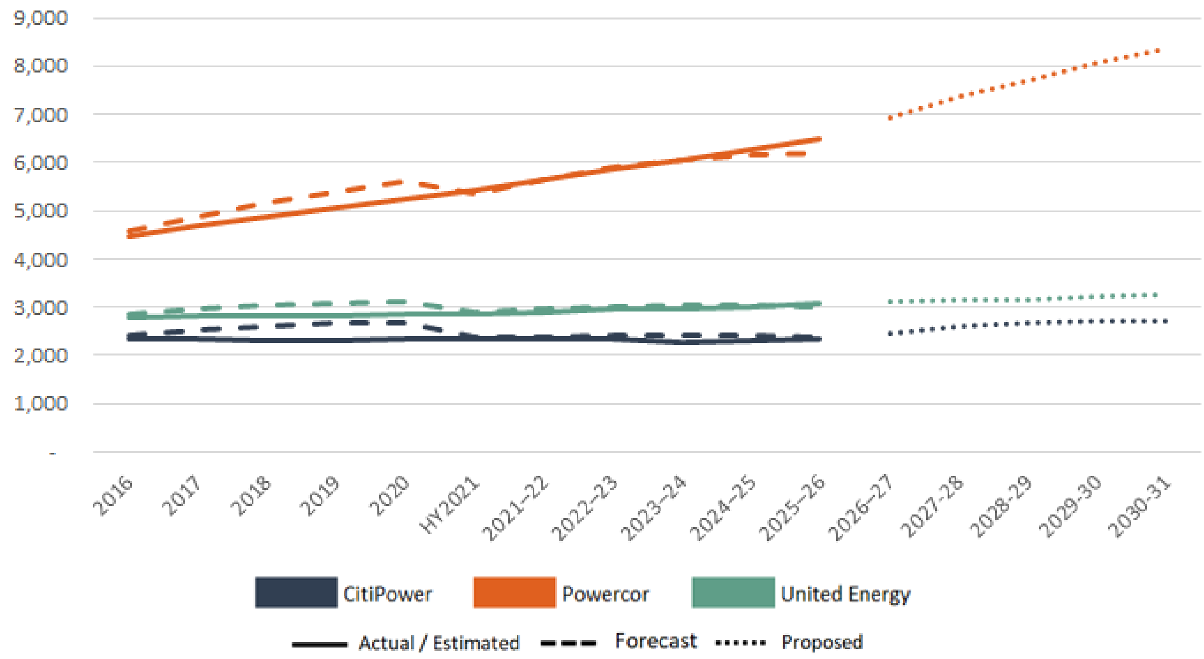
Figure 2-5 shows the value of each network's Regulatory Asset Base (RAB) over time in real terms. The RAB substantially affects a network business' revenue requirement, and the price customers ultimately pay. We expect the RAB to change over time, as capital investment will depend on the network's age and technology, load characteristics, the levels of new connections and reliability and safety requirements.

For each of the three networks, the actual RAB growth in the 2021–26 period is broadly in line with our forecasts for that period. For Powercor and United Energy, actual RAB growth is slightly higher than forecast and this is driven by capex estimates in the final 2 years of this period which are higher than forecast.

The proposals project continued RAB growth in real terms over the 2026–31 period. Powercor's RAB growth—the greatest over the current period— is also projected to increase at a faster rate over the 2026–31 period than CitiPower's and United Energy's:

- Powercor's RAB grew 19.5% in the current 2021–26 period while CitiPower's reduced by 1.1% and United Energy's increased by 6.8%.
- Powercor's proposal forecasts a further 29.0% real RAB increase in the 2026–31 period, compared to a 16.5% increase for CitiPower and a 6.3% increase for United Energy.

Figure 2-5 RAB value over time ($ million, 2025–26)



Source: AER analysis.

Increases in forecast operating expenditure (opex) are also putting upward pressure on revenue, most notably for Powercor and United Energy. These networks are proposing significant step increases in vegetation management in order to meet required safety standards over the 2026-31 period and beyond.

For CitiPower and United Energy, straight-line depreciation has increased by more than the RAB indexation component as a result of the proposed forecast capex increases, leading to an increase in regulatory depreciation. Conversely for Powercor, the increase to the RAB indexation is higher than the increase to straight-line depreciation, resulting in a reduction in regulatory depreciation.

CitiPower is also forecasting a higher estimated cost of corporate income tax in 2026-31, due mainly to an increase in capital contributions paid by customers. Powercor proposed a zero amount of corporate income tax, consistent with the 2021–26 period. United Energy's proposed amount is lower compared to the 2021–26 period due to its increased tax depreciation. For Powercor and United Energy, the impacts of a higher return on equity, regulatory depreciation and customer contributions are offset by the impact of higher tax depreciation.

This forecast increase in revenues are partially offset by lower revenue adjustments under AER incentive schemes. In 2021–26 period, each network received a positive carryover under the Capital Expenditure Sharing Scheme (CESS). In 2026–31 CitiPower's proposal has forecast a lower CESS reward, and Powercor and United Energy have each forecast a negative CESS carryover or penalty.

2.2 What would these proposals mean for electricity bills?

For illustrative purposes, CitiPower, Powercor and United Energy's proposals estimate their proposed revenue would result in network tariffs that are:

- 2.1% higher on average over the 2026–31 period compared to 2025–26 for CitiPower's customers.
- 8.1% higher on average over the 2026–31 period compared to 2025–26 for Powercor's customers.
- 6.8% higher on average over the 2026–31 period compared to 2025–26 for United Energy's customers.

The cost of the network components of the electricity supply chain makes up about 25 to 29% of the average electricity bill for household customers and 29 to 36% for small business customers in CitiPower, Powercor and United Energy's networks and are ultimately recovered through electricity retail charges.[3]

For illustrative purposes again, CitiPower, Powercor and United Energy's proposals estimate the impact of its proposed revenue on the average distribution network component of an annual electricity bill over the 2026–31 period for a residential customer would be:

- $7 or 0.6% higher ($nominal) than 2025–26 for CitiPower's residential customers.
- $37 or 2.4% higher ($nominal) than 2025–26 for Powercor's residential customers.
- $24 or 1.7% higher ($nominal) 2025–26 for United Energy's residential customers.

Similarly for small business customers the impact of the proposed revenues on the average distribution network component is estimated to be:

- $17 or 0.6% higher ($nominal) than 2025–26 for CitiPower's small business customers.
- $89 or 2.9% higher ($nominal) than 2025–26 for Powercor's small business customers.
- $64 or 2.2% higher ($nominal) than 2025–26 for United Energy's small business customers.

These network tariff and bill impact outcomes are not set by our determination. They are high level estimates calculated by dividing CitiPower, Powercor and United Energy's forecast revenues by their forecasts of the energy that will be delivered through their networks over the 2026–31 period. This means that for the same amount of revenue an increase in energy delivered would lead to lower tariffs over the period, and vice versa.

Under the revenue cap form of control that currently applies to Victorian electricity distribution networks, our determination sets the maximum regulated revenue CitiPower, Powercor and United Energy can recover for each year of the regulatory control period. Those revenue caps impose a binding constraint: each network can only recover revenue equal to or less than its maximum regulated revenue. They comply with this constraint by forecasting

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[3] CitiPower, *CP RIN 05 - Workbook 5 - Bill Impacts*, January 2025; Powercor, *PAL RIN 05 - Workbook 5 - Bill Impacts,* January 2025; United Energy, *UE RIN 05 - Workbook 5 - Bill Impacts*, January 2025.

volumes for each year and setting prices for that year such that their expected revenue is equal to or less than the maximum regulated revenue. At the end of each year, CitiPower, Powercor and United Energy reports its actual revenue to us. Any differences between the actual revenue recovered and the maximum regulated revenue are then accounted for in future years.[4] This means the risk of over-forecasting demand is borne by customers, rather than by the distributor. Under other forms of control, such as price caps, demand risk is borne by the distributor (see further discussion below).

In considering the estimated bill impacts above, this means that customers would be protected from volume risk if the actual energy delivered by CitiPower, Powercor and United Energy in the 2026–31 period is higher than their forecasts. That is, the networks will not be entitled to earn more revenue as a result of higher demand. In this case average network tariffs would be lower than expected.

However, if actual energy delivered is lower than the forecasts in the proposals, customers could experience higher distribution network tariffs than expected because CitiPower, Powercor and United Energy are still entitled to recover the revenue we determine, regardless of the actual energy delivered.

Each proposal forecasts a significant increase in the amount of annual energy delivered through its network:

- CitiPower forecasts an increase of 1486 GWh (26.3%), from 5639 GWh in 2025–26 to 7125 GWh in 2030–31.
- Powercor forecasts an increase of 4013 GWh (34.9%), from 11,506 GWh in 2025–26 to 15,519 GWh in 2030–31.
- United Energy forecasts an increase of 1961 GWh (25.4%), from 7726 GWh in 2025–26 to 9688 GWh in 2030–31.

These are the forecasts that have informed the illustrative estimates of tariff and bill impacts in the proposals.

However, if the amount of energy delivered were to increase at a slower rate, the impact of the proposed revenues on tariffs would be higher. Table 2-1 and Figures 2-6 to 2-8 provide some examples.

[4] This operation occurs through an "overs and unders" account, whereby any over-recovery (under-recovery) is deducted from (added to) the maximum regulated revenue in future years.

Table 2-1 Sensitivity of energy delivered on distribution network tariffs 2026–31 ($/MWh, nominal)

Scenario	CitiPower	Powercor	United Energy
If energy delivered were to increase at the same rate as we've seen in the current, 2021–26 period:	An increase in energy delivered of 9.4% could see 8.5% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[5]	An increase in energy delivered of 7.4% could see 19.5% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[6]	An increase in energy delivered of 3.1% could see 18.3% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[7]
If energy delivered were to increase at a faster rate than we've seen to date, 10% lower than forecast in the proposals:	An increase in energy delivered of 23.7% could see 3.2% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[8]	An increase in energy delivered of 31.4% could see 9.5% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[9]	An increase in energy delivered of 22.8% could see 7.9% higher average annual distribution network tariffs (nominal) compared to 2025–26 tariffs.[10]

5 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 0.1% lower than 2025–26 for CitiPower customers if energy delivered were to increase at the same rate as we have seen in the current, 2021–26 period.

6 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 10% higher than 2025–26 for Powercor customers if energy delivered were to increase at the same rate as we have seen in the current, 2021–26 period.

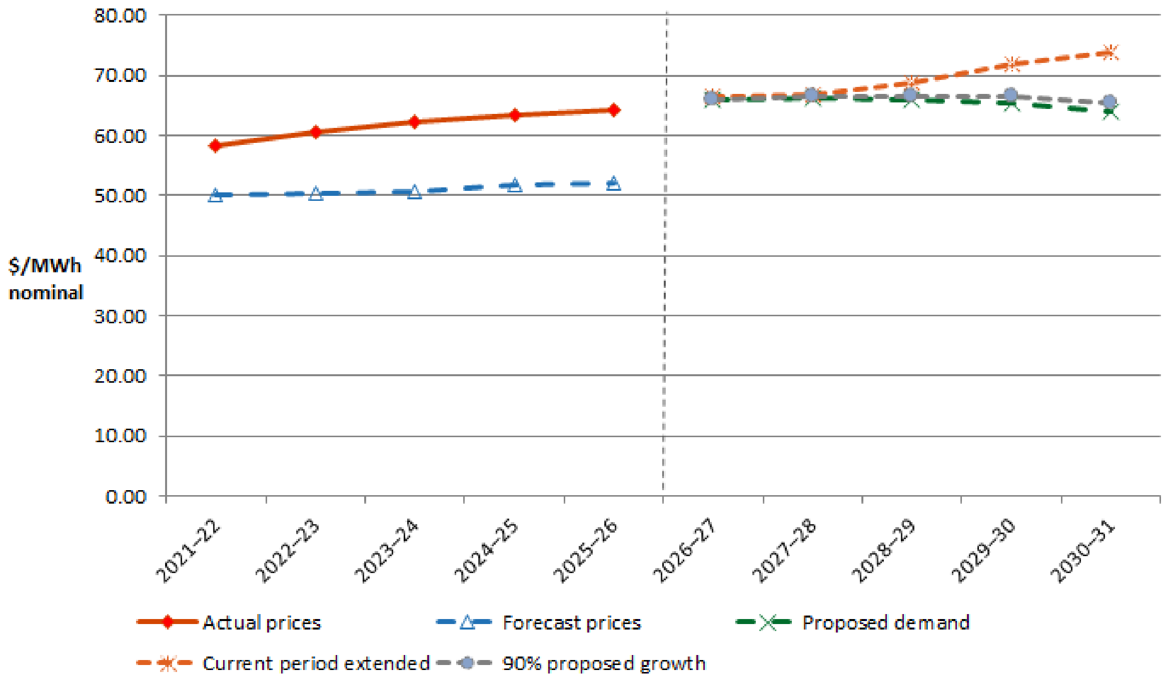
7 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 8.9% higher than 2025–26 for United Energy customers if energy delivered were to increase at the same rate as we have seen in the current, 2021–26 period.

8 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 4.8% lower than 2025–26 for CitiPower customers.

9 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 1.1% higher than 2025–26 for Powercor customers.

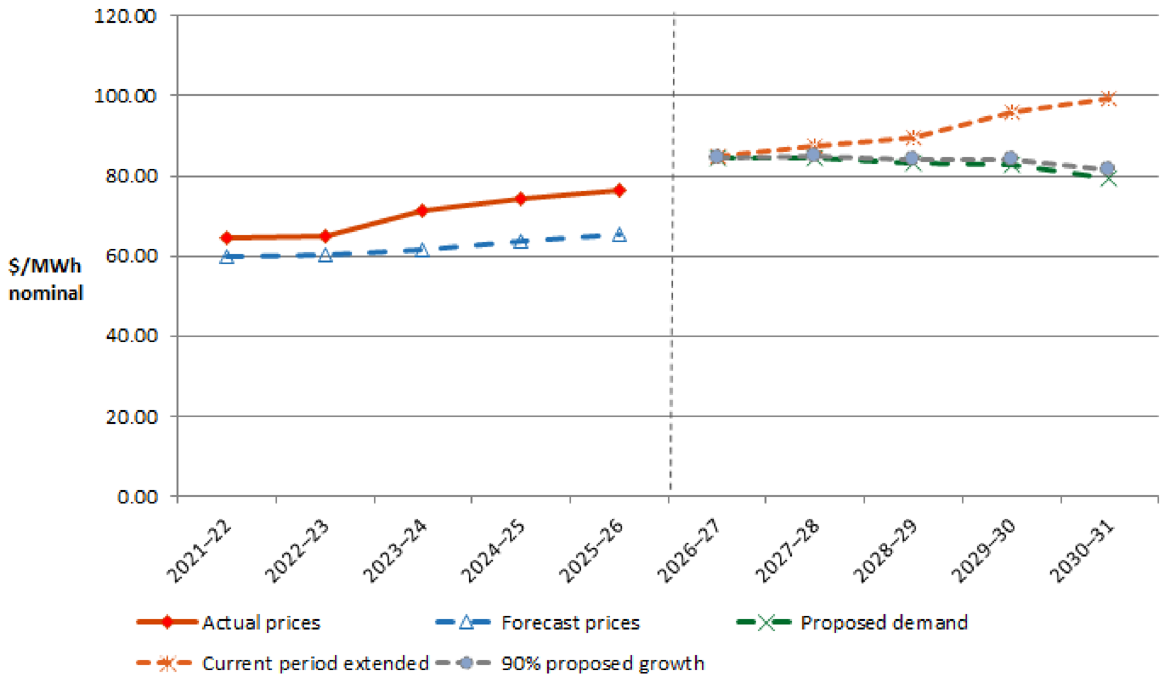
10 In real terms (ignoring the impact of expected inflation), average annual distribution tariffs could be expected to be 0.4% lower than 2025–26 for United Energy customers.

Figure 2-6 CitiPower - Sensitivity of energy delivered on distribution network tariffs 2026–31 ($/MWh, nominal)



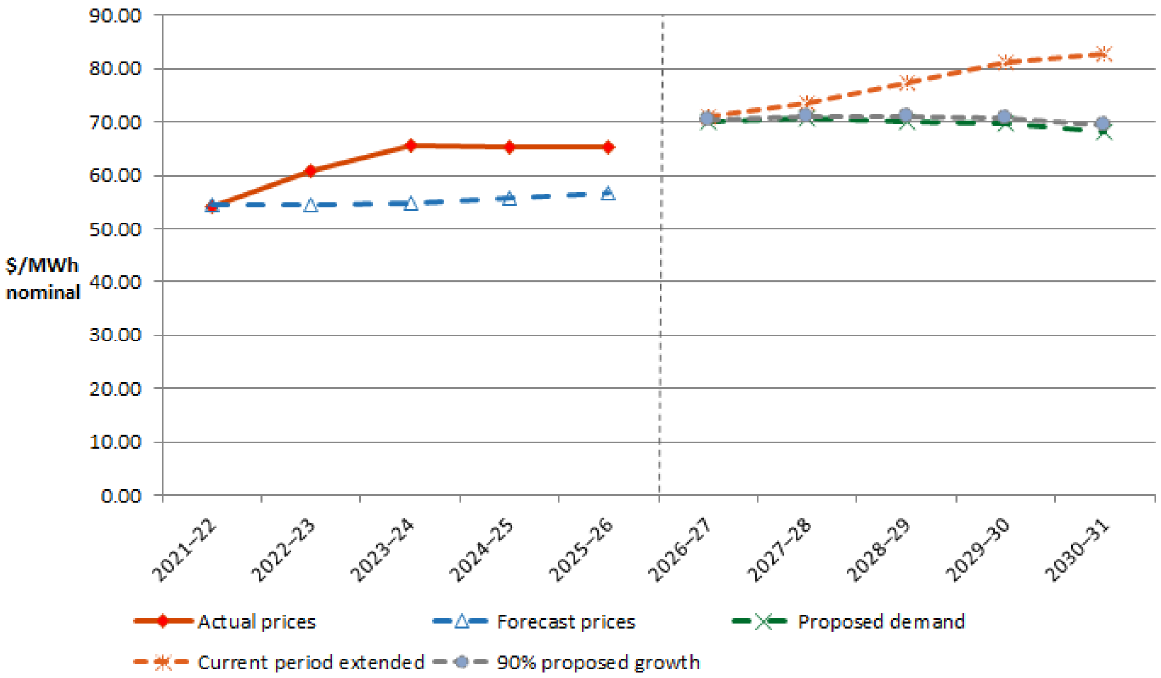
Source: AER analysis

Figure 2-7 Powercor - sensitivity of energy delivered on distribution network tariffs 2026–31 ($/MWh, nominal)



Source: AER analysis

Figure 2-8 United Energy - Sensitivity of energy delivered on distribution network tariffs 2026–31 ($/MWh, nominal)



Source: AER analysis

As shown in Table 2-2, estimated bill impacts under those same scenarios would also change:

Table 2-2 Sensitivity of energy delivered on estimated bill impacts ($nominal)

	CitiPower	Powercor	United Energy
If energy delivered were to increase at the same rate as we have seen in the current, 2021–26 period:	An increase in energy delivered of 9.4% could see average annual bills that are: $30 (2.2%) higher than 2025–26 bills (nominal) for residential customers $68 (2.5%) higher than 2025–26 bills (nominal) for small business customers	An increase in energy delivered of 7.4% could see average annual bills that are: $89 (5.7%) higher than 2025–26 bills (nominal) for residential customers $214 (7.1%) higher than 2025–26 bills (nominal) for small business customers	An increase in energy delivered of 3.1% could see average annual bills that are: $65 (4.6%) higher than 2025–26 bills (nominal) for residential customers $172 (5.9%) higher than 2025–26 bills (nominal) for small business customers
If energy delivered were to increase at a faster rate than what we have seen to date, but 10% lower than	An increase in energy delivered of 23.7% could see average annual bills that are: $11 (0.8%) higher than 2025–26 bills (nominal) for residential customers	An increase in energy delivered of 31.4% could see average annual bills that are: $43 (2.8%) higher than 2025–26 bills (nominal) for residential customers	An increase in energy delivered of 22.8% could see average annual bills that are: $28 (2.0%) higher than 2025–26 bills (nominal) for residential customers

	CitiPower	Powercor	United Energy
forecast in the proposals:	$26 (0.9%) higher than 2025–26 bills (nominal) for small business customers	$104 (3.4%) higher than 2025–26 bills (nominal) for small business customers	$74 (2.4%) higher than 2025–26 bills (nominal) for small business customers

Price cap vs revenue cap regulation: how current forms of control differ for gas and electricity networks

Victoria's gas distribution networks are subject to a different form of control. In their gas distribution access arrangements, we set a weighted average price cap instead of a revenue cap.

Under a weighted average price cap, a target revenue is established which the distributor uses to set its prices based on forecast volumes. That cap on prices, rather than revenue, is the binding constraint. This means that:

- If actual volumes are lower than forecast volumes used to set tariffs, the distributor will sell less but must do so at the same price. It will therefore not recover the full amount of revenue we targeted with our access arrangement determination.
- If actual volumes are higher than forecast volumes used to set tariffs, the distributor will be able to sell more at the same price. It will therefore recover more than the revenue we targeted with our access arrangement determination.

Therefore, in contrast to a revenue cap, the distributor faces demand risk as opposed to customers.

2.3 Forecast demand and consumption

Demand for electricity plays a crucial role in forecasting network expenditure. This includes:

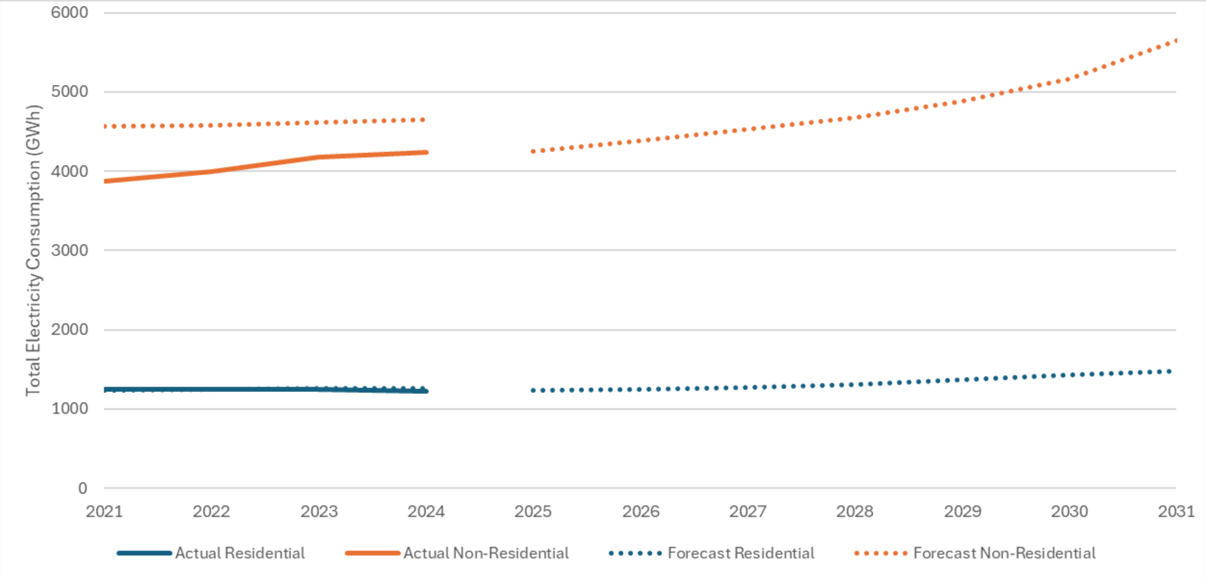
- augmentation expenditure – the construction of new assets to service added demand and higher peak demand.
- replacement expenditure – the renewal or replacement of assets which can be accelerated by increased demand.
- connections expenditure – typically driven by growth in residential customer numbers, however new drivers of larger and more expensive connections are emerging, including data centres, batteries and electric vehicle charging stations.

It is essential that demand forecasts are accurate to ensure that customers are not paying more than necessary. As noted in section 2.2, under the revenue cap control mechanism, prices are adjusted each year for errors in forecast demand that result in revenue recovery above or below the allowed revenue. This means that customers could experience higher distribution network tariffs than expected if actual demand is less than forecast demand.

The regulatory framework includes some mechanisms which can mitigate uncertainty associated with demand forecasts. These mechanisms include cost pass through events and contingent projects, which can be specified in the distribution determination. Cost pass throughs can increase or decrease allowed revenue, whereas contingent projects only increase allowed revenue. Both mechanisms are subject to a materiality threshold prescribed by the NER. CitiPower and Powercor have each proposed contingent projects, and all three networks have proposed a new cost pass through event to address the uncertainty resulting from the energy transition, particularly in respect of the timing and pace at which electrification will occur.

As shown in Figure 2-9, CitiPower forecasts that total consumption will increase to 7,125 GWh in 2031, an increase of 31% compared to actual total consumption in 2024. This includes a forecast increase of 22% in residential consumption and 33% in non-residential consumption.

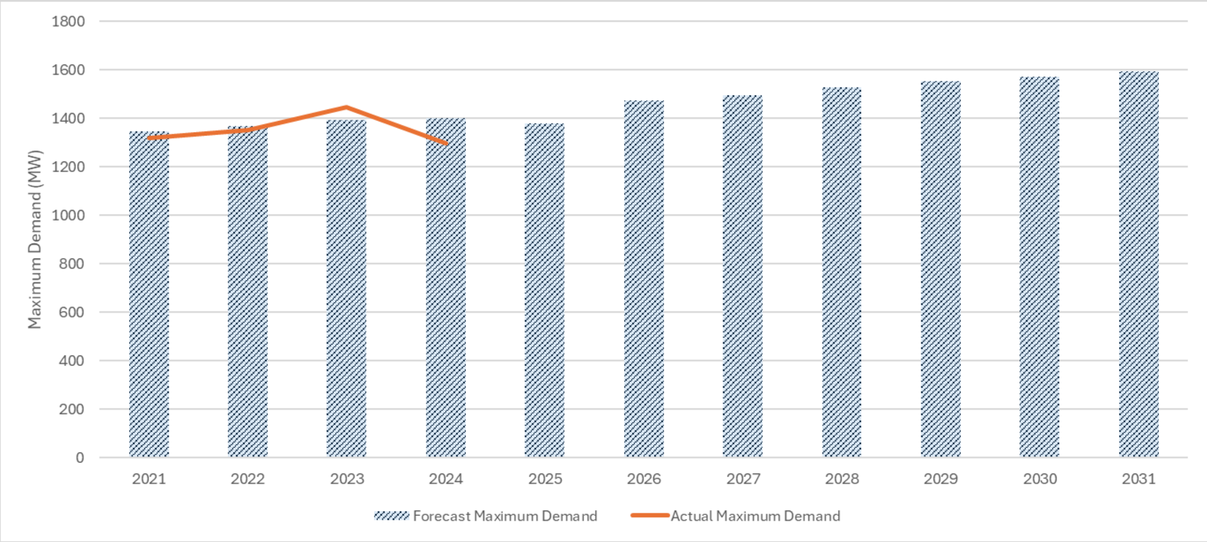
Figure 2-9 CitiPower - Forecast and actual consumption by customer type



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).

As shown in Figure 2-10, CitiPower forecasts that maximum demand will increase to 1,596 MW in 2031, an increase of 23% compared to actual maximum demand in 2024.

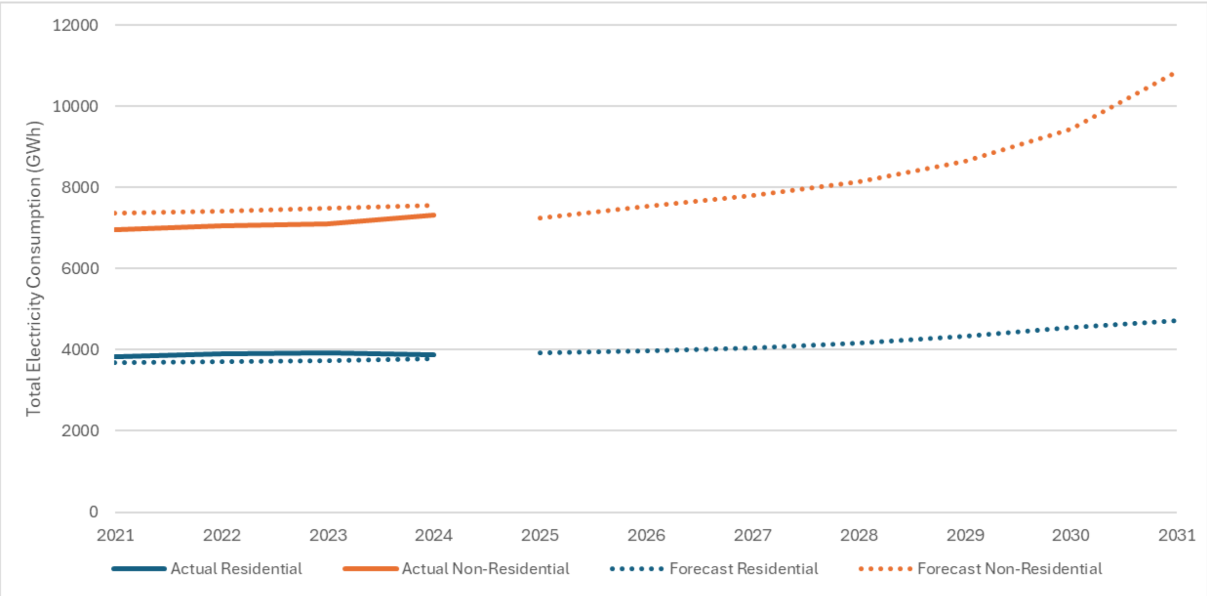
Figure 2-10 CitiPower - Forecast and actual maximum demand



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Maximum demand refers to non-coincident summated weather adjusted system annual maximum demand, 50% probability of exceedance.

As shown in Figure 2-11, Powercor forecasts that total consumption will increase to 15,562 GWh in 2031, an increase of 39% compared to actual total consumption in 2024. This includes a forecast increase of 21% in residential consumption and 48% in non-residential consumption.

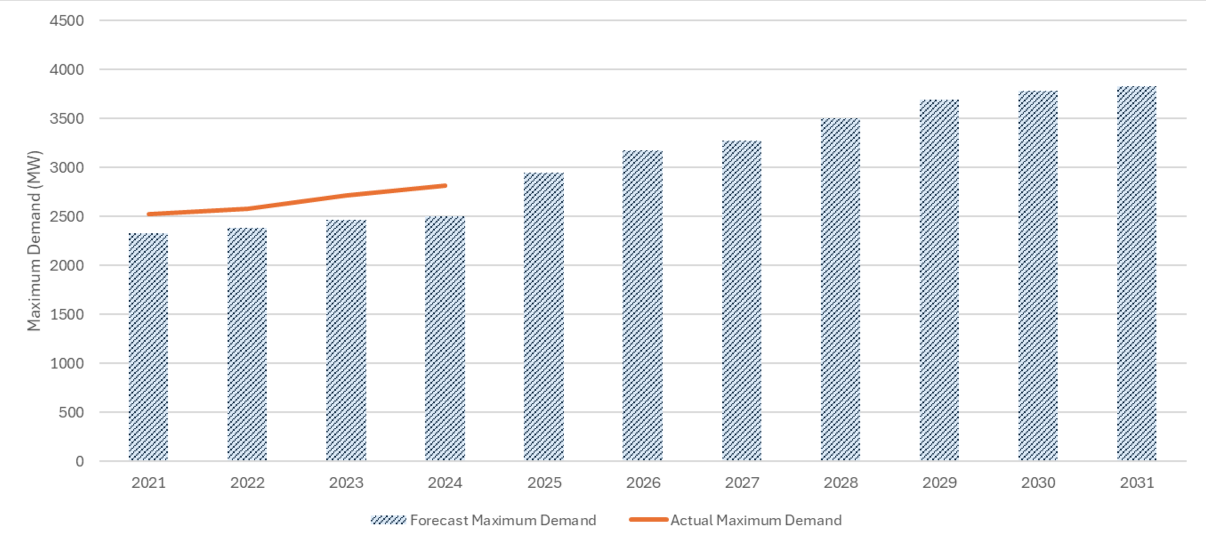
Figure 2-11 Powercor - Forecast and actual consumption by customer type



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).

As shown in Figure 2-12, Powercor forecasts that maximum demand will increase to 3,830 MW in 2031, an increase of 36% compared to actual maximum demand in 2024.

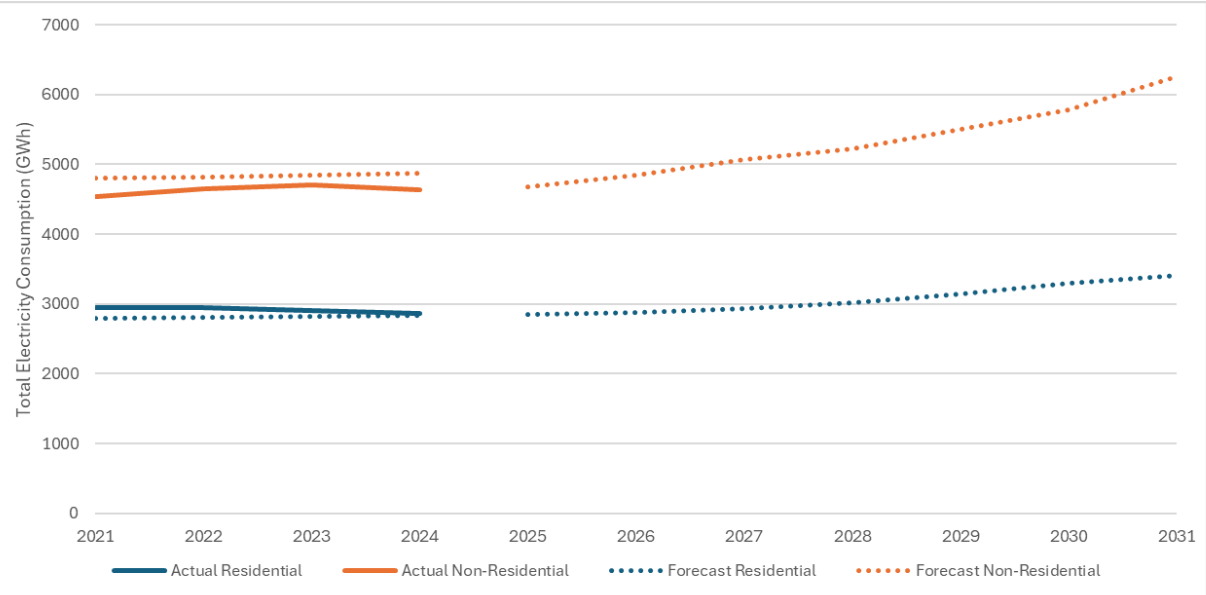
Figure 2-12 Powercor - Forecast and actual maximum demand



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Maximum demand refers to non-coincident summated weather adjusted system annual maximum demand, 50% probability of exceedance.

As shown in Figure 2-13, United Energy forecasts that total consumption will increase to 9,669 GWh in 2031, an increase of 29% compared to actual total consumption in 2024. This includes a forecast increase of 19% in residential consumption and 35% in non-residential consumption.

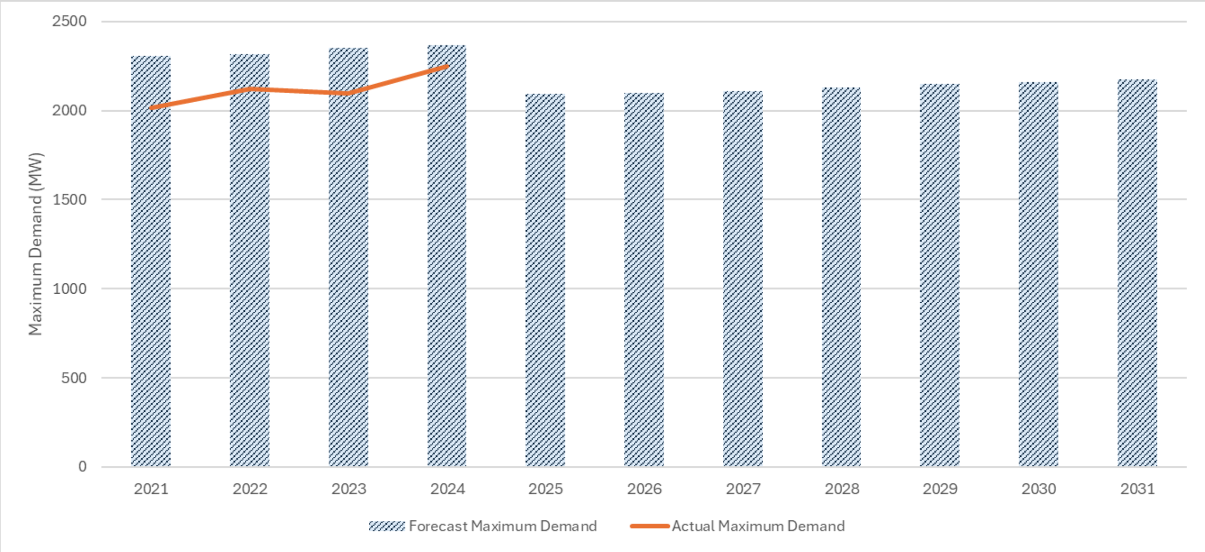
Figure 2-13 United Energy - Forecast and actual consumption by customer type



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).

As shown in Figure 2-14, United Energy forecasts that maximum demand will decrease to 2,176 MW in 2031, which is 3% lower than actual maximum demand in 2024.

Figure 2-14 United Energy - Forecast and actual maximum demand



Source: 2021 Reset RIN and Economic Benchmarking RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Maximum demand refers to non-coincident summated weather adjusted system annual maximum demand, 50% probability of exceedance.

Questions on demand forecasts

1) Do you have any feedback on the demand forecasts that have informed these proposals?

2.4 Network utilisation

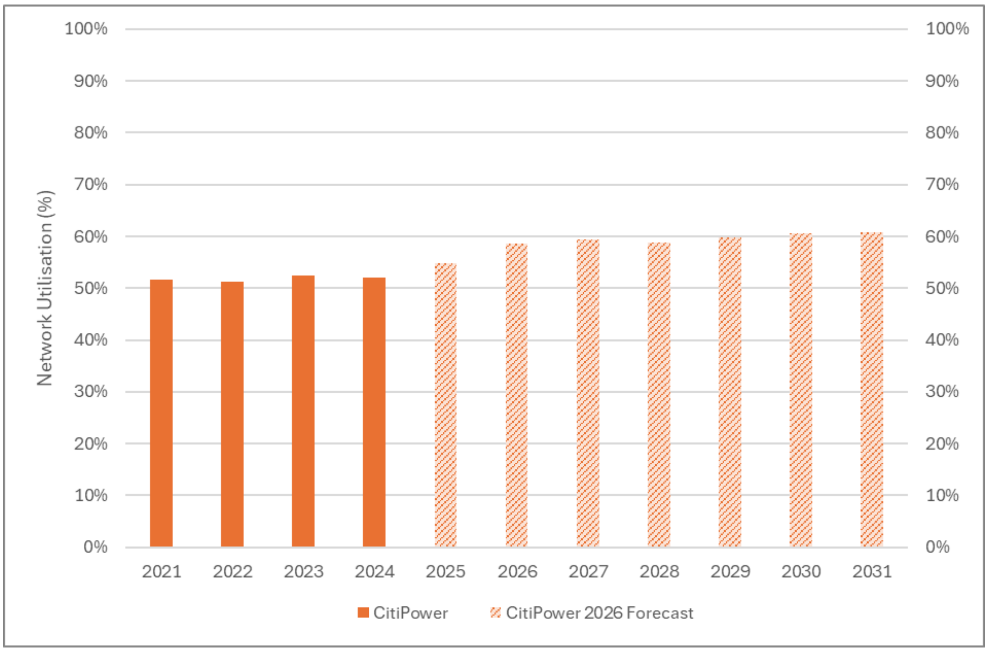
Network utilisation refers to the extent that network assets are used to meet customer demand. We calculate utilisation by dividing non-coincident maximum demand by the total capacity of the DNSP's zone substation transformers. Low utilisation means that a network can service large increases in peak demand but could indicate that customers are paying for network assets they rarely use. Conversely, high levels of utilisation could indicate that investment is necessary to meet increases in peak demand.

The Victorian DNSPs have high rates of network utilisation compared to DNSPs in other jurisdictions. This reflects several factors, including:

- The use of probabilistic planning practices instead of deterministic planning
- The use of smart meters enabling the Victorian DNSPs to plan more precisely, by having access to more granular and accurate customer load data
- Tariff innovation, such as the use of critical peak demand pricing for large customers

As shown in Figure 2-15, CitiPower forecasts that its network utilisation will increase to 61% in 2031.

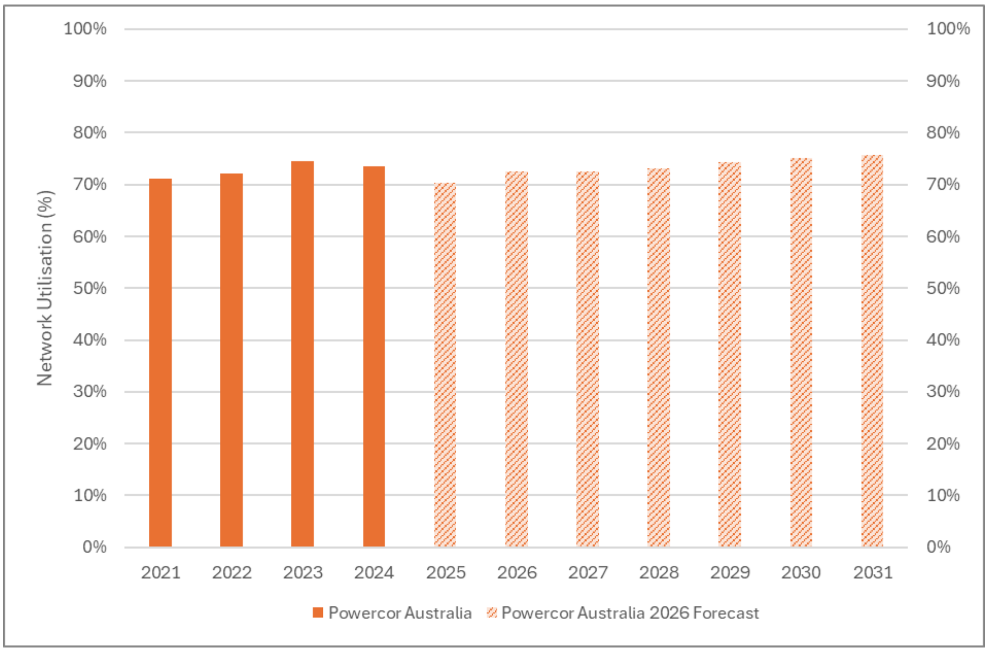
Figure 2-15 CitiPower - Forecast network utilisation



Source: 2021 Reset RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Network utilisation is calculated by dividing non-coincident summated weather adjusted system annual maximum demand, 10% POE (MVA) by the total zone substation transformer capacity (MVA).

As shown in Figure 2-16, Powercor forecasts that its network utilisation will increase to 76% in 2031.

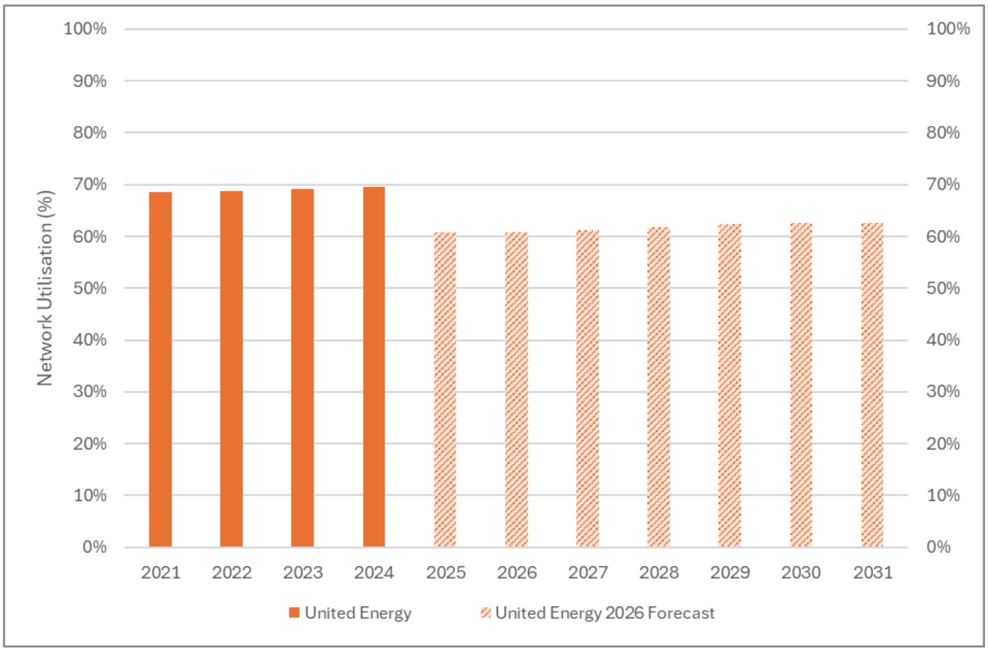
Figure 2-16 Powercor - Forecast network utilisation



Source: 2021 Reset RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Network utilisation is calculated by dividing non-coincident summated weather adjusted system annual maximum demand, 10% POE (MVA) by the total zone substation transformer capacity (MVA).

As shown in Figure 2-17, United Energy forecasts that its network utilisation will increase to 63% in 2031.

Figure 2-17 United Energy - Forecast network utilisation



Source: 2021 Reset RIN (2021-24 data), 2026 Reset RIN (2025-31 data).
Note: Network utilisation is calculated by dividing non-coincident summated weather adjusted system annual maximum demand, 10% POE (MVA) by the total zone substation transformer capacity (MVA).

Questions on network utilisation

2) How well do you think these proposals take existing and forecast network utilisation levels into account?

2.5 Consumer engagement and the Better Resets Handbook

CitiPower, Powercor and United Energy supply an essential service to Victorian consumers. High quality consumer engagement is critical to their development of a proposal that supports delivery of services and outcomes that reflect consumers' needs and preferences. Our framework for considering consumer engagement in network revenue determinations is set out in the Better Resets Handbook:

- We look to the nature of engagement, and how networks engage with their consumers. Our expectations are that network businesses will sincerely partner with consumers and equip them to effectively engage in the development of their proposals.
- We consider the breadth and depth, including the scope of issues on which consumers were engaged and at what level of detail The breadth and depth of engagement also covers the variety of avenues used to engage with consumers
- We have regard to how a proposal represents and is shown to represent consumer views. We look for evidence of a clear link between consumer research and engagement, a network business's representation of the outcomes desired by consumers, and how the proposal gives effect to those outcomes.

Experience shows that proposals that reflect consumer preferences, and which also meet our expectations for 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.

In the lead up to submission of their proposals, three core priorities emerged in customer feedback across the three networks:[11]

- **Reliability, safety and resilience**—to stay connected with uninterrupted and safe electricity supply that can withstand extreme weather.

  Customers want reliable electricity supply maintained, with no deterioration of existing service levels. They expect the networks to be managed safely and in accordance with applicable obligations and standards. Larger commercial and industrial users want their networks to provide capacity to ensure consistent power quality to better support their operations.

  Powercor and United Energy customers brought greater focus on network resilience and improved support during emergencies. They called for their distributors to work with communities to better prepare for extreme weather events, and to work to minimise the likelihood and impact of disruptions to supply during extreme weather events.

- **Energy transition—**to shift towards mode sustainable energy sources and practices for a cleaner future.

  Customers want greater energy supply independence. They expect their distributors to manage additional capacity requirements on their networks and to support electrification at the lowest possible cost. They also expect them to lower carbon emissions from the provision of their energy supply.

- **Affordability and equity**—everyone to have access to the electricity supply they value, regardless of where they live or work.

  Customers want clear value from their networks. Customers want tools to help them manage their electricity bills, including safeguards for customers experiencing (or at risk of) vulnerable circumstances.

  Powercor and United Energy customers brought greater focus on equitable opportunities to participate in the energy transition, with rural and regional customers calling for improved service level outcomes to ensure they are not left behind.

In addition to expectations for engagement, the Handbook also sets out our expectations (consistent with the NER framework) in topic areas such as capex, opex, regulatory depreciation and tariff structure statements, which tend to have the most significant impact on consumers. Each business has proposed a significant uplift in capex and opex, and a number of significant opex step changes. These do not meet Handbook expectations for steady growth in spending that might have lent themselves to a relatively limited or targeted

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11 CitiPower, *Regulatory Proposal 2026-31 - Part A – Overview, Januar*y 2025, pp. 17, 26-27; Powercor *Regulatory Proposal 2026-31 - Part A – Overview,* January 2025, pp. 17, 25-28; United Energy, *Regulatory Proposal 2026-31 - Part A – Overview*, January 2025, pp. 17, 26-29.

review. Where consumers have expressed support for the outcomes CitiPower, Powercor and United Energy seek to achieve, our role is to now carefully assess the prudency and efficiency of the expenditure they submit is necessary to deliver them.

Customer support is an important part of this assessment. The National Electricity Rules (NER) require us to consider the extent to which the forecasts of opex and capex CitiPower, Powercor and United Energy have proposed include expenditure to address the concerns of their end users, as identified by the businesses in the course of their engagement with end users or groups representing them.[12] It is a factor to which we must have regard in determining whether the total forecasts of opex and capex proposed reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs.[13]

In considering other capex and opex factors we will look to supporting information including governance and the robustness of its forecasting methods. We will also consider in-depth business cases. Before expenditure is approved, we need to satisfy ourselves that the forecast expenditure CitiPower, Powercor and United Energy have proposed not only addresses the concerns and preferences of their users, but also that it does so prudently and efficiently and that the ambitious programs for which businesses are seeking to recover costs can actually be delivered in the timeframes proposed. Together, these considerations support a decision that will ensure customers are paying no more than necessary for safe, reliable and secure delivery of their electricity distribution services and the outcomes they have told CitiPower, Powercor and United Energy they value.

Similarly, the effectiveness and outcomes of engagement on proposed tariff structure statements, including export tariff transition strategies[14] will inform our assessment of proposed tariff structures. For example, we will have regard to information exchanged and feedback provided as part of consumer engagement when we are considering whether the structure of a tariff is reasonably capable of being understood by retail customers, and of being directly or indirectly incorporated by retailers or Small Resource Aggregators in contract terms offered to those customers.[15]

Throughout this paper we have asked questions about the engagement CitiPower, Powercor and United Energy have undertaken on, and consumer and stakeholder support for, particular aspects of their proposals. At an overall level, we would value consumer and stakeholder perspectives on the questions below.

Questions on consumer engagement

3) How satisfied are you that CitiPower, Powercor and United Energy have sincerely partnered with consumers and equipped them to effectively engage in the development of their proposals?
4) How satisfied are you with the scope of issues on which consumers were engaged, and the level of detail at which CitiPower, Powercor and United Energy engaged?

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12 NER, cll. 6.5.6(e)(5A), 6.5.7(e)(5A).

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

14 NER, cl. 6.8.2(c1)(2).

15 NER, cl. 6.18.5(i).

5) How satisfied are you with the variety of avenues CitiPower, Powercor and United Energy used to engage with consumers?
6) How satisfied are you with the evidence CitiPower, Powercor and United Energy have provided of consumer preferences identified through their various engagement channels, and that those preferences have been reflected in the proposals?
7) How well do you feel CitiPower, Powercor and United Energy have responded to consumer and stakeholder feedback on their proposals, including but not limited to feedback on their draft proposals?
8) How would your views on these proposals change if estimated network tariff and electricity bill impacts presented with the proposals did not eventuate? For example:

- If tariff or bill impacts were potentially higher, are there areas in which you would be willing to accept a different outcome or prefer CitiPower, Powercor and/or United Energy to spend less in order to avoid this?
- If tariff or bill impacts were potentially lower, are there areas in which you would prefer CitiPower, Powercor and/or United Energy to deliver more, or would you prefer the same outcomes at a lower cost or price?

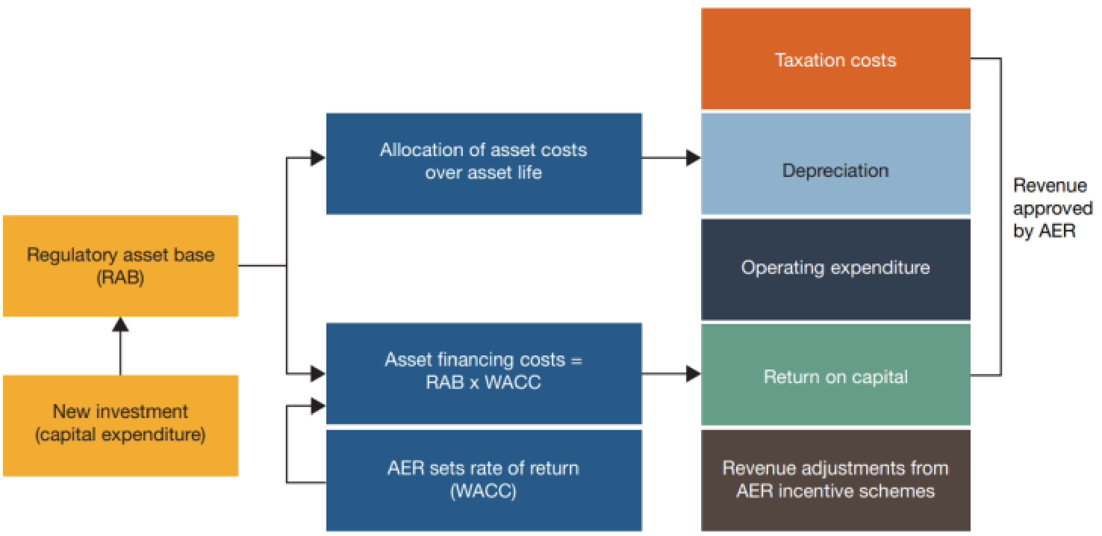
3 Key elements of the revenue proposal

The foundation of our regulatory approach is an incentive framework to setting maximum revenues: once regulated revenues are set for a five-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 drive lower cost forecasts in subsequent regulatory periods. By only allowing prudent and efficient costs in our approved revenues, we promote delivery of the NEO and ensure consumers pay no more than necessary for safe, secure, reliable, and affordable energy future for Australia as it transitions to net zero emissions.

The revenue CitiPower, Powercor and United Energy have proposed reflects their forecasts of the prudent and efficient cost of providing distribution network services in their network areas over the 2026–31 period. Their proposals, and our assessment under the National Electricity Law and Rules (NEL, NER), are based on a 'building block' approach which looks at five cost components (see Figure 3-1):

- 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 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 and allowances, such as the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and Demand Management Innovation Allowance Mechanism (DMIAM)
- estimated cost of corporate income tax.

Figure 3-1 The building block approach to forecasting revenue



Source: AER

3.1 Regulatory asset base

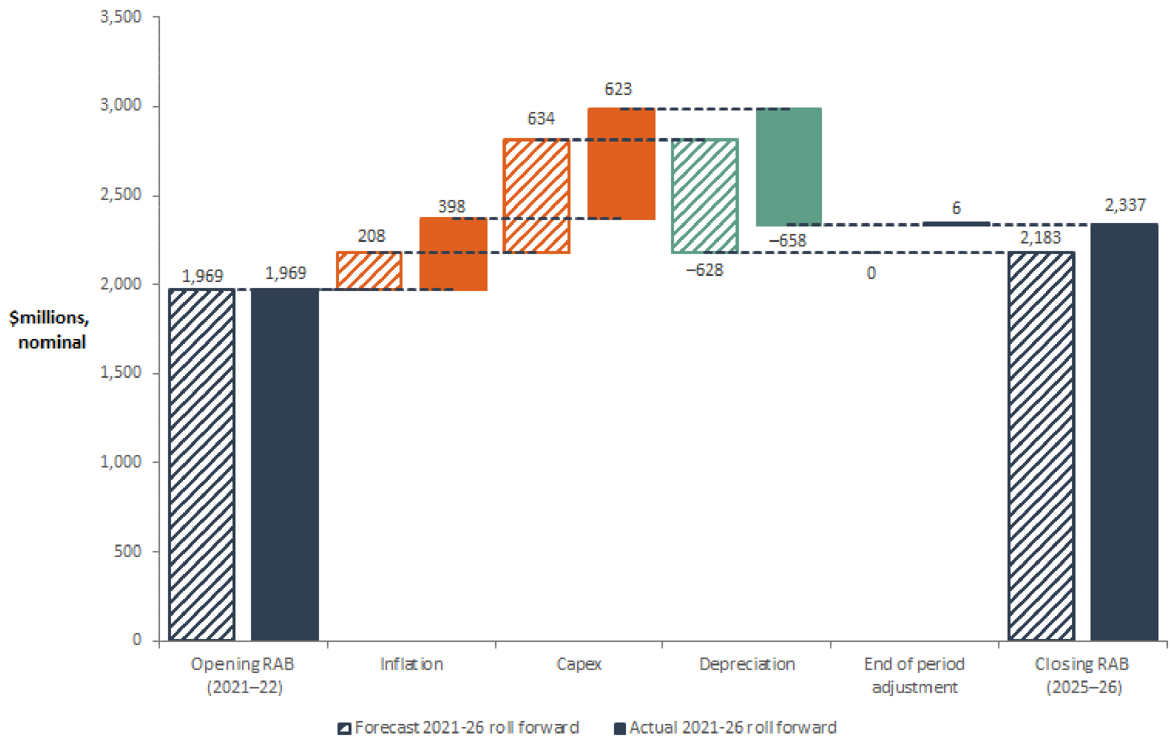
The RAB is the value of assets used by CitiPower, Powercor and United Energy to provide distribution network services. To set revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding 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. Other things being equal, a higher RAB would increase both the return on capital and regulatory depreciation components of the revenue determination.

The opening RAB at the start of the 2026–31 period depends on the value of existing assets, and on actual capex, actual inflation outcomes and depreciation in the past. In nominal terms, CitiPower, Powercor and United Energy have each reported increases in their RABs over the current, 2021–26 period:

- CitiPower’s RAB has increased by $368.0 million (18.7%)
- Powercor’s RAB has increased by $1,957.1 million (43.4%)
- United Energy’s RAB has increased by $672.2 million (28.1%)

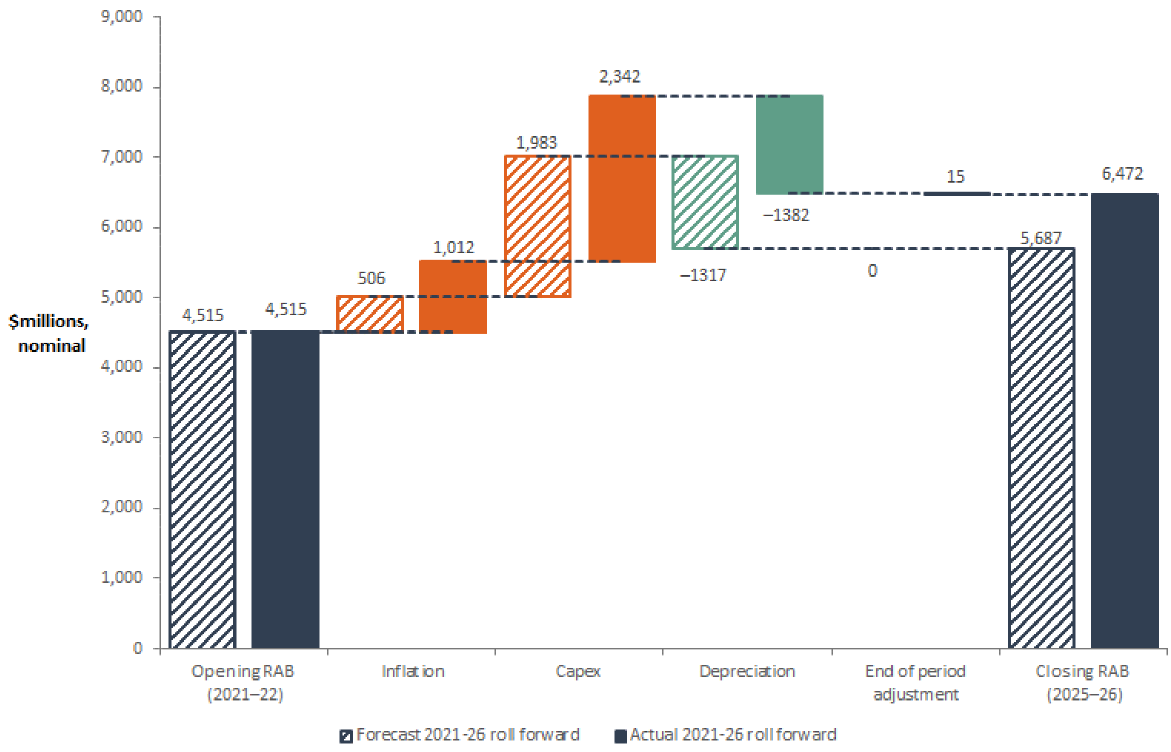
As shown in Figure 3-2 to 3-4, for each network the closing RAB at 30 June 2026 is higher than was forecast in our 2021–26 determinations. This difference is driven by the inflation of the RAB (indexation) and by capex. The higher actual RAB inflation component for each network is driven mainly by actual inflation rates in the current 2021–26 period exceeding the expected inflation of 2.00% per annum approved for that period. The actual capex each network expects to have invested by the end of the 2021-26 period is also different to that forecast at the time of our determination for that period. In CitiPower’s case, actual capex is lower than forecast. Powercor and United Energy have spent more than forecast.

Figure 3-2 Key drivers of changes in CitiPower's RAB over the 2021–26 period – Proposal compared to AER's 2021-26 determination ($ million, nominal)



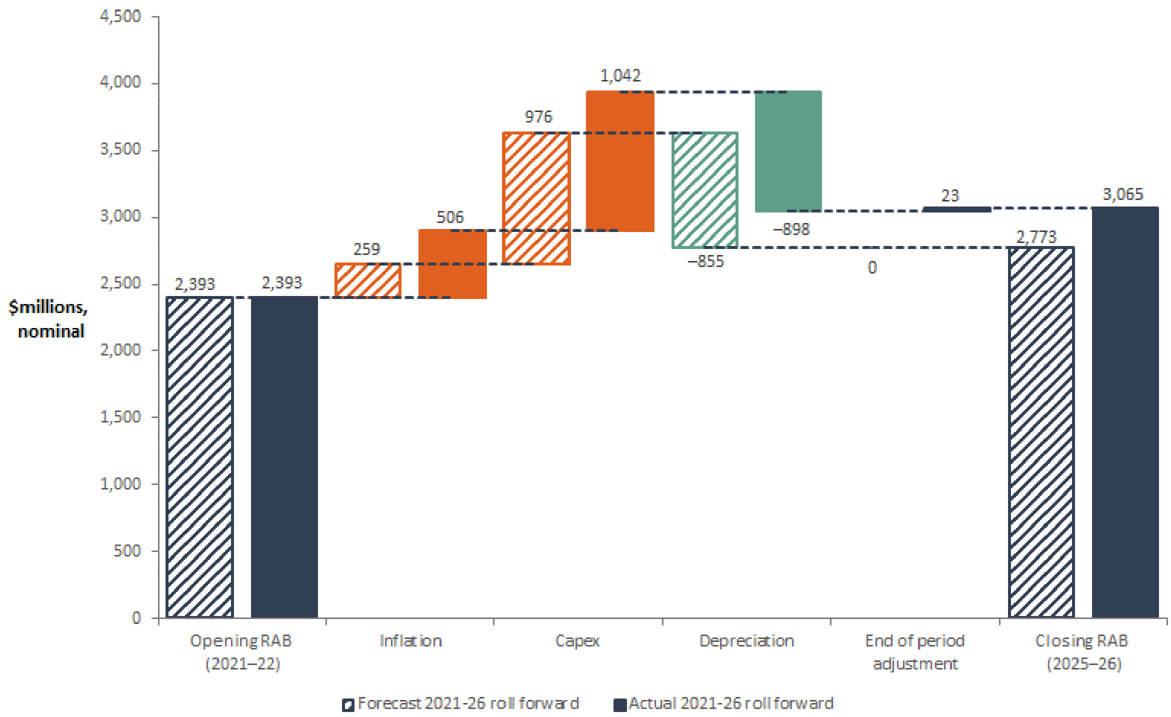
Source: AER analysis.

Figure 3-3 Key drivers of changes in Powercor's RAB over the 2021–26 period – Proposal compared to AER's 2021-26 determination ($ million, nominal)



Source: AER analysis.

Figure 3-4 Key drivers of changes in United Energy's RAB over the 2021–26 period – Proposal compared to AER's 2021-26 determination ($ million, nominal)



Source: AER analysis.

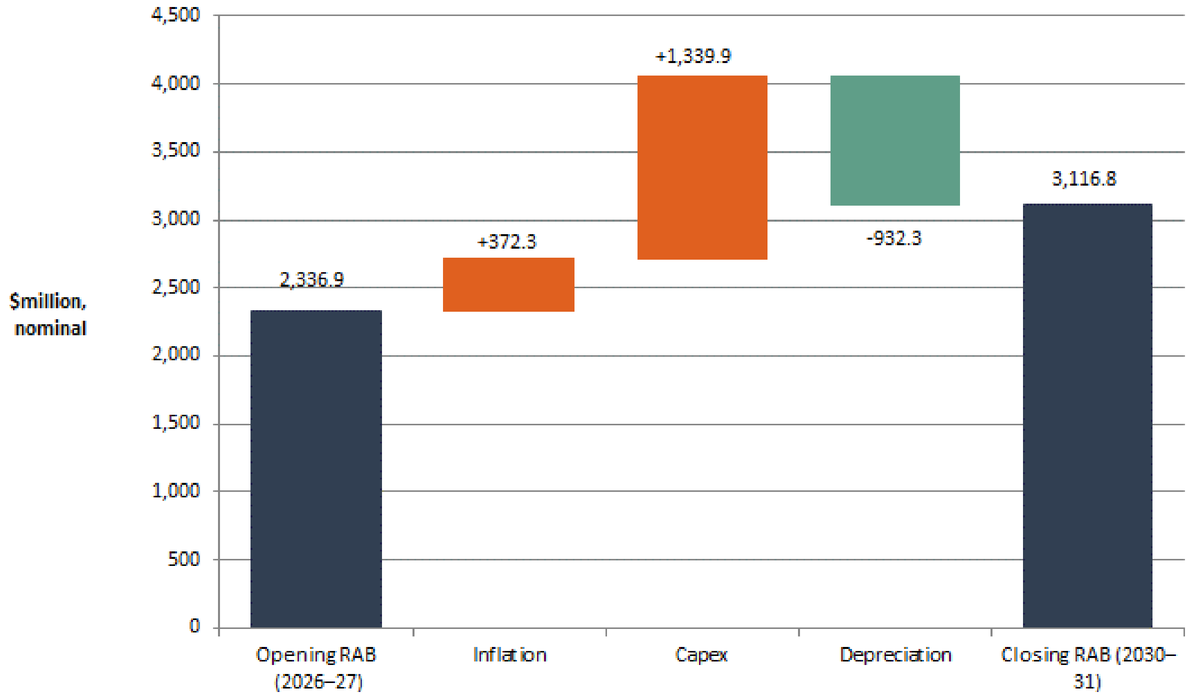
The RAB when projected to the end of the period increases due to both forecast new capex and the inflation indexation adjustment. Depreciation, on the other hand, reduces the RAB. The depreciation amount depends on the size of the opening RAB, the forecast net capex and depreciation schedules applied to the assets. Inflation, regulatory depreciation and capex are discussed in sections 3.2, 3.3 and 3.4 respectively.

The proposals project the following RAB increases over the 2026–31 period:

- CitiPower: $779.9 million (33.4%) ($nominal)
- Powercor: $3,085.8 million (47.7%) ($nominal)
- United Energy: $666.1 million (21.7%) ($nominal).

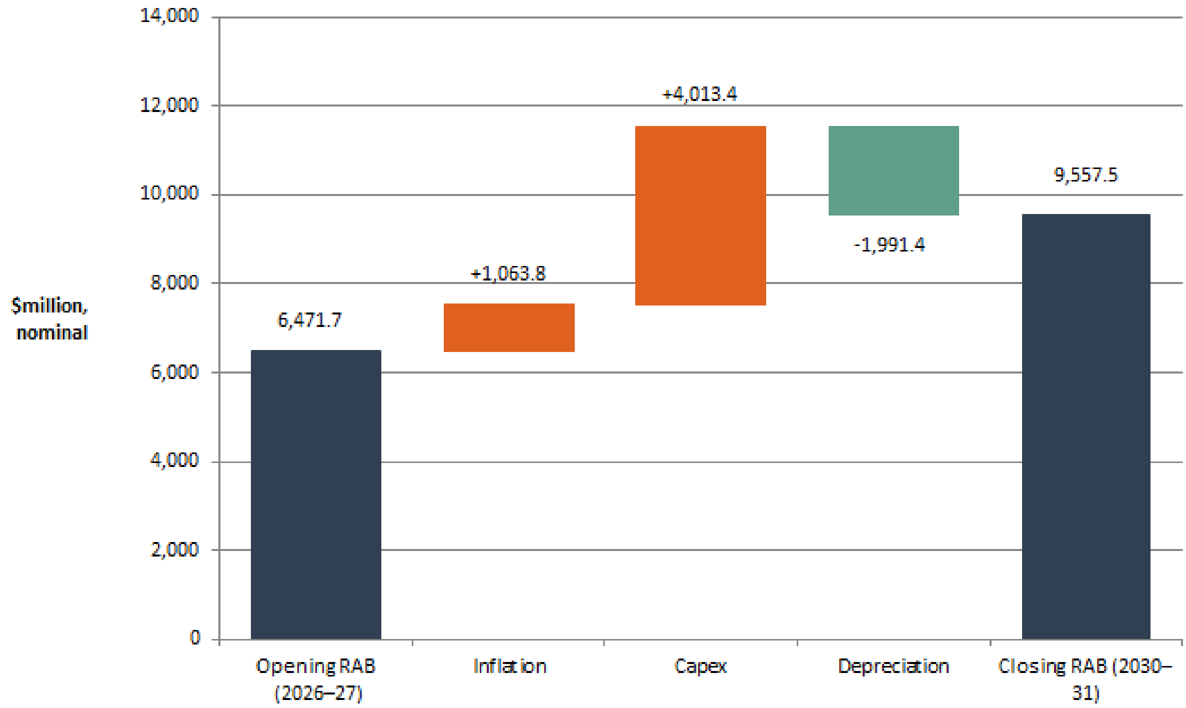
As shown in Figures 3-5 to 3-7, the increases in RAB are driven by proposed forecast capex and, to a lesser extent, inflation. Powercor's proposed projected RAB growth is higher than CitiPower and United Energy. This is driven by its relatively higher net capex (62.0% of its opening RAB) and lower depreciation (30.8% of its opening RAB). This proportionally lower depreciation occurs due to it having a larger share of long-lived assets in its RAB compared to CitiPower and United Energy.

Figure 3-5 Key drivers of changes in CitiPower's RAB over the 2026–31 period ($ million, nominal)



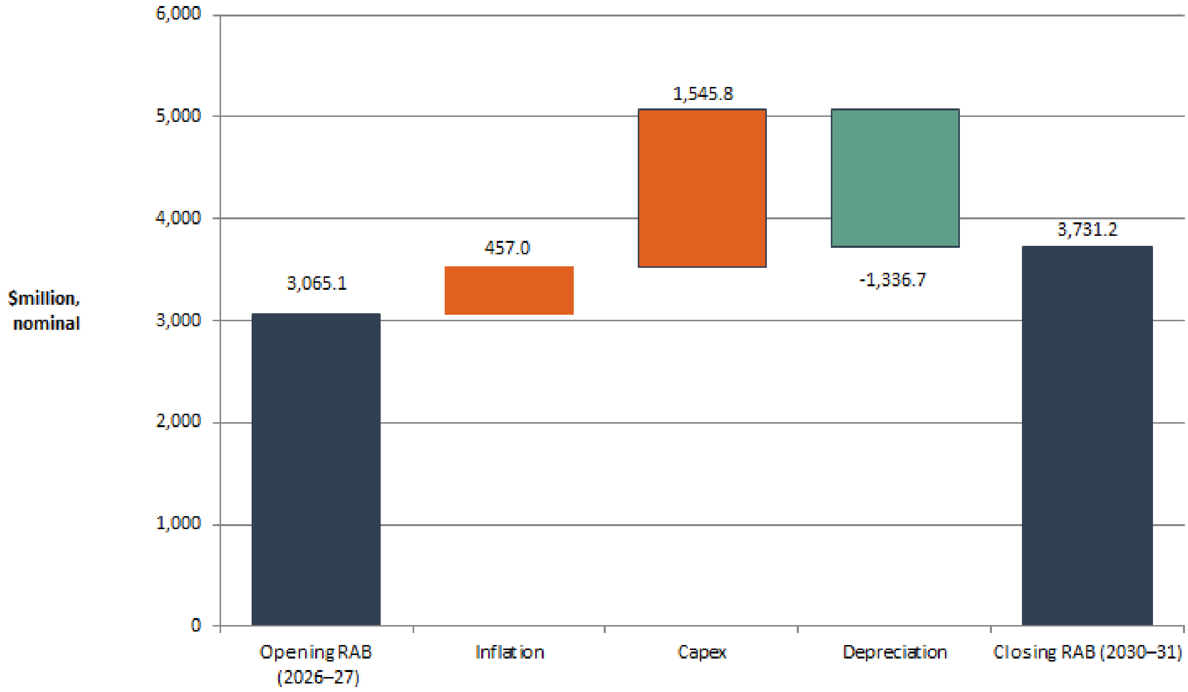
Source: AER analysis.

Figure 3-6 Key drivers of changes in Powercor's RAB over the 2026–31 period ($ million, nominal)



Source: AER analysis.

Figure 3-7 Key drivers of changes in United Energy's RAB over the 2026–31 period ($ million, nominal)



Source: AER analysis.

3.2 Rate of return on capital and inflation

The AER's 2022 Rate of Return Instrument (2022 RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[16]

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 two 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.

CitiPower, Powercor and United Energy's proposals include a higher estimate of the rate of return for the first year of the 2026–31 period (5.84%), compared to the first year estimate applied in our 2021–26 final decisions (4.73% for CitiPower and Powercor, and 4.76% for United Energy).

The proposals also include a higher estimate of expected inflation for the 2026–31 period (2.75%) compared to the estimate applied in our 2021–26 final decisions (2.00%).

The estimate of the rate of return and expected inflation are significant contributors to the increases in revenue CitiPower, Powercor and United Energy have proposed relative to the current period.

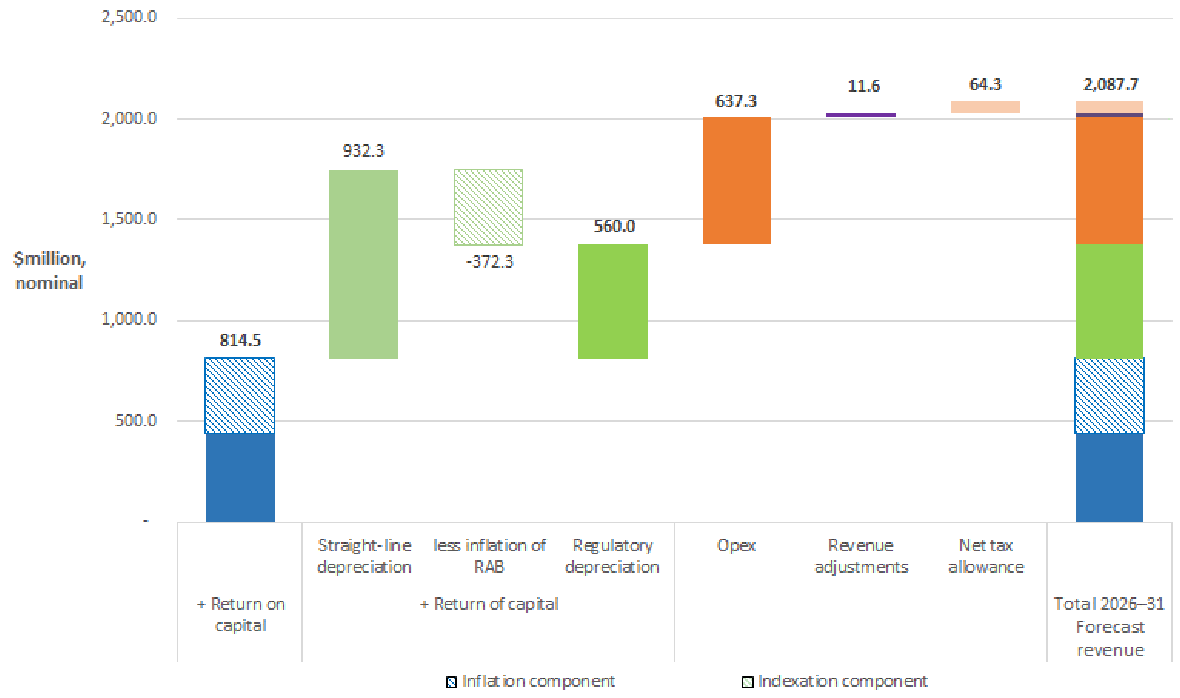
16 AER - Rate of Return Instrument (Version 1.2) – March 2024

At this stage, these values are placeholders only. It is important that they are updated throughout the determination process—in our draft decisions, in the businesses' revised proposals and again in our final decisions—for the latest market data. By setting a rate of return that reflects current financial market conditions, our determination will enable CitiPower, Powercor and United Energy to attract the capital they need to provide the services their consumers want.

Moreover, the return investors receive on their assets should reflect the risks of their investment, including the prospect of inflation eroding their purchasing power. In Figure 3-8 - Figure 3-10, we show how the estimate of expected inflation impacts forecast building block revenue:

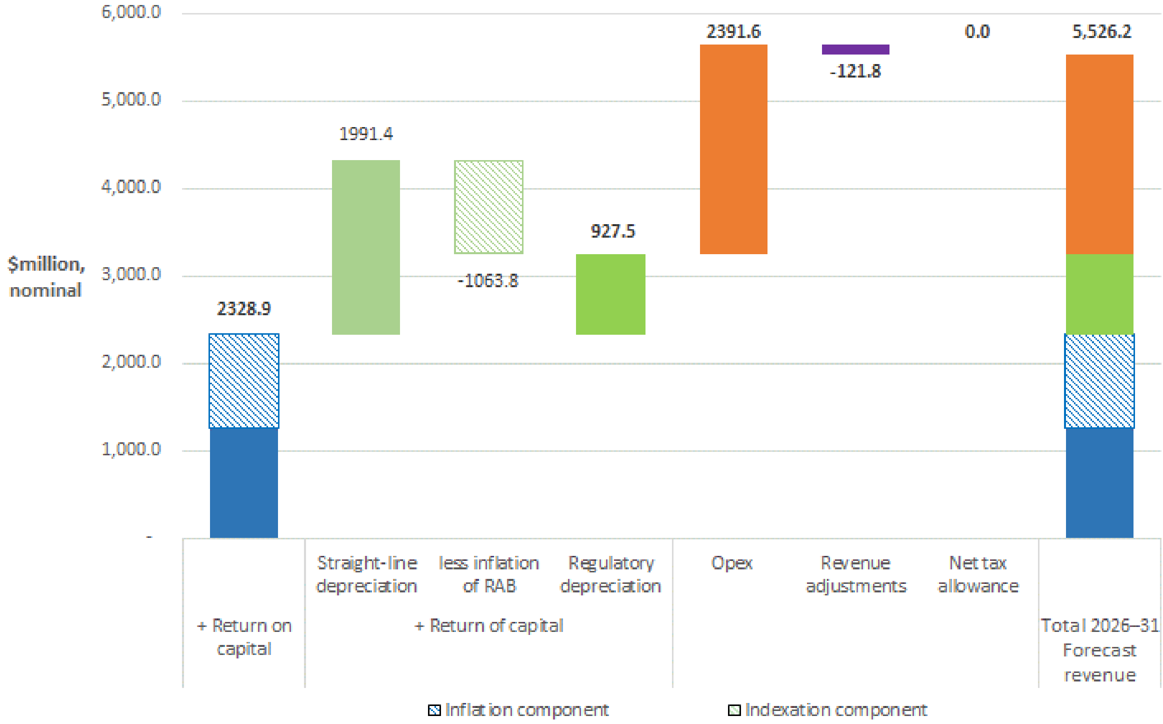
- The return on capital building block applies a nominal rate of return to the RAB. That nominal rate of return includes expected inflation. Higher expected inflation increases the return on capital and adds to the impact higher forecast capex is having on this building block.
- The return of capital building block removes expected inflation indexation of the RAB from forecast depreciation. This avoids compensation arising from the effects of inflation being double-counted by including it in the return on capital building block and also as a capital gain (through the indexation of the RAB). Higher expected inflation reduces the regulatory depreciation allowance.
- Other building blocks, such as opex and revenue adjustments, include an inflation component, as these costs are forecast in real dollar terms and then escalated to nominal dollars using expected inflation to determine the required nominal revenue. Higher expected inflation increases opex and revenue adjustments.

Figure 3-8 Inflation in CitiPower's revenue building blocks ($ million, nominal)



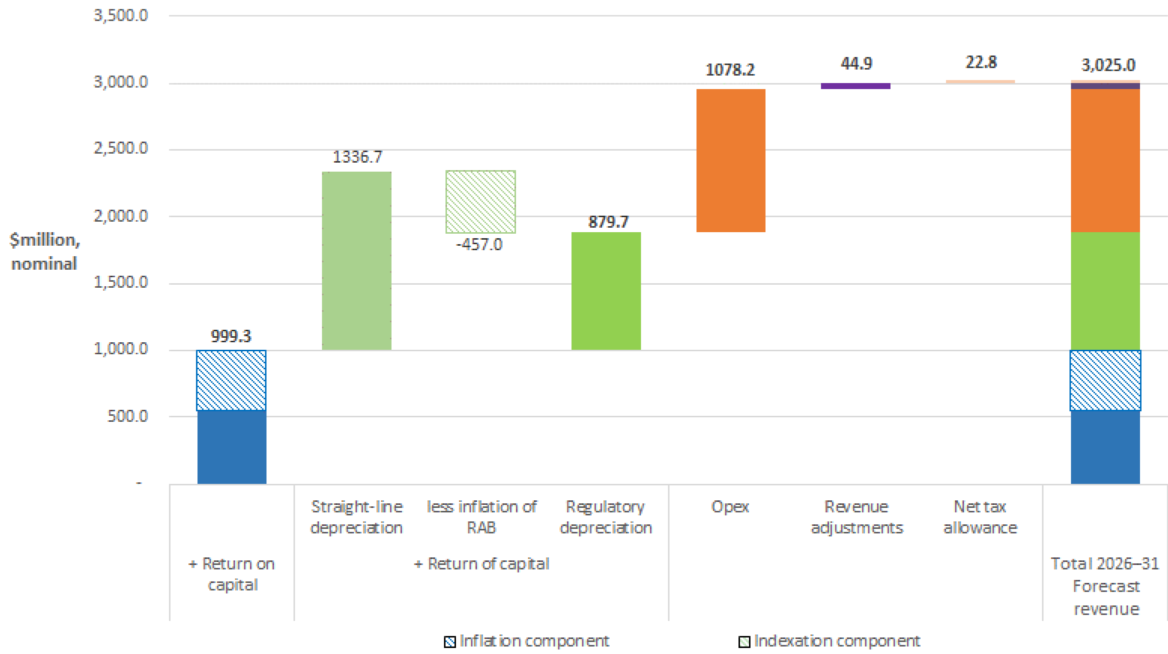
Source: AER analysis.

Figure 3-9 Inflation in Powercor's revenue building blocks ($ million, nominal)



Source: AER analysis.

Figure 3-10 Inflation in United Energy's revenue building blocks ($ million, nominal)



Source: AER analysis.

3.3 Regulatory depreciation (return of capital)

Depreciation is the method used in our determinations to allocate the cost recovery of different types of network assets over their useful lives. 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.

For the 2026–31 period:

- CitiPower has proposed regulatory depreciation of $514.1 million ($2025–26), which is $40.9 million (8.6%) higher than for the 2021–26 period.
- Powercor has proposed regulatory depreciation of $851.3 million ($2025–26), which is $62.6 million (6.9%) lower than for the 2021–26 period.
- United Energy has proposed regulatory depreciation of $807.8 million ($2025–26), which is $136.9 million (20.4%) higher than for the 2021–26 period.

For each network, the higher expected inflation is increasing the adjustment for the RAB indexation component, and this is offsetting forecast capex increases. For Powercor, the increase to the RAB indexation is higher than the increase to straight-line depreciation, resulting in a reduction in regulatory depreciation. Conversely, for CitiPower and United Energy, straight-line depreciation has increased by more than the RAB indexation component leading to an increase in regulatory depreciation. This difference is driven by the composition of the RAB for each network with Powercor having a higher proportion of long-lived assets compared to CitiPower and United Energy.

CitiPower, Powercor and United Energy used our standard regulatory models[17] and proposed to continue applying the year-by-year tracking approach in determining its forecast straight-line depreciation of existing assets. They have applied the same asset classes and standard asset lives from the 2021–26 regulatory determinations.

We will assess forecast expenditure for each network to ensure that the various proposed asset lives remain appropriate for the nature of the capex.

Questions on regulatory depreciation

9) Do you have any feedback on the regulatory depreciation approach proposed by each network?

3.4 Capital expenditure

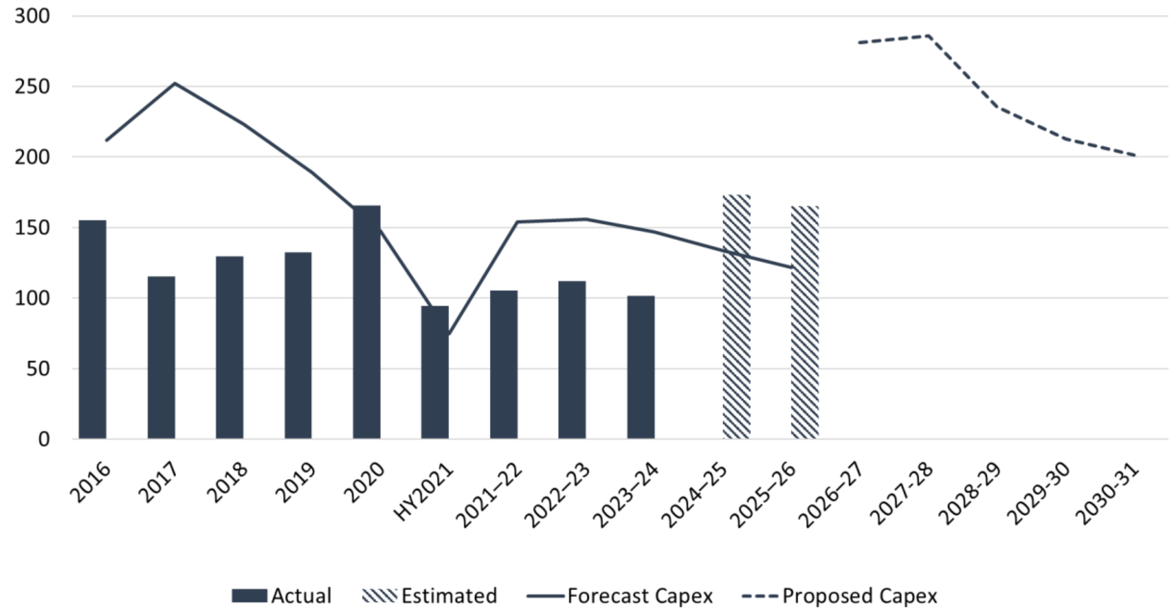
Capital expenditure (capex) refers to the capital costs and expenditure incurred to provide network services. Capex mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Capex is added to the RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances.

[17] We amended our standard RAB roll forward model (RFM) to reflect the half-year extension period of 1 January 2021 to 30 June 2021.

CitiPower, Powercor and United Energy have all proposed increases in total forecast capex compared to the current period.

CitiPower has proposed total forecast capex of $1,216.3 million ($2025–26) for the 2026–31 period. This is $504.7 million (70.9%) higher than the total forecast capex we approved (and used to set revenues) in our decision for the current, 2021–26 period. It is $559.2 million (85.1%) higher than CitiPower's actual/estimated capex in that period (see Figure 3-11).

Figure 3-11 Trend in CitiPower's forecast and actual capex over time ($m, 2025-26)



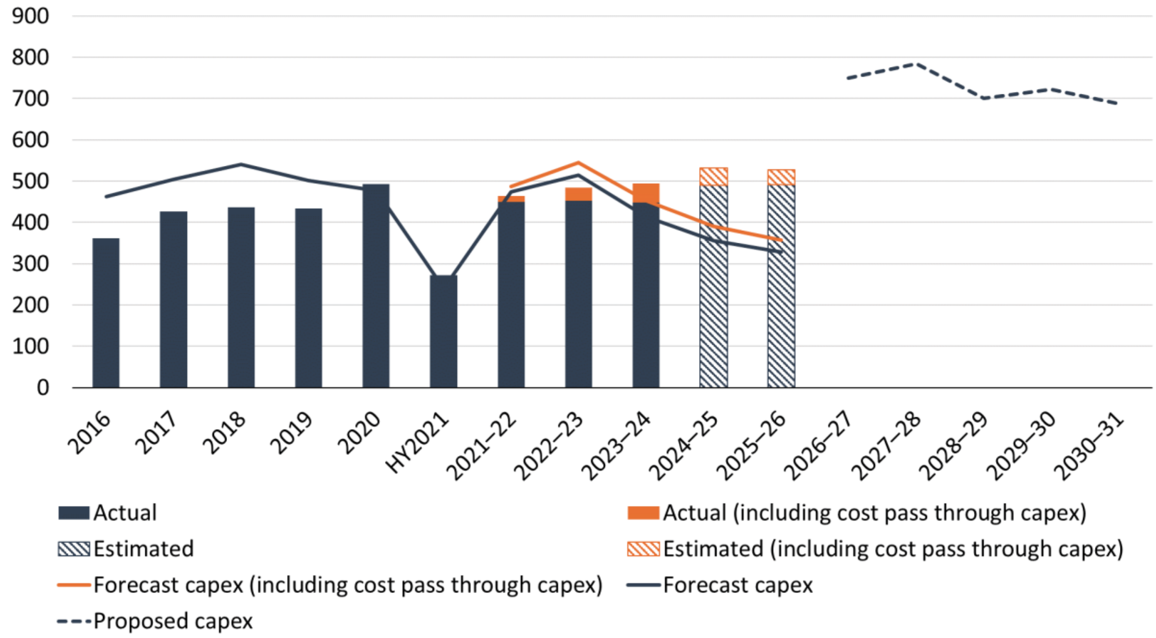
Source: Roll forward model, post-tax revenue model, and CitiPower's proposal.
Note: Net; estimates only for 2024-25 and 2025-26.

Powercor has proposed total forecast capex of $3,644.9 million ($2025–26) for the 2026–31 period. This is $1,559.7 million (74.8%) higher than the total forecast capex we approved (and used to set revenues) in our decision for the current, 2021–26 period.[18] It is $1,312.3 million (56.3%) higher than Powercor's actual/estimated capex in that period (See Figure 3-12).[19]

[18] For Powercor, we have not included forecast cost pass through capex in this calculation.

[19] For Powercor, we have not included actual/estimated cost pass through capex in this calculation.

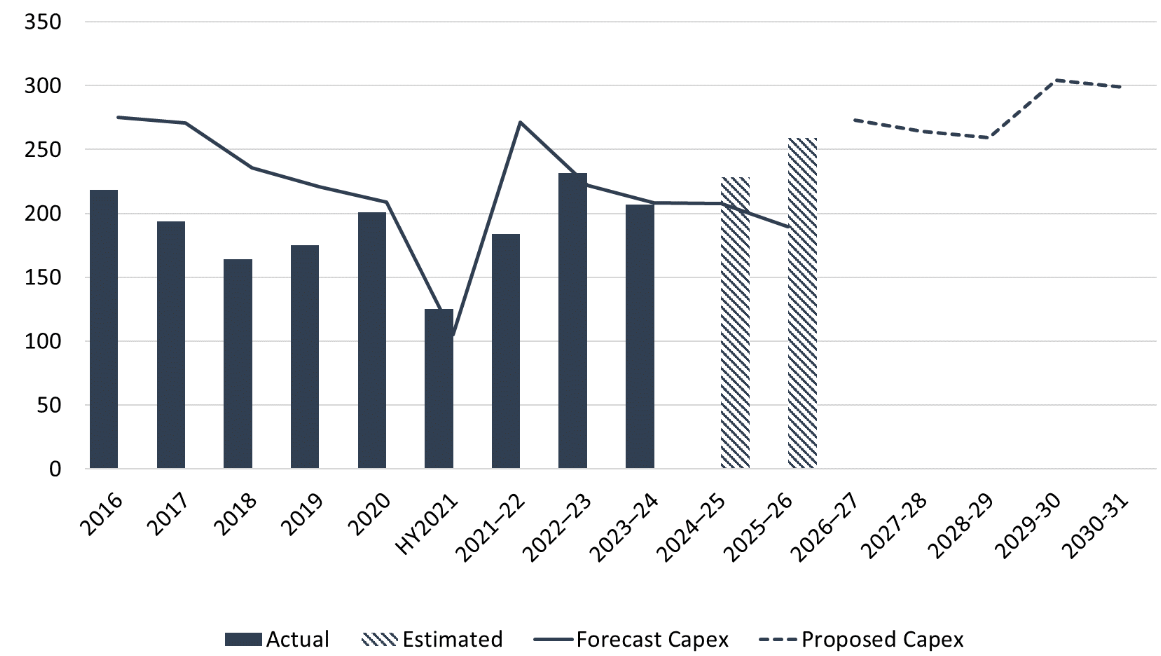
Figure 3-12 Trend in Powercor's forecast and actual capex over time ($m, 2025-26)



Source: Roll forward model, post-tax revenue model, Powercor's proposal, and response to information request IR#03.
Note: Net; estimates only for 2024-25 and 2025-26.

United Energy has proposed total forecast capex of $1,399.3 million ($2025–26) for the 2026–31 period. This is $300.6 million (27.4%) higher than the total forecast capex we approved (and used to set revenues) in our decision for the current, 2021–26 period. It is $289.4 million (26.1%) higher than United Energy's actual/estimated capex in that period (See Figure 3-13).

Figure 3-13 Trend in United Energy's forecast and actual capex over time ($m, 2025-26)



Source: Roll forward model, post-tax revenue model, and United Energy's proposal.
Note: Net; estimates only for 2024-25 and 2025-26.

We have assessed that an ex-post review (a review of past expenditure) is not required for CitiPower, Powercor or United Energy as part of these determinations, because they did not overspend in the ex-post review period.[20] We will assess whether an ex-post review is required in the next determinations noting the elevated levels of expenditure proposed.

CitiPower, Powercor and United Energy are required to propose the total forecast capex it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, and to maintain the safety, reliability, quality, and security of each of their respective networks and to contribute to achieving the targets for reducing Australia's greenhouse gas emissions (the capex objectives).[21] We must decide whether we are satisfied that these forecasts reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[22] Where a business's capex forecast is a material step up, we will also have regard to the deliverability of a businesses' total capex program in assessing the reasonableness of the capex forecast. We typically expect businesses to provide evidence of how they would address resourcing constraints, immediate skill gaps, supply chain limitations and other deliverability risks.

When considering whether the forecast reasonably reflects the expenditure criteria, we must have regard to the capex factors.[23] 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 supply, and contribute to achieving targets for reducing Australia's greenhouse gas emissions, for the benefit of consumers in the long term (as required under the NEO).[24] Our *Capital expenditure assessment outline for electricity distribution determinations* explains our and distributors' obligations under the NEL and NER in more detail.[25] It also describes the techniques we use to assess distributors' capex proposals against the capex criteria and objectives. Where relevant we also assess capex associated with emissions reduction proposals taking into account our *Guidance on amended National Electricity Objectives.*[26]

The Handbook sets our expectations for capex forecasts. In summary:

- the business should demonstrate that the proposed expenditure is not significantly above current period spending. All components of the total capex forecast should be well-justified, consistent with past spending for recurrent components, and, for replacement capex (repex), not materially above our repex model
- the business should show evidence of prudent and efficient decision-making on key projects/programs

[20] The ex post review period includes years for which actual, and not just estimated, capex is available for review. It covers only the first three years of the 2021-26 period, and the final two years of the previous period.

[21] NER, cl. 6.5.7(a).

[22] NER, cl. 6.5.7(c).

[23] NER, cl. 6.5.7(e).

[24] NEL, ss. 7, 16(1)(a).

[25] AER, *AER capital expenditure assessment outline for electricity distribution determinations*, February 2020.

[26] AER, *Guidance on amended National Electricity Objectives,* September 2023.

- the business should provide evidence that the proposal aligns with industry risk management standards
- the business should provide evidence of genuine consumer engagement.

CitiPower, Powercor and United Energy have proposed total forecast capex for the 2026–31 period that is materially above their current period spends, with step ups in most capex categories. These step ups in capex appears to extend to some recurrent expenditure areas like repex and fleet.

At this stage, we are still assessing the businesses' supporting material to assess whether they have provided sufficient evidence of prudency and efficient on key projects and programs, whether their asset and risk management aligns with good industry practice, and whether there has been genuine consumer engagement on their capex proposals.

For all three businesses, we intend to look closely at repex, augmentation capex (augex), connections and Information and Communications Technology (ICT) as these areas are material portions of the total forecast. We will also review expenditure for integration of Consumer Energy Resources (CER) in more detail as there are interrelationships with ICT, and it is an evolving area of expenditure. Similarly, we will also review Powercor and United Energy's resilience proposal closely given this emerging area of expenditure.

We will also closely review CitiPower's and Powercor's proposed contingent projects.

3.4.1 Key drivers of CitiPower's capex proposal

CitiPower's forecast capex for the 2026–31 period is $1,216.3 million, which is 85.1% higher than its actual/estimated capex for the 2021–26 period. It expects to underspend its capex forecast by 7.7% in the 2021–26 period. CitiPower submits its net capex in the current period will be lower than the AER's allowance but will exceed this allowance after asset disposals are excluded.[27]

CitiPower explains that there was lower expenditure than anticipated in the current period because there has been a deferral of some major augmentation works due to lower CBD and inner-city peak demand consumption and efficiencies from CER delivery. CitiPower also observes that this lower expenditure was offset by rising input costs that arose during the pandemic and continued supply chain pressures.[28]

Table 3-1 sets out the composition of CitiPower's capex proposal for 2026–31. As can be seen, CitiPower is forecasting a step up in all capex categories, relative to the current period. The largest component of forecast capex is repex, connections and augex, with CitiPower proposing material increases in these categories.

We discuss CitiPower's proposal in the sections below for capex categories that are likely areas of focus for our assessment. This includes its forecasting approach and key drivers.

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27 CitiPower, *Regulatory proposal 2026-31, Part B: explanatory statement, Revenue and expenditure forecasts*, January 2025, p.10.

28 CitiPower, *Regulatory proposal 2026-31, Part B: explanatory statement, Revenue and expenditure forecasts*, January 2025, p.10.

Table 3-1 CitiPower's 2026–31 capex proposal compared to 2021–26 ($million 2025–26)

Driver	2021-26 actual/ estimate	2026-31 proposal	2026-31 proposal vs 2021-26 actual/ estimate (%)	Proportion of 2026-31 net capex (%)
Replacement	206.8	354.1	71.2%	29.1%
Resilience	-	-	n/a	n/a
Augmentation	107.0	215.0	100.8%	17.7%
Connections	156.8	236.7	51.0%	19.4%
Fleet	12.6	21.1	67.9%	1.7%
Property	19.8	84.3	325.3%	6.9%
Cyber security	-	5.6	n/a	0.5%
ICT	88.4	119.5	35.2%	9.8%
CER integration	22.7	11.8	-48.2%	1.0%
Other non-network	6.2	7.0	13.0%	0.6%
Capitalised overheads	136.0	162.1	19.2%	13.3%
Total capex (excluding capital contributions)	**756.3**	**1,217.1**	**60.9%**	
Less asset disposals	99.1	0.7	-99.3%	
Net capex	**657.2**	**1216.3**	**85.1%**	

Source: CitiPower 2021–26 final decision capex model, Reset RIN, RFM, PTRM, CitiPower 2026–31 proposal capex model, and CitiPower's response to information request #05.

Note: CitiPower's 2021-26 actual/estimate may include cyber security capex in other categories that is not identifiable in the Category Analysis RIN. CitiPower's regulatory proposal shows forecast capex for each category and project in $real 2025-26 un-escalated dollars. In this paper, we present all forecast capex for the 2026-31 period in $real 2025-26 escalated dollars

3.4.1.1 Replacement expenditure (repex)

CitiPower has proposed repex of $354.1 million, which is 71.2% higher than its actual/estimated capex for the 2021–26 period. We note CitiPower expects to overspend its repex forecast for the 2021–26 period by 33.8%. This indicates that CitiPower expects to maintain the higher level of repex it has incurred in the current period.

CitiPower explains that the higher level of repex is likely to continue due to:[29]

- rising input costs from the impacts of the pandemic and ongoing global supply chain pressures which limits the ability for contract management to mitigate these uplifts.
- the longer-term trend of increasing asset replacements of high-volume distribution assets, which is reflective of the characteristics of its underlying asset populations.

We note CitiPower is proposing forecast increases relative to current period spend across almost all asset classes, with the largest differences in switchgears and underground cables.

CitiPower states it will only propose replacement based on risk or condition-based modelling to ensure assets are replaced only when benefit outweighs the costs, given affordability concerns.[30] It will also propose investment to maintain reliability outcomes as well as gradually increase replacement rates of asset classes where a majority are deteriorating due to condition and load increase such as underground cables.[31]

Consistent with our typical top-down assessment, we will review the outcomes of the AER's repex model to assess how CitiPower's forecast modelled repex performs against all other distributors in terms of replacement life and unit rates. As CitiPower's modelled repex is 65% of its total repex,[32] the results of the AER's repex model are a reasonable top-down check of CitiPower's forecast repex.

3.4.1.2 Augmentation capex (augex)

CitiPower has proposed augex of $215.0 million for the 2026–31 period. This is 100.8% higher than actual/estimated capex for the 2021–26 period. We note CitiPower expects to underspend its augex forecast for the 2021–26 period by 16.1%.

CitiPower states that the key drivers of demand-driven augmentation for the next period are electrification of gas and transport.[33] Major components of CitiPower's proposal include augex on its Brunswick Modernisation Program ($60.3 million), Customer-Driven Electrification ($40.9 million) and Zone Substation Capacity Upgrades ($29.1 million).[34]

CitiPower states that the key drivers of non-demand augmentation are its compliance obligations, maintaining systems security and ensuring safety and reliability for customers.[35] Major components of the proposal include $19.7 million for CBD security of supply, $14.2 million for under-frequency load shedding and $23.5 million for Yarra Trams pole relocation.[36]

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29 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 42.

30 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 44.

31 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 44.

32 Calculated from the modelled repex categories in Reset RIN table 2.2 and CitiPower's total replacement program including resilience.

33 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 31.

34 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 34-37.

35 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 39.

36 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 39-40.

CitiPower notes that its augmentation expenditure is typically more expensive than other networks due to the high-density nature of its network, with more than 50% of the network underground. This also results in a 'lumpier' expenditure profile.[37]

3.4.1.3 Connections capex

CitiPower forecasts net connections capex of $236.7 million for the 2026–31 period. This is 51.0% higher than actual/estimated capex for the 2021–26 period. We note CitiPower expects to overspend its net connections capex forecast for the 2021–26 period by 5.9%.

It cites that the actual connection activity exceeding the allowance has placed pressure on the entire capex program given that connections expenditure is not discretionary. CitiPower states the growing challenges and impacts of forecasting connections has resulted in its proposal to exclude connections from future capital efficiency sharing scheme (CESS).[38]

The key drivers of connections investment in the forecast period are the strong rebound being experienced in residential connections following the pandemic as well as an increase in data centre connections.[39]

3.4.1.4 CER integration

CitiPower has proposed $11.8 million capex to integrate CER.[40] Of this amount, approximately $9.8 million is for flexible exports to maximise existing hosting capacity, and $1.3 million to develop capabilities to implement flexible load products in the future.[41]

CitiPower's CER integration strategy includes using enhanced forecasting capabilities to better understand potential customer and network impacts as well as maximising utilisation of its existing infrastructure and exhausting all possible low-cost solutions. CitiPower indicated it had regard to the AER's customer export curtailment value methodology and value of customer reliability when developing its CER proposals.[42]

We will review CitiPower's proposals having regard to our *DER Integration Expenditure Guidance note* and customer export curtailment value methodology.[43]

We note that CER integration and ICT capex are interrelated, with opex also proposed in these areas.

Information and communications technology (ICT)

CitiPower forecasts $119.5 million for ICT capex, which is 35.2% higher than actual/estimated capex for the 2021–26 period. CitiPower expects to overspend its ICT capex forecast for the 2021–26 period by 2.1%.

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37 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 33.

38 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 53.

39 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 53.

40 CitiPower's proposal and RIN documents refer to distributed energy resources (DER).

41 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 26-29.

42 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 28.

43 AER, *DER integration expenditure guidance note*, June 2022; AER, *Customer export curtailment value methodology*, June 2022.

CitiPower's ICT proposal is driven by an increase in non-recurrent ICT ($30.8 million) and recurrent ICT capex ($76 million), and new compliance requirements related to AEMO's post-2025 NEM market reform program ($12.6 million).[44] CitiPower notes the NEM reforms will require significant changes to its IT systems to accommodate the increasing uptake of new technologies, including CER.[45]

Major components of CitiPower's recurrent ICT proposal include network management ($17 million), an infrastructure refresh ($14.2 million) and the end user device management program ($10.8 million). CitiPower's non-recurrent ICT proposal includes $30.8 million for its ERP and billing system replacement program.

3.4.1.5 Contingent projects

CitiPower has proposed 3 contingent projects totalling $192.0 million to address demand growth in Lauren street ($70 million), Spencer street ($54 million) and Richmond ($68 million). CitiPower has identified these areas have uncertain load growth and may require zone substation rebuilds if specific demand triggers are met.

We will analyse whether the proposed triggers for these projects are objectively verifiable and whether these projects should rightfully be considered contingent projects.

3.4.2 Key drivers of Powercor's capex proposal

Powercor's forecast capex for the 2026–31 period is $3,644.9 million, which is 56.3% higher than its expected capex for the 2021–26 period.[46] It also expects to overspend its total capex forecast by approximately 12% in the 2021–26 period.[47]

Powercor explains its overspend in the current period has been driven by more connections activity than anticipated, which is partly offset by efficiencies from CER delivery.[48]

Table 3-2 sets out the composition of Powercor's capex proposal for 2026-31. Powercor is forecasting a step up in almost all capex categories, relative to the current period. The largest component of forecast capex is repex, connections, and augex, with Powercor proposing material increases in these categories.

We discuss Powercor's proposal in the sections below for capex categories that are likely areas of focus for our assessment. This includes its forecasting approach and key drivers.

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44 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 59.

45 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 65.

46 Powercor had cost pass through capex approved by the AER for repex and ICT in the 2021-26 period. We have not included actual/estimated cost pass through capex in this calculation.

47 This is true whether factoring in cost pass through capex or not.

48 Powercor, *Regulatory proposal 2026-31, Part B: explanatory statement, Revenue and expenditure forecasts*, p.10.

Table 3-2 Powercor's 2026–31 capex proposal compared to 2021–26 ($million 2025–26)

Driver	2021-26 actual/ estimate	2026-31 proposal	2026-31 proposal vs 2021-26 actual/ estimate (%)	Proportion of 2026-31 net capex (%)
Replacement	913.4	1,418.9	55.3%	38.9%
Resilience	-	91.6	n/a	2.5%
Augmentation	317.9	550.1	73.0%	15.1%
Connections	440.4	607.7	38.0%	16.6%
Fleet	107.3	105.9	-1.3%	2.9%
Property	143.7	137.8	-4.1%	3.8%
Cyber security	-	13.0	n/a	0.4%
ICT	169.4	277.8	63.9%	7.6%
CER integration	27.6	27.4	-0.6%	0.8%
Other non-network	25.5	28.9	13.3%	0.8%
Capitalised overheads	328.8	392.3	19.3%	10.7%
Total capex (excluding capital contributions)	**2,474.1**	**3,651.4**	**47.6%**	
Less asset disposals	141.5	6.6	-95.3%	
Net capex	**2,332.6**	**3,644.9**	**56.3%**	

Source: Powercor's 2021–26 final decision capex model, Reset RIN, RFM, PTRM, Powercor's 2026–31 proposal capex model, and Powercor's response to information request #03.

Note: As Powercor's cost pass through capex is material for the 2021–26 period, we have not included this in Powercor's 2021–26 actual/estimate capex. Our assessment of Powercor's 2026–31 capex proposal will be based primarily at the individual business case level rather than the capex trend. Powercor's 2021–26 actual/estimate may include cyber security capex in other categories that is not identifiable in the Category Analysis RIN. Powercor's regulatory proposal shows forecast capex for each category and project in $real 2025–26 un-escalated dollars. In this paper, we present all forecast capex for the 2026–31 period in $real 2025–26 escalated dollars

3.4.2.1 Replacement expenditure (repex)

Powercor has proposed repex of $1,418.9 million, which is 55.3% higher than actual/estimated capex in the 2021–26 period. We note Powercor expects to overspend its repex forecast for the 2021–26 period by 58.2%.[49] This indicates that Powercor expects to maintain the higher level of repex it has incurred in the current period.

Powercor explains the higher level of repex is likely to continue due to:[50]

- rising input costs from the impacts of the pandemic and ongoing global supply chain pressures which limits the ability for contract management to mitigate these uplifts
- the longer-term trend of increasing asset replacements of high-volume distribution assets, which is reflective of the characteristics of its underlying asset populations.

We note that Powercor is proposing forecast increases relative to current period spend across all asset classes, with the largest differences in SCADA and comms, overhead conductors, underground cables and transformers.

Powercor states that it will only propose replacement based on risk or condition-based modelling to ensure assets are replaced only when benefit outweighs the costs, given the affordability concerns.[51] It will also propose investment to maintain reliability outcomes as well as gradually increase replacement rates of asset classes where a majority are deteriorating due to condition and load increase.[52]

Consistent with our typical top-down assessment, we will review the outcomes of the AER's repex model to assess how Powercor's forecast modelled repex performs against all other distributors in terms of replacement life and unit rates. As Powercor's modelled repex is 71% of its total repex,[53] the results of the AER's repex model are a reasonable top-down check of Powercor's forecast repex.

3.4.2.2 Resilience

Powercor has proposed resilience expenditure of $91.6 million, including network hardening ($87.2 million) and community support ($4.3 million).[54]

The network hardening program is comprised of installing taller poles to maintain clearance level during floods ($20.7 million), fire resistant concrete poles ($52.0 million), microgrids ($13.1 million) and battery capacity at radio communication sites across the network ($1.5 million).[55]

We also note that some other repex and augex expenditure appears to be resilience-related expenditure.

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49 This calculation does not include cost pass through capex. When factoring in this capex, Powercor expects to overspend its repex forecast by 50.5%.

50 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 42.

51 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 49.

52 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 49.

53 Calculated from the modelled repex categories in Reset RIN table 2.2 and Powercor's total replacement program including resilience.

54 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp 64-65.

55 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp. 64-65.

We will review Powercor's resilience proposals having regard to the AER's Value of Network Resilience (VNR), and guidance note on network resilience.[56]

We also note that the following legislative changes may impact our assessment of Powercor's resilience proposal:

- The AEMC has released a draft determination in February 2025 to amend the NER to explicitly include the consideration of network resilience as an expenditure factor. This draft determination proposes that the rule change would take effect in the Victorian distributors' revised proposals.[57]
- The Victorian Government initiated the 'Electricity Distribution Network Resilience Review' in response to the June and October 2021 storms. The government has supported most of the review's recommendations to boost network and community resilience, including creating obligations for Victorian distributors to propose Network Resilience Plans to strengthen resilience.[58]
- the Victorian Government's support in December 2024[59] for some of the recommendations in the August 2024 Network Outage Review[60] including annually reporting to the Minister for Energy and Resources about its emergency risk management practices including its restoration time such as early deployment of vegetation crews.

3.4.2.3 Augmentation capex (augex)

Powercor forecasts augex of $550.1 million for the 2026–31 period. This is 73.0% higher than actual/estimated capex in the current period. We note Powercor expects to underspend its augex forecast for the 2021–26 period by 9.8%. Powercor notes the cause of the underspend as being better than expected performance from operational solutions to enable solar exports, deferred augmentation works, delays in zone substations and general impacts associated with the pandemic.[61]

Powercor states that the key drivers of demand-driven augmentation for the next period are electrification of gas and transport.[62] Major components of Powercor's proposal include augex on its Greater Western Melbourne Supply Area ($93 million), customer-driven electrification ($100.6 million), feeder upgrades ($14.0 million), regional and rural SWER upgrades ($65.4 million) and alternative supply: SAPS and feeder ties ($19 million).[63]

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56 AER, *Value of Network Resilience 2024*, 30 September 2024; AER, *Note on the key issues of network resilience*, April 2022.

57 AEMC, *Draft rule determination, National Electricity Amendment (Including distribution network resilience in the national electricity rules) Rule*, 13 February 2025.

58 DEECA, *Electricity Distribution Network Resilience Review*, Department of Energy, Environment and Climate Action, Victorian Government, page last updated 11 April 2024, accessed 27 February 2025.

59 Victorian Department of Energy, Environment and Climate Action, *Victorian Government Response to the Network Outage Review*, December 2024.

60 Victorian Department of Energy, Environment and Climate Action, *February 2024 Storm and Power Outage Event – Independent Review of Transmission and Distribution Businesses Operational Response*, Final Report, August 2024.

61 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 31.

62 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 31.

63 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp. 34-43.

Powercor states that the key drivers of non-demand augmentation are its compliance obligations, maintaining systems security, and ensuring safety and reliability for customers.[64] Major components of the proposal include $97.8 million for maintaining REFCL compliance, and $26.2 million for managing bushfire risk.[65]

3.4.2.4 Connections capex

Powercor forecasts net connections capex of $607.7 million for the 2026–31 period. The proposed net connections proposal is 38.0% higher than actual/estimated capex for the 2021–26 period.

We note Powercor expects to overspend its net connections capex forecast for the 2021–26 period by 18.1%. It cites that the actual connection activity exceeding the allowance has placed pressure on the entire capex program given that connections expenditure is not discretionary. Powercor states the growing challenges and impacts of forecasting connections has resulted in its proposal to exclude connections from future capital efficiency sharing scheme (CESS).[66]

Powercor notes its proposed connections capex reflects the strong rebound being experienced in residential connections following the pandemic and an increase in data centre connections.[67]

3.4.2.5 CER integration

Powercor has proposed $27.4 million capex to integrate CER.[68] Of this amount, approximately $22.8 million is for flexible exports to maximise existing hosting capacity, and $1.7 million to develop capabilities to implement flexible load products in the future.[69]

Powercor's CER integration strategy includes using enhanced forecasting capabilities to better understand potential customer and network impacts as well as maximising utilisation of its existing infrastructure and exhausting all possible low-cost solutions. Powercor indicated it had regard to the AER's customer export curtailment value methodology and value of customer reliability when developing its CER proposals.[70]

We note that CER integration and ICT capex are interrelated, with opex also proposed in these areas.

We will review Powercor's proposals having regard to our *DER Integration Expenditure Guidance note* and customer export curtailment value methodology.[71]

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64 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 43.

65 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp. 43-46.

66 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 66.

67 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 66.

68 Powercor's proposal and RIN documents refer to distributed energy resources (DER).

69 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p. 14.

70 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 28.

71 AER, *DER integration expenditure guidance note*, June 2022; AER, *Customer export curtailment value methodology*, June 2022.

3.4.2.6 Information and communications technology (ICT)

Powercor forecasts $277.8 million for ICT capex, which is 63.9% higher than actual/estimated capex from the 2021–26 period. Powercor expects to overspend its ICT capex forecast for the 2021–26 period by approximately 20%.[72]

Powercor's ICT proposal is driven by an increase in non-recurrent ICT ($72.1 million), recurrent ICT capex ($176.3 million) and new compliance requirements related to AEMO's post-2025 NEM market reform program ($29.4 million).[73] Powercor notes the NEM reforms will require significant changes to its IT systems to accommodate the increasing uptake of new technologies, including CER.[74]

Major components of Powercor's recurrent ICT proposal include investing in network management ($39.6 million), an infrastructure refresh ($33.1 million) and the end user device management program ($25.1 million). Powercor's non-recurrent ICT proposal includes $72.1 million for its ERP and billing system replacement program.

3.4.2.7 Contingent projects

Powercor has proposed a $58.0 million contingent project to address demand growth in Point Cook zone substation. Powercor has identified uncertain load growth in this area and may require a zone substation rebuild if specific demand triggers are met.

We will analyse whether the proposed triggers for these projects are objectively verifiable and whether these projects should rightfully be considered contingent projects.

3.4.3 Key drivers of United Energy's capex proposal

United Energy's forecast capex for the 2026–31 period is $1,399.3 million, which is 26.1% higher than its actual/estimated capex for the 2021–26 period. It expects its actual capex in the 2021–26 period to be in line with the forecast. United Energy submits its net capex in the current period will exceed the AER's allowance and will further exceed this allowance after asset disposals are excluded.[75]

Table 3-3 sets out the composition of United Energy's capex proposal for 2026–31; it shows that United Energy is forecasting a step up in most capex categories, relative to the current period. The largest components of forecast capex are repex, ICT, capitalised overheads and augex, with United Energy proposing material increases in these categories.

We discuss United Energy's proposal in the sections below for capex categories that are likely areas of focus for our assessment. This includes its forecasting approach and key drivers.

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72 This is true whether cost pass through capex is factored in or not.

73 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 73.

74 Powercor, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 79

75 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 10.

Table 3-3 United Energy's 2026–31 capex proposal compared to 2021–26 ($million 2025–26)

Driver	2021–26 actual/ estimate	2026–31 proposal	2026–31 proposal vs 2021-26 actual/ estimate (%)	Proportion of 2026–31 net capex (%)
Replacement	431.0	525.4	21.9%	37.3%
Resilience	-	30.7	n/a	2.2%
Augmentation	102.9	153.4	49.1%	10.9%
Connections	53.8	97.0	80.2%	6.9%
Fleet	22.7	64.4	183.2%	4.6%
Property	156.0	17.8	-88.6%	1.3%
Cyber security	-	19.4	n/a	1.4%
ICT	233.7	287.4	22.9%	20.5 %
CER integration	33.5	17.6	-47.6%	1.3%
Other non-network	1.0	1.0	2.1%	0.1%
Capitalised overheads	175.3	187.0	6.7%	13.3%
Total capex (excluding capital contributions)	**1,210.2**	**1,401.1**	**15.8%**	
Less asset disposals	100.2	1.8	-98.2%	
Net capex	**1,109.9**	**1,399.3**	**26.1%**	

Source: United Energy's 2021–26 final decision capex model, Reset RIN, RFM, PTRM, United Energy's 2026–31 proposal capex model and United Energy's response to information request #03.

Note: United Energy's 2021–26 forecast, and actual/estimate includes cost pass through capex of $10 million for ICT. United Energy's 2021–26 actual/estimate may include cyber security capex in other categories that is not identifiable in the Category Analysis RIN. United Energy's regulatory proposal shows forecast capex for each category and project in $real 2025–26 un-escalated dollars. In this paper, we present all forecast capex for the 2026–31 period in $real 2025–26 escalated dollars

3.4.3.1 Replacement expenditure (repex)

United Energy has proposed repex of $525.4 million, which is 21.9% higher than actual/estimated capex from the 2021–26 period. We note it expects to overspend its repex forecast for the 2021–26 period by 12.6%. United Energy states the reasons for the overspend is to reflect rising input costs from the COVID-19 pandemic and ongoing global supply chain pressures.[76]

United Energy notes its forecast repex is mainly driven by an uplift in wood pole and overhead conductor replacements ($131.8 million and $68.6 million respectively), as it forecasted increasing risk in these assets due to their age and condition. It also notes these increases are partially offset by a reduction in zone substation replacement works after significant investment was made in the current and previous periods.[77]

United Energy submits its proposed repex is based on risk or condition-based modelling and on cost-benefit assessment of intervention costs. United Energy states that although pole failures have been relatively low, the failure rate has increased since 2017 and wood pole defects have started to increase.[78] As such, it has proposed a material increase in wood pole replacements in the 2026–31 period in response to these indicators. Regarding overhead conductors, United Energy notes it forecasted that 44% of these assets will have higher risks of failure if there is no intervention before 2031.[79]

Consistent with our typical top-down assessment, we will review the outcomes of the AER's repex model to assess how United Energy's forecast modelled repex performs against all other distributors in terms of replacement life and unit rates. As United Energy's modelled repex is 65% of its total repex,[80] the results of the AER's repex model are a reasonable top-down check of United Energy's forecast repex.

3.4.3.2 Resilience

United Energy has proposed resilience expenditure of $30.7 million. This expenditure relates to building a new zone substation at Shoreham as part of its network hardening program ($26.9 million) and community support ($3.8 million).[81]

The proposed community support program involves deploying additional mobile emergency response vehicles, engaging community support officers and developing improved situational awareness for extreme weather events.[82]

United Energy notes that its approach to resilience is strongly influenced by the Victorian Government's expectations for distribution businesses to improve network resilience.[83]

We will review United Energy's resilience proposals having regard to the AER's Value of Network Resilience (VNR) and guidance on network resilience.[84]

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76 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 39.

77 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 39.

78 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 44.

79 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 45.

80 Calculated from the modelled repex categories in Reset RIN table 2.2 and United Energy's total replacement program including resilience.

81 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp. 53-54.

82 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 54.

83 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp 49–50.

84 AER, *Value of Network Resilience 2024*, 30 September 2024; AER, *Note on the key issues of network resilience*, April 2022.

We also note that the following legislative changes may impact our assessment of United Energy's resilience proposal:

- The AEMC has released a draft determination in February 2025 to amend the NER to explicitly include the consideration of network resilience as an expenditure factor[85]
- The Victorian Government initiated the 'Electricity Distribution Network Resilience Review' in response to the June and October 2021 storms. The government has supported most of the review's recommendations to boost network and community resilience, including creating obligations for Victorian distributors to propose Network Resilience Plans to strengthen resilience.[86]

3.4.3.3 Augmentation expenditure (augex)

United Energy forecasts augex of $153.4 million, which is 49.1% higher than actual/estimated capex from the 2021–26 period. Its actual/estimated expenditure for the current period is expected to be in line with the augex forecast for the 2021–26 period.

A major component of United Energy's proposal includes augex to support its customer-driven electrification program ($70.4 million).[87] United Energy submits the electrification of gas and transport will increase consumption and peak demand across its network, and as such proactive investment in the 2026–31 period will benefit its customers and ensure reliable and secure supply in future periods.[88]

United Energy's augex forecast also includes a new 66kV sub-transmission line in Mornington Peninsula to meet increasing demand and customer growth ($41.1 million).[89] United Energy states this program is more efficient than its current demand management program and will go towards future-proofing growth and electrification of the Mornington Peninsula.[90]

3.4.3.4 Connections capex

United Energy has proposed $97.0 million in net connections capex for the 2026–31 period, which is 80.2% higher than actual/estimated capex from the 2021–26 period. We note United Energy expects to underspend its net connections capex forecast for the 2021–26 period by 61.6%.

The key drivers of connections capex include forecasted additional connection activity (which is underpinned by development to support the Suburban Rail Loop) and growth in connection activity in all customer categories.[91]

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85 AEMC, *Draft rule determination, National Electricity Amendment (Including distribution network resilience in the national electricity rules) Rule*, 13 February 2025.

86 DEECA, *Electricity Distribution Network Resilience Review*, Department of Energy, Environment and Climate Action, Victorian Government, page last updated 11 April 2024, accessed 27 February 2025.

87 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 36.

88 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, pp 35-36.

89 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 34.

90 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 34.

91 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 55.

United Energy also notes it may need to undertake major electrical infrastructure upgrades associated with recent Victorian Government policy announcements regarding housing precincts along key rail corridors. As the timing and locations for these works are uncertain, United Energy has not included these projects in its initial proposal but noted it may submit a revised proposal if needed.[92]

3.4.3.5 Information and communications technology (ICT)

United Energy forecasts $287.4 million for ICT capex, which is 22.9% higher than actual/estimated capex from the 2021–26 period. We note United Energy expects to overspend its ICT capex forecast for the current period by 12.3%.

United Energy's proposal is driven by an increase in recurrent ICT capex ($170.8 million) and non-recurrent ICT ($71.1 million), and new compliance requirements related to AEMO's post-2025 NEM market reform program ($45.5 million).[93] United Energy notes the NEM reforms will require significant changes to its IT systems to accommodate the increasing uptake of new technologies, including CER.[94]

Major components of United Energy's recurrent ICT proposal include network management ($61.1 million) and an infrastructure refresh ($34.2 million).

United Energy's proposed non-recurrent ICT is a material step up from the current period and includes refreshing two of its outdated core ICT systems ($71 million). United Energy noted that moving to modern systems will allow it to support and manage its assets and better integrate new services to customers in light of the energy transition.[95]

Questions on forecast capex

10) Are there any particular areas of CitiPower, Powercor and United Energy's capex proposals that you would expect further engagement on?
11) Do you consider that these proposals reflect consumers' preferences?
12) Do you consider that the areas we have identified for greater assessment focus are appropriate, and, if not, what other areas should be considered and why?
13) Do you have any views on the prudency (need) and efficiency (cost) of any aspects of the proposed capex?

3.5 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require for the efficient operation of its network. Unlike capex, the total forecast opex approved for the 2026–31 period will be

92 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 55.

93 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 61.

94 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 67.

95 United Energy, *Regulatory proposal 2026–31, Part B: explanatory statement*, January 2025, p 66.

recovered within that one period. This means opex has a more immediate impact on revenue than capex.

CitiPower, Powercor and United Energy have all proposed increases in total forecast opex compared to the current period.

- CitiPower has proposed total forecast opex of $586.1 million ($2025–26), including debt raising costs, for the 2026–31 period. This is:
  - $2.5 million (0.4%) lower than the total forecast opex we approved (and used to set revenues) in our decision for the current, 2021–26 period.
  - $115.9 million (24.7%) higher than CitiPower's actual and estimated opex in that period.
- Powercor has proposed total forecast opex of $2,195.7 million ($2025–26), including debt raising costs, for the 2026-31 period. This is:
  - $427.7 million (24.2%) higher than the total forecast opex we approved (and used to set revenues) in our decision for the current, 2021–26 period.
  - $635.4 million (40.7%) higher than Powercor's actual and estimated opex in that period.
- United Energy has proposed total forecast opex of $990.8 million ($2025–26), including debt raising costs, for the 2026–31 period. This is:
  - $87.9 million (9.7%) higher than the total forecast opex we approved (and used to set revenues) in our decision for the current, 2021–26 period.
  - $209.1 million (26.8%) higher than United Energy's actual and estimated opex in that period.

The Handbook sets out our expectations for opex forecasts. In summary:

- the business will use our base-trend-step approach, including our standard assumptions
- step changes will be small in number and well-justified
- category specific costs will be small in number and well-justified
- there should be evidence of genuine consumer engagement.

Based on our initial assessment, these opex proposals adopt our base-step-trend approach. From an estimated base year of 2024–25—which our benchmarking suggests is not materially inefficient for each business—each network has incorporated trends in output and price growth that appear to be consistent with our standard approach. Each business has also applied our standard 0.5% productivity growth forecast.

CitiPower, Powercor and United Energy appear to have applied a genuine approach to consumer engagement in relation to their opex proposals. We are interested in the views of stakeholders on the extent to which the opex proposals for each business addresses the concerns identified by electricity consumers during their engagement processes.

However, the opex proposals each include 6 - 7 step changes, representing a material proportion of total opex forecast (see below for further detail for each business). We consider this is not consistent with our expectation of few or no proposed step changes. Given the materiality of the step change increases, individually and collectively, we propose to prioritise assessment of the proposed step changes. Our assessment will focus on the prudency and efficiency of the proposed costs increases. We will consider potential interactions of these step changes with each other, and with any related proposed capex. We will also test that the proposed additional expenditures are not already accounted for in the base year or captured in the trend forecast used to escalate base opex.

Material step changes are proposed for vegetation management, new ICT capabilities, costs associated with integrating CER into the networks, and the 'customer package' of programs to improve services to customers, especially those at risk of energy poverty integration costs. The most material of these step changes, for vegetation management expenditure, amounts to an additional $339.3 million across the three networks in the 2026-31 period, over and above existing base year vegetation management expenditure.

Vegetation management

CitiPower, Powercor and United Energy submitted that the introduction of new technologies providing faster and more accurate visibility of the network now provides greater visibility of the number of spans that require cutting in order to comply with the Code of Practice for Electric Line Clearance (the Code). The businesses consider that full Code compliance will require cutting approximately an additional 33,000 spans each year on the Powercor network, 5,500 spans on the CitiPower network and 10,000 spans on the United Energy network, compared to cutting activities in 2024–25.

CitiPower, Powercor and United Energy submitted that the vegetation management step changes are required to comply with new regulatory obligations. The businesses submitted that while the Code requirements are deterministic and have not themselves changed, the standard of compliance with these requirements required by law is informed by what is possible, having regard to industry best practice. As industry best practice has evolved during the 2021–26 regulatory period, the standard of Code compliance that is possible has also increased. At the same time, the businesses consider that Energy Safe Victoria has become more active in its enforcement activities as vegetation management capabilities have developed and is holding the networks to the higher standard of compliance now required. This results in a large potential exposure to fines from ESV enforcement action due to the number of non-compliances identified at the time of inspection during any one season.

We welcome views from stakeholders on the prudency and efficiency of these proposed step change costs, including with regard to the businesses' characterisation of their vegetation management regulatory obligations; the scope of and timing of the proposed increase in vegetation management activity (including with regard to deliverability); and the efficiency of proposed expenditure.

Each business has also proposed 3 category specific forecasts (for Guaranteed Service Level (GSL) payments, innovation, and debt raising costs). For GSL payments and debt raising costs, the businesses have adopted our standard approach for forecasting these costs. At this stage, we intend to focus our assessment on the proposed network innovation category specific forecasts, as this is a new category of expenditure for the 2026–31 period.

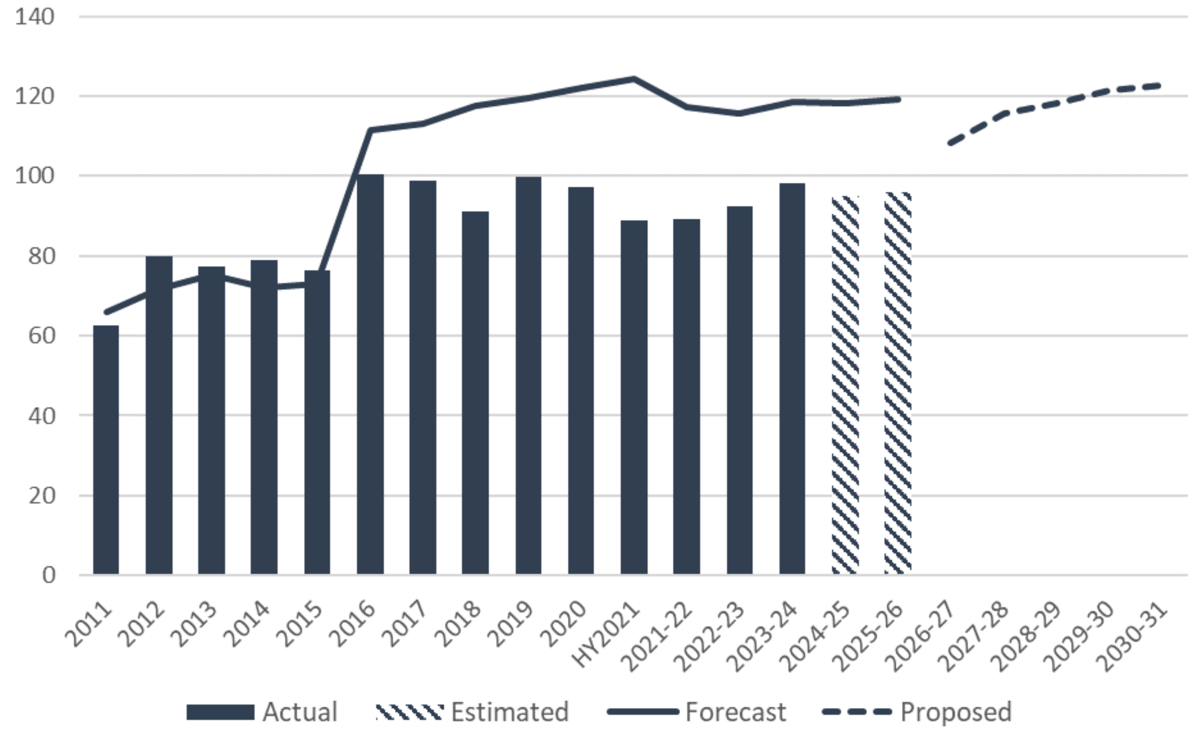
We provide further detail on the drivers of total forecast opex for each business below.

3.5.1 Key drivers of CitiPower's opex proposal

Figure 3-14 shows the trend in CitiPower's opex over time and the AER's approved opex forecast.

CitiPower's actual opex increased noticeably from 2015–16 and has stayed relatively constant since, and consistently well below the AER's approved opex forecast.

Figure 3-14 Trend in forecast and actual opex over time – CitiPower ($million, 2025–26)



Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis

CitiPower used an estimate of opex in 2024–25 as the base year to forecast opex ($94.8 million or $474.1 million over 5 years). It chose 2024–25 as the proposed base year, stating this year will be the most recent year with audited actual data by the time of our final decision. It then:

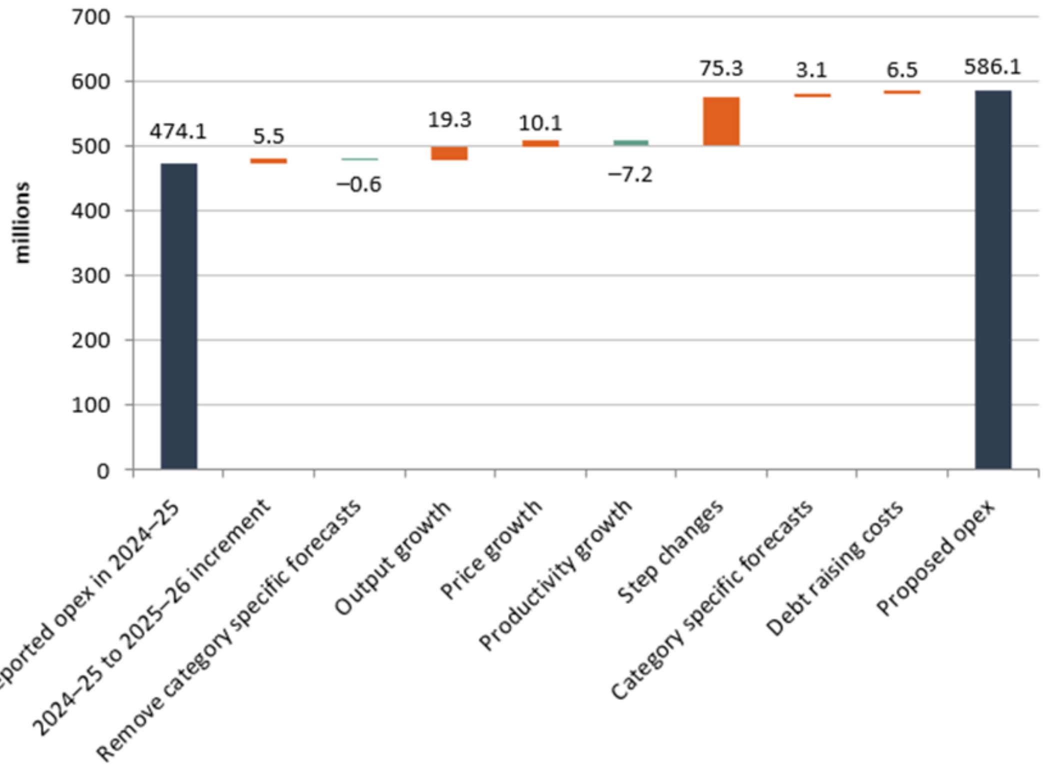
- added $5.5 million to reflect the change in opex between the base year (2024–25) and final year (2025–26), using the approach outlined in the *Expenditure Forecast Assessment Guideline*
- removed $0.6 million of category specific costs, which are forecast separately
- applied a rate of change consistent with our standard approaches, comprised of:
  - forecast growth in the real price of inputs, averaging 0.7% per year ($10.1 million)
  - forecast output growth, averaging 1.5% per year ($19.3 million)
  - forecast productivity growth, averaging 0.5% per year (–$7.2 million)
- added 6 step changes (including one negative step change) totalling $75.3 million:
  - $33.6 million for vegetation management
  - $12.3 million for CER integration

- $11.6 million for ICT modernisation and new capability
- $11.3 million for cloud services
- $6.8 million for its customer assistance package
- - $0.2 million for fleet electrification

- added category specific forecasts totalling $9.6 million, comprised of:
  - $0.3 million for GSL payments
  - $2.9 million for network innovation
  - $6.5 million for debt raising costs.

Figure 3-15 how the components discussed above are contributing to CitiPower's proposed opex forecast.

Figure 3-15 Breakdown of CitiPower's opex forecast ($million, 2025–26)



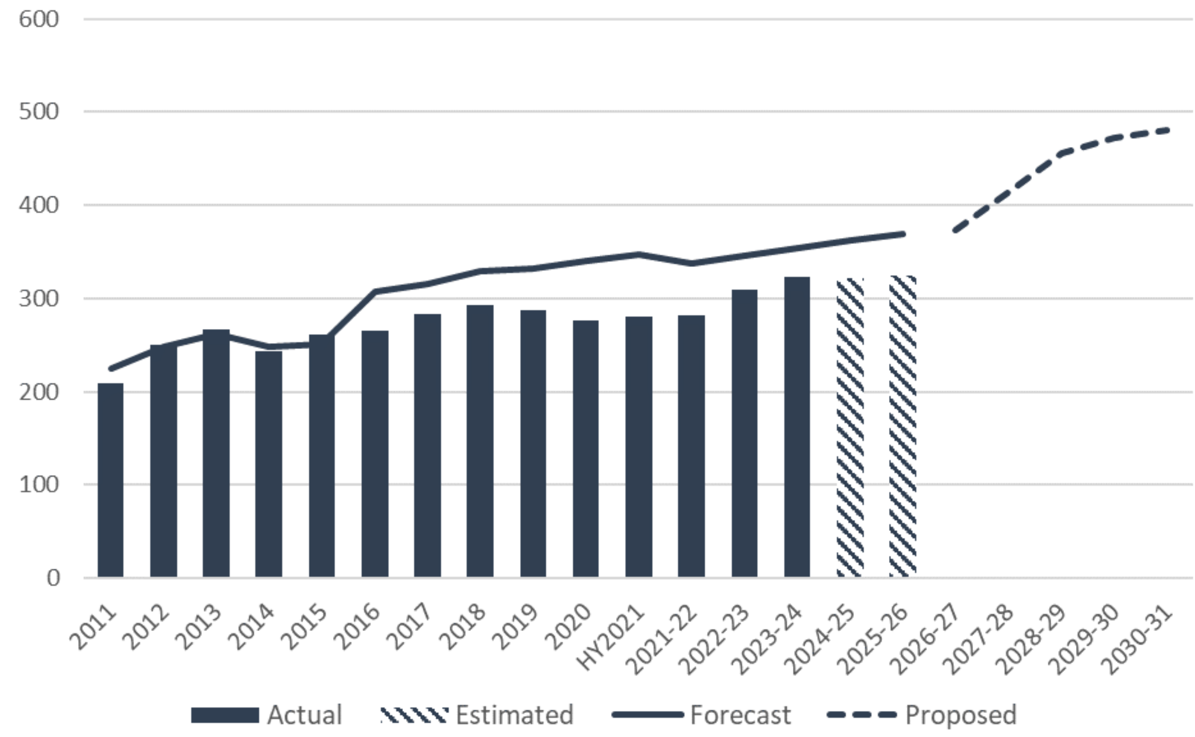
Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.

3.5.2 Key drivers of Powercor's opex proposal

Figure 3-16 shows the trend in Powercor's opex over time and the AER's approved opex forecast.

Powercor's actual opex remained relatively stable from 2016 to 2021–22 but has seen a noticeable increase in the last four years. Powercor's actual opex has remained below the AER's approved opex forecast since 2016.

Figure 3-16 Trend in forecast and actual opex over time – Powercor ($million, 2025–26)



Source: Powercor, *PAL MOD 1.05 – Opex*, January 2025; AER analysis

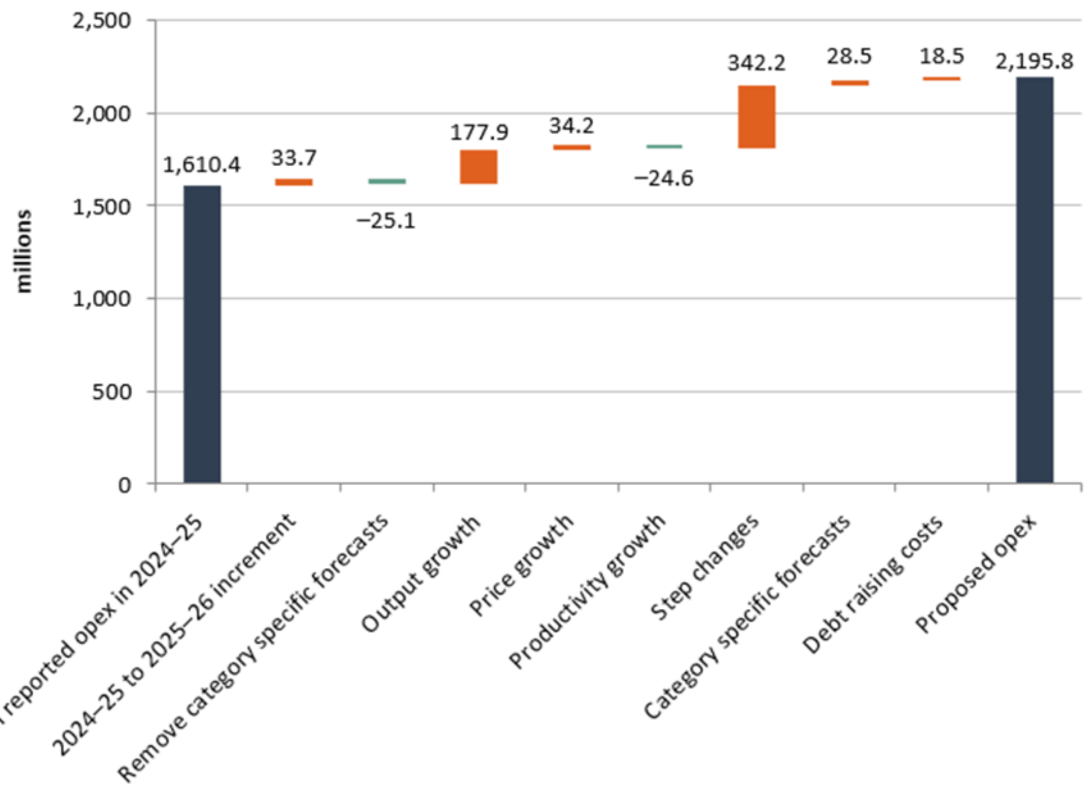
Powercor used an estimate of opex in 2024–25 as the base year to forecast opex ($322.1 million or $1,610.4 million over five years). It chose 2024–25 as the proposed base year, stating this year will be the most recent year with audited actual data by the time of our final decision. It then:

- added $33.7 million to reflect the change in opex between the base year (2024–25) and final year (2025–26), using the approach outlined in the *Expenditure Forecast Assessment Guideline*
- removed $25.1 million of category specific costs, which are forecast separately
- applied a rate of change consistent with our standard approaches, comprised of:
  - forecast growth in the real price of inputs, averaging 0.7% per year ($34.2 million)
  - forecast output growth, averaging 3.3% per year ($177.9 million)
  - forecast productivity growth, averaging 0.5% per year (–$24.6 million)
- added 7 step changes (including one negative step change) totalling $342.2 million:
  - $232.9 million for vegetation management
  - $28.7 million for CER integration
  - $22.0 million for ICT modernisation and new capability
  - $26.1 million for cloud services
  - $26.7 million for its customer assistance package
  - $6.8 million for network and community resilience
  - - $1.0 million for fleet electrification
- added category specific forecasts totalling $47.0 million, comprised of:

- $20.6 million for GSL payments
- $7.9 million for network innovation
- $18.5 million for debt raising costs.

Figure 3-17 shows how the components discussed above are contributing to Powercor's proposed opex forecast. While the proposed step changes are the main driver of higher forecast opex, the output growth trend factor is also a significant contributor. Output growth captures forecast changes in customer numbers, circuit length and ratcheted maximum demand. We will assess the drivers of Powercor's forecast output growth in the 2026–31 period, which is above recent historical levels of growth for its network.

Figure 3-17 Breakdown of Powercor's opex forecast ($million, 2025–26)



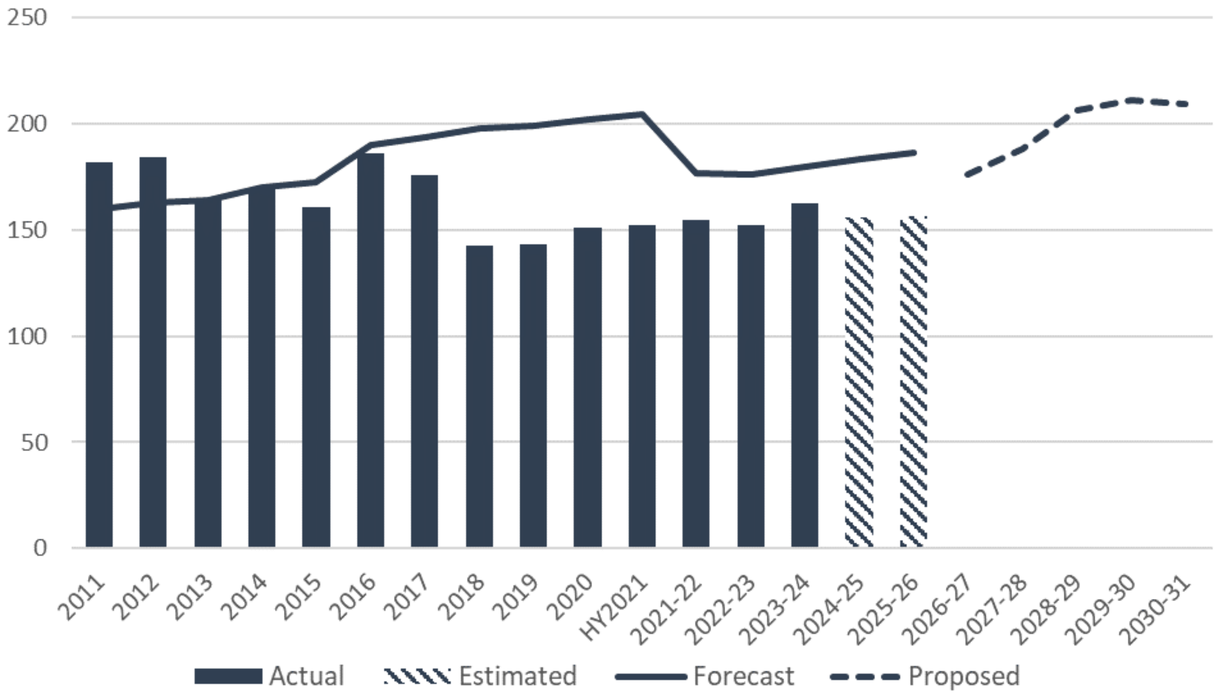
Source: Powerlink, *PAL MOD 1.05 – Opex*, January 2025; AER analysis.

3.5.3 Key drivers of United Energy's opex proposal

Figure 3-18 shows the trend in United Energy's opex over time and the AER's approved opex forecast.

Since 2016–17, United Energy's actual opex has consistently been lower than our respective annual opex forecast, while its actual opex has remained relatively stable since 2017–18, after noticeably declining since 2016.

Figure 3-18 Trend in forecast and actual opex over time – United Energy ($million, 2025–26)



Source: United Energy, *UE Mod 1.05 – opex*, January 2025; AER analysis.

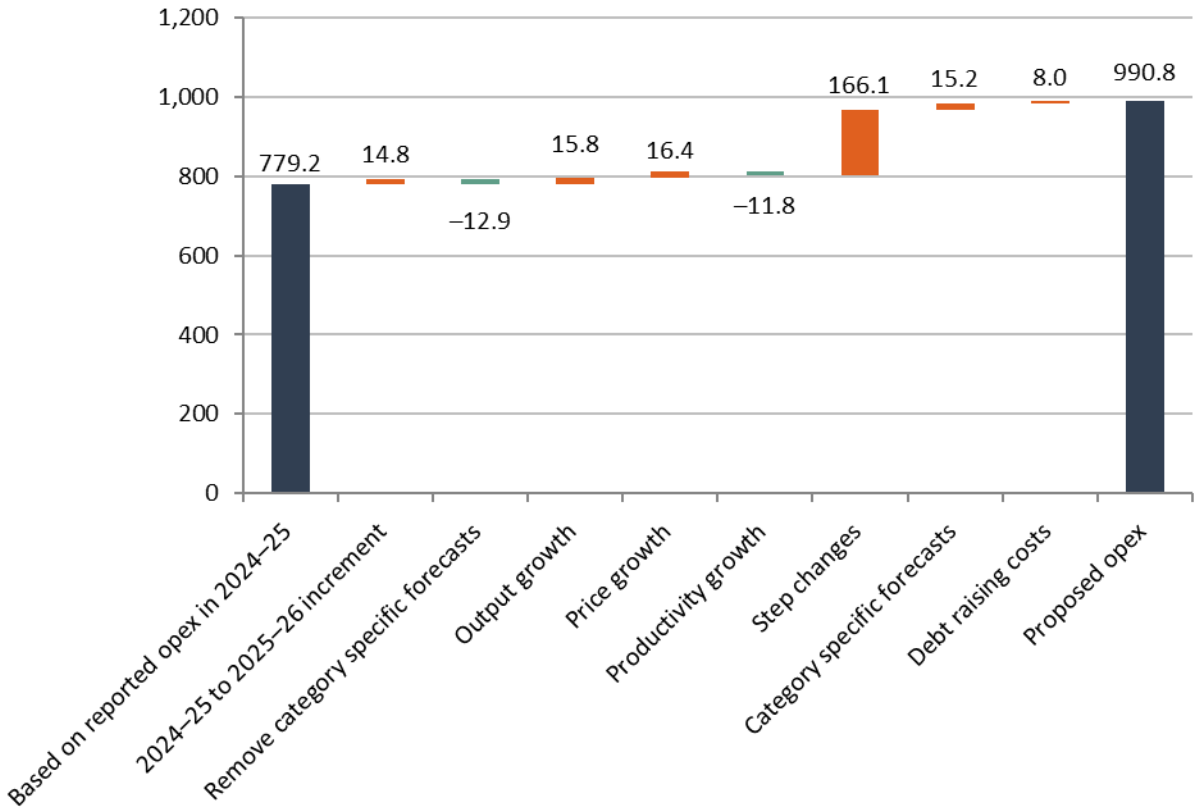
United Energy used an estimate of opex in 2024–25 as the base year to forecast opex ($155.8 million, or $779.2 million over 5 years). It chose 2024–25 as the proposed base year, stating this year will be the most recent year with audited actual data by the time of our final decision. It then:

- added $14.8 million to reflect the change in opex between the base year (2024–25) and final year (2025–26), using the approach outlined in the *Expenditure Forecast Assessment Guideline*
- removed $12.9 million of category specific costs, which are forecast separately
- applied a rate of change consistent with our standard approaches, comprised of:
  - forecast growth in the real price of inputs, averaging 0.7% per year ($16.4 million)
  - forecast output growth, averaging 0.9% per year ($15.8 million)
  - forecast productivity growth, averaging 0.5% per year (–$11.8 million)
- added 7 step changes (including one negative step change) totalling $166.1 million:
  - $72.3 million for vegetation management
  - $31.6 million for ICT modernisation and new capability
  - $24.3 million for cloud services
  - $18.9 million for CER integration
  - $14.7 million for its customer assistance package
  - $4.4 million for network and community resilience
  - –$0.2 million for fleet electrification
- added category specific forecasts totalling $23.2 million, comprised of:

- $9.2 million for GSL payments
- $6.0 million for network innovation
- $8.0 million for debt raising costs.

Figure 3-19 shows how the components discussed above are contributing to United Energy's proposed opex forecast.

Figure 3-19 Breakdown of United Energy's opex forecast ($million, 2025–26)



Source: United Energy, UE Mod 1.05 – opex, January 2025; AER analysis.

Questions on opex

14) Are there any particular areas of the opex proposals that you would expect further engagement on?

15) Do you consider that these proposals reflect consumers' preferences?

16) Do you consider that the areas we have identified for greater assessment focus are appropriate, and, if not, what other areas should be considered and why?

17) Do you have any views on the prudency (need) and efficiency (cost) of any aspects of the proposed opex?

3.6 Revenue adjustments under AER incentive schemes

Our calculation of total revenue for 2026–31 for each network will include adjustments for the expenditure incentive schemes (the Capital Expenditure Sharing Scheme (CESS) and opex

Efficiency Benefit Sharing Scheme (EBSS)) that were applied to CitiPower, Powercor and United Energy as part of our determination for the 2021–26 period.

These adjustments are summarised below and are intended to provide a fair sharing of any efficiency gains (or losses) derived from spending less (or more) than our approved forecasts or capex and opex with customers.

Table 3-4 Revenue adjustments accrued under the CESS and EBSS in 2021-26 ($million, 2025-26)

Network	CESS adjustment[96]	EBSS adjustment
CitiPower	$10.6 million	-$2.3 million
Powercor	-$90.3 million[97]	-$28.8 million
United Energy	-$9.8 million	$55.1 million

Source: CitiPower, *CP MOD 1.01 - SCS PTRM*, January 2025; Powercor, *PAL MOD 1.01 - SCS PTRM*, January 2025; United Energy, *UE MOD 1.01 - SCS PTRM*, January 2025.

CitiPower, Powercor and United Energy's proposals for the application of the CESS and EBSS to their expenditure in the 2026–31 period is discussed in section 4.

CitiPower, Powercor and United Energy have also proposed that their regulated revenue for 2026–31 includes the following allowances 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:[98]

Table 3-5 Proposed DMIAM allowances for 2026–31 ($million, 2025–26)

CitiPower	Powercor	United Energy
$2.31 million	$5.18 million	$3.33 million

Source: CitiPower, *CP MOD 1.01 - SCS PTRM*, January 2025; Powercor, *PAL MOD 1.01 - SCS PTRM*, January 2025; United Energy, *UE MOD 1.01 - SCS PTRM*, January 2025.

Note: Consistent with the design of the DMIAM, this allowance is included in each revenue proposal as a positive revenue adjustment.

Distributors may use assets to provide both the standard control services we regulate and unregulated services, for example by the stringing of telecommunications cables on the electricity network poles for the provision of telecommunication services. These assets are called shared assets. If the revenue from shared assets is material, 10% of the unregulated

96 The CESS adjustments are based on CitiPower, Powercor and United Energy's total actual/estimated expenditure for the 2021-26 period. This does not include Year 2020 true-up adjustments.

97 This amount represents the figures reported in Powercor's CESS model and post-tax revenue model. We note a discrepancy between the amount reported in Powercor's proposal and its CESS model. We are seeking further information from Powercor.

98 We developed and implemented the DMIAM under cl. 6.6.3A of the NER: [AER - Demand management innovation allowance mechanism - 14 December 2017](#).

revenues that a distributor earns from shared assets will be used to reduce the distributor's revenue for standard control services.[99]

CitiPower and United Energy have included revenue adjustments (reductions) of -$2.9 million and -$4.7 million ($2025–26), respectively, because their forecast annual unregulated revenue from shared assets has exceeded our materiality threshold. We will assess whether these proposed adjustments are reasonable based on our shared asset guideline.

3.7 Corporate income tax

Our determinations of the total revenue requirement for each of CitiPower, Powercor and United Energy will include the estimated cost of corporate income tax for the 2026–31 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our post-tax revenue model (PTRM).

CitiPower, Powercor and United Energy's proposals include $64.3 million, zero and $22.8 million ($ nominal) respectively for the estimated costs of corporate income tax over the 2026–31 period. They have each:

- proposed to maintain their approach to immediately expensed capex, consistent with methodology applied in the 2021–26 determinations, updated for overhead rates and 2026–31 forecast capex. The proposed amounts for immediately expensed capex are $504.0 million for CitiPower, $1838.4 million for Powercor and $683.3 million for United Energy ($ nominal)
- adopted the diminishing value method for tax depreciation to all forecast capex, except for a limited number of assets which must be depreciated using the straight-line depreciation method under the tax law
- applied the same tax asset lives from the 2021–26 regulatory determination.

We will assess the appropriateness of the proposed amounts of immediate expensing and capex allocated for straight-line depreciation, based on the approach we have taken in recent determinations.

3.8 Uncertainty mechanisms

Our decisions on CitiPower, Powercor and United Energy's proposals will set the revenue allowance that forms the major component of their network charges for the next 5 years. They provide 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. These include cost pass through events or contingent project such as those proposed by CitiPower and Powercor. The triggers set out for these events (either in the NER or in our determination) will, if met, allow CitiPower, Powercor and United Energy to apply for additional revenue throughout the period, at which point proposed costs will be subject to further consultation and assessment. In limited circumstances they may also apply

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99 AER, *Shared asset guideline*, November 2013, Appendix A, p. 15.

to reopen our determination for further capex[100], as Jemena has done during the current period.[101]

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. The prescribed cost pass through events (regulatory change event, service standard event and tax change event) apply to all distributors.

In addition to the NER prescribed pass through events, CitiPower, Powercor and United Energy have proposed eight nominated pass through events. Of these, five 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).

The following events would be new inclusions for the 2026-31 period:

- *Fault level event*—Network businesses are subject to regulatory obligations requiring them to ensure that all parts of the network are operating within applicable fault level limitations. CitiPower, Powercor and United Energy submitted that in recent years, the number of areas on the networks that are operating above, or approaching, their fault level limit has significantly increased. This is primarily a result of the number of new generation projects AusNet and AEMO are connecting to the 220kV transmission network.

  The networks consider there is a risk that the connection of either synchronous condensers or new generation to parts of the 220kV transmission network will increase the fault level on areas of the distribution network to the extent that those areas exceed their applicable fault level limit. The network businesses have therefore proposed including a fault level pass through event in the 2026-31 distribution determinations, to enable them to recover the prudent and efficient costs of works required to correct a fault level exceedance if a transmission connection causes an area of the network to begin operating at fault levels above applicable limits.

- *AEMO participant fee event*—AEMO recovers its budgeted revenue requirements from NEM market participants through participant fees. The allocation of participant fees is set every 5 years, with the next period beginning from 1 July 2026.

  AEMO's next participant fee review is scheduled to commence in early 2025, ahead of a 1 July 2026 start. The network businesses submitted that the timing of this review will not allow them to account for any fee imposed by AEMO in their revised proposals for the 2026–31 period. Additionally, the NER permits AEMO to determine a separate fee to recover the costs of specific projects (declared NEM projects) during the term of a participant fee structure determination. Accordingly, AEMO could impose further fees on distributors in the 2026–31 regulatory period, in addition to any annual fees imposed in its 2025-26 determination.

[100] NER, cl. 6.6.5.

[101] https://www.aer.gov.au/industry/registers/determinations/jemena-determination-2021-26/update-application-reopen-capex

The network businesses have therefore proposed the AEMO participant fee event to capture the fees that may be imposed by AEMO as part of its 2025-26 participant fee review process, and any additional fees imposed in respect of a declared NEM project.

- *Electrification event*—The network businesses have proposed an electrification pass through event to address the uncertainty resulting from the energy transition, particularly in respect of the timing and pace at which electrification will occur.

  The businesses submitted that achieving emissions reductions targets will require significant changes in energy consumption. The Victorian Government has already announced and introduced some restrictions on the use of natural gas and moves towards electrification, which are not fully reflected in their consumption, demand and expenditure forecasts for the 2026–31 period. As the businesses are unable to reflect all existing and future measures in expenditure forecasts for the 2026–31 regulatory period, they submitted that it is appropriate to account for future measures leading to increased electricity consumption via the pass through mechanism, rather than in forecast capex. This is one way of addressing uncertainty in forecast demand, outside of the ex-ante expenditure forecasts.

Our assessment will focus on the three new nominated cost pass through events, to consider whether these should be included as nominated events for the 2026-31 period, with regard to the nominated pass through considerations defined in chapter 10 of the NER.

Questions on uncertainty mechanisms

18) Do you have any feedback on the new nominated costs pass through events?

4 Incentive schemes to apply in 2026-31

Incentive schemes are a component of the incentive framework to setting maximum revenues 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 decision as to which schemes will apply to CitiPower, Powercor and United Energy in 2026-31, and how each scheme will apply, is made as part of our determination and takes effect from the commencement of the new regulatory control period. This establishes the parameters for rewards and penalties upfront to provide certainty and clear incentives to businesses.

4.1 Capital expenditure sharing scheme (CESS)

The CESS 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, Powercor and United Energy have proposed to continue applying the CESS to standard control services in accordance with our current Capital Expenditure Incentive Guideline over the 2026–31 regulatory period.[102]

However, CitiPower, Powercor and United Energy proposed to exclude the innovation and connection capex categories from the CESS calculations.[103]

Our current CESS guideline does not allow specific capex categories to be excluded from the application of the CESS.[104]

We are currently undertaking a review of the Capital Expenditure Incentive Guideline to accommodate the Australian Energy Market Commission's rule change on managing ISP project uncertainty through targeted ex post reviews.[105] As part of this review we are also considering whether to modify the CESS to allow specific capex categories to be excluded from the CESS.[106] We are required to complete this review by 4 September 2025.[107] Any changes to the CESS will be applied in our draft determination for 2026-31 regulatory control period.

102 AER, *Final decision – Capital expenditure incentive guideline*, April 2023

103 CitiPower, *Regulatory Proposal 2026-31 – Part B Explanatory Statement*, January 2025, p. 84; Powercor, *Regulatory Proposal 2026-31 – Part B Explanatory Statement*, January 2025, p. 100; United Energy, *Regulatory Proposal 2026-31 – Part B Explanatory Statement*, January 2025, p. 85.

104 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, July 2024.

105 AEMC, *Managing ISP project uncertainty through targeted ex post reviews*, August 2024

106 AER, *Capital Expenditure Incentive Guideline Review 2025*.

107 NER, cl. 11.172.2(a).

We are interested in seeking stakeholder views on the proposed exclusions from the CESS.

Questions on CESS

19) Do you have any concerns with the application of the CESS for CitiPower, Powercor and United Energy in the 2026-31 regulatory period?

20) Do you consider there is need to modify the application of the CESS to allow CESS exclusions on certain capex categories? Please explain why.

21) If we were to modify the application of CESS, what factors should we consider in determining whether specific capex should be excluded from the CESS?

4.2 Opex Efficiency benefit sharing scheme (EBSS)

The Efficiency Benefit Sharing Scheme (EBSS) provides a continuous incentive to pursue efficiency improvements in opex and provide for a fair sharing of these between the business and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods.

CitiPower, Powercor and United Energy proposed to continue to apply the EBSS in the 2026–31 regulatory control period, subject to removing categories of opex not forecast using a single year revealed cost approach including:

- debt raising costs
- the demand management innovation allowance
- GSL payments
- innovation fund allowance.

These exclusions are consistent with our previous determinations.

Questions on EBSS

22) Do you have any feedback on the application of the EBSS for CitiPower, Powercor and United Energy in the 2026-31 regulatory control period?

4.3 Demand management incentive scheme (DMIS) and Demand management innovation allowance mechanism (DMIAM)

The DMIS provides network businesses with financial incentives for undertaking efficient demand management activities as an alternative to more expensive capital investment in their networks, the costs of which have longer term impacts on consumers.

The DMIAM works alongside the DMIS to fund research and development into further, innovative demand management projects that have the potential to reduce long term network costs.

CitiPower, Powercor and United Energy have proposed to continue to apply the DMIS and DMIAM in the 2026-31 regulatory control period.[108]

CitiPower, Powercor and United Energy have not identified any projects suitable for inclusion under the DMIS in the current regulatory period. However, they have proposed to have access to the DMIS in the next regulatory period as opportunities may arise.

In the current period, CitiPower, Powercor and United Energy used the DMIAM to:

- CitiPower – trial new network tariffs, research the effectiveness of residential demand management, and implement a low voltage DERMS and flexible exports trial.
- Powercor – trial new network tariffs, research the effectiveness of residential demand management, install neighbourhood battery and research and modelling to better understand the impacts of electrification for commercial and industrial customers.
- United Energy – trial new network tariffs and electric vehicle hotspots and investigate the technical and commercial feasibility of using pole-mounted batteries.

CitiPower, Powercor and United Energy have proposed the following maximum allowances for the DMIAM for the 2026-31 regulatory period:

- CitiPower - $2.73 million[109]
- Powercor - $5.08 million[110]
- United Energy - $3.38 million[111]

4.4 Service target performance incentive scheme (STPIS)

The STPIS provides financial incentives for network businesses to maintain and improve network reliability and customer service performance, to the extent that consumers are willing to pay for such improvements. The STPIS acts as a balance to our expenditure incentive schemes, ensuring businesses focus on genuine efficiency gains and do not compromise service levels when reducing expenditure. Penalties and rewards under the STPIS are set based on consumers' willingness to pay for improved service.

The STPIS that applies to Victorian distributors, including CitiPower, Powercor and United Energy, consists of a service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services.[112] This scheme rewards distributors for improved service compared to predetermined targets, or penalises them for diminished service.

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

109 CitiPower Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025, p.86

110 Powercor Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025, p. 103

111 United Energy Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025, p. 88

112 While our STPIS also allows for a guaranteed service level (GSL) component—under which direct payments are made by distributors to customers experiencing service below a predetermined level—we only apply this component if there is not another GSL scheme already in place. The GSL component of our STPIS will **not** apply to CitiPower, Powercor or United Energy, because Victorian businesses remain subject to a jurisdictional GSL scheme established and administered by the Essential Services Commission of Victoria, which serves the same purpose.

Targets relate to service parameters concerning reliability and quality of supply, and customer service.

As in the current period, CitiPower, Powercor and United Energy have proposed that the Customer Service (telephone answering) component of the STPIS will not apply if we accept their proposed Customer Service Incentive Schemes (CSIS) for the 2026-31 period. We discuss the proposed CSIS further below.[113]

If the CSIS is applied, CitiPower, Powercor and United Energy are seeking to split the revenue at risk under the two schemes as follows:

- ±4.5% for STPIS (reliability component only); and
- ±0.5% for the proposed CSIS.

This is the same allocation that applied in the current, 2021-26 period.

Questions on STPIS

23) Do you have any views on the proposed allocation of revenue at risk between the STPIS and the CSIS?

4.5 Customer service incentive scheme (CSIS)

The CSIS is designed to encourage electricity distributors to engage with their customers to:

- identify the customer services their customers want improved, and
- set targets to improve those services based on their customers' preferences and support.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers. It allows for the evolution of customer engagement and adapts to new technologies. Safeguards ensure that any rewards or penalties are commensurate with improvements or detriments to customer service. For the CSIS to be applied, incentive designs must meet the scheme's principles and be developed through genuine customer engagement.

We support the application of a CSIS where a distributor's CSIS proposal contains an incentive design that meets the scheme's principles, includes a sound measurement methodology, and comes with evidence of supporting customer engagement on, and co-design of, the CSIS.[114]

113 CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 84-85; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 100-101; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 85-86

114 AER, *Framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, July 2024, p.19.

4.5.1 CitiPower

This is the second regulatory period for which CitiPower is proposing a CSIS. In the first three years of the current, 2021-26 regulatory period, CitiPower met performance measures for the two parameters included in its original CSIS, which were:

- Grade of Service – measured by percentage of fault calls answered within 30 seconds. CitiPower's target was 87.4%, and its performance was 94.2% in 2021-22, 95.1% in 2022-23, and 94.4% in 2023-24.
- SMS delivery – measured by percentage of SMS delivered within six minutes of an unplanned outage. CitiPower's target was 57.4%, and its performance was 68.7% in 2021-22, 74.5% in 2022-23, and 66.2% in 2023-24.

CitiPower's proposed CSIS for 2026-31 has been developed in consultation with customers and CitiPower's Customer Advisory Panel (CAP).[115] In light of positive performance against the 2021-26 CSIS measures, CitiPower has asked AER to consider minor changes to its CSIS to expand its original parameters. These are:

- Grade of service – CitiPower has proposed expanding this parameter to cover both fault calls and general enquiries and applying a new performance target of 73.4%, with a maximum penalty of 65.9% and a maximum incentive of 80.9%. CitiPower also proposed amending the weighting of this parameter from 0.25% to 0.30% and retaining its incentive rate of 0.04 (meaning for every 1% improvement on the baseline CitiPower will receive 0.04% of revenue.)
- SMS notification – CitiPower has proposed increasing the baseline target of this parameter to 69.5%, with a maximum penalty of 64.5% and a maximum incentive of 74.5%. CitiPower also proposed reducing the revenue at risk attached to this measure from 0.25% to 0.20, on the basis that large improvements have been made, limited additional investments are possible, and that this revenue incentive would be better aligned with further improvements to grade of service.

CitiPower has proposed a total revenue at risk of 0.5% of its annual revenue requirement.

Questions on CitiPower's proposed CSIS

24) Do you have any feedback on the design of CitiPower's proposed CSIS?

25) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 73.4% from 87.4%?

26) Do you do you have views on the amended weighting of the SMS notification parameter from 0.25% to 0.20%, on the basis that CitiPower thinks room for additional improvements is limited?

27) Do you have any views on CitiPower's engagement on the design of its CSIS?

[115] CitiPower, *Attachment 9.01 – Customer Service Incentive Scheme*, January 2025

4.5.2 Powercor

Like CitiPower, Powercor's 2026-31 CSIS proposal also builds on targets set in its original 2021-26 CSIS, having met performance measures for its three listed parameters:

- Grade of service – measured by percentage of fault calls answered within 30 seconds. This measure was weighted at 0.20%. Powercor's target was 82.3%, and its performance was 88.1% in 2021-22, 89.5% in 2022-23, and 87.8% in 2023-24.
- Planned outages – measured by both number of outages and minutes off supply for planned outages. This measure was weighted at 0.15%.
  - Powercor's target for average outage frequency was 0.32 planned interruptions per customer. Their performance was 0.24 in 2021-22, 0.31 in 2022-23, and 0.28 in 2023-24.
  - Powercor's target for average minutes off supply was 65.98 per customer. Their performance was 48.77 in 2021-22, 70.56 in 2022-23, and 56.79 in 2023-24.
- SMS delivery – measured by percentage of initial 'aware' SMS messages (alerting customers to unplanned outage and including estimated time for restoration) which are delivered within six minutes of an unplanned outage. This measure was weighted at 0.15% CitiPower's target was 63.1%, and its performance was 76.6% in 2021-22, 77.0% in 2022-23, and 74.1% in 2023-24.

Powercor's 26-31 proposed CSIS incentive design expands existing performance measures towards targets developed through customer engagement and refined by CitiPower's Customer Advisory Panel (CAP).[116] These changes comprise:

- Grade of service – Like CitiPower, Powercor has proposed expanding this parameter to cover both fault calls and general enquiries and applying a new performance target of 71.9%, with a maximum penalty of 65.6% and a maximum incentive of 78.1%. Powercor also proposed amending the weighting of this parameter from 0.20% to 0.25% and retaining its incentive rate of 0.04 (meaning for every 1% improvement on the baseline Powercor will receive 0.04% of revenue.)
- Planned outages – Powercor has proposed adapting the planned outages measure so that these calculate the number of outages and minutes off supply for a given outage incident, rather than measuring the numbers and minutes for overall outages across the network which has the unintended effect of penalising large scale network upgrades that improve service. Powercor points out in its CSIS attachment that in the 2022/23 financial year it carried out its largest planned work program across the three measured years, and because of this did not meet its target for that year. Further detail on Powercor's proposed new measurement methodology is contained in its CSIS Attachment.[117] Powercor has proposed maintaining the revenue at risk attached to this measure at 0.15% and reducing the incentive by 50% to account for the fact that customers are likely to value reliability related to unplanned outages higher than planned outages.

116 Powercor, Attachment 10.01 – Customer Service Incentive Scheme, January 2025

117 Powercor, Attachment 10.01 – Customer Service Incentive Scheme, January 2025, p14.

  - Powercor's 2026-31 target for average outage frequency is 0.278, with a maximum penalty of 0.295 and a maximum incentive of 0.26.
  - Powercor's 2026-31 target for average minutes off supply is 58.81 minutes per customer, with a maximum penalty of 61.23, and a maximum incentive of 56.41.
- SMS delivery – Powercor has proposed increasing the baseline target of this parameter to 75.8%, with a maximum penalty of 73.4% and a maximum incentive of 78.4%. Powercor also proposed reducing the revenue at risk attached to this measure from 0.15% to 0.10%, on the basis that large improvements have been made, limited additional investments are possible, and that this revenue incentive would be better aligned with further improvements to grade of service.

Powercor has proposed a total revenue at risk of 0.5% of its annual revenue requirement. Powercor's proposed 2026-31 CSIS parameters are not subject to other incentive payments.

Questions on Powercor's proposed CSIS

28) Do you have any feedback on the design of Powercor's proposed CSIS?

29) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 71.9% from 82.3%?

30) Do you have views on the amended weighting of the SMS notification parameter from 0.15% to 0.10%, on the basis that additional improvements are limited?

31) Do you have views on Powercor's proposed new targets and methodology for the calculation of planned outage numbers and minutes off supply?

32) Do you have any views on Powercor's engagement on the design of its CSIS?

4.5.3 United Energy

United Energy has also performed well against the three parameters listed in its 2021-26 CSIS:

- Grade of service – measured by percentage of fault calls answered within 30 seconds. This measure was weighted at 0.20%. United Energy's target was 75.2%, and its performance was 81.1% in 2021-22, 83.0% in 2022-23, and 82.5% in 2023-24.
- Planned outages – measured by both number of outages and minutes off supply for planned outages. This measure was weighted at 0.15%.
  - United Energy's target for average outage frequency was 0.234 planned interruptions per customer. Their performance was 0.18 in 2021-22, 0.23 in 2022-23, and 0.28 in 2023-24.
  - United Energy's target for average minutes off supply was 73.81 per customer. Their performance was 54.58 in 2021-22, 69.28 in 2022-23, and 63.86 in 2023-24.
- SMS delivery – measured by percentage of initial 'aware' SMS messages (alerting customers to unplanned outage and including estimated time for restoration) which are delivered within six minutes of an unplanned outage. This measure was weighted at 0.15% United Energy's target was 60.3%, and its performance was 63.7% in 2021-22, 83.2% in 2022-23, and 62.7% in 2023-24.

United Energy's proposed 2026-31 CSIS incentive design expands existing performance measures towards targets developed through customer engagement and refined by United Energy's Customer Advisory Panel (CAP).[1] Its proposed measures include:

- Grade of service, calls answered within 30 seconds – United Energy has proposed to expand this parameter to cover both fault calls and general enquiries. United Energy proposed to apply a target of 66.7%, down from its previous target of 75.2%. This is to take consideration of the expanded measure that previously did not include general enquiry calls. United Energy proposed to amend the weighting of this parameter from 0.20% to 0.25%.
- Planned outages – United Energy has adjusted this measure's methodology to capture the number and minutes of supply for a given outage, rather than for total outages. This change was undertaken to better align the metric with productivity gains and losses at an individual outage level. United Energy's proposed targets for its planned outage measure are 62.38 (SAIDI) and 0.21 (SAIFI). The targets have been calculated using historical 3-year performance of planned SAIDI and SAIFI, adjusted for its updated methodology. It proposed to maintain revenue at risk for this measure at 0.15%.
- SMS notification, customer SMS notifications sent within 6 minutes of awareness of an unplanned outage – United Energy proposed a 75.8% target, up from its previous target of 60%. United Energy proposed to amend the weighting of this parameter from 0.15% to 0.10%, noting that due to the large improvements it has made during the 2021-26 period there are limited additional investments that can be undertaken in 2026-31 to further improve its performance.

United Energy has proposed a total revenue at risk of 0.5% of its annual revenue requirement.

Questions on United Energy's proposed CSIS

33) Do you have any feedback on the design of United Energy's proposed CSIS?

34) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 66.7% from 75.2%?

35) Do you have views on the amended weighting of the SMS notification parameter from 0.15% to 0.10%, on the basis that additional improvements are limited?

36) Do you have views on United Energy's proposed new targets and methodology for the calculation of planned outage numbers and minutes off supply?

37) Do you have any views on United Energy's engagement on the design of its CSIS?

4.6 Victorian f-factor scheme

The f-factor scheme is a regulatory instrument under the *National Electricity (Victoria) Act 2005*, which provides Victorian businesses with an incentive to lower the number of fire-starts

[1] United Energy, Attachment 10.01 – Customer Service Incentive Scheme, January 2025.

on their networks. Application of the f-factor scheme to Victorian distributors is a requirement under the *National Electricity (Victoria) Act 2005* F-factor Scheme Order 2016.[118]

The AER's role in the f-factor scheme is limited and is focused on giving effect to incentive payments and penalties by adjusting the distributors' allowable revenue each year in accordance with the F-factor Order, as based on fire start reporting validated by Energy Safe Victoria. All other aspects of the scheme are set out by the Victorian government including the targets and incentive rates. As part of our determinations for CitiPower, Powercor, and United Energy, we will forecast incentive payments for the 2026-31 period which will take the form of adjustments to each network's regulated revenues for each regulatory year.

118 *National Electricity (Victoria) Act 2005 F-FACTOR SCHEME ORDER 2016 Order in Council*, 22 December 2016, section 8, p. 3239 - http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf.

5 Network pricing

Our determinations for CitiPower, Powercor and United Energy divides the regulated direct control services they provide into different classifications, which determine how they will recover the cost of providing those services through network prices:

- Standard control services are those that can only be provided by the relevant distributor, and are common to most, if not all, of a distributor's customers. The costs of providing these services are captured in the building block revenue determination we've discussed in the previous sections of this paper and shared between all customers.
- Alternative control services are those that can only be provided by the relevant distributor but will only be required by some of its customers, some of the time; or services that can be purchased from the relevant distributor, 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.

We set out our proposed approach to the classification of distribution services to be provided by CitiPower, Powercor and United Energy in 2026–31 in our Framework and Approach paper in July 2024.[119] Our proposed approach to service classification is set out prior to the submission of revenue proposals, in order to provide certainty as to how costs for various services should be allocated for the purposes of recovery. Our determinations must apply the classifications set out in the Framework and Approach paper unless we consider a material change in circumstances justifies departure from them.[120]

CitiPower, Powercor and United Energy have not proposed any such departures.

Questions on service classification

38) Do you have feedback on the classification of services set out in the Framework and Approach Paper, and whether there has been a material change of circumstances since July 2024 that may require changes?

5.1 Control mechanisms for standard and alternative control services

A distribution determination must impose controls over the prices and/or revenues of direct control services.[121] The forms of control that are to apply, and the control formulae that give effect to them, are set out in our Framework and Approach paper prior to the submission of revenue proposals, in order to provide certainty to CitiPower, Powercor, United Energy and other stakeholders. There are only limited circumstances in which our distribution

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

120 NER, cl. 6.12.3(b).

121 NER, cl. 6.2.5(a).

determination can depart from the decision we made in the Framework and Approach paper regarding control mechanisms.[122]

We can only depart from the form of control set out in our Framework and Approach paper if:[123]

a) We have departed from the classification of a distribution service as set out in that paper; *and*

b) We consider that no form of control mechanism set out in that paper should apply to that distribution service.

We can only depart from the formulae that give effect to the control mechanisms set out in our Framework and Approach paper if we consider that a material change in circumstances justify departing from those formulae.[124]

In our Framework and Approach paper for the 2026–31 period, our decision was to continue to apply the same control mechanisms as we applied in the current, 2021–26 period:[125]

- A revenue cap for standard control services
- A revenue cap for metering services (as alternative control services)
- A price cap for ancillary network services and public lighting (as alternative control services).

We discuss some of the differences between these forms of control in section 2.2.

In our consultation on the Framework and Approach paper we did not receive any submissions suggesting we depart from them. As part of this consultation, we are interested to hear to whether, in light of the proposals, stakeholders consider there is a basis to change the control mechanisms set out in the paper.

We made only minor changes to the formulae for those forms of control, to align with our final decisions for control mechanisms for other distributors and to remove obsolete true ups associated with the 2009–2015 Victorian smart meter rollout.[126]

CitiPower, Powercor and United Energy adopted this approach in their proposals.

Questions on control mechanisms

39) Do you have any feedback on the form of control set out in the Framework and Approach paper and the proposals and whether, if you've suggested a change to service

122 NER, cll. 6.12.3(c)(1) and (2); 6.12.3(c1).

123 NER, cl. 6.12.3(c).

124 NER, cl. 6.12.3(c1).

125 AER, *Final decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021-26 – Attachment 14 – Control mechanisms*, April 2021.

126 *AER – Final Framework and Approach – Victorian electricity distribution determinations 2026-31* – July 2024, Chapter 3.

classifications in response to the question above, the control mechanisms set out in that paper remain appropriate?

40) Do you have any feedback on the control formulae set out in the Framework and Approach paper and the proposals, and whether there has been a material change in circumstances which might justify a departure from these formulae?

5.2 Tariff structure statement

As part of their regulatory proposals, distributors are required to submit a tariff structure statement (TSS) to the AER, accompanied by an indicative pricing schedule.[127] The TSS will apply for the 5-year regulatory control period. A TSS must set out a distributor's:

- proposed network tariffs (including tariff structures and charging parameters)
- export tariff transition strategy
- policies and procedures the distributor will use to assign customers to network tariffs or reassign customers from one network tariff to another.

Network tariffs provide the charging framework through which distributors recover their costs for providing network services (transporting electricity to customers). After AER approval, a TSS becomes a compliance document against which the AER assesses the distributor’s annual pricing proposals.

TSSs also set out how distributors propose to progressively reform their network tariffs to better signal to customers the cost of providing network services. As customers ultimately pay for upgrades to network services, tariff reform that encourages more efficient use of the network will lead to lower network costs for all customers.

Network tariffs are targeted at retailers who package them with other costs in their service offerings to electricity customers, including the cost of wholesale energy. As a result, the retail electricity tariff may not directly reflect the network tariff.

Victorian distributors plan and develop their TSSs for strong consistency across the distributors. For this reason, much of this section of the issues paper refers to Victorian distributors generally, only drawing out CitiPower, Powercor or United Energy specifically where they proposed something unique.

This is the third regulatory period for which Victorian distributors have been required to submit a TSS. Their TSSs for the 2026–31 regulatory period each continued a process of incremental tariff reform. However, the energy sector transition has increased the importance and urgency for greater progress on network tariff reform. We’ve already seen the benefits from cost reflective tariffs to consumers in another jurisdiction when the AER rejected $76.1 million in proposed capex from Evoenergy that it proposed to support EV driven demand (almost 15% of its proposed capex). We rejected that capex on consideration that there would be near 100% smart meter roll out by 2030 and all EV owners would be assigned to cost reflective network tariffs.

127 NER, cll. 6.12.3(c)(1) and (2); 6.12.3(c1); 6.18.1A(e).

The AER considers tariff reform should ultimately progress to 100% assignment to cost reflective network tariffs to ensure lowest cost network services for all consumers. We also note the ongoing importance of small customers retaining the option to choose a flat retail offer and to have the choice (through their retailer) of an alternative cost reflective network tariff.

Historically, distributors charged retailers based on their customers' electricity use irrespective of when it was consumed. But distribution costs are driven by how consumers use (or supply) energy during periods of maximum (and minimum) demand. Increasing consumption during periods of abundance and reducing consumption (and increasing supply) during periods of scarcity, mitigates network investment needs. This leads to cheaper electricity bills and is in the long-term interests of all consumers. Cost reflective network tariffs provide a low-cost mechanism to incentivise this outcome.

Cost reflective network tariffs ensure the price charged for individual consumers more accurately reflects the way they use electricity. Under cost reflective pricing, electricity use at times of abundance attracts lower rates that reflect there is plenty of unused network capacity, electricity use in peak periods (times of scarcity) attracts higher rates that better reflect the costs of network investment needed to accommodate peak demand. Similarly, exports at times of abundance will attract charges to reflect the cost of providing export services and exports in times of scarcity could receive rewards.

Network tariffs are charged to retailers and cost reflective pricing is intended to facilitate retailer innovation to increase network capacity utilisation. Retailers can achieve this with retail offers that encourage consumers with flexible load to shift their behaviour (only some of the load, some of the time is required to mitigate network investment) or with business models that offer control and orchestration of load and supply. More specifically, retailers may manage and respond to network price signals by offering customers insurance style flat tariffs (either with a price premium to account for network tariff price risk or with elements of control to manage the price risk), pass network prices through to end users, or offer 'prices for devices' style offers. Where customers prefer flat electricity charges, including for customers experiencing vulnerability, it is retailers who are best placed to offer flat billing structures as retailers already manage the complexities of the wholesale market on behalf of their customers (a fundamental part of their role).

With increasing levels of CER, we anticipate more retailers and intermediaries will be developing business models that seek value from cost reflective tariffs and flexible load/supply. We encourage retailers to continue to innovate to access this value through helping consumers shift and reduce their load, including through drawing on energy efficiency initiatives and offering flat retail tariffs where this is preferred by customers.

Cost reflective network tariffs remain as important now as when reform commenced. All distributors are anticipating an increase in maximum demand and increasing prevalence of minimum demand periods, both of which drive capex. As discussed in section 2.2, under the revenue cap form of control that currently applies to Victorian distributors there is a risk that—for the same amount of revenue—lower than forecast volumes could mean higher network tariffs. This would further increase the importance and scope for cost reflective network tariffs to increase network utilisation.

CER are increasing rapidly and are a material contributor to the maximum and minimum demand issues. However, they are also generally flexible and represent a potential solution to demand driven capex if they can be operated in ways that shift demand to periods of abundance and shift supply to periods of scarcity (i.e. increase network capacity utilisation for both import and export services). Over the past two resets, Victorian distributors have progressively increased the cost reflectivity of their cost reflective tariffs by more narrowly targeting the periods of scarcity and abundance and by increasing the price ratios between periods of scarcity and abundance.

However, despite having long-term 100% smart meters, only 29.39% of Victorian residential customers (CitiPower 18.57%, Powercor 31.71% and United Energy 15.77%) are on cost reflective network tariffs.[128] In this context, with increasing maximum demand, increasing prevalence of minimum demand and increasing uptake of CER, the AER expects all Victorian distributors to demonstrate ambition in progressing tariff reform, including to encourage assignment to cost reflective tariffs. We are interested in stakeholder views on what more the Victorian distributors should be doing in their tariff strategies to progress tariff reform and further increase network capacity utilisation.

Based on our initial review we consider the Victorian distributors have provided TSSs that aim to meet our expectations. However, we will assess each TSS in further detail against the pricing principles and other NER requirements, including with respect to demonstrating progress on tariff reform to mitigate future network costs (i.e. by aligning their tariff strategies with their broader business plans).

Questions on TSS

41) Do you consider there are further tariff reforms CitiPower, Powercor and United Energy should implement to encourage increased network capacity utilisation and mitigate future network costs? Identify any specific options you think should be considered.

42) Do you consider there are any aspects of CitiPower, Powercor and United Energy's proposed TSSs that require adjustment?

5.2.1 Expectations for tariff structure statements

The Handbook sets out our expectations that a proposed TSS will:

- Demonstrate progression of tariff reform consistent with the network pricing objective and pricing principles set out in the NER
  - The Victorian distributors' progress on tariff reform is limited by assignment policies for small customers to cost reflective tariffs that remain largely opt-in (to align with Victorian Government positions). With that constraint, they incentivise uptake by continuing to discount the residential time-of-use tariff relative to tariffs without cost-reflective price signals. They also proposed new default residential tariffs that include a solar soak period and optional residential tariffs that also feature stronger price

128 Annual RIN Responses for AusNet Services, Jemena, CitiPower, Powercor and United Energy, consolidated, October 2024.

signals, and export charges and rewards. Large business customers are in the process of moving to or already on fully cost-reflective tariffs.

- Demonstrate incorporation of its tariff strategy in its overall business plan
  - The distributors linked their proposed TSSs to their forecast network expenditure and designed tariffs to encourage increased network capacity utilisation. This was demonstrated in their respective overview documents.
- Demonstrate significant stakeholder engagement and broad stakeholder support
  - The distributors collectively held 3 tariff workshops over 7 months which included a broad and diverse range of stakeholders. The distributors' proposed TSSs explain how their proposed suites of tariffs were linked to stakeholder feedback.
- Demonstrate insight into and management of any adverse customer impacts
  - The distributors modelled customer bill impacts for a variety of residential and small business customers, including for different load profiles (customer archetypes). The distributors also provided the option for small customers to opt-out of the default time-of-use tariffs.

5.2.2 Progress on tariff reform

The Victorian distributors' proposed tariff reforms focus on providing increasingly cost reflective tariffs that encourage efficient integration of consumer energy recourses. Key reforms proposed and common to all networks are:

- default residential time-of-use tariffs which feature new solar soak periods and shorter peak periods than current time-of-use tariffs
- continued discounting of the residential time-of-use tariff relative to tariffs without cost-reflective price signals to encourage uptake
- optional residential time-of-use tariffs with stronger (than default tariff) price signals, export charges (during peak export periods when excess roof-top solar is contributing to network constraints) and export rewards to encourage export of energy to the network during evening peak periods when more energy is needed
- withdrawal of the optional residential demand tariff
- withdrawal of legacy residential time-of-use tariffs (except AusNet)

Additional reforms proposed by CitiPower, Powercor and United Energy are:

- amended thresholds for assignment to the medium and large business tariff classes to be based on consumption instead of demand
- commitment to tariff trials for low voltage electric vehicle charging sites
- amended large business tariffs to provide for winter demand charges instead of summer (for customers on winter peaking parts of their networks)
- optional flexible business tariffs for storage and generation connections

5.2.3 Long run marginal cost (LRMC)

LRMC refers to the distributor's forward-looking cost of providing one more unit of service, measured over the long run where all factors of production can be varied.[129] Under the NER, a distributor's TSS must comply with the pricing principles.[130] One of these pricing principles requires that network tariffs be based on the LRMC of providing a distribution service to the customer.[131]

Distributors typically demonstrate compliance with this pricing principle by calculating LRMC using forecasts for demand and expenditure (where it relates to forward-looking costs) as inputs. The Victorian distributors used 5 years of capital expenditure forecasts in their LRMC calculations. This forecast horizon does not adequately capture the long run – we have previously considered a forecast horizon of at least ten years was required.[132]

We are interested in stakeholder views on the distributors' approach to calculating LRMC.

Questions on TSS

43) Do you have views on CitiPower, Powercor and United Energy's approach to calculating LRMC?

5.2.4 Export reward tariffs

All Victorian distributors proposed to introduce opt-in export reward tariffs for residential customers, that is, opt-in rewards and charges for customers who export electricity to the grid.[133] The tariffs included relevant customer protections as required by the NER, including:

- a basic export level (the amount of electricity a customer may export at no cost during peak export periods in the middle of the day)
- an export tariff transition strategy.

No export reward tariffs have been proposed for small or large business customers.

All Victorian distributors proposed that the export reward and export charge periods align with the proposed default residential TOU charging windows. From 4pm to 9pm, during the evening peak period, all exports would receive an export reward (to incentivise exporting when it is most needed). From 11am to 4pm, exports above the basic export level would attract a modest charged (to incentivise self-consumption when solar exports are abundant). All Victorian distributors proposed a basic export level of 1 kWh per day.

129 NER, Chapter 10 defines long run marginal cost as 'the cost of an incremental change in demand for direct control services provided by a distribution network service provider over a period of time in which all factors of production required to provide those direct control services can be varied.'

130 NER, cl. 6.18.1A(b).

131 NER, cl. 6.18.5(f).

132 AER, *Draft decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021-26 - Attachment 19 - Tariff structure statement - September 2020*, p. 41.

133 As allowed for under the AEMC's Access, pricing and incentive arrangements for distributed energy resources rule change (12 August 2021).

CitiPower, Powercor, and United Energy proposed export reward tariffs that include seasonality. Export charges would only apply in non-winter months (September to May), and export rewards would only apply in summer (December to February) and winter (June to August) months. The distributors retain the option to apply an export charge during winter (June to August). In addition, peak import prices are higher during summer and winter months compared to the rest of the year.

Export reward tariffs remain a relatively new feature for TSSs, so we intend to closely examine Victorian distributors' proposals - as the AER has done for the NSW and ACT 2024–29 resets and is currently doing for the QLD and SA 2025–30 resets.

5.2.5 Large business tariffs

The Victorian distributors proposed large business tariffs that would be or would become fully cost reflective over the 2026–31 regulatory period. AusNet and Jemena also proposed individually calculated customer (ICC) tariffs in response to the AER's 2021–26 regulatory period determination which requested that distributors pursue the development of these tariffs for the 2026–31 period.[134] ICC tariffs are typically offered to customers whose energy use is so large they can have localised impacts on a networks' investment needs and the tariffs are designed to reflect the individual costs or benefits they could drive.

All large business customers on the CitiPower, Powercor, and United Energy networks are currently on cost reflective demand tariffs. The three distributors have not proposed any changes to their large business tariffs except to introduce winter demand charges instead of summer demand charges for customers in winter peaking parts of their networks. CitiPower, Powercor, and United Energy have not proposed to offer ICC tariffs.

5.2.6 Grid-scale storage tariffs

All Victorian distributors either proposed or proposed to trial grid-scale storage tariffs for the 2026–31 period. The proposed tariffs for community batteries include either a fixed or a capacity charge alongside volumetric import and export charges and rewards. The tariffs are similar in structure to the proposed optional residential export reward tariffs.

CitiPower, Powercor and United Energy proposed new 'flexible connection' tariffs that target storage and generation.[135] The flexible small tariff, targeting storage in residential areas, includes seasonal pricing and no import charges during specified times. The distributors also proposed flexible tariffs for larger customers that include capacity and demand charges. All the flexible tariffs are based on existing tariff trials – customers currently on the tariff trials would be reassigned to the respective flexible tariff.

5.2.7 Tariffs for electric vehicles (EVs)

The Victorian distributors' TSS proposals include features to address the increasing uptake of electric vehicles on their distribution networks. However, we are interested in whether

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134 AER, *Final decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021-26 - Attachment 19 - Tariff structure statement*, April 2021, p. 12.

135 The CitiPower, Powercor and United Energy TSSs define it as: 'Flexible connection is demand management actioned through connection agreements such as agreement to be controlled by our distribution energy resource management system (DERMS).'

there is more that distributors could do to give effect to their assignment policies for small customers with electric vehicle supply equipment (colloquially termed EV chargers).

The distributors maintained their current assignment policies for residential and small business customers with a dedicated EV charger.[136] These customers must be on a cost-reflective network tariff and cannot opt out to a flat network tariff. The default time-of-use tariffs are designed to encourage these customers with a dedicated charger to charge EVs during the lower priced off-peak and solar soak periods. In addition, these customers can access the optional residential export reward tariffs which are designed to encourage residential EV owners to charge EVs using their own solar.

Relevant to EV public charging stations, the distributors have continued their current assignment policy of offering medium business customers access to the default demand tariff or an optional time-of-use tariff.[137]

These small customer and medium business assignment policies align to a Victorian Government Order in Council that requires distributors to:

- not allow access to a flat network tariff if they can identify a small customer with a dedicated EV charger
- allow medium business customers to have access to a tariff other than a demand tariff.[138]

However, Victorian distributors and Victorian Government have not identified a formal mechanism by which distributors can identify that a customer has an EV charger. We note that installation or replacement of electric vehicle supply equipment concerns work that must be covered by a Certificate of Electrical Safety (CoES) as required by Energy Safe Victoria; the CoES lists or describes electrical work done, that it has been tested and meets current wiring rules. While the data as currently collected and recorded may not be readily extractible for/by distributors, we consider it may provide the foundation for a mechanism to identify customers with EV chargers. We are interested in what more Victorian distributors could do to identify small customers with EV chargers in order to give effect to their assignment policies.

The distributors are also trialling innovative tariffs for EVs. CitiPower, Powercor and United Energy proposed a new tariff trial for dedicated low voltage EV public charging stations.

136 The Advanced Meter Infrastructure (Retail and Network Tariffs) Order in Council defines a dedicated charger as ‘a dedicated charger for an electric powered passenger car with a specified capacity or charging rate of 3.6kW or greater’

137 The Advanced Meter Infrastructure (Retail and Network Tariffs) Order in Council defines a medium customer as ‘a customer who is not a small customer and whose aggregate consumption of electricity is not […] more than 160 MWh per annum.’ The same Order defines a small customer as a domestic customer or a small business customer (consumption not more than 40 MWh per annum).

138 Victorian Advanced Meter Infrastructure (Retail and Network Tariffs) Order in Council, s11 and s12.

Questions on TSS

44) Are there formal mechanisms the distributors could pursue or develop to identify small customers with electric vehicle supply equipment (EV chargers)?

5.3 Alternative control services

Alternative control services are customer specific, or customer requested services and so the full cost of the service is attributed to the customer, or group of customers, benefiting from the service. Our determinations set service specific prices to provide a reasonable opportunity to the distributor to recover the efficient cost of each service from customers using that service. Our F&A classified the following as ACS:

- metering services
- ancillary network services,
- certain connection services, and
- public lighting services.

5.3.1 Metering

Metering services include the maintenance, reading, data services and recovery of capital costs of meters. Victorian distributors are currently the exclusive providers of metering services to residential and small business in Victoria.[139]

As a result of the mandated smart meter rollout in Victoria from 2006, nearly all Victorian households and businesses have smart meters installed. This differs from other networks across the NEM, where the AEMC has recently introduced a rule to accelerate the rollout of smart meters.[140]

The smart meters in Victoria are now coming to the end of their asset life, both financially (through depreciation) and, as indicated by the Victorian distributors in their proposals, mechanically (through failure of the meter or component). As these smart meters come to the end of their financial asset life (set at 15 years), the capital cost to be recovered reduces. This significantly reduces the costs to be recovered in relation to metering services as capital costs make up between 49% and 72% of the Victorian distributors' metering revenues in 2025–26.[141] However, as any smart meters come to the end of their mechanical life (determined by failure and not a set number of years as is the case for financial asset life),

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139 Victoria Government Gazette, *No. S 346*, 12 October 2017 - https://resources.reglii.com/VGG.2017.10.12.S346.pdf

140 AEMC, *National Electricity Amendment (Accelerating Smart Meter Deployment) Rule*, November 2024.

141 AER, *AusNet Services 2021–26 metering PTRM – 2024–25 RoD update*, February 2024; AER, *CitiPower 2021–26 metering PTRM – 2024–25 RoD update*, March 2024; AER, *Jemena 2021–26 metering PTRM – 2024–25 RoD update*, December 2023; AER, *Powercor 2021–26 metering PTRM – 2024–25 RoD update*, March 2024; AER, *United Energy 2021–26 metering PTRM – 2024–25 RoD update*, March 2024; AER analysis.

the likelihood of failure of the meter or its components increases[142] [143]. Capital costs then increase to reflect the replacement of these meters.

The Victorian distributors proposed to take a proactive approach to replacing smart meters in their 2026–31 regulatory proposals (with some differences).[144] This would mean smart meters are replaced to avoid failure, based on end of financial asset life and anticipating end of mechanical asset life, and would be expected to produce relatively stable price increases over the 2026–31 regulatory period and beyond. That is, the price decline that would otherwise occur would be offset by a proactive replacement of smart meters, meaning that prices would not decline as significantly (or at all) and therefore not increase as much (or at all) as replacements occur. This approach also allows for more efficient replacement programs, taking advantage of economies of scale, reducing the overall costs of meter replacement.[145] A more proactive replacement is also likely to reduce risks related to safety and reliability.[146]

In contrast, a reactive approach of replacing these smart meters upon failure or anticipated failure (that is, based on mechanical asset life), would produce a sharp decline in prices over the 2026–31 regulatory period as capital cost recovery winds up. This would be followed by a slow increase in prices as meters are replaced, with this increase expected to get more apparent in the following 2031–36 regulatory control period as failure rates, and therefore replacements, increase. The Victorian distributors noted this approach includes the risk of large numbers of meters failing in a similar timeframe, requiring replacement and increasing price volatility, as well as increasing compliance risks.[147] [148] It would be expected that in the long-term prices would naturally stabilise as a more organic replacement of meters takes place over time.

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142 Failures generally relates to meter batteries, load switch controls, flash storage/memory chip errors, mesh network interface cards, and display screens, all of which contribute to data quality or functional issues.

143 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, pp. 347–8; CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97; Jemena, *Attachment 10-01 Advanced Metering Infrastructure*, January 2025, p. 21; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 112; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97.

144 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 350; CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 95; Jemena, *2026-31 Proposal*, January 2025, p. 121; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 110; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 95.

145 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 353; CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97; Jemena, *2026-31 Proposal*, January 2025, p. 121; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 112; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97.

146 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 353; CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97; Jemena, *Attachment 10-01 Advanced Metering Infrastructure*, January 2025, pp. 21–2; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 112; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97.

147 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 345; CitiPower, *BUS 11.01 - Metering*, January 2025, p. 17; Jemena, *Attachment 10-01 Advanced Metering Infrastructure*, January 2025, pp. 21–2; Powercor, *BUS 12.01 - Metering*, January 2025, p. 17; United Energy, *BUS 12.01 - Metering*, January 2025, p. 17.

148 Victorian distributors are required to repair/replace faulty meters within 10 business days of being reported, which differs to 15 business days allowed for other jurisdictions in the NEM.

The Victorian distributors noted in their proposals that any savings from more reactive replacement programs, either through replacement of failed meters or failed components, are unlikely to offset the additional labour costs of replacement.[149] The Victorian distributors also noted the increased demand for multi-phase meters either for new connections or upgrades to current meters to support Victoria's Gas Substitution Roadmap, which cannot be addressed through the use of refurbished single-phase meters.[150]

We will consider several factors as a part of our assessment of these proposals and seek stakeholder views on these below. These include:

- Affordability – whether the potential decreases in prices under a more reactive approach are more appropriate in the current environment or may offset potential increases in other areas of the network or retail bill.
- Resource strain and deliverability – whether a proactive metering replacement program in Victoria puts the AEMC's accelerated smart meter rollout across other NEM networks at risk by increasing demand for materials and labour from shared markets and reduces the possibility of deliverability in Victoria
- Forecast risk burden – under a revenue cap if forecasts for proactive replacement programs are not met, customers still pay the same prices as if the replacement program goes to plan. Mechanisms have been introduced in other jurisdictions to true-up forecasts and manage such risks
- Alternatives – whether other options are viable, such as proactive replacement of components that are at risk of failure, or opportunities to defer the start of the proactive meter replacement program to achieve some short-term cost-relief.

Summaries of CitiPower, Powercor, and United Energy's proposals are provided below. The Victorian distributors have proposed slightly different proactive approaches and pricing outcomes, with summaries for AusNet and Jemena available in their respective issues papers. More detailed information is available in each of the Victorian distributors' proposals.

CitiPower, Powercor, and United Energy proposed to replace 33%, 35%, and 34% of their total meter populations across the 2026–31 regulatory period, respectively.[151]

CitiPower, Powercor and United Energy proposed a proactive program that aims to reduce the risk of high failure rates requiring reactive replacements that can be both disruptive and

149 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 351; CitiPower, *BUS 11.01 - Metering*, January 2025, p. 17; Jemena, *Attachment 10-01 Advanced Metering Infrastructure*, January 2025, p. 22 Powercor, *BUS 12.01 - Metering*, January 2025, p. 17; United Energy, *BUS 12.01 - Metering*, January 2025, p. 17.

150 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 352; CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp. 98-99; Jemena, *Attachment 10-01 Advanced Metering Infrastructure*, January 2025, p. 22; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp. 113-114; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp. 98-99.

151 CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 95; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p.110; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 95.

expensive.[152] It considered the proposed program delivers efficiencies from a coordinated rollout approach due to the bulk purchase of meters and lower labour costs related to installation. [153]

- CitiPower's proposal includes a reduction of the main single phase metering tariff from $68.20 in 2024–25 to $61.21 in 2030–31 ($nominal), a reduction of 10%.[154]
- Powercor's proposal includes a reduction of the main single phase metering tariff from $67.00 in 2024–25 to $66.12 in 2030–31 ($nominal), a reduction of 1%.[155]
- United Energy's proposal includes an increase of the main single phase metering tariff from $48.20 in 2024–25 to $52.30 in 2030–31 ($nominal), an increase of 9%.[156]

Questions on metering

45) Do you consider proactive metering replacement is appropriate, and do you have any views around the different approaches proposed by the businesses?

46) In the short-term, how do you consider affordability and price stability should be balanced in relation to the pricing of metering services?

47) Do you have any views on how proactive metering replacement programs in Victoria may affect the ability for non-Victorian networks to complete the AEMC's accelerated smart metering rollout program and / or impact deliverability in Victoria?

48) Do you consider any alternative approaches may be more appropriate such as a proactive metering component replacement program, or a delayed start to a proactive metering replacement program (as proposed by AusNet)?[157] If so, please explain why.

49) Do you consider a true-up mechanism should be introduced to ensure customers are protected from unfulfilled forecasts in relation to proactive replacement programs? Why?

50) More generally, do you have any other comments on the Victorian distributors' metering services proposals?

5.3.2 Ancillary network services

Ancillary network services are non-routine services provided to individual customers on request. These services are either charged on a fee or quotation basis. Fee-based services

152 CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 112; United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, p. 97.

153 CitiPower, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp. 96-97; Powercor, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp.112-113, United Energy, *Regulatory Proposal 2026-31 - Part B - Explanatory Statement*, January 2025, pp. 97-98.

154 AER, *Stakeholder report – CitiPower – 2024–25 Annual Pricing Proposal*, May 2024; CitiPower, *ATT TSS.02 - ACS indicative prices*, January 2025; AER analysis.

155 AER, *Stakeholder report – Powercor – 2024–25 Annual Pricing Proposal*, May 2024; Powercor, *ATT TSS.02 - ACS indicative prices*, January 2025; AER analysis.

156 AER, *Stakeholder report – United Energy – 2024–25 Annual Pricing Proposal*, May 2024; United Energy, *ATT TSS.02 - ACS indicative prices*, January 2025; AER analysis.

157 AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 345.

tend to be homogeneous in nature and can be costed in advance of supply with reasonable certainty. Quoted service prices are determined at the time of a customer's enquiry and reflect each customers' individual requirements.

Ancillary network services are regulated by price cap. Our distribution determination sets first year price caps for fee-based services, labour escalators used to escalate prices for the remaining years of the regulatory period, and capped labour rates used in quoted services. Labour costs make up a large proportion of ancillary network service costs. Another significant cost element is the time taken to perform the service, including travel time. Our assessment includes review of these elements for the most frequently requested ancillary network services. We also benchmark proposed labour rates and prices for fee-based services across distribution networks as well as with prices from the current regulatory period.

In March 2022, we published a standardised ancillary network services model for use by electricity distributors to develop their prices. This streamlines our assessment, increases consistency, and provides stakeholders greater scope to engage in our distribution determinations.

5.3.2.1 Pre-lodgement engagement and service offerings

CitiPower, Powercor and United Energy's ancillary service engagement involved consulting retailers and councils regarding the end of life of mercury vapor lamps. As a result, CitiPower, Powercor and United Energy proposed to cease offering new watchman light services and to actively remove remaining watchman lights that cannot be replaced with standard LEDs.[158,159]

In their proposals CitiPower, Powercor and United Energy proposed to establish new quoted services. These have been approved / are consistent with the final F&A and are:[160]

- Enhanced connection service.
- Reversion of embedded networks, relating to the Victorian government ban of new residential apartment embedded networks.
- Embedded generator control equipment, in compliance with the Victorian government mandate.
- Bulk conversion to 5-minute meter readings.

158 CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.12-13, Powercor, PAL ATT 12.02 – Ancillary Network Services – January, pp.12-13, United Energy, UE ATT 12.02 – Ancillary Network Services – January 2025, pp.11-12.

159 CitiPower EDPR 2026-31 – information request #002 – ANS stakeholder engagement – 20250214; Powercor EDPR 2026-31 – information request #001 – ANS stakeholder engagement – 20250214; United Energy EDPR 2026-31 – information request #001 – ANS stakeholder engagement – 20250214.

160 CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.13, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.13, United Energy, UE ATT 12.02 – Ancillary Network Services – January 2025, pp.12.

CitiPower, Powercor and United Energy also proposed to reclassify its 'reserve feeder maintenance' from a quoted to fee-based service[161]. This is to avoid year-to-year volatility in charges, which arises from the impracticality of calculating actual reserve feeder maintenance costs annually. Using data from regulatory information notices (RIN), this charge will be calculated by taking an average cost based upon the reserve feeder type. They proposed to reclassify 'connection application' from a quoted to fee-based service.[162] This was to ensure applicants who request a connection but do not accept the offer still contribute to the costs they impose on the network. The proposed fee will be calculated using average time taken for administration and for non-basic connection applications.

5.3.2.2 Benchmarking labour rates

Labour rates are a key cost input for ancillary network service prices. The distributors' proposed labour rates are assessed against benchmark efficient maximum labour rates developed using a bottom-up cost build up across six categories (administration, field worker, technical specialist, engineer, senior engineer, and project manager).

The benchmark rates include increases to the superannuation allowance and the vehicle allowance because of the changes in the superannuation guarantee and inflation. The 'transmission line design engineer' has been removed from the engineer benchmark category as this occupation is not an appropriate benchmark for distributors' engineers.

CitiPower, Powercor and United Energy proposed that an additional labour category be included in its benchmarking. This is for an engineering manager.[163] The proposed cost for this labour category is suggested to be 20% higher than a senior engineer. It has been proposed to enable more precise calculation of quoted service costs.

The majority of CitiPower, Powercor and United Energy's proposed labour rates are below the AER's preliminary benchmark rates. However, the following labour rates are above AER's preliminary maximum efficient benchmark rate: administration, by 5.8%, field worker, by 0.6% (CitiPower and Powercor only) and technical specialist, by 5.0%.

Our draft decision on CitiPower, Powercor and United Energy's labour rates will be dependent on the updated maximum efficient benchmark rates we determine after applying the most recent inputs.

5.3.2.3 Benchmarking fee-based services prices

Proposed fee-based services are also benchmarked against prices from the current regulatory control period as well as similar services supplied by other distributors. Cost inputs may also be benchmarked.

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161 CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.5-6, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.5-6, United Energy, UE ATT 12.02 – Ancillary Network Services – January 2025, pp.5.

162 CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.5, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.5.

163 CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.5, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.12.

In terms of price impacts, all of CitiPower, Powercor and United Energy fee-based charges are proposed to be escalated by CPI and an X-factor[164]. CitiPower, Powercor and United Energy have included an 8.8% economic tax calculation in the standardised ancillary services model, which is applied to both fee-based and quoted services.[165] In the first year of the regulatory period, connection services, that include this tax addition, are proposed to increase by 14.1%.

Questions on ancillary network services

51) Do you consider that sufficient justification has been provided in relation to the proposed provision of new services?

52) Do you consider the introduction of the engineering manager to the labour categories reasonable, and the proposed costs reasonable?

53) Do you consider the proposed labour rates benchmarking above the AER's maximum efficient benchmark rate, and the proposed fee-based charges reasonable?

5.3.3 Public lighting

Public lighting services include the provision, construction and maintenance of public lighting assets. Customers of public lighting services primarily are local government councils and jurisdictional main roads departments.

There are a number of different tariff classes and prices for public lights. The factors influencing prices for a particular installation include which party is responsible for capital provision, and which party is responsible for maintaining and/or replacing installations.

CitiPower, Powercor and United Energy's prices recover costs of providing public lighting services (including capex and opex as appropriate). CitiPower, Powercor and United Energy proposed opex over the 2026–31 period of $9.9 million, $30.4 million and $16.4 million respectively. Important drivers include asset failures rates, spot and bulk maintenance cycles, labour rates and traffic controller assumptions. CitiPower, Powercor and United Energy also proposed net capex over the period of $8.0 million, $38.8 million and $27.6 million respectively. The price of materials is the underlying driver for capex. Corporate overheads are also a material driver of public lighting prices.

For the 2026–31 period, CitiPower, Powercor and United Energy proposed to use a model similar to our post-tax revenue model (PTRM) to develop its public lighting prices. The proposed use of a PTRM is consistent with our expectations.

5.3.3.1 Pre-lodgement engagement

CitiPower, Powercor and United Energy conducted an online stakeholder consultation session with local councils and the Department of Transport and Planning (DTP) in mid-July

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[164] CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.3, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.3 United Energy, UE ATT 12.02 – Ancillary Network Services – January 2025, pp.3.

[165] CitiPower, CP ATT 11.02 - Ancillary network services - January 2025, pp.4 & 12, Powercor, PAL ATT 12.02 – Ancillary Network Services – January 2025, pp.4 & 12 United Energy, UE ATT 12.02 – Ancillary Network Services – January 2025, pp.4 & 11.

2024. Key topics on proposed public lighting plans were set out in detail, and stakeholders were invited to participate in a Q&A session to seek further clarification.[166]

In its proposals CitiPower, Powercor and United Energy noted it received the following feedback from its public lighting customers which it has responded to:[167]

- Support for the proactive replacement of non-Light Emitting Diode (LED) residential lighting that will be banned in the 2026–31 period
- Interest in a central management system (CMS) for smart lighting to enable remote dimming, constant light output and improve fault restoration
- Support for trials for solar powered lights to determine if it should be included in its 2031–36 period
- Supported for transition of the management and control of public lighting in non-trafficable parks, gardens and laneways to councils, especially with financial assistance.

5.3.3.2 Service and price offerings

For the 2026–31 period, CitiPower, Powercor and United Energy proposed the following in relation to operation, maintenance, repair and replacement (OMR) public lighting services:[168]

- Achieving 100% MV replacement by 2026, commencing CFL replacement from 2024 and commencing T5 replacement from 2026.
- Transitioning major road high pressure sodium lights at end of serviceable life to LED and 3000k lighting in residential areas when energy efficiency is comparable. 4000k lighting is proposed to continue to be used on all major roads as required by DTP.
- Continue to approve non-standard lanterns where reasonable and appropriate.

CitiPower, Powercor and United Energy also proposed to give councils management and control of public lighting in non-trafficable parks, gardens and laneways to help ensure safety and access.[169]

In terms of price impacts, for OMR public lighting services CitiPower, Powercor and United Energy proposed the following average price increases for LED lights in the first year of the 2026–31 period: 3.7%, 5.6% and 4.0% respectively. This is followed by proposed CPI and X factor adjustments for the remaining four years. This proposed approach largely reflects implementing the above service changes.

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166 CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, pp.2-3, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, pp.2-3, United Energy, *UE ATT 12.02 – Ancillary Network Services – January*, pp.2-3.

167 CitiPower, *CitiPower Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025*, pp. 99-100, Powercor, *Powercor Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025,* pp.99-100, United Energy, *United Energy Regulatory Proposal 2026-31 - Part B - Explanatory Statement - January 2025, pp. 99-100.*

168 CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, pp.4-5, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, pp.4-5, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, pp.4-5.

169 CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, p.7, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, p.7, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, p.7.

5.3.3.3 LED and other new technologies

Since 2009, CitiPower, Powercor and United Energy have replaced approximately 60% to 86% of its legacy lights with LED lights in minor roads across its network. It also started to replace legacy luminaries on major high-traffic roads from 2017.[170]

CitiPower, Powercor and United Energy proposed to continue to retrofit LED lights to existing non-standard decorative lights to preserve the visual identity of local areas while providing more energy-efficient and environmentally friendly public lighting.[171]

CitiPower, Powercor and United Energy also proposed to implement a basic CMS where councils can control the light output and access energy consumption data. The proposals noted that Councils and DTP supported this. The costs of the CMS are to be distributed across all public light types. For CitiPower, Powercor and United Energy the proposed cost per light per year is $2.20, $1.50 and $0.40. The proposals also noted that the basic CMS would be installed before 2026 due to demand from some councils.[172]

In response to customer interest in solar lighting, CitiPower, Powercor and United Energy proposed to continue to complete current trials to potentially include this service in the 2031–36 period.[173]

Questions on public lighting

54) Do you consider CitiPower, Powercor and United Energy's public lighting proposal generally incorporates stakeholder inputs from its pre-lodgement engagement? If not, did the network communicate these potential departure points to stakeholders and provide adequate explanation during pre-lodgement engagement?

55) Do you support CitiPower, Powercor and United Energy's proposed suite of public lighting services and prices?

56) Do you have any other comments on CitiPower, Powercor and United Energy's public lighting proposal and their pre-lodgement engagement?

[170] CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, p.3, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, p.3, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, p.3.

[171] CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, p.6, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, p.6, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, p.6

[172] CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, p.5, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, p.5, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, p.5.

[173] CitiPower, *CP ATT 11.01 - Public lighting - January 2025*, p.7, Powercor, *PAL ATT 12.01 - Public lighting - January 2025*, p.7, United Energy, *UE ATT 12.02 – Ancillary Network Services – January 2025*, p.7.

Summary of questions

We encourage you to make submissions on any aspects of the proposals that are of interest to you. In this issues paper, we have highlighted the following questions we are particularly interested in.

Questions on demand forecasts

1) Do you have any feedback on the demand forecasts that have informed these proposals?

Questions on network utilisation

2) How well do you think these proposals take existing and forecast network utilisation levels into account?

Questions on consumer engagement

3) How satisfied are you that CitiPower, Powercor and United Energy have sincerely partnered with consumers and equipped them to effectively engage in the development of their proposals?
4) How satisfied are you with the scope of issues on which consumers were engaged, and the level of detail at which CitiPower, Powercor and United Energy engaged?
5) How satisfied are you with the variety of avenues CitiPower, Powercor and United Energy used to engage with consumers?
6) How satisfied are you with the evidence CitiPower, Powercor and United Energy have provided of consumer preferences identified through their various engagement channels, and that those preferences have been reflected in the proposals?
7) How well do you feel CitiPower, Powercor and United Energy have responded to consumer and stakeholder feedback on their proposals, including but not limited to feedback on their draft proposals?
8) How would your views on these proposals change if estimated network tariff and electricity bill impacts presented with the proposals did not eventuate? For example:

- If tariff or bill impacts were potentially higher, are there areas in which you would be willing to accept a different outcome or prefer CitiPower, Powercor and/or United Energy to spend less in order to avoid this?
- If tariff or bill impacts were potentially lower, are there areas in which you would prefer CitiPower, Powercor and/or United Energy to deliver more, or would you prefer the same outcomes at a lower cost or price?

Questions on regulatory depreciation

9) Do you have any feedback on the regulatory depreciation approach proposed by each network?

Questions on forecast capex

10) Are there any particular areas of CitiPower, Powercor and United Energy's capex proposals that you would expect further engagement on?
11) Do you consider that these proposals reflect consumers' preferences?

12) Do you consider that the areas we have identified for greater assessment focus are appropriate, and, if not, what other areas should be considered and why?

13) Do you have any views on the prudency (need) and efficiency (cost) of any aspects of the proposed capex?

Questions on opex

14) Are there any particular areas of the opex proposals that you would expect further engagement on?

15) Do you consider that these proposals reflect consumers' preferences?

16) Do you consider that the areas we have identified for greater assessment focus are appropriate, and, if not, what other areas should be considered and why?

17) Do you have any views on the prudency (need) and efficiency (cost) of any aspects of the proposed opex?

Questions on uncertainty mechanisms

18) Do you have any feedback on the new nominated costs pass through events?

Questions on CESS

19) Do you have any concerns with the application of the CESS for CitiPower, Powercor and United Energy in the 2026-31 regulatory period?

20) Do you consider there is need to modify the application of the CESS to allow CESS exclusions on certain capex categories? Please explain why.

21) If we were to modify the application of CESS, what factors should we consider in determining whether specific capex should be excluded from the CESS?

Questions on EBSS

22) Do you have any feedback on the application of the EBSS for CitiPower, Powercor and United Energy in the 2026-31 regulatory control period?

Questions on STPIS

23) Do you have any views on the proposed allocation of revenue at risk between the STPIS and the CSIS?

Questions on CitiPower's proposed CSIS

24) Do you have any feedback on the design of CitiPower's proposed CSIS?

25) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 73.4% from 87.4%?

26) Do you do you have views on the amended weighting of the SMS notification parameter from 0.25% to 0.20%, on the basis that CitiPower thinks room for additional improvements is limited?

27) Do you have any views on CitiPower's engagement on the design of its CSIS?

Questions on Powercor's proposed CSIS

28) Do you have any feedback on the design of Powercor's proposed CSIS?

29) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 71.9% from 82.3%?

30) Do you have views on the amended weighting of the SMS notification parameter from 0.15% to 0.10%, on the basis that additional improvements are limited?

31) Do you have views on Powercor's proposed new targets and methodology for the calculation of planned outage numbers and minutes off supply?

32) Do you have any views on Powercor's engagement on the design of its CSIS?

Questions on United Energy's proposed CSIS

33) Do you have any feedback on the design of United Energy's proposed CSIS?

34) Do you have views on the proposed expansion of the grade of service parameter to cover general and fault calls, and the corresponding decrease of the baseline target measure for calls answered within 30 seconds to 66.7% from 75.2%?

35) Do you have views on the amended weighting of the SMS notification parameter from 0.15% to 0.10%, on the basis that additional improvements are limited?

36) Do you have views on United Energy's proposed new targets and methodology for the calculation of planned outage numbers and minutes off supply?

37) Do you have any views on United Energy's engagement on the design of its CSIS?

Questions on service classification

38) Do you have feedback on the classification of services set out in the Framework and Approach Paper, and whether there has been a material change of circumstances since July 2024 that may require changes?

Questions on control mechanisms

39) Do you have any feedback on the form of control set out in the Framework and Approach paper and the proposals and whether, if you've suggested a change to service classifications in response to the question above, the control mechanisms set out in that paper remain appropriate?

40) Do you have any feedback on the control formulae set out in the Framework and Approach paper and the proposals, and whether there has been a material change in circumstances which might justify a departure from these formulae?

Questions on TSS

41) Do you consider there are further tariff reforms CitiPower, Powercor and United Energy should implement to encourage increased network capacity utilisation and mitigate future network costs? Identify any specific options you think should be considered.

42) Do you consider there are any aspects of CitiPower, Powercor and United Energy's proposed TSSs that require adjustment?

43) Do you have views on CitiPower, Powercor and United Energy's approach to calculating LRMC?

44) Are there formal mechanisms the distributors could pursue or develop to identify small customers with electric vehicle supply equipment (EV chargers)?

Questions on metering

45) Do you consider proactive metering replacement is appropriate, and do you have any views around the different approaches proposed by the businesses?

46) In the short-term, how do you consider affordability and price stability should be balanced in relation to the pricing of metering services?

47) Do you have any views on how proactive metering replacement programs in Victoria may affect the ability for non-Victorian networks to complete the AEMC's accelerated smart metering rollout program and / or impact deliverability in Victoria?

48) Do you consider any alternative approaches may be more appropriate such as a proactive metering component replacement program, or a delayed start to a proactive metering replacement program (as proposed by AusNet)?[174] If so, please explain why.

49) Do you consider a true-up mechanism should be introduced to ensure customers are protected from unfulfilled forecasts in relation to proactive replacement programs? Why?

50) More generally, do you have any other comments on the Victorian distributors' metering services proposals?

Questions on ancillary network services

51) Do you consider that sufficient justification has been provided in relation to the proposed provision of new services?

52) Do you consider the introduction of the engineering manager to the labour categories reasonable, and the proposed costs reasonable?

53) Do you consider the proposed labour rates benchmarking above the AER's maximum efficient benchmark rate, and the proposed fee-based charges reasonable?

Questions on public lighting

54) Do you consider CitiPower, Powercor and United Energy's public lighting proposal generally incorporates stakeholder inputs from its pre-lodgement engagement? If not, did the network communicate these potential departure points to stakeholders and provide adequate explanation during pre-lodgement engagement?

55) Do you support CitiPower, Powercor and United Energy's proposed suite of public lighting services and prices?

56) Do you have any other comments on CitiPower, Powercor and United Energy's public lighting proposal and their pre-lodgement engagement?

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[174] AusNet, *EDPR 2026 - 2031 Regulatory Proposal*, January 2025, p. 345.

Glossary

Term	Definition
ACS	alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation capital expenditure
CBD	central business district
capex	capital expenditure
CAP	Consumer Advisory Panel
CER	consumer energy resources
CESS	capital expenditure sharing scheme
CMS	central management system
CoES	certificate of electrical safety
CPI	consumer price index
CSIS	customer service incentive scheme
DER	distributed energy resources
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
DNSP or distributor	distribution network service provider
DTP	Department of Transport and Planning
EBSS	efficiency benefit sharing scheme
ESV	Energy Safe Victoria
EV	electric vehicle
F&A	framework and approach
GSL	guaranteed service level
ICC	individually calculated customer
ICT	Information and communication technologies
ISP	Integrated System Plan
LED	light emitting diode

Term	Definition
LRMC	long run marginal cost
NEL	National Electricity Laws
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulated asset base
REFCL	rapid earth fault current limiter
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RORI	rate of return instrument
SCADA	supervisory control and data acquisition
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
TOU	time of use
TSS	tariff structure statement
VNR	value of network resilience