Final decision

CitiPower electricity distribution determination
1 July 2026 – 30 June 2031

Attachment 3 – Operating expenditure

April 2026

AUSTRALIAN ENERGY REGULATOR

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3 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of CitiPower's proposed opex forecast for the 2026–31 regulatory control period (2026–31 period).

3.1 Final decision

Our final decision is to accept CitiPower's total forecast opex of $555.8 million ($2025–26),[1] including debt raising costs, for the 2026–31 period.[2] This is because our alternative estimate of $551.1 million is not materially different ($4.7 million, or –0.8%, lower) than CitiPower's total forecast opex proposal. Therefore, we consider that CitiPower's total forecast opex reasonably reflects the opex criteria.

The difference in our alternative estimate is primarily driven by our lower forecasts for CitiPower's vegetation management step change and output growth, to reflect our assessment of efficient costs required for the 2026–31 period.

Our final decision (CitiPower's revised proposal) is:

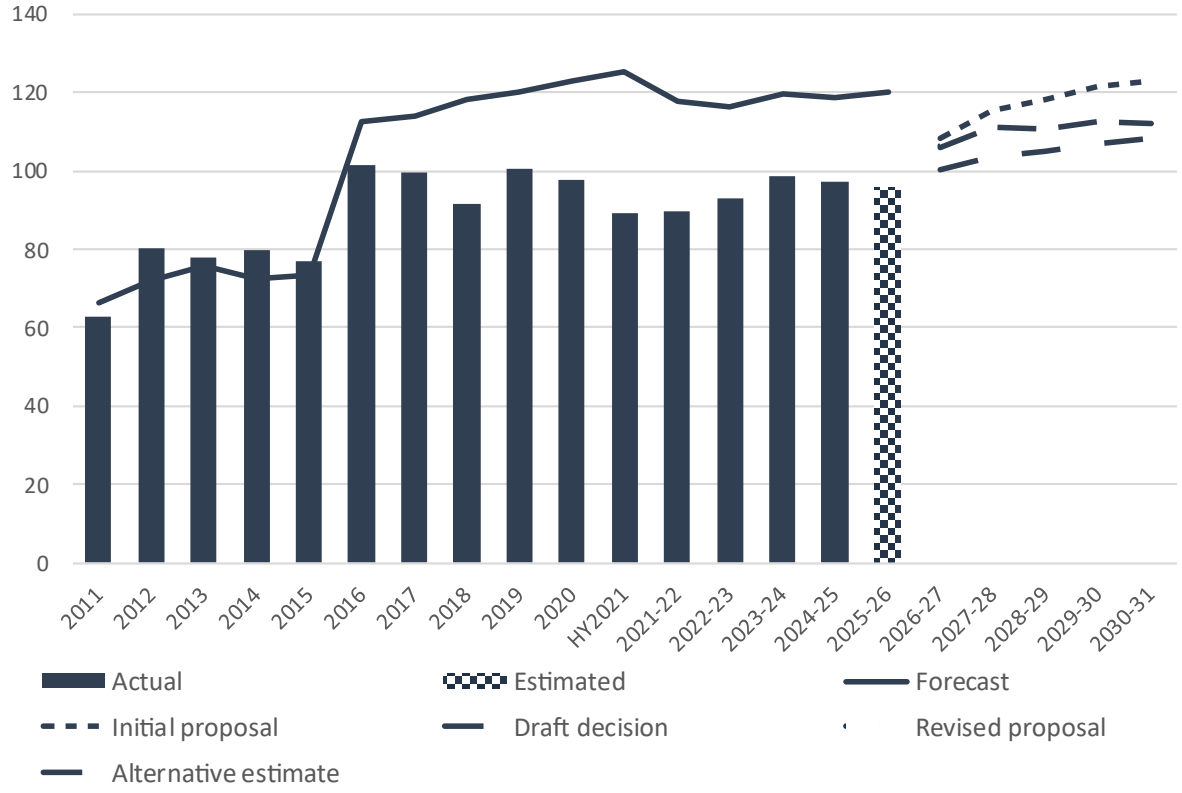
- $36.7 million (–6.2%) lower than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $81.5 million (17.2%) higher than CitiPower's actual (and estimated) opex in the 2021–26 period.

In Figure 3-1 we compare our alternative estimate of opex to CitiPower's proposal for the next regulatory control period, the forecasts we approved for the last 2 regulatory control periods, and CitiPower's actual and estimated opex over these periods.

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

2 CitiPower, *RRP MOD 2.05 – Opex*, December 2025.

Figure 3-1 Historical and forecast opex ($million, 2025–26)



Source: CitiPower, *Economic benchmarking – Regulatory Information Notice response 2010–24*; AER, *Final decision PTRM 2010–2015*; AER, *Final decision PTRM 2015–20*; AER, *Final decision 2021–26 PTRM*; CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.

Table 3-1 sets out CitiPower's revised opex proposal, our alternative estimate for the final decision and the differences between these forecasts.

Table 3-1 Comparison of CitiPower's revised opex proposal and our alternative opex estimate ($million, 2025–26)

Category	CitiPower Initial proposal	AER Draft decision	CitiPower Revised proposal	AER alternative estimate	Difference ($)
Based on reported opex in 2024–25	**474.1**	**473.9**	**476.6**	**490.5**	**13.9**
2024–25 to 2025–26 increment	**5.5**	**5.5**	**8.4**	**8.4**	**–0.0**
Remove category specific forecasts	**1.2**	**–0.2**	**–0.4**	**–0.3**	**0.1**
Base year adjustment: licence fees	**–1.8**	**–1.8**	**–1.8**	**–1.8**	**–**
Trend: Output growth	19.3	6.6	12.8	8.3	–4.5
Trend: Price growth	10.1	8.7	8.6	7.7	–0.9
Trend: Productivity growth	–7.2	–7.2	–7.3	–7.5	–0.2
Total trend	**22.1**	**8.2**	**14.1**	**8.6**	**–5.5**
Step change: Customer assistance package	6.8	–	–	–	–
Step change: vegetation management	33.6	8.7	14.7	3.5	–11.1
Step change: CER integration	12.3	9.4	12.2	12.2	–
Step change: cloud services	11.2	1.2	10.9	10.9	–
Step change: ICT modernisation	11.6	8.6	8.6	8.6	–
Step change: fleet electrification	–0.2	–0.2	–0.2	–0.2	–
Step change: Flexible trading arrangements	–	–	–	–1.1	–1.1
Total step changes	**75.3**	**27.8**	**46.3**	**34.0**	**–12.3**
GSL	0.3	0.2	0.3	0.3	0.0
Innovation Fund	2.9	0.5	1.9	1.1	–0.9
Customer assistance package	–	4.0	4.0	4.0	–
Total category specific forecasts	**3.1**	**4.8**	**6.2**	**5.4**	**0.9**
Debt raising costs	6.5	6.2	6.3	6.3	–0.0
Total	**586.1**	**524.4**	**555.8**	**551.1**	**–4.7 (–0.8%)**

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

The key differences between CitiPower's opex proposal, which we have accepted, and our alternative estimate are that we have included:

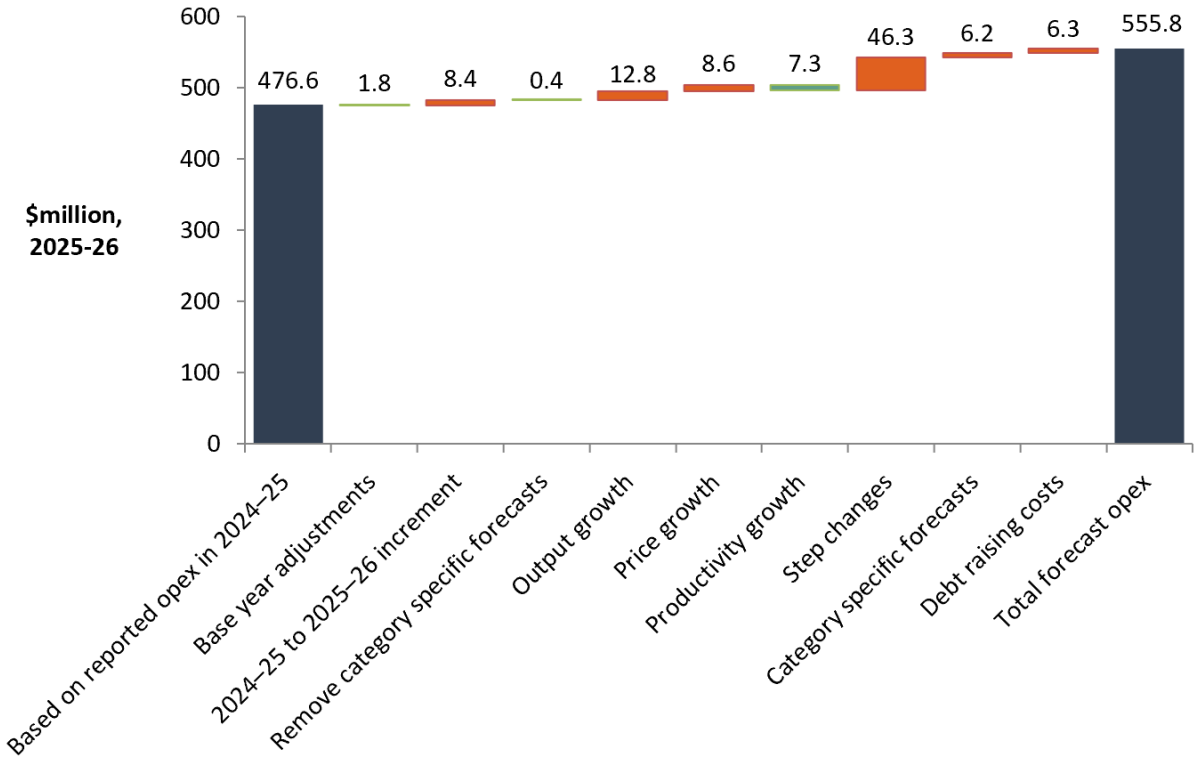
- a lower estimate for the vegetation management step change (–$11.1 million)
- a lower estimate for forecast output growth (–$4.5 million)
- a negative step change for the *Unlocking CER benefits through flexible trading* cost pass through (–$1.1 million)
- a lower estimate for CitiPower's proposed innovation fund (–0.9 million)
- updated inputs for inflation and base year opex.

3.2 CitiPower's revised proposal

CitiPower's revised proposal applied a base–step–trend approach to forecast opex for the 2026–31 period, consistent with our standard approach.[3]

CitiPower's forecast applying our base–step–trend approach is set out in Table 3-1. In Figure 3-2 below, we show the different components that make up CitiPower's opex forecast for the 2026–31 period.

Figure 3-2 CitiPower's revised opex forecast ($million, 2025–26)



Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.

3.2.1 Stakeholder views

We received 2 stakeholder submissions on CitiPower's revised opex proposal from:

[3] CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts, December 2025*, p. 51.

- CitiPower's Customer Advisory Panel, who were pleased that the AER had accepted most of CitiPower's customer assistance program in our draft decision, and who highlighted their support of CitiPower's innovation program in its revised proposal.[4]
- CCP32, on CitiPower's vegetation management step change, who noted the comprehensive review undertaken by EMCa and the AER in the draft decision. CCP32 considered the importance of vegetation management was clearly accepted, but the efficient implementation was questioned in the draft decision.[5]

3.3 Assessment approach

Under the regulatory framework, a business must include a forecast of total opex that 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 its network and contribute to achieving emissions reduction targets (the opex objectives).[6]

Our role is to decide whether to accept a business's total forecast opex. We are to form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[7] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER). [8]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[9] While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[10]

Our approach is to assess the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base step trend' approach.[11] We compare our alternative estimate with the business's total forecast opex to form a view on the reasonableness of the business's proposal. If we are satisfied the business's forecast reasonably reflects the opex criteria, we accept the forecast.[12] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[13]

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4 CPU Customer Advisory Panel, *Submission – CitiPower electricity distribution proposal 2026–31*, January 2026, 99. 1–8.

5 CCP32, *Submission, CitiPower electricity distribution proposal 2026–31*, January 2026, p. 16.

6 NER, cl. 6.5.6(a).

7 NER, cl. 6.5.6(c).

8 NER, cl. 6.5.6(e).

9 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024; AER, *explanatory statement – expenditure forecast assessment guideline*, November 2013.

10 NER, cl. 6.2.8(c)(1).

11 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total forecast opex from the 'bottom up.'

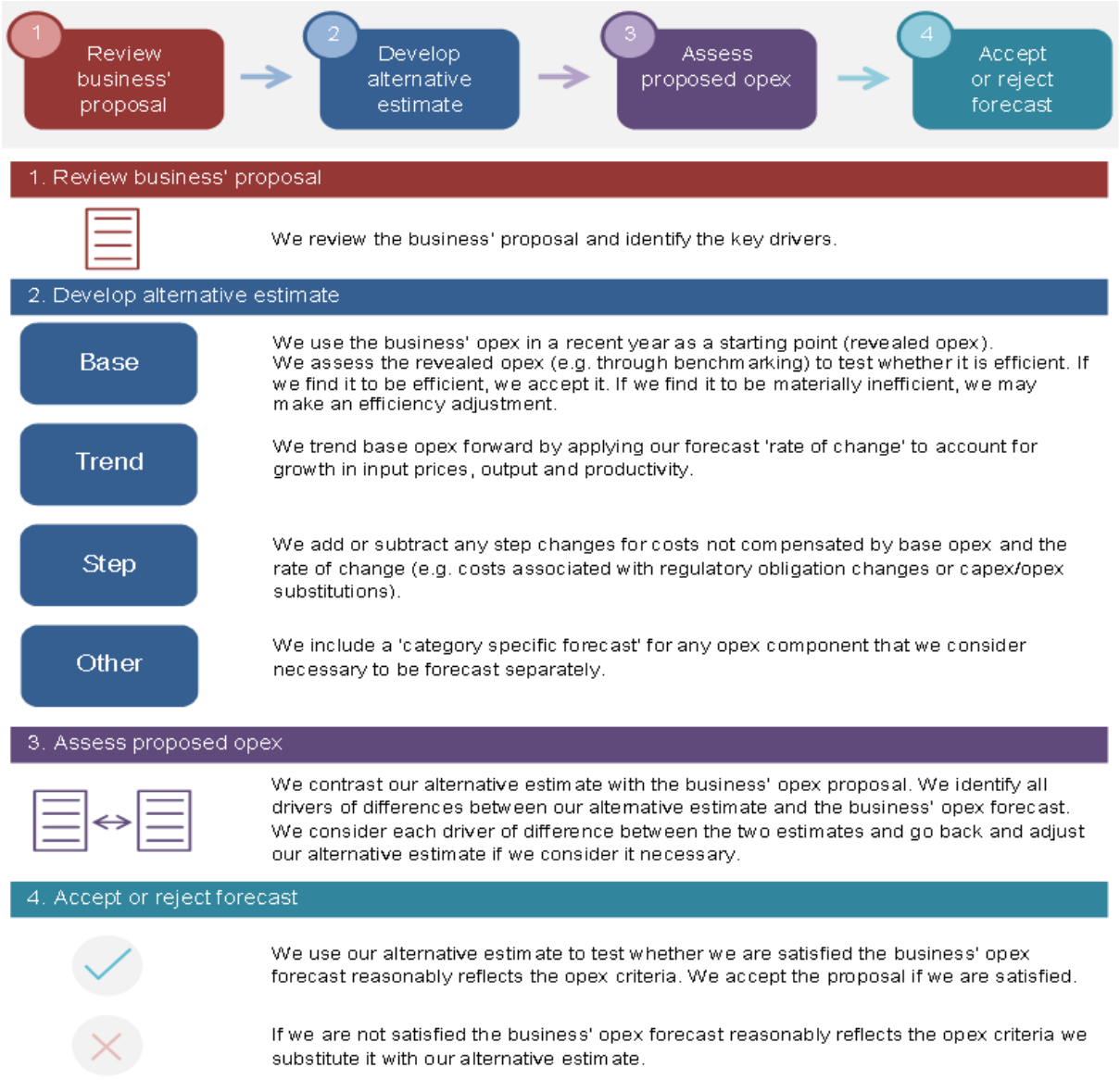
12 NER, cl. 6.5.6(c).

13 NER, cl. 6.5.6(c).

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we take into consideration interrelationships between opex and the other building block components of our decision.[14]

Figure 3-3 summarises the 'base step trend' forecasting approach.

Figure 3-3 Our opex assessment approach



3.3.1 Interrelationships

In assessing CitiPower's total forecast opex, we also took into account other components of its proposal that could interrelate with our opex decision. The matters we considered in this regard included:

[14] NEL, s. 16(1)(c).

- the Efficiency Benefit Sharing Scheme (EBSS) carryover—the level of opex used as the starting point to forecast opex (the final year of the current regulatory control period) should be the same as the level of opex used to forecast the EBSS carryover. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the EBSS in the 2021–26 period, which provided CitiPower an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- the outcomes of CitiPower's engagement with consumers and stakeholders in developing its proposal and any feedback we have had.

3.4 Reasons for draft decision

Our final decision is to accept CitiPower's total forecast opex of $555.8 million, including debt raising costs, for the 2026–31 period. Our alternative estimate of $551.1 million is not materially different from CitiPower's total forecast opex proposal (–$4.7 million, or –0.8%, lower). Therefore, we are satisfied that CitiPower's total opex forecast reasonably reflects the opex criteria, having regard to the opex factors.

Table 3-1 (above) sets out CitiPower's revised proposal, our alternative estimate that has informed this final decision, and the difference between our alternative estimate and the revised proposal.

The main drivers for this difference are also set out in section 3.1, and we discuss each of the components of our alternative estimate, and our assessment of CitiPower's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

3.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider CitiPower would need for the safe and reliable provision of network services over the 2026–31 period.

CitiPower proposed a base year of 2024–25 and base year opex of $95.3 million in its revised proposal (after having updated its initial proposal base year opex with actual 2024–25 data).[15] This equates to $476.6 million over the 5 years of the next regulatory control period. We accepted CitiPower's choice of base year in our draft decision, having found it unlikely to be materially inefficient.[16] Our assessment is unchanged in light of the

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15 CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts,* December 2025, p. 51.

16 AER, *Attachment 3 – Operating Expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 6–9.

latest results published in the 2025 Annual Benchmarking Report.[17] Our alternative estimate of CitiPower's 2024–25 base year is $490.5 million over the 5 years ($13.9 million higher than CitiPower's revised proposal), as a result of mechanical updates related to the most recent inflation data and movements in provisions.

CitiPower adjusted its base year opex to:

- remove movements in provisions
- add the final year increment
- remove the amounts for categories forecast separately, namely debt raising costs and GSL payments
- remove licence fees, which will be recovered as a jurisdictional scheme.

We applied the same adjustments in our final decision.

Consistent with CitiPower's revised proposal, we have included a higher final year increment than we did in our draft decision. This is to incorporate our decision on CitiPower's *Unlocking CER benefits through flexible trading* pass through application. To ensure the approved forecast opex reflects CitiPower's efficient costs for flexible trading arrangements over the 2026–31 period we have also included a step change, which we discuss in section 3.4.3.3.

In this final decision we have removed a smaller amount for GSL payments than CitiPower did. We have used the amount CitiPower reported in its annual information order for 2024–25, where it reported opex by category.

3.4.2 Rate of change

Having determined an efficient base year opex and estimated final year opex by adding a final year increment, we trend forward estimated final year opex to account for the forecast growth in prices, output and productivity over the regulatory control period. We refer to this as the rate of change.[18]

CitiPower largely applied our standard approach to forecast the rate of change, including:[19]

- **Price growth:** adopting our standard input price weightings of 59.2% labour and 40.8% non-labour. It forecast labour price growth using an average of the updated forecasts of the growth in the wage price index from BIS Oxford Economics (its consultant) and Deloitte Access Economics (our consultant).
- **Output growth:** applying the output weights from our 4 econometric models, consistent with our standard approach. It applied these weights to its forecasts of the growth in its customer numbers, circuit length and ratcheted maximum demand. We have only

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17 AER, 2025 *Annual Benchmarking Report – Electricity distribution network service providers*, November 2026, pp. 20–21.

18 AER, *Final decision – Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, pp. 22–24.

19 CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts, December 2025*, pp. 51–53.

provided an alternative estimate for CitiPower's ratcheted maximum demand forecast in our alternative estimate.

- **Productivity growth:** using our 0.5% per year productivity growth forecast, as per our draft decision.

The rate of change proposed by CitiPower contributed $14.1 million, or 2.5%, to CitiPower's revised total forecast opex of $555.8 million. This equates to an average opex increase of 0.9% each year. We have included a rate of change that contributes $8.6 million, or 1.6%, to our alternative estimate of total forecast opex of $551.1 million. This equates to an average opex increase of 0.6% each year in our alternative estimate.

Table 3-2 Forecast annual rate of change in opex (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower revised proposal					
Price growth	0.5	0.6	0.7	0.7	0.7
Output growth	1.7	0.4	0.5	0.5	0.6
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**1.7**	**0.4**	**0.7**	**0.7**	**0.8**
AER alternative estimate					
Price growth	0.4	0.5	0.6	0.7	0.7
Output growth	0.6	0.5	0.5	0.6	0.6
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.5**	**0.5**	**0.6**	**0.7**	**0.8**
Difference	**–1.2**	**0.0**	**–0.0**	**0.0**	**0.0**

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

3.4.2.1 Forecast price growth

CitiPower proposed average annual price growth of 0.6%, which increased its total opex forecast by $8.6 million. We have also used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex estimate by $7.7 million.

The key differences between our real price growth forecasts and CitiPower's are that we have updated our forecasts with the most recent inflation data and updated our labour price growth forecast to include more recent forecasts from our consultant, Deloitte Access Economics.

Table 3-3 compares our forecast labour price growth with CitiPower's revised proposal.

Table 3-3 Forecast labour price growth (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower revised proposal					
Deloitte Access Economics	0.7	0.9	1.1	1.1	1.0
BIS Oxford Economics	1.0	1.0	1.2	1.4	1.4
Average	**0.8**	**1.0**	**1.1**	**1.2**	**1.2**
AER's alternative estimate					
Deloitte Access Economics	0.3	0,7	0.8	0.9	0.9
BIS Oxford Economics	1.0	1.0	1.2	1.4	1.4
Average	**0.6**	**0.9**	**1.0**	**1.1**	**1.1**
Overall difference	**–0.2**	**–0.1**	**–0.1**	**–0.1**	**–0.1**

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

3.4.2.2 Forecast output growth

CitiPower proposed average annual output growth of 0.7%, which increased its proposed opex forecast by $12.8 million. We have forecast average annual output growth of 0.5%. This increases our alternative estimate by $8.3 million, which is $4.5 million less than CitiPower's proposal.

In our latest 2025 Annual Benchmarking Report, the Stochastic Frontier Analysis Translog model failed to converge and was excluded. As a result, we have only used the output weights derived from the 3 remaining econometric models in this final decision.

Forecast customer number and circuit length figures are unchanged from our draft decision and CitiPower's revised proposal. We have adjusted CitiPower's ratcheted maximum demand forecasts to exclude non-data centre block loads from the forecast.

In our draft decision, we stated that we were concerned that the non-data centre block loads included in CitiPower's system-level maximum demand forecasts may be double-counting load included in the trend growth. In its revised proposal, CitiPower stated that the maximum potential overlap was 2.9% of the total cumulative maximum demand growth of 4.5% from 2025–26 to 2030–31. CitiPower, however, considered that on balance it had likely under estimated demand growth because it did not include uncontracted data centres as block loads within its demand forecast.[20]

We sought further information from CitiPower, including the contribution of block loads to system-level maximum demand. We recognise that there is significant uncertainty regarding the forecast of data centre demand growth. However, we do not consider this to be a reason to overstate other sources of demand growth. Given CitiPower did not provide any evidence

[20] CitiPower, *Revised Proposal 2026–31, Revenue and expenditure forecasts*, December 2025, pp. 52–53.

that the non-data centre block loads were not captured within the trend growth used to forecast system-level maximum demand, we have not included it in the forecast of maximum demand we have used to forecast output growth.

We compare our ratcheted maximum demand growth with CitiPower's revised proposal in Table 3-4 below.

Table 3-4 Forecast growth in ratcheted maximum demand (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower revised proposal	3.2	–	0.3	0.3	0.6
AER revised proposal	0.6	0.2	0.4	0.5	0.7
Difference	**–2.6**	**0.2**	**0.1**	**0.2**	**0.1**

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '–' represents zero.

3.4.2.3 Forecast productivity growth

CitiPower proposed average productivity growth of 0.5% per year, which decreased its total opex by $7.3 million. We have forecast the same productivity growth rate, which reflects our standard approach. This decreases our alternative opex estimate by $7.5 million over the 2026–31 period.

3.4.3 Step changes

In developing our alternative estimate of total opex, we may include prudent and efficient step changes. As we explain in the Guideline, we will generally include a step change amount in our alternative estimate of total opex if the level of efficient base year opex and the rate of change in opex does not already account for the proposed step up in costs that is required to meet the opex criteria. This means that step changes should not double count costs implicitly provided through other components of forecast opex, such as the base year and rate of change.[21]

Under the top-down revealed cost approach we use to forecast total opex, actual total opex in the base year should reasonably reflect the opex criteria.[22] That is, it should be representative of the level of efficient, ongoing overall cost needed to provide the required level of safe and reliable distribution services in the next regulatory period. The base year is then trended forward to account for the overall increase in costs in the next period, considering the required increase in the quantity of inputs, the costs of those inputs, and the level of productivity or efficiencies that can be achieved by implementing good industry practices. The trend or rate of change component in our top-down base-step-trend opex

21 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 24.

22 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 22.

forecasting approach is based on econometric modelling of a total opex cost function.[23] That is, trend is calculated on a top-down basis, and is intended to model the change in total opex over time, such as for continued growth and adaptation of the business.

Where base and trend opex do not capture all cost changes that reasonably reflect the opex criteria, we may add step changes, such as for the cost of complying with a new regulatory obligation.[24] However, in assessing a step change, we must ensure it does not double count costs likely to be already provided for through the base and trend components of our top down opex forecasting approach, which can include costs otherwise provided for though the output measure, efficient discretionary changes in inputs, or costs from increased regulatory burden over time, which forecast productivity growth may already account for.[25]

For example, if the forecast increase in the regulatory burden over the regulatory period is consistent with the increase in regulatory burden over the sample period, step changes would not be required. We will only approve step change costs if they demonstrably do not reflect the historic 'average' change in costs.[26] Namely, the costs represent an upward step up in regulatory costs, and it can be demonstrated that it is not capable of being managed otherwise under total forecast opex through in-built provisions for output, price and productivity growth.[27]

We consider what might constitute a step change at each revenue reset, on a case-by-case basis, but our starting position is that only exceptional events are likely to require explicit compensation as step changes.[28] In determining whether the incremental cost of a proposed step change may be double counted, we do not apply a quantitative threshold, but may have regard to a range of factors, and the specific circumstances of a decision. These can include, but are not limited to, the extent to which the proposed cost represents an increase in a business's existing recurrent opex requirements, is likely to otherwise be provided for through the base year and trend growth used to forecast total opex; and is the result of an exceptional change to a business's existing inputs, activities, or level of service provision.

Table 3-1 shows the step changes CitiPower included in its initial and revised proposal, as well as the step changes we have included in our draft and final decision.

Our alternative estimate includes step changes that are $12.2 million lower than CitiPower's revised proposal, but are nevertheless $6.2 million higher than our draft decision. We discuss each step change further below.

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23 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, pp. 22–24.

24 AER, *Expenditure forecast assessment guideline – Explanatory statement – Final*, November 2013, p. 71; AER, *Better Resets Handbook*, July 2024, p. 26.

25 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 24.

26 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 24.

27 AER, *Better Resets Handbook*, July 2024, p. 26.

28 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 24.

3.4.3.1 Vegetation management step change

CitiPower proposed a $14.7 million step change for increased vegetation management costs.[29] We are satisfied that CitiPower requires additional forecast opex to comply with its regulatory obligations in the 2026–31 period, and have included a step change of $3.5 million in our alternative estimate of opex.

Table 3-5 Vegetation management step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	3.0	3.0	2.9	2.9	2.9	**14.7**
CitiPower amended forecast	1.5	1.4	1.4	1.4	1.4	**7.1**
AER alternative estimate	0.7	0.7	0.7	0.7	0.7	**3.5**
Difference	**−2.2**	**−2.2**	**−2.2**	**−2.2**	**−2.2**	**−11.1**

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

CitiPower has made substantial progress in addressing vegetation management compliance issues in the current period. Nonetheless, we consider, based on the information available, that CitiPower's total base opex, and the rate of change, is not sufficient for CitiPower to comply with its electric line clearance obligations in the 2026–31 period.

CitiPower's revised proposal

CitiPower stated that in recent years it has introduced helicopter mounted LiDAR technology to inspect its electricity lines for compliance against its obligations under the Electricity Safety (Electric Line Clearance) Regulations. Prior to using LiDAR, it relied on visual inspections. It stated that using LiDAR provides increased accuracy and precision that has shown previously unidentified non-compliance. It stated it needs increased opex (as a step change) to address this non-compliance.[30]

In its revised proposal, CitiPower stated that it had carefully considered our draft decision and made significant updates to its forecasts.[31] We sought further information from CitiPower on its revised proposal and, as part of its response, it provided an amended forecast of its vegetation management step change. However, CitiPower stated that, notwithstanding the issues it identified and addressed in the revised calculations, it did not propose to update its revised proposal vegetation management step change. It stated that, while it has confidence in its modelling, which has been further refined and improved due to the scrutiny from the AER, it recognised the inherent uncertainty in all forecasts and the sensitivity of its modelling outputs to key inputs.[32] We have based our assessment on this more recent forecast.

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29 CitiPower, *RRP MOD 2.05 – Opex*, December 2025.

30 CitiPower, *ATT 9.02, Vegetation management step change*, January 2025, pp. 2–4.

31 CitiPower, *RRP BUS 4.01, Vegetation management*, December 2025, p. 2.

32 CitiPower, *Response to information request IR#064*, 23 January 2026, p. 1.

Stakeholder engagement

We received one submission that addressed CitiPower's proposed vegetation management step change.

CCP32 noted the comprehensive review undertaken by EMCa and the AER in the draft decision. CCP32 considered the importance of vegetation management was clearly accepted, but the efficient implementation was questioned in the draft decision.[33]

Our assessment of CitiPower's vegetation management step change

We have found that CitiPower is not currently fully complying with all its vegetation management obligations, and are satisfied that it needs to increase its vegetation management expenditure to comply. However, we are not satisfied that the inputs and assumptions CitiPower used to forecast its step change are reasonable. We consider that the proposed step change overstates the additional opex it requires. Our alternative estimate of the required step change amount is $3.5 million.

CitiPower is not currently complying with its vegetation management obligations

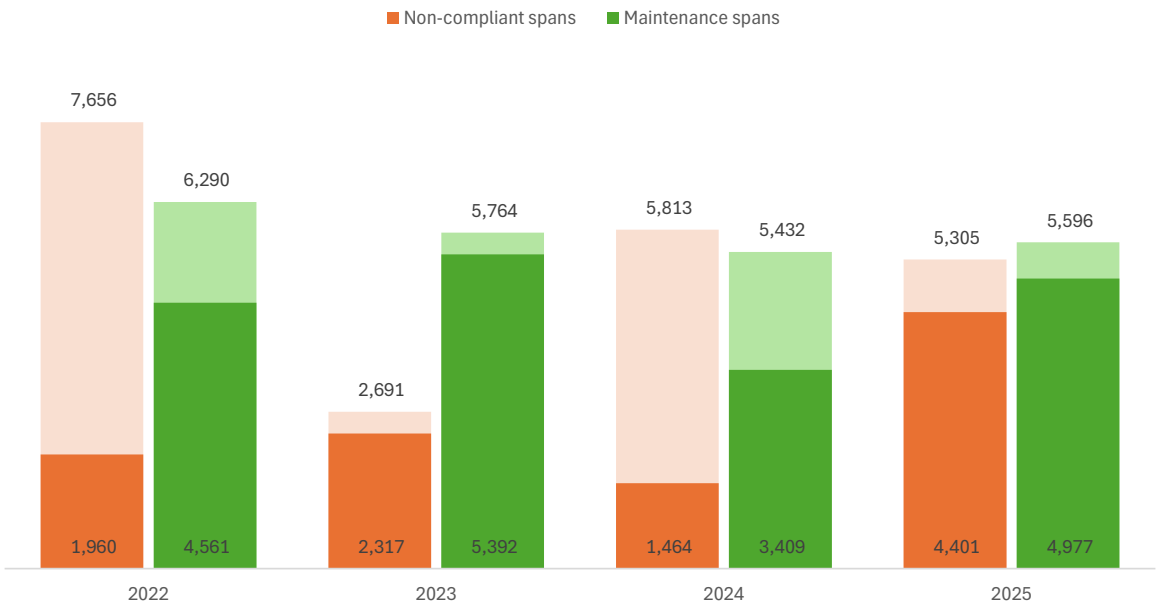
In the years since CitiPower introduced LiDAR, it has not been able to rectify all the non-compliant spans it has identified. This can be seen in Figure 3-4, which shows the number of spans cut and remaining in CitiPower's low bushfire risk areas (LBRA). We can see that CitiPower has made progress in cutting the number of non-compliant spans it has identified.

Since making our draft decision CitiPower has completed its vegetation management program for 2025. We now know that CitiPower made significant progress in its LBRA, but still had a significant number of 'remaining' spans.

We can also see that the total number of spans (cut and remaining) has been largely steady over time. We are satisfied that these total cut counts provide a reasonable basis on which to forecast cutting volumes.

[33] CCP32, *Submission, CitiPower electricity distribution proposal 2026–31*, January 2026, p. 16.

Figure 3-4 LBRA spans cut and remaining, 2022 to 2025



Source: CitiPower, *Response to information request IR017*, 22 April 2025; CitiPower, *Response to information request IR#062*, 23 January 2026; AER analysis.

CitiPower likely overstated the increase in cutting required

CitiPower forecast the number of additional cuts it would need to make based on the average number of spans it did not rectify in 2024 and 2025.

When we asked why an average of 2024 and 2025 was the appropriate basis for forecasting hourly rate cuts, rather than using just 2025, CitiPower stated the change in grow ins is due to seasonal variation, with the lower number in 2025 due to the cumulative impact of multiple years of low rainfall.[34] While we consider this has likely been a factor, we do not consider this likely to be the sole or primary reason. CitiPower has significantly increased its vegetation opex in recent years to improve its compliance. If the reduction in non-compliant spans has been due solely to weather, then the significant increase in vegetation management expenditure was not efficient.

We do not consider it reasonable to assume that 2024 and 2025 vegetation management expenditure was efficient and a reasonable basis for forecasting but also assume that the recent improvements in compliance have been solely due to weather factors beyond CitiPower's control.

We have used the volume of hourly rate cuts made in 2025

In the absence of useful evidence on which to forecast the number of hourly rate cuts, we propose using the approach used by CitiPower, but using the volume in 2025 rather than the average of 2024 and 2025. While favourable weather may have reduced the volume required in 2025, we also consider that the number of grow ins will otherwise reduce as CitiPower continues to improve its compliance.

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[34] CitiPower, *Response to information request IR#062*, 23 January 2026, p. 3.

Hazard trees

CitiPower stated that it has an obligation to assess hazard trees every 3 years. However, due to the lack of qualified resources, it only achieved these volumes in 2025. It forecast hazard tree removals based on its 2025 assessment volumes and historical find rates. On this basis, it forecast its hazard tree cutting opex would increase from $5,493 in 2024–25 to $17,097 each year.[35]

We sought further information from CitiPower as to why an increase in inspection frequency would lead to more hazard tree cutting. We noted that a change in inspection frequency would not change the number of trees that become hazard trees. It would only change when those trees are identified as hazardous.

In response to our information request, CitiPower agreed with this. In its amended vegetation management step change model, it forecast hazard tree cutting volumes based on its historic average rate.[36]

Given this, we do not consider the step change should include an amount for increased hazard tree cutting expenditure. We do not consider step changes are required when opex for a specific category is abnormally low in the base year. This is because forecasting some categories bottom up, but others using revealed cost risks upwardly biasing forecasts. This is because networks would have an incentive to only use an alternative forecasting approach for those lumpy cost categories where expenditure is atypically low in the base year. For categories where expenditure is higher than usual in the base year, they have an incentive to forecast using revealed costs. If total opex is not materially lumpy then a revealed cost forecast is appropriate regardless of whether individual categories are lumpy or not. Further, the EBSS shares any atypically high or low costs in the base year between the network and consumers.

Inspection costs

CitiPower forecast its inspection costs based on the average of its costs in calendar years 2024 and 2025. It then calculated the step change as the difference between the forecast costs and the costs incurred in financial year 2024–25 (the base year). CitiPower inspects its network on a calendar year cycle. Due to completing its inspections early in 2024, but later in 2025, its financial year 2024–25 inspections opex was unusually low. This timing difference, and CitiPower's forecasting approach, increases the proposed step change by $0.4 million.

For the reasons described in the hazard trees section above, we don't provide step changes because base year opex is atypically low (or high), particularly at the category level.

Given CitiPower has not identified any change in its obligations relating to vegetation management inspections, and is not proposing any changes to its inspection practices, we have not included an increase in opex for inspection costs in the vegetation management step change.

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35 CitiPower, *RRP MOD 2.05 – Opex*, December 2025.

36 CitiPower, *Response to information request IR#062*, 23 January 2026.

Rate of change

CitiPower stated that, in response to feedback in our draft decision, it amended its modelling to account for the impact of the rate of change, which reduced its forecast step change.

However, in doing so it used the rate of change from our draft decision, not the rate of change it subsequently used for its revised proposal opex forecast.

We have used the rate of change we have used in this final decision to calculate the vegetation management step change.

Difference between backcast and actual 2024–25 expenditure

As stated by CitiPower, its forecasting approach is sensitive to the modelling inputs and assumptions used. This sensitivity, at least in part, is due to the model forecasting total vegetation management opex, not just the additional expenditure required. Using the step change model to backcast vegetation management opex in 2024–25 yields a backcast amount $0.5 million higher than the actual opex incurred.

To address this, we have forecast the step change as the difference between forecast expenditure for the 2026–31 period and the backcast value for 2024–25.

3.4.3.2 Flexible trading arrangements pass through

We have included a negative step change of –$1.1 million to account for our decision on CitiPower's positive pass through application related to the *Unlocking CER benefits through flexible trading* rule change, which it submitted on 29 September 2025.[37] We have accepted this pass through event, and our reasons can be found on our website. This step change ensures that the total forecast opex we have approved in this decision provides the forecast opex we approved in the separate pass through decision.

CitiPower did not include this step change in its revised proposal, but did include the proposed 2024–25 and 2025–26 amounts in the approved forecast opex amounts it used to estimate total opex for 2025–26. These forecasts opex amounts were also used to forecast total opex for the 2026–31 period. The effect of this is that CitiPower's total forecast opex included the approved pass through amount for 2025–26, escalated for the rate of change, in each year of the 2026–31 period.

We have included this step change to ensure that our estimate of total opex reflects the opex amounts approved in the pass through application for the 2026–31 period. We calculated the step change as the difference between the forecast opex in the step change and the forecast opex for 2025–26, escalated by the rate of change.

[37] CitiPower, *Flexible trading arrangements (FTA) cost pass through application*, 29 September 2025.

Table 3-6 Flexible trading arrangements pass through step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	–	–	–	–	–	–
AER alternative estimate	0.4	0.0	–0.3	–0.6	–0.6	–1.1
Difference	**0.4**	**0.0**	**–0.3**	**–0.6**	**–0.6**	**–1.1**

Source: AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.4.3.3 Consumer Energy Resources (CER) integration step change

We have included $12.2 million for CER integration in our alternative estimate for the final decision. This is the same amount CitiPower included in its revised proposal, and reflects that we are satisfied that this step change is likely to be prudent and efficient.

Table 3-7 CER integration step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	0.8	2.6	2.7	3.0	3.1	12.2
AER alternative estimate	0.8	2.6	2.7	3.0	3.1	12.2
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '–' represents zero.

In its initial proposal, CitiPower proposed $12.3 million for CER integration to support its broad CER strategy, which it considered is required to meet the needs of an evolving network undergoing a fundamental energy transition.[38] This step change consisted of 3 sub-programs for flexible services, a non-network procurement platform, and data visibility. We discuss this step change, our assessment and the reasons for including a lower amount of $9.4 million, further in our draft decision.[39]

CitiPower's revised proposal included $12.2 million for CER integration, consisting of the same 3 sub-programs as its initial proposal:

1. Flexible services ($9.4 million). Our draft decision included $9.4 million for this program.
2. Non-network procurement platform ($1.5 million). Our draft decision did not include this program.
3. Data visibility ($1.3 million). Our draft decision did not include this program.

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[38] CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, pp. 14, 19– 30; CitiPower, *MOD 8.03 – Opex step changes*, January 2025.

[39] AER, *Attachment 3 – Operating expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 29–30; AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 47–51.

For its revised proposal, CitiPower provided additional information to support these programs, including its Distributed Service Operator (DSO) vision.[40] This further clarified how these programs will integrate to build CitiPower's DSO capabilities, and thus create value for its customers through the network transition and the continued growth of CER resources.[41]

The above programs all relate to investments proposed in CitiPower's capital expenditure proposal, and are consistent for all 3 businesses: CitiPower, Powercor and United Energy (CPU). Consistent with the draft decision, we have therefore jointly assessed this proposal with capex and across the CPU businesses. We provide details on each of these programs, our assessment and the reasons for our decisions (both opex and capex), in **Attachment 2** of this final decision. In summary, we have included costs as proposed for all 3 components of the CER integration step change.

3.4.3.4 'Cloud services' and 'ICT modernisation and new capability' step changes

We have included $19.5 million for 'Cloud services' and 'ICT modernisation and new capabilities' in our alternative estimate of total forecast opex for the final decision. This is the same amount CitiPower included in its revised proposal, and reflects that we are satisfied that these step changes are likely to be prudent and efficient.

Consistent with our draft decision, we have combined these 2 step changes as they largely reflect the recurrent (ICT modernisation & new capabilities) and non-recurrent (Cloud services) costs of the respective programs within the 2 step changes.

Table 3-8 Cloud services step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	1.5	3.7	2.2	2.5	1.0	10.9
AER alternative estimate	1.5	3.7	2.2	2.5	1.0	10.9
Difference	–	–	–	–	–	–

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '–' represents zero.

Table 3-9 ICT modernisation step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	0.2	1.0	1.9	2.6	2.9	8.6
AER alternative estimate	0.2	1.0	1.9	2.6	2.9	8.6
Difference	–	–	–	–	–	–

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis
Note: Numbers may not add up to totals due to rounding. Values of '–' represents zero.

[40] CitiPower, *RRP ATT 3.2.01 – DSO vision*, December 2025.

[41] CitiPower, *RRP ATT 3.2.01 – DSO vision*, December 2025, pp. 5–7.

CitiPower's initial proposal included $22.8 million for 'Cloud services' and 'ICT modernisation and new capabilities'. CitiPower submitted these costs were for additional opex to support new ICT programs, and for the reclassification of cloud services from capex to opex. The proposed costs consisted of 4 sub-programs: cyber security, infrastructure refresh, market interface technology enhancements (MITE), and enterprise resource planning and billing systems (ERP). We discuss this step change, our assessment and the reasons for including a lower amount of $9.8 million, in our draft decision.[42]

CitiPower's revised proposal included $19.5 million for these 2 step changes, or $3.3 million lower than its initial proposal. Consistent with its initial proposal, these step changes consist of 4 sub-programs:

1. Cyber security – $5.6 million. This is consistent with our draft decision.
2. Infrastructure refresh – $3.2 million. This is consistent with our draft decision.
3. MITE – $0.9 million. This is consistent with our draft decision.
4. ERP – $9.7 million, or $1.1 million lower than its initial proposal. Our draft decision did not include costs for this program.

CitiPower's revised proposal provided further information to address some of the concerns raised in the draft decision, especially related to its cloud services step change and the Software-as-a-Service implementation element in its ERP and billing system. Based on our review of this information, including through information obtained through subsequent information requests, we are satisfied that this ERP component reflects prudent and likely efficient costs. This is also consistent with our recent treatment of SaaS implementation costs.[43]

For our final decision, we have therefore included the proposed $19.5 million for the 'Cloud services' and 'ICT modernisation and new capabilities' step changes. This is $9.7 million more than our draft decision, and reflects the incremental amount for the ERP and billing system component.[44]

3.4.3.5 Fleet electrification step change

CitiPower's revised proposal included a forecast of –$0.2 million for its fleet electrification step change. This amount remains unchanged from our draft decision.

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42 AER, *Attachment 3 – Operating expenditure – Draft decision – CitiPower distribution determination 2026–31, September 2025*, pp. 30–31; AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 37–46.

43 AER, *Final decision, Attachment 6 – Operating expenditure – Ausgrid – 2024–29 Distribution revenue proposal*, April 024, pp. 15–16.

44 CitiPower, *RRP MOD 4.02 – Opex step changes*, 18 December 2025.

Table 3-10 Fleet electrification step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	–	–0.0	–0.0	–0.0	–0.0	–0.2
AER alternative estimate	–	–0.0	–0.0	–0.0	–0.0	–0.2
Difference	**–**	**–**	**–**	**–**	**–**	**–**

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

3.4.4 Category specific forecasts

CitiPower's revised proposal included 4 category specific forecasts, which were not forecast using the base-step-trend approach. These were for[45]:

- Customer assistance package ($4.0 million)
- Network innovation fund ($1.9 million)
- GSL Payments ($0.3 million)
- Debt raising costs ($6.3 million)

3.4.4.1 Customer assistance package

CitiPower's revised proposal accepted our draft decision for its customer assistance package forecast of $4.0 million. We have included the same amount in our alternative estimate.

Table 3-11 Customer assistance package ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	0.8	0.8	0.8	0.8	0.8	4.0
AER alternative estimate	0.8	0.8	0.8	0.8	0.8	4.0
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis
Note: Numbers may not add up to totals due to rounding. Values of '–' represents zero.

3.4.4.2 Innovation fund

We have included $1.1 million for the innovation fund in our final decision. This is $0.9 million lower than CitiPower's proposal, and reflects that we are not satisfied that all proposed costs are prudent and efficient, including that they do not satisfy our innovation criteria.[46]

45 CitiPower, *RRP MOD 2.05 – Opex*, December 2025; AER analysis.

46 AER, *Final decision, Attachment 5 – Capital expenditure – Ausgrid – 2024–29 Distribution revenue proposal,* April 2024, p. 37.

Table 3-12 Innovation fund ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	0.5	0.6	0.3	0.2	0.3	1.9
AER alternative estimate	0.2	0.2	0.2	0.2	0.2	1.1
Difference	**–0.3**	**–0.4**	**–0.1**	**–0.0**	**–0.0**	**–0.9**

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

CitiPower's initial proposal included $2.9 million for an innovation fund, consisting of 12 projects broadly grouped in 3 categories:

1. Assisting the energy transition
2. Improving customer experiences
3. Developing sustainable networks.

We discuss this proposal, our assessment and the reasons for including a lower amount of $0.5 million, further in our draft decision.[47]

CitiPower's revised proposal included $1.9 million for an innovation fund, consisting of 9 projects.[48] These projects all also relate to investments proposed in CitiPower's capital expenditure proposal, and are largely consistent for all 3 CPU businesses.

Consistent with the draft decision, we have jointly assessed this proposal with capex and across the CPU businesses. We provide details on each of these programs, our assessment and the reasons for our decisions (both opex and capex), in **Attachment 2** of this final decision.

3.4.4.3 Guaranteed service level (GSL) payments

CitiPower's revised proposal included a forecast of $0.3 million for GSL payments. Its forecast of GSL payments is based on an average of customer outages over the years 2021–22 to 2024–25. CitiPower updated the forecast in its revised proposal to reflect its actual customer outages in 2024–25. Its initial proposal, and our draft decision, used an estimate of outages for 2024–25.

We have also included a forecast of $0.3 million in our alternative estimate. We have updated CitiPower's revised proposal forecast to reflect our final decision on forecast inflation.

47 AER, *Attachment 3 – Operating expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 32–33; AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 51–57.

48 CitiPower, *RRP MOD 3.8.01 – Innovation allowance cost-benefit analysis*, December 2025.

Table 3-13 GSL payments ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	0.1	0.1	0.1	0.1	0.1	0.3
AER alternative estimate	0.1	0.1	0.1	0.1	0.1	0.3
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

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

3.4.4.4 Debt raising costs

We have included debt raising costs of $6.3 million in our alternative estimate. CitiPower's revised proposal also included a forecast of $6.3 million for debt raising costs.

Table 3-14 Debt raising costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower revised proposal	1.2	1.2	1.3	1.3	1.3	6.3
AER alternative estimate	1.2	1.2	1.3	1.3	1.3	6.3
Difference	**0.0**	**0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

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

Shortened forms

Term	Definition
AER	Australian Energy Regulator
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	Consumer Energy Resources
CPU	CitiPower, Powercor and United Energy
EBSS	Efficiency benefit sharing scheme
ERP	Enterprise resource planning and billing systems
DSO	Distributed Service Operator
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	Guaranteed service levels
LBRA	Low bushfire risk areas
MITE	Market interface technology enhancements
NEL	National Electricity Law
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
opex	operating expenditure