Final decision

Powercor electricity distribution determination
1 July 2026 – 30 June 2031

Attachment 3 – Operating expenditure

April 2026

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	30 April 2026	34

Contents

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 Powercor's proposed opex forecast for the 2026–31 regulatory control period (2026–31 period).

3.1 Final decision

Our final decision is to not accept Powercor's total forecast opex of $2,064.5 million,[1] including debt raising costs, for the 2026–31 period.[2] This is because our alternative estimate of $2,029.7 million is materially different ($34.7 million, or 1.7%, lower) than Powercor's total forecast opex proposal. Therefore, we consider that Powercor's total forecast opex does not reasonably reflect the opex criteria.

This difference is primarily driven by our lower alternative estimate for Powercor's vegetation management step change, a lower output growth forecast and our negative insurance step change, to reflect our assessment of efficient costs required for the 2026–31 period.

Our final decision is:

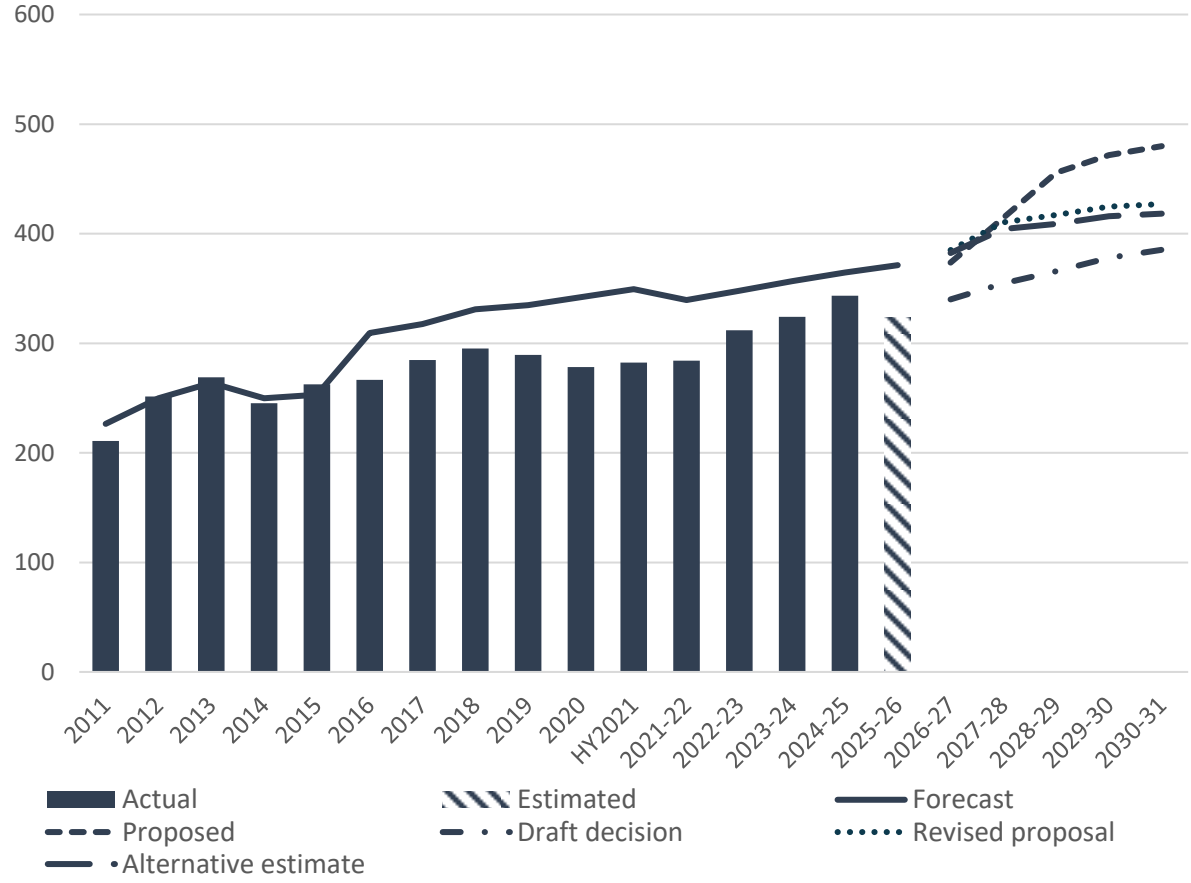
- $250.0 million (14.0%) higher than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $442.5 million (27.9%) higher than Powercor's actual (and estimated) opex in the 2021–26 period.

In Figure 3-1 we compare our alternative estimate of opex to Powercor's proposal for the 2026–31 period, the forecasts we approved for the last 2 regulatory control periods, and Powercor's actual and estimated opex over these periods.

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

2 Powercor, *PAL MOD 2.05 – Opex*, December 2025

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



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

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

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

Category	Powercor initial proposal	AER draft decision	Powercor revised proposal	AER alternative estimate	Difference ($)
Based on estimated opex in 2024–25	**1,610.4**	**1,609.7**	**1,679.0**	**1,696.9**	**17.9**
Non-recurrent efficiency gain	**–**	**71.6**	**–**	**–**	**–**
2024–25 to 2025–26 increment	**33.7**	**33.7**	**40.4**	**40.6**	**0.2**
Remove category specific forecasts	**−20.4**	**−20.4**	**−20.4**	**−9.1**	**11.3**
Base year adjustment: licence fees	**−4.7**	**−4.7**	**−4.7**	**−4.7**	**–**
Trend: Output growth	177.9	108.2	184.5	166.7	−17.8
Trend: Price growth	34.2	31.1	30.2	26.8	−3.4
Trend: Productivity growth	−24.6	−25.6	−25.6	−26.0	−0.4
Total trend	**187.6**	**113.8**	**189.1**	**167.5**	**−21.5**
Step change: customer assistance package	26.7	–	–	–	–
Step change: vegetation management	232.9	–	53.3	23.5	−29.8
Step change: CER integration	28.7	22.0	28.6	28.6	–
Step change: cloud services	26.1	2.7	25.4	25.4	–
Step change: ICT modernisation	22.0	20.1	20.1	20.1	–
Step change: network resilience	6.8	–		–	
Step change: fleet electrification	−1.0	−1.0	−1.0	−1.0	–
Step change: insurance	–	−76.4	–	−6.9	−6.9
Step change: flexible trading arrangements	–	–	–	−3.1	−3.1
Total step changes	**342.2**	**−32.5**	**126.4**	**86.6**	**−39.8**
GSL	20.5	18.0	16.6	16.3	−0.4
Innovation Fund	7.9	1.8	4.4	2.0	−2.5
Customer assistance package	–	15.8	15.8	15.8	–
Total category specific forecasts	**28.5**	**35.6**	**36.8**	**34.0**	**−2.8**
Debt raising costs	18.5	17.4	17.9	18.0	0.0
Total	**2,195.8**	**1,824.2**	**2,064.5**	**2,029.7**	**−34.7**

Source: Powercor, *PAL 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 Powercor's revised opex proposal, which we have not accepted, and our alternative estimate are that we have included:

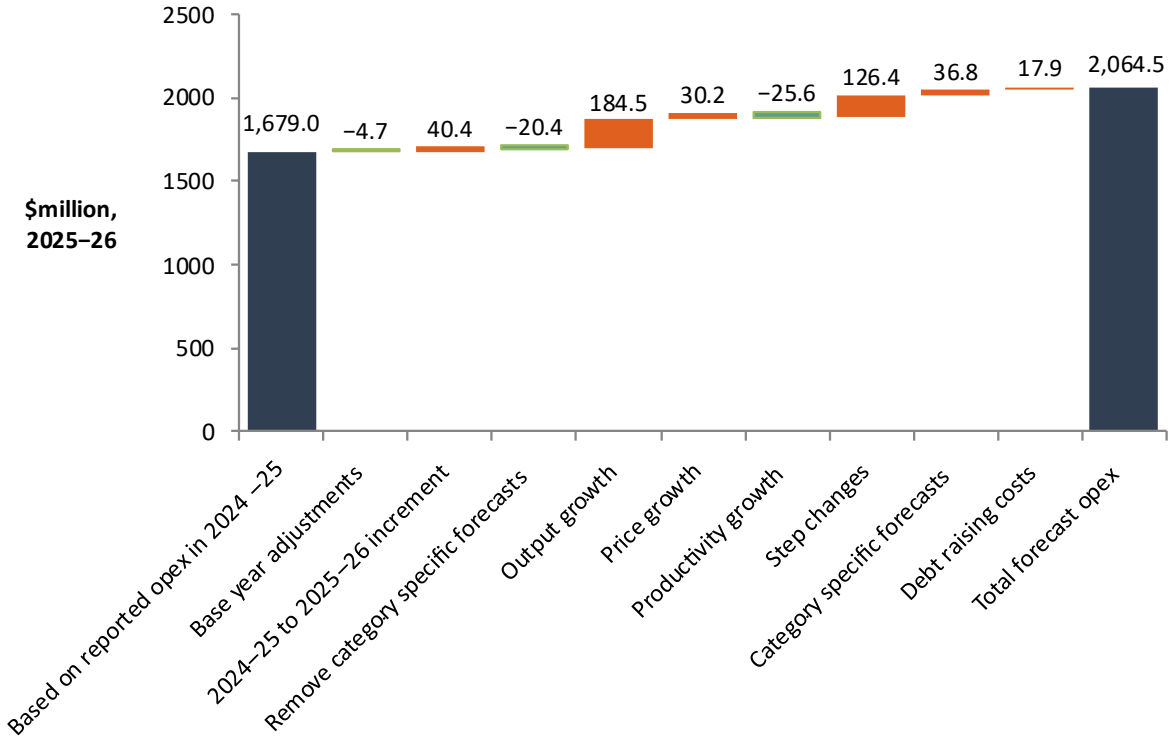
- a lower estimate for the vegetation management step change (–$29.8 million)
- a lower estimate for forecast output growth (–$17.8 million)
- a negative step change for insurance (–$6.9 million)
- a negative step change for the *Unlocking CER benefits through flexible trading* cost pass through (–$3.1 million)
- a slightly lower estimate for Powercor's proposed innovation fund
- updated inputs for inflation and base year opex.

3.2 Powercor's revised proposal

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

Powercor's forecast is set out in Table 3-1. In Figure 3-2 below we show the different components that make up Powercor's opex forecast for the 2026–31 period.

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



Source: Powercor, *PAL 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] Powercor, *Revised Proposal 2026–31 – Revenue and expenditure forecasts, December 2025*, pp. 63–72.

3.2.1 Stakeholder views

We received three stakeholder submissions on Powercor's revised opex proposal from:

- Powercor's Customer Advisory Panel, who were concerned about the removal of Powercor's vegetation management and network resilience expenditure in our draft decision[4]
- Ausgrid, who did not support the AER's negative insurance step change for Powercor, as it potentially engendered regulatory uncertainty for all distributors and undermined the effectiveness of incentive frameworks[5]
- the Committee of Greater Shepparton, who had broad concern about the reduction of Powercor's expenditure in our draft decision, including our reduction to innovation and network resilience expenditure.[6]

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).[7]

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'.[8] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER). [9]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[10] 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.[11]

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.[12] We compare our alternative estimate with the business's total

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4 CPU Customer Advisory Panel, Submission – Powercor *electricity distribution proposal 2026-31*, January 2026, pp. 6 – 7.

5 Ausgrid, *Submission – Victorian electricity distribution proposals 2026-31*, January 2026, p. 1.

6 Committee for Greater Shepparton, *Submission – Powercor electricity distribution proposal 2026-31*, January 2026, pp. 1 – 4.

7 NER, cl. 6.5.6(a).

8 NER, cl. 6.5.6(c).

9 NER, cl. 6.5.6(e).

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

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

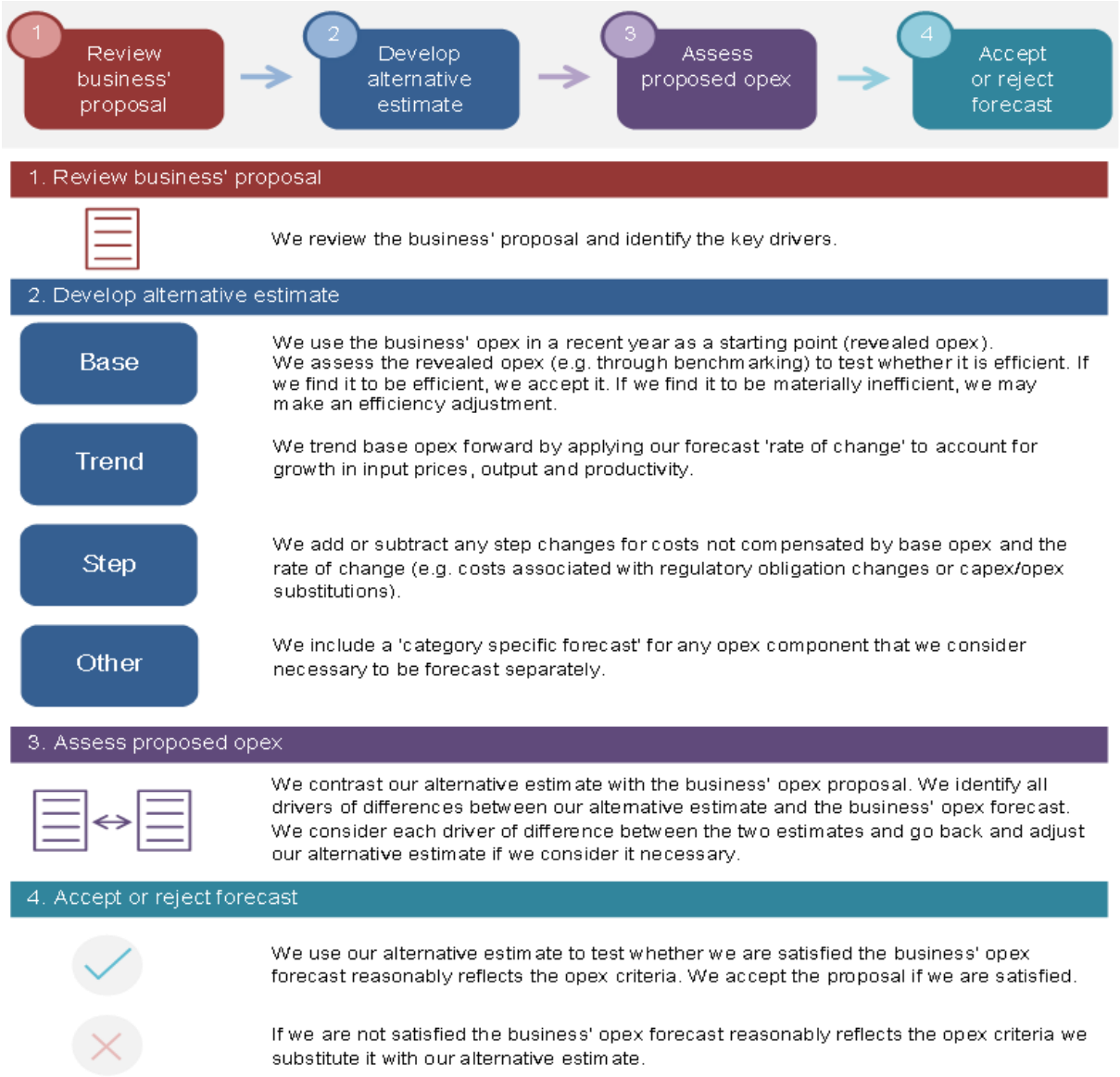
12 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total forecast opex from the 'bottom up.'

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.[13] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[14]

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.[15]

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

Figure 3-3 Our opex assessment approach



13 NER, cl. 6.5.6(c).

14 NER, cl. 6.5.6(d).

15 NEL, s. 16(1)(c).

3.3.1 Interrelationships

In assessing United Energy'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:

- 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 Powercor 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 Powercor'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 not accept Powercor's total forecast opex of $2,064.5 million, including debt raising costs, for the 2026–31 period. This is because we consider our alternative estimate of $2,029.7 million is materially different from Powercor's revised total forecast opex ($34.7 million, or 1.7%, lower). Therefore, we are not satisfied that Powercor's total forecast opex reasonably reflects the opex criteria, having regard to the opex factors.

Table 3-1 (above) sets out Powercor'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 Powercor'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 Powercor needs for the safe and reliable provision of network services over the 2026–31 period.

Powercor proposed a base year of 2024–25 and base year opex of $335.8 million in its revised proposal. This updated the estimate of 2024–25 opex it used in its initial proposal.[16]

[16] Powercor, *Revised Proposal 2026–31 – Revenue and expenditure forecasts, December 2025*, pp. 63–65.

This equates to $1,679.0 million over the five years of the next regulatory control period. We accepted Powercor's choice of base year in our draft decision, having found it unlikely to be materially inefficient.[17] Our assessment is unchanged in light of the latest results published in the 2025 Annual Benchmarking Report.[18]

Our alternative estimate of Powercor's 2024–25 base year is $1,696.9 million over the five years ($17.9 million higher than Powercor's revised proposal). Our higher amount is due to us removing lower amounts for guaranteed service level (GSL) payments, consistent with those reported in its 2024–25 annual information order, and using a more recent forecast of inflation for the year to June 2026.

Powercor adjusted its base year opex to:

- remove movements in provisions
- add the final year increment
- remove 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 Powercor's revised proposal, we have included a higher final year increment than in our draft decision. This is to incorporate our decision on Powercor's *Unlocking CER benefits through flexible trading* pass through application. To ensure the approved forecast opex reflects Powercor'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 below.

In this final decision we have removed a smaller amount for GSL payments than Powercor did ($1.8 million each year compared to the $4.0 million each year Powercor used for its revised proposal). We have used the amount Powercor reported in its annual information order for 2024–25, where it reported opex by category.[19]

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.[20]

Powercor largely applied our standard approach to forecast the rate of change, including:[21]

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

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

19 Specifically, we have used the amount reported in EB RIN table 3.2.1.

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

21 Powercor, *Revised Proposal 2026-31 – Revenue and expenditure forecasts, December 2025*, pp. 65–66.

- **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 updated forecasts of the growth in the wage price index (WPI) from BIS Oxford Economics (its consultant) and Deloitte Access Economics (our consultant).
- **Output growth:** applying the output weights from our four 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 updated the 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 Powercor contributed $189.1 million, or 9.2%, to Powercor's revised total forecast opex of $2,064.5 million. This equates to an average opex increase of 3.1% each year. We have included a rate of change that contributes $167.5 million, or 8.3%, to our alternative estimate of total forecast opex of $2,029.7 million. This equates to an average opex increase of 2.8% 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
Powercor revised proposal					
Price growth	0.5	0.6	0.7	0.7	0.7
Output growth	3.7	4.9	2.9	1.8	1.7
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**3.7**	**5.0**	**3.0**	**2.1**	**1.9**
AER alternative estimate					
Price growth	0.4	0.5	0.6	0.7	0.7
Output growth	3.2	4.5	2.6	1.7	1.7
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**3.0**	**4.5**	**2.7**	**1.9**	**1.8**
Difference	**–0.6**	**–0.5**	**–0.3**	**–0.2**	**–0.1**

Source: Powercor, *PAL 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.

3.4.2.1 Forecast price growth

Powercor proposed average annual price growth of 0.6%, which increased its total forecast opex by $30.2 million over the regulatory period. We have used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex estimate by $26.8 million over the regulatory period.

The key difference between our real price growth forecasts and Powercor's is that we have 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 Powercor's proposal.

Table 3-3 Forecast labour price growth (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
Powercor 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: Powercor, *PAL 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.

3.4.2.2 Forecast output growth

Powercor proposed average annual output growth of 3.0%, which increased its proposed opex forecast for the 2026–31 period by $184.5 million. We have forecast average annual output growth of 2.7%. This increases our alternative estimate of total opex by $166.7 million, which is $17.8 million less than Powercor'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 three remaining econometric models in this final decision.

Forecast customer number and circuit length figures are unchanged from our draft decision and Powercor's revised proposal. We have adjusted Powercor'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 Powercor's system-level maximum demand forecasts may be double-counting load included in the trend growth. In its revised proposal, Powercor stated that the maximum potential overlap was 2.0% of the total cumulative maximum demand growth of 30.1% from 2025–26 to 2030–31.[22] Powercor, however, considered that on balance it had likely

[22] Powercor, *Revised Proposal 2026–31*, *Revenue and expenditure forecasts*, December 2025, pp. 65–66.

under-estimated demand growth because it did not include uncontracted data centres as block loads within its demand forecast.

We sought further information from Powercor, 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 Powercor did not provide any evidence 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 forecast with Powercor'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
Powercor's revised proposal	6.9	9.9	4.9	2.4	2.1
AER final decision	5.7	9.0	4.3	2.2	2.0
Difference	**–1.2**	**–1.0**	**–0.6**	**–0.2**	**–0.1**

Source: Powercor, *PAL 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.

3.4.2.3 Forecast productivity growth

Powercor proposed average productivity growth of 0.5% per year, which decreased its total opex by $25.6 million. We have forecast the same average productivity growth rate, which reflects our standard approach. This decreases our alternative opex estimate by $26.0 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.[23]

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.[24] That is, it should be representative of the level of efficient, ongoing overall cost needed to provide the required

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

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

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 forecasting approach is based on econometric modelling of a total opex cost function.[25] 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.[26] 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.[27]

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.[28] 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.[29]

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.[30] 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 Powercor included in its initial and revised proposal, as well as the step changes we have included in our draft and final decision.

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

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

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

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

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

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

Our alternative estimate includes total step changes of $86.6 million, which is $39.8 million lower than Powercor's revised proposal, but nevertheless $119.1 million higher than our draft decision. We discuss each step change further below.

3.4.3.1 Vegetation management step change

Powercor proposed a $53.3 million step change for increased vegetation management costs.[31] We are satisfied that Powercor requires additional forecast opex to comply with its regulatory obligations in the 2026–31 period, and have included a step change of $23.5 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
Powercor revised proposal	16.9	13.6	10.6	7.4	4.8	**53.3**
Powercor amended forecast	20.8	17.5	14.4	11.2	8.6	**72.6**
AER alternative estimate	11.5	7.1	4.1	1.6	−0.8	**23.5**
Difference	**−5.4**	**−6.5**	**−6.5**	**−5.7**	**−5.6**	**−29.8**

Source: Powercor, *PAL 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.

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

Powercor's revised proposal

Powercor 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.[32]

In its revised proposal, Powercor stated that it had carefully considered our draft decision and made significant updates to its forecasts.[33] We sought further information from Powercor on its revised proposal and, as part of its response, it provided an amended forecast of its vegetation management step change. However, Powercor 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

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

32 Powercor, *PAL ATT 9.02, Vegetation management step change*, January 2025, pp. 2–4.

33 Powercor, *PAL RRP BUS 4.01, Vegetation management*, December 2025, p. 2.

AER, it recognised the inherent uncertainty in all forecasts and the sensitivity of its modelling outputs to key inputs.[34] We have based our assessment on this more recent forecast.

Stakeholder engagement

We received 2 submissions that addressed Powercor's proposed vegetation management step change.

Powercor's Customer Advisory Panel stated that vegetation management has a major impact on affected communities and 'many customers in those communities might be surprised by the AER's outright rejection of the vegetation management step change'.[35]

CCP32 noted the comprehensive review undertaken by EMCa and the AER in the draft decision. CCP32 considered there was no suggestion that the importance of vegetation management was not accepted. Rather, it was the efficient implementation that was questioned in the draft decision.[36]

Our assessment of Powercor's vegetation management step change

We have found that Powercor 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 Powercor 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 $23.5 million.

Powercor is not currently complying with its vegetation management obligations

In the years since Powercor 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 and Figure 3-5, which show the number of spans cut and remaining in Powercor's high bushfire risk areas (HBRA) and low bushfire risk areas (LBRA). We can see that Powercor has made significant progress in its HBRA, but is less progressed in its LBRA.

In our draft decision we stated that it appeared that Powercor might rectify all its non-compliant spans in its HBRA in 2025.[37] We now know that Powercor cut most, but not all its non-compliant and maintenance spans in its HBRA in 2025.

Powercor also made significant progress in its LBRA, but still had a significant number of 'remaining' spans.

We can 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.

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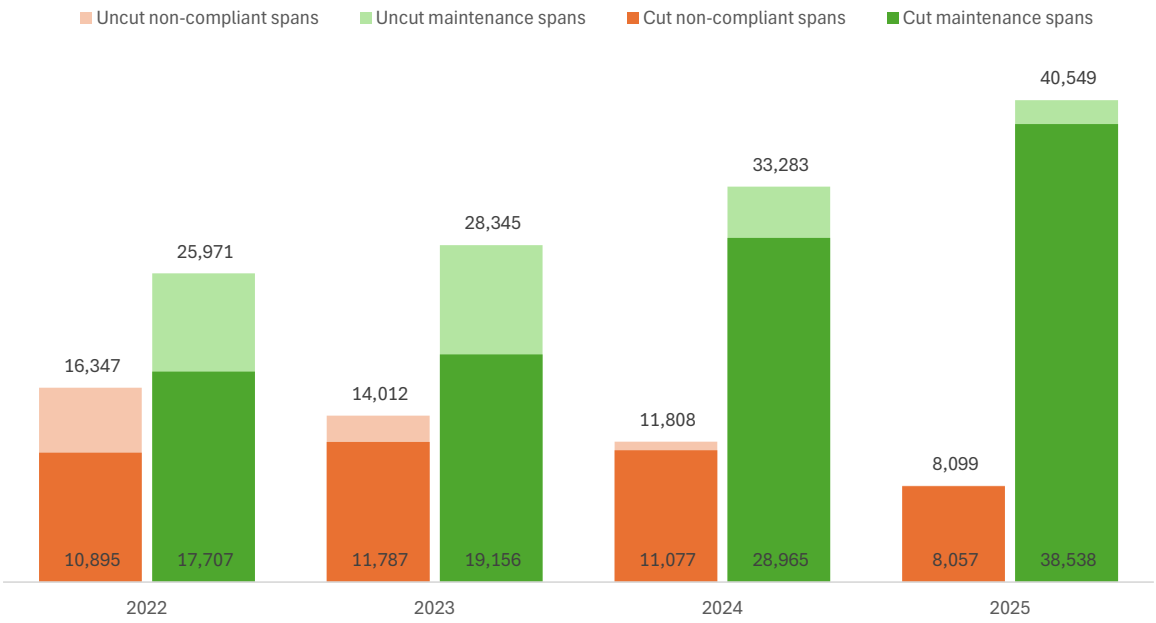
34 Powercor, *Response to information request IR#064*, 23 January 2026, p. 6.

35 CPU Customer Advisory Panel, *Submission, Powercor electricity distribution proposal 2026–31*, January 2026, p. 7.

36 CCP32, *Submission, Powercor electricity distribution proposal 2026–31*, January 2026, p. 17.

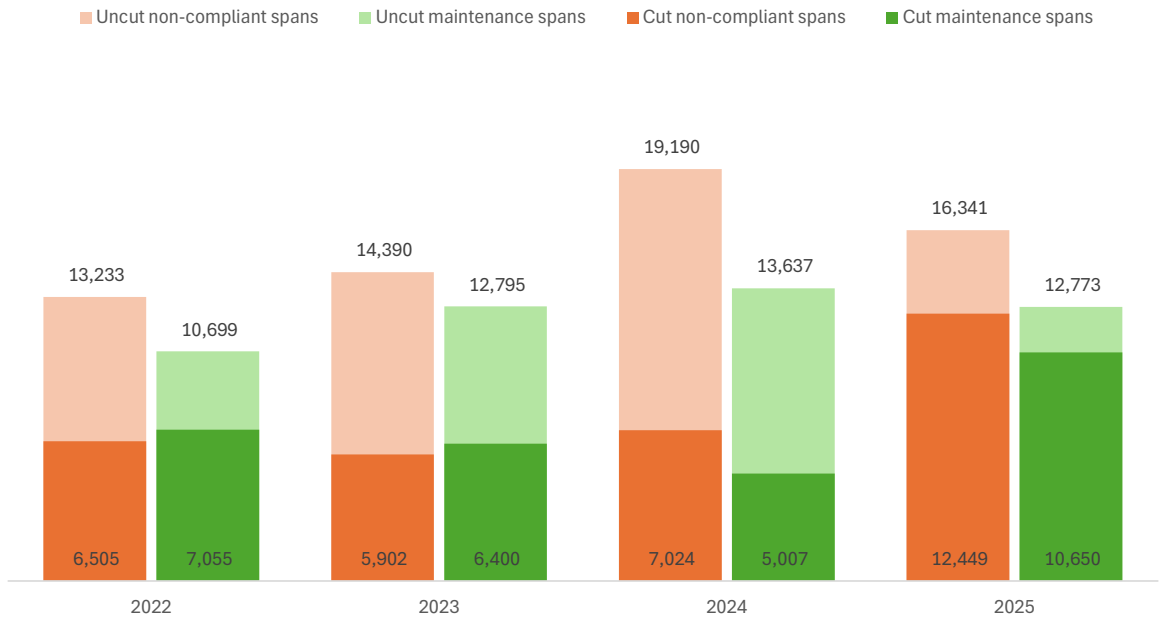
37 AER, *Draft decision, Powercor distribution determination 2026–31, Attachment 3, Operating expenditure*, September 2025, p. 26.

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



Source: Powercor, *Response to information request IR016*, 24 April 2025; Powercor, *Response to information request IR#064*, 23 January 2026; AER analysis.

Figure 3-5 LBRA spans cut and remaining, 2022 to 2025



Source: Powercor, *Response to information request IR016*, 24 April 2025; Powercor, *Response to information request IR#064*, 23 January 2026; AER analysis.

In its revised proposals, Powercor also stated that it needed to increase its volumes of hourly rate cutting. It then applied a glidepath to transition toward compliant cutting timeframes.[38]

[38] Powercor, *PAL RRP BUS 4.01, Vegetation management*, December 2025, p. 7.

Broadly, Powercor's vegetation management program includes span rate cutting and hourly rate cutting. Powercor stated that it uses hourly rate cutting in the following circumstances:

- when spans have been are identified as high risk to either fire starts or public safety
- to meet the rectification timeframes in its management plans, for example where the next maintenance cycle would otherwise occur outside rectification timeframes
- to rectify non-compliant spans identified by ESV within a specified timeframe
- in response to challenging or hostile customers (including police escort or additional security)
- for spans requiring extensive traffic management, such as road closures and/or around metro rail
- to rectify storm damage
- for environmentally sensitive or culturally significant spans, which require extensive negotiation/stakeholder management/approvals.

Powercor stated that it needs to use more hourly rate cutting crews to meet the rectification timeframes in its approved management plans.

We asked Powercor to provide details on each non-compliant span identified in 2024 and 2025. This included the date the non-compliance was identified and the date the vegetation was cut.[39] Based on our analysis of this data, Powercor is not currently meeting the timeframes in its approved management plan for all spans.

Powercor likely overstated the increase in hourly rate cutting required

Powercor forecast the number of hourly rate cuts it would need based on the average of the number it did in 2024 and in 2025. The number it used in 2025 was significantly lower than the number in 2024. It also added an additional amount equal to the average number of HBRA spans it did not rectify within the required timeframes in 2024 and 2025. It applied a glidepath to this amount, reducing it to the average number of 'repeat' spans in 2024 and 2025 by the end of the forecast period.[40] (A repeat span is a span that has vegetation inside the minimum clearance space which also had vegetation cleared from within the minimum clearance space in the preceding year.)

This assumption reflects an expectation that Powercor will continue to reduce its grow ins but that it cannot reduce grow ins to zero due to repeat spans. Powercor's approach effectively assumes that the hourly rate cuts done in 2024 and 2025 were for reasons other than meeting the timeframes in its management plan. However, historically, the number of hourly rate cuts Powercor has done has been strongly correlated to the number of non-compliant spans. As it has reduced the number of spans with vegetation inside the clearance space, the number of hourly rate cuts has also reduced.

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39 Powercor, *Response to information request IR#064*, 23 January 2026.

40 Powercor, *PAL RRP MOD 4.01_IR064 update – vegetation management – Dec2025 – confidential*, 23 January 2026.

As such, Powercor's proposal represents a significant shift in the recent trend in the volume of hourly rate cuts. As shown in Figure 3-4, Powercor has improved its compliance and reduced the number of spans with vegetation growing into the minimum clearance space. Part of the justification for this step change is to minimise 'grow ins', since no vegetation is allowed inside the minimum clearance space. We would expect the number of hourly rate cuts required should reduce as Powercor continues to improve its vegetation clearance compliance.

When we asked why an average of 2024 and 2025 was the appropriate basis for forecasting hourly rate cuts, rather than using just 2025, Powercor 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.[41] While we consider this has likely been a factor, we do not consider this likely to be the sole or primary reason. Powercor has significantly increased it 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 Powercor's control.

Nonetheless, we expect that due to the last 4 reasons for hourly rate cutting listed above, Powercor will need to use some hourly rate cuts even if it is able to avoid all grow ins. We sought more information from Powercor to better understand how many spans fit these categories. Powercor responded that its systems don't record the type of cutting used (hourly rate or span rate) to rectify each span.[42] While we accept this is likely the case, we would expect that a prudent operator would have a record of which spans require particular treatment. For example, we would expect Powercor would have a record of the spans which have environmentally or culturally significant vegetation. If not, it would be at risk of not meeting its obligations relating to environmentally or culturally significant vegetation, for example.

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 Powercor, 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 Powercor continues to improve its compliance.

Hazard trees

Powercor stated that it has an obligation to assess hazard trees every three 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

41 Powercor, *Response to information request IR#064*, 23 January 2026, p. 9.

42 Powercor, *Response to information request IR#082*, 18 February 2026, p. 3.

this basis it forecast its hazard tree cutting opex would increase from $0.48 million in 2024–25 to $1.86 million each year

Powercor also included an additional $0.78 million each year for 6 additional arborists, which commenced in May 2025.

We sought further information from Powercor 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 Powercor agreed with this. In its amended vegetation management step change model, it forecast hazard tree cutting volumes based on its historic average rate.[43]

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.

We also sought further information from Powercor on the role of the additional arborists. Powercor confirmed that the arborists are required to increase its hazard tree inspections from 5 yearly to 3 yearly. Given this is required to comply with its management plan, we have included these costs in our alternative step change amount, with a small reduction to reflect the 2 months of this expenditure already in the base year.[44]

Inspection costs

Powercor 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). Powercor inspects its network on a calendar year cycle and its inspection costs have been consistent on a calendar year basis. However, 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 Powercor's forecasting approach, increases the proposed step change by $10.2 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.

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43 Powercor, *Response to information request IR#064*, 23 January 2026, p. 10.

44 Powercor, *Response to information request IR#064*, 23 January 2026, p. 10.

Given Powercor 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.

Rate of change

Powercor 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.[45]

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

Making the changes above results in a step change of –$11.6 million for Powercor, despite forecasting additional cutting going forward. As stated by Powercor, 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 $7.0 million lower 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 Insurance step change

We have included a step change of –$6.9 million in our alternative estimate opex for insurance premiums, as shown in Table 3-6. This ensures that forecast opex reflects the premiums Powercor will pay in 2025–26 (plus an amount for the rate of change) and meets the opex criteria.

Table 3-6 Insurance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	–	–	–	–	–	–
AER alternative estimate	–1.3	–1.3	–1.4	–1.4	–1.4	–6.9
Difference	**–1.3**	**–1.3**	**–1.4**	**–1.4**	**–1.4**	**–6.9**

Source: Powercor, *PAL 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.

We have changed our approach from the draft decision because we now consider the EBSS does not allow for the non-recurrent efficiency gain to be used in the way we did in our draft

[45] Powercor, *PAL RRP BUS 4.01, Vegetation management*, December 2025, p. 7.

decision.[46] We consider that regulatory certainty is important for incentive schemes to provide effective incentives. Consequently, we have not applied a non-recurrent efficiency gain in this final decision.

The change in approach allows Powercor to retain the benefits of underspending its insurance premium forecasts as a recurrent efficiency gain. The draft decision approach treated Powercor's underspending of its forecast insurance premiums as a non-recurrent efficiency gain.

Background and draft decision

In our final decision for the 2021–26 regulatory period we included a significant step change for forecast increases in bushfire liability insurance premiums.[47] In that decision, we considered that the forecast increase qualified as a step change because it was driven by a major external factor outside of the control of the business and was not captured in base opex or trend.

However, as noted in our draft decision, the forecast of significant insurance premiums did not eventuate, and Powercor significantly underspent the forecast insurance premiums.

Under our framework, when we approve a step change, we implicitly assume the expenditure forecast in the final year is required in perpetuity. Our standard approach to forecast total opex applies a final year increment to roll forward any additional expenditure required from the base year approved forecast to final year approved forecast.

Including the insurance premium component of the final year increment assumes insurance premiums would rise significantly more than required. We now know these increases will not occur and reflecting them in our alternative estimate of total forecast opex would not meet the opex criteria. That is, forecast opex would be higher than that required by a prudent and efficient operator.

To remove the insurance premium component of the final year increment, in the draft decision we included a combination of a non-recurrent efficiency gain and a negative insurance step change to reduce forecast opex.[48] This ensured our alternative estimate of total forecast opex met the opex criteria and the EBSS shared the efficiency gains and losses between Powercor and network users. Under this approach the EBSS treated the underspend as a non-recurrent efficiency gain and required Powercor to return the 2021–26 insurance premium underspends to network users through EBSS decrements 6 years later. Powercor retained its share of the insurance premiums underspend by retaining the time value of holding the underspends for 6 years.

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46 AER, *Efficiency benefit sharing scheme*, November 2013.

47 AER, *Final decision, Powercor distribution determination 2021–26, Attachment 6, Operating expenditure, April 2021*, pp. 36–39.

48 AER, *Attachment 3, Operating expenditure, Draft decision, Powercor distribution determination 2026–31*, September 2025, pp. 35–36

Powercor's revised proposal

Powercor disagreed with our treatment of insurance premiums in the draft decision and considered the approach to be unlawful. It provided a legal opinion from DLA Piper (the DLA Piper advice) to support this position.[49]

Powercor considered the draft decision approach would create perverse incentives for distributors and would undermine the objectives and intent of the economic regulatory regime. To support this, it submitted a report from HoustonKemp.[50]

Powercor also provided a confidential report from its insurance broker, Marsh, that sought to demonstrate that the underspends were likely impacted by efficient cost management.[51]

Stakeholder engagement

We received two submissions relating to our draft decision approach to treating insurance in the EBSS and when forecasting opex.

CCP32 stated that it understood that the objective of the EBSS (and incentive regulation) is to share genuine business efficiency gains between a business and its customers. The question for it was whether the insurance premium underspend was a windfall gain, or a result of management efficiency initiatives. CCP32 saw no reason for a business to retain windfall gains and agreed they should be passed back to customers.[52]

CCP32 noted that the distributors' revised proposals included some information about management efficiency initiatives, which the distributors claimed were instrumental in achieving the insurance premium reductions. However, these were heavily redacted. Consequently, CCP32 considered it impossible for customers and stakeholders to understand or form an opinion on the extent to which management actions played a role in achieving the significant insurance premium underspends, and whether they deserved to be rewarded under the EBSS.[53]

Ausgrid submitted that the draft decision approach raises important questions about the integrity of the ex-ante incentive framework that we administer. It considered the approach creates regulatory uncertainty for networks across broader expenditure areas, with potential implications for the effectiveness of incentives to promote efficient cost management and longer-term consumer outcomes.[54]

Our assessment

In this final decision we have changed our approach to treating Powercor's significant underspending of the forecast insurance premiums approved for the 2021–26 period.

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49 Powercor, *RRP ATT 4.02 – Hon. John Middleton AM KC – legal opinion*, December 2025.

50 Powercor, *RRP ATT 4.04 – HoustonKemp – Victorian DNSP insurance premiums*, December 2025.

51 Powercor, *RRP ATT 4.03 – Marsh – report on insurance premiums*, December 2025.

52 CCP32, *Submission - Powercor electricity distribution proposal 2026–31,* January 2026, p. 29.

53 CCP32, *Submission - Powercor electricity distribution proposal 2026–31,* January 2026, p. 29.

54 Ausgrid, *Submission - Victorian electricity distribution proposals 2026–31,* January 2026, pp. 2–3.

In our draft decision we stated that the approach we adopted sought two outcomes:

1. it would return the 2021–26 insurance premium underspends to network users through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains)
2. it set forecast opex equal to that required by a prudent and efficient operator.

HoustonKemp asserted that the draft decision approach did not achieve these objectives. We requested HoustonKemp's modelling and found that it had not applied the EBSS equations. We provided Powercor, and HoustonKemp, our modelling and asked them if they considered the modelling to be incorrect. HoustonKemp did not identify any calculation errors but did, however, raise broader concerns with the draft decision approach.[55] We do not agree with most of the concerns raised by HoustonKemp.

We set out below our reasons for changing our approach, as well as our views on the concerns raised by Powercor, the HoustonKemp report and the DLA Piper advice.

The EBSS does not allow a non-recurrent efficiency gain to be used to apply the draft decision approach

As noted in the DLA Piper advice, the EBSS does not define the term 'non-recurrent efficiency gain', and provides limited commentary on what that term means, and how it should be applied.[56] Where we did discuss a non-recurrent efficiency gain in the EBSS explanatory statement, we stated that:

- expenditure should be treated as a non-recurrent efficiency gain in circumstances where a distributor cannot sustain the level of expenditure that it incurred in the base year, as a result of a one-off factor that led to an underspend relative to forecast opex in that base year
- the purpose of the non-recurrent efficiency gain adjustment is to enable revenue to be shifted from the EBSS carryover to the opex allowance, rather than to reduce the overall allowed revenue.

The DLA Piper advice considered that the EBSS only allows an opex underspend in the base year to be treated as a non-recurrent efficiency gain in limited circumstances. Further, distributors should not be left worse off in their total revenue allowance because of any base year non-recurrent efficiency gain.[57] We are satisfied that this is accurate and, as such, the EBSS does not allow a non-recurrent efficiency gain to be used in the way we did in our draft decision.

Incentives

HoustonKemp asserted that the draft decision approach would undermine the future regulatory ex ante incentive properties of the NER's economic regulatory regime because networks will no longer have certainty that they will be rewarded for outperforming their opex

55 HoustonKemp, *Victorian DNSP insurance premiums*, *Supplemental report*, 25 February 2026, pp. 4–6.

56 Powercor, *RRP ATT 4.02 – Hon. John Middleton AM KC – legal opinion*, December 2025, p. 19.

57 Powercor, *RRP ATT 4.02 – Hon. John Middleton AM KC – legal opinion*, December 2025, p. 19.

forecasts.[58] As an underlying principle, we agree with HoustonKemp that regulatory certainty is important for incentive schemes to provide effective incentives.

However, we disagree with HoustonKemp's view that the distributors would no longer have certainty that they will be rewarded for outperforming their opex forecasts under that draft decision approach. We maintain that Powercor would have benefited from underspending its forecast insurance premiums in the 2021–26 period under the draft decision approach. Nonetheless, we consider that it is important the distributors have a clear understanding of how EBSS carryovers will be calculated and how actual opex will be used to forecast opex in the subsequent period.

Reasonable opportunity to recover efficient costs

In its report, HoustonKemp asserted that the draft decision approach would reduce Powercor's overall compensation for insurance premiums for the 2026–31 regulatory control period and would not allow it a reasonable opportunity to recover its efficient costs.

We provided a mathematical proof to Powercor and HoustonKemp, showing that the draft decision approach would provide a forecast of insurance premiums equal to the final year actual insurance premium amount plus an increment for the rate of change.

HoustonKemp agreed that the draft decision approach has the result that the forecast of insurance premiums for the 2026–31 regulatory control year is equal to actual insurance premiums in the final year of the 2021–26 period plus an increment for the rate of change.[59] However, it argued that by also applying negative EBSS carryover amounts, Powercor cannot recover its efficient costs.[60] We consider this conflates two separate building blocks that must be considered separately. Under the NER, the opex building block must meet the opex criteria. If we accept HoustonKemp's interpretation, then EBSS carryovers cannot be negative. However, the NER explicitly allows for EBSS decrements.

The EBSS carryovers Powercor has accrued (regardless of how you calculate them) are not 'compensation for insurance premiums for the 2026–31 regulatory control period'. Rather they are increments or decrements that are meant to share the efficiency gains or losses Powercor has achieved in the 2021–26 period.

Managerial effort

Our draft decision approach treated the insurance premium underspends over the 2021–26 period as non-recurrent efficiency gains. This implicitly attributes the lower than forecast insurance premiums to external factors outside of the control of the businesses and not the result of management efforts to efficiently manage their insurance premiums.

Powercor provided a confidential report from its insurance broker, Marsh, that sought to demonstrate that the underspends were likely impacted by efficient cost management. However, when Powercor proposed a step change for insurance premiums for the 2021–26 period it stated the step change was required because insurance premiums were rising due

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58 HoustonKemp, *Victorian DNSP insurance premiums*, *Supplemental report*, 25 February 2026, p. 6.

59 HoustonKemp, *Victorian DNSP insurance premiums*, *Supplemental report*, 25 February 2026, pp. 4–5.

60 HoustonKemp, *Victorian DNSP insurance premiums*, *Supplemental report*, 25 February 2026, p. 4.

to material macroeconomic factors outside its control. We accepted this reasoning when we included the step changes in forecast opex.

Prior to the draft decision, we asked Powercor to explain the reasons for the significant underspend in insurance premiums. At that time Powercor did not mention that managerial efforts played a role in these underspends. Only in its revised proposal has Powercor asserted that managerial effort contributed to the significant insurance premium underspends.

Powercor's most recent submission appears inconsistent with its earlier position. We recognise that managerial effort would have played some role in Powercor's underspends, but it is difficult to ascertain how much. However, we consider that the proportion of the underspends attributable to managerial efforts would be minimal compared to the impact of external market factors.

The draft decision approach would not effect a claw back

Powercor, HoustonKemp and the DLA Piper advice describe the draft decision approach as a clawback of the insurance underspends in the current period. We disagree with this characterisation. It is true that the draft decision approach would return the underspend to network users six years after it was achieved. But we would not characterise this as a clawback. Under the draft decision approach, Powercor retains the time benefit of holding the underspend for six years (it keeps the interest earned on the underspend for six years). A clawback would require Powercor to return the underspend and the time value of money.

This is consistent with the sharing of any non-recurrent efficiency gain under the standard application of the EBSS. Under the standard application of the EBSS, networks are required to share non-recurrent efficiency gains with network users six years later (and receive non-recurrent overspends back six years later).[61]

3.4.3.3 Flexible trading arrangements pass through

We have included a step change of –$3.1 million to account for our decision on Powercor's positive pass through application related to the *Unlocking CER benefits through flexible trading* rule change, which it submitted on 29 September 2025. We have accepted this pass through event and our reasons can be found on our website.[62] 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.

Powercor did not include this step change in its revised proposal, but did include the pass through costs it proposed for 2024–25 and 2025–26 in the approved forecast opex amounts used to estimate total opex for 2025–26, which it used to forecast total opex for the 2026–31 period. The effect of this is that Powercor'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.

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61 AER, *Explanatory Statement, Proposed Electricity distribution network service providers efficiency benefit sharing scheme*, April 2008, p. 27.

62 https://www.aer.gov.au/documents/citipower-flexible-trading-arrangements-fta-cost-pass-through-application-29-september-2025

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.

Table 3-7 Flexible trading arrangements pass through step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	–	–	–	–	–	–
AER alternative estimate	0.9	0.0	–0.9	–1.6	–1.6	–3.1
Difference	**0.9**	**0.0**	**–0.9**	**–1.6**	**–1.6**	**–3.1**

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.

3.4.3.4 CER integration step change

We have included $28.6 million for CER integration in our alternative estimate for the final decision. This is the same amount Powercor included in its revised proposal, and reflects that we are satisfied that this step change is likely to be prudent and efficient.

Table 3-8 CER integration step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	1.9	6.2	6.2	7.0	7.3	28.6
AER alternative estimate	1.9	6.2	6.2	7.0	7.3	28.6
Difference	**–**	**–**	**–**	**–**	**–**	**–**

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

In its initial proposal, Powercor proposed $28.7 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.[63] This step change consisted of 3 sub-programs for flexible services, non-network procurement platform, and data visibility. We discuss this step change, our assessment and the reasons for including a lower amount of $22.0 million, further in our draft decision.[64]

[63] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, pp. 14, 19–30; Powercor, *MOD 9.03 – Opex step changes*, January 2025.

[64] AER, *Attachment 3 – Operating expenditure – Draft decision – Powercor 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.

Powercor's revised proposal included $28.6 million for CER integration, consisting of the same 3 sub-programs as its initial proposal:

1. Flexible services ($22.0 million). Our draft decision included $22.0 million for this program.
2. Non-network procurement platform ($3.6 million). Our draft decision did not include this program.
3. Data visibility ($2.9 million). Our draft decision did not include this program.

For its revised proposal, Powercor provided additional information to support these programs, including its Distributed Service Operator (DSO) vision.[65] This further clarified how these programs will integrate to build Powercor's DSO capabilities, and thus unlock value for its customers through the network transition and the continued growth of CER resources.[66]

The above programs all relate to investments proposed in Powercor'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.

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

We have included $45.5 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 Powercor 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 and new capabilities) and non-recurrent (cloud services) costs of the respective programs within the 2 step changes.

Table 3-9 Cloud services step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	3.4	8.6	5.2	5.8	2.3	25.4
AER alternative estimate	3.4	8.6	5.2	5.8	2.3	25.4
Difference	–	–	–	–	–	–

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

65 Powercor, *RRP ATT 3.2.01 – DSO vision*, December 2025.

66 Powercor, *RRP ATT 3.2.01 – DSO vision*, December 2025, pp. 5–7.

Table 3-10 ICT modernisation step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	0.5	2.3	4.5	6.0	6.7	20.1
AER alternative estimate	0.5	2.3	4.5	6.0	6.7	20.1
Difference	–	–	–	–	–	–

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

Powercor's initial proposal included $48.1 million for 'Cloud services' and 'ICT modernisation and new capabilities'. Powercor 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 $22.8 million, further in our draft decision.[67]

Powercor's revised proposal included $45.5 million for these 2 step changes, $2.6 million lower than its initial proposal. Consistent with its initial proposal, these step changes consist of 4 sub-programs:

1. Cyber security – $13.2 million. This is consistent with our draft decision.
2. Infrastructure refresh – $7.5 million. This is consistent with our draft decision.
3. MITE – $2.2 million. This is consistent with our draft decision.
4. ERP – $22.7 million, or $2.6 million lower than its initial proposal. Our draft decision did not include costs for this program.

Powercor's revised proposal provided further information to address some of the concerns we raised in the draft decision, especially related to its cloud services step change and the SaaS 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.[68]

For our final decision, we have therefore included the proposed $45.5 million for the 'Cloud services' and 'ICT modernisation and new capabilities' step changes. This is $22.7 million more than our draft decision, and reflects the incremental amount for the ERP and billing system component.[69]

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67 AER, *Attachment 3 – Operating expenditure – Draft decision – Powercor distribution determination 2026–31, September 2025*, pp. 31–32; AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 37–46.

68 AER, *Final decision, Attachment 6 – Operating expenditure – Ausgrid – 202429 Distribution revenue proposal*, April 2024, pp. 15–16.

69 Powercor, *PAL RRP MOD 2.05 – Opex*, December 2025.

3.4.3.6 Fleet electrification step change

Powercor's revised proposal included a forecast of –$1.0 million for a negative fleet electrification step change. This amount remains unchanged from our draft decision.

Table 3-11 Fleet electrification step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	–	–0.2	–0.3	–0.3	–0.3	–1.0
AER alternative estimate	–	–0.2	–0.3	–0.3	–0.3	–1.0
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: Powercor, *PAL 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

Powercor's revised proposal included 4 category specific forecasts, which were not forecast using the base-step-trend approach. These were for:[70]

- GSL payments ($16.6 million)
- network innovation fund ($4.4 million)
- customer assistance package ($15.8 million)
- debt raising costs ($17.9 million)

3.4.4.1 Customer assistance package

Powercor's revised proposal accepted our draft decision for its customer assistance package forecast of $15.8 million. We have included the same amount in our alternative estimate.

Table 3-12 Customer assistance package ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	3.1	3.1	3.2	3.2	3.2	15.8
AER alternative estimate	3.1	3.1	3.2	3.2	3.2	15.8
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: Powercor, *PAL 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.

3.4.4.2 Innovation fund

We have included $2.0 million for the innovation fund in our alternative estimate for the final decision. This is $2.5 million lower than Powercor's revised proposal, and reflects that we are

[70] Powercor, *PAL RRP MOD 2.05 – Opex*, December 2025.

not satisfied that all proposed costs are prudent and efficient, including that they do not satisfy our innovation criteria.[71]

Table 3-13 Innovation fund ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	1.1	1.2	0.8	0.7	0.6	4.4
AER alternative estimate	0.4	0.4	0.4	0.4	0.4	2.0
Difference	**–0.8**	**–0.8**	**–0.4**	**–0.3**	**–0.2**	**–2.5**

Source: Powercor, *PAL 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.

Powercor's initial proposal included $7.9 million for an innovation fund, consisting of 12 projects broadly grouped into 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 $1.8 million further in our draft decision.[72]

Powercor's revised proposal included $4.4 million for an innovation fund, consisting of 12 projects.[73] These projects all also relate to investments proposed in Powercor'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

Powercor's revised proposal included a forecast of $16.6 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. Powercor 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 included a forecast of $16.3 million in our alternative estimate. We have updated Powercor's revised proposal forecast to reflect our final decision on forecast inflation.

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71 AER, *Final decision, Attachment 5 – Capital expenditure – Ausgrid – 2024–29 Distribution revenue proposal,* April 2024, pp. 37–40.

72 AER, *Attachment 3 – Operating expenditure – Draft decision – Powercor distribution determination 2026–31*, September 2025, pp. 37–38; AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025, pp. 51–57.

73 Powercor, *RRP MOD 3.9.01 – Innovation allowance cost-benefit analysis*, December 2025.

Table 3-14 GSL payments ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	3.5	3.4	3.3	3.2	3.2	16.6
AER alternative estimate	3.4	3.3	3.3	3.2	3.1	16.3
Difference	**–0.1**	**–0.1**	**–0.1**	**–0.1**	**–0.1**	**–0.4**

Source: Powercor, *PAL 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.

3.4.4.4 Debt raising costs

We have included debt raising costs of $18.0 million in our alternative estimate. Powercor's revised proposal included a forecast of $17.9 million for debt raising costs.

Table 3-15 Debt raising costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor revised proposal	3.2	3.4	3.6	3.8	3.9	17.9
AER alternative estimate	3.2	3.5	3.6	3.8	3.9	18.0
Difference	**0.0**	**0.0**	**0.0**	**–0.0**	**–0.0**	**0.0**

Source: Powercor, *PAL 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.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CPI	consumer price index
DNSP	distribution network service provider
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	guaranteed service levels
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
NPV	net present value
NSP	network service provider
opex	operating expenditure
PTRM	post-tax revenue model
repex	replacement expenditure
RIN	regulatory information notice
SCS	standard control services