Draft decision

Powercor electricity distribution determination

1 July 2026 – 30 June 2031

Attachment 3 – Operating expenditure

September 2025

Inquiries about this publication should be addressed to:

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

AER reference: AER23008249

Amendment record

Version	Date	Pages
1	30 September 2025	43

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 Draft decision

Our draft decision is to not accept Powercor's total opex forecast of $2,195.8 million,[1] including debt raising costs, for the 2026–31 period. This is because our alternative estimate of $1,824.2 million is materially different ($371.6 million, or 16.9% lower) than Powercor's total opex forecast proposal.[2] Therefore, we consider that Powercor's total opex forecast does not reasonably reflect the opex criteria.[3]

This material difference is primarily driven by not including, or including lower alternative estimates, for most of Powercor's proposed step changes, and lower forecast output growth to reflect our assessment of efficient costs required for the 2026–31 period.

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

- $64.3 million (3.7%) higher than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $269.0 million (17.3%) higher than Powercor's actual (and estimated) opex in the 2021–26 period.

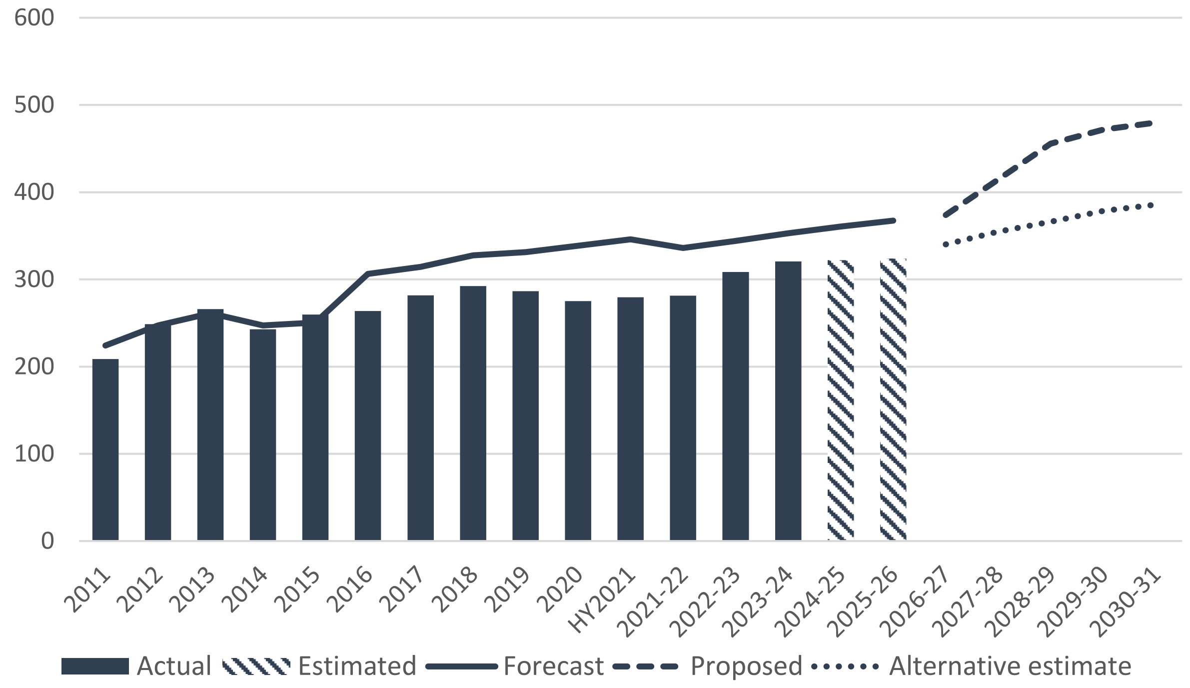
In Figure 3.1, we compare our alternative estimate of opex to Powercor's proposal for the next regulatory control period. We also show the forecasts we approved for the last 2 regulatory control periods and Powercor's actual and estimated opex over these periods.

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

2 Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 89.

3 NER, cl. 6.5.6(c)–(e).

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

Table 3.1 sets out Powercor's opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 3.1 Comparison of Powercor's opex proposal and our alternative opex estimate ($million, 2025–26)

Category	Powercor proposal	AER draft decision	Difference ($)
Based on estimated opex in 2024–25	**1,610.4**	**1,609.7**	**–0.7**
Base year non-recurrent efficiency gain	**–**	**71.6**	**71.6**
2024–25 to 2025–26 increment	33.7	**33.7**	**0.0**
Base adjustment: remove licence fees	–4.7	–4.7	0.0
Remove category specific forecasts	**–20.4**	**–20.4**	**0.0**
Trend – Output growth	177.9	108.2	–69.7
Trend – Price growth	34.2	31.1	–3.1
Trend – Productivity growth	–24.6	–25.6	–1.0
Total trend	**187.6**	**113.8**	**–73.8**
Step change: customer assistance package*	26.7	–	**–26.7**
Step change: vegetation management	232.9	–	–232.9
Step change: CER integration	28.7	22.0	–6.7
Step change: cloud services	26.1	2.7	–23.3
Step change: ICT modernisation	22.0	20.1	–1.9
Step change: Network and community resilience	6.8	–	–6.8
Step change: fleet electrification	–1.0	–1.0	–
Step change: insurance	–	–76.4	–76.4
Total step changes	**342.2**	**43.9**	**–298.4**
GSL payments	20.5	18.0	–2.6
Innovation Fund	7.9	1.8	–6.1
Customer assistance package	–	15.8	15.8
Debt raising costs	18.5	17.4	–1.1
Total category specific forecasts	**47.0**	**53.0**	**6.1**
Total	**2,195.8**	**1,824.2**	**–371.6 (–16.9%)**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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 opex proposal, which we have not accepted, and our alternative estimate are that we have:

- not included the following step changes:
  - vegetation management step change (–$232.9 million)
  - network and community resilience step change (–$6.8 million)
- included lower alternative estimates for the following step changes:
  - CER integration (–$6.7 million)
  - cloud services (–$23.3 million)
  - ICT modernisation (–$1.9 million) step changes.

  We discuss these further in section 3.3.4.
- reclassified the customer assistance package step change as a category specific forecast and included a lower amount (–$10.9 million). We discuss this further in sections 3.3.4.1 and 3.3.5.3.
- included a base year non-recurrent efficiency gain ($71.6 million), and new negative step change (–$76.4 million) to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 period do not impact forecast opex for the 2026–31 period. The net impact of these 2 adjustments reduces forecast total opex by $4.8 million.
- substituted our output growth forecast, reducing forecast opex by $69.7 million. We discuss this further in section 3.3.3.2.

3.2 Powercor's proposal

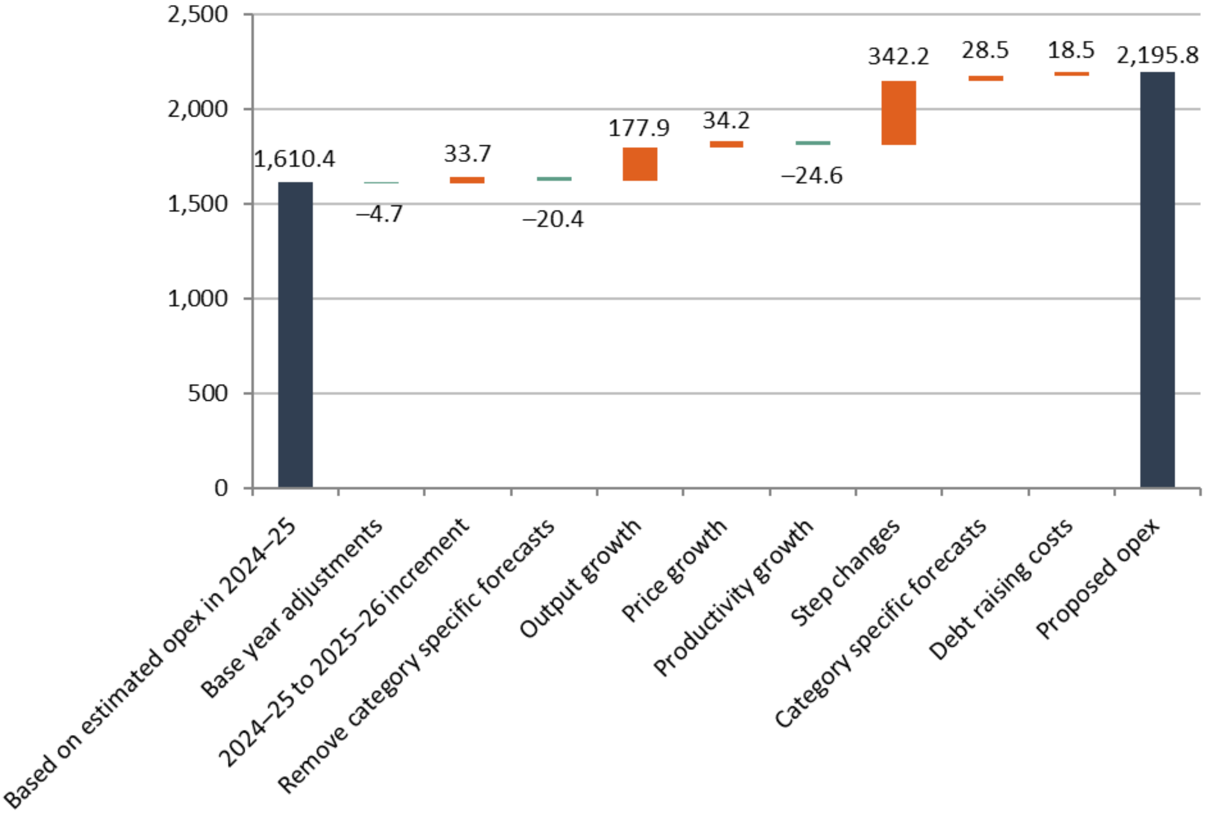
Powercor's proposal applied a base–step–trend approach to forecast opex for the 2026–31 period, consistent with our standard approach.[4]

Powercor's approach to applying our base–step–trend approach is set out in Table 3.1. Figure 3.2 shows the different components that make up Powercor's opex forecast for the 2026–31 period.

---

[4] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 89.

Figure 3.2 Powercor's opex forecast ($million, 2025–26)



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

3.2.1 Stakeholder views

We received 5 submissions that commented on Powercor's opex proposal from: Powercor's Consumer Advisory Panel, Origin Energy, Victorian Greenhouse Alliances, Farmers for Climate Action, and the Consumer Challenge Panel subpanel 32 (CCP32).

Submissions did not raise strong issues related to Powercor's opex proposal, and were generally supportive. Submissions noted the electrification effort currently taking place in Victoria, and particularly noted the impact on demand and the interactions with CER penetration on the networks. CCP32 queried whether some of Powercor's step changes met the Better Reset Handbook requirements for a step change, but concluded the vegetation management and customer assistance step changes were likely consistent with government and community expectations.[5] CCP32 particularly noted the strong customer support for the vulnerable customer assistance step change.[6] The Victorian Greenhouse Alliances recommended establishing a consistent methodology for consumer energy resource (CER) expenditure proposals. It considered this would provide a more meaningful overview to

5 CCP32, *Submission – Powercor electricity distribution proposal 2026–31*, May 2025, pp. 22–24.

6 CCP32, *Submission – Powercor electricity distribution proposal 2026–31*, May 2025, p. 24.

consumers on these proposals.[7] Farmers for Climate Action were supportive of more investment to help vulnerable consumers and community CER projects.[8]

3.3 Reasons for draft decision

Our draft decision is to not accept Powercor's total opex forecast of $2,195.8. million, including debt raising costs, for the 2026–31 period. Our alternative estimate of $1,824.2 million is materially different ($371.6 million or 16.9% lower) from Powercor's total forecast opex proposal. Therefore, we are not satisfied that Powercor's total opex forecast reasonably reflects the opex criteria, having regard to the opex factors.[9]

Table 3.1 sets out Powercor's proposal, our alternative estimate that has informed this draft decision, and the difference between our alternative estimate and the 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.

3.3.1 Base opex

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

3.3.1.1 Proposed base year

Powercor proposed a base year of 2024–25, and base year opex of $322.1 million.[10] This equates to $1,610.4 million over the 5 years of the next regulatory control period.

Powercor's base year actual opex is $38.5 million (–10.7%) lower than the forecast opex approved for that year and $18.6 million, or 6.1%, higher than the average actual opex over the period 2021–22 to 2023–24.

Powercor submitted that 2024–25 is the most suitable base year because it will be the most recent year where audited actual data will be available at the time of our final decision.[11]

While there will be year to year fluctuations in reported opex over the current regulatory period, due to the interaction with the EBSS, we do not generally have concerns with the choice of base year, provided we find Powercor's opex in the base year to be efficient.

In our alternative estimate for the draft decision, we have updated the base opex amount for 2024–25 to $321.9 million, or $1,609.7 million over the next regulatory control period. This is because we have used the latest inflation values to convert the nominal amount into real

---

7 Victorian Greenhouse Alliances, *Submission – Victorian electricity distribution proposals 2026–31*, May 2025, pp. 16–17.

8 Farmers for Climate Action, *Submission – Powercor electricity distribution proposal 2026–31*, May 2025, p. 1.

9 NER, cl. 6.5.6(c)–(e).

10 Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 90.

11 Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 90.

terms. We have used the actual inflation for the year to June 2025, from the Australian Bureau of Statistics, and the Reserve Bank of Australia's (RBA) forecast of inflation for the year to June 2026, from its May Statement on Monetary Policy.[12] These inflation values were not available at the time of Powercor's initial proposal, and represent the best available forecast, because they are either an actual figure or the most up-to-date information available at this time.

3.3.1.2 Efficiency of Powercor's opex

As summarised in our Expenditure Forecast Assessment Guideline (the Guideline), our preferred approach for forecasting opex is to use a revealed cost approach. This is because opex is largely recurrent and stable at a total level. Where a distribution business is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations. However, we do not assume that the business's revealed opex is efficient. We examine the trend in opex and use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently historically and particularly in the base year.

We consider Powercor's estimate of its opex in 2024–25 is not materially inefficient, as indicated by its opex trend over time and our benchmarking results. Accordingly, we have used Powercor's estimated costs in 2024–25 to develop our alternative estimate.

In terms of the trend in opex, Figure 3.1 shows Powercor's opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods and our previous regulatory decisions.

Overall, Powercor's opex has been historically lower than our approved forecast since 2015–16. Powercor's estimated opex in the base year (2024–25) of $322.1 million is $38.5 million, or 10.7%, below the approved forecast opex for that year.

In line with our standard approach, we have used our benchmarking tools and other cost analysis to assess and establish whether Powercor is operating relatively efficiently, both over time and in the base year. We conclude that Powercor performs well compared to other networks and is not materially inefficient.

As set out in more detail in past decisions,[13] in assessing base opex efficiency, our standard approach is to benchmark a business's efficiency on the basis of its average efficiency over time (using a period-average efficiency score from our econometric opex cost function models). We consider that this is the appropriate place to start rather than initially looking at the efficiency of a single year (such as the base year) as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility. Reflecting our

---

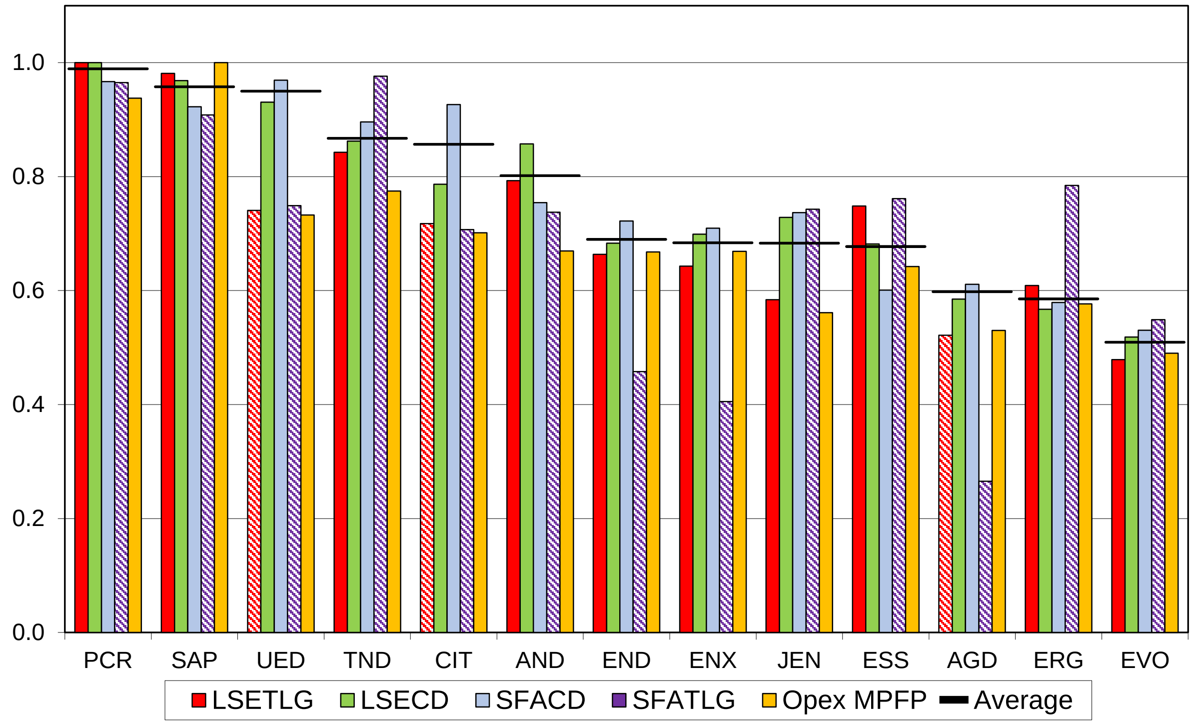
12 Australian Bureau of Statistics (ABS), *Consumer Price Index, Australia, released on 30 July 2025* (accessed on 31 July 2025: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release); Reserve Bank of Australia (RBA), *Statement on monetary policy*, *August 2025*, (accessed on 17 September 2025: https://www.rba.gov.au/publications/smp/2025/aug/outlook.html#3-5-detailed-forecast-information).

13 AER, *Final Decision, Ergon Energy 2025–30, Attachment 6 Operating expenditure*, April 2025, p. 17.

conservative approach, we use a 0.75 benchmark comparison point (rather than 1.0) to assess the relative efficiency of distribution businesses.

Our benchmarking results indicate that Powercor has consistently been amongst the most productive and efficient distributors in the National Electricity Market (NEM). Our recent 2024 Annual Benchmarking Report shows Powercor continues to perform well, relative to other distribution businesses in the NEM.[14] In particular, as shown in Figure 3.5 for the 2006–23 period, Powercor remains a benchmark comparator business, with an econometric model-average score across the 2006–23 period of 0.99 and the 2012–23 period of 0.98, which are appreciably above our benchmark comparison point of 0.75.

Figure 3.3 Econometric opex efficiency scores and opex MPFP, 2006–23



Source: AER, *2024 Annual Benchmarking Report – Electricity distribution network service providers, November 2024*, p. 35.

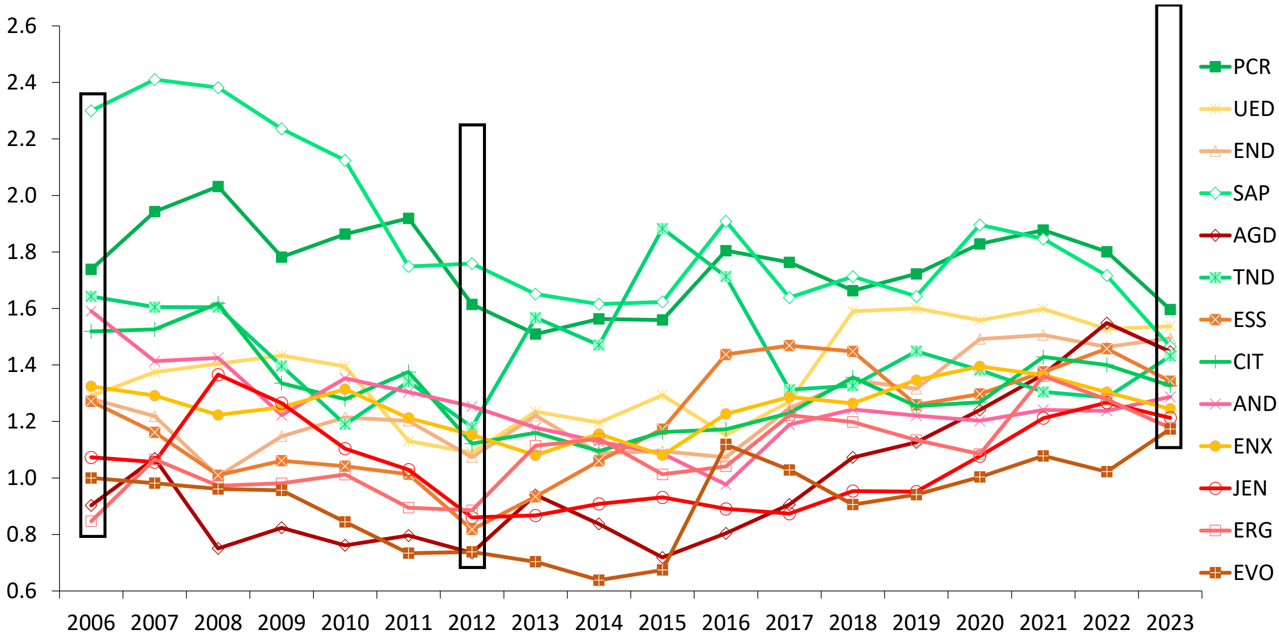
Note: Columns with a hatched pattern represent results that violate the key property that an increase in output is achieved with an increase in cost. These results also do not reflect the impact of a range of material operating environment factors. Opex MPFP scores for each distributor are displayed for comparison and are not included in the calculation of the average efficiency score, which also excludes any results affected by monotonicity violations.

We also use productivity index number techniques to enable comparisons of productivity levels over time and between distributors. The multilateral total factor productivity (MTFP) index measures the total factor productivity of each business over time, whereas the opex and capital multilateral partial factor productivity (MPFP) indexes measure the productivity of opex or capital inputs respectively. Our opex MPFP efficiency results are also not adjusted for material operating environment factors. As shown in Figure 3.4, Powercor has either been

14 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2024.

leading or in the top 3 for distribution businesses in opex MPFP throughout the period, albeit it has declined/converged the last 3 years.

Figure 3.4 Individual distributors opex MPFP indexes, 2006–23



Source: AER, *2024* Annual Benchmarking Report – Electricity distribution network service providers, November 2024, p. 28.

We also observe that Powercor performs well for various total cost and opex cost category partial performance indicators over the 5-year period 2019–23.[15]

We consider that these results warrant the use of revealed costs in 2024–25 as the base year in our alternative estimate, as it provides a not materially inefficient base from which to form the 2026–31 period opex allowance.

3.3.2 Adjustments to base year opex

Powercor proposed the following adjustments to its base year opex:[16]

- add $6.7 million for the increase in opex between base year 2024–25 and the final year, 2025–26 (final year increment). This is consistent with our standard approach and we have made the same adjustment in our alternative estimate. This increases our alternative estimate by $33.7 million over the 5 years of the 2026–31 period.
- remove $4.1 million from the estimated final year opex for the removal of opex categories forecast separately. We have also subtracted $4.1 million in our alternative estimate. This decreases our alternative estimate by $20.4 million over the 5 years of the 2026–31 period.

---

15 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2024, pp. 38–47.

16 Powercor, *PAL MOD 1.05 – Opex*, January 2025.

- remove $0.9 million from the estimated final year opex for licence fees. These costs will be recovered as a jurisdictional scheme from 2025–26. We have made the same adjustment. This reduces our alternative estimate by $4.7 million over the 5 years of the 2026–31 period.

We have also included a base year non-recurrent efficiency gain in our alternative estimate relating to the insurance premiums step change we approved in the current regulatory control period. This adds the difference between the forecast of insurance premiums reflected in the approved step change and actual insurance premiums in the base year, which is equal to $14.3 million. This increases our alternative estimate by $71.6 million over 5 years. We also added a negative step change for insurance premiums. We discuss both adjustments, including the reasons for them, in section 3.3.4.7.

3.3.3 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.[17]

Powercor largely applied our standard approach to forecast the rate of change, including:[18]

- **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 forecasts of the growth in the wage price index (WPI) from BIS Oxford Economics (its consultant) and Deloitte (our consultant), as a placeholder).
- **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.
- **Productivity growth:** using our 0.5% per year productivity growth forecast.

The rate of change proposed by Powercor contributed $187.6 million, or 8.5%, to Powercor's total opex forecast of $2,195.8 million. This equates to an average opex increase of 3.4% each year. We have included a rate of change that contributes $113.8 million, or 6.2% to our alternative estimate of total forecast opex of $1,824.2 million. This equates to an average opex increase of 2.2% each year in our alternative estimate.

---

[17] AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, pp. 22–24.

[18] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, pp. 91–92.

Table 3.2 Forecast annual rate of change in opex (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
Powercor proposal					
Price growth	0.9	0.5	0.6	0.7	0.7
Output growth	3.4	4.1	3.6	2.9	2.3
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**3.8**	**4.1**	**3.7**	**3.2**	**2.4**
AER alternative estimate					
Price growth	0.5	0.6	0.7	0.7	0.7
Output growth	1.3	2.8	2.3	2.4	1.6
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**1.3**	**2.9**	**2.5**	**2.6**	**1.8**
Difference	**–2.5**	**–1.2**	**–1.2**	**–0.5**	**–0.7**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 2025; AER, *Powercor 2026–31 – Distribution – Draft decision – Opex model*, September 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

3.3.3.1 Forecast price growth

Powercor proposed average annual price growth of 0.7%, which increased its total opex forecast by $34.2 million. 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 $31.1 million.

Both we and Powercor forecast price growth as a weighted average of forecast labour price growth and non-labour price growth (real price growth rate of zero), using weights of 59.2% and 40.8% respectively.

Consequently, the key differences between our real price growth forecasts and Powercor's are that:

- we have updated our labour price growth forecast to include more recent forecasts from our consultant Deloitte Access Economics
- we have not included a superannuation increase in 2026–27 in our labour price growth rates since the final superannuation guarantee increase is in 2025–26.

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 proposal					
Deloitte Access Economics	0.8	0.7	0.8	1.1	1.1
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	**1.0**	**0.9**	**1.0**	**1.2**	**1.1**
Superannuation guarantee increases	0.5	–	–	–	–
Average, including super guarantee	**1.5**	**0.9**	**1.0**	**1.2**	**1.1**
AER's alternative estimate					
Deloitte Access Economics	0.7	0.9	1.1	1.1	1.0
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	**0.9**	**0.9**	**1.2**	**1.2**	**1.1**
Overall difference	**–0.6**	**0.1**	**0.1**	**–0.0**	**–0.0**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 2025; Deloitte Access Economics, *Labour price growth forecasts*, 30 July 2025, p. 10; 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 will receive updated WPI forecasts prior to our final decision. We will use these to update our labour price growth forecasts in the final decision.

3.3.3.2 Forecast output growth

Powercor proposed average annual output growth of 3.3%, which increased its proposed opex forecast for the 2026–31 period by $177.9 million. We have forecast average annual output growth of 2.1%. This increases our alternative estimate of total opex by $108.2 million, which is $69.7 million less than Powercor's proposal.

Customer numbers growth

We are satisfied that Powercor's forecast customer number growth, as set out in Table 3.4, reflects a realistic expectation. This forecast is consistent with the customer number forecast Powercor provided in its reset RIN and is similar to actual growth rates in recent years.

Table 3.4 Forecast growth in customer numbers, %

	2026–27	2027–28	2028–29	2029–30	2030–31
Powercor proposal	1.9	1.9	1.9	1.8	1.8
AER alternative estimate	1.9	1.9	1.9	1.8	1.8
Difference	–	–	–	–	–

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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.

Circuit length growth

We are satisfied that Powercor's forecast circuit length, as set out in Table 3.5, reflects a realistic expectation. This forecast is consistent with the circuit length forecast Powercor provided in its reset RIN and is similar to actual growth rates in recent years.

Table 3.5 Forecast growth in circuit length, %

	2026–27	2027–28	2028–29	2029–30	2030–31
Powercor proposal	0.6	0.6	0.6	0.7	0.7
AER alternative estimate	0.6	0.6	0.6	0.7	0.7
Difference	–	–	–	–	–

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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.

Ratcheted maximum demand growth

We are not satisfied that Powercor's forecast growth rates for ratcheted maximum demand reflect a realistic expectation. We have used the ratcheted maximum demand forecast in Table 3.6.

Table 3.6 Forecast growth in ratcheted maximum demand, %

	2026–27	2027–28	2028–29	2029–30	2030–31
Powercor proposal	6.1	7.9	6.7	5.1	3.5
AER alternative estimate	1.0	4.8	3.5	3.9	1.9
Difference	–5.2	–3.1	–3.2	–1.3	–1.6

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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.

The maximum demand forecasts that Powercor used in its opex model were different to those that Powercor included in its reset RIN.[19] We asked Powercor why it did not use the demand forecast in its reset RIN, and it stated that it used its actual maximum demand in 2023–24 escalated by the forecast growth rates in its reset RIN, plus half the L.E.K. Consulting forecast of new data centre capacity over 2027–31.[20] It did not provide a reason for doing this.

We engaged Baringa to review Powercor's maximum demand forecasts, and it noted that Powercor had treated the L.E.K. Consulting data centre demand forecasts inconsistently across its forecasts. Baringa considered that Powercor's approach of only including data centres that are committed and contracted in the maximum demand forecasts in its reset RIN was reasonable. Baringa considered that data centres that are yet to be contracted should be excluded from the forecasts.[21] We agree that there is insufficient certainty to include the L.E.K. Consulting data centre demand forecasts in the maximum demand forecasts, and have not included them in the forecast we have used to forecast ratcheted maximum demand to forecast opex.

We also have concerns with how Powercor included non-data centre block loads, which we consider double counts loads captured in the trend and other components of the modelling. The block load register provided by Powercor included blocks that are substantially lower than the loads of large customers. It may be appropriate to include a block at a particular asset (for example, at the feeder level). But when forecasting demand at the system level, this load may be captured by the trend growth factor (such as population growth or economic growth). We are not satisfied that Powercor sufficiently accounted for the potential overlap between block loads and other components of the modelling for system-level demand, because it was limited to population-driven block loads. Baringa raised similar concerns, noting that the approaches to block loads at the spatial level compared to the system level, and how they reconcile to each other, was unclear.[22]

We expect Powercor to update its maximum demand forecasts in its revised proposal.

3.3.3.3 Forecast productivity growth

Powercor proposed average productivity growth of 0.5% per year, which decreased its total opex by $24.6 million. We have forecast the same average productivity growth rate, which reflects our standard approach.[23] This decreases our alternative opex estimate by $25.6 million over the 2026–31 period.

---

[19] Specifically, we use non-coincident maximum demand, 50% PoE, forecast at the transmission connection point in MW.

[20] Powercor, *Response to information request IR021*, 5 May 2025.

[21] Baringa, *Distribution demand forecast assessment, Review of Powercor's 2026–31 regulatory proposal*, July 2025, pp. 8–9.

[22] Baringa, *Distribution demand forecast assessment, Review of Powercor's 2026–31 regulatory proposal*, July 2025, p. 33.

[23] AER, *Forecasting productivity growth for electricity distributors*, *Final decision*, March 2019.

3.3.4 Step changes

In developing our alternative estimate for the draft decision, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the Guideline, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider does not already include the proposed cost for such items and they are required to meet the opex criteria.[24]

Powercor's proposal included 7 step changes totalling $342.2 million, or 18.5% of its proposed total opex forecast.[25] These are shown in Table 3.7, along with our alternative estimate for the draft decision, which is to include step changes totalling $43.9 million. This is $298.4 million lower than Powercor's proposal. While we consider most of these step changes to be prudent, we are not satisfied they reflect the efficient level of expenditure, hence our lower estimate in most cases.

We have also included an additional negative step change to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 period do not impact forecast opex for the 2026–31 period.

We discuss our assessment of each step change below.

Table 3.7 Powercor's proposed step changes and the AER's alternative estimate ($million, 2025–26)

Step change	Powercor proposal	AER alternative estimate	Difference
Customer assistance package	26.7	–	–26.7
Vegetation management	232.9	–	–232.9
CER integration	28.7	22.0	–6.7
Cloud services	26.1	2.7	–23.3
ICT modernisation	22.0	20.1	–1.9
Network and community resilience	6.8	–	–6.8
Fleet electrification	–1.0	–1.0	–
Insurance	–	–76.4	–76.4
Total step changes	**342.2**	**32.5**	**–374.8**

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

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

25 Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, pp. 92–96.

3.3.4.1 Customer assistance package

Powercor proposed $26.7 million (1.2% of forecast total opex) for its customer assistance package, which aims to improve services to customers experiencing vulnerability.[26] The package combines 5 programs, as follows:[27]

- Energy care ($2.6 million)
- Community energy fund ($6.3 million)
- Vulnerable customer assistance program ($7.7 million)
- Energy advisory services ($2.7 million)
- First Peoples program ($7.3 million).

Based on our review, we have included a lower amount of $15.8 million for this step change in our alternative estimate of total opex. This is 41% lower than Powercor's proposal. We have also treated this step change as a category specific forecast. Our alternative forecast of annual costs is provided in the category specific forecast section 3.3.5.3.

Table 3.8 Customer assistance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	5.2	5.3	5.3	5.4	5.4	**26.7**
AER alternative estimate	–	–	–	–	–	**–**
Difference	–5.2	–5.3	–5.3	–5.4	–5.4	**–26.7**

Source: Powercor, *PAL MOD 1.05 – Opex,* January 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.

Assessment

We have had regard to Powercor's consumer engagement in our assessment of the customer assistance package. We note that the customer assistance package was developed with input from, and is strongly supported by, both customers and Powercor's Consumer Advisory Panel (CAP). For example, Farmers for Climate Action submitted:

> Other investments including $5.9 million for vulnerable customer assistance to support electrification, $4.8 million for community-led renewable energy projects, $2.1 million for expert energy advisory services, and $2 million for energy literacy programs, were welcomed by attendees.[28]

The CAP submitted:

> We are particularly pleased about increases in the regional and rural supply program and the customer assistance package, as well as the commitment to

[26] Powercor, *PAL BUS 9.02 – Operating Expenditure – Customer Assistance Package*, January 2025, p. 6.

[27] Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

[28] Farmers for Climate Action, *Submission – Powercor electricity distribution proposal 2026–31,* May 2025, p. 1.

> create a vulnerability strategy with an emphasis on partnerships with community organisations who already support people in vulnerable circumstances.[29]

The CAP emphasised that Powercor should adopt a partnership-based approach, underpinned by a vulnerability strategy, and focus on areas where it is uniquely positioned to have the greatest impact in assisting vulnerable customers on its network.[30] We agree these are important factors in considering whether the proposed costs are prudent, efficient, and provide incremental benefits to consumers.

Vulnerable customer costs do not meet our standard step change categories (i.e. new regulatory obligation, capex/opex trade-off, material change in external market factors). However, we recognise these programs represent new incremental costs (not covered by base/trend opex) and we have provided for similar costs in other recent determinations on the basis of strong customer support and detailed analysis. We also note CCP32's view that:

> strong customer support, along with regulator and government expectations, are close enough to meeting step change criteria for this proposal to be actively considered.[31]

We have assessed each proposed program separately, based on the cost breakdown provided by Powercor in its step change model, as well as the objectives of each program outlined in the proposal. We set out our conclusions on each program which forms part of the overall vulnerable customer package step change below. The key considerations we have had regard to in our assessment are whether the proposed programs align with a partnership-based approach to assisting vulnerable customers, are not duplicative of existing programs or costs, and reflect activities where a distribution network is specifically or uniquely well placed to assist.

We consider that vulnerable customer package costs should be treated as a category specific forecast, rather than an opex step change. This treatment is consistent with our approach in recent determinations, and means incurred costs will not be automatically rolled into base opex. We consider a review of the outcomes of the programs, with ongoing input and oversight from consumers, is warranted.

Energy Care

Powercor proposed $2.6 million for its Energy care program,[32] which aims to provide information and training sessions to community support workers, as well as in-person electricity literacy for vulnerable customers.[33]

We have included part of Powercor's proposal, where costs align with CAP's recommendation to focus on partnerships with other organisations, and areas where

---

29 CPU Customer Advisory Panel – *Submission – Powercor electricity distribution proposal 2026–31,* April 2025, p. ii.

30 CPU Customer Advisory Panel – *Submission – Powercor electricity distribution proposal 2026–31*, April 2025, pp. 3, 27, 28 and 34.

31 CCP32, *Submission – Powercor electricity distribution proposal 2026–31*, May 2025, p. 25.

32 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

33 Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, p. 6.

Powercor is uniquely positioned to assist. Our alternative estimate is $0.7 million, covering community support worker training and one supporting employee.

Based on our review, we have not included the remaining costs associated with delivering direct energy literacy services, as we are not satisfied that these costs are prudent and efficient, given the existence of similar in-person, phone-based, and web-based programs.[34]

Community energy fund

Powercor proposed $6.3 million for its Community energy fund program, which aims to provide funding for initiatives such as community batteries and solar hubs.[35] The program proposes to fund 6 (unspecified) projects annually, with any unused funds to be returned to customers.[36]

Based on our review, we have not included this program in our alternative estimate, as it appears duplicative of similar initiatives already provided for or supported by other existing programs and bodies from time to time.[37]

Additionally, we note there is no clear mechanism under the National Electricity Rules (NER) to ensure unspent funds are returned to customers, creating a risk of increased costs if suitable projects are not identified. As a result, we are not satisfied this program is prudent or efficient.

Vulnerable customer assistance program

Powercor proposed $7.7 million for its Vulnerable customer assistance program,[38] which aims to assist vulnerable customers and communities in transitioning away from gas appliances by reducing fees for necessary fuse or phase upgrades, and by developing a vulnerability strategy.[39]

We have included this program in our alternative estimate, as we consider Powercor to be uniquely positioned to provide these services and there is evidence of consumer support that the program aligns with the intent of the Game Changer and other reforms to reduce barriers and enhance outcomes for vulnerable customers.

However, we also note that the CCP32 considered customer engagement on the program details to be limited, with a greater focus on general customer views.[40] While the fuse upgrade component of the program is well detailed in the proposal, other cost categories are

---

34 For example: Energy Assistance Program, Anglicare-EAP ,Useful tools on Energy Made Easy | Energy Made Easy).

35 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

36 Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, pp. 7–8.

37 For example: 100 Neighbourhood Batteries Program Grants.

38 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

39 Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, pp. 7–8.

40 CCP32, *Submission – Powercor electricity distribution proposal 2026–31*, May 2025, pp. 10–11.

not well explained,[41] and it is unclear from the information available whether the CAP or consumers generally support the full scope and cost of the program.

Therefore, while we have included this program, we encourage Powercor to further engage with CAP and other consumers to confirm consumers are aware of and support the detailed costs of this program.

Energy Advisory Service

Powercor proposed $2.7 million for its Energy Advisory Service program,[42] which aims to provide discounted or waived fees for bespoke data requests and advice for community groups. Powercor proposed that any unspent funds be returned to customers.[43]

Based on our review, we have not included this program due to the following key concerns:

- bespoke data requests are not a new service, and it is unclear why discounted services have not been offered previously, especially given significant opex underspend in the current regulatory period. Minor additional costs can likely be managed within base and trend opex growth
- the proposal focuses on discounted data services; however, the cost breakdown also includes existing services and a web hub, which appears to overlap with the CER Data Visibility initiative, raising potential double-counting issues
- there is no clear mechanism to ensure unspent funds are returned to customers.

First Peoples program

Powercor proposed $7.3 million for its First Peoples program[44] to improve energy access through multiple initiatives, including:[45]

- energy literacy sessions delivered through community engagement by First Peoples
- $500 annual rebates for people over 60 to help offset heating and cooling costs
- a community energy fund for renewable projects
- climate resilience projects to support safe community gatherings during emergencies
- energy appliance upgrades.

We note that Powercor has proposed additional initiatives for its First Peoples customers compared to CitiPower and United Energy, which we consider as reflective of the higher proportion of First Peoples communities within Powercor's distribution area.

41 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

42 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

43 Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, p. 8.

44 Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

45 Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, pp.11–17.

We have included this program based on the strong support from stakeholders including the First Peoples Advisory Committee (FPAC) and its alignment with the AER's Game Changer intent.

However, we also note a relatively high proportion of administrative costs (approximately 40%) associated with delivering the service.[46] We have included this program as a placeholder, but encourage further consultation with FPAC to evidence support for the benefits of the program relative to administrative costs.

Conclusion

The following table summarises Powercor's proposal for its customer assistance package, our alternative estimates, and draft decisions for each program.

Table 3.9 Customer assistance package draft decision summary ($million, 2025–26)

Program	Proposal	Alternative Estimate	Draft decision	Comment
Energy Care	2.6	0.7	Partially accepted	Accept costs for partnership delivery and areas of unique positioning, avoiding duplication
Community Energy Fund	6.3	–	Not accepted	Powercor not uniquely positioned to provide this service. Overlap with other organisations
Vulnerable Customer Assistance Program	7.7	7.7	Accepted	Accept as a placeholder; subject to Powercor confirming CAP support detailed program costs
Energy Advisory Service	2.7	–	Not accepted	Not a new service; potential double-counting with CER Data Visibility program
First Peoples Program	7.3	7.3	Accepted	Accept as a placeholder; seek further evidence that FPAC supports net benefits of program
Total	**26.7**	**15.8**	**41% reduction**	

3.3.4.2 Vegetation management

Powercor proposed a $232.9 million step change (10.6% of forecast total opex) for increased vegetation management costs.[47] We have not included a step change for vegetation

[46] Powercor, *PAL BUS 9.02 – Operating expenditure – Customer assistance package*, January 2025, p. 17.

[47] Powercor, *PAL MOD 1.05 – Opex*, January 2025.

management in our alternative estimate of total opex for this draft decision. Powercor has made substantial progress in addressing vegetation management compliance issues over the last 2 years. We consider, based on the information available, that Powercor's total base opex, and the rate of change, provides sufficient opex for Powercor to comply with its electric line clearance obligations in the 2026–31 period. This view is based on our own analysis, which aligns with, and is supported by, EMCa's advice. We expect Powercor to consider our feedback, and account for updated base year expenditure and the current status of its cutting program, when considering its revised proposal.

Table 3.10 Vegetation management step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	16.7	31.2	60.1	61.8	63.1	**232.9**
Powercor amended forecast	30.2	49.3	49.8	50.2	50.5	**230.0**
AER alternative estimate	–	–	–	–	–	**–**
Difference	–16.7	–31.2	–60.1	–61.8	–63.1	**–232.9**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 2025; Powercor, *Response to information request IR016*, 24 April 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 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.[48] Of note, Jemena and AusNet, which are subject to the same regulations, did not propose similar step changes for vegetation management.

In response to an information request, Powercor provided an amended forecast of its vegetation management step change to reflect more up to date information.[49] We have based our assessment on this more recent forecast.

We have identified several concerns with the proposed vegetation management step change. While we consider that Powercor will need to make further improvements to its vegetation management practices to ensure compliance with its vegetation management obligations, we are not satisfied, based on the evidence provided, that an increase in opex beyond that provided in base opex and the rate of change is required.

Stakeholder engagement on the vegetation management step change

Powercor stated that it designed its regulatory proposals with Victorian electricity consumers in mind and had consulted on this step change with its consumer advisory panel (CAP). It

---

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

49 Powercor, *Response to information request IR016*, 24 April 2025.

stated that the CAP was supportive of it receiving additional expenditure to comply with its safety related regulatory obligations, and in turn minimise bushfire risk.[50]

The CCP32, however, stated that if the need for increased opex was due to Powercor underspending consistently over recent years, and needing to get back to the levels forecast, then this would not be a reason for a step change. Otherwise, it considered a step change may be appropriate, subject to the appropriate level being considered by the AER.

The Victorian Greenhouse Alliances considered that the distributors should be required to implement more frequent pruning cycles, to reduce unnecessary destruction of mature trees.

Powercor's regulatory obligations

Powercor's regulatory obligations are set by the *Electricity Safety Act 1998*, and the Electricity Safety (Electric Line Clearance) Interim Regulations 2025. The Code of Practice for Electric Line Clearance is a schedule to the Regulations.

There has been no substantive change to the Electric Line Clearance Regulations or the Code of Practice in the 2021–26 control period. The current Regulations are due to expire on 25 June 2026. We are not expecting the new regulations to include any material changes from the existing regulations or the Code of Practice.

Although there has been no substantive change to the regulations, Powercor submitted that it is subject to a new regulatory obligation. It states that it is now using LiDAR technology to inspect vegetation clearances and this is identifying non-compliance that it was not able to identify previously. Once it identifies non-compliance, it must address that non-compliance. Powercor stated that this has the effect of increasing the standard of compliance.[51]

As required under the Regulations, Powercor prepared and submitted to Energy Safe Victoria a management plan in September 2022 outlining how it will comply with the Code.[52] Powercor noted that the Regulations require that it 'must not contravene a requirement of the management plan if the management plan is approved by Energy Safe Victoria'. Consequently, Powercor stated that once its management plan was approved by ESV it became a regulatory obligation.[53]

Regardless of whether the management plan itself is a regulatory obligation, we are satisfied that Powercor must meet all the requirements of its plan. Accordingly, the forecast total opex we approve must be sufficient for Powercor to meet all the requirements in its approved management plan, as well as its regulatory obligations under the relevant Act, Regulations and Code of Practice.

---

50 Powercor, *PAL ATT 9.02 – Vegetation management step change*, January 2025, p. 5.

51 Powercor, *PAL ATT 9.02 – Vegetation management step change*, January 2025, p. 10.

52 CitiPower, Powercor and United Energy, *PAL ATT 9.05 – 2021–2026 Electric Line Clearance (Vegetation) Management Plan*, September 2022.

53 Powercor, *PAL ATT 9.02 – Vegetation management step change*, January 2025, p. 10.

Powercor also noted that it ‘has been prosecuted by the ESV for Code non-compliance 4 times since 2019’, as well as a large number of fines. It stated that reflects the higher standard of compliance now required.[54]

EMCA’s assessment

We engaged EMCa to provide an expert view on Powercor’s proposed vegetation management step change. EMCa was satisfied that LiDAR data has identified additional cutting is required for Powercor to meet its obligations. However, EMCa considered the approach to forecasting the step change significantly overstates the required expenditure, including:[55]

- indications from data provided by Powercor that the LiDAR program has identified a smaller vegetation management program than what Powercor has proposed
- the cutting volume for 2024–25 is higher than the estimate relied upon by Powercor to forecast the uplift in volumes it requires. When combined with a smaller total volume to achieve compliance, this means Powercor has overestimated the uplift it requires.
- a lack of justification for the proposed uplifts in contractor liaison and hazard trees costs
- unit rates are higher than an efficient level, and the introduction of additional resourcing should result in an increase in delivery capability, and place downward pressure on rates
- relatively new application of LiDAR technology, which amongst other things will require several years to be refined including updating of the vegetation management systems to establish a stable vegetation management program. Once stabilised, this can be expected to enable efficiencies to be realised which are not currently included in the forecast of opex requirements. EMCa considers these efficiencies can be material.

EMCa undertook sensitivity analysis and found that only conservative corrections to the underlying assumptions resulted in the need for the step change falling away. Given this, EMCa concluded that Powercor does not need a step change in opex to comply with its vegetation management obligations.

Our assessment of Powercor’s vegetation management step change

EMCa’s findings are broadly consistent with our own analysis. We found several flaws in the Powercor modelling that significantly overstate the opex required for it to comply with its vegetation management obligations. We also have concerns that the proposed step change may be inconsistent with the intended opex incentive framework.

Overall, we have considered whether Powercor’s base year expenditure, plus the rate of change, is sufficient for it to comply with its regulatory obligations. Powercor’s proposed base year is 2024–25.

We have assessed Powercor’s vegetation management from both a top-down perspective as well as doing a bottom-up assessment. In terms of our top-down assessment, we looked at Powercor’s vegetation management costs over time. We also looked at how Powercor’s

---

54 Powercor, *PAL ATT 9.02 – Vegetation management step change*, January 2025, p. 7.

55 EMCa, *Powercor 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, August 2025, pp. 139–142.

vegetation management opex compared to its Victorian peers, who operate under the same regulatory framework, albeit in different parts of Victoria.

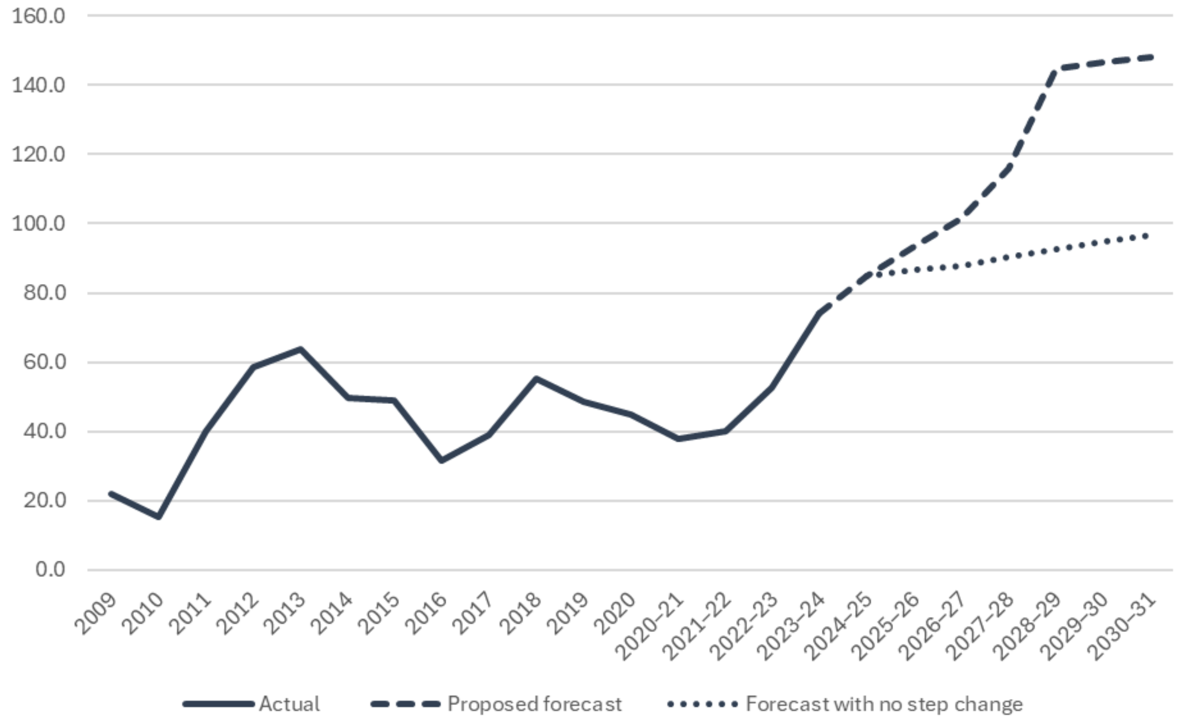
Powercor has reduced its vegetation management opex over the past 15 years

We note that Powercor's vegetation management opex rose significantly from 2011, as shown in Figure 3.5. This followed a significant increase in its obligations imposed following the Black Saturday bushfires in 2009. From 2013, Powercor significantly reduced its vegetation management opex. After introducing its LiDAR program, and identifying significant non-compliance, Powercor's vegetation management opex started to increase from around 2022–23.

Powercor's forecast vegetation management opex for the 2026–31 period is 90% more than its actual and estimated vegetation management opex for the 2021–26 period, and 199% more than the 2016–2020 period.

Without a step change, base year vegetation opex, plus the rate of change, would provide Powercor 34% more than its actual and estimated vegetation management opex for the 2021–26 period, and 110% more than the 2016–2020 period.

Figure 3.5 Powercor's vegetation management opex, $m, 2025–26



Source: Powercor, *Category analysis – Regulatory Information Notice response 2009–24*; AER analysis.

Powercor appears to be spending more on vegetation management than its Victorian peers

We understand that AusNet Services and Jemena have not been subject to the same enforcement actions as Powercor has. Given this, we have examined how the vegetation management opex of the 5 Victorian distributors compare. We compared Powercor's unit rate (vegetation management opex divided by the number of maintenance spans) to AusNet Services', the closest peer to Powercor. We found that, prior to 2021–22, Powercor's unit rate was typically lower than AusNet Services'. But from 2021–22 Powercor's unit rate has risen significantly such that in 2023–24 it was 2.2 times AusNet Services'. This significant increase in unit rates was driven by both an increase in Powercor's total vegetation management opex, and a decrease in the number of maintenance spans.

EMCa compared Powercor to both its Victorian peers, and the other distributors in the wider NEM.[56] EMCa found that Powercor was among the highest cost businesses for vegetation management, and did not appear to be undertaking the work at an efficient cost. It considered that this was indicative of a program that is progressing towards compliance and has not been optimised.[57] EMCa also considered that Powercor had not justified the further increases in its unit rates that it included in it forecast vegetation management costs.[58]

Our bottom-up assessment shows that Powercor has significantly overestimated the opex required to comply with its regulatory obligations

In addition to this top-down analysis, we also looked closely at the model Powercor used to forecast its vegetation management step change. We have identified concerns with several of the underlying assumptions. The model forecasts the number of spans to be cut each year. This included both regular maintenance cuts and rectification cuts, which are required when vegetation is found within the minimum clearance space. It applied different unit rates to these volumes, with rectification cuts typically more expensive. For spans in a high bushfire risk area (HBRA) Powercor separately forecast cuts made in the fire danger period and those outside the fire danger period. This is because Powercor's management plan requires it to cut non-compliant spans quicker within the fire danger period.

As noted by EMCa, Powercor proposed a volume of cutting that is significantly higher than its own LiDAR program identified as necessary in 2024. Powercor provided information showing that had it completed its full program of maintenance cuts in 2024, and cleared all spans that were found to have vegetation in the minimum clearance space, it would have needed to do 77,918 cuts. However, Powercor proposed to increase the number of cuts to around 91,600 from 2027–28. We have identified 2 forms of double counting that explain this difference, and which thus overestimate the volume of cutting required.

Further, we consider the 77,918 number likely overestimates the volume of cutting needed once it achieves compliance because this volume likely includes a backlog of non-compliant spans. We discuss these issues in greater detail below.

Powercor double counted rectification cuts

Powercor separately forecast rectification cuts in its HBRA areas made in the fire danger period and outside of that period. This reflects the different timeframes it has to rectify non-compliant spans in those periods. We consider Powercor has double counted rectification cuts by doing this. All else equal, every rectification cut done prior to the start of the fire danger period avoids a cut that needs to be made in the fire danger period. This

---

56 EMCa, *Powercor 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, August 2025, p. 133.

57 EMCa, *Powercor 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, Date, pp. 133–134.

58 EMCa, *Powercor 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, Date, p. 134.

reflects the fact that the LiDAR inspections are completed prior to the start of the fire danger period.

CitiPower, Powercor and United Energy's weekly status reports show the total count of non-compliant spans in Powercor's high bushfire risk areas over time.[59] VP1 spans are the highest priority with vegetation closest to the powerline. VP3 is the lowest priority with vegetation only just within the clearance space.

Powercor forecast the number of rectification cuts it needs to make in the fire danger period based on the maximum VP counts in 2024. However, this peak occurs outside the fire danger period and most, if not all, of these non-compliant spans were rectified prior to the start of the fire danger period. For example, Powercor was able to rectify all VP1 and VP2 spans before the end of the year in 2024. However, despite rectifying all its VP2 spans in 2024, Powercor is forecasting that it will need to do an additional 2000 VP2 cuts in the bushfire danger period because its VP2 count peaked around 2000 in 2024. Similarly, it forecast it will need to do an additional 4,200 VP3 cuts in the bushfire danger period. In this way we consider Powercor has over forecast the volume of rectification cuts it will need to do by 6,200 cuts. CPU provided no reason to explain why the peak of its VP counts was a reasonable basis to forecast the additional number of rectification cuts required within the bushfire season.

Powercor double counted cuts in its base and uplift volumes

Powercor forecasts the volume of cuts it will need to do by forecasting a base volume plus an 'uplift'. As discussed above, it forecasts the uplift based on its cutting volumes for 2024, when it completed 52,073 cuts. But to forecast the base volume it used its estimated volume for 2025, which is 58,976. This double counts 6,903 cuts.

These 2 forms of double counting explain the difference between the 77,918 total cuts required in 2024 and the 91,600 Powercor has forecast from 2027–28.

Powercor has assumed that the number of spans with vegetation inside the minimum clearance space will not improve from the high level of 2024

Powercor assumed that the number of non-compliant spans it will have in the 2026–31 period will not improve from what it was able to achieve in 2024. This is despite also forecasting an increase in the number of maintenance spans it will cut, which should reduce the number of non-compliant spans that need rectifying. Powercor has already significantly reduced the number of non-compliant spans it has identified in 2025. This can be seen in CitiPower, Powercor and United Energy's weekly status reports where the number of non-compliant spans in HBRA areas has fallen significantly over the past 2 years, with some improvement in 2024 and significant improvement in 2025. While we do not yet have a complete picture of 2025 it appears possible that Powercor will have no remaining non-compliant spans in its HBRA areas before the start of the next bushfire danger period.

The bushfire danger period is an important deadline in Powercor's management plan. Prior to the start of the bushfire danger period Powercor has 6 months, or until the start of the fire danger period, to rectify any non-compliance under its approved management plan. Once the

---

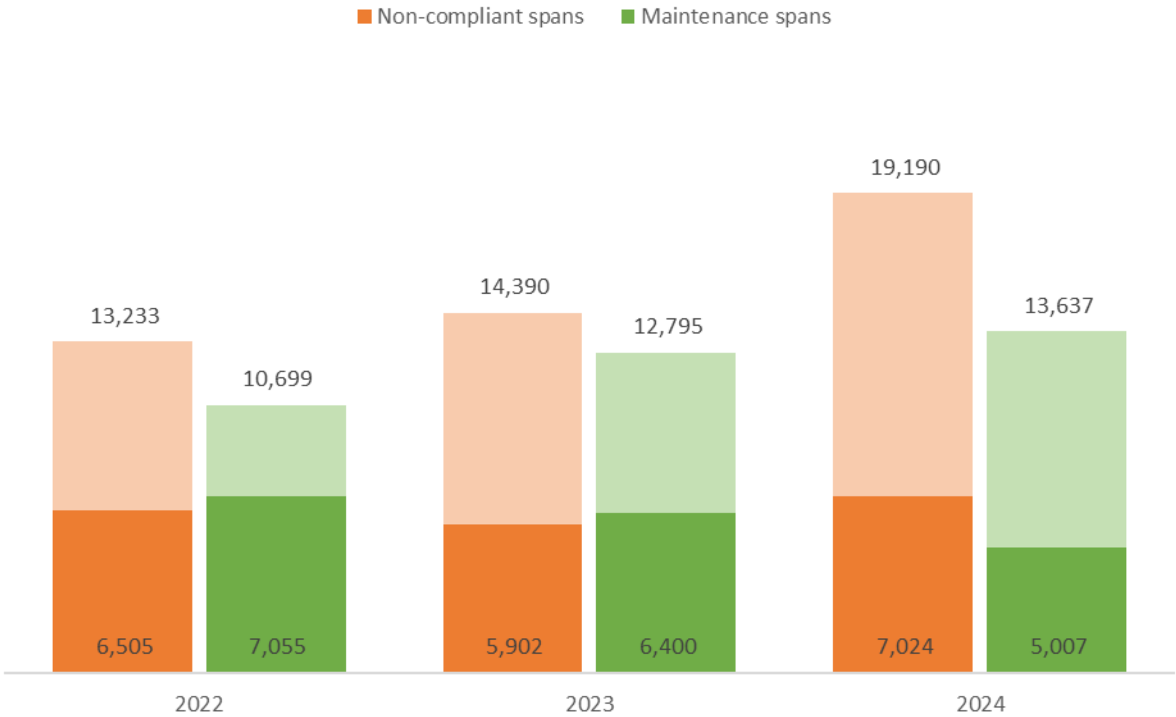
59 Powercor, *Response to IR016 – vegetation management opex step change*, 24 April 2025.

fire danger period starts it must rectify non-compliant spans within 2 days to 2 weeks, depending on how close the vegetation is to the powerline.[60]

Compliance is lagging in LBRA areas

We consider Powercor has already significantly improved its compliance in its HBRA areas, which it has prioritised. It is less advanced in its low bushfire risk areas (LBRA). It has made some improvements in its LBRA rural areas, but compliance has worsened in its LBRA urban areas. This can be seen in Figure 3.6, which shows the number of cuts made and the remaining non-compliant spans in its LBRA areas. We can see the number of cuts made has fallen and the number of non-compliant spans has increased over recent years. The darker shaded columns in the stacks represent the cuts made. The lighter shaded columns reflect the spans that remained uncut at the end of the year.

Figure 3.6 LBRA spans cut and remaining, 2022 to 2024



Source: Powercor, *Response to information request IR016*, 24 April 2025; AER analysis.

Powercor forecast cut volumes for the 2026–31 control period based on the 'total' cuts in 2024, the sum of cuts made and 'remaining' cuts. We are concerned that approach would likely overestimate the number of cuts that will be required once compliance is achieved since 2024 appears to include a backlog of non-compliant spans. To test this, we compared the ratio of rectification cuts to maintenance cuts in Powercor's LBRA areas compared to its HBRA areas. In its HBRA areas, Powercor's total rectification cuts (cut and remaining) were 35% of its total maintenance cuts (cut and remaining) in 2024. But in its LBRA areas, total rectification cuts (cut and remaining) were 141% of its total maintenance cuts (cut and

60 Powercor, PAL ATT 9.05, *CitiPower, Powercor and United Energy 2021–2026 Electric Line Clearance (Vegetation) Management Plan*, September 2022, pp. 26–27.

remaining) in 2024. We would expect this to reduce significantly once Powercor achieves compliance. If Powercor reduces the proportion of rectification cuts to a similar proportion as in its HBRA areas, this would reduce its total cuts in 2024 from 77,918 to 63,566.

Hazard trees

Powercor included additional opex of $22.9 million to increase the frequency of hazard tree inspections from every 5 years to every 3 years. Powercor stated that its management plan specifies a 3-year cycle.[61] This 3-year cycle was included in the management plan Powercor submitted in June 2020.[62]

Within its model, Powercor calculates the uplift in its hazard tree program as the difference between a hard-coded value of $6 million and its hazard tree costs in 2022–23. It also accounts for increased real prices. It provides no explanation for the proposed increase other than to say that it estimates it will need to carry out just over double the hazard tree inspections per year than it is currently carrying out.[63]

We are not satisfied that Powercor requires additional opex in order to inspect for hazard trees at the frequency set out in its management plan. We consider that there is sufficient opex in Powercor's base opex and the rate of change. Further, Powercor has not explained the basis for the proposed increase. The 2.3 times increase is more than would be required to undertake the same work in a 3-year period compared to a 5-year period (which would require a 1.7 times increase).

We also note that Powercor appears to have increased its total cost for hazard tress, not just its inspection costs. Powercor gave no reason why increasing the frequency of hazard tree inspections would increase its hazard tree mitigation costs. Increasing the inspection frequency will not change the number of hazard trees, only the timing of when they are identified.

Contractor liaison costs

Powercor included an additional $480,000 per year for the salaries of new staff that it stated it will need to manage its contractors.[64]

As noted by EMCa, the costs for LiDAR and contractor liaison are already included in the base year expenditure and the increase in volumes appears to be being met with the same contractors.[65] Like EMCa, we are not satisfied that Powercor has provided sufficient justification for this increase. We consider that there is sufficient opex in Powercor's base opex, and the rate of change, for it to manage its contractors.

---

61 Powercor, *PAL ATT 9.02, Vegetation management step change*, January 2025, p. 16.

62 Powercor, *PAL ATT 9.04, 2020–2021 Electric Line Clearance (Vegetation) Management Plan*, June 2020, p. 25.

63 Powercor, *PAL ATT 9.02, Vegetation management step change*, January 2025, p. 16.

64 Powercor, *PAL ATT 9.02, Vegetation management step change*, January 2025, p. 16.

65 EMCa, *Powercor 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, August 2025, p. 137.

Powercor did not account for the impact of the rate of change on base year expenditure

Powercor calculated its proposed step change as the difference between its forecast of vegetation management costs in a given year, and the amount it estimated for the base year (2024–25). In forecasting its vegetation management costs, it accounted for forecast price growth. However, in calculating the step change it did not account for the application of the rate of change to base year opex. This, in effect, double counts the impact of the rate of change on Powercor's vegetation management base year opex.

Powercor's proposed step change may not share efficiency gains and losses symmetrically

Since 2010, the Electricity Safety (Electric Line Clearance) Regulations, and the underlying Code of Practice, have not changed significantly. In that time Powercor has not increased its opex to a level that Powercor considers it needs to comply with those obligations. Under the opex incentive framework, Powercor retains incremental efficiency gains (and losses) for 6 years. This means that if Powercor reduces its ongoing level of opex its revenue (forecast opex and EBSS carryovers) doesn't reduce to the lower level until 6 years later. In this way Powercor benefited from not increasing its vegetation management opex for 6 years. If we provide a step change for Powercor to comply with its vegetation management obligations, it will not need to wait 6 years for its revenues to increase to the level it needs to comply with its regulatory obligations.

One of the opex factors we must have regard to when deciding whether forecast opex meets the opex criteria is whether the opex forecast is consistent with any incentive scheme that applies. Consequently, we must have regard to the EBSS when considering forecast opex.

In implementing the EBSS we must have regard to the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses. Consistent with this, we consider that the opex incentive framework should operate in a symmetric way. That is, Powercor should be penalised for any additional costs it needs to incur to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

However, while the NER requires us to have regard to the EBSS, we must ensure the forecast opex is sufficient for Powercor to comply with all its regulatory obligations. We cannot reject a step change on the grounds it should be paid for by EBSS rewards. That said, both the *Expenditure forecast assessment guideline* and the EBSS allow for non-recurrent efficiency gains in the base year.

We are considering whether Powercor's failure to maintain compliance with its vegetation management obligations constitutes a non-recurrent efficiency gain. We would welcome stakeholders' views on this issue. If we were to consider the additional opex required to comply with vegetation management obligations was a non-recurrent efficiency gain, then the additional opex would be recognised in the EBSS. This would penalise Powercor for the additional opex it needed to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

3.3.4.3 Consumer Energy Resource (CER) integration step changes

We have included $22.0 million for CER integration in our alternative estimate of total forecast opex. This is $6.7 million less than the amount proposed by Powercor, and reflects that we are not satisfied that the full proposed costs are prudent and efficient.

Table 3.11 CER integration step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	1.9	6.2	6.3	7.0	7.4	**28.7**
AER alternative estimate	1.4	4.6	4.7	5.5	5.8	**22.0**
Difference	–0.5	–1.5	–1.6	–1.6	–1.6	**–6.7**

Source: Powercor, PAL *MOD 1.05 – Opex*, January 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 proposed $28.7 million (1.3% of forecast total opex) 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.[66] Powercor submitted this change is driven by factors including a customer-led change to the interaction with energy services, such as CER, the government's net-zero commitment, growing renewable generation and battery deployment, and the anticipated electrification of transport and gas.[67] Powercor further submitted that although the CER and electrification investments will come at some cost to customers in the short-term, these will be materially outweighed by the resulting benefits in the long-term.[68] Powercor's CER integration step change broadly consists of 3 key programs:

1. Flexible services ($22.0 million) – investments to transition from static CER controls to flexible CER operation and management
2. Non-network procurement platform ($3.7 million) – development of a non-network marketplace
3. Network data visibility ($3.0 million) – development of a customer portal.

The above programs also relate to investments proposed in Powercor's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 3 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on these programs, our assessment and the reasons for our decisions on Powercor's respective programs (both opex and capex), in **Attachment 2** of our draft decision for CitiPower. We have provided details in CitiPower's attachment only, because the proposals are largely consistent across CitiPower, Powercor and United Energy. We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses.[69] In summary, we have included costs as proposed for flexible services.

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

[67] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 19–20.

[68] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, p. 14.

[69] AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

3.3.4.4 Cloud services and ICT modernisation step changes

We have included $22.8 million (combined) as our alternative estimate for the Cloud services and ICT modernisation and new capabilities step changes for the draft decision. This is $25.2 million less than the amount proposed by Powercor and reflects that we are not satisfied that the full proposed costs and programs are efficient.

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 3.12 Cloud services step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	3.5	8.8	5.4	6.0	2.4	**26.1**
AER alternative estimate	0.6	0.3	0.4	0.9	0.5	**2.7**
Difference	–2.9	–8.6	–5.0	–5.1	–1.8	**–23.3**

Source: Powercor, PAL *MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

Table 3.13 ICT modernisation step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	–0.4	2.3	5.5	7.0	7.7	**22.0**
AER alternative estimate	0.5	2.3	4.5	6.0	6.7	**20.1**
Difference	0.9	0.1	–1.0	–1.0	–1.0	**–1.9**

Source: Powercor, PAL *MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

Powercor proposed these step changes (2.2% of forecast total opex) for additional opex to support new programs, and for the reclassification of cloud services from capex to opex, consistent with the change in accounting treatment. Powercor submitted that these costs largely relate to additional opex to support new ICT investments, consisting of the following programs:[70]

- Cyber security ($13.2 million) – investment to maintain prudent cyber maturity and protection
- Enterprise resourcing planning and billing systems (25.2 million) – upgrade its current systems reaching end-of-life and to achieve convergence across the other businesses
- Infrastructure refresh ($7.5 million) – transition to cloud-based services

[70] Powercor, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 75–80; Powercor, *PAL MOD 9.03 – Opex step changes*, January 2025.

- Market interface technology enhancements (MITE) ($2.2 million) – AEMO compliance-driven reforms.

The above programs relate to investments proposed in Powercor's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 4 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on each of these programs, our assessment and the reasons for our decisions on Powercor's respective programs (both opex and capex), in **Attachment 2** of our draft decision for CitiPower.[71] We provided details in CitiPower's attachment only, because the proposals are largely consistent across all 3 businesses (CitiPower, Powercor and United Energy). We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses. In summary, we have included costs, as proposed, for cyber security, infrastructure refresh and for MITE.

3.3.4.5 Network and community resilience

We have not included the $6.8 million network and community resilience step change in our alternative estimate of total opex. We consider that Powercor's total base opex, and the rate of change, provides sufficient opex for Powercor to undertake these activities in the 2026–31 period.

Table 3.14 Network and community resilience step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	1.3	1.4	1.4	1.4	1.4	**6.8**
AER alternative estimate	–	–	–	–	–	**–**
Difference	–1.3	–1.4	–1.4	–1.4	–1.4	**–6.8**

Source: Powercor, PAL MOD 1.05 – Opex, January 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 proposed $6.8 million (0.3% of forecast total opex) to onboard 5 new community support officers,[72] and to upgrade its IT capabilities to process data in a systematic manner, enabling faster and better response during event situation.[73] It submitted that the community support officers will strengthen community partnerships and enable better sharing of information across parties.[74] Powercor submitted this expenditure is in response to Victorian

71 AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

72 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, p. 71.

73 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, pp. 77–78.

74 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, pp. 73–74.

Government reviews and expectations, including the 2021 Electricity Distribution Network Resilience Review and 2024 Network Outage Review.[75]

Powercor further stated that these initiatives respond to community expectations,[76] including that, since major storm events in 2021, a recurring theme for communities across its network has been a strong desire for resilience planning through on-the-ground engagement by a permanent local presence.[77] Similarly, its proposed IT capabilities uplift responds to the expectations that communities have communicated to it through consultation since 2021.[78]

We received 3 submissions on Powercor's network and community resilience proposal. The CAP welcomed the proposed community support officers and affirmed broad support for this initiative, and also suggested ongoing engagement and regular reviews to ensure resources remain sufficient.[79] The CCP32 echoed the CAP's observation that the business got it 'about right',[80] further commending the business for affording resilience the level of priority and commitment on consumer engagement.[81] The CCP32 also supported the community support officers, noting that the modest expenditure is both prudent and appropriate.[82] The Victorian Government also expressed its support for the resilience expenditure, and noted our assessments should have a focus on individual and case-by-case projects. It also cautioned for awareness of any double counting, particularly for resilience expenditure already included in the current period.[83]

We assessed the information provided by Powercor, including through the initial proposal and subsequent information requests. The above programs also relate to investments proposed in Powercor's capital expenditure proposal. We provide further details on some of these programs in **Attachment 2** of this draft decision.

In summary, we are satisfied these initiatives represent prudent activities for the business to undertake. We are also satisfied that there is strong community and government support behind these programs. However, we are not satisfied that the step change costs represent efficient forecast opex.

We consider these programs can be managed by Powercor without the need for an opex step change. Through our opex base-step-trend forecasting approach, we provide for an uplift in opex through the trend factor. This uplift provides for continued growth and adaptation of the business. Including these step change costs would therefore risk double counting through our opex forecasting approach. We provide guidance on step changes both in the Expenditure Forecast Assessment Guideline and the Better Resets Handbook. This

---

75 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, p. 72.

76 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, p. 67.

77 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, p. 67.

78 Powercor, *PAL BUS 5.01 – Resilience*, January 2025, p. 81.

79 CPU Customer Advisory Panel – *Submission – Powercor electricity distribution proposal 2026–31*, April 2025, pp. 3 and 28.

80 CCP32, *Submission – Powercor electricity distribution proposal 2026–31,* May 2025, p. 16.

81 CCP32, *Submission – Powercor electricity distribution proposal 2026–31,* May 2025, p. 30.

82 CCP32, *Submission – Powercor electricity distribution proposal 2026–31,* May 2025, p. 31.

83 Hon Lily D'Ambrosio MP, *Submission – Victorian electricity distribution proposals 2026–31* – June 2025, pp. 2–3.

guidance reiterates that step changes should be for material changes in costs not able to be accommodated within existing allowances, and should not double count costs provided through other components of forecast opex, such as through rate of change.[84]

We also note Powercor's awareness of the likely need for these activities, including through both government and stakeholder feedback over several years of the current period. Powercor submitted that to date, it has taken a reactive approach to these matters, due to resource constraints. It considered it would not be prudent to presuppose outcomes from the Victorian Government's response to the network resilience review, including because the AER's approach to approving network resilience expenditure was not yet clear. Powercor instead sampled customer sentiment across 2022 and 2023, including to establish the scale of the preferred investment, and in 2024, it continued to test and refine the investment following the government's response to the network outage review in late 2024.[85]

Given the material opex underspend in the current period, we do not consider resource constraints to be a justification for the approach taken to date, and therefore the need for a step change in the 2026–31 period. Providing a step change in these circumstances risks encouraging imprudent deferral of investments across periods, to the detriment of customers. It further limits customers being able to share in the relevant EBSS rewards.

For the reasons discussed above and in **Attachment 2**, we have not included the network and community resilience step change in our alternative estimate of total forecast opex.

3.3.4.6 Fleet electrification

Powercor proposed a negative step change of –$1.0 million related to fleet electrification. Powercor stated this was in response to an expected reduction in its vehicle operating costs due to its proposed electric vehicle transition program. Consistent with our capex position in **Attachment 2**, which has accepted Powercor's fleet electrification program, we have included this step change in our alternative estimate, without any adjustments.

Table 3.15 Fleet electrification step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor 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 MOD 1.05 – Opex*, January 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.

[84] AER, Final decision, *Expenditure forecast assessment guideline – electricity distribution*, October 2024, p. 26; AER, *Better Resets Handbook,* July 2024, p. 25.

[85] Powercor, *Response to information request IR#024*, 13 May 2025, pp. 4–7.

3.3.4.7 Insurance

We have included a negative step change of –$76.4 million (3.5% of forecast total opex) to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 regulatory period don't impact forecast opex for the 2026–31 period.

Table 3.16 Insurance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	–	–	–	–	–	**–**
AER alternative estimate	–15.3	–15.3	–15.3	–15.3	–15.3	**–76.4**
Difference	–15.3	–15.3	–15.3	–15.3	–15.3	**–76.4**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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.

Our final decision for the 2021–26 regulatory period included a $67.7 million ($2020–21) step change for forecast increases in insurance premiums in our alternative estimate. In that decision, we considered that the forecast increases qualified as a step change because they were driven by a major external factor outside of the control of the business and were not captured in base opex or trend.

Under our framework when we approve a step change, we assume the expenditure 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. This results in Powercor's proposed final year increment including the difference between the forecast insurance premiums (insurance step change) in the final year (2025–26) and base year (2024–25), which equates to $1.3 million or $6.3 million over the 2026–31 period.

We asked Powercor to provide its actual insurance premiums in the current period. These showed that the forecast of significant insurance premiums did not eventuate, and it significantly underspent the forecast insurance premiums.[86]

Under the NER we must accept or not accept a distributor's proposed opex forecast.[87] This choice depends on whether we consider the proposed forecast reasonably reflects the opex criteria. The criteria provide that the forecast must reasonably reflect the efficient costs that a prudent operator would require to meet expenditure objectives, given a realistic forecast of demand and cost inputs. In making this decision we must have regard to the opex factors.

One of the opex factors we must have regard to is whether an opex forecast is consistent with any incentive schemes that apply to a network service provider (NSP).[88] The NER

86 Powercor, *Response to information request IR#020*, 5 May 2025.

87 NER clause 6.5.6(c)–(d).

88 NER clause 6.5.6(e)(8).

requires that we must develop and publish an EBSS that provides a fair sharing of efficiency gains and losses between NSPs and network users.[89]

Including the insurance premium component ($1.3 million) 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 materially higher than that required by a prudent operator.

We also consider, this would not provide a fair sharing of efficiency gains or losses under the EBSS and that the previously approved 2021–26 insurance step changes are not a recurrent step up in costs required in perpetuity (that is, we consider they are non-recurrent). Including this insurance component of the final year increment results in network users waiting 6 years before the previously forecast insurance premium increases are no longer reflected in allowed revenues.

To remove the insurance premium component of the final year increment, our alternative estimate for the draft decision includes a combination of a negative insurance step change and a non-recurrent efficiency gain. This ensures our alternative estimate of total forecast opex meets the opex criteria and the EBSS provides a fair sharing of efficiency gains and losses between NSPs and network users.

The negative step change, calculated as the difference between the final year premium allowance and actual premium, removes the expected over forecasting of insurance premiums in 2025–26, thus ensuring this over forecasting doesn't continue into the 2026–31 period. It then sets the non-recurrent efficiency gain in the base year equal to the insurance underspend in the base year. Together, this results in:

- forecast opex equal to that required by a prudent operator
- Powercor returning all the 2021–26 insurance premium underspends through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains). Powercor retains its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years.

3.3.5 Category specific forecasts

Powercor's proposal included 3 category specific forecasts, which were not forecast using the base-step-trend approach. These were for:

- its proposed innovation fund ($7.9 million)
- GSL payments ($20.5 million)
- debt raising costs ($18.5 million).

Additionally, as mentioned in section 6.4.3.1, we have reclassified Powercor's customer assistance package step change ($15.8 million – our lower amount) as a category specific forecast in our alternative estimate.

89 NER clause 6.5.8(a).

3.3.5.1 Innovation fund

We have included $1.8 million for Powercor's Network innovation fund in our alternative estimate of total forecast opex for the draft decision. This is $6.1 million less than the estimate proposed by Powercor, and reflects that we are not satisfied that the full proposed costs and programs are prudent and efficient.

Table 3.17 Innovation fund ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	2.0	2.0	1.3	1.3	1.3	**7.9**
AER alternative estimate	0.4	0.4	0.4	0.4	0.4	**1.8**
Difference	–1.6	–1.6	–1.0	–1.0	–1.0	**–6.1**

Source: Powercor, PAL *MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

Powercor proposed $7.9 million (0.4% of forecast total opex) for a network innovation fund, which the business submitted will ensure it continues to keep pace with changes underway in the energy market and to meet the expectations placed on networks in this environment.[90] The business submitted that without explicit innovation funding, new approaches and the associated benefits are unlikely to be realised, particularly for customer focused innovation programs. It therefore considered its innovation allowance will deliver projects that will contribute long term customer value.[91] In total, Powercor's proposal included 12 individual projects, broadly grouped into 3 categories:

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

Powercor proposed to self-fund 10% of the total program, and to further exclude the innovation expenditure from the EBSS. However, Powercor also raised concerns with our requirements for forecasting innovation expenditure, including the requirement to specify all the proposed innovation projects, and to provide supporting cost-benefit analysis data for these projects.[92]

This program also contains corresponding capital expenditure. We have jointly assessed the above programs with Powercor's capital expenditure proposal, including through the information provided in its initial proposal and through responses to our information requests.

We provide details on each of these programs, our assessment and the reasons for our decisions on Powercor's respective programs (both opex and capex), in **Attachment 2** of our draft decision for CitiPower.[93] We provided details in CitiPower's attachment only, because

90 Powercor, *PAL BUS 10.01 – Innovation allowance*, January 2025, p. 9.

91 Powercor, *PAL BUS 10.01 – Innovation allowance*, January 2025, p. 12.

92 Powercor, *PAL BUS 10.01– Innovation allowance*, January 2025, pp. 10–12.

93 AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

the proposals are largely consistent across all 3 businesses (CitiPower, Powercor and United Energy). We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses.

For our alternative estimate of total forecast opex for the draft decision, and for the reasons discussed in **Attachment 2** of our draft decision for CitiPower, we have therefore included a lower amount of $1.8 million in our alternative estimate.

3.3.5.2 Guaranteed service level (GSL) payments

Powercor also included a category specific forecast for GSL payments of $20.5 million (0.9% of forecast opex) in its proposal. These are payments Powercor makes to customers who experience reliability less than the specified performance thresholds in the Electricity Distribution Code. We have made one adjustment to the forecast we have included in our alternative estimate. Powercor increased the GSL payments by 15% in the expectation that the Essential Services Commission (ESC) will update the GSL payment rates, which it typically does every 5 years. The ESC, however, has not updated the GSL scheme. We will update the GSL payment amounts in our final decision to reflect any amendments the ESC makes to the scheme prior the final decision.

We also note that the proposed forecast of GSL payments was calculated using an estimate of outages for 2024–25. We expect that Powercor will update the forecast in its revised proposal using actual outage data for 2024–25.

Table 3.18 GSL payments ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	4.3	4.2	4.1	4.0	3.9	**20.5**
AER alternative estimate	3.8	3.7	3.6	3.5	3.4	**18.0**
Difference	–0.6	–0.5	–0.5	–0.5	–0.5	**–2.6**

Source: Powercor, *PAL MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

3.3.5.3 Customer assistance package

As discussed in section 3.3.4.1, we have reclassified Powercor's proposed customer assistance package step change ($26.7 million) as a category specific forecast for our lower alternative estimate of $15.8 million.

Table 3.19 Customer assistance package ($million, 2025–26)

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

Source: Powercor, PAL MOD 1.05 – Opex, January 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.

3.3.5.4 Debt raising costs

We have included debt raising costs of $17.4 million in our alternative estimate. This is $1.1 million less than the estimate proposed by Powercor.

Table 3.20 Debt raising costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Powercor proposal	3.3	3.5	3.7	3.9	4.1	**18.5**
AER alternative estimate	3.2	3.4	3.5	3.6	3.7	17.4
Difference	–0.0	–0.1	–0.2	–0.3	–0.4	–1.1

Source: Powercor, *PAL MOD 1.05 – Opex*, January 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.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides consistency with the forecast of the cost of debt in the rate of return building block. This is the basis for our alternative estimate Table 3.20. We used our standard approach to forecast debt raising costs.

Shortened forms

Term	Definition
AER	Australian Energy Regulator
CAP	Consumer Advisory Panel
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	Consumer energy resource
DNSP	distribution network service provider
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
ESC	Essential Services Commission
FPAC	First Peoples Advisory Committee
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	guaranteed service levels
HBRA	High bushfire risk area
LBRA	Low bushfire risk areas
MTFP	Multilateral total factor productivity
MPFP	Multilateral partial factor productivity
NEM	national electricity market
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
RIN	regulatory information notice
SCS	standard control services