Draft Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 6
Operating expenditure

September 2024

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6 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services (SCS). This attachment discusses opex for the main SCS, with metering SCS being discussed in Attachment 20. Forecast opex is one of the building blocks we use to determine a service provider's total regulated revenue requirement.

This attachment outlines our assessment of Ergon Energy's proposed opex forecast for the 2025–30 regulatory control period.

6.1 Draft decision

Our draft decision is to accept Ergon Energy's total opex forecast of $2,379.1 million,[1] including debt raising costs, for the 2025–30 regulatory control period.[2] This is because our alternative estimate of $2,401.8 million is higher ($22.8 million, or 1.0% higher) than Ergon Energy's total opex forecast proposal. Therefore, we consider that Ergon Energy's total opex forecast satisfies the opex criteria.[3]

Our draft decision, which is the same as Ergon Energy's proposed total opex forecast, is:

- $5.8 million (0.2%) higher than Ergon Energy's actual (and estimated) opex in the 2020–25 regulatory control period
- $90.8 million (4.0%) higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period.

We recognise the forecast moderation in opex by Ergon Energy over the next regulatory control period, including in terms of its base year opex efficiency, productivity adjustments and proposing only one step change.

In our final decision, we will update our alternative estimate of total opex to reflect actual opex for 2023–24. Our draft decision is based on the estimate of base year opex included in Ergon Energy's initial proposal because actual data for 2023–24 was not available at the time the proposal was submitted. We will also make mechanical updates for the latest inflation and labour price growth forecasts.

During our assessment process, Ergon Energy indicated that its actual opex for 2023–24 is likely to significantly exceed the estimate it provided in its initial proposal.[4] For our final decision, we will need to consider actual opex for 2023–24. In particular, we will examine the drivers of the higher opex, and any non-recurrent costs, as well as whether it, or some other year, best represents the costs that Ergon Energy requires for the next regulatory control period. We will also undertake further benchmarking analysis on Ergon Energy's updated base year opex to test the efficiency of its updated base year opex.

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1 All dollars in this document are in $2024-25 terms unless otherwise stated.

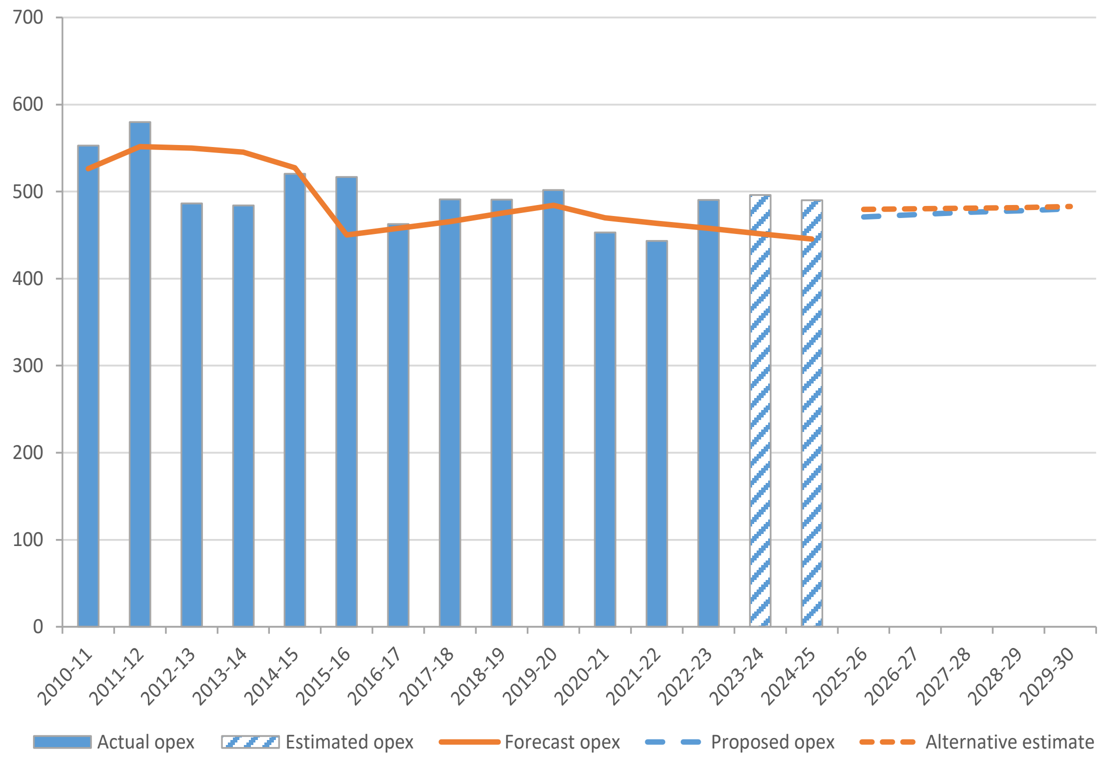
2 As noted above, this is for main SCS, with metering SCS discussing separately in Attachment 20.

3 See section 6.3 Assessment approach.

4 Ergon Energy, *Response to AER information request, IR#044 – Explanation of changes in actual opex and achievement of base opex efficiencies,* 19 June 2024, p. 3.

In Figure 6.1, we compare our alternative estimate of opex to Ergon Energy's proposal for the next regulatory control period. We also show the forecasts we approved for the last 2 regulatory control periods, and Ergon Energy's actual and estimated opex over these periods.

Figure 6.1 Historical and forecast opex ($2024–25)



Source: Ergon Energy, *Economic benchmarking – regulatory information notice responses 2010–23*; AER, *Final decision PTRM 2010–15*, May 2010; AER, *Final decision PTRM 2015–20*, October 2015; AER, *Final decision PTRM 2020–25* and *Opex Model*, June 2020; Ergon Energy, *2025–30 Regulatory proposal*, January 2024; AER analysis.

Table 6.1 sets out Ergon Energy's opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 6.1 Comparison of Ergon Energy's proposal and our alternative estimate of opex ($million, 2023–24)

	Ergon Energy 's proposal	AER alternative estimate	Difference
Base (estimated opex in 2023–24)	**2,481.0**	**2,476.3**	**–4.7 (–0.2%)**
Efficiency adjustment	**–55.3**	**–45.2**	**10.1 (0.4%)**
Transition costs	**–**	**18.3**	**18.3 (0.8%)**

	Ergon Energy 's proposal	AER alternative estimate	Difference
Base year adjustments[5]	**–68.0**	**–67.9**	**0.1 (0.0%)**
2023–24 to 2024–25 increment	**–30.7**	**–30.5**	**0.2 (0.0%)**
Remove debt raising costs	**–30.4**	**–30.3**	**0.1 (0.0%)**
Trend: Real price growth	51.8	46.8	–5.0 (–0.2%)
Trend: Output growth	49.4	29.0	–20.4 (–0.8%)
Trend: Productivity growth	–68.7	–34.6	34.1 (1.4%)
Total trend	**32.5**	**41.2**	**8.7 (0.4%)**
Step change – Smart meter data	**6.8**	**–**	**–6.8 (–0.3%)**
Total opex, excluding debt raising costs	**2336.0**	**2361.9**	**26.0 (1.1%)**
Debt raising costs	43.1	39.9	**–**3.2 (**–**0.1%)
Total opex, including debt raising costs	**2,379.1**	**2,401.8**	**22.8 (1.0%)**

Source: Ergon Energy*, 6.02 – Model – SCS Opex Model,* January 2024.; AER analysis.
Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents zero.

Our higher alternative total opex forecast is primarily due to differences between Ergon Energy's and our approach to making an efficiency adjustment to Ergon Energy's base year opex and our use of a lower productivity growth forecast.

- Ergon Energy proposed a 2.3% efficiency adjustment to its base year opex (removing $55.3 million from its opex proposal), and did not include transition costs to provide it with a glide path over the next regulatory control period to the more efficient level of base opex it proposed.[6] We applied a slightly lower efficiency adjustment to base opex of 1.9% (removing $45.2 million from our alternative estimate of total opex), but added $18.3 million in transition costs. Overall, this means we made a lower total efficiency adjustment over the 2025–30 regulatory control period of $26.9 million, representing an adjustment as a percentage of our alternative estimate of base year opex of 1.1%.
- For the productivity growth forecast, Ergon Energy proposed 1.0% per annum productivity growth,[7] while we adopted our standard 0.5% per annum. This results in us removing $34.6 million from our alternative estimate as compared to the $68.7 million Ergon Energy proposed to remove.

[5] This is the removal of the Electrical Safety Office levy and lease costs, as discussed further in section 6.2 and section 6.4.

[6] Ergon Energy – *6.02 – Model – SCS Opex Model,* January 2024.

[7] Ergon Energy – *6.02 – Model – SCS Opex Model,* January 2024.

- These are partially offset by us including a lower forecast for output growth of $29.0 million, compared to Ergon Energy's forecast of $49.4 million. Ergon Energy forecast maximum demand over the next regulatory control period but had not adopted our standard approach of ratcheting these forecasts to its historic peak maximum demand, which was recorded in 2010.[8] This results in an average annual ratcheted maximum demand growth rate of 0%, compared to 0.8% forecast by Ergon Energy. This decreases our alternative estimate by $20.4 million relative to Ergon Energy's proposal.

6.2 provides our assessment of the extent to which Ergon Energy's initial proposal met the Better Resets Handbook (the Handbook) expectations in relation to forecast opex.

6.2 Better Reset Handbook opex expectations

Opex expectations	Comment
1. Opex forecasting approach	Ergon Energy met this expectation, as it applied our standard base-step-trend forecasting approach to forecast opex for the 2025–30 period. Ergon Energy's opex forecast is also consistent with the opex forecast used in the Efficiency Benefit Sharing Scheme (EBSS).
2. Base opex	Ergon Energy largely met this expectation. While it did not use the latest year for which actual data is available for the draft decision, this will be the case for the final decision. It has also reflected that our benchmarking results show it is materially inefficient and incorporated an efficiency adjustment.
3. Trend	Ergon Energy largely met this expectation, as it applied our standard approach to forecast the opex rate of change, particularly for price and output growth and included a higher productivity growth forecast. For output growth, we have a different view around the growth rate of the ratcheted maximum demand output, which has since been accepted by Ergon Energy.
4. Step changes	Ergon Energy met this expectation, as it proposed only one step change, representing 0.3% of total opex forecast.
5. Category specific forecasts	Ergon Energy met this expectation and proposed only debt raising costs as a category specific forecast.
6. Genuine consumer engagement on operating expenditure forecasts	Ergon Energy did not meet this expectation as it appears to have undertaken limited consultation on its opex proposal and the specific components, although it did respond to affordability concerns of its customers through its base opex efficiency adjustment, productivity growth forecast and not including potential step changes.

8 Ergon Energy, *Response to AER information request, IR#032 – Rate of change (Ratcheted Maximum Demand),* Q1, p. 1, 27 May 2024.

6.2 Ergon Energy's proposal

Ergon Energy's proposal applied a base-step-trend approach to forecast opex for the 2025–30 regulatory control period, consistent with our standard approach.

In applying our base-step-trend approach to forecast opex, Ergon Energy:[9]

- used estimated opex in 2023–24 as the base from which to forecast ($496.2 million or $2,481.0 million over the next regulatory control period)
- subtracted $55.3 million as an efficiency adjustment
- adjusted its total base year forecast opex by subtracting $68.0 million for:
  - the Electrical Safety Office levy that will be treated as a jurisdictional scheme in the forecast period ($38.5 million)
  - property lease costs that will be reported as capital expenditure (capex), rather than opex, in the forecast period ($29.5 million)
- subtracted $30.4 million of debt raising costs to account for the removal of opex categories forecast separately from its base opex
- added an estimate of the difference between the base year opex and the opex it will incur in the final year of the current regulatory period, decreasing opex by $30.7 million
- applied its overall rate of change forecast to its final year adjusted opex estimate, increasing opex by $32.5 million. This included:
  - output growth ($49.4 million)
  - price growth ($51.8 million)
  - productivity growth (–$68.7 million)
- added one step change totalling $6.8 million for smart meter data
- added $43.1 million of debt raising costs, to arrive at a total opex forecast of $2,379.1 million over the 2025–30 regulatory control period.

Table 6.3 Ergon Energy's opex for the 2025–30 period ($million, 2024–25)

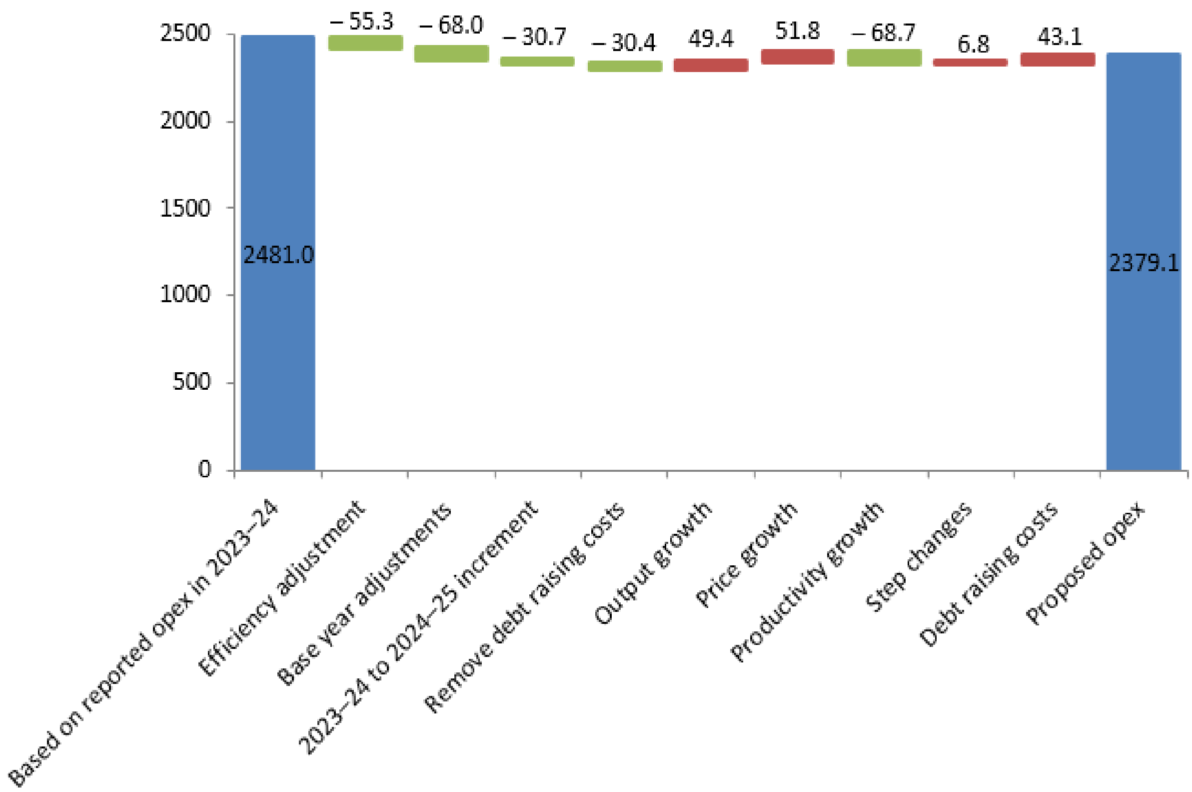
	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Total Opex, excluding debt raising costs	462.7	465.2	467.7	469.1	471.3	2,336.0
Debt raising costs	8.1	8.4	8.6	8.9	9.1	43.1
Total Opex, including debt raising costs	**470.8**	**473.6**	**476.4**	**477.9**	**480.4**	**2,379.1**

Source: Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 141, AER analysis.
Note: Numbers may not add up to total due to rounding.

9 Ergon Energy, *6.02, Model, SCS Opex Model,* January 2024.

Figure 6.2 shows the different components that make up Ergon Energy's opex forecast for the 2025–30 regulatory control period.

Figure 6.2 Ergon Energy's proposed opex ($million, 2024–25)



Source: Ergon Energy, *6.02 – Model – SCS Opex model,* January 2024, AER analysis.
Note: Numbers may not add up to total due to rounding.

6.2.1 Stakeholder views

We received 4 submissions on Ergon Energy's proposal which discussed opex issues.

We have taken these submissions into account in developing the positions set out in this draft decision. Table 6.4 summarises the stakeholder issues raised in the submissions in relation to opex.

Table 6.4 Submissions on Ergon Energy's 2025–30 opex proposal

Stakeholder	Issue	Description
EQ's Reset Reference Group (RRG), AER's Consumer Challenge Panel (CCP30)	Base opex	Energy Queensland Reset Reference Group (RRG) noted that Ergon Energy's forecast seems to reasonably reflect the efficient costs of a prudent operator under the AER's opex framework. However, RRG stated that it does not believe the AER's productivity benchmarking framework, in particular use of a benchmark comparison point of 0.75, truly reflects efficiency. The RRG noted the comparison point is a matter for a future AER, expected in 2026. RRG supported

Stakeholder	Issue	Description
		consideration by the AER of a base opex efficiency adjustment for this decision.[10] CCP30 stated that it had no significant concerns with Ergon Energy's opex calculations and noted that it looked forward to the AER's consideration of the base year efficiency as this is the main driver of opex cost proposals.[11] CCP30 questioned the achievability of the opex proposal by highlighting that Ergon Energy has noted upward pressures on its operating costs. CCP30 also noted the trend of 'over expenditure' by Ergon Energy in its operating costs, and in the context of the proposal that the EBSS apply in the next regulatory control period, noted there is a clear risk that this over expenditure will impact consumers.[12]
RRG, CCP30	Productivity growth forecast	RRG supported inclusion of a 1.0% per annum productivity growth factor as a response to affordability concerns. However, it also noted this is insufficient to improve affordability by itself, and may not be achievable due to the cost pressures Energy Queensland has noted Ergon Energy will continue to face for some years.[13] CCP30 also supported inclusion of a 1.0% per annum productivity growth rate but noted there was little detail on how it would be achieved.[14]
RRG, CCP30, Master Electricians Australia, Amanda Pummer	Step change – smart meter data	RRG supported the step change, including data acquisition of near real time data, noting the AER should assess the prudency and efficiency of the expenditure. Further, the RRG welcomed Ergon Energy's indication that it did not include potential step changes on cyber security and increased insurance premiums to improve affordability.[15] CCP30 stated that it expects that the recent changes to the National Electricity Rules (NER) on costs of accessing smart meter data will be reflected in the draft decision.[16] CCP30 also noted that Ergon Energy had taken actions to limit the number of step changes. For example, by stating that planned step changes on cyber security and increased insurance premiums could be regarded as immaterial and absorbed into the existing opex allowance to improve affordability.[17]

10 RRG, *Submission –2025–30 Electricity Determination – Energex & Ergon,* May 2024, pp. 4, 56–61.

11 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 27.

12 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 26.

13 RRG, *Submission –2025–30 Electricity Determination – Energex & Ergon,* May 2024, pp. 4, 60–61.

14 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 14.

15 RRG, *Submission –2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 61.

16 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 28.

17 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 27.

Stakeholder	Issue	Description
		Master Electricians Australia's submission noted that more expenditure than that proposed by Ergon Energy is required to enable faster integration of consumer energy resources (CER).[18] A personal submission by Amanda Pummer noted that Ergon Energy proposed total opex and smart meter data step change were 'grossly inadequate' to enable a transition to renewables.[19]
RRG, CCP30	Consumer engagement	CCP30 and the RRG noted that specific engagement on the opex proposal was limited in scope.[20] CCP30 stated that the engagement it observed tended to inform stakeholders about the proposals rather than explain options and was not clear on how consumers could influence positions.[21]

Source: Submissions to Ergon Energy's regulatory proposal.

6.3 Assessment approach

Our role is to decide whether to accept a business's total opex forecast. If we do not accept the business's forecast, we must develop our own estimate. We are to form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[22] In doing so, we must have regard to the opex factors specified in the NER.[23]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[24] While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[25]

Our approach is to assess the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the

18 Master Electricians Australia, *Submission – 2025–30 Electricity Determination – Ergon Energy*, May 2024, p. 4.

19 Amanda Plummer, *Submission 2025–30 Electricity Determination – Energex & Ergon,* May 22024, p. 2.

20 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 5; RRG, Submission –*2025–30 Electricity Determination – Energex & Ergon,* May 2024, pp. 3, 5.

21 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 7.

22 NER, cl. 6.5.6(c). The opex criteria relate to the prudent and efficient costs of achieving the opex objectives. The opex objectives were recently updated and are to promote efficient investment in, and use of, energy services for the long-term interests of consumers with respect to price, quality, safety, reliability and security of supply of electricity, and the electricity system, and achievement of targets set by participating jurisdictions for reducing greenhouse gas emissions.

23 NER, cl. 6.5.6(e).

24 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022; AER, *Expenditure forecast assessment guideline – Explanatory statement*, November 2013.

25 NER, cl. 6.2.8(c).

'base-step-trend' approach.[26] We compare our alternative estimate with the business's total opex forecast to form a view on the reasonableness of the business's proposal. If we are satisfied the business's forecast reasonably reflects the opex criteria, we accept the forecast.[27] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[28]

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we take into consideration interrelationships between opex and the other building block components of our decision.[29]

Figure 6.3 summarises the 'base-step-trend' forecasting approach.

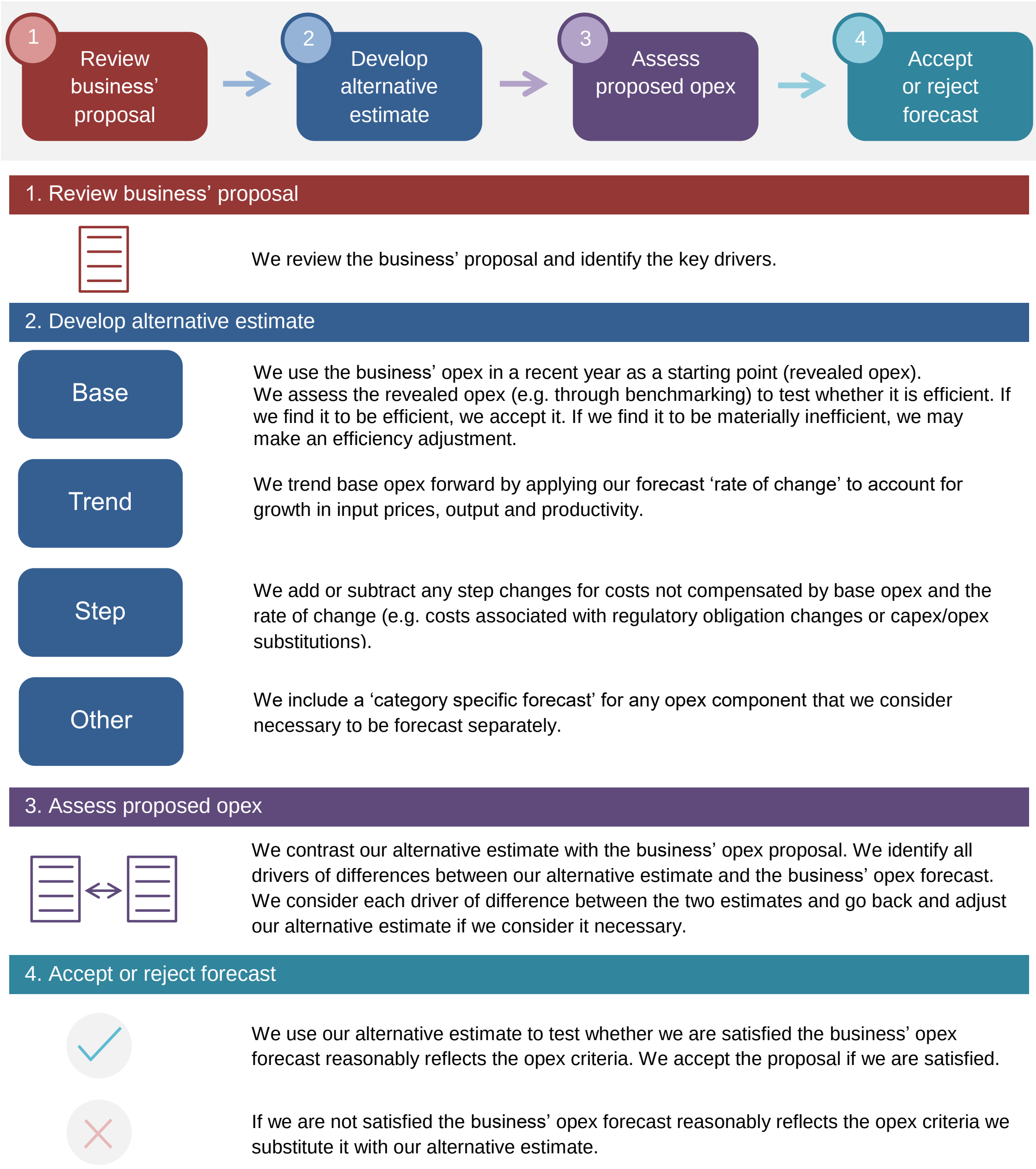
26 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up.'

27 NER, cl. 6.5.6(c).

28 NER, cl. 6.12.1(3).

29 We are required to consider these interrelationships under s. 16(1)(c) of the NEL.

Figure 6.3 Our opex assessment approach



6.3.1 Interrelationships

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

- The EBSS carryover—the estimate of opex for 2024–25 (the final year of the current regulatory control period) that we use to forecast opex should be the same as the level of opex used to forecast the EBSS carryover. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years.

- The operation of the EBSS in the 2020–25 regulatory control period, which provided Ergon Energy an incentive to reduce opex in the base year.
- The impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects both forecast capex and our forecast price growth used to estimate the rate of change in opex.
- The approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block.
- The outcomes of Ergon Energy's engagement with consumers and stakeholders in developing its proposal and any feedback we have had.

6.4 Reasons for draft decision

Our draft decision is to accept Ergon Energy's total opex forecast of $2,379.1 million, including debt raising costs, for the 2025–30 regulatory control period.[30] Our alternative estimate of $2,401.8 million is higher ($22.8 million or 1.0%) than Ergon Energy's total opex forecast proposal. Therefore, we are satisfied that Ergon Energy's total opex forecast satisfies the opex criteria. [31]

Table 6.1 sets out Ergon Energy's proposal, which is the basis for the draft decision, our alternative estimate and the difference between our alternative estimate and the proposal.

The main drivers for the differences are also set out in section 6.1, and we discuss the components of our alternative estimate, and our assessment of Ergon Energy's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider Ergon Energy would need for the safe and reliable provision of electricity services over the 2025–30 regulatory control period.

Ergon Energy proposed a base year of 2023–24 and used an estimate of base year opex of $496.2 million, or $2,481.0 million over the next regulatory control period.[32] It considered that the opex in this year would be reasonably representative of its recurrent efficient opex requirements over the 2025–30 regulatory period.[33]

In support of this, Ergon Energy used our benchmarking approach to assess the efficiency of its estimated base year opex. Ergon Energy tested its estimate using our most recent economic benchmarking models from the AER's 2023 *Annual Benchmarking Report*, including use of the same operating environment factors (OEF) as we applied in its 2020–25 revenue determination decision and our new approach to addressing capitalisation differences.[34] Ergon Energy stated that as a result, it applied a 2.3% efficiency adjustment to

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30 As noted above, this is for main SCS, with metering SCS discussing separately in Attachment 20.

31 The opex criteria are set out in NER, cl. 6.5.6(c).

32 Ergon Energy, 6.02 – Model – SCS Opex Model, January 2024.

33 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 136.

34 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024.

reduce its base year opex to the level of efficient opex supported by our benchmarking model.[35] Ergon Energy did not include 'transition costs' in its initial proposal to allow it to transition its operations to its proposed more efficient level of opex over the 2025–30 regulatory control period. Ergon Energy also noted that while it considered that an efficiency adjustment was not required, in light of the material concerns that it has with the AER's benchmarking model, it incorporated the efficiency adjustment to address affordability concerns of its customers.[36]

While we do not agree with Ergon Energy's position that an efficiency adjustment is not required, we welcome its decision to include one. Consistent with the approach used by Ergon Energy, and as set out below, we have applied our most recent benchmarking results and conclude that Ergon Energy's estimate of opex in the base year is a materially inefficient basis for a forecast. Our benchmarking analysis, which includes some minor updates relative to that undertaken by Ergon Energy, found an efficiency 'gap' of 1.9% (compared to Ergon Energy's 2.3%) between our estimated efficient base year opex and Ergon Energy's estimate of base year opex.

Straight application of this as an efficiency adjustment would result in a $9.0 million per year, or a total $45.2 million adjustment over the 2025–30 regulatory control period. However, we have incorporated a linear glide path to transition Ergon Energy to the more efficient opex level by the end of the 2025–30 regulatory control period. This is consistent with our standard approach of making an efficiency adjustment to base opex when we consider it is materially inefficient. It recognises it will take time and involve costs to implement the required programs to realise opex reductions. In practice, this means a total efficiency adjustment over the 2025–30 regulatory control period of $26.9 million, reflecting an opex efficiency adjustment, as a percentage of our alternative estimate of base year opex after base adjustments, of 1.1%.

In relation to Ergon Energy's concerns with our benchmarking models (as detailed in the Frontier Economics report to Ergon Energy),[37] we consider that while our benchmarking tools are not perfect, this does not limit us from using them in revenue determination processes to assess the efficiency of opex in a proposed base year. Particularly important in this regard is that we only apply results where we consider they reliably inform our overall base year opex efficiency assessment (e.g. by removing the results of econometric opex cost function models that do not satisfy monotonicity requirements). Further, that using a 0.75 comparison point, adjusted for material OEFs, instead of 1.0, inherently builds in a degree of conservativeness, in part reflecting that we acknowledge our benchmarking tools are not exactly precise or perfect tools. We note this in the context of the concerns raised by the RRG around the 0.75 comparison point not being sufficient. We respond further to Frontier's report on benchmarking in section 6.4.1.2.4.

We note that during our engagement with Ergon Energy on its initial proposal, it notified us that the level of actual opex for 2023–24, its proposed base year, will be significantly higher

35 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 136.

36 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 142.

37 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024.

than the estimate it used in its initial proposal.[38] Ergon Energy provided us with an early estimate of its unaudited actual opex for 2023–24, which was approximately 21% higher than the estimate it included in its initial proposal.[39] Ergon Energy noted that the higher actual opex is due to ongoing cost increases it faces from a variety of internal and external drivers, including rising labour, materials and overhead costs and significant weather events.[40] Ergon Energy stated that it expects some of these drivers (i.e. increasing labour and overhead costs) to be recurrent, increasing its opex over the next regulatory control period, while some of the drivers (i.e. above average emergency response costs related to severe storms) are one–off costs in 2023–24.[41]

Ergon Energy further stated that in its revised proposal it intends to apply the same approach as it used in its initial proposals in making an efficiency adjustment to the higher actual opex for 2023–24. That is, it intends to adjust the actual 2023–24 opex reported in its revised proposals to the level of efficient opex targeted in its initial proposal. Ergon Energy noted that in doing this, it intends to remove the non-recurrent costs relating to storm expenditure from its proposed base year opex, and that as the size of the efficiency adjustment is likely to be materially larger than that proposed in its initial proposal, it will consider including transition costs. Ergon Energy noted this would be consistent with recent AER determinations.[42]

We present our views on Ergon Energy's choice of base year in section 6.4.1.1 and the efficiency of its estimated base year opex in in section 6.4.1.2 to inform our alternative estimate for this draft decision. This is based on the estimate of 2023–24 opex included in Ergon Energy's initial proposal.

For our final decision, we will need to consider the actual opex for 2023–24 as reported in Ergon Energy's revised proposal. In particular, we will examine the drivers of the higher than estimated opex, and any adjustments Ergon Energy proposes to make to remove non-recurrent costs to determine if 2023–24, or another year, best represents the costs that Ergon Energy requires for the next regulatory control period. In terms of the efficiency assessment of Ergon Energy's base year opex, we welcome Ergon Energy's commitment to continue to apply our benchmarking models to determine the efficient level of base year opex. We encourage it to consider how it will achieve these savings and provide this detail in its revised proposal. We will also undertake further benchmarking analysis on Ergon Energy's actual base year opex, including assessing the merits of any base year adjustments Ergon Energy proposes and rerun our benchmarking models with the newly updated data.

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38 Ergon Energy, *Response to AER information request, IR#044 – Explanation of changes in actual opex and achievement of base opex efficiencies,* 19 June 2024, p. 3.

39 Ergon Energy, *Response to AER information request IR047*– actual base year opex update (spreadsheet), 17 July 2024.

40 Ergon Energy, Response to AER information request, IR#044 – Explanation of changes in actual opex and achievement of base opex efficiencies, 19 June 2024.

41 Ergon Energy, Response to AER information request IR047 – actual base year opex update (spreadsheet), 17 July 2024.

42 Ergon Energy, *Response to AER information request IR047*, 12 July 2024, p. 2.

6.4.1.1 Proposed base year

Ergon Energy proposed a base year of 2023–24 and used an estimate of base year opex of $496.2 million, or $2,481.0 million over the 5 years of the next regulatory control period.[43] It stated that it selected 2023–24 as its base year because it represents:

- the most recent year for which audited data is available by the time of the final determination
- a realistic expectation of the efficient and sustainable on-going opex that is required to provide SCS services over the 2025–30 regulatory control period.[44]

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

We consider it is feasible to use 2023–24 as the base year because it will be based on actual opex for the final decision. However, we will not be able to determine if 2023–24 will be representative of the nature of costs that Ergon Energy requires for the next regulatory control period, and therefore an appropriate choice of base year, until we have audited actual opex. Ergon Energy will provide this in its revised proposal.

As set out above, Ergon Energy has indicated that the level of actual opex for 2023–24 will be significantly higher than in its initial proposal. Ergon Energy also noted the drivers of this and that it intends to consider the removal of one-off costs from the actual base year opex it will report in its revised proposal.[45] We will consider this in our final decision and if 2023–24 is an appropriate choice of base year, or whether another year may be a better, more representative, base year. In developing its revised proposal, Ergon Energy should also consider these issues and include an updated rationale for its choice of base year.

In our alternative estimate for this draft decision, we have updated Ergon Energy's estimated opex for 2023–24 to $495.3 million, or $2,476.3 million over the next regulatory control period. The difference between Ergon Energy's estimated amount and our alternative is due to the use of different inflation forecasts. We have used the latest inflation forecasts published by the Reserve Bank of Australia (RBA) and consumer price index (CPI) data from the Australian Bureau of Statistics. We consider these inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available at the time.

6.4.1.2 Efficiency of Ergon Energy's opex

As summarised in our *Expenditure Forecast Assessment 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

43 Ergon Energy, 6.02 – Model – SCS Opex Model, January 2024.

44 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 136.

45 Ergon Energy, *Response to AER information request IR047*, 12 July 2024, p. 2.

network and meet its relevant regulatory obligations. However, we do not assume that the business's revealed opex is efficient. We examine the historical trend in opex and use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating materially inefficiently over the benchmarking period and particularly whether its opex in the base year is higher than our estimate of efficient opex.

6.4.1.2.1 Analysis of revealed costs

Figure 6.1 shows that Ergon Energy's actual opex trended downward between 2010–11 to 2016–17 (the second year of the 2015–2020 regulatory control period) to a level closer to our forecasts. Since then, Ergon Energy's actual opex has fluctuated at between 1.0% and 5.5% above our forecasts, apart from 2020–21 and 2021–22 (the first 2 years of the current regulatory control period), where total opex decreased to be below the AER forecasts.[46]

Ergon Energy noted that the key drivers of the lower opex in 2020–21 and 2021–22 included a reduction in maintenance costs, due to a reduction in work completed during the Coronavirus pandemic, and a decrease in other support costs, including training and redundancy costs.[47] Ergon Energy further noted that its actual opex rebounded in 2023–23 (the third year of the current regulatory control period) to be $32.8 million or 7.2% above our forecast for that year due to an increase in general labour, material and contractor costs across expenditure categories as a result of increased inflation and the Coronavirus pandemic.[48] Ergon Energy estimated that this higher level of opex would be maintained in 2023–24 (Ergon Energy's proposed base year) and 2024–25 (the last year of the current regulatory period), and remain significantly above our forecasts. Ergon Energy estimated its opex would be $44.6 million (approximately 10%) above our forecasts in both 2023–24 and 2024–25, and $90.8 million (4.0%) above our forecast for the 2020–25 regulatory control period.

In acknowledging its projected overspend over the current 2020–25 regulatory control period, Ergon Energy noted it is facing increasing operating costs. It outlined the main drivers included major flood and storm costs in 2021–22, increasing costs for vegetation management contracts, a general increase in costs from the Coronavirus pandemic, and increased labour and overhead costs related to the growth in its capital program.[49]

As set out above, Ergon Energy's unaudited data on actual opex in 2023–24 indicates that its proposed base year opex will be approximately 30% above our forecast, reinforcing the trend of increasing costs observed since 2021–22.

We consider this demonstrates that the recent increase in Ergon Energy's operating costs warrants further analysis. This analysis is outlined below.

6.4.1.2.2 Benchmarking the efficiency of Ergon Energy's opex over time

We have used our benchmarking tools and other cost analysis to assess and establish whether Ergon Energy is operating relatively efficiently, both over time and in its proposed

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46 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 132.

47 Ergon Energy, *Response to AER information request IR044,* 19 June 2024, p. 2.

48 Ergon Energy, *Response to AER information request IR044*, 19 June 2024, p. 2.

49 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 33.

base year, 2023–24. Our benchmarking results over the long and short time periods indicate that Ergon Energy has historically been amongst the lower performing distribution network service providers (DNSPs). Further, while Ergon Energy has made improvements in its opex efficiency since 2012, its relative performance has remained at the lower end of performance. Consequently, we have undertaken additional analysis to check the relative efficiency of Ergon Energy's estimated base year opex.

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. Our annual benchmarking reports include information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the National Electricity Market (NEM).[50]

While opex at the total level is generally recurrent, year-to-year fluctuations can be expected. To shed light on Ergon Energy's general level of operating efficiency, in this section we first look at the efficiency of its opex over time, using our top-down benchmarking tools. This is followed in section 6.4.1.2.3 by looking at the efficiency of its estimated opex in the 2023–24 base year.

Period-average econometric opex cost function and productivity index number results

This section presents the results of the 4 econometric opex cost function models that compare the relative opex efficiency of Ergon Energy to other distribution businesses in the NEM. These model the relationship between opex (as the input) and outputs, and so measure opex efficiency. The results presented below reflect an average efficiency score over a specified period – the long period (2006 to 2022) and the short period (2012 to 2022). We examine the short period as it can take some time for more recent improvements in efficiency by previously poorer performing DNSPs to be reflected in period-average efficiency scores. These efficiency scores do not account for the presence of OEFs, as discussed further below.

Econometric opex cost function benchmarking results based on the *2023 Annual Benchmarking Report* are presented in Figure 6.4, over the long period, and in Figure 6.5, over the short period. These results reflect our preferred approach to addressing corporate overhead capitalisation differences, and incorporate circuit line length and corporate overhead data for Evoenergy that was updated since the release of the *2023 Annual Benchmarking Report*. These results were used in the Evoenergy 2024–29 final decision.[51]

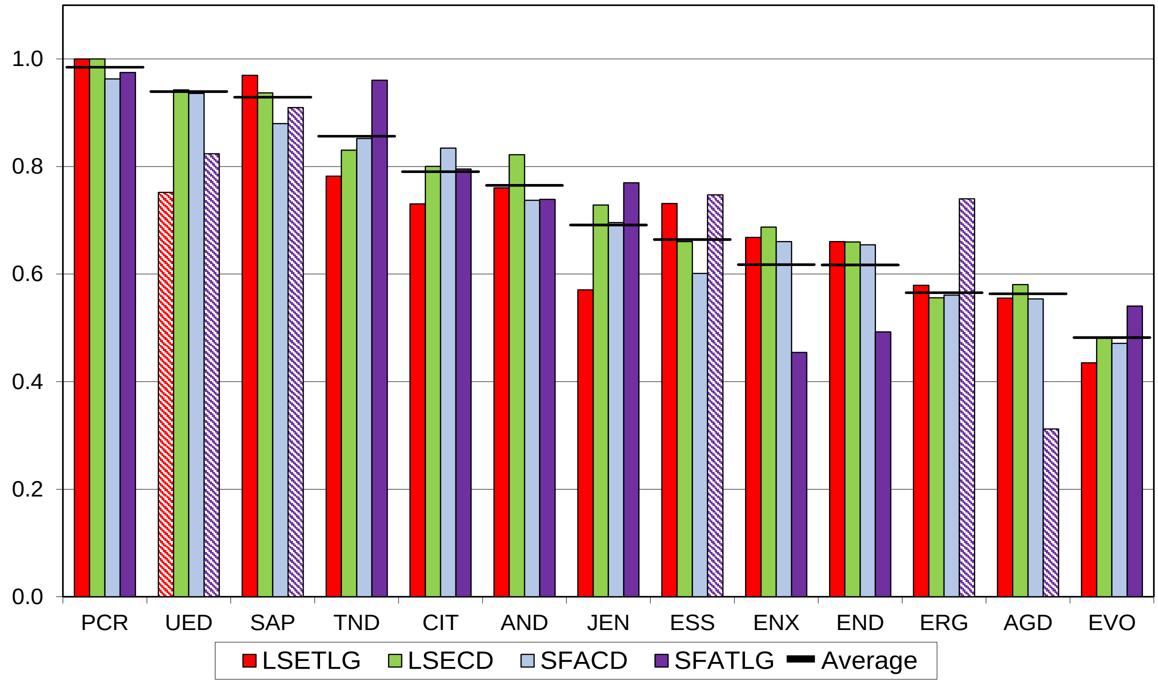
These results indicate that when examined over time, Ergon Energy’s opex has been relatively inefficient. Figure 6.4 shows that over the long period, Ergon Energy is ranked eleventh out of 13 DNSPs (with an average efficiency score of 0.57), and in the short period it is also ranked eleventh out of 13 DNSPs (with an average efficiency score of 0.59). Our standard approach is to use an efficiency score comparison point of 0.75, rather than 1.0, to recognise data and modelling imperfections when assessing the relative efficiency of

50 AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers,* November 2023.

51 AER, *Final Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal*, April 2024, pp. 14–37.

DNSPs. Where the econometric model-average score is below 0.75, we take this as prima facie evidence that a network has been operating materially inefficiently over the relevant period. We consider this is the case with Ergon Energy's efficiency score performance.

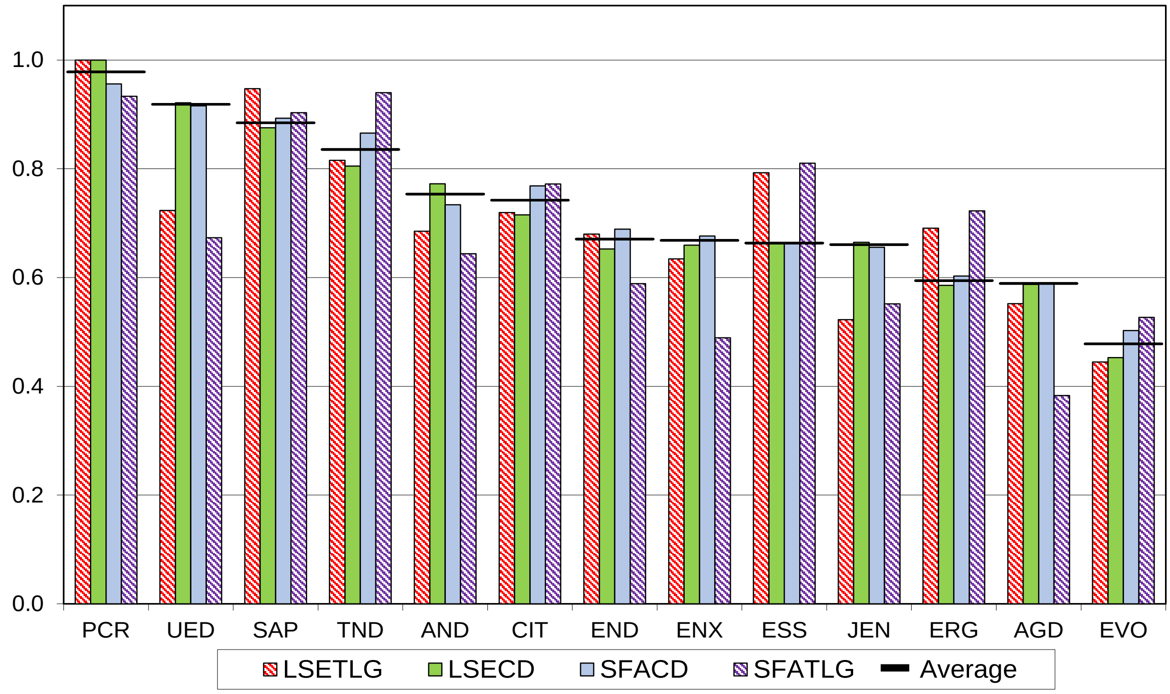
Figure 6.4 Distribution businesses' average opex efficiency scores, 2006–2022



Source: AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers*, November 2023; AER analysis.

Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate circuit line length and corporate overhead data for Evoenergy that was updated since the release of the *2023 Annual Benchmarking Report* and used in the Evoenergy 2024-29 final decision. Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).

Figure 6.5 Distribution businesses' average opex efficiency scores, 2012–2022



Source: AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers*, November 2023; AER analysis.

Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate circuit line length and corporate overhead data for Evoenergy that was updated since the release of the *2023 Annual Benchmarking Report* and used in the Evoenergy 2024-29 final decision.. Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).

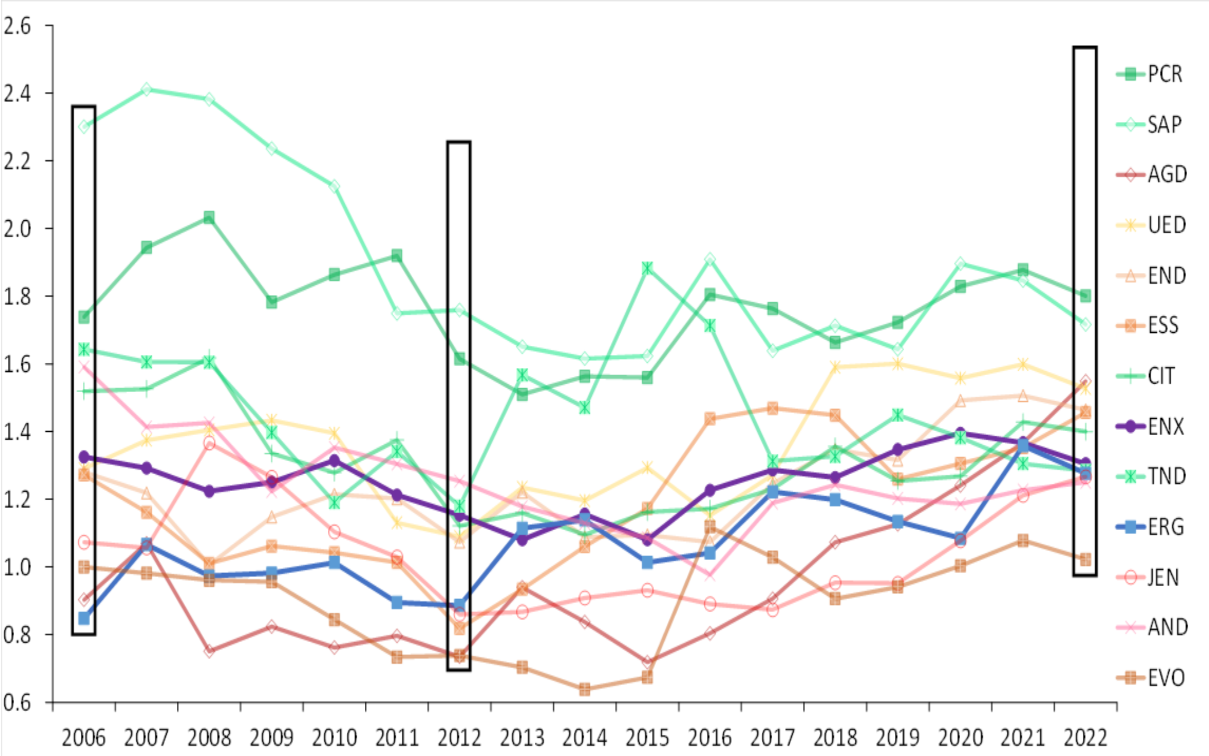
In addition to the econometric opex cost function models, we also use productivity index number techniques to enable comparisons of productivity levels over time and between DNSPs. The multilateral total factor productivity (MTFP) index measures the total factor productivity of each business, whereas 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 OEFs.

The results from our opex MPFP analysis can be seen in Figure 6.6, where a higher score means that a DNSP is more productive relative to its peers. These are based on our *2023 Annual Benchmarking Report* results, again using our preferred approach to addressing corporate overhead capitalisation differences, and updated as applied in our recent decision for the Evoenergy 2024–29 final decision.

The opex MPFP results show Ergon was ranked as one of the lowest performing DNSPs between 2006 and 2012, but its opex MPFP scores have trended upward since 2012. However, in the context of similar improvements by other relatively low ranked DNSPs over this period of time, Ergon Energy is still ranked 10th out of 13 distribution networks in 2022.

We note that the opex MPFP results are broadly consistent with the econometric opex cost function results.

Figure 6.6 Opex MPFP for individual businesses, 2006–22



Source: AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers*, November 2023; AER analysis.

Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate updated circuit line length and corporate overhead data for Evoenergy.

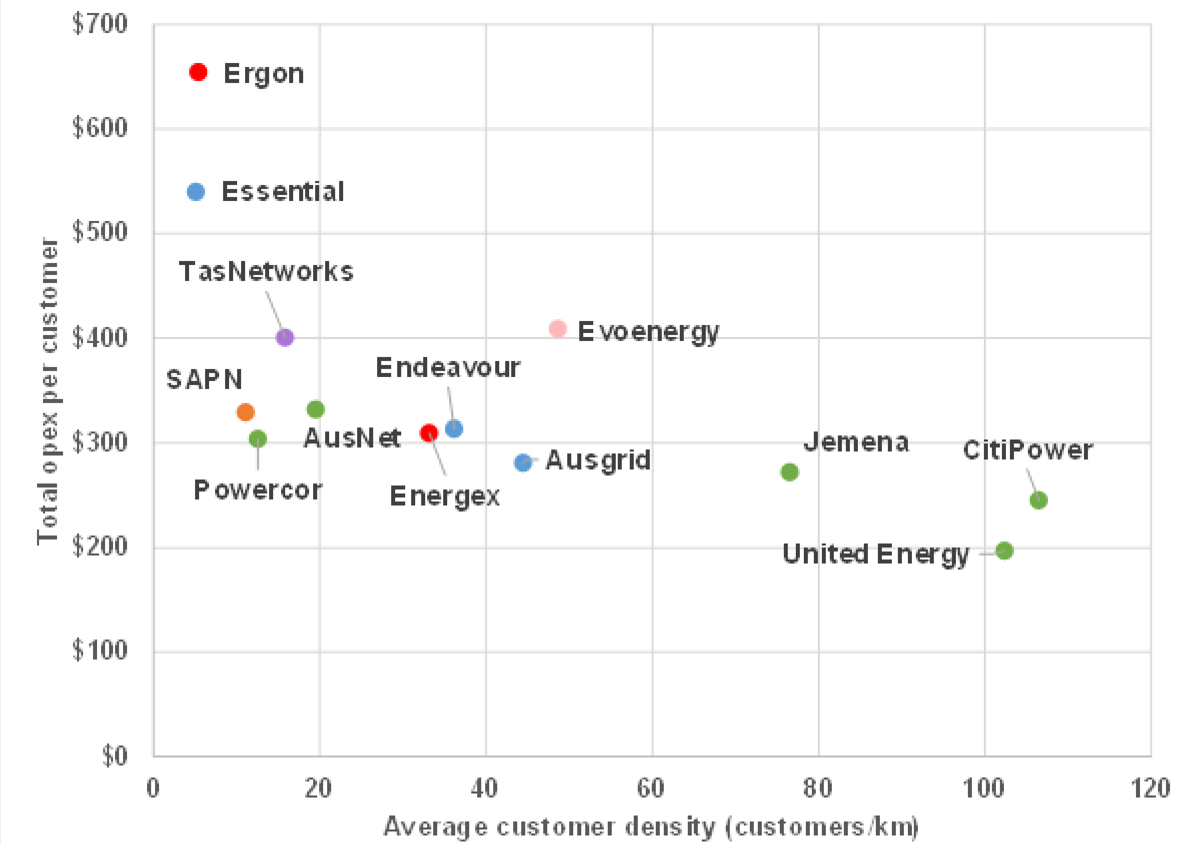
Partial Performance Indicators and cost category analysis

We have also examined the relative opex performance of Ergon Energy over the 5-year period (2018 – 2022) using partial performance indicators (PPIs). This simple ratio method relates one input to one output. PPIs provide some information about the total and category specific opex performance of a business, and may help as cross checks and in understanding potential drivers of relative efficiency or inefficiency. Rankings for PPIs may be affected by factors outside the control of the DNSPs (as for our other benchmarking techniques) and must be analysed with caution, with comparisons also generally limited to businesses with similar characteristics (e.g. customer density).

The evidence on Ergon Energy's performance on the range of opex PPIs is relatively consistent with findings of relative inefficiency from the other benchmarking metrics, and suggests some possible drivers. Ergon Energy underperforms on the total opex per customer metric when compared to other similar networks.

Figure 6.7 shows that Ergon Energy has significantly higher 'total opex per customer' compared to all other networks with similar levels of customer densities, particularly Essential Energy. A similar pattern is found for the PPIs of maintenance, total overheads and emergency response opex per customer.

Figure 6.7 Total opex per customer against customer density (2018-22 average)



Source: AER analysis.

Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate circuit line length and corporate overhead data for Evoenergy that was updated since the release of the *2023 Annual Benchmarking Report* and used in the Evoenergy 2024-29 final decision.

6.4.1.2.3 Benchmarking the efficiency of Ergon Energy's base year opex

Given the evidence outlined above about the relative inefficiency of Ergon Energy's opex over the 2006–22 period, and the more recent 2012–22 period, we have undertaken further analysis.

Consistent with past decisions, this involves the application of our economic benchmarking roll-forward-model, which includes adjusting for OEFs, to test the efficiency of Ergon Energy's estimated base year opex more directly. We use the results from our econometric opex cost function benchmarking and our benchmarking roll-forward models to derive an estimate of efficient base year opex, and compare this to Ergon Energy's estimated 2023–24 base year opex. We then determine whether there is an efficiency 'gap' and if so, the magnitude of the 'gap'.[52] Where our modelled efficient rolled-forward base year opex is less

[52] In this application to Ergon Energy, we have applied the results incorporating the approach to addressing capitalisation practices, which treats capitalised corporate overheads as opex for benchmarking purposes. This means that both the estimated efficient rolled-forward base year opex and Ergon Energy's base year opex include capitalised corporate overheads. As discussed further below, the resulting efficiency gap is expressed in percentage terms, and applied as an efficiency adjustment to SCS opex (excluding capitalised corporate overheads) in the opex model.

than a network's base year opex, we infer that the network's proposed base year opex is materially inefficient. We reach this conclusion for Ergon Energy.

In summary, our roll forward model estimates Ergon Energy's efficient base year opex (with capitalised corporate overheads) to be $504.7 million. This is an average of our estimates of Ergon Energy's efficient base year opex for the long period of $526.9 million, and for the short period of $482.4 million. This average is $9.7 million (1.9%) less than Ergon Energy's estimate of base year opex (with capitalised corporate overheads) of $514.4 million. This efficiency gap provides further support for the conclusion that Ergon Energy's estimated base year opex is materially inefficient.

This section sets out in more detail 2 key aspects of how we have derived this efficiency gap for our alternative estimate including:

- deriving the estimated efficient rolled forward opex in the base year, taking into account OEFs, which are separately discussed. and the 0.75 comparison point
- calculating the efficiency gap between the estimated efficient rolled-forward opex in the base year and Ergon Energy's estimated base year opex.

As discussed in section 6.4.1.2.5, we then draw on the efficiency gap from this modelling to inform an efficiency adjustment to Ergon Energy's estimate of base opex. MTFP / MPFP and PPI benchmarking is not used as a part of this further testing.

Deriving the estimate of efficient rolled-forward base year opex

Our econometric opex cost function models produce average opex efficiency scores for DNSPs across the short and long periods, respectively. Using our benchmarking roll-forward-model, we convert these period-average results into an estimate of the level of network services opex required by an efficient service provider operating in Ergon Energy's circumstances in the base year of 2023–24.[53]

Using our benchmarking roll-forward model, we first apply Ergon Energy's econometric efficiency scores to its period-average opex to obtain a period-average efficient level of opex for Ergon Energy.[54] This takes account of material OEFs and the benchmarking comparison point of 0.75. This estimated efficient period-average opex is then rolled forward from the mid-point year (of the relevant benchmarking period) to the base year (2023–24 in this case) using the parameters of the econometric opex cost function model to account for the drivers of efficient opex. This includes output growth, opex partial productivity change that incorporates the impact of the estimated time trend, undergrounding and returns to scale. We outline our approach in further detail in recent decisions.[55]

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53 We benchmark distribution businesses on the basis of the network services component of standard control services opex, which comprises the majority of standard control services opex. Network services opex excludes opex categories that are part of standard control services opex, such as opex for metering, customer connections, street lighting, ancillary services and solar feed-in tariff payments.

54 As explained above, this also includes capitalised corporate overheads.

55 AER, *Final Decision, Jemena distribution determination 2021–26 – Attachment 6 – Operating expenditure, April 2021*, p. 25.

To inform its initial proposal, Ergon Energy's consultants' Frontier Economics noted that they derived estimates of efficient base year opex using our benchmarking method as applied in our recent revenue determinations (including for the NSW and ACT DNSPs). This included:[56]

- using the data from the *2023 Annual Benchmarking Report* (the latest dataset available at the time of preparing its report)
- expensing 100% of corporate overheads as first implemented in the Evoenergy draft decision[57]
- using the latest data on backcast capitalised corporate overheads submitted by Ergon Energy and Energex to the AER
- using the OEF adjustments employed by us in the draft decisions for the NSW and ACT DNSPs and that are relevant to Ergon Energy and Energex.

Operating Environment Factor adjustments

We have applied the same OEF adjustments as used by Frontier Economics,[58] but with some minor refinements to the taxes and levies and network accessibility OEFs via data updates. We set out the adjustments used by Frontier Economics and the nature of our updates below.

Table 6.5 also shows each of these material OEFs that we have used to derive our alternative estimate of efficient rolled-forward base year opex.

Table 6.5 AER OEF adjustments, 2006–22 and 2012–22 period, %

OEF	2006–22	2012–22
Cyclones	5.0	4.7
Sub–transmission	5.4	5.3
Taxes and levies	0.4	0.4
Termite exposure	1.0	1.0
Workers' comp	–0.2	–0.2
Vegetation management (Division of responsibility)	2.2	2.0
Vegetation management (Bushfire risk)	–4.5	–6.3
Network accessibility	1.5	1.5
Total	10.9%	8.4%

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2023; Sapere Research Group and Merz Consulting, Independent review of Operating Environment Factors used to adjust efficient

56 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024, p. 14.

57 AER, *Draft Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal,* September 2023.

58 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024, p. 15.

operating expenditure for economic benchmarking, August 2018; AER analysis; AER, *Final Decision, Evoenergy determination 2024–29, Attachment 6, Operating Expenditure*, April 2024.

Note: While Sapere-Merz identified vegetation management as a material OEF, it did not quantify it given data issues. We have calculated the OEF for vegetation management, as explained below.

Taxes and levies OEF

Frontier Economics applied a taxes and levies OEF of 0.3% for the short period and long period, respectively.[59] We have refined the taxes and levies OEF to reflect data updates that we considered were required. The impact of this update is to increase the taxes and levies OEFs to 0.4% for the short and long periods.

During our quality assurance checks, we observed that we had omitted a material tax paid by AusNet Services that is related to a set of regulatory fees.[60] This is relevant to the OEF used to derive our estimate of efficient rolled-forward base year opex for Ergon Energy (and Energex) because AusNet Services is a comparator network. This means its taxes affect the relative calculated cost advantage or disadvantage of other DNSPs like Ergon Energy. This update corrects for this issue by including AusNet Services' regulator fees.

Network accessibility OEF

Frontier Economics applied a network accessibility OEF of 1.4% for the short and long periods.[61] This was an increase in this OEF from the 0.9% used in previous decisions by us.[62] We have refined the network accessibility OEF to reflect revised data provided by Ergon Energy. The impact of these adjustments is to increase the updated 1.4% network accessibility OEF used by Frontier Economics for the short and long periods to the 1.5% we apply for both periods.

In the OEF modelling Frontier Economics prepared for Ergon Energy, there was an approximate doubling of non-standard vehicle route length over the 2010–2022 period compared to what we had previously used. We have reviewed the data update and accept it is appropriate. Our analysis also indicated the increase in the proposed OEF adjustment was due to this data correction. It is apparent that the data on route length we relied on in the original 2015 network accessibility OEF model, and subsequent updates, was incorrect. We collect this data from the Economic Benchmarking Regulatory Information Notices (RIN), and it appears that the data reflected Ergon Energy's standard vehicle access, rather than non-standard vehicle access route length. This reflected an error that Ergon Energy was making in its Economic Benchmarking RIN submissions until 2019, when it corrected this data. We are satisfied that the revised data appropriately reflects non-standard vehicle access route length.

Further, in reviewing the proposed data update, we undertook additional checking of the relevant data in our OEF model across all comparators, particularly on non-standard vehicle

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59 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024, p. 15.

60 Our standard approach for the taxes and levies OEF data set, as applied in our recent NSW and ACT 2024–29 revenue determination decisions, is to include only the taxes and levies that are energy-industry specific.

61 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report*, January 2024, p. 15.

62 AER, *Final decision, Ergon Energy distribution determination 2020-25 – Attachment 6 – Operating expenditure*, June 2020, p. 23.

length and total route length. We identified additional minor errors in relation to other DNSPs' data, which we have corrected noting that these have only a minor impact.

Network overheads OEF

Frontier Economics did not propose nor include an OEF adjustment for network overheads in the benchmarking analysis it undertook for Ergon Energy. However, in our recent 2024–29 final decision for Evoenergy, we recognised that there can be material variations between DNSPs in terms of the proportion of network overheads that are expensed or capitalised.[63] This was in response to the argument and evidence put forward by Evoenergy in its revised proposal that this should be reflected as a new OEF adjustment for network overhead capitalisation practices.[64]

Our final decision for Evoenergy was to not accept the proposed new OEF. However, we noted that not providing any recognition of these differences would imply that capitalisation of network overheads has no impact on the measured opex efficiency results, which we did not consider realistic. Instead, we accounted for differences in these practices through sensitivity testing and regulatory judgement. This was "to recognise that while Evoenergy has historically expensed 100% of network overheads, other networks have expensed only 50–70%, and not accounting for this in any way would likely disadvantage Evoenergy in terms of measured opex efficiency."[65]

We intend to undertake similar sensitivity testing of the impact of a network overhead capitalisation differences in the benchmarking analysis we undertake for our final decision. However, this will require further data on Ergon Energy's (and Energex's) network overheads, both expensed and capitalised. The network overheads data used (but not published) in the Evoenergy 2024–29 final decision drew on the network overheads data for Ergon Energy (and Energex) from the Category Analysis RINs. However, this data was reported on the basis of Ergon Energy's (and Energex's) Cost Allocation Methods that prevailed at the time of the reporting. To be consistent with the opex and corporate overheads series we are using for our benchmarking we would require this data to be reported on the basis of Ergon Energy's (and Energex's) current Cost Allocation Methods to calculate network overheads capitalisation rates that are consistent with the modelling approach applied in our benchmarking. This is in turn requires a backcast of Ergon Energy's and Energex's expensed capitalised network overheads for the period prior to the introduction of their current Cost Allocation Methods, namely the 2006–20 period.

We have undertaken preliminary sensitivity testing using this Category Analysis RIN data, which indicates that allowing for this would not have a material impact on our draft decision to accept Ergon Energy's total opex forecast. To enable more complete sensitivity testing, we seek Ergon Energy's (and Energex's) network overheads data based on the current Cost Allocation Method, as described above. In our final, decision we will apply the network

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63 AER, *Final Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal*, April 2024, pp. 23–26.

64 AER, *Final Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal*, April 2024, pp. 14, 17–20; Frontier Economics, *Evoenergy – Frontier Economics – Appendix 31 AER benchmarking of DNSP opex*, November 2023, p. 5.

65 AER, *Final Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal*, April 2024, p. 34.

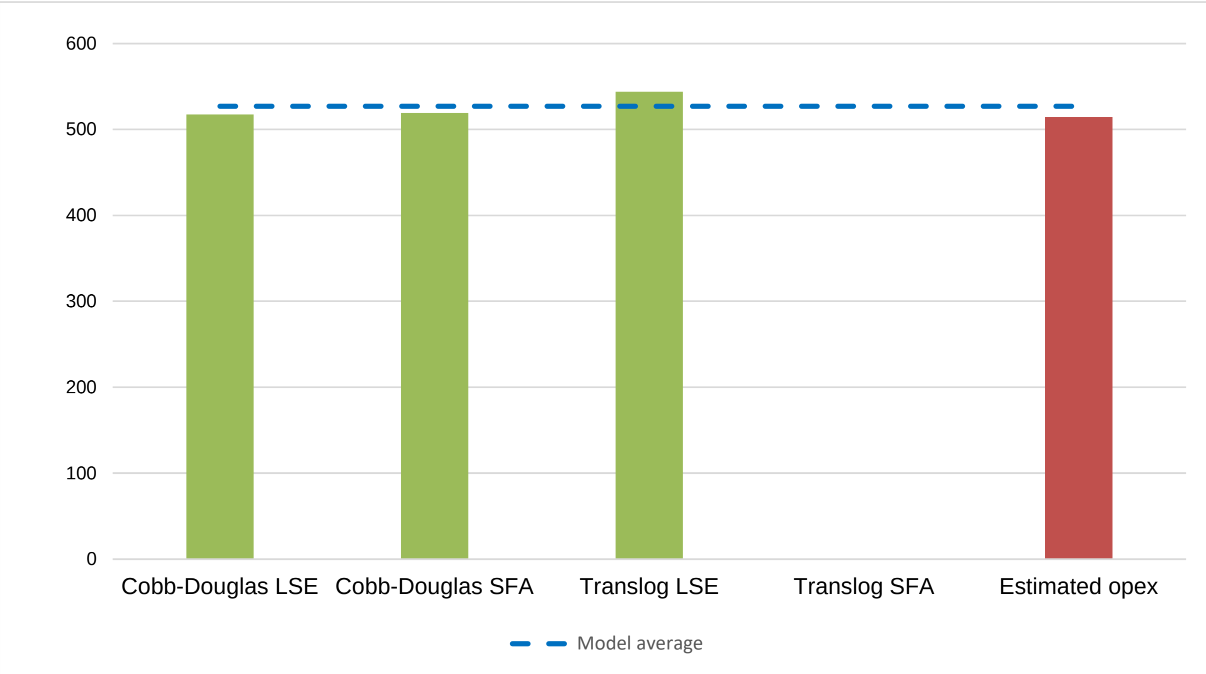
overheads capitalisation sensitivity approach, as per the Evoenergy final decision, to inform the benchmarking analysis in our final decision.

Calculation of efficiency gap between base year opex and estimated efficient base year opex

The results of using our benchmarking roll-forward model (as discussed above) to derive estimated efficient base year opex and compare it to estimated base year opex for Ergon Energy) are set out in Figure 6.8 for the long period and in Figure 6.9 for the short period. These figures use the econometric opex cost function benchmarking results from the *2023 Annual Benchmarking Report,* updated as outlined above. We have also applied the OEF adjustments we consider appropriate as set out in Table 6.5.

Figure 6.8 shows our estimates of efficient network services opex plus capitalised corporate overheads (over the long period, including adjustments for OEFs) in the base year in green, with an average of $526.9 million (the blue dashed line). Ergon Energy's estimated opex plus capitalised corporate overheads in the base year of 2023–24 is shown in red ($514.4 million). As can be seen, our estimated efficient base year opex plus capitalised corporate overheads (the blue dashed line) is above Ergon Energy's estimated network services opex plus capitalised corporate overheads, indicating that opex in the base year is not materially inefficient.

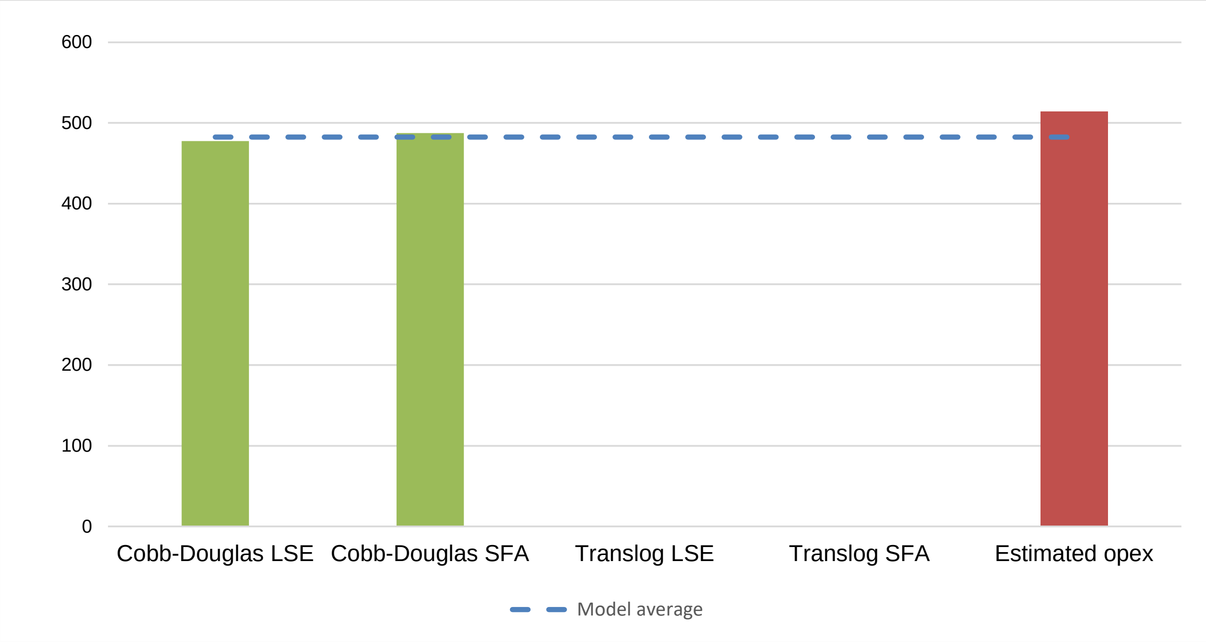
Figure 6.8 Estimates of efficient network services opex using data over the 2006–22 period ($million, 2024–25)



Source: Quantonomics, *Benchmarking results for the AER – Distribution*, November 2023; AER analysis.
Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate updated circuit line length and corporate overhead data for Evoenergy. We exclude the efficiency score for the Translog SFA model for Ergon Energy as it does not satisfy the monotonicity requirement. Monotonicity is a key economic property required for these econometric opex cost function models, which is that an increase in output can only be achieved with an increase in inputs (opex), holding other things constant.

In Figure 6.9 our estimates of efficient network services opex plus capitalised corporate overheads in the base year (over the short period) are shown in green, with an average of $482.4 million (the blue dashed line). In this case, our estimated efficient base year opex plus capitalised corporate overheads (the blue dashed line) is below Ergon Energy's estimated network services opex plus capitalised corporate overheads, indicating that opex in the base year is materially inefficient.

Figure 6.9 Estimates of efficient network services opex using data over the 2012–22 period ($million, 2024–25)



Source: Quantonomics, *Benchmarking results for the AER – Distribution*, November 2023; AER analysis.
Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate updated circuit line length and corporate overhead data for Evoenergy. We exclude the efficiency score for the Translog SFA and LSE models for Ergon Energy as they do not satisfy the monotonicity requirement. Monotonicity is a key economic property required for these econometric opex cost function models, which is that an increase in output can only be achieved with an increase in inputs (opex), holding other things constant.

As a final step, we average the estimated model-average rolled forward efficient opex (plus capitalised corporate overheads) in the base year for the long period ($526.9 million) and short period ($482.4 million) to generate an average amount of $504.7 million. We then compare this with the proposed base year opex (also including capitalised corporate overheads). This average is $9.7 million (1.9%) less than Ergon Energy's estimated base year opex (plus capitalised corporate overheads) of $514.4 million ($2024–25). This provides further support for our conclusion that Ergon Energy's estimated base year opex is materially inefficient. We consider it is a conservative estimate of the size of the efficiency gap between the amount of opex an efficient network like Ergon Energy would need in its base year, and the estimate Ergon Energy has provided.

While this represents the efficiency gap in relation to opex plus capitalised corporate overheads, we also consider this translates as the efficiency gap in opex alone (i.e. exclusive of capitalised corporate overheads). This assumes the efficiency of opex and capitalised corporate overheads is similar, which we consider reasonable.

As discussed in section 6.4.1.2.5, we have drawn on this efficiency gap to inform an efficiency adjustment that is applied to Ergon Energy's opex (exclusive of capitalised corporate overheads).

6.4.1.2.4 Ergon Energy's argument on limitations of benchmarking results

Ergon Energy submitted that while it considered that an efficiency adjustment was not required in light of the material concerns it has with our benchmarking model, it nevertheless incorporated an efficiency adjustment based on our most recent benchmarking model to address affordability concerns of its customers.[66] Ergon Energy's initial proposal did not detail any specific concerns regarding our benchmarking, but referred to analysis undertaken for it by its consultant Frontier Economics.

The Frontier Economics' report outlines what it considered are limitations associated with the AER's benchmarking approach. Broadly, these limitations have been previously raised by Evoenergy and its consultant, Frontier Economics, in Evoenergy's regulatory proposals for its recent 2024–29 revenue determination.[67] At a high level, these limitations can be summarised as:

- the statistical uncertainty associated with the benchmarking results, and a proposed approach to take this into account[68]
- concerns in relation to the econometric opex cost function models that it considered make the results unreliable, specifically: [69]
  - the translog models continue to exhibit monotonicity violations, and that these, in turn, reflect misspecification in relation to the models' not adequately capturing DNSPs improving their efficiencies over time
  - questions around whether to use translog models versus the Cobb-Douglas models.

The Frontier Economics report also commented on a report by Quantonomics. This Quantonomics report, commissioned by the AER as part of our ongoing benchmarking development work, examined options to further develop and improve the performance of the opex cost function used in our distribution benchmarking translog models.[70] Frontier Economics noted some of the modelling and analysis in the option paper is related to issues it raised in its report to Ergon Energy. In particular, Frontier Economics provided the following comment on issues raised by Quantonomics:

- The possibility of redefining monotonicity violations as only occurring when they are statistically "significant". Frontier Economics considered this approach defined away the problem, by lowering the standard for what is considered to be a monotonicity violation. In its view, the AER should, rather, address the root causes of monotonicity violations.[71]
- The proposal to introduce a time trend for Australian DNSPs. Frontier Economics considered this supported its conclusion that there is a strong time-related factor for the Australian DNSPs that is not accounted for properly in the AER's models. However, it

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66 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 142.

67 Evoenergy, *Appendix 2.1 Base year efficiency, January 2023*, pp. 5–6, 35–37; Evoenergy, *Attachment 3 Operating Expenditure, November 2023*, pp. 25–26; Evoenergy, *Frontier Economics – Appendix 3.1 AER benchmarking of DNSP opex,* November 2023, pp. 34–42.

68 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report,* January 2024, pp. 1–2.

69 Ergon Energy, *6.04 – Frontier Economics – Opex benchmarking report,* January 2024, pp. 8–13.

70 Quantonomics, *Opex cost function – options to address performance issues of translog models*, 25 October 2023.

71 Frontier Economics, *Appendix 3.1, AER benchmarking of DNSP opex,* November 2023, pp. 10–11.

considered it would be premature to adopt this specification before alternative specifications, including allowing for time varying efficiency, had been tested.[72]

- The possibility of "restricted" Translog models, whereby some of the higher order and interaction terms are removed. As noted above, Frontier Economics considered a key cause of the monotonicity violations is misspecification of the models and not accounting for efficiency improvements over time. It was of the view the AER should address the root cause of the problem, rather than 'treating the symptoms' of the problem by limiting the flexibility of the Translog models.[73]
- Mis-estimation of the short sample SFA-TLG model. Frontier Economics considered there are other SFA-TLG models that fit the data better than Quantonomics' model, and hence their statistical properties are unknown. Further investigation of the likelihood function shows that for this model it has an unconventional shape, which Frontier Economics believes is the cause of the mis-estimation. The unusual likelihood function likely reflects the misspecification issues noted above.[74]

In forming our draft decision, we have considered these benchmarking limitations, including with the expert input of our benchmarking consultant, Quantonomics. Our views and responses to the issues raised by Frontier Economics are outlined in our Evoenergy draft[75] and final[76] decisions, and we summarise those below. Quantonomics' views and responses to many of the benchmarking limitations raised by Frontier Economics in the context of the Evoenergy decision are also set out in a memorandum published with the Evoenergy draft decision.[77]

In summary, we consider that while our benchmarking tools are not perfect, and are subject to an ongoing development program, this does not limit us from using them in revenue determination processes to assess the efficiency of opex in a proposed base year. Particularly important in this regard, is that we only apply results where we consider they reliably inform our overall base year opex efficiency assessment (e.g. by removing the results of econometric opex cost function models that do not meet the monotonicity requirements.) Further, using a 0.75 comparison point, adjusted for OEFs, instead of 1.0, builds in a degree of conservativeness in part reflecting that we acknowledge our benchmarking tools are not exactly precise or perfect tools.

We also acknowledge that there are issues of judgement involved in developing and applying a benchmarking approach. Further, we acknowledge that there is scope for future benchmarking development work to ensure it continually improves. In relation to Frontier Economics' comments on the Quantonomics report prepared in the context of our benchmarking development work program, the options in the report were put forward for

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72 Frontier Economics, *Appendix 3.1, AER benchmarking of DNSP opex,* November 2023, p. 11.

73 Frontier Economics, *Appendix 3.1, AER benchmarking of DNSP opex,* November 2023, p. 12.

74 Frontier Economics, *Appendix 3.1, AER benchmarking of DNSP opex,* November 2023, pp. 12–13.

75 *AER*, Draft Decision, *Attachment 6 – Operating expenditure – Evoenergy– 2024–29 Distribution revenue proposal,* September 2023, pp. 38–40.

76 AER, *Final Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal*, April 2024, pp. 35–40.

77 Quantonomics, *AER – Evoenergy 2024–29 – Draft Decision –Quantonomics – Benchmarking limitations*, September 2023.

stakeholder consideration and are not settled positions. These issues are a priority to be further considered as part of this ongoing development work, as stated in the 2023 Annual Benchmarking Report.[78]

We consider the causes of monotonicity violations to be complex, and are likely to include factors such as multicollinearity, insufficient data variation in the context of the Translog model's flexibility and potential misspecification issues. In this regard, we do not consider it likely that monotonicity violations are solely attributed to misspecification issues, including in relation to the models' assumption of time invariant efficiency as argued by Frontier Economics. However, we are further investigating the merits and feasibility of time varying efficiency specifications.

In relation to Frontier Economics' specific comments:

- In relation to how the monotonicity violations are defined, we are further investigating whether this would be appropriate. However, we agree with Frontier Economics that it would be a significant departure from our standard approach to defining monotonicity. This approach is to exclude model results where there are excessive[79] monotonicity violations. We consider this approach remains fit for purpose while we continue to examine alternative solutions and have applied it to this decision as set out in section 6.4.1.2.3.
- The Australian-specific time trend was a particular specification explored by Quantonomics. It showed that an additional Australia-specific time trend may improve the standard specification, but it did not result in a reduction in the number of Australian DNSPs affected by excessive monotonicity violations. Given this, we now agree with Frontier Economics that further time trend variations should be explored before firm conclusions are drawn over the most appropriate model.
- In relation to restricted Translog models, we do not share Frontier Economics' characterisation that these models merely treat the symptom, rather than the root cause. Our initial investigations have shown promise that multicollinearity is a potential contributor to monotonicity issues, and the thus the removal of highly collinear variables in the restricted Translog models could alleviate one of the causes of monotonicity.
- In relation to Frontier Economics' view on mis-estimation in the SFATLG short-period model, we recognise that this model presented issues in the 2023 Annual Benchmarking Report. However, in practice for this decision, due to monotonicity, that model's results have been excluded from the efficiency analysis.
- In relation to statistical uncertainty in the econometric opex cost function modelling results, we agree this is present. However, we consider statistical uncertainty is largely symmetrically distributed around the point estimate, and hence the upper side and lower

78 AER, *2023 Annual Benchmarking Report, Electricity distribution network service providers*, 2023 November 2023, pp. 80–83.

79 We require this property to hold for at least half the data points of a business in order to include the efficiency score from a Translog model in our efficiency assessment. In addition, if a model does not satisfy monotonicity for the majority of Australian DNSPs, then we exclude the model from calculating the model average efficiency score for all Australian DNSPs (even though the property may be satisfied for some DNSPs).

side uncertainties are likely to offset each other. We consider the 0.75 benchmark comparison point recognises the modelling and data limitations in benchmarking.

6.4.1.2.5 Efficiency adjustment to Ergon Energy's base year opex

Taking the above analysis into account, we have concluded on balance that Ergon Energy's estimated base year opex is above the level that is consistent with what an efficient service provider operating in Ergon Energy's circumstances would require to deliver its network services.

Given the results from our benchmarking analysis, and the conservatism built into our benchmarking approach, we consider that Ergon Energy's base year opex is materially inefficient. Consequently, to determine our alternative estimate of base opex, we have drawn on our efficiency gap analysis to make an efficiency adjustment to Ergon Energy's base year opex to establish a level of opex that we consider reflects an efficient distributor's opex.

The size of the efficiency adjustment for Ergon Energy suggested by the benchmarking results, adjusted to take account of the relevant OEFs, is 1.9%, as indicated in the analysis above.

However, we have incorporated a glide path to transition Ergon Energy from its current opex levels to the more efficient opex level. Consistent with our most recent application of the benchmarking results for this purpose (for Evoenergy in our 2024–29 draft decision),[80] we have transitioned to the efficient lower cost base via a linear transition path over the next regulatory control period. This recognises that it will take time, and involve costs, to implement the required programs over the next regulatory control period to realise opex reductions. This contrasts with moving straight to what we consider is the efficient base opex based on our benchmarking results.

In practice, this means a total efficiency adjustment over the period of $26.9 million, comprising adjustments of: year 1 –$1.8 million, year 2 –$3.5 million, year 3 –$5.4 million, year 4 –$7.2 million and year 5 –$9.0 million. This results in an effective 5-year efficiency adjustment, as a percentage of our alternative estimate of base year opex after base adjustments (discussed below), of 1.1%.

We consider that the glide path provides for a prudent, practicably achievable target that will allow Ergon Energy to achieve cost efficiency while at the same time maintaining the quality, reliability, security and safety of services over the next regulatory control period.

6.4.2 Adjustments to base year opex

Ergon Energy proposed a total adjustment to its base opex of –$25.8 million or –$129.1 million over the next regulatory control period. These adjustments were for the Electrical Safety Office levy, property leases, actual debt raising costs and to add a final year increment.[81]

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80 AER, *Draft Decision, Attachment 6 – Operating expenditure – Evoenergy – 2024–29 Distribution revenue proposal,* September 2023, pp. 40–41.

81 Ergon Energy, *6.02 – Model – SCS Opex Model,* January 2024.

We have considered these proposed adjustments and have adjusted our alternative estimate of opex in the base year by $25.7 million, or $128.7 million over 5 years to:

- Subtract $7.7 million for the Electrical Safety Office levy. This decreases our alternative estimate of total opex by $38.4 million over 5 years. This is further explained in section 6.4.2.1.
- Subtract $5.9 million for the reclassification of ongoing lease costs as capex in the 2025–30 period. This decreases our alternative estimate of total opex by $29.5 million over 5 years. This is further explained in section 6.4.2.2.
- Subtract $6.1 million for actual debt raising costs. This decreased our alternative estimate of total opex by $30.3 million over 5 years. This is further explained in section6.4.2.3.
- Subtract $6.1 million for the change in opex between 2023–24 and 2024–25. This decreased our alternative estimate by $30.5 million over 5 years. This is further explained in section6.4.2.4.

The key difference between our total adjustment and that of Ergon Energy's is that we used the most recent inflation data.

6.4.2.1 Electrical safety office levy

Ergon Energy reduced its base year opex by $7.7 million ($38.5 million over the next regulatory control period) to remove costs it incurred for the Electrical Safety Office levy. Ergon Energy is obliged, under the *Electrical Safety Act 2002* (Qld), to pay the Queensland Electrical Safety Office an annual electrical safety contribution to fund compliance and electrical safety activities. However, Ergon Energy stated that from July 2025 these costs will no longer be paid through opex, but instead will be recovered as a jurisdictional scheme.[82] Ergon Energy therefore removed these costs from its base year opex to ensure that it only recovers these costs from network users once.

This approach is consistent with our April 2023 final determination on Ergon Energy's application for the Electrical Safety Office levy to become a jurisdictional scheme.[83] We have also requested, and reviewed, information received through an information request that demonstrated Ergon Energy's methodology to estimate the levy amount for its base year of 2023–24.[84] We found no concerns regarding the proposed amount.

As a result, we have made the same adjustment as Ergon Energy in our alternative estimate for the draft decision. We will update our alternative estimate for the final decision with actual data for the Electrical Safety Office Levy for 2023–24 once available.

6.4.2.2 Removal of property leases

Ergon Energy reduced its base year opex by $5.9 million ($29.5 million over the next regulatory control period), to allocate costs from opex to capex as a result of a change in the

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82 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 137.

83 AER, *Determination on jurisdictional scheme application in relation to the Electrical Safety Act (Qld)*, 3 April 2023.

84 Ergon Energy, *Response to AER information request, IR#017 – Base adjustment Electrical Safety Office Levy,* 7 May 2024.

AASB 16 accounting standards.[85] Ergon Energy noted that changes to AASB 16 on July 2019 require that newly entered or renewed leases must be capitalised (i.e. treated as capex).[86] Although the change in accounting standards occurred in 2019, the capitalisation of leases was not applied to Ergon Energy's 2020–2025 regulatory control period, as we typically do not consider it appropriate to change the cost allocations mid-period.

In response to our requests for further information on how it had calculated this base adjustment, Ergon Energy provided data on the types and costs of existing property leases it (and Energex) held over the 2025–30 period.[87] Further, it explained how it had allocated these costs between the 2 distribution businesses and between SCS and alternative control services opex. It also verified that lease costs have been treated as opex over the current regulatory control period and that an appropriate amount would be capitalised from the first year of the 2025–30 regulatory control period.[88]

Based on our assessment of this information, we agree that the proposed base adjustment amount of $5.9 million is appropriate. As a result, we have made the same adjustment in our alternative estimate, with differences due to our use of more recent inflation data.

6.4.2.3 Actual debt raising costs

Ergon Energy reduced its base year opex by $6.1 million ($30.4 million over the next regulatory control period) to remove actual debt raising costs.[89]

We forecast debt raising costs using a benchmarking approach, rather than a service provider's actual costs in a single year. This means we do not forecast debt raising costs on a revealed cost basis, but instead provide a debt raising allowance as a category specific forecast (see section 6.4.5). That is, adjusting base year opex ensures a debt raising allowance is received through our standard approach, via a category specific forecast, and not again through our base-step-trend forecasting approach.

We have made the same adjustment to our alternative estimate.

6.4.2.4 Final year increment

Our standard practice to calculate 'final year opex' is to add the estimated change in opex between the base year (2023–24) and the final year (2024–2025) of the current (2020–25) regulatory control period to the base year opex amount.[90]

We have included –$30.5 million for the final year increment in our alternative estimate, which is $0.2 million higher than Ergon Energy's proposed amount of –$30.7 million.[91] The

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85 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 137; Ergon Energy, *Response to AER information request, IR003 – Base opex, base adjustments and nominated pass through events*, 19 April 2024, p. 4.

86 Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p. 162.

87 Ergon Energy, *Response to AER information request, IR#003 – Base opex, base adjustments and nominated pass through events, spreadsheet – public,* 19 April 2024.

88 Ergon Energy, *Response to AER information request, IR#003 – Base opex, base adjustments and nominated pass through events,* Q2–Q6 (public), 19 April 2024.

89 Ergon Energy, *6.02 – Model – SCS Opex Model,* January 2024.

90 AER, *Expenditure forecast assessment guideline – distribution*, August 2022, pp. 24–25.

91 Ergon Energy, *6.02 – Model – SCS Opex Model,* January 2024.

variance between our alternative estimate of the final year increment and Ergon Energy's proposal is due to:

- Ergon Energy incorrectly excluding debt raising costs from the opex forecasts for the 2020–25 regulatory control period
- our use of the latest inflation figures, which were not available at the time of Ergon Energy's proposal.

6.4.3 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[92]

Ergon Energy largely applied our standard approach to forecasting the rate of change. It proposed:[93]

- **Price growth:** adopting the input price weightings of 59.2% labour and 40.8% non-labour, as used in our Annual Benchmarking Report. It forecast labour price growth using an average forecast wage price index (WPI) growth from its Consultant, BIS Oxford Economics, and from our consultant, KPMG. It used the KPMG report from August 2023 report and the national rate as a placeholder. This was because KPMG's forecasts for Queensland were not available for its initial proposal. It also added legislated superannuation guarantee increases to its labour price growth forecast.
- **Output growth:** applying the output weights from our 4 econometric benchmarking models as adopted in our most recent determination. It forecast growth in its customer numbers and circuit length based on historic growth rates, and growth in maximum demand based on the estimated impact of factors such as new customer connections, block loads and transfers.
- **Productivity growth:** using 1.0% per year productivity growth forecast.

The rate of change proposed by Ergon Energy contributed $32.5 million, or 1.5%, to Ergon Energy's total opex forecast of $2,379.1 million. This equates to opex increasing on average by 0.4% each year. We have also included a rate of change that increases opex on average by 0.6% each year in our alternative estimate, noting that we have different price, output and productivity growth forecasts to Ergon Energy.

We compare both forecasts in Table 6.6, and the reasons for the differences are set out below.

Table 6.6 Forecast annual rate of change in opex, %

	2025–26	2026–27	2027–28	2028–29	2029–30
Ergon Energy's proposal					
Price growth	0.9	0.7	0.6	0.7	0.7

92 AER, *Expenditure forecast assessment guideline – distribution*, August 2022, pp. 25–26.

93 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 139–140; Ergon Energy, 6.02 – Model – SCS Opex Model, January 2024.

	2025–26	2026–27	2027–28	2028–29	2029–30
Output growth	0.6	0.8	0.9	0.6	0.7
Productivity growth	1.0	1.0	1.0	1.0	1.0
Rate of change	**0.5**	**0.5**	**0.5**	**0.3**	**0.4**
AER alternative estimate					
Price growth	0.9	0.6	0.5	0.6	0.7
Output growth	0.4	0.4	0.4	0.4	0.4
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.8**	**0.5**	**0.4**	**0.5**	**0.6**
Difference	**0.3**	**0.0**	**–0.1**	**0.3**	**0.2**

Source: Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024: AER analysis.
Note: The rate of change = (1 + price growth) × (1 + output growth) × (1 – productivity growth) – 1. Numbers may not add up to totals due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

6.4.3.1 Forecast price growth

Ergon Energy proposed average annual price growth of 0.7%, which increased its total opex forecast by $51.8 million. The average annual real price growth we have used in our alternative estimate was also 0.7%. This increases our total opex alternative estimate by $46.8 million. The differences between the price growth in Ergon Energy's proposal and alternative estimate is explained by the underlying inflation series used.

Both we and Ergon Energy forecast price growth as a weighted average of forecast labour price growth and non-labour price growth:

- Both we and Ergon Energy used an average of two WPI growth forecasts for the electricity, gas, water and waste services (utilities) industry to forecast labour price growth, broadly consistent with our standard approach. Ergon Energy used forecasts from its consultant, BIS Oxford Economics, and our consultant, KPMG. It sourced the KPMG forecasts from the August 2023 KPMG report prepared for us, and used the national rate as Queensland specific WPI forecast were not available at that time.[94] In our alternative estimate, we have updated the KPMG forecasts with more recent and Queensland-specific forecasts from our consultant, Deloitte Access Economics.[95]
- Both we and Ergon Energy applied a forecast non-labour real price growth rate of zero.[96]
- Both we and Ergon Energy have applied the same weights to account for the proportions of opex that is labour and non-labour, 59.2% and 40.8%, respectively.[97]

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94 Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p. 139.

95 Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10.

96 Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024.

97 Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024.

Consequently, the difference between our real price growth forecasts and Ergon Energy's is that we have updated our labour price growth forecast to include the more recent and Queensland-specific forecasts from our consultant, now Deloitte.

Table 6.7 compares our forecast labour price growth with Ergon Energy's proposal.

Table 6.7 Forecast labour price growth, %

	2025–26	2026–27	2027–28	2028–29	2029–30
Ergon Energy's proposal					
KPMG as AER's consultant	0.9	1.1	1.1	1.1	1.1
BIS Oxford Economics	1.3	1.2	0.9	1.2	1.4
Average	1.1	1.1	1.0	1.2	1.2
Superannuation guarantee increases	0.5	–	–	–	–
Average, including superannuation guarantee increases	**1.6**	**1.1**	**1.0**	**1.2**	**1.2**
AER's alternative estimate					
Deloitte Access Economics	0.6	0.8	0.8	0.9	1.1
BIS Oxford Economics	1.3	1.2	0.9	1.2	1.4
Average	1.0	1.0	0.8	1.1	1.2
Superannuation guarantee increases	0.5	–	–	–	–
Average, including superannuation guarantee increases	**1.5**	**1.0**	**0.8**	**1.1**	**1.2**
Overall difference	**–0.1**	–0.2	–0.2	–0.1	–0.0

Source: Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024; KPMG, *WPI forecast report*, August 2023, p. 38; DAE, *WPI forecast report*, August 2024, p. 37; 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.

6.4.3.2 Forecast output growth

Ergon Energy proposed average annual output growth of 0.7%, which increased its proposed opex forecast by $49.4 million. We have forecast average annual output growth of 0.4%. This increases our alternative estimate of total opex by $29.0 million.

We and Ergon Energy have forecast output growth by:[98]

- calculating the growth rates for 3 outputs (customer numbers, circuit line length, and ratcheted maximum demand)
- calculating 4 weighted average overall output growth rates using the output weights from the 4 econometric opex cost function benchmarking models in our *2023 Annual Benchmarking Report*
- averaging the four-model specific weighted overall output growth rates.

We discuss these components below.

6.4.3.2.1 Forecast growth of the individual output measures

We are satisfied that Ergon Energy's forecast of the growth in customer numbers and circuit length reflect a realistic expectation. Specifically:

- **Customer numbers:** Ergon Energy proposed forecast customer numbers based on reported historic growth rates.[99] We have reviewed and validated Ergon Energy’s forecasts and consider them reasonable.
- **Circuit length**: Ergon Energy forecast growth in its circuit length using projects’ data and the historical growth rate.[100] We have reviewed and validated Ergon Energy’s forecasts, and consider them reasonable.

In terms of **ratcheted maximum demand,** Ergon Energy forecast maximum demand using the estimated impact of factors such as new customer connections, block loads and transfers.[101] However, in a response to our information request, Ergon Energy agreed that it had not adopted our standard approach of ratcheting these forecasts to its historic peak maximum demand, which was recorded in 2010.[102] This results in an average annual ratcheted maximum demand growth rate of 0%, compared to 0.8% forecast by Ergon Energy. This is because the forecast maximum demand for the next period is below this historic peak. This growth rate of 0% decreases our alternative estimate of total opex by $20.1 million, relative to Ergon Energy’s proposal. As noted, we consulted with Ergon Energy and it accepted our standard approach.[103]

Table 6.8 compares our forecast output growth with Ergon Energy’s proposal.

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98 Ergon Energy*, 6.02 – Model – SCS Opex model*, January 2024.

99 Ergon Energy, *Response to AER information request, IR#028 – Rate of change supporting information, Q1(a), pp.* 1–2 and spreadsheet, 16 May 2024.

100 Ergon Energy, *Response to AER information request, IR#028 – Rate of change supporting information, Q1(b), p.* 2 and spreadsheet, 16 May 2024.

101 Ergon Energy, *Response to AER information request, IR#028 – Rate of change supporting information, Q1(c), p.* 2 and spreadsheet, 16 May 2024.

102 Ergon Energy, *Response to AER information request, IR#032 – Rate of change (Ratcheted Maximum Demand), Q1,* p. 1, 27 May 2024.

103 Ergon Energy, *Response to AER information request, IR#032 – Rate of change (Ratcheted Maximum Demand), Q1,* p. 1, 27 May 2024.

Table 6.8 Forecast growth in individual output measures, %

	2025–26	2026–27	2027–28	2028–29	2029–30
Ergon Energy's proposal					
Customer numbers	0.8	0.8	0.8	0.8	0.7
Circuit length	0.3	0.3	0.3	0.3	0.3
Ratcheted maximum demand	0.4	1.0	1.3	0.4	0.8
AER alternative estimate					
Customer numbers	0.8	0.8	0.8	0.8	0.7
Circuit length	0.3	0.3	0.3	0.3	0.3
Ratcheted maximum demand	–	–	–	–	–
Difference					
Customer numbers	–	–	–	–	–
Circuit length	–	–	–	–	–
Ratcheted maximum demand	–0.4	–1.0	–1.3	–0.4	–0.8

Source: Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024; 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.

6.4.3.2.2 Output weights

The output weights that we have used in our alternative estimate are set out in Table 6.9. These are calculated from the results in our *2023 Annual benchmarking report*.[104] Ergon Energy used the same output weightings.[105]

Table 6.9 Output weights, %

	Cobb-Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA
Customer numbers	38.9	57.7	42.2	43.2
Circuit length	12.7	17.7	19.1	9.9
Ratcheted maximum demand	48.3	24.7	38.7	46.9

104 AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers*, November 2023.

105 Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024.

Source: Quantonomics, *Economic benchmarking results for the Australian Energy Regulator's 2023 Annual Benchmarking Report*, November 2023, pp. 165-167; Ergon Energy, *6.02 – Model – SCS Opex model*, January 2024; AER analysis.

We will publish our *2024 Annual benchmarking report* in late November 2024. In our final decision, we will update our output growth rate forecast to reflect the output weights in this report. Full details of our approach to forecasting output growth are set out in our opex model, which is available on our website.

6.4.3.3 Forecast productivity growth

Ergon Energy proposed average productivity growth of 1.0% per year, noting that it included this to address affordability concerns raised by its customers and due to the expected material increases in its overall revenues in the 2025–30 regulatory control period.[106]

We have forecast a lower average productivity growth of 0.5% per year, which reflects our standard approach. This decreases our alternative opex estimate by $34.6 million over the regulatory control period, which is less than the decrease proposed by the Ergon Energy of $68.7 million.

RRG supported inclusion of a 1.0% per annum productivity growth factor as a response to affordability concerns of customers, while noting this is insufficient to improve affordability by itself. However, the RRG also noted that this may not be achievable due to the cost pressures Energy Queensland has noted it will continue to face for some years.[107] CCP30 also supported inclusion of a 1.0% per annum productivity growth rate, but noted there was little detail on how it would be achieved.

We seek additional information in Ergon Energy's revised proposal on how it proposes to meet its 1.0% productivity forecast (and its proposed base year adjustment). This is particularly (as noted in section 6.4.1) in light of the indication from Ergon Energy that its 2023–24 actual opex to be reported in its revised proposal will be significantly higher than the estimate included in its initial proposal.[108]

6.4.4 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 *Expenditure forecast assessment guideline* for electricity, 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.[109]

Ergon Energy's proposal included one step change for smart meter data acquisition and analysis totalling $6.8 million, or 0.3% of its proposed total opex forecast. The step change is shown in Table 6.10 along with our alternative estimate for the draft decision, which is to not

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[106] Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p. 140.

[107] RRG, *Submission* – 2025–30 Electricity Determination – Energex & Ergon, May 2024, pp.4, 61.

[108] Ergon Energy, *Response to AER information request, IR#044 – Explanation of changes in actual opex and achievement of base opex efficiencies,* 19 June 2024, p. 3.

[109] AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, p. 26.

include the step change. We have not included any costs in our alternative estimate because while we find some of the proposed costs are prudent and efficient, we conclude that these costs will be met by expenditures already included in Ergon Energy's base year opex. We discuss this below.

Table 6.10 Ergon Energy's proposed step changes and the AER's alternative estimate decision

Step change	Ergon Energy's proposal	AER's alternative estimate	Difference
Smart meter data acquisition and analysis	6.8	–	–6.8

Source: Ergon Energy, *6.02 – Model – SCS Opex model,* January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding.

6.4.4.1 Smart meter data acquisition and analysis step change

Ergon Energy proposed a step change of $6.8 million over the 2025–30 regulatory control period, for the acquisition and analysis of smart meter data to increase its low voltage (LV) network visibility.[110] Ergon Energy subsequently submitted a revised smart meter data business case, which increased the proposed step change costs to $9.4 million.[111] Our draft decision is to not include the proposed smart meter data step change in our alternative estimate. While we are satisfied that costs associated with option 1 in Ergon Energy's business case are prudent and efficient, we conclude that costs will be met by expenditures already included in Ergon Energy's base year opex.

Table 6.11 Ergon Energy's smart meter data step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy's proposal	1.0	1.2	1.4	1.6	1.7	6.8
AER draft decision	–	–	–	–	–	–
Difference	–1.0	–1.2	–1.4	–1.6	–1.7	–6.8

Source: Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 139; AER analysis.
Note: Numbers may not add up to totals due to rounding.

In its initial proposal, Ergon Energy proposed $6.8 million to improve its LV network visibility by acquiring and analysing a mixture of near real-time and 6 hourly data from available smart meters.[112] Ergon Energy considered the purchase of near-real time power quality data, for both its overhead and underground service lines, would capture both safety and reliability benefits, including improve distribution transformer failure response and optimisation of service line replacement. Ergon Energy also stated that this step change captures additional benefits associated with consumer energy resource (CER) integration, including to enable

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110 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, pp. 137–139.

111 Ergon Energy, *6.05A – Business case – Smart meter data acquisition*, 10 May 2024, p. 23; Ergon Energy included the step change costs in $2022–23. We converted these amounts to $2024–25 using Ergon Energy's opex model inflation data.

112 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 138.

highly efficient operating envelopes.[113] Ergon Energy noted that the step change was required to meet the increasing costs it faces from a number of major external factors outside the control of the business, including the Australian Energy Market Commission's (AEMC) Review of the Regulatory Framework for Metering Services and the Queensland Energy and Jobs Plan that target 100% smart meter penetration by 2030.[114]

In support of the step change, Ergon Energy provided an initial business case and cost-benefit analysis that assessed 4 options to uplift these capabilities in what it considered was a prudent and efficient manner. Ergon Energy selected option 2 (overhead services and 25% of underground services) as its preferred option.[115]

In response to an information request, Ergon Energy informed us that it had identified errors in its original business case and modelling, and subsequently resubmitted an updated smart meter data business case, which included updates to the business case inputs, assumptions and changes to the scenarios for the 4 options considered.[116] These changes resulted in an increase to the step change of $2.6 million, to a revised amount of $9.4 million.[117] This also involved selecting option 4 (all services, with capture of near real-time data for 25% for overhead and underground service lines) as its preferred option in its revised business case, and considered this option to deliver the highest NPV of the options assessed.[118] However, this update also significantly lowered Ergon Energy's modelled NPV outcome from $554.3 million to $74.1 million.[119] Ergon Energy identified the dominant benefits from this step change arose from increased reliability and safety, with the additional key benefits arising from improved CER integration and service line deferral.[120]

We engaged Energy Market Consultants associates (EMCa) to assess this step change and have taken its advice into account as a part of our assessment. We, and EMCa, assessed the information that Ergon Energy provided in its proposal, including its initial and updated business cases, and information provided at an on-site workshop, to justify the proposed costs.

We consider it prudent for Ergon Energy to uplift its low voltage network visibility, including through upgrading its analytical capability. EMCa's assessment also supported Ergon Energy uplifting its network visibility.[121] This is also consistent with our capex decision, in which Ergon Energy will undertake a program to install LV monitors to gain network visibility on its

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114 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 138.

115 Ergon Energy, *6.05A – Business case – Smart meter data acquisition,* January 2024, pp. 14, 24.

116 Ergon Energy, *Response to AER information request, IR#019 – DER,* 10 May 2024; Ergon Energy, *6.05A – Business case – Smart meter data acquisition*, 10 May 2024.

117 Ergon Energy, *6.05A – Business case – Smart meter data acquisition*, 10 May 2024, p. 23; Ergon Energy included the step change costs in $2022–23. We converted these amounts to $2024–25 using Ergon Energy's opex model inflation data.

118 Ergon Energy, *6.05A – Business case – Smart meter data acquisition, May 2024,* p. 24.

119 Ergon Energy, *6.05A – Business case – Smart meter data acquisition, May 2024,* p. 23; Ergon Energy, *6.05A – Business case – Smart meter data acquisition,* January 2024, p. 23.

120 Ergon Energy, *6.05A – Business case – Smart meter data acquisition, May 2024,* pp. 20–21.

121 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, p. 19.

low-voltage service lines.[122] Additionally, we observe the AEMC's work and draft decision on the accelerated rollout of smart meters, which identified the benefits arising from access to power quality data for distribution businesses to better manage their networks, including through greater network visibility.[123]

However, we are not satisfied that Ergon Energy has demonstrated that the proposed step change is prudent and efficient, and particularly that the acquisition of near real-time power quality data is justified and that the costs are not being double counted.

In terms of near real-time data, we consider that the identified drivers and benefits in Ergon Energy's business case may largely be achieved through power quality data that will be made available at no charge.[124] In this regard, EMCa considered that essentially the same benefits as using near real-time meter data may be provided with 6-hourly data. EMCa also considered that Ergon Energy overstated the main drivers of safety and reliability benefits related to near real-time data.[125] Information received through an information request also raised concerns regarding the accuracy of Ergon Energy's modelling and cost assumptions, which would further decrease Ergon Energy's NPV scenario for the use of near real-time data.[126]

In terms of the safety benefits, Ergon Energy did not provide supporting information to demonstrate that its key benefit assumptions are supported by evidence, including any incremental additional benefit from higher frequency near-real time data.[127] EMCa also considered, based on its experience, that the proposed uplift to near real-time data will not result in higher safety outcomes. This is also consistent with the AEMC's findings, which described the use case of service line safety through loss of neutral detection. Specifically, the AMEC stated that distribution businesses are expected to use 'basic' power quality data for detecting loss of neutral.[128] Therefore, we consider the more realistic assumption to be

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122 AER, *Draft decision, Attachment 5 – Capital expenditure – Ergon Energy – 2025–30 Distribution revenue proposals,* September 2024, section A7.

123 AEMC, *Final report, Review of the Regulatory Framework for metering services*, 30 August 2023, p. 110; AEMC, *Draft determination – National Electricity Amendment (Accelerating Smart Meter Deployment) Rule National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule*, 4 April 2024, pp. 17–19. We note that the AEMC's Final Determination on the accelerating smart meter deployment rule change will not be made until November 2024. If required, we will take this into account as a part of our final decision.

124 AEMC*, Final report, Review of the Regulatory framework for metering services, 30 August, p. 115; AEMC, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule*, 4 April 2024, pp. 17–19.

125 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, pp. 12–13, 29.

126 Energex, *Response to AER information request IR#017,* 29 July 2024, p. 9*;* EMCa, *Review of proposed network visibility opex step change*, 29 July 2024, p. 9.

127 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, p. 12.

128 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, p. 13; AEMC, *Final report, Review of the Regulatory Framework for metering services*, 30 August 2023, p. 118.

that both data provision types (6-hourly and near real-time) will provide a materially similar safety benefit.[129]

In terms of the reliability benefits, overall, we consider the claimed transformer reliability benefits to be overstated. The 90% failure-based outage durations reduction assumption, in effect, implies supply will be restored in an average of 0.4 hours.[130] However, and in general, businesses become aware of distribution transformer failures relatively quickly, and thus only likely marginal additional benefits are achievable. That is, the remaining processes, such mobilising a crew and manually repairing the defect, remain constant and independent of data frequency.[131] We also observe that independent from the safety and reliability benefits, the other identified benefits, such as the benefits arising from CER integration, do not justify the additional costs in purchasing near real-time data.

Based on the above analysis, we conclude that Ergon Energy's option 1 (no near real-time data and only analytics) reflects costs required for Ergon Energy to uplift its analytical capabilities to process and manage power quality data that will be made available to distribution businesses at no charge. This includes data received through Ergon Energy's capex LV monitors program. We are satisfied that this represents the prudent and efficient amount that will enable Ergon Energy to increase its network visibility.

However, in response to an information request, Ergon Energy clarified that its opex in the base year included relevant expenditure that had not been accounted in the proposed step change.[132] Our base-step-trend forecasting approach inherently provides Ergon Energy this base year opex amount for each of the years trended forward, including an uplift of costs through the rate of change methodology. Therefore, to prevent the risk of double counting, we subtracted the amount Ergon Energy will receive through our forecasting approach from its option 1. This showed that Ergon Energy's trended base year amount sufficiently provides costs that are consistent with uplifting Ergon Energy's network visibility with its option 1 strategy.

The RRG supported this step change, including data acquisition of near real time data, noting it would leave it to the AER to assess the prudency and efficiency of the expenditure amount.[133] CCP30 noted that it expected that the recent changes to the NER on costs of accessing smart meter data will be reflected in the draft decision.[134] We considered this feedback in undertaking our assessment of this step change, noting that the step change does not include any costs for smart meter data to be made freely available under the recent draft rule change. Further, that we do not consider the real time smart meter data is justified.

For our alternative estimate, we therefore do not consider any forecast costs are required via this step change. We are satisfied that Ergon Energy will receive the prudent and efficient

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129 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, p. 12.

130 Ergon Energy, *6.05A – Business case – Smart meter data acquisition,* January 2024, p. 8.

131 EMCa, *Energex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals – Review of proposed network visibility opex step change*, August 2024, p. 13.

132 Ergon Energy, *Response to AER information request, IR#019 – DER,* 10 May 2024, Q4, p. 3.

133 RRG, *Submission –2025–30 Electricity Determination – Energex & Ergon,* May 2024, pp. 4, 61.

134 CCP30, *Submission – 2025–30 Electricity Determination – Energex & Ergon,* May 2024, p. 28.

costs required to uplift its network visibility, consistent with its option 1, through our base-step-trend forecasting approach.

6.4.5 Category specific forecasts

Ergon Energy's proposal included one category specific forecasts, which was not forecast using the base-step-trend approach. This was for debt raising costs. We have included this category specific forecast for debt raising costs in our alternative estimate of total opex.

6.4.5.1 Debt raising costs

We have included debt raising costs of $39.9 million in our alternative estimate. This is $3.2 million lower than the $43.1 million proposed by Ergon Energy.

Table 6.12 Debt raising costs ($million, 2023–24)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy's proposal	8.1	8.4	8.6	8.9	9.1	43.1
AER alternative estimate	7.8	7.9	8.0	8.1	8.1	39.9
Difference	–0.3	–0.5	–0.6	–0.8	–0.9	–3.2

Source: Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p. 141; AER analysis.
Note: Numbers may not add up to totals due to rounding.

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 6.12.

We used our standard approach to forecast debt raising costs, which is discussed further in Attachment 3 to the draft decision.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	Consumer energy resources
CPI	consumer price index
DNSP	Distribution network service provider
EBSS	efficiency benefit sharing scheme
EMCa	Energy EMarket Consultants associates
LV	Low voltage
MPFP	Multilateral partial factor productivity
MTFP	Multilateral total factor productivity
NEM	national electricity market
NER or the Rules	National Electricity Rules
OEF	Operating environmental factors
opex	operating expenditure
PPI	partial performance indicator
RBA	Reserve Bank of Australia
RIN	regulatory information notice
RRG	Energy Queensland Reset Reference Group
SCS	standard control services
WPI	Wage price index