# Draft Decision

## Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

## Attachment 1
## Annual revenue requirement

September 2024

AUSTRALIAN ENERGY REGULATOR

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# Contents

# 1 Annual revenue requirement

This attachment sets out our draft decision on Ergon Energy's annual revenue requirement (ARR) and expected revenues for the provision of standard control services (SCS) over the 2025–30 regulatory control period. Specifically, it sets out our draft decision on:[1]

- the ARRs (unsmoothed), which are the sum of annual building block costs
- the total revenue requirement, which is the sum of the ARRs
- the annual expected revenues (smoothed)
- the X factors.

This attachment discusses our draft decision on the above for the main SCS, with metering SCS being discussed in Attachment 20.

We determine Ergon Energy's ARR using a building block approach. We determine the X factors by smoothing the ARR over the 2025–30 period. The X factor is used in the CPI–X methodology to determine the annual expected revenue (smoothed).

## 1.1 Draft decision

We determine a total ARR of $8,369.2 million ($ nominal, unsmoothed) for Ergon Energy over the 2025–30 period for the main SCS. This amount reflects our draft decision on the various building block costs and represents a reduction of $153.0 million (1.8%) to Ergon Energy's proposed total ARR of $8,522.2 million. This reduction is largely driven by the lower return on capital building block determined in this draft decision, which have been partially offset by reduced negative revenue adjustments and a higher cost of corporate income tax building block.

We determine the annual expected revenue (smoothed) and X factor for each regulatory year for the 2025–30 period by smoothing the ARR. For the 2025–30 period, our draft decision is to approve total expected revenues of $8,365.9 million ($ nominal, smoothed) for Ergon Energy.

At the time of making this draft decision, we have used placeholder values for certain components such as the rate of return and expected inflation. We will make further updates for these values as part of our final decision. It is for this reason that we expect the total expected revenues approved in our final decision to be different to this draft decision.

Table 1.1 sets our draft decision on the building block costs, the ARR, annual expected revenue and X factor for Ergon Energy over the 2025–30 period.

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1 NER, cll. 6.3.2(a)(1), 6.5.9(a) and 6.5.9(b)(1)–(2).

**Table 1.1 AER's draft decision on Ergon Energy's ARR, annual expected revenue and X factor for the 2025–30 period ($ million, nominal)**

| | 2025–26 | 2026–27 | 2027–28 | 2028–29 | 2029–30 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 940.1 | 983.3 | 1,030.2 | 1,084.9 | 1,142.0 | 5,180.6 |
| Regulatory depreciation[a] | 201.7 | 230.4 | 255.5 | 283.8 | 292.3 | 1,263.7 |
| Operating expenditure[b] | 484.3 | 500.9 | 518.2 | 534.8 | 552.8 | 2,591.1 |
| Revenue adjustments[c] | –150.4 | –166.7 | –176.8 | –131.0 | –111.1 | –736.0 |
| Cost of corporate income tax | 4.9 | 11.9 | 13.9 | 18.4 | 20.7 | 69.8 |
| Annual revenue requirement (unsmoothed) | 1,480.7 | 1,559.8 | 1,641.0 | 1,790.9 | 1,896.8 | 8,369.2 |
| **Annual expected revenue (smoothed)** | **1,478.2** | **1,569.8** | **1,667.1** | **1,770.5** | **1,880.2** | **8,365.9** |
| X factor[d] | n/a[e] | –3.26% | –3.26% | –3.26% | –3.26% | n/a |

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), the capital expenditure sharing scheme (CESS) and the demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) Ergon Energy is not required to apply an X factor for 2025–26 because we set the 2025–26 expected revenue in this decision. The expected revenue for 2025–26 is around 3.3% higher than the approved total annual revenue for 2024–25 in real terms, or 6.2% higher in nominal terms.

Our draft decision also allows Ergon Energy to recover $170.9 million ($ nominal, smoothed) from its customers for the 2025–30 period for legacy metering services. Our assessment of metering revenue is not included in the total revenue set out in this attachment and is discussed in Attachment 20 of this draft decision.

## 1.2 Ergon Energy's proposal

Ergon Energy proposed a total expected revenue (smoothed) of $8,522.3 million ($ nominal) for the 2025–30 period. Table 1.2 shows Ergon Energy proposed building block costs, the ARR, expected revenue and X factor for each year of the 2025–30 period.

**Table 1.2 Ergon Energy's proposed ARR, annual expected revenue and X factor for the 2025–30 period ($ million, nominal)**

| | 2025–26 | 2026–27 | 2027–28 | 2028–29 | 2029–30 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 982.0 | 1,048.8 | 1,121.8 | 1,204.4 | 1,292.1 | 5,649.1 |
| Regulatory depreciation[a] | 207.6 | 233.1 | 256.8 | 280.5 | 283.7 | 1,261.6 |
| Operating expenditure[b] | 484.0 | 500.4 | 517.5 | 533.8 | 551.5 | 2,587.2 |
| Revenue adjustments[c] | –196.8 | –214.3 | –225.7 | –181.2 | –162.1 | –980.2 |
| Cost of corporate income tax | 0.0 | 0.0 | 0.0 | 2.1 | 2.5 | 4.6 |
| Annual revenue requirement (unsmoothed) | 1,476.8 | 1,568.0 | 1,670.3 | 1,839.5 | 1,967.6 | 8,522.2 |
| **Annual expected revenue (smoothed)** | **1,463.1** | **1,574.9** | **1,695.2** | **1,824.8** | **1,964.2** | **8,522.3** |
| X factor | n/a[d] | –4.71% | –4.71% | –4.71% | –4.71% | n/a |

Source: Ergon Energy, *8.03–Model–SCS PTRM Model,* January 2024.
(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
(b) Includes debt raising costs.
(c) Includes revenue adjustments from EBSS, CESS and DMIAM.
(d) Ergon Energy is not required to apply an X factor for 2025–26 because we set the 2025–26 expected revenue in this decision.

# 1.3 Assessment approach

In this section, we describe the building block approach used to determine the ARR and expected revenue for Ergon Energy for each year of the 2025–30 period.[2]

## 1.3.1 The building block approach

The ARR is calculated using the post-tax revenue model (PTRM).[3] For the applicable control mechanism (Attachment 14) applying to SCS, the revenue to be earned by the distributor (expected revenues) for the regulatory control period must be equal to the net present value (NPV) of the total revenue requirement.[4] The total revenue requirement is the sum of the ARRs for the regulatory control period. In turn, the ARR must be determined using a building block approach.[5] Therefore, we adopt a building block approach when making our decision on Ergon Energy's total ARR and expected revenue for each regulatory year of the regulatory control period. Under this approach, we determine the value of the building block costs that make up the ARR for each regulatory year. The ARR for each year is the sum of the building block costs. These building block costs are set out in section 1.3.2.

2 NER, cll. 6.3.2(a)(1), 6.5.9(b)(2).

3 NER, cl. 6.4.2.

4 NER, cl. 6.5.9(b)(3)(i).

5 NER, cl. 6.4.3.

We developed the PTRM, which brings together the various building block costs and calculates the ARR for each year of the regulatory control period.[6] The PTRM also calculates the X factors required under the CPI–X methodology[7] which is used to escalate the expected revenue for each year (other than the first year) of the regulatory control period.[8] Using the X factors and ARR, the annual expected revenue (smoothed) is forecast for each year of the regulatory control period. Ergon Energy's proposal must be prepared using our PTRM.[9]

The ARR can be lumpy over the regulatory control period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. Smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period so that the NPV of the annual expected revenue (smoothed revenues) is equal to the NPV of the ARR (unsmoothed revenues). That is, a smoothed profile of the expected revenue is determined for the regulatory control period under the CPI–X methodology.

The expected revenue for the first year is generally set equal to the ARR for the first year of the regulatory control period. At times, it may be more appropriate to set the expected revenue for the first year to align with the revenue from the last year of the previous regulatory control period to avoid any large revenue variation between periods (or $P_0$).[10]

In this determination for Ergon Energy, we first calculate the ARR for each year of the 2025–30 period. To do this we consider the various costs facing Ergon Energy and the trade-offs and interactions between these costs, service quality and across years. This reflects our holistic assessment of Ergon Energy's proposal.

We understand the trade-offs that occur between building block costs and test the sensitivity of these costs to their various driver elements. These trade-offs are discussed in the interrelationships section of the various attachments to this draft decision and are reflected in the calculations made in the PTRM.[11] Such understanding allows us to exercise judgement in determining the final inputs into the PTRM and the ARR that result from this modelling.

Having determined the total revenue requirement for the 2025–30 period, we smooth the ARR for each regulatory year across that period. This step reduces revenue variations between years, and calculates the expected revenue and X factor for each year.[12] The X

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6 NER, cl. 6.4.2.

7 NER, cl. 6.2.6(a).

8 NER, cl. 6.5.9.

9 NER, cl. 6.3.1(c).

10 The expected revenue for year 1 of the next regulatory control period may include adjustments for the performance incentive that applied during the previous regulatory control period, and under or over recovery adjustments from previous regulatory years.

11 There are trade-offs that are not modelled in the PTRM but are reflected in the inputs to the PTRM. For example, service quality is not explicitly modelled in the PTRM, but the trade-offs between service quality and price are reflected in the forecast capital expenditure and operating expenditure inputs to the model. Other trade-offs are obvious from the calculations in the PTRM. For example, while it may be expected that a lower RAB would also lower revenues, the PTRM shows that this will not occur if the reduction in the RAB is due solely to an increase in the depreciation rate. In such circumstances, revenues increase as the increased depreciation more than offsets the reduction in the return on capital caused by the lower RAB.

12 NER, cl. 6.5.9(a).

factors equalise (in net present value terms) the total expected revenues to be earned by Ergon Energy with the total revenue requirement for the 2025–30 period.[13] The X factor profile must also minimise, as far as reasonably possible, the variance between the expected revenue and ARR for the last regulatory year of the period.[14] By minimising this divergence, it helps to manage the prospect of a significant revenue change (and consequently prices) between the last year of the 2025–30 period, and first year of the following 2030–35 period. We consider a divergence of up to 3% between the expected revenue and ARR for the last year of the regulatory control period is reasonable, if this can promote smoother price changes across the regulatory control periods.

The building block costs (and the elements that drive those costs) used to determine the unsmoothed ARR are set out in section 1.3.2.

### 1.3.2 Building block costs

The efficient costs to be recovered by a distributor can be thought of as being made up of various building block costs. Our draft decision assesses each of the building block costs and the elements that drive these costs. The building block costs are approved reflecting trade-offs and interactions between the cost elements, service quality and across years.

Table 1.3 shows the building block costs that form the ARR for each year and where discussion on the elements that drive these costs can be found within this draft decision.

**Table 1.3 Building block costs**

| Building block costs | Attachments where elements are discussed |
|---|---|
| Return on capital | Regulatory asset base (Attachment 2)<br>Rate of return (Attachment 3)<br>Capital expenditure (Attachment 5) |
| Regulatory depreciation (return of capital) | Regulatory asset base (Attachment 2)<br>Regulatory depreciation (Attachment 4)<br>Capital expenditure (Attachment 5) |
| Operating expenditure | Operating expenditure (Attachment 6) |
| Estimated cost of corporate income tax | Corporate income tax (Attachment 7) |
| Other revenue adjustments | |
| Adjustments for shared assets | Annual revenue requirement (Attachment 1) |
| Operating efficiency benefits/penalties | Efficiency benefit sharing scheme (Attachment 8) |

13 NER, cl. 6.5.9(b)(3)(i). The X factors represent the real revenue path over the 2025–30 period under the CPI–X framework.

14 NER, cl. 6.5.9(b)(2).

| Building block costs | Attachments where elements are discussed |
|---|---|
| Capital efficiency benefits/penalties | Capital expenditure sharing scheme (Attachment 9) |
| Demand management innovation allowance | Demand management incentive scheme and Demand management innovation allowance mechanism (Attachment 11) |

## 1.4 Reasons for draft decision

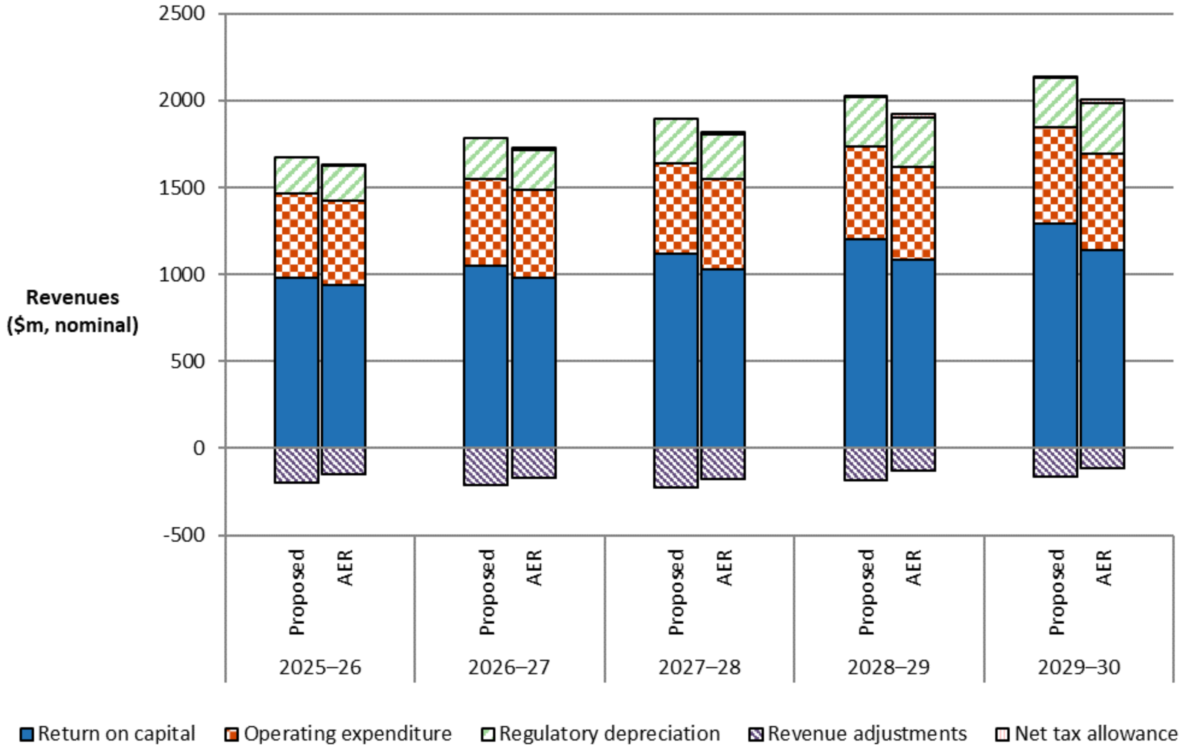
We determine a total ARR of $8,369.2 million ($ nominal, unsmoothed) for Ergon Energy over the 2025–30 period. This is a reduction of $153.0 million (1.8%) to Ergon Energy's proposed total ARR of $8,522.2 million for this period. This reflects the impact of our draft decision on the various building block costs.

The changes we made to Ergon Energy's proposed building blocks include (in nominal terms):

- a reduction in the return on capital of $468.5 million (8.3%) (Attachments 2, 3 and 5). This is driven primarily by lower opening RAB, forecast capital expenditure (capex) and rate of return determined in our draft decision compared to Ergon Energy's proposal.
- an increase in the regulatory depreciation of $2.1 million (0.2%) (Attachments 2, 4 and 5). Our amendments to forecast and actual capex have the effect of reducing straight-line depreciation, but this has been offset by the lower indexation of the RAB as a result of these capex reductions. A lower RAB indexation leads to an increase in regulatory depreciation since indexation is deducted from straight-line depreciation.
- an increase in the operating expenditure (opex) forecast of $3.9 million (0.1%) (Attachment 6). This is due to the higher expected inflation rate applied in this draft decision compared to Ergon Energy's proposal. Our draft decision has accepted Ergon Energy's proposed total opex in real 2024–25 dollar terms.
- an increase in the estimated cost of corporate income tax of $65.3 million (Attachment 7). This is driven primarily a lower tax depreciation amount determined in this draft decision compared to Ergon Energy's proposal.
- an increase in the revenue adjustments of $244.3 million (24.9%) (Attachments 8, 9 and 11). This is driven primarily by lower CESS penalties determined in this draft decision compared to Ergon Energy's proposal, reflecting the reduced actual capex for 2018–23 as a result of our ex-post review.

Figure 1.1 shows the building block components from our determination that make up the ARR for Ergon Energy, and the corresponding components from its proposal.

**Figure 1.1 AER's draft decision and Ergon Energy's proposed ARR ($ million, nominal)**




Source: AER analysis; Ergon Energy, *8.03–Model–SCS PTRM Model*, January 2024.
Note: Revenue adjustments include EBSS, CESS and DMIAM amounts. Opex includes debt raising costs.

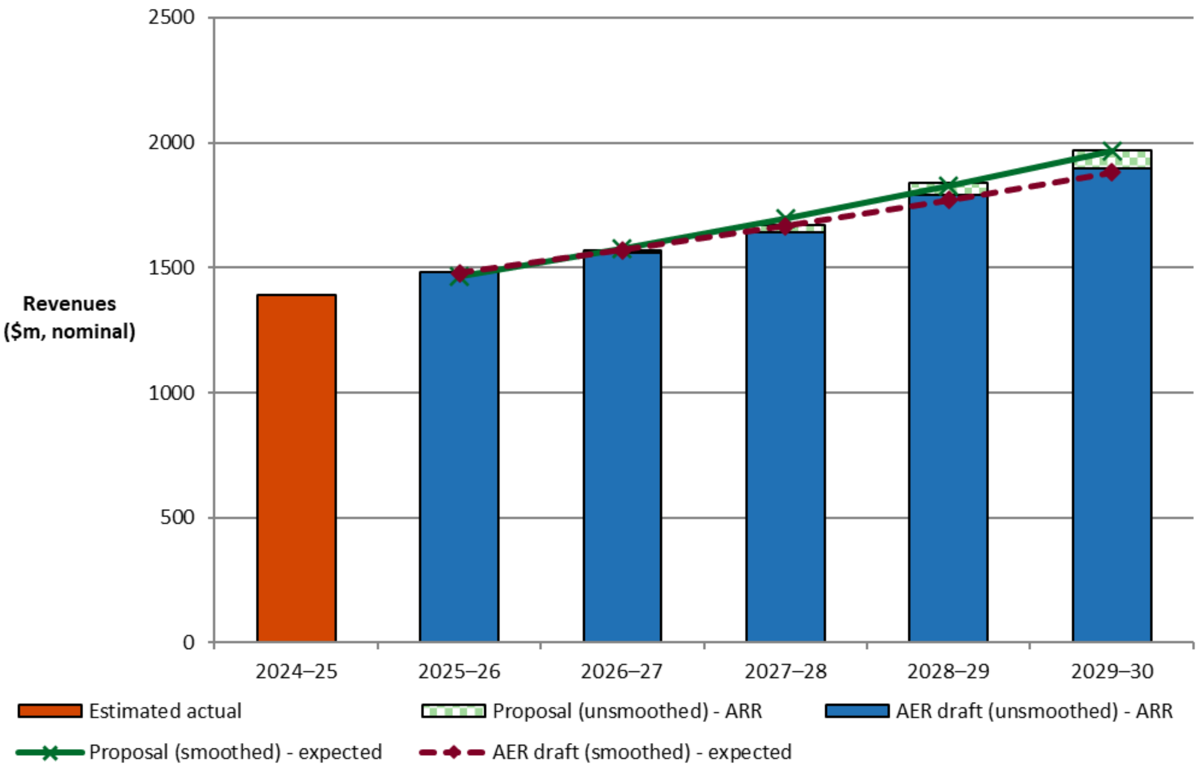
### 1.4.1 X factor and annual expected revenue

For this draft decision, we determine an X factor for Ergon Energy of –3.26% per annum for the four years of the regulatory control period from 2026–27 to 2029–30.[15] The NPV of the ARRs is $6,980.1 million ($ nominal) as at 1 July 2025. Based on this NPV and applying the CPI–X framework, we determine that the expected revenue (smoothed) for Ergon Energy is $1,478.2 million in 2025–26 increasing to $1,880.2 million in 2029–30 ($ nominal). The resulting total expected revenue is $8,365.9 million for the 2025–30 period.

Figure 1.2 shows our draft decision on Ergon Energy's annual expected revenue (smoothed revenue) and the ARR (unsmoothed revenue) for the 2025–30 period.

[15] Ergon Energy is not required to apply an X factor for 2025–26 because we set the 2025–26 expected revenue in this decision.

**Figure 1.2 AER's draft decision on Ergon Energy's revenue for the 2025–30 period ($ million, nominal)**




Source: AER analysis; Ergon Energy, *8.03–Model–SCS PTRM Model*, January 2024.

To determine the profile of expected revenue for Ergon Energy over the 2025–30 period, we have set the expected revenue for the first regulatory year at $1,478.2 million ($ nominal). This is $2.5 million lower than the ARR for that first year. We then apply an expected inflation rate of 2.85% per annum and a profile of X factors to determine the expected revenue in subsequent years.[16] We consider that our profile of X factors results in an expected revenue in the last year of the regulatory control period that is as close as reasonably possible to the ARR for that year.[17] We will review this smoothing profile for the final decision.

In addition, we note that the Queensland Government's Solar Bonus Scheme is due to expire on 1 July 2028.[18] In our previous decisions, we have accounted for such known impacts which are material (and sits outside of our building block determination) in our total revenue smoothing approach to provide an overall smoother revenue outcome. In our draft decision for SA Power Networks, we have adjusted the revenue smoothing profile to account for the impact of the cessation of the South Australian Government's Solar Feed-in Tariff Scheme in the 2025–30 period. This is consistent with the approach proposed by SA Power Networks.[19]

16 NER, cl. 6.5.9(a).

17 NER, cl. 6.5.9(b)(2). We consider a divergence of up to 3% between the expected revenue and ARR for the last year of the regulatory control period is appropriate, if this can promote smoother price changes for users across the regulatory control period. In the present circumstances, based on the X factors we have determined for Ergon Energy, this divergence is around 0.9%.

18 Queensland Government, *Solar Bonus Scheme 44c feed-in tariff*, 12 March 2024

19 AER, *Draft decision–SA Power Networks electricity distribution determination 2025 to 2030, Attachment 1–Annual revenue requirement*, September 2024, p. 9.

Ergon Energy did not account for such impact in its initial proposal on revenue smoothing submitted in January 2024. However, it may propose a similar adjustment to its revenue smoothing profile in its revised proposal.

Our draft decision results in an annual increase of 6.2% per annum ($ nominal) in the expected revenues over the 2025–30 period.[20]

Our draft decision also results in an increase of $2,359.5 million (39.3%) in nominal dollar terms to Ergon Energy's total ARR relative to that in the 2020–25 period.[21] This is because:

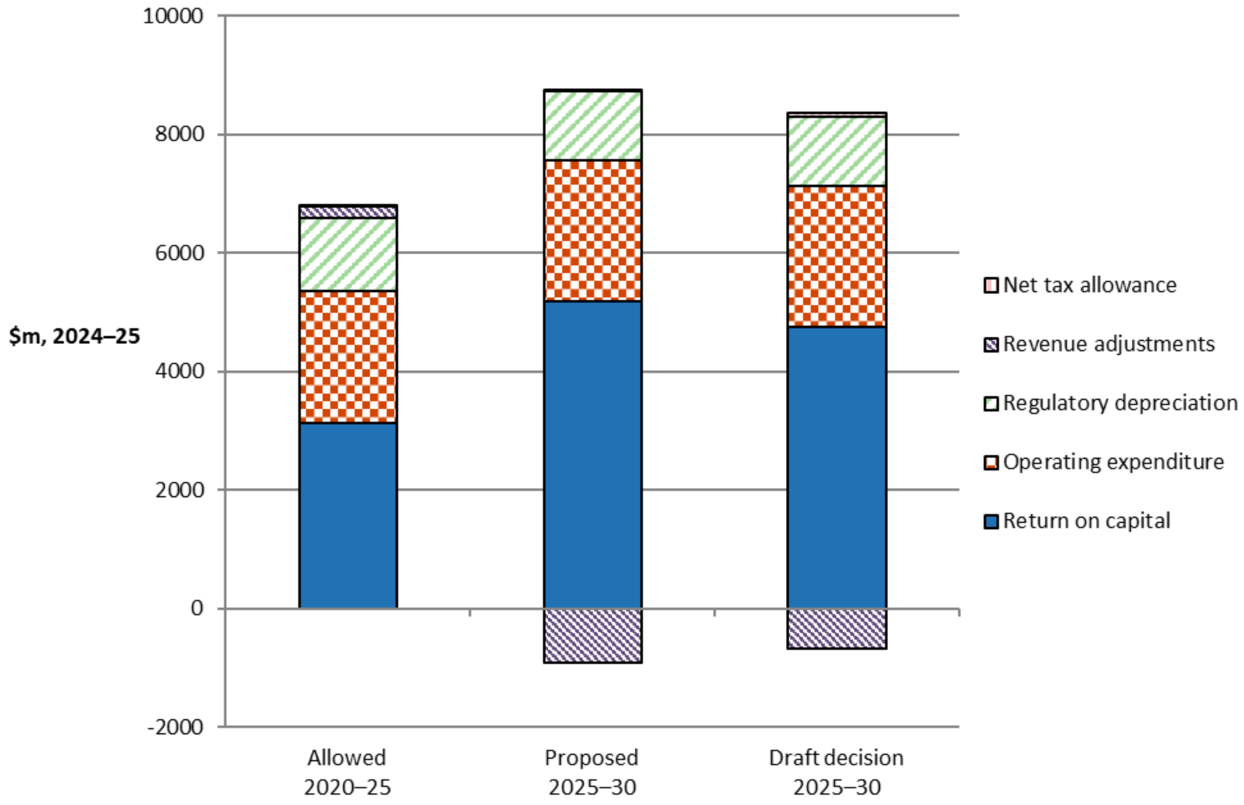
- Approximately 56% of the increase is due to factors potentially outside the control of Ergon Energy. This includes higher actual inflation rates for the 2020–25 period, which increase the indexation component of the RAB. It is also driven by higher interest rates for the 2025–30 period, which lead to a higher forecast rate of return (Attachment 3). Together, these changes in market variables result in a much higher return on capital building block compared to the current period.
- The other 44% of the increase is driven by a higher RAB growth due to higher actual and forecast capex (Attachment 5) and a higher opex (Attachment 6) determined in this draft decision for the 2025–30 period than that approved in the 2020–25 determination.

Figure 1.3 compares our draft decision building blocks for Ergon Energy's 2025–30 period with its proposal for the same period, and the approved unsmoothed revenue for the 2020–25 period.

[20] In real 2024–25 dollar terms, our draft decision results in an annual increase of 3.3% per annum in the expected revenues over the 2025–30 period.

[21] In real 2024–25 dollar terms, our draft decision results in an increase of $895.9 million (13.2%) to Ergon Energy's total ARR relative to that in the 2020–25 period.

Figure 1.3 Total revenue by building block components ($ million, 2024–25)




Source: AER analysis.

### 1.4.2 Shared assets

Distributors, such as Ergon Energy, may use assets to provide both the SCS we regulate and unregulated services, for example by the stringing of telecommunications cables on the electricity network poles for the provision of telecommunication services. These assets are called 'shared assets'.[22] If the revenue from shared assets is material, 10% of the unregulated revenues that a distributor earns from shared assets will be used to reduce the distributor's revenue for SCS.[23]

The shared asset principles establish that use of shared assets should be material before cost reductions are applied.[24] The National Electricity Rules (NER) do not define materiality in this context. Our approach to what constitutes a material use of shared assets is that unregulated use of shared assets in a specific regulatory year is material when a distributor's annual average unregulated revenue from shared assets is expected to be greater than 1% of its expected revenue for that regulatory year.[25]

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22 NER, cl. 6.4.4.

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

24 NER, cl. 6.4.4(c)(3).

25 AER, *Shared asset guideline*, November 2013, pp. 8–9.

Ergon Energy submitted that its total revenue requirement is not subject to a shared asset adjustment because its forecast annual unregulated revenue from shared assets does not exceed the AER's materiality threshold.[26]

We consider Ergon Energy’s forecast unregulated revenues from shared assets for the 2025–30 period to be reasonable, noting that its forecasts have increased compared to the 2020–25 period due to expected increases from license fees and the introduction of a new Equipment Rental Agreement.[27] Ergon Energy's forecast unregulated revenues must be compared to the regulated revenues we determine, rather than those proposed by Ergon Energy. Based on the lower expected revenues in our draft decision, we determined that the materiality threshold is still not met in any year the 2025–30 period. As such, our draft decision does not apply any shared asset revenue adjustment.[28]

### 1.4.3 Indicative average distribution price impact

Our draft decision on Ergon Energy’s expected revenues ultimately affects the prices consumers pay for electricity. There are several steps required in translating our revenue decision into indicative distribution price impacts.

We regulate Ergon Energy’s SCS under a revenue cap form of control. This means our draft decision on Ergon Energy’s expected revenues does not directly translate to price impacts. This is because Ergon Energy’s revenue is fixed under the revenue cap form of control, so changes in the consumption of electricity will affect the prices ultimately charged to consumers.

We are not required to establish the distribution prices for Ergon Energy as part of this determination. However, we will assess Ergon Energy’s annual pricing proposals before the commencement of each regulatory year within the 2025–30 period. In each assessment we will administer the pricing requirements set in this distribution determination.

For this draft decision, we have estimated some indicative average distribution price impacts flowing from our determination on the expected revenues for Ergon Energy over the 2025–30 period. In this section, our estimates only relate to SCS (that is, the core electricity distribution charges),[29] not alternative control services (such as public lighting). These indicative price impacts assume that actual energy consumption across the 2025–30 period matches Ergon Energy’s forecast energy consumption, which we have adopted for this draft decision. We also have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

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26 Ergon Energy, *Ergon Energy–2025–30 regulatory proposal,* February 2024, p. 166.

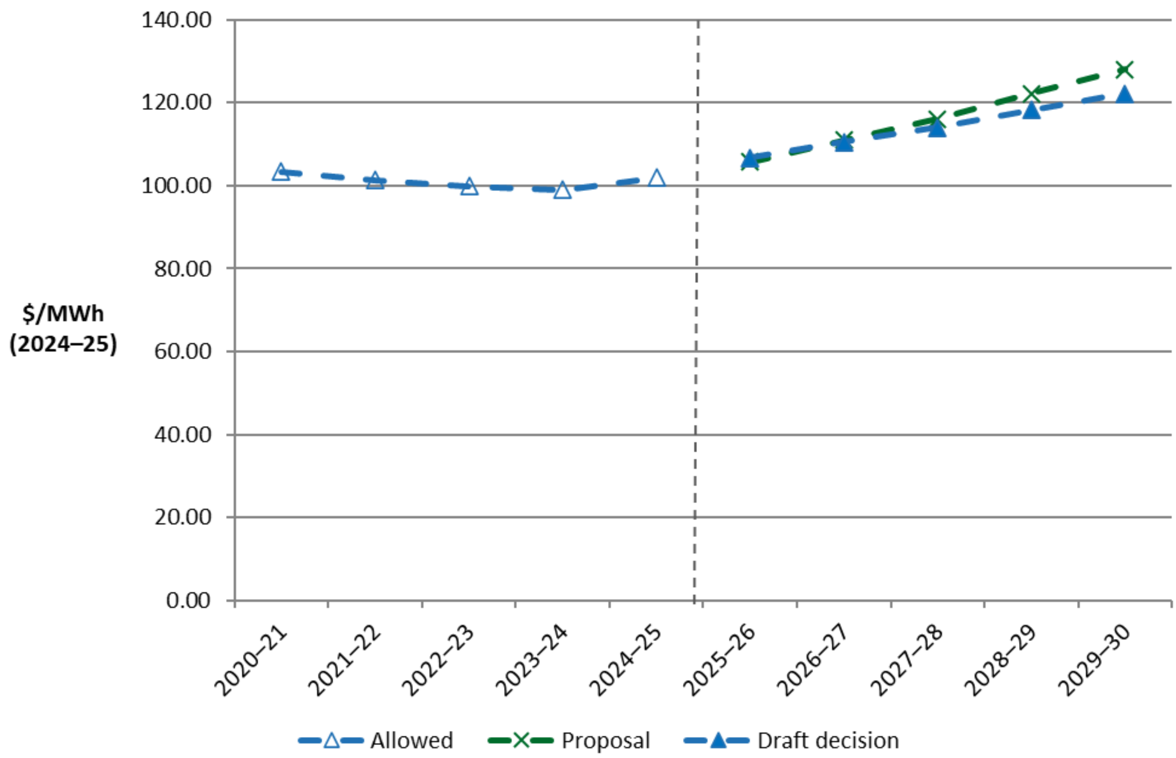
27 AER analysis; Ergon Energy, *RIN.01-Forecast Data*, January 2024.

28 We will reassess the materiality of the forecast shared asset unregulated revenues for our final decision.

29 Ergon Energy has reclassified its legacy metering services from alternative control services (ACS) to SCS in its revised proposal based on the AEMC’s review of the regulatory framework for metering services in August 2023 and our guidance on metering issued in November 2023. Ergon Energy, *2025-30 Regulatory Proposal*, February 2024, pp. 181–182; Our final decision on metering services is discussed in Attachment 20.

Figure 1.4 shows Ergon Energy's indicative distribution price path over the period from 2020–21 to 2029–30 in real 2024–25 dollar terms based on the expected revenues established in our draft decision compared to Ergon Energy's proposed revenue requirement. The indicative price path is estimated using the approved expected revenue and dividing by forecast energy consumption for each year of the 2020–25 period.

**Figure 1.4 Indicative distribution price path for Ergon Energy ($/MWh, 2024–25)**




Source: AER analysis.

We estimate that our draft decision on Ergon Energy's annual expected revenue will result in an increase to average distribution charges by about 3.5% per annum over the 2025–30 period in real 2024–25 dollar terms.[30] This compares to the real average increase of approximately 4.9% per annum proposed by Ergon Energy over the 2025–30 period.[31] These high-level estimates reflect the aggregate change across the entire network and do not reflect the particular tariff components for specific end users.

Table 1.4 displays in nominal terms the comparison of the revenue and price impacts of Ergon Energy's proposal and our draft decision.

30 In nominal terms, we estimate average distribution charges to increase by 6.4% per annum. This amount reflects an expected inflation rate of 2.85% per annum as determined in this draft decision.

31 In nominal terms Ergon Energy's proposal would increase distribution charges by 7.9% per annum. This amount reflects an expected inflation rate of 2.80% per annum as proposed by Ergon Energy in its proposal.

**Table 1.4 Comparison of revenue and price impact of Ergon Energy's proposal and the AER's draft decision ($ nominal)**

| | 2024–25 | 2025–26 | 2026–27 | 2027–28 | 2028–29 | 2029–30 |
|---|---|---|---|---|---|---|
| **AER draft decision** | | | | | | |
| Revenue ($m, nominal) | 1,391.9 | 1,478.2 | 1,569.8 | 1,667.1 | 1,770.5 | 1,880.2 |
| Price path ($/MWh)[a] | 103.01 | 109.73 | 116.81 | 124.04 | 132.31 | 140.65 |
| Revenue (change %) | – | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% |
| Price path (change %) | – | 6.5% | 6.5% | 6.2% | 6.7% | 6.3% |
| **Ergon Energy proposal** | | | | | | |
| Revenue ($m, nominal) | 1,359.3 | 1,463.1 | 1,574.9 | 1,695.2 | 1,824.8 | 1,964.2 |
| Price path ($/MWh)[a] | 100.59 | 108.61 | 117.19 | 126.13 | 136.37 | 146.93 |
| Revenue (change %) | – | 7.6% | 7.6% | 7.6% | 7.6% | 7.6% |
| Price path (change %) | – | 8.0% | 7.9% | 7.6% | 8.1% | 7.7% |

Source: AER analysis; Ergon Energy, *8.03–Model–SCS PTRM Model*, January 2024.
(a) The price path is in nominal terms and is constructed by dividing nominal expected revenue for SCS by forecast energy consumption for each year of the period.

## 1.4.4 Expected impact of draft decision on electricity bills

Our bill impact calculations for Ergon Energy adopt the network charges in our draft decision for Energex. This is because retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy results in regulated retail electricity prices in Ergon Energy's distribution area being matched to those in Energex's area.[32]

The annual electricity bill for customers in Ergon Energy's network reflects the combined cost of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. This draft decision primarily relates to the distribution charges for Ergon Energy's SCS, which represent on average approximately 27.1% of residential customers' annual electricity bills and 26.5% of small business customers' annual electricity bills in Ergon Energy's network area.[33]

We estimate the expected bill impact by varying the distributions charges in accordance with our draft decision in this attachment, while holding all other components—including the

[32] Queensland Competition Authority, *Regulated electricity prices for regional Queensland 2024–25 Final determination*, pp. 10-11.

[33] AER analysis; Energex, *2024-25 annual SCS pricing model*, 28 March 2024; AER, *Revised final determination – Default Market Offer Prices 2024–2025*, June 2024, p. 6.

metering component—constant.[34] This approach isolates the effect of our draft decision on the core distribution charges only for Ergon Energy. However, this does not imply that other components will remain unchanged across the period.[35]

Based on this approach, we expect that our draft decision on the distribution component will increase the average annual residential electricity bill in 2029–30 by about $197 ($ nominal) or 9.6% from the 2024–25 total bill level. By comparison, had we accepted Ergon Energy's proposal, the expected change in the distribution component would increase the average annual residential electricity bill in 2029–30 by about $254 ($ nominal) or 12.3% from the 2024–25 total bill level.

Similarly, we expect that our draft decision will result in the distribution component of the average annual electricity bill for a small business customer in 2029–30 to increase by about $397 ($ nominal) or 9.3% from the 2024–25 total bill level. By comparison, had we accepted Ergon Energy's proposal, the expected change in the distribution component would increase the average annual small business electricity bill in 2029–30 by about $511 ($ nominal) or 12.0% from the 2024–25 total bill level.

Our estimated bill impact is based on the typical annual electricity usage of 4,600 kWh and 10,000 kWh for residential and small business customers in Ergon Energy's network, respectively.[36] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other factors, such as metering, wholesale and retail costs, which affect electricity bills.

Table 1.5 shows the estimated impact of our draft decision and Ergon Energy's proposal on the average annual electricity bills for residential and small business customers in its network over the 2025–30 period.

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[34] We also have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

[35] It also assumes that actual energy consumption will equal the forecast adopted in our draft decision. Since Ergon Energy operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2025–30 period.

[36] AER, *Revised final determination – Default Market Offer Prices 2024–2025*, June 2024, p. 6.

### Table 1.5 Estimated impact of Ergon Energy’s proposal and AER’s draft decision on annual electricity bills for the 2025–30 period ($ nominal)

| | 2024–25 | 2025–26 | 2026–27 | 2027–28 | 2028–29 | 2029–30 |
|---|---|---|---|---|---|---|
| **AER draft decision** | | | | | | |
| Residential annual electricity bill | 2,066[a] | 2,103 | 2,142 | 2,180 | 2,223 | 2,263 |
| Annual change[b] | – | 38 (1.8%) | 38 (1.8%) | 38 (1.8%) | 43 (2.0%) | 40 (1.8%) |
| Small business annual electricity bill | 4,261[a] | 4,336 | 4,414 | 4,491 | 4,577 | 4,658 |
| Annual change[b] | – | 76 (1.8%) | 77 (1.8%) | 77 (1.7%) | 86 (1.9%) | 81 (1.8%) |
| **Ergon Energy proposal** | | | | | | |
| Residential annual electricity bill | 2,066[a] | 2,111 | 2,159 | 2,209 | 2,265 | 2,319 |
| Annual change[b] | – | 45 (2.2%) | 49 (2.3%) | 50 (2.3%) | 56 (2.5%) | 55 (2.4%) |
| Small business annual electricity bill | 4,261[a] | 4,351 | 4,449 | 4,549 | 4,661 | 4,771 |
| Annual change[b] | – | 91 (2.1%) | 98 (2.2%) | 100 (2.3%) | 112 (2.5%) | 110 (2.4%) |

Source: AER analysis; Energex, *2024-25 annual SCS pricing model*, 28 March 2024; AER, *Revised final determination – Default Market Offer Prices 2024–2025*, June 2024, p. 6.

Note: Energex’s bill impacts are used for this table reflecting the Queensland Government's uniform tariff policy.

(a) AER, *Revised final determination – Default Market Offer Prices 2024–2025*, June 2024, p. 6.

(b) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2024–25 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by Ergon Energy. Actual bill impacts will vary depending on electricity consumption and tariff class.

# Shortened forms

| Term | Definition |
|---|---|
| AER | Australian Energy Regulator |
| ARR | annual revenue requirement |
| capex | capital expenditure |
| CESS | capital expenditure sharing scheme |
| CPI | consumer price index |
| DMIAM | demand management innovation allowance mechanism |
| DMO | default market offer |
| EBSS | efficiency benefit sharing scheme |
| NER | National Electricity Rules |
| NPV | net present value |
| opex | operating expenditure |
| PTRM | post-tax revenue model |
| RAB | regulatory asset base |
| RFM | roll forward model |
| SCS | standard control services |