Final Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 1
Annual revenue requirement

April 2025

AUSTRALIAN ENERGY REGULATOR

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1	30 April 2025	14

List of attachments

This attachment forms part of the Australian Energy Regulator’s (AER's) final decision on the distribution determination that will apply to Ergon Energy for the 2025–30 period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all attachments. Where an attachment has not been prepared, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Contents

1 Annual revenue requirement

This attachment sets out our final 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 (period). Specifically, it sets out our final 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 final 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 Final decision

We determine a total ARR of $8,578.8 million ($ nominal, unsmoothed) for Ergon Energy over the 2025–30 period for the main SCS. This amount reflects our final decision on the various building block costs and represents a reduction of $92.1 million (1.1%) to Ergon Energy's proposed total ARR of $8,760.9 million.

This reduction is largely driven by our final decision to reduce Ergon Energy's forecast operating expenditure (opex) by $259.3 million. This is due to our decision to adopt Ergon Energy's actual 2022–23 opex as the base year, updates made to Ergon Energy's maximum demand forecasts, and not including an amount for the smart meter data step change.

The reduction in total ARR is also driven by our final decision to apply the Efficiency Benefit Sharing Scheme (EBSS), which Ergon Energy did not apply in its revised proposal. This has reduced the revenue adjustments building block by $36.7 million.[2]

We determine the annual expected revenue (smoothed) and X factor for each regulatory year for the 2025–30 period by smoothing the ARR. Our final decision is to approve total expected revenues of $8,579.5 million ($ nominal, smoothed) for Ergon Energy for the 2025−30 period. Our approved X factors are –4.09% for 2026–27, –4.04% for 2027–28, −6.50% in 2028–29 and –3.57% in 2029–30.[3]

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

2 We have applied a larger negative revenue adjustment in our final decision compared to Ergon Energy's revised proposal because of our final decision to apply the EBSS, which Ergon Energy proposed to not apply in its revised proposal.

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

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

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

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Return on capital	960.2	1,005.7	1,056.0	1,113.9	1,174.6	5,310.3
Regulatory depreciation[a]	209.0	236.4	267.9	296.1	311.7	1,321.2
Operating expenditure[b]	474.2	489.8	505.2	521.3	538.5	2,529.0
Revenue adjustments[c]	–147.4	–163.3	–173.1	–127.4	–45.0	–656.2
Cost of corporate income tax	6.7	12.9	15.5	18.4	20.9	74.4
Annual revenue requirement (unsmoothed)	1,502.7	1,581.4	1,671.5	1,822.4	2,000.7	8,578.8
Annual expected revenue (smoothed)	**1,481.3**	**1,583.9**	**1,692.7**	**1,851.7**	**1,969.9**	**8,579.5**
X factor[d, e]	n/a	–4.09%	–4.04%	–6.50%	–3.57%	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 3.6% higher than the approved total annual revenue for 2024–25 in real terms, or 6.4% higher in nominal terms.

Our final decision also allows Ergon Energy to recover $170.7 million ($ nominal, smoothed) from its customers for the 2025–30 period for metering SCS. 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 final decision.

1.2 Ergon Energy's revised proposal

Ergon Energy's revised proposal included a total expected revenue (smoothed) of $8,691.7 million ($ nominal) for the 2025–30 period.

Table 1.2 sets out Ergon Energy's revised proposal building block costs, the ARR, annual expected revenue and X factor for each year of the 2025–30 period.

Table 1.2 Ergon Energy's revised proposal 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	932.2	983.0	1,039.8	1,104.8	1,173.9	5,233.7
Regulatory depreciation[a]	190.3	216.9	247.7	275.4	290.8	1,221.0
Operating expenditure[b]	542.7	548.6	557.7	565.2	574.2	2,788.4
Revenue adjustments[c]	–117.1	–120.4	–123.8	–127.3	–130.9	–619.5
Net tax allowance	4.1	7.5	9.7	14.2	11.8	47.2
Annual revenue requirement (unsmoothed)	1,552.1	1,635.6	1,731.2	1,832.3	1,919.8	8,670.9
Annual expected revenue (smoothed)	**1,496.7**	**1,599.9**	**1,712.9**	**1,877.9**	**2,004.3**	**8,691.7**
X factor[d]	n/a	–3.93%	–4.10%	–6.59%	–3.77%	n/a

Source: Ergon Energy, *8.03–Model SCS AER PTRM,* November 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

We did not change the building block approach we use to determine the expected revenue from our draft decision. Attachment 1 (section 1.3) of our draft decision details that approach.[4]

1.4 Reasons for final decision

For this final decision, we determine a total ARR of $8,578.8 million ($ nominal, unsmoothed) for Ergon Energy over the 2025–30 period. This is a reduction of $92.1 million (1.1%) to Ergon Energy's revised proposal total ARR of $8,670.9 million for this period. This reflects the impact of our final decision on the various building block costs.

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

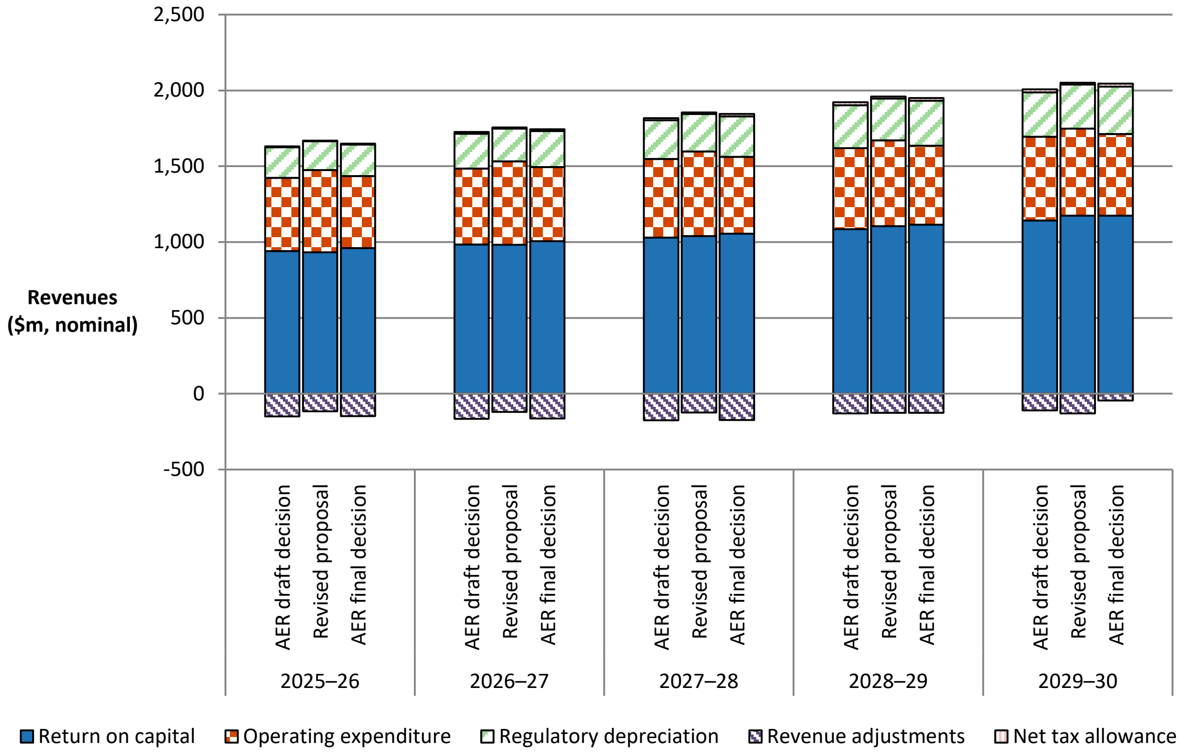
- an increase in the return on capital of $76.6 million (1.5%). This is driven by a higher rate of return over the 2025–30 period compared to Ergon Energy's revised proposal, which is partly offset by our reductions to forecast capex (capital expenditure), a lower opening RAB and a lower expected inflation rate (see section 2.2 of the Overview to this final decision, Attachment 2 and Attachment 5).

4 AER, *Draft Decision: Ergon Energy distribution determination 2025–30 – Attachment 1 – Annual revenue requirement*, September 2024, pp. 3–6.

- an increase in the regulatory depreciation of $100.2 million (8.2%) (Attachment 4). This is driven by a lower expected inflation rate in our final decision than at the time of Ergon Energy's revised proposal, which reduces the RAB indexation component of regulatory depreciation. This is partially offset by lower straight-line depreciation from a lower opening RAB and reductions to forecast capex.
- a reduction in the opex forecast of $259.3 million (9.3%) (Attachment 6). This is due to our use of Ergon Energy's actual 2022–23 opex as the base year, updates to Ergon Energy's maximum demand forecasts, and not including an amount for the smart meter data step change.
- an increase in the cost of corporate income tax of $27.2 million (57.6%) (Attachment 7). This is driven primarily by a higher return on equity and higher regulatory depreciation than Ergon Energy's revised proposal.
- a reduction in the revenue adjustments of $36.7 million (5.9%) (see section 3 of the Overview to this final decision and Attachment 8). This is driven by our decision to apply the EBSS, which Ergon Energy proposed to not apply in its revised proposal.

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

Figure 1.1 AER's draft and final decision and Ergon Energy's revised proposal ARR ($ million, nominal)



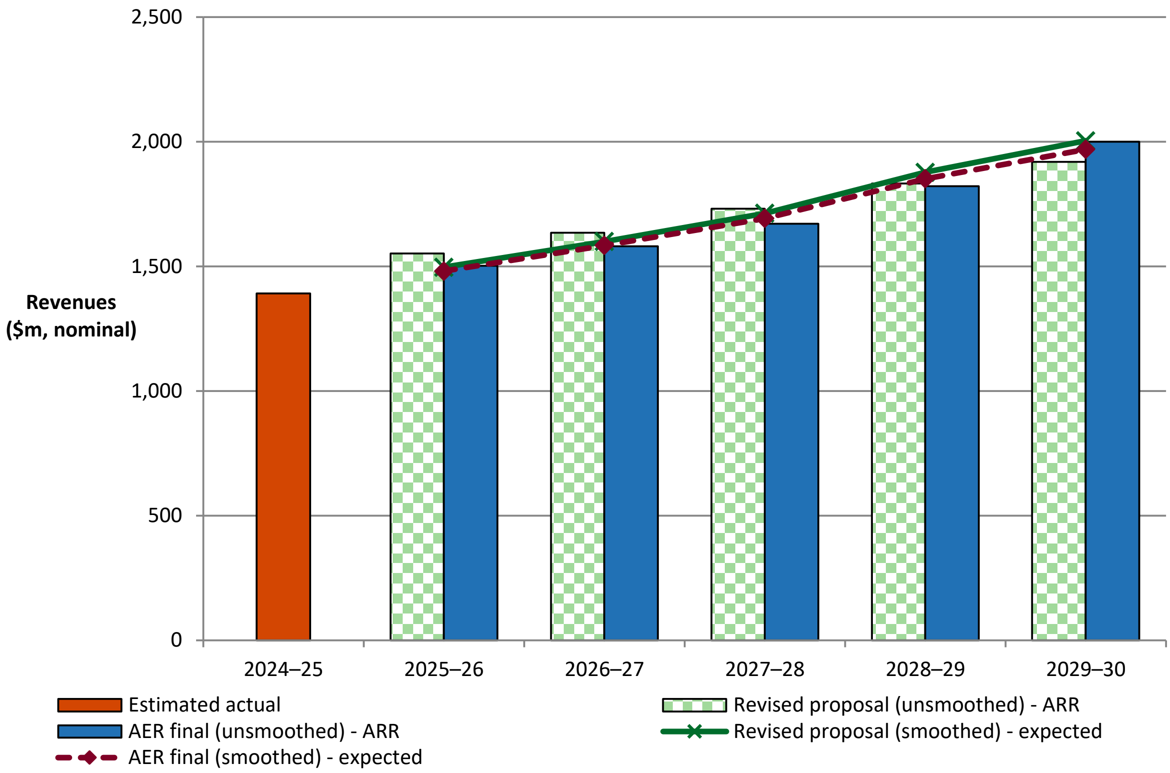
Source: AER analysis; Ergon Energy, *8.03–Model–SCS PTRM*, November 2024.
Note: Revenue adjustments include EBSS, CESS and DMIAM amounts. Opex includes debt raising costs.

1.4.1 X factor and annual expected revenue

For this final decision, we determine X factors for Ergon Energy of –4.09% for 2026–27, −4.04% for 2027–28, –6.50% in 2028–29 and –3.57% in 2029–30.[5] The net present value (NPV) of the ARRs is $7,136.5 million ($ 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 $1,481.3 million in 2025–26 increasing to $1,969.9 million in 2029–30 ($ nominal). The resulting total expected revenue is $8,579.5 million for the 2025–30 period.

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

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



Source: AER analysis; Ergon Energy, *8.03–Model–SCS PTRM*, November 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 $1,481.3 million ($ nominal). This is $21.4 million lower than the ARR for that first year. We then apply an expected inflation rate of 2.72% per annum and a profile of X factors to determine the expected revenue in subsequent years.[6] We consider that our profile of X factors results in an

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

[6] NER, cl. 6.5.9(a).

expected revenue in the last year of the 2025–30 period that is as close as reasonably possible to the ARR for that year.[7]

Our draft decision revenue smoothing profile provided a final year revenue difference of 3.0%. However, Ergon Energy's revised proposal profile resulted in a final year revenue difference of 4.4%, which is outside our preferred ±3% target range. We did not receive any stakeholder submissions on revenue smoothing.

The Queensland Government's Solar Bonus Scheme is due to expire on 1 July 2028.[8] In our previous decisions, we have accounted for such known impacts that are material (and sit outside of our building block determination) in our total revenue smoothing approach to provide an overall smoother revenue outcome.[9] Consistent with Ergon Energy's initial proposal, our draft decision revenue smoothing approach did not account for the expiry of this scheme. In our draft decision, we noted that Ergon Energy might consider accounting for the scheme's expiry in its revised proposal and that, in our draft decision for SA Power Networks, we had 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.[10]

Ergon Energy's revised proposal included a similar adjustment to account for jurisdictional scheme revenue in its approach to revenue smoothing. Ergon Energy forecast that the expiry of the Solar Bonus Scheme is expected to result in the removal of approximately $48 million ($ nominal) in annual revenue in 2028–29.[11] For its revised proposal revenue smoothing, Ergon Energy also considered the impact of the introduction of the Electrical Safety Office (ESO) jurisdictional scheme, which will begin in 2025–26. For the ESO scheme, Ergon Energy forecast relatively consistent annual revenues across the 2025–30 period of about $8 million.

Our final decision revenue smoothing approach also accounted for the forecast jurisdictional scheme revenue in the 2025–30 period, consistent with Ergon Energy's revised proposal.[12] We have accounted for the impact of the jurisdictional scheme revenue by applying a larger increase in the smoothed revenue for year 4 (2028–29). This increase will be offset by the

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7 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 –1.5%.

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

9 AER, *Final decision: Energex determination 2015–20 – Attachment 1 – Annual revenue requirement*, October 2015, pp. 11–14; AER, *Final decision: Transgrid determination 2023–28 – Attachment 1 – Maximum allowed revenue*, April 2023, p. 12.

10 AER, *Draft decision: SA Power Networks determination 2025–2030 – Attachment 1 – Annual revenue requirement*, September 2024, p. 9.

11 This amount reflects the difference from the forecast 2027–28 revenue amount for this scheme. The average revenue amount forecast for this scheme over the first 3 years of 2025–30 period is $52 million. Ergon Energy, *Response to information request 088,* March 2025.

12 Jurisdictional scheme revenue we accounted for in our final decision consisted of: the Solar Bonus Scheme, Australian Energy Market Commission levy, and the new Queensland ESO Levy starting in 2025–26. We did not include Ergon Energy's unders/overs adjustments in years 2024–25 and 2025–26 because these adjustment amounts are uncertain for the remaining years of the 2025–30 period.

expected reduction in revenue at the annual pricing stage to account for the expiry of the Solar Bonus Scheme.

Our final decision revenue smoothing results in a final year difference of –1.5%. On balance, we consider that our profile of X factors for this final decision results in an expected revenue in the last year of the 2025–30 period that is as close as reasonably possible to the ARR for that year.[13] We are satisfied that our revenue smoothing approach balances the need of promoting smoother price changes for customers across the 2025–30 period and minimising a large revenue variance at the commencement of the subsequent regulatory control period (2030–35).

Our final decision results in an average increase of 7.2% per annum ($ nominal) in the expected revenue over the 2025–30 period.[14] This consists of initial increase of 6.4% per annum in 2025–26, followed by average annual increases of 7.4% during the remainder four years of the 2025–30 period.[15]

Our final decision also results in an increase of $2,569.0 million (42.7%) in nominal dollar terms to Ergon Energy's total ARR relative to that in the 2020–25 period.[16] We estimate that:

- approximately 57% of the increase is due to factors outside the control of Ergon Energy. This includes higher actual inflation rates for the 2020–25 period, which increase the opening RAB as at 1 July 2025. It also includes a higher forecast rate of return (see section 2.2 of the Overview). Together, these changes in market variables result in a much higher return on capital building block compared to the current period.
- the other 43% of the increase is driven by controllable factors including higher forecast opex (Attachment 6) and higher forecast capex (Attachment 5) determined for the 2025−30 period compared to the amounts approved in the 2020–25 distribution determination.

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

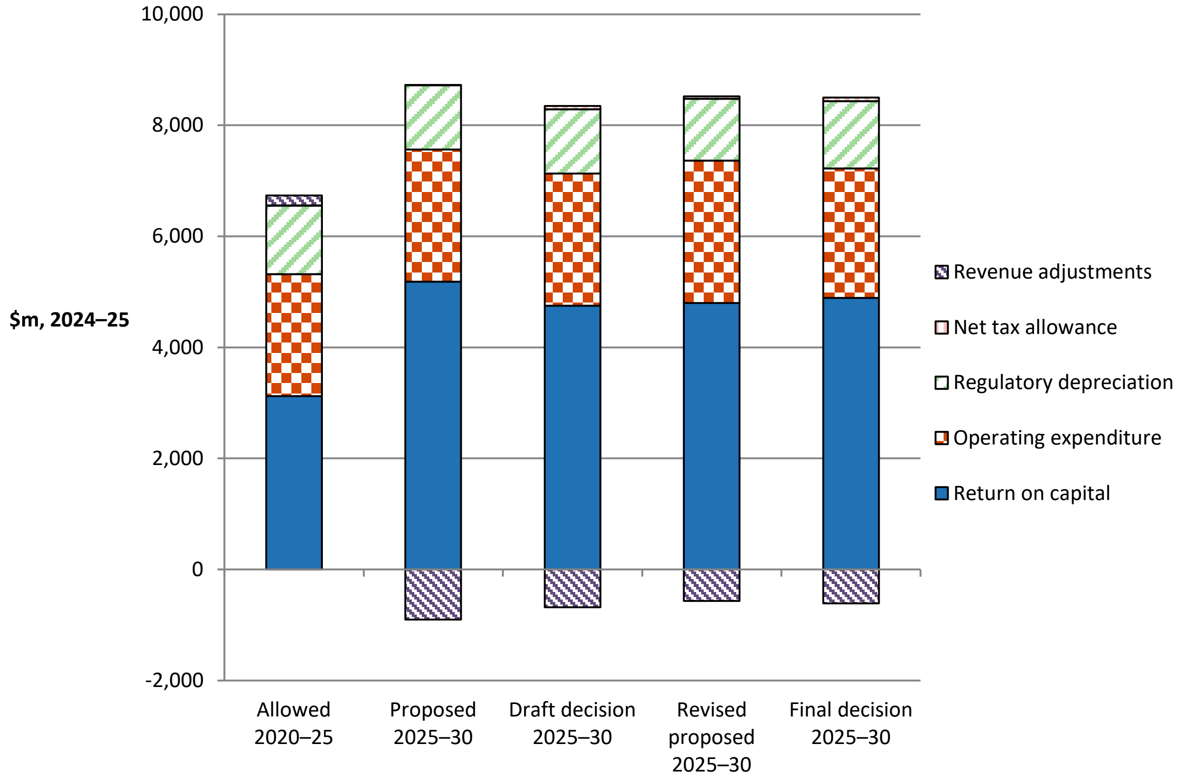
13 NER, cl. 6.5.9(b)(2).

14 In real 2024–25 dollar terms, our approved expected revenue for Ergon Energy results in an average increase of 4.4% per annum over the 2025–30 period.

15 In real 2024–25 dollar terms, this consists of initial increase of 3.6% in 2025–26, followed by annual average increases of 4.5% during the remainder of the 2025–30 period.

16 In real 2024–25 dollar terms, our final decision results in an increase of $1,152.8 million (17.1%) 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

Our final decision is not to apply a shared asset revenue adjustment to Ergon Energy's total expected revenue for the 2025–30 period.

In our draft decision, we did not apply a shared asset revenue adjustment to Ergon Energy's revenues because we estimated that the unregulated revenues were less than 1% of its expected revenues in each year of the 2025–30 period. Therefore, the materiality threshold was not met in any year of the 2025–30 period.[17] Using the same assessment approach as we used for the draft decision, we consider that this materiality threshold is also not met in any year of the 2025–30 period for this final decision, and therefore we do not apply a shared asset revenue adjustment.

1.4.3 Indicative average distribution price impact

Our final 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 final 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

17 AER, *Draft Decision: Ergon Energy distribution determination 2025–30 – Attachment 1 – Annual revenue requirement*, September 2024, pp. 10–11.

changes in the consumption of electricity will affect the prices ultimately charged to consumers.

For these reasons, 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 final 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 core SCS (that is, the core electricity distribution charges),[18] 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 final decision. We 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.

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 final decision compared to Ergon Energy's revised proposal revenue requirement. The indicative price path is estimated using the approved expected revenue and dividing it by forecast energy consumption for each year of the 2025–30 period.

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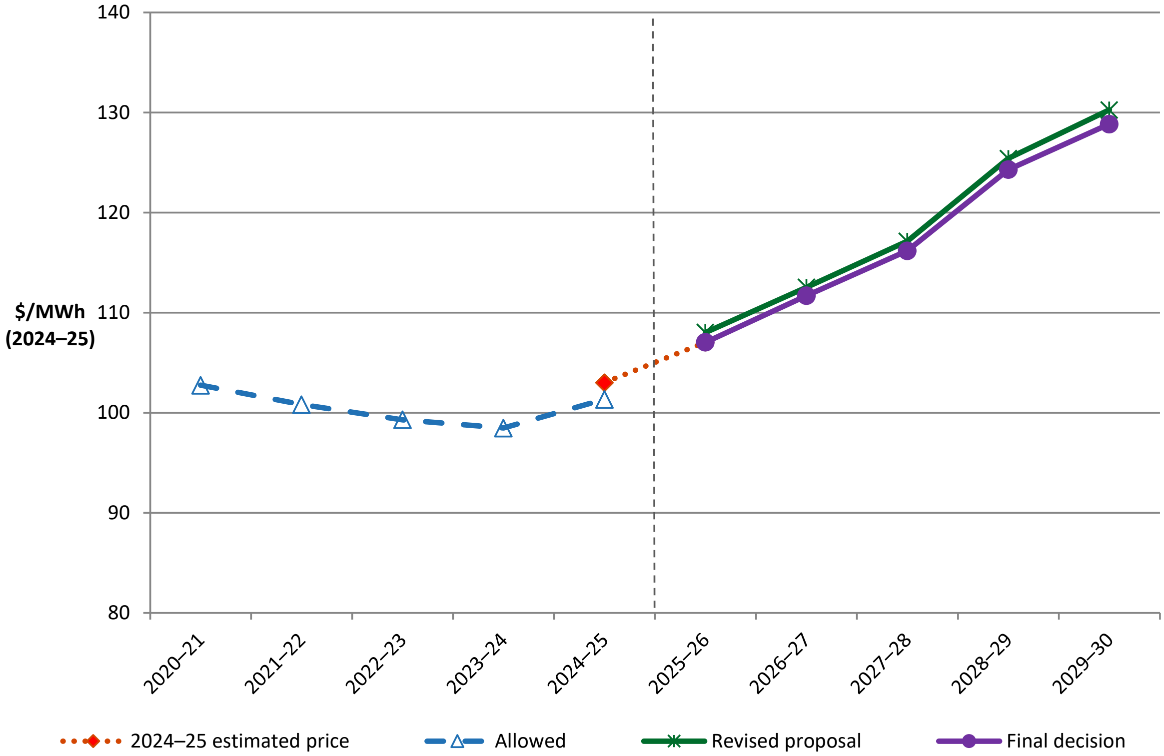
[18] Our final decision on metering SCS is discussed in Attachment 20. In our draft decision, we accepted Ergon Energy's proposal to reclassify its legacy metering services from alternative control services to SCS.

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



Source: AER analysis.

We estimate that our final decision on Ergon Energy's annual expected revenue will result in an increase to average distribution charges by about 4.6% per annum over the 2025–30 period in real 2024–25 dollar terms.[19] Ergon Energy's revised proposal provided for an average real increase of approximately 4.8% per annum over the 2025–30 period for its distribution charges.[20] 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 1.3 displays in nominal terms the comparison of the revenue and price impacts of Ergon Energy's revised proposal and our final decision.

[19] In nominal terms, we estimate average distribution charges to increase by 7.4% per annum. This amount reflects an expected inflation rate of 2.72% per annum as determined in this final decision.

[20] In nominal terms, Ergon Energy's revised proposal would increase distribution charges by 7.8% per annum. This amount reflects an expected inflation rate of 2.85% per annum as proposed by Ergon Energy in its revised proposal.

Table 1.3 Comparison of revenue and price impact of Ergon Energy's revised proposal and the AER's final decision ($ nominal)

	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30
AER final decision						
Revenue ($ million)	1,391.9	1,481.3	1,583.9	1,692.7	1,851.7	1,969.9
Price path ($/MWh)[a]	103.0	110.0	117.9	125.9	138.4	147.4
Revenue (change %)	-	6.4%	6.9%	6.9%	9.4%	6.4%
Price path (change %)	-	6.7%	7.2%	6.9%	9.9%	6.5%
Ergon Energy revised proposal						
Revenue ($ million)	1,391.9	1,496.7	1,599.9	1,712.9	1,877.9	2,004.3
Price path ($/MWh)[a]	103.0	111.1	119.0	127.4	140.3	149.9
Revenue (change %)	-	7.5%	6.9%	7.1%	9.6%	6.7%
Price path (change %)	-	7.9%	7.1%	7.1%	10.1%	6.8%

Source: AER analysis; Ergon Energy, *8.03–Model SCS AER PTRM*, November 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 final decision on electricity bills

Our bill impact calculations for Ergon Energy adopt the network charges in our final 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.[21]

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 final decision primarily relates to the distribution charges for Ergon Energy's SCS, which represent on average approximately 27% of residential customers' annual electricity bills and 26% of small business customers' annual electricity bills in Ergon Energy's network area.[22]

We estimate the expected bill impact by varying the distributions charges in accordance with our final decision in this attachment, while holding all other components—including the metering component—constant.[23] This approach isolates the effect of our final decision on

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

22 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.

23 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.

the core distribution charges only for Ergon Energy. However, this does not imply that other components will remain unchanged across the period.[24]

Based on this approach, we expect that our final decision on the distribution component will increase the average annual residential electricity bill in 2029–30 by about $242 ($ nominal) or 11.7% from the 2024–25 total bill level.

Similarly, we expect that our final 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 $486 ($ nominal) or 11.4% from the 2024–25 total bill level.

Our estimated bill impact is based on the typical annual electricity usage of 4,600 kWh for residential customers and 10,000 kWh for small business customers in Energex's network.[25] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other factors, such as metering, and wholesale and retail costs, which affect electricity bills.

Table 1.4 shows the estimated impact of our final decision and Ergon Energy's revised proposal on the average annual electricity bills for residential and small business customers in its network over the 2025–30 period.

[24] 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.

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

Table 1.4 Estimated impact of Ergon Energy's revised proposal and AER's final decision on annual electricity bills for the 2025–30 period ($ nominal)

	2024–25[a]	2025–26	2026–27	2027–28	2028–29	2029–30
AER final decision						
Residential annual electricity bill	2,066	2,107	2,151	2,194	2,265	2,307
Annual change[b]	-	41 (2%)	44 (2.1%)	43 (2%)	71 (3.3%)	42 (1.8%)
Small business annual electricity bill	4,261	4,344	4,431	4,519	4,663	4,747
Annual change[b]	-	83 (1.9%)	88 (2%)	88 (2%)	144 (3.2%)	84 (1.8%)
Ergon Energy revised proposal						
Residential annual electricity bill	2,066	2,117	2,152	2,187	2,248	2,281
Annual change[b]	-	52 (2.5%)	35 (1.6%)	35 (1.6%)	61 (2.8%)	33 (1.5%)
Small business annual electricity bill	4,261	4,364	4,435	4,505	4,627	4,694
Annual change[b]	-	104 (2.4%)	70 (1.6%)	70 (1.6%)	122 (2.7%)	66 (1.4%)

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. 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
ESO	Electrical Safety Office
NER	National Electricity Rules
NPV	net present value
opex	operating expenditure
period	regulatory control period
PTRM	post-tax revenue model
RAB	regulatory asset base
SCS	standard control service