Draft Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 3
Rate of return

September 2024

AUSTRALIAN ENERGY REGULATOR

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3 Rate of return

The return each network business is to receive on its regulatory asset base (RAB), known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the network business with a return on capital to service the interest on its loans and give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

We also make an estimate of expected inflation over the next 5 years. Alongside our nominal estimate of the rate of return, these determine the effective real return that will be provided to investors over time.

3.1 Draft decision

We are required by the National Electricity Law (NEL) and National Electricity Rules (NER) to apply the Rate of Return Instrument to estimate an allowed rate of return.[1] For this draft decision, we have applied the 2022 Rate of Return Instrument (2022 Instrument).

The 2022 Instrument specifies how we will estimate the return on debt, the return on equity, and the overall rate of return. In this draft decision, we have applied the 2022 Instrument to Ergon Energy's proposal for the 2025–30 regulatory control period (2025–30 period) and have estimated a placeholder allowed rate of return of 6.04% (nominal vanilla). This will be updated for our final decision on the averaging periods. Ergon Energy's proposal also applied the 2022 Instrument.[2]

Our calculated rate of return in Table 3.1 would apply to the first year of the 2025–30 period. A different rate of return may apply for the remaining regulatory years of the 2025–30 period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 Instrument, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods. We will update the estimate of the rate of return and expected inflation in our final decision.

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1 AER, *Rate of Return Instrument 2022*. The *2022 Rate of Return Instrument* was amended in March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

2 Ergon Energy, *2025-30 Regulatory Proposal*, 31 Jan 2024, p. 164.

Table 3.1 Draft decision on Ergon Energy's rate of return (nominal)

	AER's previous decision (2020-25)	Ergon Energy's proposal (2025–30)	AER's draft decision (2025–30)	Allowed return over the regulatory control period
Nominal risk-free rate	1.03%	4.22%	4.35%[a]	
Market risk premium	6.10%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	4.69%	7.94%	8.07%	Constant (%)
Return on debt (nominal pre-tax)	4.76%[c]	4.78%	4.68%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.73%[c]	6.04%	6.04%	Updated annually for return on debt
Expected inflation	2.27%	2.80%	2.85%	Constant (%)

Source: AER analysis; AER, *Final decision – Ergon Energy distribution determination 2020-25 – Attachment 3 – Rate of return*, 5 June 2020, p. 6; Ergon Energy, *2025-30 Regulatory Proposal*, 31 Jan 2024, pp. 163-165.

(a) Calculated using a placeholder averaging period of 20 business days ending 31 July 2024, which will be updated for the final decision.

(b) Calculated using a placeholder averaging period of 20 business days ending 31 July 2024, which will be updated for the final decision.

(c) Applied to the first year of the 2020–25 regulatory control period.

Our draft decision is also to accept Ergon Energy's proposed risk-free rate averaging period[3] and debt averaging periods[4] because they comply with the conditions set out in the 2022 Instrument. We specify these periods in confidential Appendix A and they will be used to update the risk-free rate and return on debt in the final decision.

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[3] Ergon Energy, *Ergon – 8.05 – Rate of Return Averaging Periods – January 2024 – confidential*, 31 January 2024, p. 1.

[4] Ergon Energy, *Ergon – 8.05 – Rate of Return Averaging Periods – January 2024 – confidential*, 31 January 2024, p. 1.

3.2 Expected inflation

Our estimate of expected inflation included in this draft decision is 2.85% (detailed in Table 3.2) which will be updated for the final decision. It is an estimate based on the approach adopted in our final position paper from our 2020 Inflation Review[5] and in the Post-Tax Revenue Model (PTRM).

Ergon Energy's proposal adopted our current approach for estimating expected inflation.[6]

Table 3.2 Draft decision on Ergon Energy's forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	3.20%	3.03%	2.85%	2.68%	2.50%	2.85%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, August 2024, Table 3.1: Forecast Table. See https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#table-3-1

Our previous approach to estimate expected inflation used a 10-year average of the Reserve Bank of Australia's (RBA) headline rate forecasts for 1 and 2 years ahead, and the mid-point of the RBA's target band (2.5%) for years 3 to 10. The period of 10 years matches the term of the rate of return.

Our Inflation Review considered that this should be augmented by:[7]

- shortening the target inflation horizon from 10 years to a term that matches the regulatory period (typically 5 years)
- applying a linear glide-path from the RBA's forecasts of inflation for year 2 to the mid-point of the inflation target band (2.5%) in year 5.

We noted subsequently that the linear glide-path can apply from the RBA's latest inflation forecasts for year 1 if there is no RBA data for year 2.[8]

The key reasons for these changes are:[9]

- There was a mismatch between our estimate of expected inflation over a 10-year term, and our roll forward of the capital base, which is done over a 5-year term. We consider that shortening the inflation term to match the regulatory period, although creating a mismatch with the term of the rate of return, is the more critical mismatch to resolve. This is because of the sustained decline in the required rate of return and the increased difference between 5- and 10-year inflation expectations due to short-term fluctuations in inflation expectations.

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5 AER, *Final position – Regulatory treatment of inflation*, December 2020.

6 Ergon Energy, *2025-30 Regulatory Proposal*, 31 Jan 2024, p. 165.

7 AER, *Final position – Regulatory treatment of inflation*, December 2020, p. 6.

8 AER, *Explanatory statement proposed amendments – Electricity transmission and distribution network service providers – Post-tax revenue models (version 5)*, December 2020, p. 11.

9 AER, *Final position – Regulatory treatment of inflation*, December 2020, p. 6.

- Applying a glide-path acknowledges that it is likely to take longer than previously for inflation to revert to the mid-point of the RBA's target band following periods of sustained low or high inflation.

We considered that these changes will provide service providers with a reasonable opportunity to recover their efficient costs more accurately in an increasingly changing market to better serve consumers with the energy services they want in the long term. Broadly, this was because we take out what we expect to put back into the capital base through our regulatory models.

3.3 Imputation credits

Our draft decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 Instrument.[10] Ergon Energy's proposal adopted the same value.[11]

3.4 Capital raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity.

We include debt raising costs in the operating expenditure (opex) forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt.

On the other hand, we include equity raising costs in the capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Our draft decision forecasts for debt and equity raising costs are included in the PTRM. In this section, we set out our assessment approach and the reasons for those forecasts.

3.4.1 Equity raising costs

Equity raising costs are transaction costs incurred when a service provider raises new equity. We provide an allowance to recover an efficient amount of equity raising costs.

We apply an established benchmark approach for estimating equity raising costs. This approach estimates the costs of two means by which a service provider could raise equity—dividend reinvestment plans and seasoned equity offerings. It considers where a service provider's capex forecast is large enough to require an external equity injection to maintain the benchmark gearing of 60%.[12]

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10 AER, *Rate of Return Instrument 2022,* Clause 27. The *2022 Rate of Return Instrument* was amended in March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

11 Ergon Energy, *2025-30 Regulatory Proposal*, 31 January 2024, p. 164.

12 AER, *Final decision Amendment Electricity distribution network service providers, Post-tax revenue model handbook*, 30 January 2015, pp. 15, 16 and 33. The approach is discussed in AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

Our benchmark approach was initially based on 2007 advice from Allen Consulting Group (ACG).[13] We amended this method in our 2009 decisions for the ACT, NSW and Tasmanian electricity service providers.[14] We further refined this approach in our 2012 Powerlink Queensland decision.[15]

Our benchmark approach is implemented in the PTRM to estimate equity raising costs. Other elements of our decision act as inputs to this assessment, particularly the level of approved capex and the return on equity. It also requires an estimate of the dividend distribution rate (sometimes called the 'payout ratio') as an input into calculating equity raising costs. The dividend distribution rate is also estimated when we estimate the value of imputation credits. We consider that a consistent dividend distribution rate should be used when estimating both the value of imputation credits and equity raising costs.

Ergon Energy has forecast zero equity raising costs in the PTRM.[16] We have updated our estimate for the 2025–30 period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

3.4.2 Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced, as well as the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. We provide an allowance in opex to recover an efficient amount of debt raising costs.

3.4.2.1 Current assessment approach

Our current approach to forecasting debt raising costs is based on the approach in a report from ACG, commissioned by the Australian Competition & Consumer Commission (ACCC) in 2004.[17] This approach compensates for the direct cost of raising debt.

It uses a 5-year window of bond data to reflect the market conditions at that time. Our estimates were updated in 2013, based on a report by PricewaterhouseCoopers (PwC) which used data over 2008–2013, and most recently in 2019 by Chairmont.[18]

The ACG method involves calculating the benchmark bond size and the number of bond issues required to rollover the benchmark debt share (60%) of the capital base. This approach looks at how many bonds a regulated service provider may need to issue to refinance its debt over a 10-year period. Our standard approach is to amortise the upfront costs that are incurred in raising the bonds using the service provider's nominal vanilla

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13 ACG, *Estimation of Powerlink's SEO transaction cost allowance – Memorandum*, 5 February 2007.

14 For example, see: AER, *Final decision, NSW distribution determination 2009–10 to 2013–14*, April 2009, Appendix N.

15 AER, *Final decision, Powerlink Queensland Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

16 Ergon Energy, *2025-30 Regulatory Proposal*, 31 January 2024, p. 164.

17 Allen Consulting Group, *Debt and Equity Raising Transaction Costs: Final Report*, December 2004.

18 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs, June 2013; Chairmont, Debt Raising Costs*, 30 June 2019.

weighted average cost of capital (WACC) over a 10-year amortisation period. This is then expressed in basis points per annum (bppa) as an input to the PTRM.

This rate is multiplied by the debt component of the service provider's projected capital base to determine the debt raising cost allowance in dollar terms. Our approach recognises that part of the debt raising transaction costs, such as credit rating costs and bond master program fees, can be spread across multiple bond issues, which lowers the benchmark allowance (as expressed in bppa) as the number of bond issues increases.

Since the debt component of the capital base, and the WACC, will vary from service provider to service provider, so too will our assessment of debt raising costs.

Since late 2019, we have been reviewing our approach to setting benchmark debt raising costs. We have considered using actual debt raising costs data obtained from relevant regulated businesses, but found a number of challenges to this approach. We do not think the benefits of further investigation outweigh the costs at this stage. Therefore, we propose to use our current approach for assessing benchmark debt raising costs—that is, using Bloomberg estimates for the 'arrangement fee' and Chairmont's 2019 estimates for the remaining debt raising costs.

3.4.2.2 Proposal

Ergon Energy has proposed debt raising costs of 8.35 bppa.[19]

3.4.2.3 Conclusion on debt raising costs

Our draft decision is to accept Ergon Energy's proposed debt raising costs of 8.35 bppa. In arriving at this decision, we have applied the approach from our 2020-25 final decision for SA Power Networks.[20] That is, we use updated Bloomberg data to inform the 'arrangement fee' component of debt raising costs and Chairmont's updated estimates for the remaining components.

We use this method because regulated businesses have previously raised concerns with Chairmont's 2019 update, with the key focus being on Chairmont's estimate of 'arrangement fee'.[21] After assessing submissions, we recognised that Bloomberg is likely to be the most suitable source of information for the 'arrangement fee' at this time because it is the only published source of data known to us and was previously used to estimate the 'arrangement fee'.

Therefore, we have updated the 'arrangement fee' using Bloomberg data and the selection criteria consistent with the PwC report. This leads to an annual total debt raising cost of 8.35 bppa.

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[19] Ergon Energy, *2025-30 Regulatory Proposal*, 31 January 2024, p. 164.

[20] AER, *Final Decision SA Power Networks Distribution Determinations 2020–2025 — Attachment 3 Rate of Return*, June 2020.

[21] SA Power Networks, *Revised Regulatory Proposal 2020–25: Attachment 3 Rate of Return*, 10 December 2019, pp. 20–21; CEG, *The cost of arranging debt issues*, November 2019, p. 3.

We note that we have accepted Ergon Energy's total opex proposal, including its proposed debt raising costs of 8.35 bppa, as set out in the opex attachment (Attachment 6). Hence, we have not substituted our updated debt raising cost amount in the total opex allowance.

A Confidential appendix (Averaging Period)

Shortened forms

Term	Definition
2022 Instrument	2022 Rate of Return Instrument
ACCC	Australian Competition and Consumer Commission
ACG	Allen Consulting Group
AER	Australian Energy Regulator
Bppa	Basis points per annum
Capex	Capital expenditure
MRP	Market risk premium
NEL	National Electricity Law
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post-tax revenue model
PwC	PricewaterhouseCoopers
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
WACC	Weighted average cost of capital