FINAL DECISION

United Energy
Distribution Determination
2021 to 2026

Attachment 3
Rate of return

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to United Energy for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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3 Rate of return

The return each 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 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 five years, which sits alongside our nominal estimate of the rate of return. Together these determine the effective real return that will be provided to investors over the upcoming regulatory control period.

3.1 Final decision

We are required by the National Electricity Law (NEL) to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[1]

The Victorian Government has moved the Victorian distributors from a calendar year regulatory control period to a financial year regulatory control period.[2] This entails a six month extension to the current regulatory control period (2016–20) through to June 2021, then a five year regulatory control period starting on 1 July 2021.[3] The 2018 Instrument will also need to be applied from 1 January 2021—that is, to the six month extension period as well as the following five financial years which form the 2021-26 regulatory control period.

However, the 2018 Instrument was developed on the basis of consecutive 12-month regulatory years, and does not contemplate or allow for an intervening six month

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1 NEL, Part 3, division 1B. AER, *Rate of return instrument*, December 2018, available at https://www.aer.gov.au/networks-pipelines/guidelinesschemes-models-reviews/rate-of-return-guideline-2018/final-decision.

2 *National Energy Legislation Amendment Act 2020* (Vic). Available at: https://www.legislation.vic.gov.au/as-made/acts/national-energy-legislation-amendment-act-2020

3 The six month extension period was also labelled as the 'mini-year' when we consulted on the modifications to the 2018 Rate of Return Instrument.

extension period when moving from calendar years to financial years. This is important for the calculation of the trailing average portfolio return on debt under the Instrument. The 2018 Instrument also did not contemplate the nomination of averaging periods for a six month extension period.

The Victorian Government has enacted the change to a financial year regulatory control period through the *National Energy Legislation Amendment Act 2020* (Vic). This also allows application of a modified 2018 Instrument to the six month extension period and to the following financial year regulatory control period.[4] Therefore, we apply modified 2018 Instruments to both periods.[5] [6]

The content of a modified 2018 Instrument is substantively the same as the 2018 Instrument with changes to nomenclature, the averaging period criteria (for debt and risk free rate) and formulae for calculation of the trailing average return on debt.[7] We have consulted with stakeholders on the substantive elements of these changes.[8]

Application of a modified 2018 Instrument in this final decision would estimate an allowed rate of return of 4.76 per cent (nominal vanilla) for the five year regulatory control period commencing 1 July 2021. We note United Energy's proposal and revised proposal also accepted the application of these modifications to the 2018 Instrument.[9]

Our calculated rate of return (in Table 3.1) will apply to the first year of the 2021–26 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with a modified 2018 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year.

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4 *National Energy Legislation Amendment Act 2020* (Vic).

5 *National Energy Legislation Amendment Act 2020* (Vic).

6 For the six month extension period instrument see: AER, *Modified rate of return instrument for the Victorian electricity distribution networks during the extension period of 1 January 2021 to 30 June 2021*, 27 October 2020; For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

7 See the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

8 AER, *Application of the 2018 Rate of Return Instrument to the Victorian Electricity Distribution Networks from 1 January 2021*, 21 August 2020.

9 United Energy, *Regulatory Proposal 2021–26, January 2020*, p. 171; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 51.

Table 3.1 Final decision on United Energy's rate of return (nominal)

	AER draft decision (2021–26)	United Energy's revised proposal (2021–26)	AER final decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	0.93%[a]	0.93%[a]	1.38%[c]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.59%	4.59%	5.04%	Constant (%)
Return on debt (nominal pre–tax)	4.65%[b]	4.65% [b]	4.57%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.62%	4.62%	4.76%	Updated annually for return on debt
Expected inflation	2.37%	2.37%	2.00%	Constant (%)

Source: AER analysis; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 55; and United Energy, *United Energy – Revised Regulatory Proposal - 2021–26 – MDO 10.02 – PTRM – March 2021.xls*, March 2021.

[a,b] Calculated using a placeholder averaging period.

[c,] Final decision risk free rate is calculated using the proposed and accepted averaging period of 2 January to 29 March 2021.

[d] Final decision return on debt is calculated using the proposed and accepted debt averaging period.

Our final decision is also to:

- Accept United Energy's proposed risk free rate averaging period[10] and debt averaging periods because they comply with conditions in a modified 2018 Instrument.[11] These were submitted with its initial regulatory proposal and we specify the debt averaging periods in confidential appendix A. We publish the dates of the risk-free rate averaging period after it has expired.[12]

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10 This is also known as the return on equity averaging period.

11 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).; see also AER, *Final decision, United Energy distribution determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, April 2021.

12 AER, *Rate of return instrument explanatory statement,* December 2018, p. 140.

- Apply a gamma of 0.585 as provided in the modified 2018 Instrument.[13] United Energy's proposal has adopted a value of 0.585 which is consistent with this.[14]

Due to the timing of the Victorian legislation and the averaging periods proposed by the Victorian distributors, a true-up in the 2021–26 period is required for revenue during the six month extension period (1 January 2021 to 30 June 2021).[15] We set out the final rate of return used for any true-up in section 3.4 of this final decision.[16]

We note four of the Victorian electricity distributors (all except Jemena) submitted a November 2020 Frontier report as part of their revised proposals.[17] The report stated that, under the 2018 Instrument and the Reserve Bank of Australia's (RBA) current monetary policy, the allowed return on equity was lower than previous AER allowances and those from international regulators. Frontier considered that this led to negative profit and did not support an investment grade credit rating.

We note Frontier's observations. However, we consider that our working paper series (which forms part of our *Pathway to the 2022 Rate of Return Instrument*) is a better forum for considering the issues in the Frontier report. This is because the 2018 Instrument is binding on us and we cannot depart from it in this decision. United Energy itself proposed to apply the 2018 Instrument in its revised proposal.[18]

3.2 Expected inflation

We estimate an expected inflation of 2.00 per cent (see Table 3.2 for calculations) based on the approach adopted in our final position paper from our 2020 inflation review.[19] United Energy supported the new approach to estimating expected inflation, and advocated that the AER adopt the new approach immediately.[20]

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13 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

14 United Energy, *Revised regulatory proposal 2021–26*, 3 December 2020, p. 55.

15 This is due to the application of placeholder averaging periods to the six month extension period instead of the nominated and accepted averaging periods, if we consider it necessary or expedient for making the variation decision.
For example, see:

16 The control mechanism chapter of our draft decision specifies how any adjustment amount will be included in regulated revenues. See AER, *Draft decision, United Energy Distribution Determination 2021 to 2026, Attachment 14 Control mechanisms*, September 2020.

17 Frontier, *The impact of artificially supressed [sic] government bond yields, Report for AusNet Services, CitiPower, Powercor and United Energy*, 23 November 2020.

18 United Energy, *Regulatory Proposal 2021–26, January 2020*, p. 171; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 51.

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

20 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 53.

Table 3.2 Final decision on United Energy's forecast inflation (per cent)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	1.50	1.75	2.00	2.25	2.50	2.00

Source: AER analysis; *RBA Statement on Monetary policy*, February 2021.

Our previous approach to estimate expected inflation used a 10 year average of the RBA's headline rate forecasts for 1 and 2 years ahead, and the mid-point of the RBA's target band—2.5 per cent—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:[21]

- Shortening the target inflation horizon from ten years to a term that matches the regulatory period (typically five 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 per cent) in year 5.

The key reasons for these changes are:[22]

- There was a mismatch between our estimate of expected inflation over a 10 year term, and our roll forward of the RAB, 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.
- 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 a reasonable opportunity to more accurately recover their efficient costs 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 RAB through our regulatory models.

3.3 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

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

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

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 final decision forecasts for debt and equity raising costs are included in Attachment 6 (opex) and Attachment 5 (capex) attachments, respectively. In this section, we set out our assessment approach and the reasons for those forecasts.

3.3.1 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 whether a service provider's capex forecast is large enough to require an external equity injection to maintain the benchmark gearing of 60 per cent.[23]

Our benchmark approach was initially based on 2007 advice from Allen Consulting Group (ACG).[24] We amended this method in our 2009 decisions for the ACT, NSW and Tasmanian electricity service providers.[25] We further refined this approach in our 2012 Powerlink decision.[26]

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 rate of 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.

We note United Energy has proposed to use our approach to estimate equity raising costs.[27] We have updated our estimate for this regulatory control period based on the

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23 AER, *Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook*, 29 January 2015, pp. 15, 16 & 33. The approach is discussed in AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

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

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

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

27 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 128; and United Energy, *United Energy – Revised regulatory proposal - 2021–26 – MDO 10.02 – PTRM – March 2021.xls*, March 2021.

benchmark approach using updated inputs. This results in equity raising costs of $0.22 million ($2020–21).

3.3.2 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.

Current assessment approach

Our current approach to forecasting debt raising costs is based on the approach in a report from the ACG, commissioned by the Australian Competition & Consumer Commission in 2004.[28] This approach compensates for the direct cost of raising debt.

It uses a five 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.[29]

The ACG method involves calculating the benchmark bond size, and the number of bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. 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 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 into the PTRM.

This rate is multiplied by the debt component of the service provider's projected RAB 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

Revised proposal

United Energy has proposed debt raising costs of 8.1 basis points per annum.[30]

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28 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013.

29 Chairmont, *Debt Raising Costs*, 29 June 2019.

30 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 122; and United Energy, *United Energy – Revised Regulatory Proposal - 2021–26 – MDO 10.02 – PTRM – March 2021.xls*, March 2021.

Conclusion on debt raising costs

Our final decision is to accept the method used in United Energy's proposal which uses an annual rate of 8.1 bppa because it is not materially different from our estimate.

In arriving at this decision, we apply the approach from our final decision for SA Power Networks.[31] 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 have previously received submissions on concerns with Chairmont's estimate of the arrangement fee.[32]

After assessing these 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'. In a separate regulatory process, Powerlink submitted a report by Incenta which supported the use of Bloomberg data for estimating the arrangement fee.[33]

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 8.1 bppa which is not materially different to the estimate proposed by United Energy of 8.0 bppa (the values appear the same due to rounding).

Review of debt raising costs approach

Since late 2019 we have been reviewing our approach to setting benchmark debt raising costs, informed by actual debt raising costs data obtained from relevant regulated businesses.

The initial response to our information request showed that each business has its own system for reporting cost categories with the number and naming of categories differing between businesses. As noted in our draft decision, this makes it difficult to aggregate costs across businesses in order to arrive at an accurate estimate.

We have considered whether to continue with further investigation of the industry data. This would entail significant further work and would require regulated businesses to work with each other as well as us to reconcile costs to mutually agreed categories. Audit assurance would also need to be considered to ensure that costs have been correctly reconciled and allocated.

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31 AER, *Final Decision SA Power Networks Distribution Determinations 2020 to 2025 Attachment 3 Rate of Return*, June 2020.

32 For example see: SA Power Networks, *2020–25 Revised Regulatory Proposal: Attachment 3 Rate of Return*, 10 December 2019, pp. 20–22; CEG, *The cost of arranging debt issues*, November 2019.

33 Incenta, *Benchmark debt and equity raising costs*, November 2020.

Further, we have had regard to the overall magnitude of the debt raising costs (that is, a small proportion of overall opex) and the level of imprecision in our current approach. Based on these considerations, we do not think the benefits of further investigation outweigh the costs

Therefore, we have used 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 True-up for six month extension period

The Order in Council (made under section 16VE of the *National Electricity (Victoria) Act 2005*) allows the application of placeholder averaging periods to the six month extension period instead of the nominated and accepted averaging periods, if we consider it necessary or expedient for making the variation decision.[34]

The Order also provides for making appropriate adjustments in the 2021–26 regulatory control period for the difference between applying the nominated and accepted averaging period, and applying the placeholder averaging period.[35]

We applied placeholder averaging periods in our final decision for the six month extension period of 1 January 2021 to 30 June 2021.[36] This was because of the unanticipated delay in the passing of the NELA Act, and to facilitate our pricing process – the nominated (and accepted) averaging periods would not have finished in time to allow practical estimation of the final rate of return (based on the accepted averaging periods).

We have calculated the rate of return for the extension period based on the nominated and accepted averaging periods, and in accordance with the modified six month instrument and the Order (see Table 3.3). We consider that the difference with the placeholder rate of return will be recovered through the C-factor as noted in our control mechanisms attachment which leads to a true-up amount of -$0.5 million ($2020–21).

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[34] Order in Council under section 16VE of the NEVA, October 2020, cl. 5(b).

[35] Order in Council made under section 16VE of the *National Electricity (Victoria) Act 2005*, Victoria Government Gazette No. S 549 Tuesday 27 October 2020, cl. 8.

[36] For example, see: AER, *Final decision United Energy six-month extension – variation decision*, October 2020, pp. 11–12.

Table 3.3 Final decision on six month extension rate of return (nominal)

	AER decision annualised (2020–21)	AER decision six months (1 Jan 2021–30 Jun 21)
Nominal risk free rate	0.9%[a]	
Market risk premium	6.1%	
Equity beta	0.6	
Return on equity (nominal post–tax)	4.56%	2.25%
Return on debt (nominal pre–tax)	4.74%[b]	2.34%
Gearing	60%	60%
Nominal vanilla WACC	4.66%	2.31%
Expected inflation	2.25%	1.12%

Source: AER analysis;

[a b] Calculated using final nominated and accepted averaging periods.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
ACG	Allen Consulting Group
bppa	basis points per annum
capex	capital expenditure
distributor	distribution network service provider
DNSP	distribution network service provider
NEL	National Electricity Law
NELA Act	National Energy Legislation Amendment Act 2020 (Vic)
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
WACC	weighted average cost of capital