DRAFT DECISION

United Energy
Distribution Determination
2021 to 2026

Attachment 3
Rate of return

September 2020

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: VIC2021-26@aer.gov.au

Note

This attachment forms part of the AER's draft 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 draft decision.

The draft 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

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme and demand management innovation allowance mechanism

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Attachment 13 – Classification of services

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Attachment A – Victorian f-factor incentive scheme

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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 10 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 time.

3.1 Draft 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 is intending to move 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 Victorian Government's policy intent was that the 2018 Instrument would apply from 1 January 2021—that is, to the six month extension period as well as the following five financial year regulatory control period.

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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 Victorian Government, *Letter re: Intention to change the timing of annual Victorian network price changes*, April 2019, available at https://www.aer.gov.au/system/files/VIC%20DELWP%20letter%20to%20AER%20re%20intention%20to%20change%20the%20timing%20of%20annual%20Victorian%20network%20price%20changes%20-%20April%202019_0.pdf.

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.

However, the 2018 Instrument was developed on the basis of consecutive 12-month regulatory years, and does not contemplate an intervening six month 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 intends to enact the change to a financial year regulatory control period through the National Energy Legislation Amendment (NELA) Bill. The intent of the NELA Bill is that we will apply a modified 2018 Instrument to the six month extension period and following financial year regulatory control period.[4] By the time of this draft decision, the Bill has not been passed. In a letter to the AER on 2 September 2020, the Minister reaffirmed the Victorian Government's commitment to change electricity and gas network regulatory control periods from a calendar to financial year basis.[5] We anticipate that we will be able to apply a modified 2018 Instrument in the final decision on this basis.[6]

Due to the timing of the Victorian legislation and the averaging periods proposed by the Victorian distributors, a true-up in the 2021–2026 period may be required for revenue during the six-month extension period (1 January 2021 to 30 June 2021). Subject to passing of the NELA Bill and any associated Orders in Council (OIC), the details of any true-up will be set out in our final decision.[7]

The content of a modified 2018 Instrument would be 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. We have consulted with stakeholders on the substantive elements of these changes.[8]

Subject to the passing of the NELA Bill and any associated OIC, application of a modified 2018 Instrument in this draft decision would estimate a placeholder allowed rate of return of 4.62 per cent (nominal vanilla) for the five year regulatory control period commencing 1 July 2021. This will be updated for our final decision on the averaging periods. We note United Energy's proposal also accepted the application of these modifications to the 2018 Instrument.[9]

Our calculated rate of return in Table 3.1 would apply to the first year of the 2021–26 regulatory control period. A different rate of return would apply for the remaining regulatory years of the period. This is because we would update the return on debt

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4 See: Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020.

5 Hon Lily D'Ambrosio MP, *Letter re: Reaffirming commitment to change the timing of Victorian network pricing*, 2 September 2020.

6 See: Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020.

7 The control mechanism chapter of this 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.

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 2021–2026*, January 2020, p. 171.

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.

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

	AER final decision (2016–20)	United Energy proposal (2021–26)	AER draft decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	2.94%	1.32%	0.93%[a]	
Market risk premium	6.5%	6.1%	6.1%	
Equity beta	0.7	0.6	0.6	
Return on equity (nominal post–tax)	7.49%	4.98%	4.59%	Constant (%)
Return on debt (nominal pre–tax)	5.62%	4.71%	4.65%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.37%	4.82%	4.62%	Updated annually for return on debt
Expected inflation	2.32%	2.4%	2.37%	Constant (%)

Source: AER analysis; United Energy, *Regulatory proposal 2021–2026*, January 2020.

[a b] Calculated using a placeholder averaging period.

We note that the draft decision return on equity is lower than the return on debt in Table 3.1. This is because our return on equity is based on the most recent averaging period and our return on debt is estimated using a 10 year trailing average. The trailing average approach entails 10 per cent of the return on debt being calculated from the most recent averaging period with 90 per cent from prior periods. This can lead to the return on debt being higher or lower than the return on equity if the prior returns on debt have been higher or lower than current rates. Over the past decade, interest rates have been declining so past values of the return on debt are higher than presently. The trailing average reflects the interest costs facing a network that spreads its debt issuance across time.

Subject to the passing of the NELA Bill and any associated OIC, our draft decision is to:

- Accept United Energy's proposed risk free rate averaging period[10] and debt averaging periods because they comply with conditions proposed for a modified

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

2018 Instrument.[11] 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.

- Apply a gamma of 0.585 as provided in the 2018 Instrument.[12] United Energy's proposal has adopted a value of 0.585 which is consistent with this.[13]

3.2 Expected inflation

Our estimate of expected inflation included in this draft decision is 2.37 per cent (detailed in Table 3.1). It is an estimate of the average annual rate of inflation expected over a ten year period.

Our current method is to estimate over a ten year term to align with the term of the rate of return. This estimate of expected inflation is calculated in accordance with the method set out in the post-tax revenue model (PTRM). The rules set out how we are to apply the PTRM and the inflation estimation method in the model in our electricity determinations.

3.2.1 United Energy's proposal

In January 2020, United Energy proposed to adopt our current approach for estimating expected inflation.[14]

However, United Energy noted that concerns were recently raised with us about the 'current PTRM method and potentially the inflation framework'. Based on our consideration of these concerns, United Energy noted that it may amend the method used to calculate expected inflation in its revised proposal.[15]

3.2.2 Our use of CPI

In submissions subsequent to United Energy submitting its proposal, AusNet Services[16] and Jemena Electricity Networks [17] requested that we use trimmed mean inflation (TMI) forecasts as the measure of inflation, rather than the usual consumer price index (CPI) forecasts when calculating our estimate of expected inflation.

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11 See AER, *Rate of return instrument*, December 2018, cll. 7–8, 23–25, 36; AER, *Draft decision, United Energy draft determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, September 2020.

12 See Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020

13 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 176; See AER, *Rate of return instrument*, December 2018; Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020.

14 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 172.

15 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 172.

16 AusNet Services, *AusNet Services response to information request #43*, June 2020.

17 Jemena, *Jemena Electricity Networks Vic Ltd – 2021–26 Electricity Distribution Price Review Intervening Period Proposal - Response to questions raised on 20 May 2020*, May 2020, p. 4.

In reaching our draft estimate of expected inflation, we have used CPI forecasts from the August 2020 Reserve Bank of Australia (RBA) Statement on Monetary Policy (SMP). We have used CPI forecasts as opposed to TMI forecasts as we consider CPI forecasts better reflect:

- Expected consumer cost inflation post 31 December 2020/
- The expected reduction in the purchasing power of money expected to be reflected in the yields on nominal bonds.
- In any event, the Reserve Bank's forecasts of CPI and TMI are identical for the relevant period.

We used TMI forecasts in making our June 2020 final decisions for SA Power Networks, Energex, Ergon Energy, Jemena Gas Networks and Directlink.[18] This was due to exceptional COVID-19 related volatility reflected in the May 2020 RBA SMP CPI forecasts over the course of the 2020 calendar year.[19]

We are currently undertaking a review into the treatment of inflation in our regulatory framework, including the method likely to result in the best estimates of expected inflation.[20] The final outcomes of this review are expected in December 2020. If we consider a different method for estimating expected inflation should be adopted, we intend to commence the consultation process under the National Electricity Rules (NER) for amending the PTRM. We expect to apply amendments to the PTRM (if any) in our final determination for United Energy in April 2021, unless a rule change proposal is required.

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 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.

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18 AER, *SA Power Networks Distribution Determination 2020 to 2025 — Attachment 3 Rate of return*, June 2020, p. 10.

19 The RBA noted in its May SMP that government policy decisions in response to the Covid-19 pandemic were expected to reduce CPI inflation by around 1.5% decrease in the June 2020 quarter, followed by a large rebound when the government policies. Reserve Bank of Australia, Statement on Monetary Policy, May 2020, p. 79.

20 See AER website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-treatment-of-inflation-2020

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.[21]

Our benchmark approach was initially based on 2007 advice from Allen Consulting Group (ACG).[22] We amended this method in our 2009 decisions for the ACT, NSW and Tasmanian electricity service providers.[23] We further refined this approach in our 2012 Powerlink decision.[24]

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.[25] We have updated our estimate for this regulatory control period based on the benchmark approach using updated inputs. This results in equity raising costs of $0.21million ($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

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21 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.

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

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

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

25 United Energy, *Regulatory Proposal 2021–26*, January 2020, p. 171, 173.

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.[26] 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.[27]

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.

Proposal

United Energy has proposed debt raising costs of 8.1 basis points per annum.[28] It noted our current review into debt raising costs may impact this draft decision and that it has responded to our request for actual debt raising costs.

United Energy also noted that it may incur some transitional hedging-related costs (from interest rate swaps) from moving to a financial year regulatory control period.[29] It noted that it has not estimated this cost but may propose this in its revised proposal if the efficient cost is material.

Conclusion on debt raising costs

Our draft 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.

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[26] PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013.

[27] Chairmont, *Debt Raising Costs*, 29 June 2019.

[28] United Energy, *Regulatory Proposal 2021–26*, January 2020, p. 172.

[29] United Energy, *Regulatory Proposal 2021–26*, January 2020, p. 173.

In arriving at this decision, we apply the approach from our final decision for SA Power Networks.[30] 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 of debt raising costs, with the key focus being Chairmont's estimate of 'arrangement fee'.[31] 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'.

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 bppa which is not materially different to the estimate proposed by United Energy of 8.1 bppa.

We note United Energy's discussion of transitional hedging costs which is shared by Citipower and Powercor.[32] We also note that Jemena proposed to recover an estimate of this cost in its proposal.[33] In contrast, AusNet Services did not propose this cost in its proposal.[34]

Based on the information available, it is not clear to us that these type of costs warrant compensation. We note that we have not yet been provided with evidence of incurrence or that the costs were efficient. United Energy did not provide any evidence in its proposal on these points.[35] Therefore, our draft decision is to provide no allowance for these costs.

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.

We have reviewed these actual cost data and found that cost category information was unclear across the industry. Specifically, each business has its own system for

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

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

32 CitiPower, *Regulator proposal 2021–26*, January 2020, p. 126; Powercor, *Regulatory proposal 2021–26*, January 2020, p. 145.

33 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal Attachment 06–05 Operating expenditure step changes Public*, 24 February 2020, p. 16.

34 AusNet Services, *Electricity Distribution Price Review 2022–26 Part III*, 31 January 2020.

35 We note that Jemena has withdrawn its proposal for these costs: Jemena, *Email Re: JEN - AER information request #IR046-Transitional Return on Debt Alignment Cost - 13 July 2020*, 20 July 2020. AusNet Services did not propose this cost category in its regulatory proposal, which suggests its costs in this area were not material.

reporting cost categories with the number and naming of categories differing between businesses.

This makes it difficult to aggregate costs across businesses in order to arrive at an accurate estimate. There is potential to double count costs where there are reported differently between businesses, or where there are complementary expenditures in different categories. Estimates for a particularly cost may be biased up or down depending on how businesses report costs. These challenges mean that at this point, we are unable to use industry data to estimate an accurate benchmark measure of debt raising costs.

We have considered whether to continue with further investigation of the industry data. This would entail significant further work. This includes requiring 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.

We have also had regard to the overall magnitude of this 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 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. We note that businesses and their consultant (CEG) have also adopted this approach.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
ACG	Allen Consulting Group
bppa	basis points per annum
capex	capital expenditure
CPI	consumer price index
distributor	distribution network service provider
NEL	National Electricity Law
NELA	National Energy Legislation Amendment (NELA) Bill
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
TMI	Trimmed mean inflation
WACC	weighted average cost of capital