



Transitional arrangements 1 January to 30 June 2021

**UE APP07 - Transition period 2021 -
Jan2020 - Public**

Regulatory proposal 2021–2026

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1 Introduction

The Victorian Government advised us on 30 October 2019 of its intention to make legislative changes to the *National Electricity (Victoria) Act 2005 (NEVA)*, amending the timing for the next Victorian distribution regulatory reset.¹

Although the changes to the NEVA are yet to take effect, we have been advised the changes will extend the current 2016–2020 regulatory period for six months and require us to submit a 'mini' regulatory proposal for the six month extension. We understand the changes to be:

- amending the NEVA to direct the Australian Energy Regulator (**AER**) to apply the 2018 Rate of Return Instrument (**RORI**) from 1 January 2021
- validate the AER's actions, retrospectively if required, regarding the process used to apply the RoRI and the process for determining the averaging periods
- give the AER discretion to make adjustments to the current and future distribution determination that are necessary or incidental to the date change.

The final changes to the NEVA are expected to pass through the Victorian Parliament in early 2020.

Following instruction from the Victorian Government, the AER contacted us on 6 November 2019 and provided further advice on how it wishes us to determine the building blocks that comprise the revenue requirement for the transition period.² The AER's advice was to apply a simple trended-forward methodology for establishing most building blocks and apply the RORI. Further, the AER proposed that:

- for operating expenditure, the 2020 allowance be trended forward by rate of change and then halved
- capital expenditure be based on the 2020 allowance and then halved
- the opening regulatory asset base (**RAB**) be based on actual capital expenditure where available, or the latest estimates where actuals are not available, for the current regulatory period using the standard 5-year roll forward model (**RFM**)
- depreciation of capital expenditure be based on the existing asset classes/lives/methods applied to the current regulatory period. For depreciation of existing assets, we are to use the depreciation model approved for the current regulatory period adjusted to reflect the half year
- no revenue adjustments be applied associated with the efficiency benefit sharing scheme (**EBSS**) or the capital efficiency sharing scheme (**CESS**) for the current regulatory period. These calculations will be considered as part of the 2021–2026 regulatory period
- corporate income tax be based on the approach used for the current regulatory period except for gamma, which is to be based on the RORI.

The AER also advised that for the transition period, the EBSS and service target performance incentive scheme (**STPIS**) would continue to apply but the CESS would not. They advised that STPIS incentive rates would remain the same as in the current regulatory period and STPIS targets would be re-calculated to only be based on performance in the first six months of the calendar year.

¹ UE ATT109 - MP - Victorian network price updates - Oct2019 - Public

² UE ATT090 - AER - Proposed interim measure - Nov2019 - Public

For determining our revenue requirement for the transition period, we have adopted all the requirements stipulated by the Victorian Government and the AER. They advised that STPIS incentive rates would remain the same as in the current regulatory period and STPIS targets for the transitional period will be based on average historical performance for the six months of each calendar year from 2010 to 2014.

Staff at the AER have also verbally advised us of their intention to:

- apply a similar approach to the above for metering alternative control services (**ACS**)
- set public lighting charges based on 2020 rates
- escalate the remaining 2020 ACS charges by consumer price index (**CPI**) and real labour escalation.

We have applied the proposed AER approach for setting ACS charges for the transition period.

2 Building blocks

2.1 Regulatory asset base

2.1.1 Roll forward of the RAB to 1 January 2021

The AER's RFM has been used to calculate the 1 January 2021 opening RAB. Refer to the attached model, UE MOD 10.08 - RFM 2016-20 - Jan2020 - Public.

Capital expenditure rolled into the RAB has been reduced by customer contributions and disposals. Net capital expenditure includes a half year's weighted average cost of capital (**WACC**).

Straight-line depreciation based on forecast capital expenditure has been deducted in accordance with the AER's 2016–2020 Final Determination (**Final Determination**).

The RAB has been adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism.

The estimated opening value of the RAB for standard control services as at 1 January 2021 and the approach taken is shown in table 2.1.

Table 2.1 Roll forward of the RAB from 1 January 2016 to 1 January 2021 (\$ million, nominal)

	Total
1 January 2016 opening RAB from previous determination	2,083
Add: true-up for 2015 capital expenditure	-11
Add: actual/estimated net capital expenditure for 2016–2020 (including half-year WACC)	816
Less: forecast straight-line depreciation for 2016–2020	-678
Add: adjustment for actual inflation for 2016–2020	180
1 January 2021 opening RAB	2,390

Source: United Energy

2.1.2 Roll forward of the RAB from 1 January to 30 June 2021

The RAB has been rolled forward over the transition period in accordance with the National Electricity Rules (**Rules**) using the AER's post-tax review model (**PTRM**). Refer to attached model, CP MOD 10.09 - PTRM 2021HY - Jan2020 - Public.

The forecast net capital expenditure (based on the 2020 regulatory allowance) for the roll forward of the RAB over the transition period has been reduced by the forecast customer contributions (based on the 2020 regulatory allowance).

The roll forward of the RAB over the transition period is shown in table 2.2.

Table 2.2 Roll forward of the RAB over the transition period (\$ million, nominal)

	1 January to 30 June 2021
Opening RAB	2,390
Add: forecast net capex (including half-year WACC)	87
Less: regulatory depreciation	-69
Add: inflation on opening RAB	29
30 June 2021 closing RAB	2,436

Source: United Energy

2.2 Regulatory depreciation

Straight-line depreciation has been calculated using year-by-year asset tracking from 2011 consistent with the approach taken in the in the Final Determination. Refer to attached model, CP MOD 10.10 - Depreciation 2021HY - Jan2020 - Public.

Standard asset lives are equal to standard lives in the Final Determination.

Our proposed standard asset lives are shown in table 2.3 .

Table 2.3 Standard and remaining asset lives (years)

Asset	Standard life
Sub-transmission	60
Distribution system assets	36
Supervisory control and data acquisition (SCADA)/network control	5
Non-network general assets—IT	5
Non-network general assets—other	5
Victorian Bushfires Royal Commission (VBRC)	5
Equity raising costs	42

Source: United Energy

Regulatory depreciation is calculated using straight-line depreciation less the inflation adjustment to the RAB. We have estimated the inflation rate in accordance with chapter 10 of the regulatory proposal.

Regulatory depreciation for transition period is shown in table 2.4.

Table 2.4 Regulatory depreciation (\$ million, nominal)

1 January to 30 June 2021	
Straight-line depreciation	69
Less: inflation adjustment	29
Regulatory depreciation	41

Source: United Energy

2.3 Rate of return

We have calculated the rate of return consistent with the RORI, modified in accordance with AER instructions to accommodate the Victorian Government's intent to extend the current regulatory period by six months³.

Our rate of return calculation is provided in model UE MOD 10.04 - Rate of return - Jan 2020 - Public.

Our annualised rate of return and the factors used to calculate the same are shown in table 2.5. For the purposes of the half-year PTRM, the annualised rate of return is converted to a half-year return.

Table 2.5 Annualised rate of return

1 January to 30 June 2021	
Nominal risk free rate (%)	1.32
Market risk premium (%)	6.10
Equity beta	0.6
Return on equity (%)	4.98
Return on debt (%)	4.82
Gearing (%)	60
Nominal rate of return (%)	4.89

Source: United Energy

2.3.1 Averaging periods

The RORI proposes an averaging risk-free rate period set for each year to determine the allowed return on debt and a single averaging risk-free rate period to determine the allowed return on equity.

We have proposed our averaging periods confidentially to the AER in accordance with the RORI and AER instructions.

³ UE ATT091 - AER - Rate of return - Sep2019 - Public

2.3.2 Return on debt

The RORI requires the return on debt to be calculated as a 10-year trailing average, updated annually. The AER have provided us with modified weightings to be used to accommodate the transition period.

We have calculated the 10-year trailing average annual return on debt using the estimated debt rate in the last 20 business days of July 2019 as the placeholder averaging period for the half-year debt rate.

2.3.3 Return on equity

Under the RORI, the return on equity must be calculated as the risk free rate plus a market risk premium of 6.1% multiplied by an equity beta of 0.6. The risk free rate must be calculated as the 10-year yield to maturity on Commonwealth Government Securities, measured over the agreed risk free rate averaging period.

We have calculated the return on equity using a placeholder risk free rate of 1.32% based on the averaging period of the last 20 business days in July 2019.

2.4 Expected inflation

The Rules require the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation. The current PTRM method is to calculate the geometric average based on the inflation forecasts for two years sourced from the latest available Reserve Bank of Australia's (RBA) Statement of monetary policy and the mid-point of the RBA's target inflation band for eight years.

Our estimate of expected inflation, for the purposes of a placeholder for the transition period, is 2.40% using the PTRM method, assuming an RBA inflation forecast of 2.0% for the first two years, and 2.5% for the remaining eight years. This annualised rate is converted to a half-year rate for the purposes of the half-year PTRM.

The energy networks recently raised concerns with the AER about the current PTRM expected inflation estimation method, and potentially the inflation framework. Based on the AER's consideration of these concerns, we may amend the method used to calculate expected inflation prior to the AER publishing its transition period determination in August 2020.

2.5 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

We have applied a placeholder debt raising cost of 8 basis points per annum for the transition period. It has been included in operating expenditure.

2.6 Equity raising costs

Equity raising costs are transaction costs incurred when a network raises new equity in order to fund capital investment.

The AER provides a benchmark allowance to recover an efficient amount of equity raising costs, when a network's capital expenditure forecast requires an equity injection to maintain the benchmark gearing of 60%.

Our calculation of equity raising costs is contained in the transition period PTRM. This calculation includes the latest AER parameters consistent with the RORI.

2.7 Other revenue adjustments

We have included half a year's demand management incentive allowance (DMIA) in the revenue building blocks as per advice we have received from the AER.

2.8 Estimated cost of corporate income tax

The Rules require that the estimated cost of corporate income tax must be for a benchmark efficient entity. The estimated costs of corporate income tax for the transition period have been calculated using the AER's half-year PTRM. The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the AER's RFM. The standard tax asset lives are consistent with the Australian Tax Office ruling Income tax: effective life of depreciating assets (applicable from 1 July 2019).⁴

We have applied a value of 0.585 for the value of imputation credits consistent with the RORI.

Estimated cost of corporate income tax is shown in table 2.6.

Table 2.6 Estimated cost of corporate income tax (\$ million, nominal)

1 January to 30 June 2021	
Estimated cost of corporate income tax	5.4

Source: United Energy

2.9 Revenue requirement

For the purposes of clause 6.4.3(a)(6) and clause 6.4.3(b)(6) of the Rules, there are no other revenue increments or decrements that have been carried forward into the transition period.

The previous sections set out our proposed building blocks. The building blocks are used to derive our proposed annual revenue requirement for standard control services which are shown in table 2.7.

Table 2.7 Revenue requirement (\$ million, nominal)

1 January to 30 June 2021	
Return on assets	58.1
Regulatory depreciation	40.8
Operating expenditure	82.8
Other revenue adjustments	0.2
Corporate income tax	5.4
Revenue requirement	187.3

Source: United Energy

2.10 Price controls

The total allowable revenue (TAR_t) is proposed to be set equal to:

- revenue requirement as calculated in the PTRM (AR_t), plus

⁴ TR 2019/5

- licence fees payable by the DNSP to the Victorian Essential Services Commission in the 2019/20 financial year ($L_{2019/20}$)
- revenue for f Factor revenue relating to 2018/19 performance year ($f_{2018/19}$)

The proposed control formulae are show below:

$$TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij} \quad TAR_t = AR_t + L_{2019/20} + f_{2018/19}$$

The standard control services side constraint formula is proposed to be:

$$\frac{\sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij}}{\sum_{i=1}^n \sum_{j=1}^m p_{t-1}^{ij} q_{t-1}^{ij}} \leq (1 + \Delta CPI_t) \times (1 + 2\%)$$

where

$$\Delta CPI_t = \frac{CPI_{July\ 2020}}{CPI_{July\ 2019}} - 1$$

No amounts for unders/overs accounts, STPIS, or cost pass-throughs are proposed to be incorporated into revenue in the transition period. The amounts which would have normally been applied in calendar year 2021 will be applied in financial year 2021/22.

2.11 Indicative charges and bill impact

For an indicative reduction on a distribution and metering bill, refer to table 2.8. Based on the proposed average revenue requirement for the transition period, the typical residential customer's annual distribution charge will decline in the order of 19% on 1 January 2021 and then rebound by a similar amount on 1 July 2021.

We consider volatility in distribution charges to be at odds with our customers' interests and doubt it would have been the intention of the Victorian Government in transitioning distribution charges to financial years. Going forward we intend to consult further with our customers and stakeholders on transition period charges with a view to minimising any future price volatility.

Table 2.8 Distribution and metering real bill reduction for typical customer (including metering charges), %

1 January to 30 June 2021	
Residential	19
Small commercial	21

Source: United Energy

Whilst these movements provide an early indication of our commitment to customers for the transition period, they are indicative only at this stage.

The actual prices that will be charged to customers for the transition period are dependent on:

- the revenue that the AER will determine for us for the transition period
- actual energy consumption:
 - if energy consumption falls below our forecast, average charges would increase more than indicated or
 - if energy consumption rises above our forecast, average charges would decline below the estimates indicated.

We note that the percentage changes outlined above represent only a portion of the total network use of system charge to customers. The network use of system charge also includes the cost of the services provided by the transmission network service provider and the recovery of an amount to satisfy obligations under the jurisdictional scheme requirements. These components are outside our control.

3 Alternative control services (ACS)

ACS are our customer requested services that are directly recovered from the customer requesting the service. They include network ancillary services, such as customer connections, as well as public lighting and metering.

For the transition period we have applied the verbal advice provided to us by AER staff. This includes:

- applying a similar approach to standard control services for metering ACS
- setting public lighting charges based on 2020 rates
- escalating the 2020 ancillary ACS charges by CPI and real labour escalation as per our independent expert, BIS Oxford Economics.

We have not altered the structure of existing charges or added or deleted any ACS charges for the transition period.

Table 3.1 Proposed fee-based metering ancillary services charges, 1 January to 30 June 2020 (\$ nominal)

Fee based service	\$
Meter equipment test	
Single phase	284.34
Single phase (each additional meter)	136.44
Multi-phase	283.99
Multi-phase (each additional meter)	136.44
Remote AMI services	
Remote meter configuration	67.81
Remote special meter reading	0.91
Remote re-energise	11.46
Remote de-energise	11.46

Source: United Energy

Table 3.2 Proposed network ancillary services charges, 1 January to 30 June 2020 (\$ nominal)

Fee based service	Business hours	After hours
Field officer visits—existing premises		
Re-energise (fuse insert)—(unit rate)	50.86	90.25
De-energise (fuse removal)—(unit rate)	50.86	N/A
Express move in re-energise (fuse insert)—(unit rate)	76.67	141.93
De-energise at point of attachment (pole/pit/premise)—(unit rate)	393.14	N/A
Temporary supplies (excluding inspection)—coincident disconnection where we are the Metering Coordinator		
Standard single phase (unit rate)	513.67	784.47
Multi-phase to 100A	513.46	784.26
Temporary supplies (excluding inspection)—where we are not the Metering Coordinator		
Single-phase servicing and energisation only (unit rate)	476.68	784.47
Multi-phase servicing and energisation only (unit rate)	476.68	784.47
New connection where we are the Metering Coordinator		
Single phase single element (unit rate)	513.67	784.47
Single phase two element (off peak) (unit rate)	513.67	784.47
Three phase direct connected (unit rate)	513.46	784.26
Routine new connections—three phase current transformer connected	Quoted	Quoted
New connection where we are not the Metering Coordinator		
Single phase single element (unit rate)	476.68	784.47
Single phase two element (off-peak) (unit rate)	476.68	784.47
Three phase direct connected (unit rate)	476.68	784.47
Routine new connections—three phase current transformer connected	Quoted	Quoted
Service vehicle visits (without inspection)		
Service truck—first 30 minutes (unit rate)	364.94	N/A

Service truck—2 hours (unit rate)	N/A	807.67
Each additional 15 minutes (unit rate)	75.46	104.65
Wasted service truck visit (unit rate)	316.54	807.67
Truck visit + 1x additional 15 minutes	440.41	912.32
Truck visit + 2x additional 15 minutes	515.88	1,017.00
Truck visit + 3x additional 15 minutes	591.33	1,121.66
Truck visit + 4x additional 15 minutes	666.79	1,226.29
Truck visit + 5x additional 15 minutes	742.26	1,330.94
Truck visit + 6x additional 15 minutes	817.70	1,435.62

Source: United Energy

Table 3.3 Proposed quoted labour type and rates, 1 January to 30 June 2020 (\$ nominal)

Labour type	Business hours	After hours
Field worker—one person	164.32	233.37
Field worker—one person plus vehicle	192.62	261.67
Administration	126.95	N/A
Senior engineer	241.99	N/A
Project planner	241.99	N/A
Field worker—one person	164.32	233.37

Source: United Energy

Table 3.4 Proposed OM&R* charges for public lighting per light type, 1 January to 30 June 2020 (\$ nominal)

Light type	Annual OM&R
Mercury vapour 80 watt	62.71
Sodium high pressure 150 watt	81.22
Sodium high pressure 250 watt	83.06
Fluorescent 2x20 watt	80.89
Fluorescent 3x20 watt	80.89
Mercury vapour 50 watt	92.81
Mercury vapour 125 watt	92.81
Mercury vapour 250 watt	75.58
Mercury vapour 400 watt	104.65
Mercury vapour 700 watt	104.65
Sodium high pressure 70 watt	137.33
Sodium high pressure 100 watt	89.34
Sodium high pressure 400 watt	104.65
Metal halide 70 watt	109.65
Metal halide 150 watt	109.65
Metal halide 250 watt	112.13
Metal halide 400 watt	112.13
T5 2X14 watt	30.59
Twin 24 watt Fluorescent	30.59
Compact Fluoro 32 watt	30.59
Compact Fluoro 42 watt	30.59

* OM&R = operation, maintenance, repair and replacement
Source: United Energy

Table 3.13 Meter data services for public lighting, 1 January to 30 June 2020 (\$ nominal)

Meter data service charges	Per light
Unmetered supplies - public lighting	1.42

Source: United Energy

Table 3.14 Metering provision charges, 1 January to 30 June 2020 (\$ nominal)

Meter type	Per NMI*
Single phase single element meter	51.83
Single phase single element meter with contactor	51.83
Three phase direct connected meter	58.46
Three phase current transformer connected meter	61.98

* NMI=National Metering Identifier

Source: United Energy

Table 3.15 Manual/special meter reading charge, 1 January to 30 June 2020 (\$ nominal)

Meter type	Per read
Special read (basic meter)	23.89
Special read (interval meter)	23.89

Source: United Energy

Table 3.16 Metering exit fees, 1 January to 30 June 2020 (\$ nominal)

Meter type	S/NM
Single phase single element meter	349.94
Single phase single element meter with contactor	360.11
Three phase direct connected meter	397.20
Three phase current transformer connected meter	517.90

Source: United Energy

4 Service target performance incentive scheme (STPIS)

The AER advised us by email of the following preliminary position for the application of the STPIS to transitional period of 1 January to 30 June 2021:

- continuation of current performance targets for 2016–2020 regulatory period, with an adjustment to reflect average performance in the first six months of the year. Specifically, actual performance of first six months of the year for 2010–2014 should be used to derive the targets for the transitional period
- adoption of the incentive rates for current 2016–2020 regulatory period to the transitional period
- application of actual performance in this period should be applied with a 2.5 year lag into the 2022/23 financial year.

We have calculated the STPIS targets in the table below in accordance with the AER preliminary position.

Table 4.1 STPIS targets 1 January to 30 June 2021

	Network segment	Target	Incentive rate
Unplanned system average interruption duration index (SAIDI)	Urban	38.7	0.0698
	Rural short	64.4	0.0034
Unplanned system average interruption frequency index (SAIFI)	Urban	0.566	4.9133
	Rural short	0.800	0.2743
Unplanned momentary average interruption frequency index (MAIFI)	Urban	0.565	0.3931
	Rural short	1.439	0.0219
Telephone answering (fault calls)	Network	56.6%	-0.04

Source: United Energy