Other step changes

UE RRP BUS 9.06 - Other step changes - Dec2020 - Public

Revised regulatory proposal 2021–2026

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Contents

1 Summary

1.1 Summary our revised proposal

In our revised proposal, we accept:

- the draft determination to accept our five-minute settlement and the IT cloud mitigation step changes
- the draft determination not to accept as step changes the expenditure associated with, the high voltage (HV) feeders and the Cranbourne Terminal Station demand management programs, Energy Safe Victoria (**ESV**) levy and the financial year regulatory information notice (**RIN**).

However, in response to the draft determination, we:

- update the value of our security of critical infrastructure step change based on a recent market test
- continue to propose a step change for our solar enablement program
- continue to propose a step change for the Lower Mornington demand management program, and in doing so update our forecasts for the proposed step change, based on our now agreed contract costs
- continue to propose a step change for increasing insurance premiums, and in doing so update the forecasts for the proposed step change based on our actual 2020/21 policy year premiums
- propose the recovery of Energy Safe Victoria (**ESV**) levy and the Australian Energy Market Operator (**AEMO**) participant fees through the L-factor of the standard control services control mechanism, refer to appendix UE RRP APP08.

This business case supports our operating expenditure chapter and outlines further considerations in respect of our solar enablement and demand management step change. Our security of critical infrastructure step change is discussed in the UE RRP BUS 9.01, our insurance premiums step change is discussed in the insurance business case UE RRP BUS 9.05 submitted with this revised proposal. We do not discuss further those aspects of the draft determination that we have accepted.

We observe at the outset that we disagree with the AER's approach to assessing step changes in the draft determination. We also do not consider the AER's consideration of our individual step changes delivers total operating expenditure that is reasonably required to achieve the operating expenditure objectives. The reasons for this are summarised below.

1.1.1 The AER's framework for assessing step changes does not comply with the Law and Rules

The AER's analytical framework for assessing our proposed step changes is deeply flawed. We do not consider that all relevant considerations are captured by the framework. In any event, any such framework cannot detract from the primacy of the National Electricity Rules (**Rules**). The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient substitution of capital expenditure with operating expenditure (**capex/opex trade-off**) on the basis that the expenditure is not 'material'. The AER's approach has no basis in the National Electricity Law (**Law**) or Rules because:

- there is no express materiality threshold under the Rules for the purposes of assessing whether operating expenditure should be included in the forecast
- there is no basis in the Rules for applying a materiality threshold to operating expenditure step changes in circumstances where we are an efficient distributor facing a range of other pressures on our operating expenditure in the next regulatory period, including:

- a negative productivity adjustment, which reduces our total operating expenditure allowance
- real non-labour price growth of zero, which means that the non-labour component of price growth is equal only to the consumer price index (**CPI**)
- the enduring impact of COVID-19, which (all other things being equal) increases our costs of providing network services
- the rejection by the AER of a number of other step changes we proposed, which costs will thus need to be absorbed

- there is no upward bias in our operating expenditure proposal as there are no matters that would warrant a negative step changes that are not reflected in our revised proposal.

Finally, the AER's approach to assessing proposed step changes based on materiality would create perverse incentives where smaller networks are compensated for relatively larger cost increases, while larger networks are not compensated for minimising cost increases.

Our specific concerns with the AER's assessment of the step changes which are the subject of this business case are summarised below.

1.1.2 Solar enablement

The draft determination regarding our solar enablement step change fails to recognise that our solar enablement program represents an efficient capex/opex trade-off. This is a fundamental flaw in the draft determination and has the consequence that the AER fails to take into account the benefits of continuing to defer capital expenditure associated with increasing distributed energy resources connected to our network or provide us with the opportunity to recover the costs associated with allowing this expenditure to be deferred. The AER's approach represents a perverse incentive to distributors to proceed with capital expenditure even where it can be efficiently deferred.

The AER also errs in its conclusion that our tapping expenditure is immaterial and captured by the rate of change. Given the step change constitutes an efficient capex/opex trade-off, under the AER's own analytical framework, an assessment of materiality is not required. In any event, the application of a materiality threshold to individual step changes has no basis in the Law or Rules, for the reasons summarised in section 1.1.1 above.

Regarding the rate of change, as recognised by the AER, the factors that the AER considers in determining output growth fail to adequately capture the increasing growth in distributed energy resources. As a result, in order to ensure we are provided with operating expenditure that reasonably reflects the operating expenditure criteria, a step change is required to allow for our expected increases in expenditure arising from this growth.

We also do not accept that the AER's alternative tapping unit rates or the AER's assessment that the costs of our correction of non-compliant inverter settings are not justified. Neither result in an operating expenditure forecast that reasonably reflects the operating expenditure criteria.

1.1.3 Lower Mornington Peninsula demand management program

In rejecting our proposed step change for the Lower Mornington Peninsula demand management program, the AER fails to recognise our efficient capex/opex trade-off. Failing to include the step change in our operating expenditure allowance would mean a capital expenditure allowance to enable us to pursue the alternative capital solution, being the installation of a new 66 kV line from Rosebud to Hastings.

Further, contrary to the draft determination, our proposed incremental expenditure on our demand management program for Lower Mornington Peninsula:

- is not captured by our base year operating expenditure or the rate of change, given the costs reflected in the base year are below actual costs and do not reflect a realistic cost of inputs in the next regulatory period
- is not overstated by reason of inflated demand forecasts.

1.1.4 Summary of step changes

A summary of the step changes we are proposing (including those not addressed in the business case) is set out in the table below.

Table 1 Summary of our proposed step changes, $ million 2021

	Original proposal	Draft determination	Revised proposal
Total step changes	73.8	40.6	58.2

Source: United Energy

2 Background

2.1 Rules requirements

The Rules provide that a distributor must include in its building block proposal the total forecast operating expenditure for the relevant regulatory period which the distributor considers is required in order to achieve each of the following (the **operating expenditure objectives**):[1]

> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> > *(i) the quality, reliability or security of supply of standard control services; or*
> >
> > *(ii) the reliability or security of the distribution system through the supply of standard control services,*
> >
> > *(iii) to the relevant extent:*
> >
> > *(iv) maintain the quality, reliability and security of supply of standard control services; and*
> >
> > *(v) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services.*

Where a distributor's forecast of required operating expenditure reasonably reflects each of the operating expenditure criteria, the AER must accept the forecast.[2] The operating expenditure criteria are:

> *(5) the efficient costs of achieving the operating expenditure objectives; and*
>
> *(6) the costs that a prudent operator would require to achieve the operating expenditure objectives; and*
>
> *(7) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*

In assessing a distributor expenditure forecast, the AER is required to perform its function in a manner that will, or is likely to, contribute to the achievement of the national electricity objective (**NEO**).[3] The NEO is:[4]

> *…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> > *(b) price, quality, safety and reliability and security of supply of electricity*
> >
> > *(c) the reliability, safety and security of the national electricity system.*

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1 Rules, clause 6.5.6(a).

2 Rules, clause 6.5.6(c).

3 Law, section 16(1)(a).

4 Law, section 7.

The AER is also required to take the revenue and pricing principles into account whenever it exercises a discretion in making those parts of a distribution determination that relate to direct control services.[5] The revenue and pricing principles include:[6]

> *(d) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(e) providing direct control network services; and*
>
> *(f) complying with a regulatory obligation or requirement or making a regulatory payment.*

2.2 Our original proposal

Our original proposal included the solar enablement and Lower Mornington Peninsula demand management program operating expenditure step changes. Each of these proposed step changes are summarised briefly below.

2.2.1 Solar enablement

In our original proposal we proposed a solar enablement step change to support our exporting excess power back into the network. Incremental operational expenditure was proposed in order to:

- 'tap down' distribution transformer voltages where possible as a less expensive option to, and reduce the need, for capital investment
- undertake compliance and monitoring of customers' inverters settings as if installers fail to apply the required new inverter settings that reduce the voltage rise from exporting solar, voltage rises will be significantly higher than forecast—as a result, the full value of the net benefits will not be realised and there will be inequitable outcomes whereby customers without the inverter settings applied will be able to export more at the expense of others.

2.2.2 Lower Mornington Peninsula demand management program

In 2016 we completed a regulatory investment test for distribution (**RIT-D**) that established a need to invest in the lower Mornington Peninsula to maintain supply security (voltage and capacity).[7] In accordance with the RIT-D, we implemented a four year demand management program in 2018 that runs through 2021. This program was to defer $29.5 million ($2015) of capital expenditure until 2022.

We have now updated actual and forecast demand to plan ongoing supply requirements for the area. The updated forecasts demonstrate the strong trend in growth has continued over the last few years, however, demand is now forecast to flatten over the next few years. As such, our original proposal included a step change in operating expenditure to enable us to continue and enhance the demand management program and defer the capital expenditure further.

The table below summarises the original proposal step change expenditure.

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5 Law, section 16(2)(a)(i).

6 Law, section 7A(2).

7 UE ATT105 - Assessment Lower Mornington Peninsula - May2016 - Public.

Table 2 Original proposal step changes, $ million 2021

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	0.9	0.8	0.8	0.8	0.8	4.2
Demand management (Lower Mornington)	0.9	1.0	1.3	1.4	1.4	6.0

Source: United Energy

2.3 The draft determination

In the draft determination, the AER did not accept our solar enablement and demand management step changes. A summary of the AER's reasons for not accepting these step changes is set out below.

2.3.1 Solar enablement

The AER accepted that, in the short term, the output growth forecast component of the rate of change may not fully account for the higher operating expenditure required for distributed energy resources management in the next regulatory period.[8] However, the AER rejected our proposed step change for solar enablement for the following reasons.

First, the AER agreed with concerns raised by its consultant, EMCa, that, having regard to the unit rates proposed by AusNet Services, the proposed unit rate for our tapping activities should be $865 or $1,000, rather than $1,535 ($2020/21). Given the resulting reduction in operating expenditure required for our proposed tapping, the AER considered the cost of our tapping activities to be immaterial and should be managed within our total forecast operating expenditure.[9]

Secondly, the AER agreed with concerns raised by its consultant EMCa that we had not explored cost effective options to proactively ensure correct inverter settings were installed and address non-compliance or justified that a separate program to our existing business-as-usual power quality program was required.[10] Accordingly, the AER was not satisfied that this cost was sufficiently justified.

2.3.2 Lower Mornington Peninsula demand management program

The AER rejected our proposed step change for continuing and enhancing our Lower Morning Peninsula demand management program for two reasons:[11]

- the costs of increased volume or scale should be compensated through the rate of change (and not a step change)
- the AER did not accept our energy demand forecast submitted with our original proposal and applied a lower demand forecast. The AER stated lower forecast demand is likely to result in lower demand management requirements and lower associated costs, all else being constant.

8 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, pp 52-54

9 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 54

10 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 54

11 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, pp 47-48

3 Revised proposal

3.1 Summary of our revised proposal position

The AER's analytical framework for assessing our proposed step changes is deeply flawed. We do not consider that all relevant considerations are captured by the framework. In any event, any such framework cannot detract from the primacy of the Rules. The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient capex/opex trade off on the basis that the expenditure is not 'material'. The AER's approach has no basis in the Law or Rules.

We continue to propose a step change for each of our solar enablement and Lower Mornington Peninsula demand management programs.

Regarding our solar enablement program, we:

- continue to propose a unit rate of $1,535 ($2021) as this unit rate reflects the rate agreed with our service provider, Zinfra, following a competitive tender process
- continue to propose our monitoring and compliance program in its original form as the success of our solar enablement program relies on new inverter settings and the only other means of ensuring compliance is costly augmentation.

Regarding our Lower Mornington Peninsula demand management program step change, the AER fails to take into account our efficient capex/opex trade-off. This is a fundamental flaw in the draft determination. The AER's approach represents a perverse incentive for distributors to proceed with capital expenditure even where it can be efficiently deferred.

We also do not accept that our incremental expenditure is reflected in our base year operating expenditure or captured by the rate of change and we consider our demand forecasts are still relevant.

3.2 Responding to the draft determination

3.2.1 Step changes in the AER's base-step-trend approach

In assessing a distributor's operating expenditure, the AER adopts a 'base-step-trend' approach.[12] The starting point (or 'base') is a distributor's revealed actual past operating expenditure. To account for changed economic conditions from one period to the next, the AER then applies a rate of change to 'trend' the forecast forward. The rate of change is estimated by forecasting the expected growth in input prices, outputs and productivity.

'Step changes' are then essential to account for any required operating expenditure not included in the base or trend component of the forecast. Without a step change, the distributor would otherwise not be provided with a reasonable opportunity to recover at least its efficient costs in providing direct control network services and/or complying with regulatory obligation or requirements.[13]

12 AER, Better regulation: Expenditure forecast assessment guideline, November 2013, p. 22.

13 Law, sections 7A(2), 16(2)(a)(i).

In addition to step changes, the AER's 2013 Expenditure Forecast Assessment Guideline also describes 'category specific forecasts', which represent:[14]

> *…an amount we may allow to be included in the opex forecast for a particular year, which is not appropriate as a step change, nor for inclusion in base opex, but which we nevertheless consider meets the legal criteria for efficient expenditure in that year.*
>
> *We may also use category specific forecasts to avoid inconsistency or double counting within our determination…*

The AER's Expenditure Forecast Assessment Guideline only expressly recognises step changes:[15]

- resulting from the introduction of new regulatory requirements
- where a capex/opex trade-off is efficient.

In its decisions, however, the AER has recognised additional circumstances in which a step change may be required. In the last Victorian distribution reset, for example, the AER recognised that step changes may be required in situations where a change in circumstances, outside of the control of the distributor, necessitates increased expenditure to meet the operating expenditure objectives.[16]

Similarly, in the draft determination, the AER indicates that in the absence of a change in regulatory obligations or a legitimate capex/opex trade-off opportunity, it would accept a step change under limited circumstances.[17] The AER goes on to state that it would consider whether the costs associated with such a step change are unavoidable and material such that the base operating expenditure, trended forward by the forecast rate of change, would be insufficient for the distributor to recover its efficient and prudent costs.[18] For example, the AER draft determinations accepted AusNet Services proposed I step change for 'innovation expenditure' and Jemena's proposed insurance premiums step change.

3.2.2 AER's approach to assessing step changes does not comply with the Law and Rules

The AER errs in seeking to apply its analytical framework for assessing step changes.

We do not consider that all relevant considerations are captured by the framework. In considering guiding principles to assist in determining whether step changes are likely to reflect the operating expenditure criteria, the Australian Competition Tribunal (**Tribunal**) has held that:[19]

- if a step change is to reasonably reflect the operating expenditure criteria, a cost saving arising from efficiencies within a distributor's business attributable to the planned capital expenditure and operating expenditure should be reflected in the forecast operating expenditure
- alternatively, if a cost saving is not expected, a step change should result in a benefit to customers that warrant the forecast operating expenditure
- identifying the expected benefit and giving a value to it is relevant to evaluating whether the expenditure is 'efficient' and 'prudent'

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14 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 19

15 AER, Better regulation: Expenditure forecast assessment guideline, November 2013, p. 11.

16 at 7-95 to 7-97.

17 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 19

18 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 19

19 *Application by EnergyAustralia and Others* [2009] ACompT 8, [194].

- alternatively, if neither a cost saving nor a customer benefit is expected, the step change should be the consequence of an unavoidable change in activity due to an external obligation.

Notably, these principles (initially proposed by the AER in the proceeding) are markedly wider than those referred to by the AER in its Expenditure Forecast Assessment Guideline and refined in subsequent decisions.

In any event, any such an analytical framework cannot detract from the primacy of the Rules. The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.[20] Overreliance on any 'step change criteria', without proper regard to the Rules, risks affecting the integrity of the AER's decision, as has been recognised by the Tribunal.[21]

The AER's assessment of materiality of step changes

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient capex/opex trade-off on the basis that the expenditure is not 'material'. The AER's approach has no basis in the Law or Rules.

First, there is no express materiality threshold under the Rules for the purposes of assessing whether operating expenditure should be included in the forecast. This can be contrasted, for example, with the cost pass through provisions, which require a pass through event to give rise to 'materially' higher or lower costs to the distributor in providing direct control services than it would have incurred but for the event, with 'materially' being defined as the change in costs being more than one per cent of the annual revenue requirement for a regulatory year.[22] The application of a materiality threshold in the pass through context is warranted given the adjustments made to operating expenditure are occurring *after* the distribution determination is made and a materiality threshold promotes the stability and predictability of the regime for the regulator and the service provider.[23] Similarly, the AER may revoke and substitute a determination during a regulatory period in the event of a 'material' error or deficiency of a specified kind.[24] Again, correction of errors occurs *after* the making of the distribution determination and a materiality threshold is important in this context in order to increase the certainty and transparency associated with the regulatory framework, and to maintain the incentives built into that framework.

Secondly, there is no basis in the Rules for applying a materiality threshold to operating expenditure step changes in circumstances where:

- we are an efficient distributor, and thus the base year operating expenditure can be assumed to reflect the prudent and efficient costs of meeting the operating expenditure criteria, having regard to the operating expenditure factors

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20 Rules, clause 6.5.6(c).

21 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, [366]-[373] (affirmed on review: *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79; *Australian Energy Regulator v Australian Competition Tribunal (No 3)* [2017] FCAFC 79).

22 Rules, clause 6.6.1; Chapter 10 definitions of 'positive change event', 'negative change event' and 'materially'.

23 See, for example: Australian Energy Market Commission (**AEMC**), National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, pp. 204-205.

24 Rules, clause 6.13(a).

- the AER is proposing to assume productivity growth of 0.5 per cent, which has the effect of reducing real expenditure allowances in the next regulatory period (for example, the AER reduced total operating expenditure by $8.7 million ($2020/21) by way of a productivity adjustment)[25]
- the AER is proposing to apply real non-labour price growth of zero (i.e. non-labour price growth equal to CPI)
- the enduring impact of COVID-19 will result in higher costs for our operations due to changed work practices beyond the next few years and will be difficult to unwind in future as expectations regarding social distancing have changed
- we are already being required by the draft determination to absorb a number of step changes, in addition to further step changes we chose not to include in our original proposal, to maintain affordability for our customers in what are challenging times.

The Rules require the AER to accept forecast operating expenditure where it reasonably reflects the prudent and efficient costs of achieving the operating expenditure objectives, and a realistic expectation of the demand forecast and cost inputs. Given the above pressures on operating expenditure that we will face in the next regulatory period, it is inconsistent with the requirements of the Rules and revenue and pricing principles to apply a 'materiality' threshold before making adjustments to the base year operating expenditure when determining total forecast operating expenditure in a distribution determination.

In addition, the AER makes a further fundamental error in rejecting a number of step changes on the basis they are, individually, not 'material'. This is not consistent with the requirements of the Rules or Law. As recognised by the AER, the assessment the AER is required to make is as to total operating expenditure and not the individual forecast expenditure components.[26] This means that it is the cumulative impact of expected changes on future total expenditure that is the relevant consideration. The AER recognises that the cumulative impact of changes is the relevant consideration when assessing materiality in the context of adjusting Powercor's capital expenditure sharing scheme reward payment, concluding that the impact of deferred expenditure on transformer replacement satisfies the materiality threshold because other expenditure considered has already met the threshold. The AER states:[27]

> *As we are satisfied that the inclusion of the deferred poles repex into Powercor's approved total capex allowance is materially higher than had the poles repex not been deferred, it follows that the addition of $8.9 million in deferred transformers repex into the approved total capex allowance satisfied the materiality threshold.*

Taken to an extreme, the AER's approach of considering the materiality of proposed step changes individually would mean a distributor's expenditure could be expected to double on the basis of step changes that are, on their own, not 'material' but which cumulatively have a significant impact such that a failure to include those step changes in the operating expenditure forecast would deprive the distributor of the opportunity to recover their prudent and efficient costs.

The AER appears to consider that a 'materiality' requirement is justified on the basis that it is necessary to avoid a potential upward bias in total operating expenditure given there is an incentive for distributors to identify

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25 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 43.

26 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 13.

27 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 9: Capital expenditure sharing scheme, September 2020, p. 12.

increasing new and costs but not the same incentive to identify decreasing costs.[28] The AER stated elsewhere in the draft determination that:[29]

> *If we were to include step changes for immaterial costs in our alternative estimate, then arguably we should also include negative step changes for decreases in immaterial costs. In this regard, we note that over the next regulatory control period a possible negative step change could arise due to the relaxing of some obligations required by ESV in their electric line clearance regulations, which may lead to immaterial reductions in costs. United Energy has not proposed this as a negative step change. We consider step changes are not meant to be bottom up assessments of all cost categories, and that immaterial increases or decreases should be managed by businesses.*

We do not agree that there is upward bias in the total operating expenditure in our revised proposal. We have assessed our expenditure and changes in obligations for potential negative step changes in preparing our revised proposal and have not identified any. This is not surprising as in our experience, the cost burden from obligations and regulations under which we operate only tends to increase, not decrease. With regard to the electric line clearance regulations, the author of the regulatory impact statement from which the AER draws support, Deloitte, accepted that there is 'some subjectivity' in relation to its impact assessment, expressly citing the potential impacts on distributors' clearance activities from the changes, which could impact the assessment of the difference between the prior and current line clearance regulations. Contrary to the AER's suggestion, the new regulations are not expected to decrease our costs of electric line clearance.

We raise our specific concerns with the AER's assessment of the step changes dealt with this in business case below.

3.2.3 Solar enablement

[The draft determination regarding our solar enablement step change fails to recognise that our solar enablement program represents an efficient capex/opex trade-off. The AER also errs in its conclusion that our tapping expenditure is immaterial and captured by the rate of change.

We also do not accept that the AER's alternative tapping unit rates or the AER's assessment that the costs of our monitoring and compliance program to ensure compliant inverter settings are not justified. Neither result in an operating expenditure forecast that reasonably reflects the operating expenditure criteria.

Each of these matters are discussed further below.

AER fails to recognise our efficient capex/opex trade-off

The AER's draft determination fails to recognise that our proposed solar enablement program represents an efficient capex-opex trade-off. This is a fundamental flaw in the draft determination.

As our step change provides benefits to customers as the most efficient solution to enable growing solar penetration on our networks, effectively deferring network augmentation, we must be afforded the opportunity to recover at least our efficient costs of enabling residential rooftop solar.

Our proposal to undertake tapping activities and monitoring and compliance program to rectify non-compliant inverter settings are low cost alternatives to incurring capital expenditure for network solutions managing distributed energy resources. This was recognised by the consultant engaged by the AER to consider our

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28 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 20.

29 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, pp 60-61

proposal, EMCa, and was a basis on which EMCa concluded that less LV augmentation capital expenditure is justified. EMCa states:[30]

> *United Energy's strategy involves LV augmentation only after seeking to address issues through customer installation compliance, use of its DVMS, and tapping. With a realistic technical/economic appraisal for each relevant LV network over the course of the next regulatory period, we consider that United Energy will find that considerably less LV augmentation expenditure is justified.*

Our tapping activities and monitoring and compliance program for addressing non-compliant inverter settings is thus recognised as reducing our likely capital expenditure, but the costs associated these activities are not funded through an operating expenditure step change.

Tapping

The draft determination concludes that our proposal to undertake tapping activities and the volume of tapping we proposed was prudent and reasonable. However, as noted in section 2.3.1 above, the AER substituted our proposed unit rate of $1,535 ($2020/21) with an EMCa benchmark figure of either $865 or $1,000, which reduced the overall value of the step change. The AER then determined that the reduced rate was 'immaterial' and should be managed within our forecast base operating expenditure and rate of change.[31]

For the reasons outlined below, we do not accept that the AER's alternative unit rates produce forecasts that reasonably reflect the operating expenditure criteria. Further, for the reasons outlined in section 3.2.2 above, we do not consider the AER's analytical framework for rejecting our proposed solar enablement step change on the basis our tapping costs are not material complies with the Law and Rules and maintain that this does not provide a basis on which to reject our proposed solar enablement step change. Finally, we do not agree that our proposed solar enablement expenditure (including tapping) is captured by the rate of change.

Unit rate efficiency

The unit rate used in our original proposal represents the rate agreed with Zinfra, our key field services provider. This rate was agreed following a rigorous competitive tender process. As our unit rate resulted from a competitive tender process, this unit rate is the best evidence of efficient costs and we do not consider it appropriate to substitute our unit rate with an AusNet Services rate.

The Tribunal has previously confirmed that evidence of the outcome of a competitive process can demonstrate an efficient price.[32] In addition, the AER does not appear to have made any attempt to ensure that our unit rate and AusNet's reflect like-for-like services, for example, at a minimum, we are aware that United Energy's rate includes the cost of managing related planned outages, whereas AusNet's does not. In addition, our unit rate (and, we imagine, AusNet's) is one cost in a schedule of many; it is not appropriate to view this unit cost in isolation, without considering the competitiveness of the tender overall. To the extent that the AER seeks to rely on an AusNet Services rate in the final determination, we request that the AER make the sufficient details of the AusNet Services unit rates available and provide us with an opportunity to comment to ensure we are informed of material issues under consideration by the AER and given a reasonable opportunity to make submissions in respect of the determinations before they are made, consistent with the requirements of section 16(1)(b) of the Law and administrative law obligations to afford natural justice and good regulatory practice.

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30 EMCa, United Energy - Review of aspects of proposed expenditure, Report prepared for: Australian Energy Regulator, August 2020, p. 151.

31 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, pp 53-54

32 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [372] (affirmed on review: *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79; *Australian Energy Regulator v Australian Competition Tribunal (No 3)* [2017] FCAFC 79).

As we are of the view that our proposed unit rate is efficient and produces forecasts that reasonable reflect the operating expenditure criteria, we do not propose to adjust our proposed unit rate.

AER errs in applying a 'materiality' threshold

The AER's approach in the draft determination of rejecting our proposed solar enablement step change on the basis that the proposed expenditure is 'immaterial' is deeply flawed.

We disagree with the AER's framework for assessing step changes for the reasons outlined in section 3.2.2 above.

Even on the AER's approach, however, there is no basis for applying a materiality threshold to our solar enablement step change. As discussed above, our proposed solar enablement step change represents a prudent and efficient capex/opex trade-off. In these circumstances, the AER general approach is not to go on to consider whether the costs associated with the step change are 'material', which approach we consider is consistent with the significance of efficient capex/opex trade-off and avoiding the perverse incentives to incur inefficient capital expenditure that would otherwise arise.[33] Even applying its own analytical framework, therefore, the AER has erred in applying a 'materiality' threshold.

Solar enablement expenditure is not captured by the rate of change

The AER states that its standard approach is not to provide a step change to manage activities in a changed operating environment as increases in operating expenditure in line with output growth would typically provide adequate compensation.[34] However, the AER accepts that in the short term the output growth forecast may not fully account for distributed energy resources. In its 2020–2025 final determination for SA Power Networks, the AER accepted a step change for LV Management Future Networks as:[35]

> *there is a likelihood that the output growth forecast may not fully compensate for the higher opex to address distributed energy resource management.*

The AER forecast output growth in the draft determination by:[36]

- calculating growth rates for four outputs: customer numbers; circuit line length; energy throughput; and ratcheted maximum demand
- calculating five weighted average overall output growth rates using the output weights from five models
- averaging the five model specific weighted overall output growth rates.

Significantly, growth in distributed energy resources, which increases the number of constraints to our network solar PV 'hosting capacity', which in turn increases the number of PV inverters tripping and thus drives our solar enablement expenditure, is not a direct input into the forecasting of output growth and is not adequately reflected in any of the outputs considered when forecasting output growth. Further, the growth in distributed energy resources actually negatively impacts the rate of change as energy consumption and peak demand decline with growth in distributed energy resources.

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33 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 19.

34 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 53.

35 AER, Final Decision SA Power Networks, Distribution Determination 2020-2025, Attachment 6: Operating expenditure, June 2020, p 23.

36 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 37.

The AER's own consultant engaged to consider the rate of change agreed that the factors the AER considers in determining output growth fail to adequately capture the increasing growth in distributed energy resources. Economic Insights states:[37]

> *We concur that the growth in DER is likely to be having a significant effect on DNSPs and could be increasing their opex as DNSPs strive to maintain network stability and capex in the face of many new small and unpredictable energy suppliers appearing on their networks. To adequately address this emerging situation we need to consider expanding the outputs included in our economic benchmarking models to include a DER output. That is, a DER output could be creating something of an omitted variable issue as the specification now stands.*

Economic Insights went on to suggest that this should be part of a wider periodic review of economic benchmarking rather than a part of a distribution determination process. However, Economic Insights indicates that, in the meantime, where distributed energy resources are increasing operating expenditure requirements, this would be best handled in the short-term via a step change.[38]

In these circumstances, there is no basis for concluding that the output growth can be expected to allow us to recover our prudent and efficient costs of enabling customers to export excess solar back into the network.

Monitoring and compliance program

The success of our solar enablement program relies on new inverter settings being applied. We have modelled voltage rise based on 100 per cent compliance of new solar systems. If installers fail to apply these settings, voltage rises will be significantly higher than forecast and we will experience quality of supply and system security issues. In addition, customers will continue to experience more constraints. As such, our original proposal included a monitoring and compliance program.

Whilst EMCa considered that addressing non-compliance of inverter settings was likely to be a relatively cost-effective means of limiting PV export voltage rise, the draft determination concluded that we had not sufficiently justified the cost of our proposed monitoring and compliance program, demonstrated that other more cost-effective options had been considered, or established that the program was required in addition to our power quality program.

Identifying and rectifying compliance is not an easy task. In contrast to the AER's conclusion, to date we have:

- updated our model standing offers to require these settings to be applied
- partnered with the Clean Energy Council to hold training with accredited solar installers to educate them on the need to apply the new standards
- required solar installers to attest that the power quality settings have been applied after completing installation
- worked with the Department of Environment Land Water and Planning to determine how best to achieve compliance, including requesting that they check for compliance as part of their Solar Homes audit, however this has not been deemed practicable.

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37 Economic Insights, Review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights, 18 May 2020, p. 17.

38 Economic Insights, Review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights, 18 May 2020, p. 17.

Yet, even after undertaking all the above precautions, around 60-70 per cent of new solar installations are non-compliant. Often customers are not aware of their non-compliance because it is due to their installer not following procedures. Our monitoring and compliance program includes costs to implement remote monitoring using our existing information management systems, based on current rates of non-compliance, assuming it takes one hour on average to rectify the non-compliance. This is a conservative estimate given we expect non-compliance with the new inverter settings to be much higher based on the experience of other distributors and our experience to date.

In querying why we do not simply extend our power quality program, the AER and EMCa have misunderstood the nature of this program (notably, neither the AER nor EMCa requested any further information on the program). The power quality program differs materially from the monitoring and compliance program in question. Power quality comprises network planners who plan and schedule works to fix voltage issues. As already described, the compliance and monitoring program we are proposing relies on running data analytics over advanced metering infrastructure data to find non-compliant sites, and a customer services team addressing and rectifying (by working with the customer i.e. not via voltage works) the identified non-compliance. The two programs do not share any complementarities and require vastly different skill sets. There would be no efficiencies found in expanding power quality to incorporate the proposed monitoring and compliance program.

The only other option to address non-compliance (leaving aside the steps we have already taken, and the proposed monitoring and compliance program) is augmentation of the network. This would be significantly more costly. As such, our monitoring and compliance program is an efficient capex/opex trade-off and should be accepted in our final regulatory determination.

3.2.4 Lower Mornington Peninsula demand management program

The draft determination fails to recognise our efficient capex/opex trade-off in proposing to extend and enhance our Lower Mornington Peninsula demand management program. Further, contrary to the draft determination, our proposed incremental expenditure on our demand management program for Lower Mornington Peninsula:

- is not captured by the rate of change
- is not overstated by reason of inflated demand forecasts.

Each of these issues are discussed in turn below, after we set out developments since our original proposal was submitted.

Developments since our original proposal

In 2020, after two years of demand management we were also looking at options to extend the solution to further defer the capital expenditure considering reduced and uncertain peak demand growth going forward.

We therefore issued a new request for non-network proposals (via its demand side engagement register) to test the market for offers and determine the most economic solution going forward via a market benefit test, see UE RRP ATT56. Three non-network options were received as part of this proposal.

The market test demonstrated that ongoing demand management continues to be the most efficient solution. The preferred and most economic option was a for combined solution which included:

- 11MW of demand side generation hire from Aggreko from summer 2020/21
- 2MW of demand response via commercial demand response and the residential summer saver program from summer 2021/22.

Subsequently, we entered a contract with Aggreko for 11MW of generation hire for the next 5 years. We have now committed to this solution for at least the next 5 years with the first year of this new solution now in place to manage the voltage collapse risk on the sub transmission loop over summer 2020/21.

AER fails to recognise our efficient capex/opex trade-off

In our original proposal, we provided actual demand and forecasts in planning ongoing supply requirements for the lower Mornington Peninsula area. The updated forecasts demonstrated that the strong trend in growth had continued over the last few years, but that demand was forecast to flatten over the next few years compared with the original RIT-D forecast. This created an opportunity to continue our demand management program and further defer the capital expenditure to the 2026–2030 regulatory period.

Demand management is critical to controlling augmentation costs and integrating renewables into our networks, as recognised by the Australian Competition and Consumer Commission (**ACCC**).[39] Our proposed continuation and enhancement of the Lower Mornington Peninsula program defers $29.5 million of capital expenditure ($2015). If our step change is not accepted, it will become necessary to allow capital expenditure to pursue the capital solution, being the installation of a new 66 kV line from Rosebud to Hastings.

The AER's failure to recognise our efficient capex/opex trade-offs creates a perverse incentive to distributors to proceed with capital expenditure even where it can be efficiently deferred. It also acts as a strong disincentive for distributors whose demand management programs are less developed than ours, to continue to develop them as it raises questions about the recoverability of efficient demand management costs.

Our incremental demand management expenditure is not reflected in the base year operating expenditure or captured by the rate of change

As shown in our original proposal (and now in our revised proposal, refer UE RRP MOD 9.01), the demand management costs in our base year are less than the demand management costs we will incur over the 2021–2026 regulatory period.

Following our competitive tender, new demand management arrangements have now been entered into. Given the arrangements have been renegotiated on the basis on improved understanding of the market dynamics and are arms-length, the AER can be satisfied that the re-negotiated demand management costs are efficient. Further, given these arrangements have been entered into, there can be no doubt that demand management will proceed i.e. demand management is not a hypothetical proposition. The costs from these new arrangements are reflected in our revised proposal.

Contrary to the draft determination, our incremental demand management expenditure is also not captured by the rate of change. In drawing this conclusion, the AER has again failed to recognise that the demand management contract costs reflected in the 2019 base year, which are the costs that are escalated for output growth, do not reasonably reflect the operating expenditure required to deliver the program in the next regulatory period. That is, the starting point is below where it needs to be to allow us to recover our prudent and efficient costs and escalating that value to reflect output growth cannot rectify this.

Further, the output growth is calculated on the basis of forecast ratcheted maximum demand of zero across all years of the next regulatory period and a reduction of energy throughput in each year of the regulatory control

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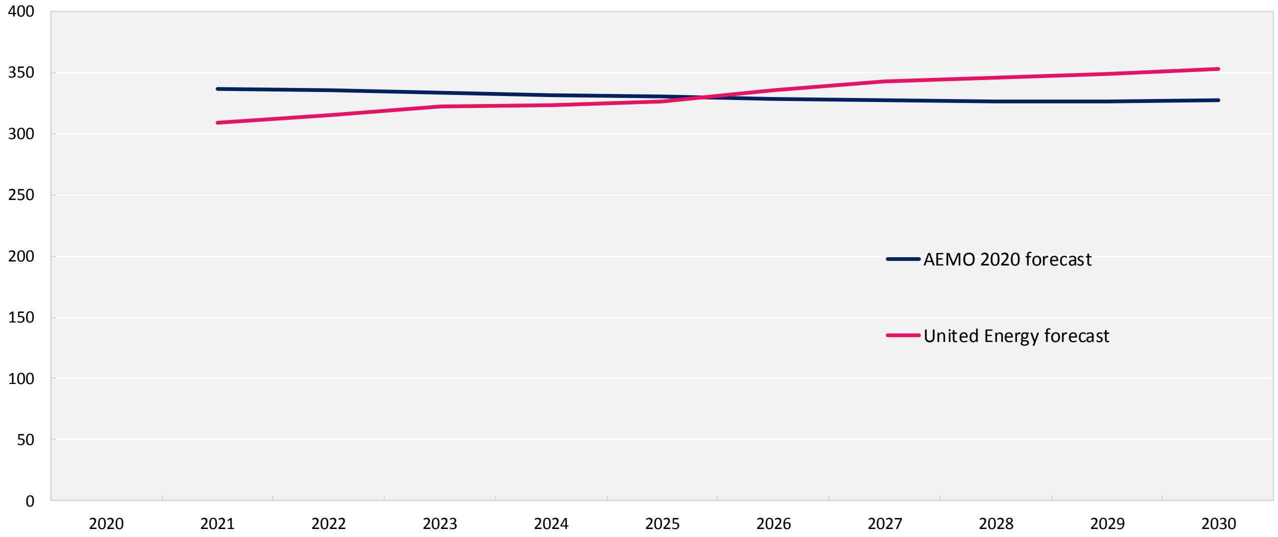
39 ACCC, Restoring affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report, June 2018, 155.

period.[40] In these circumstances, there is no uplift to our operating expenditure to allow recovery for our higher costs associated with the Lower Mornington Peninsula demand management program.

Our demand forecasts are realistic

The AER expressed concerns in relation to our demand forecasts. Our analysis shows that the demand forecasts used in the most recent market test are still relevant and is already forecast to be well above the voltage collapse limit requiring the demand management solution to be in place to manage for this coming summer. In addition it should be noted that United Energy's forecasts for Tyabb Terminal Station (which supplies the Lower Mornington Peninsula) is lower than AEMO's demand forecast for the Tyabb Terminal Station (**TBTS**) (that is, our demand forecasts in this area are even more conservative than AEMO's on which the AER has sought to rely), see figure below.

Figure 1 Comparison of United Energy demand forecasts and AEMO demand forecasts at TBTS, MW



Source: United Energy

Current loading is well above the voltage collapse limits, driven by holiday makers on the lower Mornington Peninsula. It is also very likely demand over the coming years will continue to be very strong and may be above current forecasts, as the effects of COVID-19 mean that international travel remains unlikely, and these areas will experience even more of a peak from local travel following the end of the Victorian lockdown.

3.3 Revised proposal forecasts

Table 3 below shows the forecast value of our solar enablement and demand management step changes.

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40 AER, Draft Decision United Energy, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p 43.

Table 3 Summary of reproposed step change, $ million 2021

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	0.9	0.8	0.8	0.7	0.8	4.0
Demand management	0.8	0.6	0.6	0.6	0.6	3.1

Source: United Energy