PRELIMINARY DECISION
United Energy distribution determination
2016 to 2020

Attachment 6 – Capital expenditure

October 2015

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's preliminary decision on United Energy's revenue proposal 2016–20. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

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Attachment 11 - Service target performance incentive scheme

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Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure

Shortened form	Extended form
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

6 Capital expenditure

Capital expenditure (capex) refers to the investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30-50 years is typical) and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return of and on capital) as part of the building blocks that form part of United Energy's total revenue requirement.[1]

This attachment sets out our preliminary decision on United Energy's total forecast capex. Further detailed analysis is in the following appendices:

- Appendix A - Assessment techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Maximum demand forecasts
- Appendix D - Real material cost escalation
- Appendix E - Predictive modelling approach and scenarios.

6.1 Preliminary decision

We are not satisfied United Energy's proposed total forecast capex of $1,104 million ($2015) reasonably reflects the capex criteria. We substituted our estimate of United Energy's total forecast capex for the 2016–20 regulatory control period. We are satisfied that our substitute estimate of $814.8 million ($2015) reasonably reflects the capex criteria. Table 6.1 outlines our preliminary decision.

Table 6.1 Our preliminary decision on United Energy's total forecast capex ($2015, million)

	2016	2017	2018	2019	2020	Total
United Energy's proposal	228.8	238.1	235.5	208.1	193.5	1,104.0
AER preliminary decision	167.8	172.0	166.9	156.4	151.7	814.8
Difference	–61.0	–66.1	–68.6	–51.7	–41.8	–289.2
Percentage difference (%)	–26.7	–27.8	–29.1	–24.8	–21.6	–26.2

Source: AER analysis.
Note: Numbers may not add up due to rounding.

Table 6.2 summarises our findings and the reasons for our preliminary decision.

[1] NER, cl. 6.4.3(a).

These reasons include our responses to stakeholders' submissions on United Energy's regulatory proposal. In the table we present our reasons by ‘capex driver’ (for example, augmentation, replacement, and connections). This reflects the way in which we tested United Energy's total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques, we found United Energy's capex forecast across all categories was higher than an efficient level, inconsistent with the NER. We are not satisfied that United Energy's proposed total forecast capex is consistent with the requirements of the NER.[2]

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our preliminary decision concerns United Energy’s total forecast capex for the 2016–20 period. We do not approve an amount of forecast expenditure for each capex driver. However we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 6.3 for a detailed discussion). We are satisfied that our estimate represents the total forecast capex that as a whole reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	United Energy proposed a total capex forecast of $1,104 million ($2015) in its proposal. We are not satisfied this forecast reflects the capex criteria. We are satisfied our substitute estimate of $814.8 million ($2015) reasonably reflects the capex criteria. Our substitute estimate is 26 per cent lower than United Energy's proposal. The reasons for this decision are summarised in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	We consider United Energy’s key assumptions and forecasting methodology are generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment and section 6.4.2.
Augmentation capex	We do not accept United Energy’s forecast augex of $166.5 million ($2015) as a reasonable estimate for this category. We consider that $127 million ($2015) is a reasonable estimate for United Energy to meet forecast demand growth and satisfy the capex criteria. While we accept the majority of United Energy’s demand driven forecast, we consider that some reductions are necessary to reflect a lower forecast of demand. In part this reflects our view that United Energy’s demand forecast does not reflect a realistic expectation of demand over the 2016–20 regulatory control period. We also consider that Untied Energy has overestimated the value of customer reliability (VCR) that it applies to plan its augmentation requirements.
Customer connections capex	We are satisfied United Energy’s forecast is a reasonable estimate for this category. We have included an amount of $249.1 million ($2015) in our substitute capex estimate. In determining this, we are satisfied that the forecast methodology United Energy has relied on represents an unbiased estimate of the capex it requires.

2 NER, cll. 6.5.7(c) and (d).

Issue	Reasons and findings
Asset replacement capex (repex)	We do not accept United Energy's forecast repex of $585 million ($2015) as a reasonable estimate for this category. We consider our alternative estimate of $414 million ($2015) will allow United Energy to meet the capex objectives and have included this amount in our alternative estimate. Our alternative estimate is 29 per cent lower than United Energy's proposed repex. Our repex modelling estimates a lower amount of "business as usual" repex is necessary compared to United Energy's forecast for the modelled categories of repex. We also do not accept United Energy's proposed increase to repex for categories it has reported under "other" repex. We accept there may be a need to replace a number of these assets. However, we are of the view that United Energy has not provided justification why it needs to spend significantly more repex on some of these categories in the forthcoming period. United Energy has not provided business cases with reasonable options analysis or sufficient cost-benefit analysis to justify the proposed repex, and there is a lack of top-down assessment.
Non-network capex	We do not accept United Energy's proposed non-network capex of $194.6 million ($2015). We have instead included in our alternative estimate of total capex an amount of $134.6 million ($2015) for non-network capex. United Energy's forecast capex for information technology does not reasonably reflect the efficient costs of a prudent operator. We are not sufficiently satisfied that forecast capex associated with the Power of Choice market reforms and RIN reporting framework is necessary to meet an applicable regulatory obligation, or reasonably reflects the capex criteria.
Real cost escalators	In respect of real material cost escalators (leading to cost increases above CPI), we are not satisfied that United Energy's proposed real material cost escalators, which form part of its total forecast capex, reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. We consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria including that it is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. Our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to United Energy's forecast capex for standard control services. We are not satisfied United Energy's proposed real labour cost escalators which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. We discuss our assessment of forecast our labour price growth for United Energy in attachment 7. The difference between the impact of the real labour and materials cost escalations proposed by United Energy and those accepted by the AER in its capex decision is $18.4 million ($2015).

Source: AER analysis.

We consider that our overall capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides United Energy a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[3]

3 NEL, s. 7A.

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the national electricity objective (NEO). We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives.[4] In making our preliminary decision, we specifically considered the impact our decision will have on the safety and reliability of United Energy's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in United Energy's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.2 United Energy's proposal

United Energy proposed total forecast capex of $1,104 million ($2015) for the 2016–20 regulatory control period.[5] This is $132.3 million ($2015) above United Energy’s actual capex of $971.7 million ($2015) for the 2011–15 regulatory control period.[6]

Figure 6.1 shows the increase between United Energy’s proposal for the 2016–20 regulatory control period and the actual capex that it spent during the 2011–15 regulatory control period. United Energy has stated that this forecast increase in capex is mainly attributable to a need to:[7]

- continue to undertake bushfire mitigation measures, including SWER replacement, in accordance with its regulatory obligations
- continue to address risks to the general public of electric shocks through activities such as the Doncaster Pillars Replacement Program
- address deteriorating network reliability. The primary areas that contribute to this outcome are replacement, augmentation, and ICT capex.

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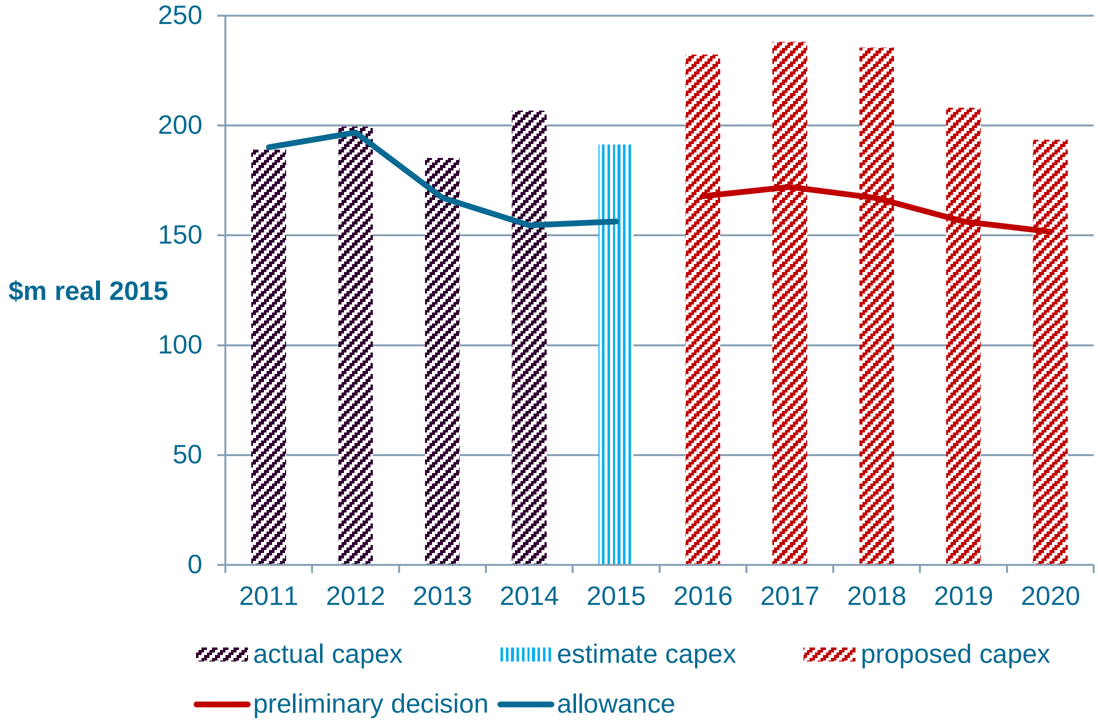
4 NER, cl. 6.5.7(a).

5 United Energy, *Regulatory Proposal 2016–20,* April 2015, pp. 43–45.

6 This includes estimated capex for the 2015 regulatory year.

7 United Energy *Regulatory Proposal 2016–20,* April 2015, pp. 45–48.

Figure 6.1 United Energy total actual and forecast capex 2011–2020



Source: AER analysis.

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The information United Energy provided in its regulatory proposal, including its response to our RIN, is a vital part of our assessment. We also took into account information that United Energy provided in response to our information requests, and submissions from other stakeholders.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is the distributor's regulatory proposal.[8] We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.[9] It also provides us with an

[8] AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

[9] NER, cl. 6.5.7(c).

alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.

- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to:[10]

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.[11] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:[12]

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[13] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular

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[10] NER, cl. 6.5.7(a).

[11] NER, cl. 6.12.1(3)(ii).

[12] NER, cl. 6.5.7(c).

[13] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113.

categories or projects informs our assessment of the total capex forecast. The AEMC stated:[14]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that United Energy's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[15] In taking the capex factors into account, the AEMC noted:[16]

> …this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.5 summarises how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[17] In particular, we take into account whether our overall capex forecast provides United Energy a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[18]

Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).[19] We released our Guideline in November 2013.[20] The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For United Energy, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.[21] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

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14 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. vii.

15 NER, cl. 6.5.7(e).

16 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 115.

17 NEL, ss. 7A and 16(2).

18 NEL, s. 7A.

19 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 114.

20 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013.

21 AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 119–120.

We note that RIN data form part of a distributor's regulatory proposal.[22] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.[23] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.1 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is the distributor’s proposal.[24] We review the proposed forecast methodology and the key assumptions that underlie the distributor's forecast. We also consider the distributor’s performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that the distributor puts forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendix A and appendix B contain further details on each of these techniques.

Some of these techniques focus on total capex, others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.[25]

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision making.

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22 NER, cll. 6.8.2(c2) and (d).

23 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

24 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

25 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. vii.

As we explained in our Guideline:[26]

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor's capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our preliminary decision on overall capex. Our preliminary decision clearly sets out the extent we accept our consultants' findings. Where we apply our consultants' findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of United Energy's proposal.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6.4.

Underlying our approach are two general assumptions:

- The capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term

[26] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[27]

- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[28]

6.3.2 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[29]

> The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a distributor’s actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent

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27 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8 and 9. The Australian Competition Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA).

28 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

29 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 112.

and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[30] Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted, the distributor and consumers share the benefits of the underspend and the costs of an overspend under the regulatory regime.

6.4 Reasons for preliminary decision

We applied the assessment approach set out in section 6.3 to United Energy. We are not satisfied United Energy's total forecast capex reasonably reflects the capex criteria. We compared United Energy's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. United Energy's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of United Energy’s total forecast capex for the 2016–20 regulatory control period.

[30] NER, r. 6.6.

Table 6.3 Our assessment of required capex by capex driver 2016–20 ($2015, million)

Category	2016	2017	2018	2019	2020	Total
Augmentation	34.7	32.3	30.9	18.7	10.5	127.0
Connections	48.2	49.3	50.6	50.1	50.9	249.1
Replacement	82	85.7	86.9	83.3	76.1	413.9
Non-Network	22.7	27.5	23.3	26.5	34.5	134.6
Labour and materials escalation adjustment	-2.1	-4.7	-6.5	-3.4	-1.7	-18.4
Gross Capex (includes capital contributions)	**185.5**	**190.1**	**185.2**	**175.1**	**170.3**	**906.2**
Capital Contributions	17.7	18.1	18.3	18.7	18.5	91.4
Net Capex (excluding capital contributions)	**167.8**	**172.0**	**166.9**	**156.4**	**151.7**	**814.8**

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of United Energy's forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers are in appendices A and B. These set out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER requires United Energy to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. United Energy must also provide a certification by its Directors that those key assumptions are reasonable.[31]

United Energy’s key assumptions are that:[32]

- the maximum demand and customer growth is consistent with its forecasts set out in chapter 9 of its regulatory proposal
- the customer connection growth is consistent with its forecasts set out in chapter 9 of its regulatory proposal

[31] NER, cll. S6.1.1.1(2), (4) and (5).

[32] United Energy, *Regulatory Proposal 2016–20,* April 2015, p. 53.

- customers value reliability in accordance with the AEMO 2014 VCR survey, and it is therefore appropriate to use:
    - for augmentation and replacement capex on power transformers, a VCR based on AEMO's 2014 VCR survey results calculated on data specific to the summer peak period; and
    - for replacement capex on all other assets, a VCR based on AEMO's 2014 VCR survey results calculated on data across all sectors and all seasons
- the forecast capex will maintain, but not improve, network reliability; and
- its current legislative and regulatory obligations will not change materially, other than as identified in its regulatory proposal (being for Power of Choice, Energy Safe Victoria Regulations, and the AER's RIN reporting requirements).

We have assessed United Energy's key assumptions in the appendices to this capex attachment.

6.4.2 Forecasting methodology

The NER requires United Energy to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[33] United Energy must include this information in its regulatory proposal.[34]

The key aspects of United Energy's forecasting methodology include:[35]

- United Energy consulted extensively with customers and other stakeholders in order to obtain, consider and reflect their views and feedback into the initiatives and projects underpinning its expenditure forecasts
- United Energy's capex forecasts are underpinned by capex governance arrangements. These arrangements include internal review of United Energy's bottom up forecasts by various management expenditure committees prior to seeking Board approval
- United Energy's capex forecasts are underpinned by an asset management framework which is being revised to move toward compliance with ISO 55000. The key aspects of this framework are:
    - Asset Management Strategy – sets out the objectives and high level network planning and management approach to achieving these objectives
    - Asset Management Plans – these translate the Asset Management Strategy and asset performance data into more detailed investment plans based on a detailed understanding of the nature and condition of United Energy's assets

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[33] NER, cll. 6.8.1A and 11.60.3(c).

[34] NER, cl. S6.1.1(2).

[35] United Energy, *Regulatory Proposal 2016–20,* April 2015, p. 42; United Energy, *Expenditure forecasting methodology,* 30 May 2014.

- Life Cycle Management Plans (Works Program) – these underpin the Asset Management Plans at an individual asset or asset class level and provide detailed work instructions on how to manage individual assets. They also contain a work plan including volumes of work and how these volumes have been derived.

We consider United Energy's forecasting methodology is generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment.

The Victorian Energy Consumer and Use Alliance (VECUA) considered the Victorian distributors overly relied on bottom up methodologies with insufficient regard to top down methods.[36] Origin Energy supported the application of both a top down and bottom up assessment:[37]

> to demonstrate that a level of overall restraint has been brought to bear. This dual exercise is necessary to ensure that forecast costs, including unit rates, have not been overstated and that inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level are adequately accounted for.

As we noted in previous determinations, the drawback of deriving a capex forecast through a bottom-up assessment is it does not of itself provide sufficient evidence that the estimate is efficient. Bottom up approaches tend to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency.[38]

6.4.3 Interaction with the STPIS

We consider that our approved capex forecast is consistent with the setting of targets under the STPIS. In particular, we consider that the capex allowance should not be set such that it would lead to United Energy systemically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient United Energy to maintain performance at the targets set under the STPIS. As such, it is appropriate to apply the STPIS as set out in attachment 11.

In making our preliminary decision, we have specifically considered the impact our decision will have on the safety and reliability of United Energy's network.

In its submission, the CCP noted the following explanation from the AEMC:[39]

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36 VECUA, *Submission: Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2105, p. 19.

37 Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 8.

38 For example, see AER, *Preliminary decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, pp. 22–23.

39 CCP, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' revised regulatory proposal*, August 2015 p. 27.

> …operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated to that role. Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which would undermine the role of the standard setting body, and create uncertainty and duplication of roles.
>
> NSPs are still free to make incremental improvements over and above the regulatory requirements at their own discretion. Such additional expenditure will not generally be recoverable, through forecast capital and operating expenditure. However, DNSPs are also provided with annual financial incentives to improve reliability performance under the STPIS.

We consider our substitute estimate is sufficient for United Energy to maintain the safety, service quality and reliability of its network consistent with its obligations. Our provision of a total capex forecast does not constrain a distributors actual spending – either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to expend particular capex differently or in excess of the total capex forecast set out in our decision. However, such additional expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

Under our analysis of specific capex drivers, we have explained how our analysis and certain assessment techniques factor in safety and reliability obligations and requirements.

6.4.4 United Energy's capex performance

We have looked at a number of historical metrics of United Energy's capex performance against that of other distributors in the NEM. We also compare United Energy's proposed forecast capex allowance against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis undertaken using data provided by the distributors for the annual benchmarking report. The report includes United Energy's relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and United Energy's historic capex trend.

We note that the NER set out that we must have regard to our annual benchmarking report.[40] This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall

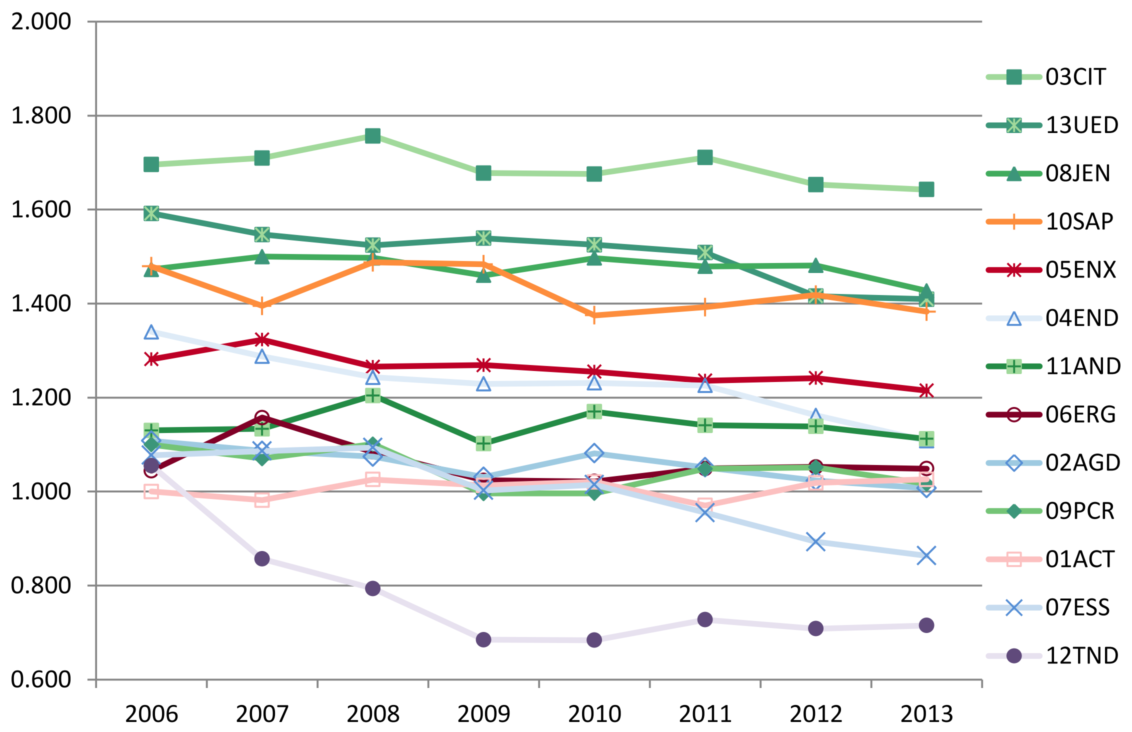
[40] NER, cl. 6.5.7(e).

understanding of United Energy's proposal in a broader context. However, in our capex assessment we have not relied on our high level benchmarking metrics set out below other than to gain a high level insight into United Energy's proposal. We have not used this analysis deterministically in our capex assessment.

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. United Energy performs relatively well on this measure, falling only behind CitiPower, and Jemena in 2012 and 2013.

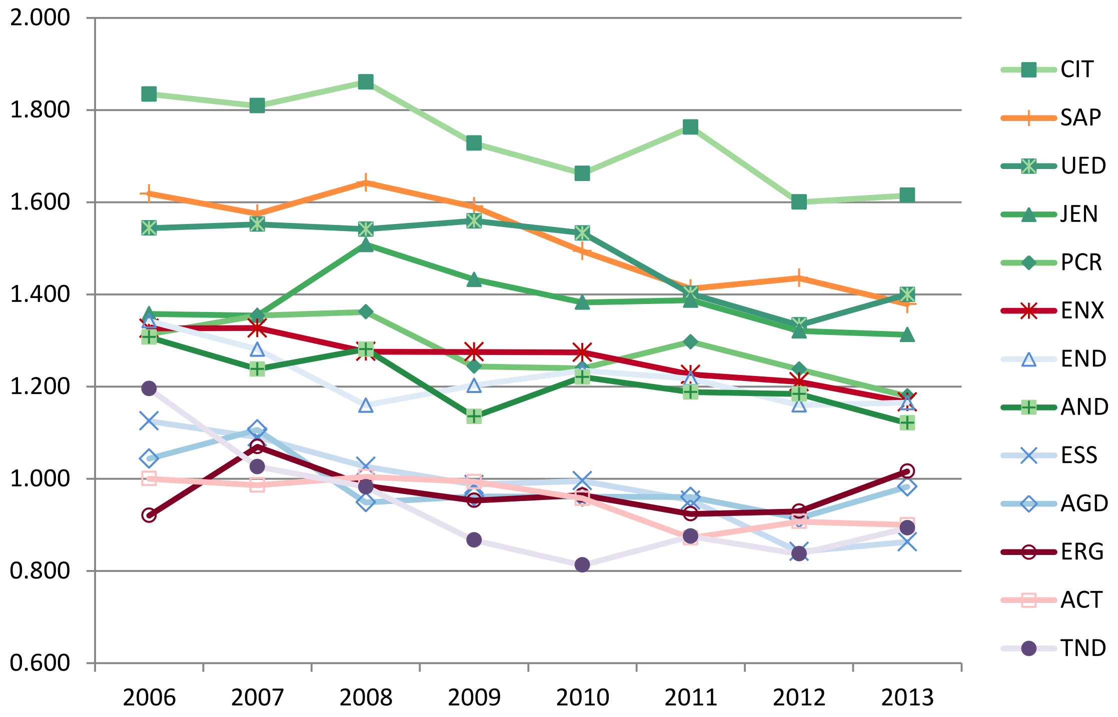
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows that United Energy ranks similarly on MTFP. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). United Energy is one of the top performers on this metric.

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

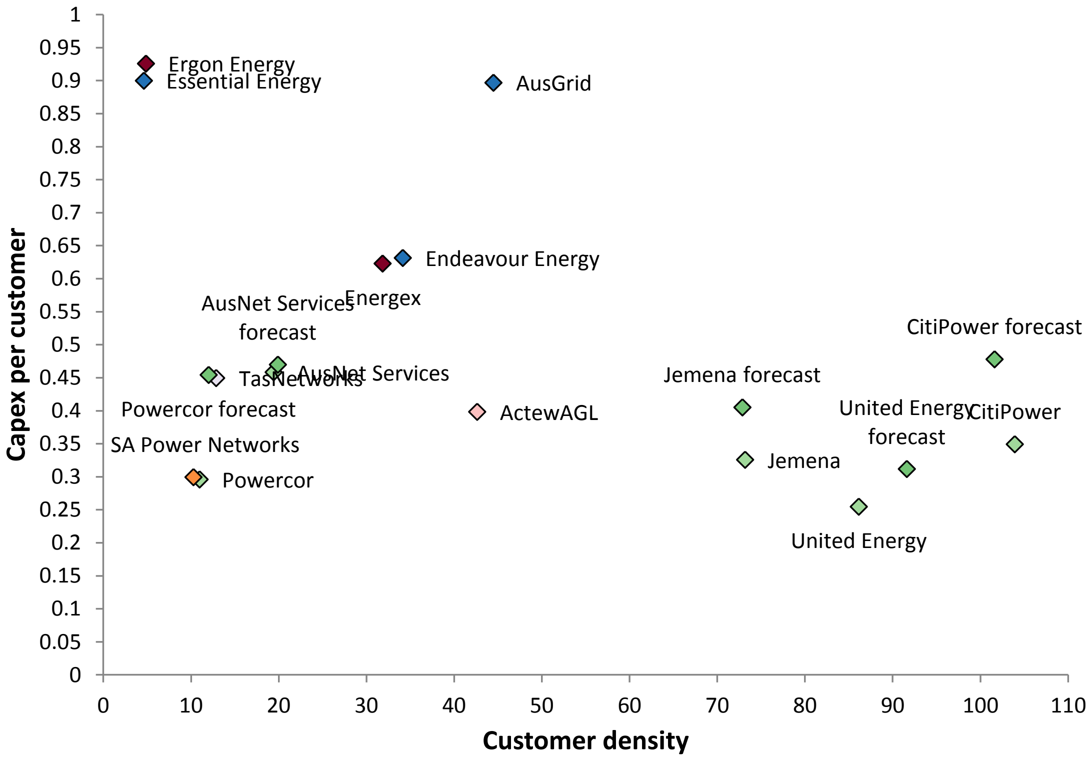
6.4.4.1 Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–12. We have considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6.4 and Figure 6.5 show the Victorian distributors generally perform well in these metrics compared to other distributors in the NEM in the 2008–12 years. We also included the other Victorian distributors' proposed capex for the 2016–20 regulatory control period in the figures. However, we do not use comparisons of United Energy's total forecast capex with the total forecast capex of the other Victorian distributors as inputs to our assessment. We consider it is appropriate to compare United Energy's forecast only with actual capex. This is because actual capex are 'revealed costs' and would have occurred under the incentives of the regulatory regime.

Figure 6.4 shows that United Energy performed well in the 2008–12 period in terms of capex per customer. However, United Energy's capex per customer will increase for the 2016–20 period based on its proposed forecast capex.

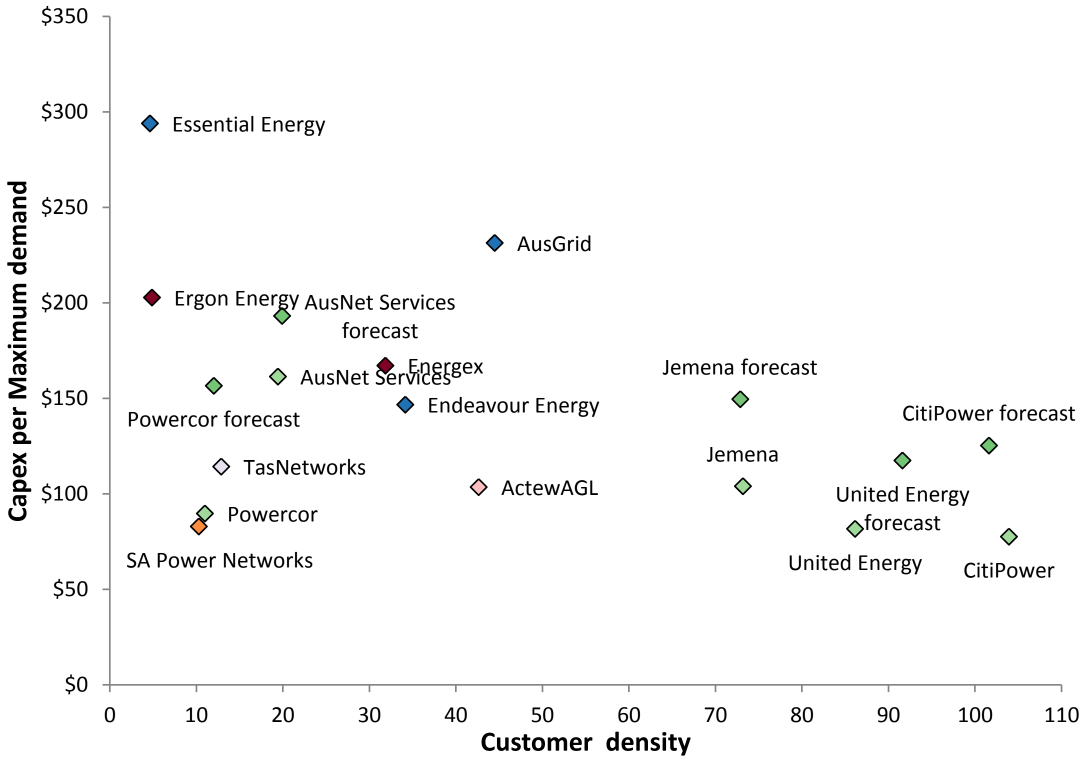
Figure 6.4 Capex per customer (000s, $2013–14), against customer density



Source: AER analysis.

Figure 6.5 shows that United Energy performed well in 2008–12 in terms of capex per maximum demand. Again capex per maximum demand is forecast to increase for United Energy in the next period.

Figure 6.5 Capex per maximum demand (000s, $2013–14), against customer density



Source: AER analysis.

The Consumer Utilities Advocacy Centre (CUAC) expressed concern about the large increases in capex some Victorian distributors proposed and the decline in productivity in recent years.[41]

The Victorian Greenhouse Alliances (VGA) noted the increases in the capex forecast of the Victorian distributors. The VGA considered the increased capex forecasts were concerning given over-investment over recent regulatory periods has led to excess levels of network capacity and declining network utilisation. The VGA also expressed concern that the Victorian distributors proposed such high levels of capex at a time of:[42]

- declining capacity utilisation
- reduced average asset age for most asset categories
- static or falling demand and consumption

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41 CUAC, *Submission: Victorian electricity distribution pricing review (EDPR) 2016 to 2020*, 13 July 2015, p. 2.

42 VGA, *Submission: Local Government response to the Victorian electricity distribution price review (EDPR) 2016–20*, July 2015, p. 33.

- reductions in the reliability standards.

The Department of Economic Development, Jobs, Transport and Resources (DEDJTR) and the VECUA made similar points in their submissions.[43] We considered these factors into detail in our assessment of capex drivers (see appendix B). For example, we made reductions to the capex forecast as we do not consider United Energy's demand forecast is realistic (see appendix B.2).

Appendix B details our assessment of United Energy's capex categories. These assessments, along with the high level analysis in this section 6.4.4, were inputs into our preliminary decision on United Energy's total capex for the 2016–20 regulatory control period. We consider our assessment results in a total capex forecast that is largely consistent with the submissions received. Figure 6.1 shows our preliminary decision capex forecast is 16 per cent lower than United Energy's actual capex in the 2011–15 regulatory control period. By comparison, United Energy's proposed capex is 14 per cent higher than its actual capex for the 2011–15 regulatory control period.

To arrive at our preliminary decision, we considered the issues noted in these submissions, such as lower demand and declining utilisation in the network. For example, we consider United Energy's demand forecast does not reflect a realistic expectation of demand over 2016–20 and substituted a lower demand forecast (see appendix C). Our assessment of United Energy's augex forecast reflects this lower demand forecast (see section B.2). Importantly, our assessment considered many other factors such as asset age and condition. We discuss these, and other issues relevant to United Energy's capex proposal, in detail in appendix B.

United Energy's historic capex trends

We have compared United Energy's capex proposal for the 2016–20 regulatory control period against the long term historical trend in capex levels.

Figure 6.6 shows actual historic capex and proposed capex between 2001 and 2020. This figure shows that United Energy's forecast is significantly higher than historical levels (actual spend), particularly for the first 3 years of the regulatory control period. We note that United Energy's capex falls towards the end of the regulatory control period.

The Consumer Challenge Panel (CCP) noted capex in the current period occurred under the 'old' National Electricity Rules, which the CCP considered overtly incentivised investment.[44] The CCP further noted the NER did not apply in Victoria

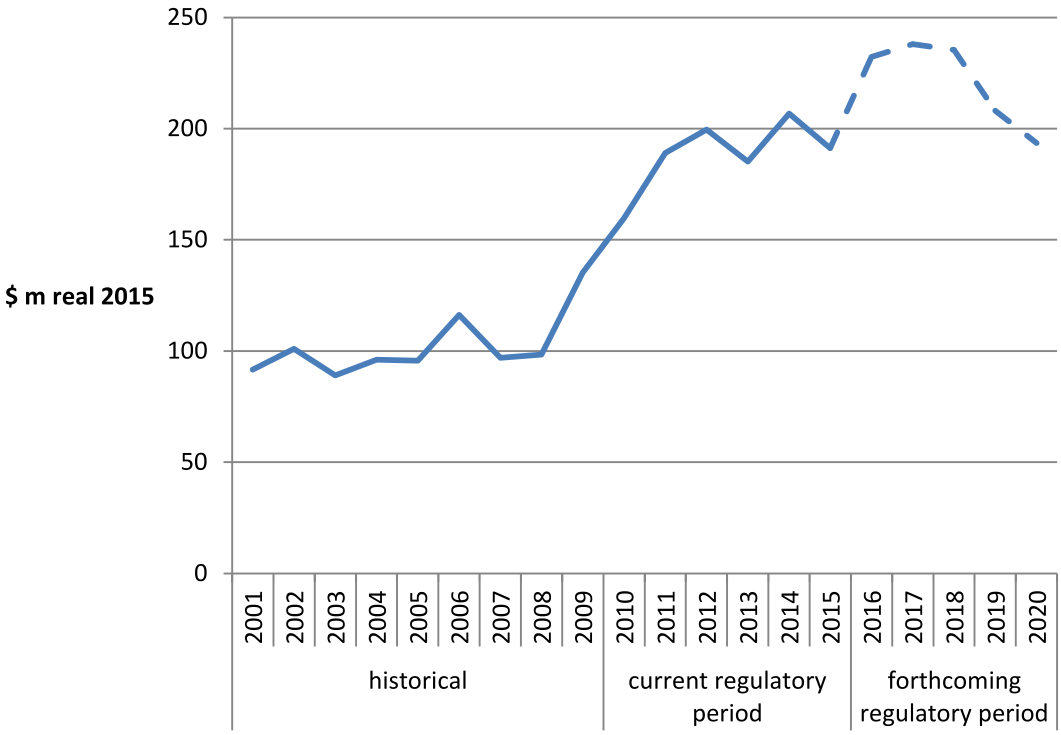
[43] DEDJTR, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6; VECUA, *Submission: Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2105, pp. 6 and 18.

[44] That is, prior the AEMC's changes to the NER in November 2012.

prior to 2011. Despite the lower incentive prior to 2011, the CCP noted that reliability did not suffer.[45]

Our detailed assessment in appendix B examines whether the increase in capex is reasonably reflective of the capex criteria.

Figure 6.6 United Energy total capex – historical and forecast for 2001–2020



Source: AER analysis.

6.4.5 Interrelationships

There are a number of interrelationships between United Energy's total forecast capex for the 2016–20 regulatory control period and other components of its distribution determination (see Table 6.4). We considered these interrelationships in coming to our preliminary decision on total forecast capex.

45 CCP, *Submission: Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 5 August 2015, p. 41.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	There are elements of United Energy's total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in Attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex. More generally, we note our total opex forecast will provide United Energy with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex United Energy needs to spend during the 2016–20 period.
Forecast demand	Forecast demand is related to United Energy's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to United Energy's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from United Energy's regulatory asset base. In particular, the CESS will ensure that United Energy bears at least 30 per cent of any overspend against the capex allowance. Similarly, if United Energy can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, United Energy risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	The STPIS is interrelated to United Energy's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2016–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow United Energy to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to United Energy systematically under or over performing against its targets.
Contingent project	A contingent project is interrelated to United Energy's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of United Energy's total forecast capex for the 2016–20 regulatory control period. We did not identify any contingent projects for United Energy during the 2016–20 period.

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing United Energy's total capex forecast.[46] Table 6.5 summarises how we have taken into account the capex factors. Where relevant, we also had regard to the capex

46 NER, cll. 6.5.7(c), (d) and (e).

factors in assessing the forecast capex associated with its underlying capex drivers such as repex, augex and so on (see appendix B).

Table 6.5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing United Energy's proposed total forecast capex and in determining our alternative estimate for the 2016–20 regulatory control period. This can be seen in the metrics we used in our assessment of United Energy's capex performance.
The actual and expected capex of United Energy during any preceding regulatory control periods	We had regard to United Energy's actual and expected capex during the 2011–15 and preceding regulatory control periods in assessing its proposed total forecast. This can be seen in our assessment of United Energy's capex performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie United Energy's total forecast capex. For some elements of non-network, augex and connections capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by United Energy in the course of its engagement with electricity consumers	We had regard to the extent to which United Energy's proposed total forecast capex includes expenditure to address consumer concerns that United Energy identified. United Energy has undertaken engagement with its customers and presented high level findings regarding its customer preferences. These findings suggest that consumers value affordability and reliable networks.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing United Energy's proposed real cost escalation factors. In particular, we have not accepted United Energy's proposal to apply real cost escalation for labour and materials.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between United Energy's total forecast capex and total forecast opex in Table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to United Energy	We had regard to whether United Energy's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between United Energy's total forecast capex and the application of the CESS and the STPIS in Table 6.4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of United Energy's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than United Energy that do not reflect arm's length terms. We do not have evidence to indicate that any of United Energy's arrangements do not reflect arms length terms.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of United Energy's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.

Capex factor	AER consideration
The extent to which United Energy has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which United Energy made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of United Energy's augex proposal.
Any other factor the AER considers relevant and which the AER has notified United Energy in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

A Assessment techniques

This appendix describes the assessment approaches we applied in assessing United Energy's proposed forecast capex. We used a variety of techniques to determine whether the United Energy total forecast capex reasonably reflects the capex criteria. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure we are assessing. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:[47]

> Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.
>
> Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

Below we set out the assessment techniques we used to asses United Energy's capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.[48] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[49] It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.[50] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[51]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and

47 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

48 NER, cl. 6.5.7(e)(4).

49 AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines,* November 2013.

50 NER, cl. 6.5.7(c).

51 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 25.

overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.[52] Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.[53]

In addition to the measures in the annual benchmarking report, we considered how distributors performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We calculated these economic benchmarks using actual data from the previous regulatory control period.

The results from economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We considered past trends in actual and forecast capex as this is one of the capex factors under the NER.[54]

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.[55] Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the

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[52] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

[53] AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

[54] NER, cl. 6.5.7(e)(5).

[55] NER, cl. 6.5.7(a)(3).

need for the projects. Growth in a business' network will also drive connections related capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in demand (and customer numbers).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important when considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected the distributor's capex requirements.

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

Expenditure category analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. The comparisons we perform include:

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we use in assessing repex.

Using standardised reporting templates, we collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by distributors, and how these factors may change over time.

A.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model (used in a qualitative sense).

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.[56] The models draw

[56] NER, cl. 6.5.7(c).

on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.[57]

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. If we consider a distributor’s proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[58] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.[59] In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.[60]

For our preliminary decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation, and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of United Energy’s augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of United Energy’s capex proposals.[61] We also relied on the technical review of our consultant, Energeia, to assist with our review of distributors' capex proposals. These involved reviewing United Energy’s processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of United Energy’s capex forecast.

Origin Energy submitted the AER must continue to apply technical assessments in concert with its benchmarking techniques to ensure a prudent balance between asset risk and input costs.[62]

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57 NER, cl. 6.5.7(e)(5).

58 Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

59 For more information, see: AER, *Guidance document: AER augmentation model handbook,* November 2013.

60 AER, *'Meeting summary – distributor replacement and augmentation capex', Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution),* 8 March 2013, p. 1.

61 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

62 Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 1.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of United Energy's forecast capex for the 2016–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2016–20 period. These drivers are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that United Energy's proposed total forecast capex reasonably reflects the capex criteria. In this appendix we set out further analysis in support of this view. This further analysis also explains the basis for our alternative estimate of United Energy's total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we have applied the assessment techniques that we discuss in appendix A.

This appendix sets out our findings and views on each sub-category of capex. The structure of this appendix is:

- Section B.1 Alternative estimate
- Section B.2 AER findings and estimates for augmentation expenditure
- Section B.3 Forecast customer connections capex, including capital contributions
- Section B.4 Forecast repex
- Section B.5 Victorian Bushfires Royal Commission
- Section B.6 Forecast non–network capex.

In each of these sections, we examine sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined United Energy's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to United Energy's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in appendix B.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 AER findings and estimates for augmentation expenditure

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

United Energy proposed a forecast of $166.5 million ($2015) for augmentation capex (augex), excluding overheads. This is an 8.7 per cent decrease compared to actual augex incurred in the 2010–15 regulatory control period. Table 6.6 sets out the components of United Energy's augex forecast.

Table 6.6 United Energy's proposed augex ($2015, million, excluding overheads)

Augex category	2016	2017	2018	2019	2020	Total
Zone substation and sub-transmission projects	12.1	14.4	21.5	23.1	12.5	83.6
HV feeders augmentation	11.4	6.0	5.1	3.3	3.5	29.3
Distribution system augmentation	11.2	11.8	11.2	10.5	8.9	53.7
Total augex proposal	34.7	32.3	37.8	36.9	24.9	166.5

Source: United Energy reset RIN; United Energy regulatory proposal; United Energy response to AER 018.

Note: Numbers may not add up due to rounding.

Our estimate of required augex for United Energy for the 2016–20 period is $127 million ($2015), a reduction of 24 percent on United Energy's proposal. We accept that a large proportion of United Energy's augex proposal reasonably reflects the capex criteria. However, we consider that United Energy's proposed augex forecast, in total, does not all reasonably reflect the capex criteria. This is because United Energy forecasts of maximum demand and inputs into its network planning framework are likely overstated, which has the effect of inflating its augex forecast. We are satisfied that our estimate of required augex, when combined with the rest of our capex decision, reasonably reflects the capex criteria over the 2016–20 period.

We have formed this view by reviewing all of the material submitted by United Energy in its regulatory proposal and in response to requests for further information, and stakeholder views from submissions. Our review used a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that Untied Energy will require to meet its obligations given expected demand growth and other augmentation drivers. This is consistent with the overall approach set out in our Expenditure Forecast Assessment Guideline.

First, we considered United Energy's proposed demand-driven expenditure in the context of past expenditure, demand and network utilisation.[63] We use this trend analysis as a starting point for our further project evaluation and as a cross-check on our overall augex estimate. As set out in appendix C, we found that United Energy's forecasts of maximum demand likely do not reasonably reflect a realistic expectation of demand over the 2016–20 period. The available evidence suggests that maximum demand will remain generally flat over the 2016–20 period, which is consistent with the AEMO's independent forecasts for United Energy's network. On this basis, we consider there is potential to delay some of United Energy's proposed augex projects.

Second, we reviewed United Energy's network planning methodology and criteria. This allowed us to consider whether it reflects good industry practice to determine if the proposed costs are consistent with incurring efficient and prudent expenditure. We found that United Energy's planning approach reflects good industry practice because it applies prudent economic and risk-based cost-benefit analysis to plan its network augmentation needs, including the application of VCR. However, we consider that United Energy has applied an unreasonably high VCR and the effect is that too many augmentation projects are included within the proposed augex forecast. We consider that AEMO's Victorian VCR estimate better reflects the willingness-to-pay of United Energy's customers for reliability supply of electricity.

Table 6.7 summarises the effect of applying AEMO's Victorian VCR on United Energy's augex forecast, based on information provided by United Energy. The primary effect is that a number of augex projects and programs can be prudently deferred into the 2020–25 regulatory control period or avoided. Section B.2.2 contains our reasoning and analysis in detail.

Table 6.7 Deferred augex based on applying AEMO's VCR ($2015, million)

Augex category	2016	2017	2018	2019	2020	Total
Zone substation and sub-transmission projects	0	0	6.8	10.8	5.5	23.1
HV feeders augmentation	0	0	0.07	1.4	2.6	4.1
Distribution system augmentation	0	0	0	6	6.4	12.4
Total deferred augex	0	0	6.9	18.2	14.4	39.6

Source: AER analysis; United Energy regulatory proposal; United Energy response to AER 003.

63 This is supported by the AER's augex model to generate trends in asset utilisation. We have not otherwise used the augex model to estimate forecast augex.

Third, we undertook a more detailed technical review of a sample of United Energy's major augex projects and programs. This informs our overall review by assessing whether United Energy adopts efficient design, costs and timing for its major projects so that the costs reflect the efficient costs that a prudent operator would require to achieve the capex objectives. We also consider the application and impact of maximum demand forecasts and VCR for the specific projects we reviewed.

In undertaking our review of United Energy's network planning methodology and the sample of its major projects, we draw on engineering and other technical expertise within the AER.

Table 6.8 sets out our alternative estimate of United Energy's augex forecast. We have calculated our alternative estimate of augex by adjusting United Energy's proposed augex forecast to exclude the capex that will be deferred using AEMO's VCR estimate. We have not made any other adjustments to United Energy's augex forecast. However we consider that our trend analysis and project technical reviews support our alternative estimate. In particular:

- The proposed augex for the Doncaster, Mornington and Carrum Downs zone substations (including the new Skye zone substation and sub-transmission line) would be deferred by applying AEMO's VCR estimate. Similarly, the forecast utilisation of these zone substations will be lower under a realistic demand forecast. This suggests that proposed augmentation of these zone substations (and associated sub-transmission lines) can be deferred or avoided under both a lower VCR and lower forecast of maximum demand.
- Some of the proposed augex for feeders and distribution transformers will be deferred by applying AEMO's VCR estimate. The proposed augex for these feeders and distribution transformers is also driven by forecast utilisation of these assets. A reduction in demand forecasts will reduce asset utilisation and allow some augmentation to be deferred or avoided. This suggests that some of the proposed augmentation of feeders and distribution transformer can be deferred or avoided under both a lower VCR and lower forecast of maximum demand.

United Energy's proposal submitted that network reliability will decrease if it defers augmentation projects based on AEMO's VCR. It submitted that because of this it would not be complying with clause 6.5.7(a) of the NER which requires it to submit a capex forecast that maintains current levels of reliability.

For the reasons set out in section B.2.2 below, we consider that this amount of capex (as included within our alternative estimate) will enable United Energy to satisfy its regulatory obligation under clause 5.2 of the Victorian Distribution Code in relation to reliability. In the same way, this also means that this capex is sufficient for United Energy to comply with clause 6.5.7(a) of the NER which relates to compliance with applicable regulatory obligations. We also consider that United Energy likely overstates the potential risks to maintain network reliability over the 2016–20 period.

Table 6.8 AER's alternative estimate of augex ($2015, million)

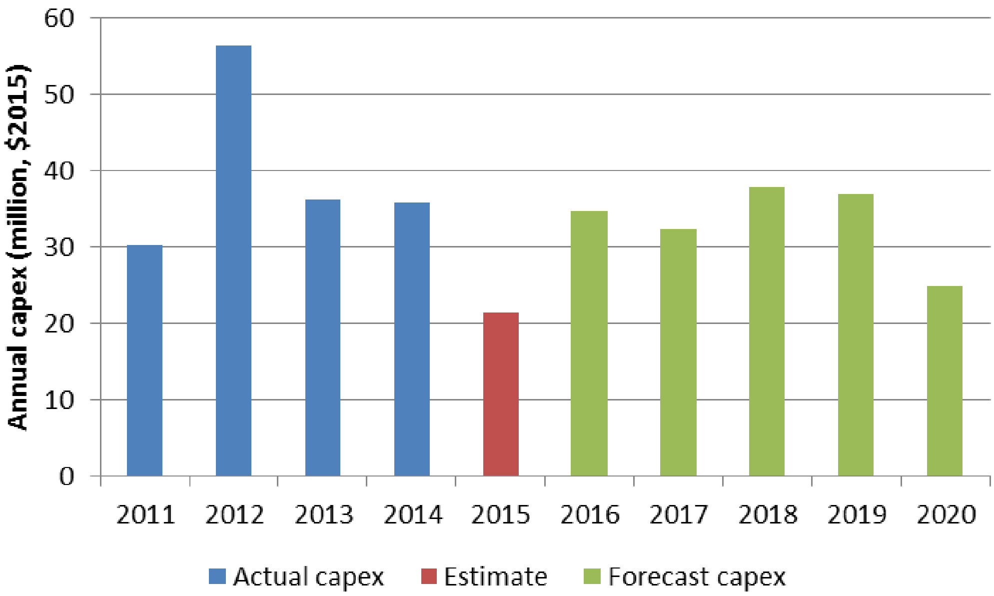
	2016	2017	2018	2019	2020	Total
United Energy augex forecast	34.7	32.3	37.8	36.9	24.9	166.5
AER adjustment	0	0	-6.9	-18.2	-14.4	-39.6
Alternative estimate	34.7	32.3	30.9	18.7	10.5	127.0
Difference	0.0%	0.0%	18.3%	49.3%	57.8%	23.8%

Source: AER analysis.

B.2.1 Trend analysis

United Energy proposes a forecast of $166.5 million ($2015) for augex (excluding overheads). Figure 6.7shows that United Energy's augex is 11 per cent lower compared to its actual augex in the 2011–15 regulatory control period, and is lower than the long-term average.[64]

Figure 6.7 United Energy's demand-driven augex historic actual and proposed for 2016–20 period ($2015, million)



Source: AER analysis, UED capex model, UED capex overview paper – augmentation, p. 10.

Note: Forecast expenditure in 2015–20 is inclusive of cost escalators and overheads. Overheads have been included in Figure 6.7 to ensure comparability with historical data.

[64] United Energy, *Regulatory Proposal 2016–20, Capital Expenditure overview*: *Augmentation*, 28 April 2015, p. 10.

United Energy stated that its forecast reduction in augex is a result of declining demand in the last couple of years due to electricity price rises and a slow economy providing some deferral of capital expenditure.[65] The proposed augex for 2016–20 is approximately 14 percent of United Energy's proposed total capex program.[66]

To examine the impact of a maximum demand on the need for network augmentation, we then look at network utilisation. Network utilisation is a measure of the installed network capacity that is, or is forecast to be, in use. Where utilisation rates decline over time (such as from a decline in maximum demand), it is expected that total augex requirements would similarly fall.

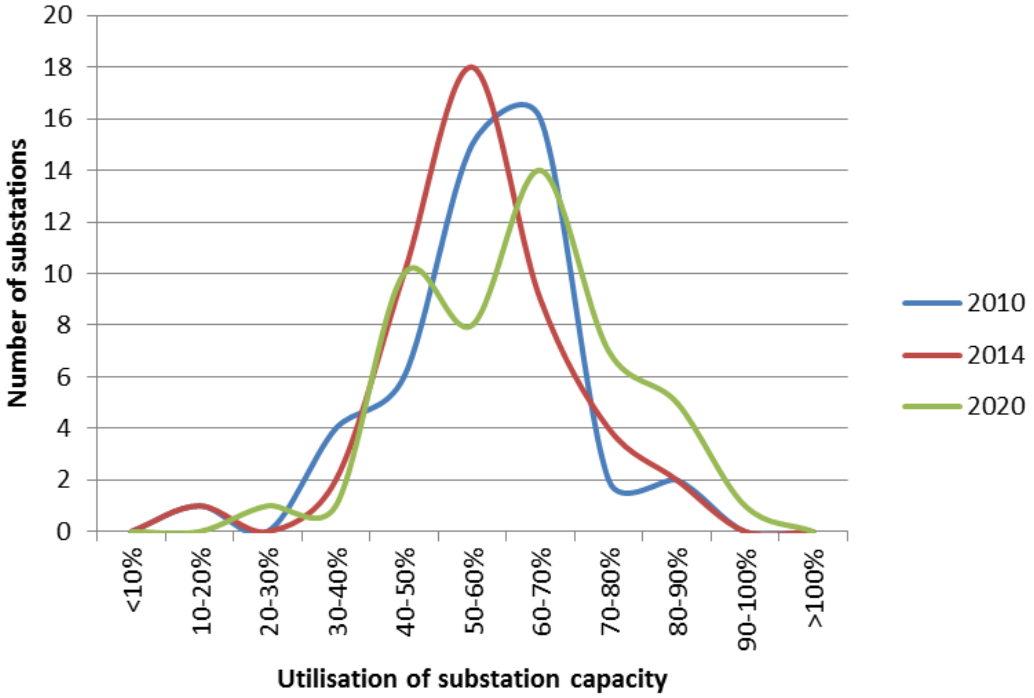
Figure 6.8 shows United Energy's zone substation utilisation between 2010 and 2014, and forecast utilisation in 2020 (at the end of the regulatory period). Between 2010 and 2014 United Energy undertook zone substation augmentation, which is shown in a decrease in the number of substations operating above 70 per cent of their maximum capacity. The flattening of maximum demand between 2010 and 2014 also contributed to reduction in the utilisation of the network.

The forecast of zone substation utilisation in 2020 is based on United Energy's forecast demand at each substation and existing levels of capacity (without additional augmentation). The increase in the number of highly utilised zone substations reflects United Energy's expectations on demand growth between 2015 and 2020 – shown in Figure 6.8 as a shift to the right compared to the utilisation recorded in 2014.

65 United Energy, *Regulatory Proposal 2016–20, Capital Expenditure overview: Augmentation*, 28 April 2015, p. 11.

66 United Energy, *Regulatory Proposal 2016–20*, 30 April 2015, p. 43.

Figure 6.8 United Energy zone substation utilisation 2010 and 2014 actual, and 2020 forecast



Source: AER analysis, United Energy's reset RIN.

Note: The utilisation rate is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.[67] Forecast utilisation in this figure is based on forecast weather corrected 50% POE maximum demand at each substation and existing capacity without additional augmentation over 2015–20.

United Energy's augex forecast and its forecast zone substation utilisation are based on a forecast of relatively high growth in maximum demand over the 2016–20 period. However, as we outline in appendix C, we consider that the available evidence points to flat demand growth for the 2016–20 period and therefore United Energy's forecast does not reasonably reflect a realistic expectation of demand.

United Energy identified the specific substations that it proposes to augment in the 2016–20 period. It proposes major projects to augment the Dromana, Notting Hill, Doncaster and Mornington Zone substations.[68] It also proposes installing a new zone substation at Skye to increase capacity in the Skye and Carrum Downs areas.[69]

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67 Normal cyclic rating is the maximum peak loading based on a given daily load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear.

68 United Energy, *Regulatory Proposal 2016–2020 Capital Expenditure overview: Augmentation*, 28 April 2015, pp. 45–48.

69 United Energy, *Regulatory Proposal 2016–20, Capital Expenditure overview: Augmentation*, 28 April 2015, p. 46.

We have reviewed the forecast utilisation at these substations under realistic demand forecasts to assess whether augmentation may be necessary to alleviate capacity constraints. This is consistent with the submission from the VECUA which states that:

> The AER needs to determine the distributors' augmentation capex needs utilising credible demand forecasts at the zone substation level and taking into account local system utilisation and excess capacity levels.[70]

Table 6.9 below shows the forecast utilisation (without augmentation) for the four zone substations proposed for augmentation (plus Carrum Downs) between 2015 and 2020, based on United Energy's demand forecasts and what we consider are realistic demand forecasts.[71] These figures show that United Energy, under its assumptions, expects utilisation to increase over the period for each substation. However, by 2020 the forecast utilisation is not expected to be consistently high at each zone substation, with forecast utilisation less than 80 per cent of normal cyclic rating for the Notting Hill and Mornington substations. This suggests that the need for augmentation is not consistent across the network, even under United Energy's demand assumptions.

Under what we consider to be realistic demand forecasts, Table 6.9 shows that forecast zone substation utilisation will generally remain flat. We consider that based on these findings, augmentation of the Notting Hill, Doncaster, Mornington and Carrum Downs (i.e. Skye) zone substations could be delayed or even avoided.

Table 6.9 Normal cyclic utilisation of zone substations proposed to be augmented

Zone substation	United Energy demand forecasts		Realistic demand forecasts	
	2015	2020	2015	2020
Dromana	0.87	0.99	0.83	0.83
Carrum Downs	0.74	0.85	0.71	0.71
Doncaster	0.78	0.84	0.74	0.70
Notting Hill	0.61	0.77	0.58	0.65
Mornington	0.57	0.62	0.54	0.52

Source: AER analysis, United Energy's reset RIN.

70 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 25.

71 As set out in Appendix C, we consider that AEMO's demand forecast reflect a more realistic expectation of demand over the 2016–20 period. We compared AEMO's forecast to United Energy's system-level demand forecast to determine the percentage overestimation of United Energy's forecast for each year of the 2016–20 period. We reduced the demand forecast for each zone substation by this percentage.

We understand United Energy (and the other Victorian electricity businesses) is in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR). We also note that AEMO will publish updated connection point demand forecasts for Victoria. We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we are open to United Energy submitting updated demand forecasts and we will consider these updated forecasts and other information (such as AEMO's revised connection point forecasts) in the final decision.

A number of submissions commented on network utilisation:

- The CCP submitted that United Energy's existing utilisation data and declining peak demand supports a view that there is little need for augmentation capex.[72] The CCP accepted that each Victorian distributor identifies that there are pockets of demand growth in its network that require augmentation. However, it also notes that there are also pockets of declining usage, meaning there is the potential to utilise assets no longer needed in some parts of the network and relocate them to where growth is being experienced.[73]
- The VECUA and the Victorian Greenhouse Alliances also submitted that there were significant investments in the Victorian networks over recent regulatory periods which have led to excess levels of network capacity and declining network utilisation.[74] Both submitted that we should consider this evidence closely in our capex assessment.

As noted by these stakeholders, we agree that current levels of network utilisation are important factors to consider in reviewing augmentation requirements over time. However, in terms of determining a level of augex for the 2016–20 period, it is also necessary to consider future demand and forecast network utilisation over this period. We considered this above.

We note the comments of CCP in relation to the ability to relocate assets. Advice from our technical and engineering staff suggests that it is generally not technically or economically feasible to relocate distribution assets to other parts of the network to any significant degree. We understand that any ability to relocate assets would be limited and would not impact materially on the required expenditure for the 2016–20 period.

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72 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, p. 17.

73 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, p. 17.

74 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 4 and 22–24; Victorian Greenhouse Alliances*, Submission to the AER - Local Government Response to the Victorian Electricity Distribution Price Review 2016–20 - 13 July 2015*, pp. 33–34.

B.2.2 Forecasting methodology and Value of Customer Reliability

This section considers United Energy's augmentation forecasting methodology and input assumptions, in particular the use of VCR assumptions.

United Energy submitted that it developed its augex forecast using a 'probabilistic planning approach'.[75] This is an economic approach to network planning in which United Energy compares the forecast cost to consumers from losing energy supply (e.g. when demand exceeds available capacity) against the proposed cost to augment capacity. The cost to consumers is calculated by multiplying the expected energy-at-risk (e.g. the energy not supplied when demand exceeds capacity) by VCR. When the cost to consumer is higher than the cost of augmentation, the investment will proceed.

VCR measures the willingness of customers to pay for the reliability support of electricity, in dollar per kilowatt hours (kWh). Probabilistic network planning that considers VCR is well accepted as being consistent with good industry practice and prudent network planning because the decision on whether to invest takes into account the economic value to customers of electricity supply. When VCR lowers, this suggests that fewer investments will proceed because customers may be more accepting of risk in terms of reliability of electricity supply.

The Victorian Distribution Code (which sets jurisdictional obligations for network reliability, asset planning and connections) also sets requirements relating to prudent network planning and reliability. In particular, it requires that United Energy:

1. use best endeavours to develop and implement plans for the maintenance of its assets and for the establishment and augmentation of transmission connections, to minimise the risks associated with the failure or reduced performance of assets and in a way which minimises costs to customers (taking into account distribution losses)[76]
2. use best endeavours to meet the reliability targets required by the AER's regulatory determination, and otherwise meet reasonable customer expectations of reliability of supply.[77]

We have reviewed United Energy's network planning and augmentation forecasting approach through a sample of its projects. On the basis of our review, we are satisfied that United Energy applies a cost-benefit and probabilistic planning methods that take into account VCR and reasonable risk-analysis to assess the merits of investment options. However, we consider that United Energy's VCR is over-estimated and likely does not reflect the expectations of its customers across its network. Our reasons are set out in detail in the next section.

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[75] United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 64.

[76] Victorian Distribution Code, clause 3.1.

[77] Victorian Distribution Code, clause 5.2.

United Energy's VCR

United Energy applies a VCR of 56.8 ($/kWh) for its augex planning. This VCR is 30 per cent higher than the VCR adopted by the other Victorian DNSPs, which adopt AEMO's 2014 Victorian VCR.

AEMO VCR

In September 2014, AEMO released the results of its first national VCR survey.[78] As shown in Table 6.10, the updated Victorian VCR has decreased significantly compared to the previous values used in 2013. This is largely driven by commercial and agricultural customers, however, decreases were observed across all customer groups. The Victorian VCR value is consistent with the VCR values for other NEM states.

Table 6.10 Summary of Victorian VCR between 2013 and 2014 ($/kWh)

Year	Victoria (weighted average)	Agriculture	Commercial	Industrial	Residential
2013	63.09	147.76	113.05	44.93	27.19
2014	39.50	47.67	44.72	44.06	24.76
Change	-38%	-68%	-60%	-2%	-9%

Source: AEMO VCR report, regulatory proposals.

AEMO suggested that the decrease in the VCR could be explained by increased electricity costs since 2007–08 and the implementation of energy efficiency savings by commercial and agricultural businesses.[79] It is also likely that previous VCR values have been over-stated because they did not reflect up-to-date customer information and the VCR has been maintained in real terms, with no comprehensive survey for a number of years.

AEMO surveyed customers to determine their willingness to pay under twenty-four different outage scenarios.[80] AEMO's VCR for each customer type is based on the weighted-average VCR of these different outages. The Victorian $39.50/kWh is then determined based on the weighted average of the VCR for each customer-type.

AEMO stated that VCR values may differ across networks due to specific characteristics and customers of the network. In its VCR application guideline, AEMO stated that VCR values may be re-calculated using one or more of the following approaches:

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78 AEMO, *Value of Customer Reliability Review*, September 2014. To develop its revised VCR, AEMO surveyed approximately 3000 residential and business customers across the NEM states. For Victoria, this is the first survey of VCR since the previous Victorian VCR study completed in 2007–08.

79 AEMO, *Value of Customer Reliability Review*, September 2014, pp. 1 and 36.

80 For example, different outage timing (e.g. summer/winter/weekend/weekday) and outage duration (e.g. 0-1 hour/1-3 hour).

- Locational VCR — calculated by re-weighting the VCR review results using the composition of the customer demand being served. This may more precisely represent the VCR value expressed by customers at a local level than using the state-level aggregated VCR value as a proxy.[81]
- Outage specific VCRs – calculated by re-weighting the probabilities of different outage types to place more weight on specific outage scenarios (i.e. ones occurring during peak times).[82]
- Local knowledge – calculate a specific VCR using local knowledge where it is possible to provide reliable evidence of alternative, better substantiated values.[83]

United Energy VCR

United Energy's VCR of $56.8/kwh is based on re-weighting the values within AEMO's Victorian VCR. While United Energy accepted that AEMO's VCR survey results reflect the best estimate of customers' willingness to pay, it does not consider that the Victorian VCR is correct for its business. United Energy made the following changes to AEMO's VCR estimate.

First, it re-weighted the different outage probabilities estimated by AEMO and focused solely on the VCR during summer peak-periods where there are outages of less than one hour and 1 to 3 hours. United Energy submitted that it only focused on these two outage scenarios because it targets network augmentation during peak summer periods where network capacity is expected to be exceeded.

Second, it changed the Victorian residential VCR value for outages less than one hour during peak summer times from $28.14/kWh to $43.10/kWh (which reflects the NSW VCR value for this outage type). In support of this change, United Energy submitted that:

Values for all other states for this condition are $42.91 for Qld, $42.75 for NSW, $41,49 for SA and $45.28 for Tas, with an average of $43.10/kWh. For Victoria, AEMO has specified $28.14/kWh. Furthermore this value is inconsistently lower than the 1-3 hour VCR values. There is no valid reason why residential customers in UE's service area value reliability any differently to any other residential customers in other states in the NEM, hence UE deems that $43.10/kWh is more appropriate to use for our residential customers for the 0-1 hour outage condition.[84]

Third, it changed the weighting placed on large and small businesses that were adopted in AEMO's VCR calculation. United Energy submitted that AEMO's Victorian

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[81] AEMO, *Value of Customer Reliability Review – Application Guide*, December 2014, p. 6.

[82] AEMO, *Value of Customer Reliability Review – Application Guide*, December 2014, p. 9.

[83] AEMO, *Value of Customer Reliability Review – Application Guide*, December 2014, p. 9.

[84] United Energy, *Regulatory Proposal 2016–20*, 30 April 2015, Attachment NET117 (Value of Customer Reliability (VCR) Application Guideline), p. 7.

VCR over-accounts for large businesses and under-accounts for small businesses when compared to its customer base.

AER position

We do not accept United Energy's composite VCR and instead consider that AEMO's Victorian VCR should be applied to United Energy's augex forecast. This is for the following reasons.

First, we disagree that the Victorian residential VCR value for outages less than one hour during peak summer times is incorrect. This outage event value is based on AEMO's Victorian survey results which we consider provide the most accurate reflection of how Victorian residential consumers value reliability. We consider that there are a number of plausible hypotheses which may explain why the results differ for Victoria compared to other states. For example, AEMO states that this is likely due to high residential gas usage in Victoria.[85]

Second, United Energy's VCR may overstate the willingness of its consumers to pay for reliability because it only reflects the willingness of consumers to pay for reliability during peak summer conditions. The outage-specific VCR is higher than during other outage times. While United Energy submitted that this VCR reflects its augmentation practices (e.g. only augmenting when demand exceeds capacity during summer peak times), it does not necessarily reflect the value placed by United Energy's customers across its network. In particular, because United Energy places zero weight on longer outage times, and off-peak, winter or weekend outages, it does not allow for a complete picture of the consumer's perspective.

In contrast, AEMO's VCR's is based on the weighted average VCR of different types of customers and outage scenarios (e.g. time of year and length of outage). This seeks to provide a complete and balanced understanding of customer preferences. While AEMO's application guideline stated that it is appropriate to place more weight on specific outage scenarios, it does not appear to contemplate scenarios in which 22 out of 24 outage scenarios are excluded.

This position is supported by a submission from the VECUA. The VECUA stated that it does not consider that United Energy's approach is evidence-based or is supported by credible willingness to pay information.[86]

We consider that United Energy's adjustments to customer composition (e.g. changing the weighting placed on large and small businesses) are reasonable. United Energy's calculations are based on reliable data sourced from Interval Meter Store and Smart Meter Data over a 12 month period, which are verified against total energy sales.

[85] AEMO, *VCR report*, December 2014, p. 18.

[86] VECUA*, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals* - 13 July 2015, p. 28.

Having said that, based on our review of United Energy's calculations, it appears that changing the customer composition has only a marginal impact on the VCR value.

We note that there may be alternative VCRs that are appropriate to apply to United Energy's network (e.g. re-weighting outage scenarios that apply more weight on peak summer days but do not ignore all other scenarios). However, in the absence of other information, we consider that AEMO's VCR should be applied to United Energy's augex forecast. We consider the implications of applying this VCR in the next section.

Implications for augmentation capex and reliability

Applying AEMO's VCR to calculate United Energy's augmentation requirements leads to $39.6 million ($2015) of proposed capex deferred from the 2016–20 period. As set out previously, when the estimate of VCR lowers this suggests that some projects will now be deferred as their cost would now exceed the value of load at risk.

Table 6.11 sets out United Energy's proposed projects and capital works that will be deferred by applying AEMO's VCR. This is based on information provided by United Energy about the proposed timing of its capital projects under its VCR and AEMO's VCR.

Table 6.11 Deferred augex based on applying AEMO's VCR ($2015, million)

Category	Capex	Years deferred	Capex deferred
Doncaster zone substation and sub-transmission upgrades	8.6	3	8.6
Mornington zone substation upgrade	2.9	2	1.4
New Skye substation and sub-transmission line	25.7	3	12.8
TSTS-WD sub-transmission line	0.2	3	0.2
Feeder upgrades	4.1	2	4.1
Distribution System (project P3)	28.6	2	11.2
Distribution System (project P2)	10.4	1	1.2
Total			39.6

Source: United Energy, *Regulatory Proposal 2016–20*, *NET117*, April 2015, pp. 14–15; United Energy, *Response to AER information requests IR#003 and IR#018.*

We have calculated our alternative estimate of United Energy's total augex by adjusting its proposed augex forecast to exclude the $39.6 million opex that will be deferred using AEMO's VCR estimate. As set out in section B.2.1 and appendix C, deferring this capex from the 2016–20 period is also supported by our analysis of United Energy's forecast demand and network utilisation and our project-specific reviews.

United Energy submitted that if this capex is deferred from the 2016–20 period, network reliability (SAIDI) will decrease by 4 minutes per annum based on proposed reductions in spare capacity and more outages occurring simultaneously. It submitted that because of this it would not be complying with clause 6.5.7(a) of the NER which requires it to submit a capex forecast that maintains current levels of reliability.[87]

At the same time, United Energy also noted that clause 5.2 of the Victorian Electricity Distribution Code requires it to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply. United Energy suggested that there is conflicting evidence of its customers' expectations of reliability of supply:

- feedback from its customers that they expect United Energy to maintain reliability and not allow reliability to deteriorate
- AEMO's Victorian VCR which United Energy states suggest reliability should be permitted to deteriorate further.[88]

[87] United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 62.
[88] United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 62.

Under NER clause 6.5.7(a)(2), United Energy is required to submit a capex forecast that maintains reliability only to the extent that there is no applicable regulatory obligation or requirement in relation to the reliability of United Energy's distribution system. We consider that clause 5.2 of the Victorian Electricity Distribution Code sets a regulatory obligation on United Energy in relation to reliability.

We consider that AEMO's VCR estimate is relevant to United Energy's obligation under clause 5.2 of the Victorian Electricity Distribution Code. This is because this reflects the most current value of customers' expectations of the reliability of electricity supply (as discussed above). This does not necessarily conflict with customer views that reliability should not deteriorate because VCR does not reflect absolute levels of reliability, or expected reliability outcomes. Rather it reflects customers' tolerance of risk and the trade-offs between reliability and prices.

Having said that, we consider it is difficult to accept the accuracy of United Energy's assertion that network reliability will deteriorate by 4 minutes per annum over 2016–20 based on deferring the capex set out in Table 6.11. This is because:

- The primary impact of the change in VCR is to defer projects from the end of the 2016–20 period into the next period. Even if these projects were not deferred, any associated reliability outcomes would have not been felt until after 2016–20. Hence, deferring these projects should not have any material effect on the reliability outcome over 2016–20.
- If maximum demand that United Energy forecasts over the 2015–20 period does not eventuate, there will likely be additional spare capacity in United Energy's network. This will allow United Energy to defer projects without risking outages. As set out in appendix C and above, we are not satisfied that United Energy's demand forecasts reasonably reflect a realistic expectation of demand and demand will likely be lower than forecast.
- United Energy's reliability performance is influenced by a number of factors, including the configuration and condition of its network assets. This is a result of its historical investment and operating practices. Given the size of United Energy's asset base and that most network assets have an expected life in excess of 50 years, a small change in capex is unlikely to result in an abrupt change in reliability performance.

In conclusion, we consider that United Energy's proposed augmentation capex does not reasonably reflect the capex necessary to comply with an applicable regulatory obligation in relation to reliability. We have substituted a forecast augex that reasonably reflects the capex criteria.

B.2.3 Project reviews

We reviewed a sample of United Energy's major augex projects and programs to consider whether United Energy's planning supports augmentation under realistic demand forecasts and AEMO's VCR. In particular, we reviewed the United Energy's supporting evidence and documentation for the proposed:

- new Skye zone substation and associated sub-transmission line (which is proposed to alleviate forecast capacity constraints at Carrum Downs zone substation)
- feeder augmentation and pole top capacitor program
- distribution system (low voltage wires and transformers) augmentation program.

On the basis of our review, we observe that reductions in demand forecasts and adopting AEMO's VCR will reduce the need for augmentation based on the specific project analysis undertaken by United Energy. Our key findings are as follows.

First, United Energy's proposed capex and timing for the Skye zone substation and sub-transmission line satisfies a cost-benefit analysis based on Untied Energy's VCR and demand forecast. However, lowering the demand forecasts and adopting AEMO's VCR means that the cost to consumers from forecast unserved energy drops by up to 50 per cent. This means that the estimate cost of this project ($26 million) no longer satisfies a cost benefit test.

Second, for United Energy's feeder augmentation program, it will only consider possible augmentation of a feeder if utilisation reaches 85 per cent and above.[89] United Energy showed that 6 feeders are expected to exceed their normal cyclic rating in 2015–16 and a further 11 by 2016–17. It also shows that a further 85 distribution feeders are expected to exceed 85 percent of their rating by 2016–17.[90] From this, United Energy selects 13 feeders that are economical to augment.[91]

Under a lower demand forecast, we calculate that up to 75 per cent of targeted feeders will not exceed their cyclic capacity rating by 2015–16. This means that it may be economical to defer augmenting these feeders until they become more highly utilised. Given that demand is not expected to grow as strongly as United Energy forecasts (as we set out in appendix C), this may mean that augmentation for a number of these feeders could be deferred into the next regulatory period.

Third, for United Energy's distribution system augmentation program, it proposed to augment distribution substations with peak utilisation of 120 per cent (daily normal cyclic rating) and low voltage circuits that have experienced outages.[92] United Energy's supporting documentation provided figures that show the utilisation of existing

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89 United Energy, *Regulatory Proposal 2016–20, Attachment: 2014 Distribution Annual Planning Report*, April 2015, p. 309.

90 United Energy, *Regulatory Proposal 2016–20, Attachment: 2014 Distribution Annual Planning Report*, April 2015, pp. 309–310.

91 United Energy, *Regulatory Proposal 2016–20, Attachment: 2014 Distribution Annual Planning Report*, April 2015, pp. 309–313.

92 United Energy, *Regulatory Proposal 2016–20, Attachment: Distribution system augmentation strategy*, 7 May 2014, p. 9.

distribution substations and how it has changed over time in response to demand.[93] This showed that reduced demand growth between 2009 and 2014 reduced the number of distribution substations with utilisation above 120 per cent. Given that actual demand over 2016–20 will likely be less than United Energy forecasts, this will likely reduce the number of distribution substations that require augmentation.

This project-specific analysis supports our findings in our analysis of United Energy's forecast demand and network utilisation, and our review of the use of VCR. In particular:

- The proposed capex for the new Skye zone-substation and sub-transmission line no longer satisfies a cost-benefit analysis under a realistic demand forecast. This suggests that the capex can be deferred or a lower cost option adopted. Under AEMO's VCR, this capex will also be deferred because it reduces the cost to consumers if the project does not proceed in the 2016–20 period.
- If actual demand over the 2015–20 period is less than Untied Energy forecasts, this will reduce asset utilisation and allow some augmentation to be deferred or avoided. Some of the proposed augex for feeders and distribution transformers will also be deferred under AEMO's VCR estimate.

B.3 Forecast customer connections capex, including capital contributions

Connections capex is incurred by United Energy to connect new customers to its network and where necessary augment the shared network to ensure there is sufficient capacity to meet the new demand.

New connection works can be undertaken by United Energy or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer contribution, United Energy is required to take into account the forecast revenue anticipated from the new connection[94]. These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all consumers. Customer contributions are sometimes referred to as capital contributions or capcons.

The mix between net capex and capcons is important as it determines from whom and when United Energy recovers revenue associated with the capex investment. For works involving a customer contribution, United Energy recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where United Energy recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the

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93 See Figure 2a in United Energy, *Regulatory Proposal 2016–20, Attachment: Distribution system augmentation strategy*, 7 May 2014, p. 12.

94 In Victoria, the Essential Services Commission's (ESCV) Guidelines 14 and 15 determine the customer connection charges.

calculation of United Energy's annual revenue requirement.[95] That is, United Energy recovers net capex investment across the life of the asset through revenue received for the provision of standard control services. United Energy has forecast $249.1 million ($2015–16) of expenditure for connection works for the 2016–20 regulatory control period, net of customer contributions. Table 6.12 shows United Energy's forecast for connections expenditure and customer contributions.

Table 6.12 United Energy proposed connections capex ($2015–16, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Gross connections capex	48.2	49.3	50.6	50.1	50.9	249.1
Customer contributions	17.7	18.1	18.3	18.7	18.5	91.3
Net connections capex	30.5	31.2	32.3	31.3	32.4	157.7

Source: United Energy, Response to information request AER 020 (note: numbers may not add due to rounding)

We accept both United Energy's net connections capex forecast and customer contributions forecast and have included these in our substitute estimate of net capex.

In determining that United Energy's forecasts meet the capex criteria, we considered:

- the trends in United Energy's connections capex across time, and
- United Energy's forecast methodology.

We note that stakeholders have raised some concerns with the classification of connection services.[96] We discuss the determination of service classifications in attachment 13.

B.3.1 Trend analysis

As we note in section A.2 above, when assessing United Energy's connections capex we have considered the trends in actual and forecast capex.[97] We have used this analysis to provide context to United Energy's proposal, in particular trend analysis has allowed us to:

- gauge the degree to which United Energy's proposal is consistent with past connections capex, and

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95 For more information on the building blocks included in the determination of United Energy's annual revenue requirement see our attachments on the Regulatory Asset Base and Regulatory Depreciation.

96 Consumer Challenge Panel 3 – Victorian DNSPs revenue reset comments on DNSPs proposal, pp. 54–56. Vector - Submission on the AER's Issues Paper on Victorian Electricity Distribution Pricing Review for 2016–2020, 13 July 2015, pp. 4–5.

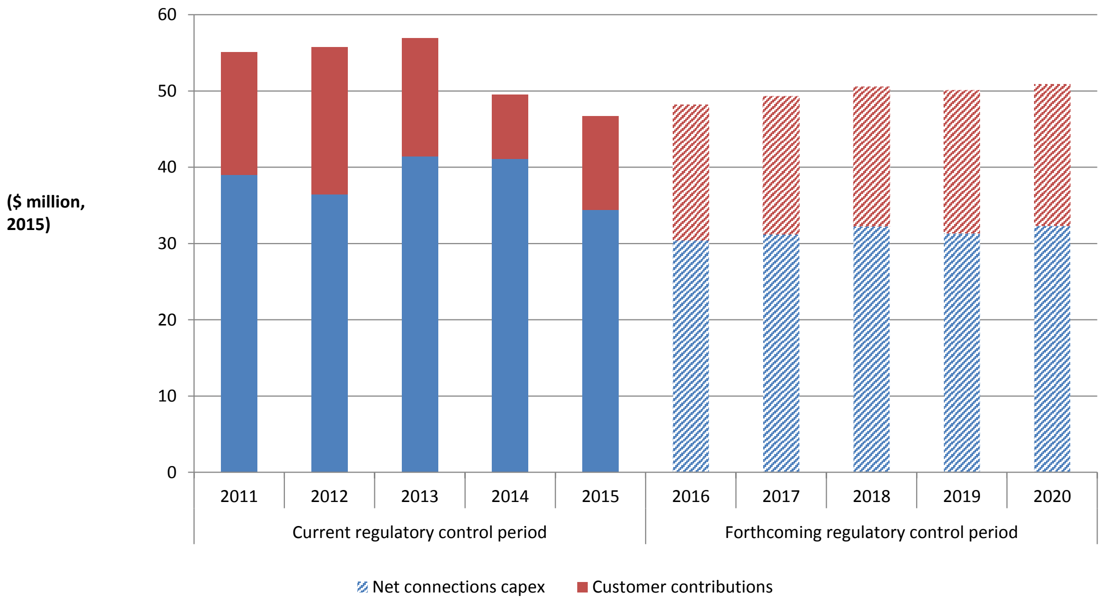
97 This is one of the capex factors to which we are required to have regard to under the NER (NER, cl. 6.5.7(a)(5)).

- understand variations between United Energy's capex allowances for connections and that incurred in the 2011–15 regulatory control period.

Actual and forecast customer connections

Figure 6.9 shows the trend in United Energy's actual and forecast gross connections capex by both net connections capex and customer contributions.

Figure 6.9 United Energy connections and capital contributions – historic actual and proposed for 2016-20 regulatory control period ($2015–16, million)



Source: United Energy, Capex Overview Paper- Connections FINAL 28 April p. 15 and Reset RIN.

Figure 6.9 shows that between 2011 and 2015 gross connections capex has been relatively stable, tailing off towards the end of the period. We note that United Energy is forecasting net connections capex that is consistent with the downward trend overserved from 2013.

Historic spend

In determining whether we are satisfied that United Energy's forecast connections capex meets the criteria in the rules we must have regard to United Energy's actual and expected capex during any preceding regulatory periods.[98] We note that United Energy is expecting to underspend its gross connections capex allowance in the current regulatory period by $34 million ($2015–16).[99] This consists of an $80 million

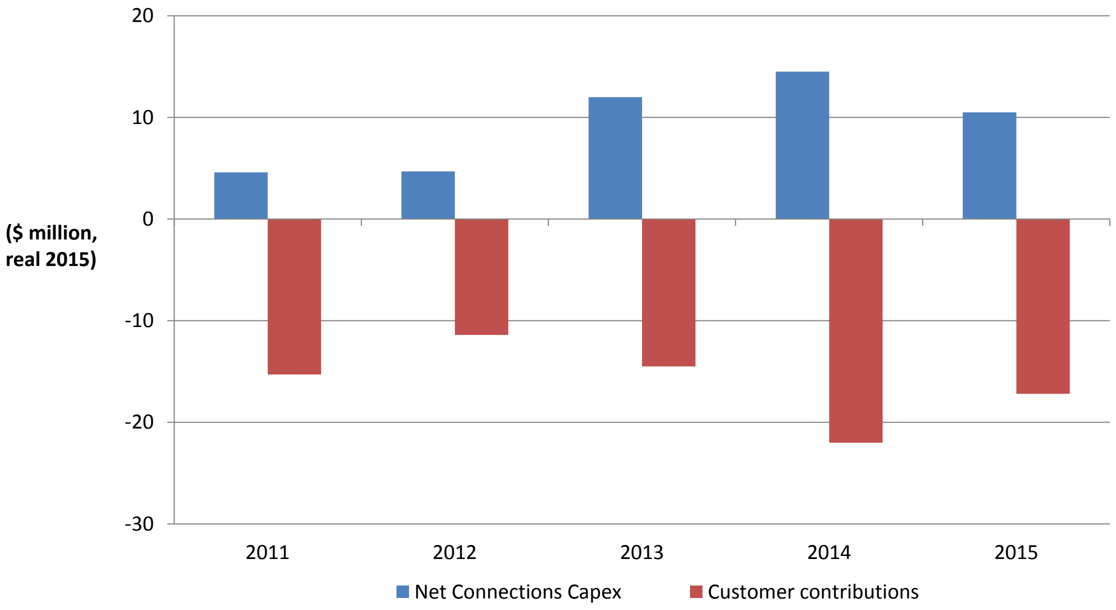
98 NER 6.5.7(e)(5).

99 United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 10.

($2015–16) under recovery of the forecast customer contributions and an overspend on net connections capex of $46 million ($2015–16).[100] This follows $70 million overspend in the previous regulatory control period compared to the AER determination.[101]

Figure 6.10 compares United Energy's connections capex spend in the 2011–15 regulatory control period with the allowance included in the capex determination.

Figure 6.10 United Energy 2011–15 regulatory control period connections capex – actual and allowed ($2015–16, million)



Source: United Energy, Capex Overview Paper- Connections 28 April Table 8.

In its proposal United Energy notes over the 2011–15 regulatory control period that United Energy:

- connected more customers than forecast
- undertook these higher volumes at a lower total cost than forecast, and
- funded more of the costs of connections directly, as a result of customer contributions being lower than forecast.[102]

United Energy considers that the above factors coupled with its expectation to underspend compared to its allowance demonstrates that its connections capex in the current regulatory period is efficient.[103] We note that a major feature of the regulatory

[100] United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 10.
[101] United Energy, *Capex Overview Pape r- Connections FINAL,* 28 April 2015, Table 8, p. 8.
[102] United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 17.
[103] United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 17.

framework is the incentives United Energy has to achieve efficiency gains whereby actual expenditure is lower than the allowance. Differences between actual and allowed connections capex could be the result of efficiency gains, forecasting errors or some combination of the two.

We have been mindful of the above trends when assessing United Energy's forecast methodology for the 2016–20 regulatory control period.

B.3.2 United Energy forecasting methodology

United Energy categorises its connections capex into a series of activity based connection type forecasts. These activity forecasts correspond to each standard control customer connection service as classified in the final framework and approach.[104]

United Energy's gross connections capex forecast consists of projections of the volumes and unit rates of these categorisations. United Energy then separately produces a forecast of customer contribution revenue to determine the split between net connection capex and customer contributions for the period.[105]

In determining whether we are satisfied United Energy's forecast meets the capex criteria, we have assessed each phase of the forecast as set out below.

Unit rates

For each connection categorisation, United Energy derives separate unit rates according to whether the volume of each type of connection project is "unitised" or "non-unitised".[106] Unitised projects have lives of up to 12 months whereas non-unitised projects have lives that can extend to up to three years.[107] Analysing each type, we note:

- the non-unitised projects are individually costed and rely on average actual unit rates. Each unit rate or average cost for a series of project types is determined by sourcing data from existing projects across the past three financial years[108], and
- the unitised projects are based on standardised contractual unit rates for unitised United Energy projects.

We are satisfied that United Energy's unit rates are reasonable given they are based on verifiable historical data. We have sought to verify this by assessing the unit rates included in United Energy's forecast and note that these are declining when compared

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104 United Energy, *Regulatory Proposal 2016–20, Attachment: Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 12. (United Energy, *Capex Overview Paper - Connections FINAL*, 28 April 2015).

105 United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 19.

106 United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 19.

107 United Energy*, Capex Overview Pape r- Connections FINAL*, 28 April 2015, p. 21.

108 United Energy, *Capex Overview Paper - Connections FINAL*, 28 April 2015, Table 8, p. 19.

to the historical unit rates underlying the current period expenditure.[109] United Energy also notes in its proposal that contracts with its service providers are competitively tendered on an arms' length basis.[110] Further, we note that the use of historical expenditure works in step with the regulatory framework to reveal efficient cost over time.

Volumes

United Energy then takes the unit rates and multiplies these by volume forecasts for each categorisation of connection. United Energy produces each volume forecast by applying growth indices to the count of projects in the most recent year for each categorisation. These growth indices rely on economic and industry forecasts published by the Australian Construction Industry Forum (ACIF).

We are satisfied that the growth rates underlying United Energy's forecast represent a realistic expectation of the volume connection activity United Energy will be required to undertake over the 2016–20 regulatory control period. In determining this we have compared this growth rate to other available data on the rate of residential construction and found they follow a similar trend.

Figure 6.11 below shows the aggregate historical and forecast of the ACIF data underlying the growth indices that United Energy relied on, which we have compared to the actual and forecast new dwelling data for Victoria published by the Housing Institute of Australia (HIA).[111] We consider the HIA is a reasonably well accepted industry standard indicator of commercial and industrial connection activity. HIA is a private-sector industry association comprising mainly house construction contractors. HIA forecasts have been used by the industry since 1984.[112]

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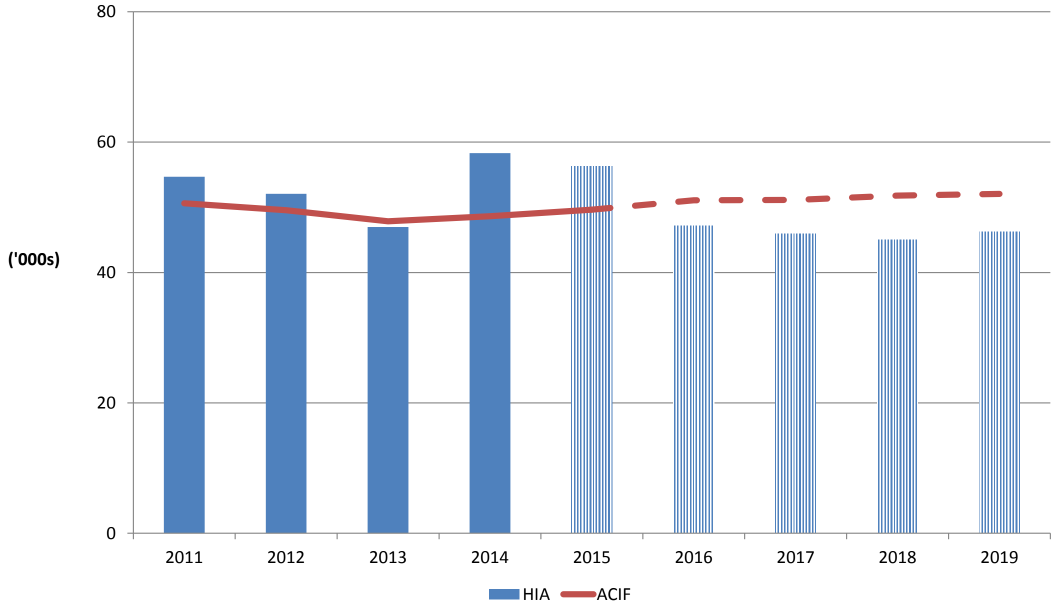
109 This is based on the volume weighted unit costs reported within United Energy's RIN data, with the exception of the "Simple connection LV - COMMERCIAL/INDUSTRIAL" category.

110 United Energy, *Capex Overview Paper - Connections FINAL,* 28 April 2015, Table 8, p. 27.

111 HIA Housing Forecasts, May 2015.

112 Mills, Anthony and Harris, David and Skitmore, Martin R., *The Accuracy of Housing Forecasting in Australia,* Engineering Construction and Architectural, Management 10(4), 2003, pp. 245–253. Accessed from: http://eprints.qut.edu.au/archive/00004441/.

Figure 6.11 ACIF and HIA Victorian dwelling growth – actual and forecast



Source: United Energy - NET 328 - ACIF report -Long term -Work Forecast and HIA Housing Forecasts, May 2015.

We note the forecast growth of both series follow the same rates of initial decline before plateauing across the actual and forecast periods. On this basis, we are satisfied that the volume growth rates relied on by United Energy to produce its connections represent a reasonable forecast.

As such we are satisfied that United Energy's combination of the unit rates and volume forecasts represents a reasonable forecast of gross connections capex and have included the proposal in our alternative capex forecast.

Customer Contributions

When a new customer connects to the network, it is required to provide a contribution towards the cost of the connection assets. This contribution can be monetary or contributed (gifted assets).

In this section we consider United Energy's application of the relevant guideline to forecast the customer contributions. We then consider the forecast of contributions, by

- assessing whether the forecast was prepared in accordance with the relevant connection charge guideline
- comparing the forecast to the trends in actual customer contributions, and
- assessing the reasonableness of United Energy's forecasting methodology.

Connection Charge Guideline

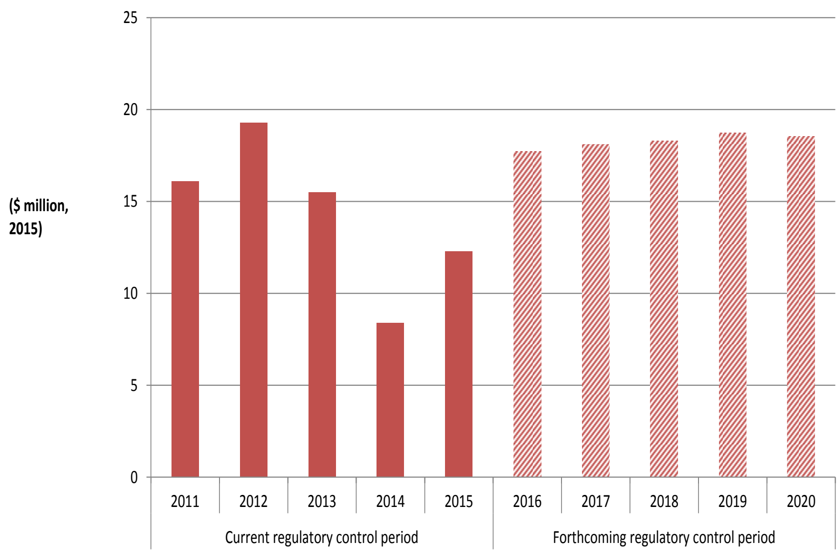
At the time of making this preliminary decision, United Energy was required to follow Essential Services Commission's (ESCV) Guidelines 14 and 15 to determine the customer connection charges. In September 2015, we were advised that the Victorian Government intended to implement Chapter 5A of the NER for the 2016–20 regulatory control period. This change will impact on how the customer contribution is calculated.

This preliminary decision sets out our views on the methodology used by United Energy to determine its customer contribution under the old framework. We intend to work with the Victorian Government and United Energy to fully implement the change to the AER's connection charging guideline under Chapter 5A of the rules. We expect that United Energy will base its revised proposal on the new charging framework and also consider, where relevant, our consideration of their existing methodology.

Actual and forecast customer contributions

Figure 6.12 shows the trend in United Energy's actual and forecast customer contributions and compares customer contributions for the 2011–15 regulatory control period with United Energy's forecast for the 2016–20 regulatory control period.

Figure 6.12 United Energy's customer contributions – actual and proposed for 2016-20 regulatory control period ($2015–16, million)



Source: United Energy, *Capex Overview Paper- Connections FINAL*, 28 April 2015.

To determine whether we are satisfied this forecast meets the capex criteria, we have assessed the methodology United Energy has relied on to produce this forecast.

United Energy forecast methodology

United Energy's forecast of customer contributions consists of a forecast of:

- cash contributions received from customers for works it undertakes, and
- gifted assets.

With respect to its cash contribution forecast, United Energy adopts a phased approach. The first step involves back-casting each project United Energy undertook in the current regulatory period to establish the contribution the customer would have made if calculated on current prices. These back-cast contribution amounts are then used to generate a historical average contribution rate for each category of connection. United Energy then applies this contribution rate for each category of connection included in its gross connections forecast.[113]

United Energy forecasts the gifted asset component of its contribution forecast based on the historic trend and internal knowledge and understanding of potential projects expected to occur in coming years.[114] United Energy combines this gifted asset component with the cash contribution component to produce a contribution amount for each category of connection. United Energy nets off these contribution amounts to produce the net capex forecast.[115]

We are satisfied that United Energy's use of historical percentage rates is derived from a sufficiently large sample of projects. Further we note that in combination with the trending approach applied to generate its gross connections forecast, we are satisfied that it has demonstrated that the sample used is reflective of the projects included in its forecast.

United Energy's application of the ESCV's Guideline 14 yields a significant increase in the proportion of the gross forecast capex being recovered through customer contributions than was the case in the 2011–15 regulatory control period. In simple terms, the customer contribution is determined by deducting the incremental revenue that United Energy will receive from the new customer over a set period, from the incremental cost of the connection.[116] Therefore, where the incremental revenue from the customer is expected to decline, the 'gap' between incremental cost and revenue widens. This has the effect of increasing the contribution required from the new customer.

United Energy in its proposal notes by applying the ESCV's guideline 14:

> In the current period, we are expecting to underspend the AER's allowance for Gross Connections capital expenditure by $34 million and we under-recovered our Customer Contributions against the AER's forecast by $80 million. This means that we overspent our Net Connections capital expenditure by $46 million. As a result, we undertook more work than was forecast and we were not funded for this by developers (and other new customers). There was therefore a "wealth transfer" from all existing customers to developers (and other new customers) during the current period.

[113] United Energy, *Capex Overview Paper- Connections FINAL,* 28 April 2015, p. 22.

[114] United Energy, *Capex Overview Paper- Connections FINAL* 28 April 2015, p. 22.

[115] United Energy, *Capex Overview Paper- Connections FINAL* 28 April 2015, p. 22.

[116] The period is set in Guideline 14 and forecasts of incremental revenue and costs are made over 15 years for a business customer and 30 years for a residential customer.

In total, we are satisfied that the customer contributions forecast by United Energy are consistent with the requirements set out in the ESCV's Guidelines 14 and 15. However, as noted above, this estimate will likely be amended in United Energy's revised proposal to take account of the implementation of Chapter 5A of the NER.

B.4 Forecast repex

Repex is driven by the inability of network assets to meet the needs of consumers and the overall network. The decision to replace can be based on cost, quality, safety, reliability, security, or a combination of these factors. In the long run, a service provider's assets will no longer meet the requirements of consumers or the network and will need to be replaced, refurbished or removed.[117] Replacement is commonly driven when the condition of the asset means that it is no longer economic or safe to be maintained. It may also occur due to jurisdictional safety regulations, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network. Technological change may also advance the timing of the replacement decision and the type of asset that is selected as the replacement.

Electricity network assets are typically long-life assets and the majority will remain in use for far longer than a single five year regulatory period. Many of these assets have economic lives of 50 years or more. As a consequence, a service provider will only replace a portion of its network assets in each regulatory control period. The majority of network assets will remain in commission well beyond the end of any single regulatory control period.

Our assessment of repex seeks to establish the portion of United Energy's assets that will likely require replacement over the 2016–20 regulatory control period, and the associated expenditure. United Energy's forecast of repex includes estimates of the capex it considers necessary to comply with safety obligations implemented in response to the 2009 Victorian Bushfires Royal Commission (VBRC). Our analysis of United Energy's repex forecast for VBRC is included at appendix B.5 as the expenditure driver is related. The repex aspects are then included in the total repex forecast.

B.4.1 Position

We do not accept United Energy's proposed repex of $585 million. We have instead included in our alternative estimate of overall total capex, an amount of $414 million ($2015) for repex, excluding overheads. This is 71 per cent of the amount that United Energy proposal. We are satisfied that this amount reasonably reflects the capex criteria.

[117] Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

B.4.2 United Energy's proposal

United Energy's proposed forecast repex is $585 million. United Energy submitted that this expenditure is driven by:[118]

- requirements to comply with mandatory regulatory obligations
- age profile of their assets which is impacted by substantial network investment during the 1960s and 1970s
- desire to address a trend decline in reliability performance.

We address United Energy's submission as part of our assessment below.

B.4.3 AER approach

We have applied several assessment techniques to assess United Energy's forecast of repex against the capex criteria. These techniques were:

- analysis of United Energy's long term total repex trends
- predictive modelling of repex based on United Energy's assets in commission
- review of United Energy's approach to forecasting replacement expenditure to meet its safety and reliability obligations
- consideration of various asset health indicators and comparative performance metrics.

We use predictive modelling to assist us in assessing approximately 58 per cent of United Energy's proposed repex. This assessment is considered in combination with the findings of our consultant, Energeia, who provided technical advice on United Energy's repex forecast. For the remaining categories of expenditure, we may use predictive modelling where suitable asset age data and historical expenditure are available, but will also rely on analysis of historical expenditure.

We note that the assessment of long term trends, the consideration of asset health indicators and comparative metrics are also considered as part of our assessment process. However, we have not ultimately used these to reject United Energy's forecast of repex or develop our alternative estimate. Our findings from these assessment techniques are consistent with our overall conclusion. We explain the reasons for this approach in the "other repex categories" section below.

We note that the assessment of long term trends, the consideration of asset health indicators and comparative metrics are also considered as part of our assessment process. However, we have not ultimately used these to reject United Energy's forecast of repex or develop our alternative estimate. Our findings from these assessment techniques are consistent with our overall conclusion.

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[118] United Energy, *Regulatory Proposal 2016–2020*, April 2015, pp. 75–76.

In its report on the Victorian distributor's the CCP considered that the suite of approaches we use in our assessment or repex provides a much better top down approach to identifying the upper bounds for efficient capex proposals than appears to be the view of the distributors'.[119]

Trend analysis

We recognise the limitations of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a distributor may have a lumpy asset age profile or legislative obligations may change over time). In recognising these limitations, we have used this analysis to draw general observations in relation to the modelled categories of repex, but we have not used it to reject United Energy's forecast of repex or develop our alternative estimate. However, we have relied on trend analysis to assist our assessment of the unmodelled categories of repex.

Predictive modelling

Our predictive model, known as the repex model, can be used to predict a reasonable amount of repex United Energy would require if it maintains its current risk profile for condition-based replacement into the next regulatory period. Using what we refer to as calibrated replacement lives in the repex model gives an estimate that reflects United Energy's 'business as usual' asset replacement practices. We explain the calibrated replacement life scenario, along with other input scenarios, below.

As part of the 'Better Regulation' process we undertook extensive consultation with service providers on the repex model and its inputs. The repex model we developed through this consultation process is well-established and was successfully implemented it in a number of revenue determination processes including the recent NSW/ACT decisions. It builds on repex modelling we undertook in previous Victorian and Tasmanian distribution pricing determinations.[120] The CCP countered the view of the distributors that there are significant shortcomings in our repex modelling approach. The CCP recognised that predictive modelling is part of our overall approach which also uses other techniques such as trend analysis.[121]

The repex model has the advantage of providing both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and once aggregated it provides a well-founded high level assessment of that data. The model can also be calibrated using data on United Energy's entire stock

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[119] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, pp. 38.

[120] We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT, QLD and SA distributors.

[121] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, pp. 38.

of network assets, along with United Energy's recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

Notably, we can use the calibrated repex model to capture a number of the drivers put forward by United Energy's in its submission. This includes replacement drivers related to the deterioration in asset condition; environmental conditions; fleet problems; asset failure risk; risk of collateral asset damage; safety risk to public and field personnel, environmental damage from asset failure; technical obsolescence; and third party damage. This is because the calibrated repex model captures the replacement practices from the last period, which include each of these drivers listed above.

We recognise that predictive modelling cannot perfectly predict United Energy's necessary replacement volumes and expenditure over the next regulatory period, in the same way that no prediction of future needs will be absolutely precise. However, we consider the repex model is suitable for providing a reasonable statistical estimate of replacement volumes and expenditure for certain types of assets, where we are satisfied we have the necessary data. We note that the service providers (including United Energy) rely on similar predictive modelling to support their forecast amount for repex.

We use predictive modelling to estimate a value of 'business as usual' repex for the modelled categories to assist in our assessment. However, predictive modelling is not the only assessment technique we have relied on in assessing United Energy's proposal. Our other techniques, which are qualitative in nature, allow us to form a view on whether or not 'business as usual' expenditure appropriately reflects the capex criteria.

Any material difference from the 'business as usual' estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age. United Energy faces a number of new safety obligations arising from the recommendations of the VBRC. These are assessed at appendix B.5 of this preliminary decision.

Technical review

We engaged Energeia to perform a technical review of United Energy's proposed repex. Energeia assessed United Energy's approach to forecasting, in particular, whether United Energy's forecast repex in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. In doing so, Energeia took account of indicators of safety and reliability, forecast expenditure, and qualitative information from United Energy on the matters it has regard to when forecasting repex. Energeia's review was limited to the six asset categories included in the repex model.

As set out above, we considered Energeia's findings in assessing whether United Energy's forecast will allow it to prudently and efficiently maintain the safety and reliability of its network. all Victorian network businesses have used predictive modelling as part of their initial proposal. this allows us to have confidence that the use of the repex model is suitable in either accepting a network business's proposal, or in arriving at our alternative estimate.

Asset health indicators and comparative performance metrics

We have used a number of asset health indicators with a view to observing asset health. While providing some context for our decision, we have not relied on these indicators to any extent to inform our alternative estimate, they have provided context for our decision and the findings are consistent with our overall conclusion.

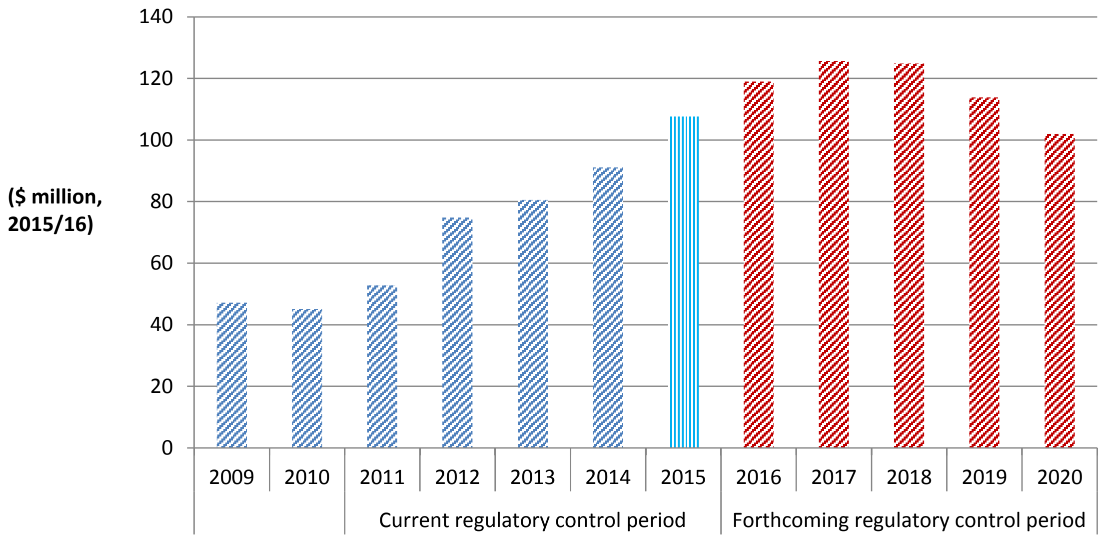
Similar to trend analysis, our use of these high level benchmarks has been to inform the relative efficiency of United Energy's previous repex. However, we have not used this analysis in rejecting United Energy's proposal and in developing our alternative estimate. We used this analysis as a cross-check with the findings of other techniques.

B.4.4 AER repex findings

Trends in historical and forecast repex

We have conducted a trend analysis of repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.[122] Our use of trend analysis is to gauge how United Energy's historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.13 shows United Energy's repex spend has been steadily increasing across time which United Energy is forecasting to continue for the first part of the 2016–20 regulatory control period before tapering off in the latter two years.

Figure 6.13 United Energy - Actual and forecast repex ($ million, 2015)



[122] NER, cl. 6.5.7(e)(5).

Source: Reset RIN 2016–20 - Consolidated Information, 2009–2013 Category Analysis RIN and 2014 Category Analysis RIN

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure.

Predictive modelling

We use predictive modelling to estimate how much repex United Energy is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories.

We have sufficient replacement volume, cost and asset age data for these modelled categories at a granular level. This gives us the ability to assess the outcomes of benchmark data across all distributors in the NEM. For other categories, we do not necessarily have sufficient data to allow such comparison, for example, repex without an associated age profile. In this instance, we rely more heavily on other assessment techniques such as business cases and high level justifications put forward by the service providers. However, where we have age and historical volumes, we may still choose to use the repex model to test both the service provider's proposal and our own findings. Our predictive modelling process is described further at appendix E. In total, the assets in these six categories represent 58 per cent of United Energy’s proposed repex.

We consider the best estimate of business as usual repex for United Energy is provided by using calibrated asset replacement lives and unit costs derived from United Energy’s recent forecast expenditure. This estimate uses United Energy’s own forecast unit costs, but it effectively 'calibrates' the proposed forecast replacement volumes to reflect a volume of replacement that is consistent with United Energy’s recent observed replacement practices, rather than relying on a purely aged based indicator. We have assessed this finding in the context of our technical review before forming a view as to the appropriate repex component of capex for United Energy. We set out below our views on their suitability for use in our assessment.

In total for all six modelled categories we have included an amount of $220 million ($2015) in our alternative estimate of total forecast capex, compared to United Energy's forecast of $346 million. We have had regard to the outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether United Energy has provided sufficient evidence to suggest that its replacement needs are higher in the next period.

Our technical consultant, Energeia, assessed United Energy’s approach to forecasting, In particular, whether United Energy’s forecast repex was necessary in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. Energeia found that while United Energy provided the most robust evidence of trading-off reliability repex, it had not evidenced trading-off safety repex between asset categories. Energeia could not conclude that United Energy's proposed repex was prudent and efficient due to the number and degree of risks and/or issues identified.[123]

The CCP stated that it is consumer experience that should be the core driver of repex levels, concluding that consumers are satisfied with current levels of repex and therefore they see no need for a step increase in repex. It considered that the distributors' proposed overall level of repex is not justified as current reliability levels do not suggest there is a need to increase repex. The CCP was of the view that the residual ages of the distributors' assets have maintained or improved over time, opex spending has been increasing, and condition based assessments appear subjective and likely conservative.[124]

Model inputs

The repex model uses the following inputs:

- The asset age profile input is the number of assets in commission and when each one was installed.
- The replacement life input is a mean replacement life and standard deviation (i.e. on average, how old assets are when they are replaced).
- The unit cost input is the unit cost of replacement (i.e. on average, how much each asset costs to replace).

In appendix E, we describe using the repex model to create three scenarios. In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data for the final two inputs.

Under all scenarios, the first input is United Energy's asset age profile (how old United Energy's existing assets are). This is a fixed input in all three scenarios.

The second and third inputs can be varied by using different input assumptions about:

- how long we expect an asset to last before it needs replacing; and
- how much it costs to replace it.

The repex model takes the replacement life input for each asset category and applies it to the actual age of the assets in each asset category. In doing this it calculates how many assets are likely to need replacement in the near future.[125] The model then applies the unit cost input to calculate how much expenditure is needed for that

[123] Energeia, *Review of Victorian Distribution Network Service Provider's Initial Replacement Capex Proposals 2016–2020*, September 2015, pp. 32–33.

[124] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 47.

[125] The repex model predicts replacement volumes for the next 20 years.

amount of replacement in each asset category. This is aggregated to a total repex forecast for each of the next 20 years.

In the remaining part of this section, we outline the replacement lives and unit cost inputs we tested in the repex model to assess United Energy’s proposed repex. As part of our assessment, we compared the outcomes of using United Energy's estimated replacement lives and its unit costs, both forecast and historical, with the replacement lives and unit costs achieved by other NEM distributors. We also used the repex model to determine calibrated replacement lives that are based on United Energy's past five years of actual replacement data. These reflect United Energy's immediate past approach to replacement.[126] We calculated historic unit costs by dividing historic expenditure by historic volumes and forecast unit costs by dividing forecast expenditure by forecast volumes. Detail on how we prepared the model inputs is at appendix E of this preliminary decision.[127]

Our repex modelling assessment is exclusive of expenditure required for VBRC repex, which United Energy has identified in various repex categories.

'Business as usual' repex

The calibrated asset life scenario gives an estimate based on United Energy’s current risk profile, as evidenced by its own replacement practices. Our estimate brings forward the current replacement practices that United Energy has used to meet the capex objectives in the past. Calibrated replacement lives use United Energy’s recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives are calculated by using United Energy’s past five years of replacement volumes, and its current asset age profile (which reveals how many, and how old, United Energy’s assets are), to find the age at which, on average, United Energy replaces its assets.

The calibrated replacement life may be different to the “nameplate” or nominal replacement age of the asset (which we considered under the “base case” scenario). United Energy reports these expected asset lives as part of its RIN response. However these reflect expectations of lives from engineering and manufacturing information, rather than observations of the economic lives achieved on the network. Using the lives provided in the RIN response in the repex model provides estimates of repex that greatly exceed United Energy’s own expectation of its replacement needs over the next period. From this, we observe that, in general, these technical estimates of asset life tend to understate the actual lives achieved on the network, and are a conservative estimate of the observable economic life of the assets, when compared to the calibrated replacement life.

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[126] For discussion on how we prepared each of the inputs see AER, *Preliminary decision, Energex distribution determination Attachment 6: Capital expenditure*, *Appendix E* :*Predictive modelling approach and scenarios*, May 2015.

[127] AER, *Preliminary decision, Energex distribution determination, Attachment 6: Capital expenditure, appendix E*, May 2015.

The calibrated asset life scenario has been our preferred modelling scenario in recent reviews of other service providers.[128] This is because we considered the calibrated replacement lives formed the basis of a business as usual estimate of repex, as they are derived from the service provider's actual replacement practice observed over the past five years and the observable (or revealed) economic replacement lives of the assets.

A service provider decides to replace each asset at a certain time by taking into account the age and condition of the asset, its operating environment, and its regulatory obligations. If the service provider is currently meeting its network reliability, quality and safety requirements by replacing assets when they reach a certain age, then by adopting the same approach to replacement in future they are likely to continue to meet its obligations. Consequently, the estimates derived from the model reflect the replacement practices that United Energy has used in the past to meet the capex objective of maintaining the safety and reliability of the network.

If underlying circumstances are different in the next regulatory control period, then this approach to replacement may no longer allow a service provider to meet its obligations. We consider a change in underlying circumstances to be a genuine change in the underlying risk of operating an asset, genuine and justifiable evidence that there has been a change in the expected non-age related condition of assets from the last regulatory control period, or a change in relevant regulatory obligations (e.g. obligations governing safety and reliability).

If we are satisfied that there is evidence of a change in a service provider's underlying circumstances, we will accept that future asset replacement should not be based on a business as usual approach. This means that where there is evidence that a service provider's obligations have changed then it may be necessary to provide a forecast of repex different to the business as usual estimate. This alternative forecast would be required in order to satisfy us that the amount reasonably reflects the capex criteria.

Where there are new obligations (or fewer obligations) we can use the service provider’s past practices as a first step before estimating the impact of the change. The new safety obligations arising from the VBRC recommendations represent a change in circumstances from the ‘business as usual’ practices of the last period. The impact of these are set out in appendix B.5 and, as noted above, are included within our consideration of total repex. We do not consider that United Energy has identified other new obligations for the next regulatory period that cannot be captured by adopting the ‘business as usual’ forecast of repex. Consequently, we have relied on our estimate from the calibrated repex model, in combination with our findings in relation to the new safety obligations, in assessing whether United Energy proposed repex reasonably reflects the capex criteria.

[128] In our determinations for NSW, Queensland and South Australian distributors.

The CCP highlighted variances across distributor's stated asset lives and anomalies in the Victorian distributors' data. The CCP supported a more standard approach to asset lives across the distributors. It noted the average residual ages of the distributors' assets have been maintained or improved over time. The current levels of capex have not resulted in a deterioration of residual asset lives, which the CCP considers implies there is no need for an increase in repex over current expenditure levels.[129] We consider these views support our use of the calibrated scenario as the asset lives are derived from a distributor's revealed replacement approach.

The Victorian Greenhouse Alliance was concerned with the significant increases to repex the Victorian distributors are proposing. It considered this was concerning given that over-investment in the networks over recent regulatory periods has led to excess levels of network capacity and declining network utilisation. It is also found it concerning that high revenue proposals were being put forward at a time of declining capacity utilisation, a reduced average asset age for most asset categories, static or falling demand and consumption, and reductions in the excessive reliability standards.[130]

As noted above, we are satisfied that with the exception of additional funding to address the impact of new safety obligations a business as usual approach to repex will provide United Energy with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system.

That said, we have also considered whether the service provider's replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for expenditure over and above what is necessary to satisfy the capex objectives. In considering the efficiency of recent replacement practices, we place some weight on the ex-ante capex incentive framework under which the service providers' operate.

There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a service provider reacting to these incentives will undertake efficient

[129] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, pp. 48, 50–51.

[130] Victorian greenhouse alliance, *Submission to the AER - Local Government Response to the Victorian Electricity Distribution Price Review 2016–20 - 13 July 2015*, p. 7.

capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider's past replacement practices are likely to reflect efficient and prudent costs, such that business as usual asset replacement approach is likely to be consistent capex objectives.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service providers' asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Calibrated scenario

The calibrated repex model scenario, which was described in the last section, provides an estimate of replacement volumes for the next period. In order to estimate how much repex is required to replace this estimated volume of assets, we must multiply the volume by the cost of replacing a single asset (unit cost). We tested two unit cost assumptions, based on data provided by United Energy:

We have modelled the calibrated lives using two unit cost assumptions, being:

- United Energy's own historical unit costs from the current regulatory period. These reflect the unit costs United Energy has incurred over the last five years.
- United Energy's own forecast unit costs for the next regulatory period. These reflect the unit costs United Energy expects to incur over the next five years.

Applied to the forecast volumes predicted from calibrated replacement lives, the repex model estimates $220 million of repex using United Energy's historical unit costs, and $272 million using forecast unit costs. These are both below United Energy's forecast of $346 million for the six modelled asset categories. This suggests that United Energy's forecast is not likely to reflect a business as usual amount of repex.

There is a significant difference between the calibrated scenario outcomes when using United Energy's historical or forecast unit costs. United Energy's forecast unit costs for the next five years are, on average, higher than its unit costs over the last five years. However, in the absence of a reasonable explanation, we would not expect forecast unit costs to be higher than historical unit costs given the incentive framework encourages a distributor to become more cost efficient over time.

We compared United Energy's historical unit costs to benchmark unit costs. These are based on the unit costs of all NEM distributors across the consistent asset categories we use in the repex model, which were provided as part of the category analysis RIN. In summary, we take unit cost observations from across the NEM and find an average unit cost, a lower quartile unit cost, and the lowest unit cost in the NEM for each asset category. When applied in the repex model average benchmark unit costs produced an almost identical forecast for the modelled categories compared to using United Energy's own historic unit costs. This suggested United Energy's historical unit costs are more likely to reflect a realistic expectation of input costs than the unit costs it forecasts.

Accordingly, we adopted United Energy's historical unit costs for the purpose of calculating a business as usual repex estimate. Consequently, we consider $220 million is the most reasonable business as usual estimation of repex. As noted above, we will rely on this outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether United Energy has provided sufficient evidence to suggest that its replacement needs are higher in the next regulatory control period, such that its forecast of $346 million is appropriate.

Testing other model inputs

As outlined earlier (and in appendix E) we used the repex model to create other scenarios combining different input data. In this section we explain how the outcomes of these other scenarios support our conclusion to use the calibrated scenario.

Base case scenario outcomes

United Energy provided its own estimate of asset replacement lives in its RIN response. To test this inputs we include them in a predictive modelling scenario that is referred to as the base case. The base case scenario gives repex estimates of $913 million (historical unit cost) and $1.3 billion (forecast unit cost). These forecasts are significantly higher than United Energy's forecast of $346 million for the six modelled asset groups.

The replacement profile predicted by the repex model under the base case scenario features a sharp step-up in expenditure in the first year of the forecast, which then declines over the remainder of the period. This replacement profile indicates that a significant portion of the asset population currently in commission is much older than would be expected using United Energy's estimated replacement lives. Using this input causes the model to immediately predict the replacement of this stock of assets. This, in turn, results in a large stock of predicted asset replacements in the first year of the forecast, which then declines over time.

Based on our analysis of the base case scenario outcomes we consider that United Energy's estimated replacement lives are not credible or reliable for the following reasons.

First, if United Energy's actual replacement lives were consistent with their estimated replacement lives, we would not expect to see the observed asset replacement profile. If United Energy's actual asset replacement profile followed its estimated replacement lives, the older assets would have:

- already reached the end of their economic (replacement) lives and would have already been largely replaced; and
- would therefore not be expected to be in the asset age profile, or be in such insignificant volumes that it would not materially affect the outcome of predictive modelling.

The 'step-up/trend down' replacement profile observed from the base case scenario suggests that a significant proportion of the asset population has survived longer than would be expected using United Energy's estimated replacement lives. These 'survivor' assets have a material effect on the observed outcome. This outcome suggests that United Energy's estimated replacement lives are shorter than those it achieves in practice.

Second, further analysis of the base case scenario reveals the replacement life inputs are the main drivers of the base case scenario outcome. Under the calibrated scenario where United Energy's estimated replacement lives are substituted with calibrated replacement lives the model outputs are $220 million for historical unit costs and $272 million for forecast unit costs. Taken together with the information from our other analytical techniques, and our concerns that United Energy's estimated replacement lives do not reflect its actual replacement practices, we consider that the estimated replacement life information provided by United Energy will not result in a reasonable forecast of business as usual repex.

Benchmarked scenario outcomes

Benchmarked uncalibrated replacement lives

We developed a series of benchmark replacement lives using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, third quartile (above average), and longest replacement lives of all NEM distributors for each category. We discuss how we prepared this data in appendix E.

As with United Energy's estimated replacement lives, we found using these benchmark replacement lives produced sharp 'step-up/trend down' forecast expenditure, indicating the replacement lives used are likely to be too short for modelling purposes as they predict a large unrealistic 'backlog' of replacement. When used in the model these also produced outcomes higher than United Energy's own forecasts.

Benchmarked calibrated replacement lives

We developed benchmark calibrated lives by first using the repex model to calculate calibrated lives based on the replacement data from all NEM distributors. For model inputs we again used the average, third quartile (above average), and longest of the calibrated lives of all NEM distributors for each category. We discuss how we prepared this data in appendix E.

When applied to the repex model, compared to using calibrated replacement lives based on United Energy’s data the:

- average benchmark and third quartile calibrated replacement lives produced higher outcomes
- longest benchmark calibrated replacement lives produced lower outcomes.

When applied to the repex model, compared to United Energy’s proposed forecast repex for the modelled categories the:

- benchmark average calibrated lives produced a higher outcome
- benchmark third quartile and longest calibrated lives produced lower outcomes.

The calibrated benchmark replacement lives may reflect to some extent the particular circumstances of a distributor and this may not be applicable to the business under review. These inputs provide us with a check that United Energy's calibrated replacement lives were reasonable against its peer service providers in the NEM. Further, these outcomes support our view that United Energy's forecast for the modelled categories is likely to be a reasonable estimate of business as usual repex.

Benchmarked unit costs

We developed industry benchmark unit costs using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, first quartile (below average), and lowest unit costs of all NEM distributors for each asset category. We discuss how we prepared this data in appendix E.

When applied to the repex model, compared to using United Energy’s unit costs the:

- average benchmark unit costs produced a similar but slightly higher outcome
- first quartile and lowest benchmark unit costs produced lower outcomes.

We consider the benchmark unit costs provide a useful comparison with the cost of other distributors in the NEM.

United Energy’s predictive modelling

United Energy submitted a report by Nuttall Consulting which we respond to in the remainder of this section. We reviewed the submissions of United Energy and Nuttall Consulting and continue to consider that our predictive modelling is a useful and important technique when assessing United Energy’s forecast of repex against the capex criteria. Our predictive modelling approach is well established having been used by us in previous distribution determinations and by other regulators.[131] It has been refined following extensive consultation as part of the Better Regulation program. It was clear from our engagement with stakeholders in that process that calibration is understood to be an integral part of good practice in repex modelling for the very reason that it utilises updated data provided by the business being regulated. It is not an arbitrary process or one which involves manipulation to arrive at a pre-determined outcome. It is a systematic process with a transparent purpose.

United Energy's forecast for the six categories we modelled was $346 million. Nuttall consulting's modelling scenarios range from 16 per cent below United Energy's repex forecast to three per cent above its forecast. However, the majority are below United Energy's forecast by between nine per cent and sixteen per cent. Nuttall consulting noted the change to its forecast unit cost parameter had the most significant effect on outcomes. The results suggesting that the unit costs United Energy is using for its forecast are materially higher, in aggregate and on average, than it has incurred in recent history.[132]

Nuttall Consulting's approach was based on our approach for the NSW draft determinations. However, it utilised a range of slightly different modelling inputs compared to those we employ in our modelling approach. Nuttall consulting also modelled pole top structures which we do not model under our approach. Further explanation of why we do not model this category is in the following section on other repex categories.[133]

United Energy note their repex forecast for the modelled categories falls within Nuttall Consulting's range of scenarios. United Energy submitted its current performance data is indicating higher asset failure rates which are not fully reflected in the repex model across certain asset categories and considered this would underestimate future repex needs. Further, that forecast repex includes expected asset failures attributable to causes other than age such as third party damage. It was of the view that the repex model was based on relatively young average asset age with a bias towards lower replacement volumes which would again underestimate future repex.[134]

We consider that Nuttall Consulting's findings are consistent with the outcome of our predictive modelling, indicating that United Energy's forecast for the modelled repex categories is higher than a business as usual estimate. We do not consider United Energy has justified that there is a reason to depart from our approach in this instance.

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131 OFGEM, *Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment*, March 2013, p. 44; AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, October 2010; AER, *Final decision: Aurora Energy distribution determination*, April 2012.

132 Nuttall Consulting, *AER repex modelling, Assessing UED's replacement forecast, a report to UED*, April 2015, pp. 19–20.

133 Nuttall Consulting, *AER repex modelling, Assessing UED's replacement forecast, a report to UED*, April 2015, pp. 1–20.

134 United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 72.

In particular, we consider that higher failure rates and third party causes of failure are captured by the calibrated model, as it utilises recent replacement practices in estimating efficient repex. The calibrated replacement lives reflect a continuing of the replacement practices that United Energy has used in the past to meet the capex objective of maintaining the safety and reliability of the network, including its responses to replacing failing assets.

Other repex categories

Repex categorised as supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA); pole top structures; and assets identified in the "other" category have generally not been included in the repex model in recent decisions. We conducted a qualitative review of United Energy's proposal on these expenditure items and comparison with historical trends. Together, these categories of repex account for $178 million (45 per cent) of United Energy's proposed repex.

As noted in appendix E, we did not consider pole top structures were suitable for inclusion in the model because of their relationship to pole replacement. That is, when a pole is replaced, it usually includes the structure, such that it is difficult to predict the number of structures that will be replaced independent of the pole category. Where we are unable to directly use predictive modelling for pole top structures we have placed more weight on an analysis of historical repex, trends, and information provided by United Energy in relation to these categories. Our analysis of these is included below.

We consider that the replacement of network assets is likely to be relatively recurrent between periods. There will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we cannot model, historical expenditure is our best high level indicator of the prudency and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria it can be a good indicator of whether forecast repex is likely to reasonably reflect the capex criteria. This is due to the predictable and recurrent nature of repex.[135]

For unmodelled asset categories we consider that if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the distributor's forecast is likely to satisfy the capex criteria. If forecast repex exceeds historical expenditure, we would expect the distributor to sufficiently justify the increase.

We have accepted United Energy's proposed repex for pole top structures of $97 million and its proposed repex for SCADA of $33 million. However, we do not accept United Energy's proposed forecast repex for "other" repex categories of $122 million. We are instead satisfied that United Energy's "other" repex from the 2011–15 period of

[135] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

$28 million is sufficient to meet business as usual requirements, and reasonably reflects the capex criteria.

We explain the reasons for our decision in the remainder of this section. There is also support from submissions that United Energy's proposed total repex may not reasonably reflect the capex criteria. While we are satisfied that United Energy's proposed repex for the six modelled categories reasonably reflects the capex criteria, our assessment of the remainder of United Energy total forecast repex does not support the entirety of its proposed increase to repex.

The CCP questioned the Victorian distributor's arguments that condition based monitoring has identified more assets at risk than occurred in the past, necessitating more repex. It considered that unless there are exogenous reasons causing faster deterioration of assets than what occurred in the past, the only reason for significant increases in repex would be:

- a more conservative approach is being used to establish asset condition
- distributors are applying less care in their maintenance practices.

Since the Victorian distributors' have not had an overall reduction in network performance the CCP considers that the first cause above is more likely. This leads the CCP to conclude that greater conservatism is being applied to condition assessments than was applied in the past.[136]

The CCP was also concerned with the approach of the businesses to assessing asset health, considering that the bulk of assessments are being made on a subjective qualitative basis. For example, visual inspections which will vary between individuals, and that the context for an inspection may produce greater conservatism like performing an assessment following bushfires. The CCP also questioned the assertion that increased failure rates have driven the increased proposed repex.[137]

The Victorian Greenhouse Alliance noted there was little information in the proposals on asset condition. It considered this makes it difficult to assess the validity of the distributors' claims, and that the distributors should provide greater transparency on asset age trends and asset condition data.[138]

Our assessment of "other" repex revealed concerns with the levels proposed, consistent with the concerns raised in submissions. We do not accept United Energy's proposed repex of $122 million for these categories. We are instead satisfied that an amount of $28 million reflects the capex criteria.

136 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 52.

137 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 47.

138 Victorian greenhouse alliance, *Submission to the AER - Local Government Response to the Victorian Electricity Distribution Price Review 2016–20 - 13 July 2015,* p. 34.

In relation to the six modelled categories, the assessment we have conducted essentially provides expenditure for a continuation of the replacement practices that United Energy has used in the last regulatory period to meet the capex objectives. The ex-ante efficiency incentives embedded in the regulatory regime, provides a degree of assurance that a service provider responding to these incentives in the past will have engaged in replacement practices are prudent and efficient. We have also considered the expenditures related to obligations arising from the recommendations of the VBRC in appendix B.5.

Pole top structures

United Energy has forecast $97 million of repex on pole top structures over the 2016–20 regulatory control period. This represents a four per cent decrease over the 2011–15 regulatory control period.

As noted above, we consider repex is likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing United Energy's forecast.

Given United Energy's forecast is lower than its expenditure in the last period, we are satisfied that forecast repex for pole top structures of $97 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

SCADA, network control and protection

United Energy's proposal includes $34 million for replacement of SCADA, network control and protection (collectively referred to as SCADA). This represents a $7 million increase over the 2010–15 regulatory control period. We consider the proposed increase is relatively low in materiality. We are satisfied that United Energy's forecast SCADA repex of $34 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Other repex

United Energy categorised a number of assets under an "Other" asset group in its RIN response. United Energy forecast $122 million of repex for these assets for the 2016–20 regulatory control period. This is over four times higher than the 2011–15 regulatory control period, or $94 million, as shown in Figure 6.14. The assets include:[139]

- various zone substation expenditure
- ACR/RCGS
- rogue
- fuse saver

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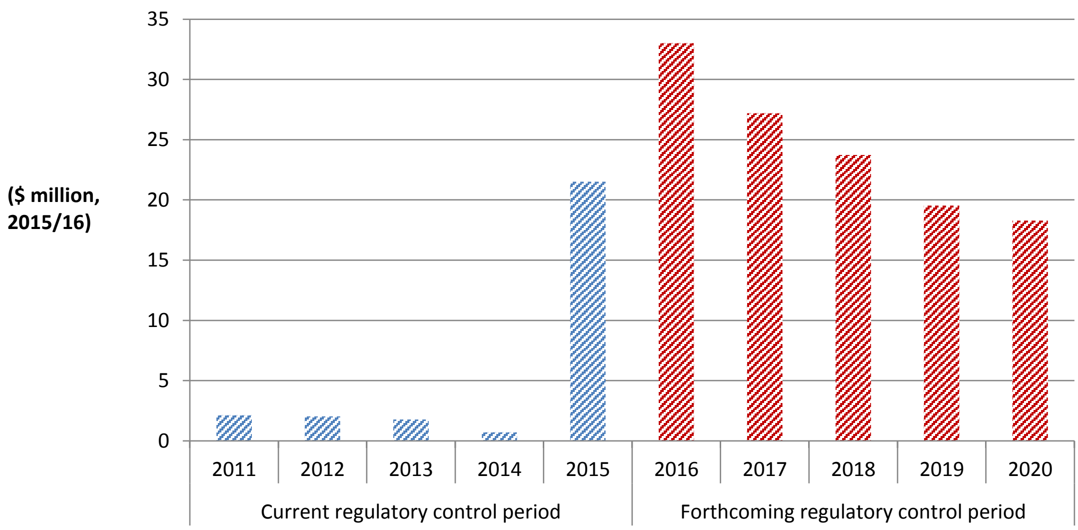
[139] United Energy, *Regulatory Proposal 2016–2020*, April 2015, p. 71.

- clashing
- animal
- communications
- environmental
- bundling/noise
- asbestos
- power quality
- PQ meter other
- LV regulator
- harmonic filter
- prot - BTOS
- safety
- CCTV
- REFCL/GFN
- operational Technology
- op Technology.

Figure 6.14 United Energy's actual and proposed "other" repex ($2015)



Source: Reset RIN 2016–20 - Consolidated Information, 2009–2013 Category Analysis RIN and 2014 Category Analysis RIN.

If repex in the forecast period exceeds historical expenditure, we would expect that the distributor to sufficiently justify the increase. As noted above, we consider repex is likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing United Energy's forecast. There are almost no historical examples of expenditure of this type in United Energy's replacement programs that we could identify. It is unclear why the need to replace these assets has suddenly and significantly arisen in the forthcoming period.

We accept there may be a need to replace a number of these assets. However, we are of the view that United Energy has not provided justification why it needs has to spend significantly more repex on some of these categories in the forthcoming period. United Energy has not provided business cases with reasonable options analysis or sufficient cost-benefit analysis to justify the proposed repex, and there is a lack of top-down assessment.

We assessed a sample of United Energy's business cases, as we could not identify comprehensive information in for all categories. We concluded these were not sufficient to support the proposed replacement expenditure. The business cases did not contain robust options analysis. For example, the project is assessed versus a do nothing option. The cost-benefit analysis also appears insufficient.

In the absence of persuasive evidence to depart from United Energy's historical repex from the last regulatory period, we are satisfied that United Energy's repex on other categories from the 2010–15 period of $28 million is sufficient to meet the capex criteria. We note our assessment of "other" repex is exclusive of expenditure required for VBRC repex, which United Energy has identified. Our assessment of VBRC expenditure is at attachment B.5.

Network health indicators

As noted above, we have looked at network health indicators and benchmarks to form high level observations about whether United Energy' past replacement practices have allowed it to meet the capex objectives. While this has not been used directly either to reject United Energy' repex proposal, or in arriving at an alternative estimate, the findings are consistent with our overall findings on repex. In summary we observed that:

- the measures of reliability and asset failures show that outages on United Energy' network have been relatively stable or declining across time with the exception of 2014 which saw a sharp increase(see Trends in reliability and asset failure, along with Table 1 and Figure 1)
- measures of United Energy' network assets residual service lives and age show that the overall age of the network is being maintained. Using age as a high level proxy for condition, this suggests that historical replacement expenditures have been sufficient to maintain the condition of the network (see Trends in the remaining service life and age of network assets, along with Figure 2)
- asset utilisation has reduced in recent years which means assets are more lightly loaded, this is likely to have a positive impact on overall asset condition (see Asset utilisation discussion below).

Further, the value of customer reliability has recently fallen. Other things being equal, this fall should result in the deferral of repex as the value customers place on reliability for replacement projects has fallen.

The above indicators generally suggest that replacement expenditure in the past period has been sufficient to allow United Energy to meet the capex objectives. This is consistent with our overall findings on repex from our other assessment techniques.

The asset health indicators are discussed in more detail below.

Trends in reliability and asset failure

Asset failure is a significant contributor to the volume of sustained interruptions on United Energy' network. Table 6.13 shows that, over the 2008–14 period 36.9per cent of total interruptions on United Energy' network were caused by the failure of assets.[140]

[140] These measures do not include planned outages, momentary outages, major event days and excluded events.

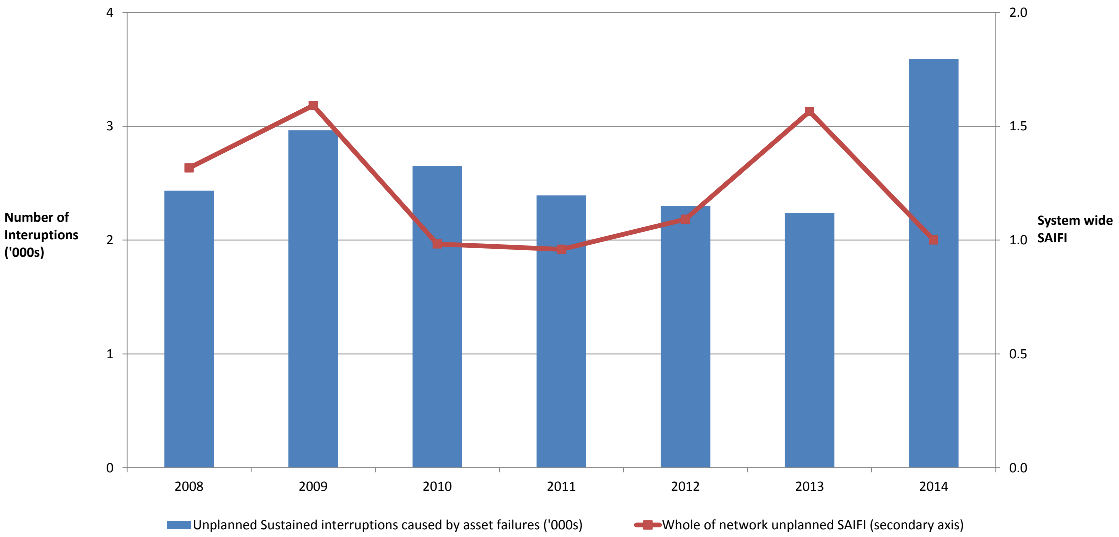
Table 6.13 United Energy - contribution of asset failures to non-excluded sustained interruptions (per cent)

	2008	2009	2010	2011	2012	2013	2014
Sustained interruptions caused by asset failures	36.0	35.7	36.8	40.1	36.6	36.9	57.1

Source: United Energy- CA RIN – 6.3 Sustained Interruptions.

Figure 6.15 compares sustained interruptions caused by asset failure with the System Average Interruption Frequency Index (SAIFI), which is an aggregate measure of the frequency of sustained interruptions on the network.[141]

Figure 6.15 Relationship between system wide SAIFI and non-excluded interruptions caused by asset failures



Source: United Energy- CA RIN – 6.3 Sustained Interruptions and EBT RIN - Whole of network unplanned SAIFI.

Figure 6.15 shows United Energy' both outages due to asset failures and SAIFI have on average been flat across time. The overall stability in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives.

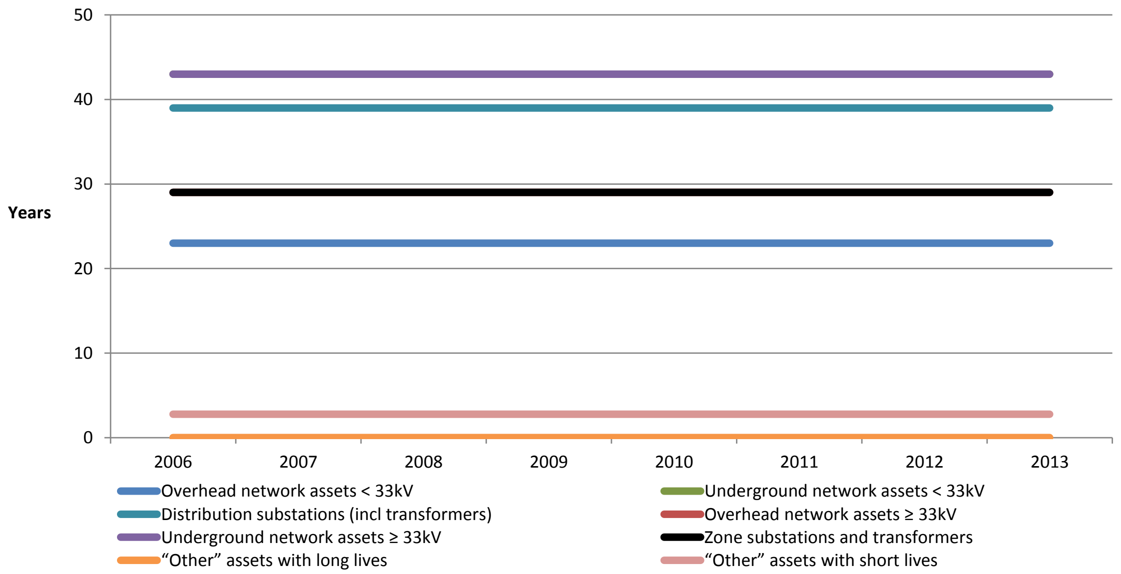
141 SAIFI: The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

Trends in the remaining service life and age of network assets

Another factor which we have considered when assessing United Energy' repex requirements for the 2016–20 period is the trend in United Energy' residual asset life across time. We are satisfied that residual service life is a reasonable high-level proxy for asset condition. Asset condition is a key driver of replacement expenditure.

Figure 6.16 shows that United Energy' residual asset lives have been flat over the period 2006–2013. This means that, on average, United Energy' network assets are staying the same age.

Figure 6.16 United Energy estimated residual service life network assets



Source: United Energy- EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services)

We acknowledge limitations exist when using estimated residual service life to indicate the trend in the underlying condition of network assets. Large volumes of network augmentation and connections can result in a large stock of new assets being installed in the network, which may bring down the network's average age. In this way, the residual service life of the assets may increase without necessarily addressing any underlying asset condition deterioration.

Noting the above, the flat trend in residual lives (where age is a proxy for asset condition) suggests that the health of United Energy' asset base has been maintained.

Asset utilisation

We consider the degree of asset utilisation can impact asset condition for certain network assets. As set out in the augex section B.2, we note United Energy has experienced a steady decrease in utilisation levels at its zone substations between 2010 and 2014. United Energy undertook zone substation augmentation projects between 2010 and 2014 that led to a decrease in the number of substations operating above 70 per cent of their maximum capacity. We note that the flattening of demand between 2010 and 2014 may have contributed to a reduction in the utilisation of the network. As of 2014, there are no substations operating above their maximum capacity.

We are satisfied this demonstrates that United Energy' network has spare capacity in its network based on past investments. All things being equal, we expect a positive correlation between asset condition and lower network utilisation exists for certain asset classes.

However we recognise that:

- The relationship between asset utilisation and condition is not uniform between asset types. For example; poles and fuses.
- The relationship is not necessarily linear (e.g. condition may not be materially impacted until a threshold point is reached).
- The condition of the asset may be difficult to determine (e.g. overhead conductor). As such early-life asset failures may be due to utilisation or, more commonly, a combination of factors (e.g. utilisation and vibration).

While noting these issues, we consider that United Energy's asset utilisation has not been high, and we do not expect any material deterioration of United Energy' network assets is likely to have occurred in recent years due to high utilisation of the assets.

B.5 Victorian Bushfires Royal Commission

B.5.1 Bushfire safety-related capital expenditure

United Energy proposed a forecast of $ 72.698 million ($2015) for bushfire safety-related capex (including overheads and escalation). This is driven by a bushfire safety mitigation program for the 2016–20 period.

We do not accept United Energy's proposed $ 72.698 million ($2015) forecast and have not included this amount in their replacement capital expenditure. Our alternative forecast of this allowance is $33.941 million ($2015) (including overheads and escalation).

In coming to this view, we have assessed the United Energy bushfire safety capex proposals. Based on our assessment, we find that the proposed capex for the bushfire safety programs do not reasonably reflect the capex criteria and therefore we have not included the proposed capex in our estimate of United Energy's capex requirements. Our assessment of this program is contained in the section below.

Table 6.14 United Energy's proposed capex for a bushfire mitigation program ($2015, million including overheads & escalation)

Strategy	Proposed capex
Connectors	4.687
Spreaders	0.475
Conductors	4,297
HV ABC	18.468
LV ABC	1.234
SWER (unmodelled)	18.367
Dampers	4.779
REFCLs	20.390
Total	**72.698**

Sources: United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, Table 8, p. 23 and United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 457 – AER Category Expenditure Explanatory Statement – Other Programs*, April 2015, Table 5.4, p. 30

AER assessment approach

For bushfire safety related capex there are three potential bases for consideration of a funding requirement. These are:

1. Business As Usual (BAU): Capex which we assess along with other capex in attachment 6. We use the tools outlined in attachment 6 to assess the efficiency of the forecast. These capex projects relate to maintaining the quality, reliability or security of supply of standard control services or the reliability or security of the distribution system through the supply of standard control services or the safety of the distribution system through the supply of standard control services.[142]
2. Approved projects are set out in the companies' Electrical Safety Management Scheme (ESMS) or Bushfire Mitigation Plan (BMP). We rely on Energy Safe Victoria to establish need. We then assess the efficiency of the forecast cost. These projects are assessed in accordance with the capital expenditure objectives to determine if they are necessary to comply with applicable regulatory obligations or requirements associated with the provision of standard control services.[143]

142 NER, cl. 6.5.7(a)(3) & (4).

143 NER, cl. 6.5.7(a)(2).

3. Pending regulations from the Victorian Government which will implement aspects of recommendation 27 of the Victorian Bushfires Royal Commission (VBRC). The timing and scope of the regulations are not yet known. We want to provide the DNSP with a mechanism to recover the prudent and efficient costs associated with any new obligations while ensuring that consumers pay no more than necessary for the implementation of these.

Our first order of assessment is to consider whether a proposed expenditure fits into one of these broad categories. This helps us to determine which are the most appropriate tools to assess whether a proposal satisfies the capital expenditure objectives.[144] We also consider if the amount sought is compliant with the capital expenditure criteria, particularly if the cost is prudent and efficient.[145]

This proposed capex amount for the bushfire safety program is incremental to United Energy's business as usual capex related to bushfire risk management. In comparison to the other Victorian distributors, United Energy's program of safety activities is less reliant on setting firm targets for specific activities in its ESMS but places higher emphasis on the results from operational activities. This difference means the United Energy program is not directly comparable to the programs of the other Victorian distributors.

Table 6.14 sets out the proposed components of the program.

Assessment of United Energy's capex

United Energy has sought allowances for the cost of work necessary to:

- install vibration dampers, armour rods and spacers in its network
- install REFCL (Rapid Earth Fault Current Limiting) technology devices
- remove SWER (single wire earth return) lines
- install or replace connectors, conductors and Low Voltage and High Voltage Aerial Bundled Cabling (ABC).

Based on the evidence submitted by United Energy and other information before us, we are not satisfied that the whole of the bushfire mitigation program as proposed by United Energy is required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be a prudent and efficient investment in the network.

As such, we do not accept United Energy's capex proposal to spend $72.698 million ($2015, including overheads and escalation) on a bushfire mitigation program. Our alternative estimate of United Energy's total capital expenditure allowance instead

144 NER, cl. 6.5.7(a).

145 NER, cl. 6.5.7(c)(1) & (2).

factors in expenditure related to United Energy's business as usual bushfire risk management, based on their current approved Electrical Safety Management Scheme.

In summary, we consider that:

- United Energy's bushfire mitigation expenditure program for armour rods, vibration dampers and spacers is in response to a mandatory program of work required under a compulsory Electrical Safety Management Scheme and is required to comply with applicable regulatory obligations or requirements.
- United Energy's VBRC proposal includes BAU capex to maintain the reliability and safety of its network. These programs are the HV ABC, LV ABC, connectors and conductors programs and the installation of four REFCL devices and the reconstruction of its SWER network.
- United Energy has not proposed any contingent projects in relation to possible future regulatory obligations associated with these programs.
- United Energy has not provided evidence of a mandatory obligation to address bushfire risk from ignition by power lines through the installation of four REFCL devices or for the reconstruction of SWER lines.
- In the absence of a regulatory obligation we do not consider that United Energy's proposed investment in REFCL technology or SWER line reconstruction is necessary to maintain the safety and reliability of the network.
- There has also been no change to regulations and / or safety standards related to bushfire risk that would justify additional expenditure on REFCL technology.
- United Energy's cost benefit analysis of their proposed program of REFCL installations is incomplete. It omits the possibility the Victorian Government may require a different solution to the REFCL in the areas to be served by some or all of the proposed REFCL units. If this occurs the installation of a REFCL may be unnecessary.
- United Energy's business cases and other supporting material it has provided does not properly evaluate the costs versus the benefits of the REFCL or SWER replacement programs.

It is open to United Energy in its revised proposal to address the issues raised in this preliminary decision and provide the necessary supporting material to show that its proposed capex for the bushfire mitigation program reasonably reflects the capex criteria, and would be in the long term interests of consumers.

We note, in our reasons below, the specific areas where sufficient supporting material was not provided or the evidence submitted did not reasonably demonstrate the program satisfied the criteria.

For these reasons, we do not accept United Energy's' proposed capex for the bushfire mitigation program satisfies the capex criteria. Each of these reasons is discussed further below.

Regulatory obligation

In Victoria, the safety obligations of major electricity companies are contained in the Electricity Safety Act 1998 (Vic). Section 99 of this Act mandates that major electricity companies must submit an approved Electricity Safety Management Scheme (ESMS) to Energy Safe Victoria for acceptance.[146] These schemes are regulated by Energy Safe Victoria. Each of the five Victorian distributors is classed as a 'major electricity company' under this Act.

It is compulsory for United Energy to comply with the accepted ESMS for its network.[147] Further, the Act requires that each major electricity company must submit a Bushfire Mitigation Plan for its network to Energy Safe Victoria and must comply with that plan.[148] The Bushfire Mitigation Plan forms part of an accepted ESMS.[149] This legislated requirement applies to the whole of the United Energy network including urban areas of the network.

On 4 January 2011 Energy Safe Victoria issued two directions under s 141 of the Electricity Safety Act to United Energy. A major electricity company must comply with a direction under s 141 of this Act that applies to it.[150] The first direction required that United Energy inspect all powerlines in its network and fit armour rods and vibration dampers by 1 November 2020 where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[151] The second direction required the fitting of spacers where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[152]

Two mechanisms exist for a major electricity company to address a safety concern of when it arises. The first is to voluntarily propose to address the safety hazard by including an undertaking in their ESMS or the Bushfire Mitigation Plan to undertake a specific activity to address the hazard. If a proposed change to their ESMS is approved by the safety regulator, the activity becomes an obligation which must be carried out.

The second mechanism is the creation of a new regulatory obligation by the Government or an action by a Government agency under existing legislation. The issuance of a direction by Energy Safe Victoria falls into this category. United Energy's VBRC capex proposal is partially in response to regulatory obligations imposed by the directions of ESV. However, a substantial component is based on the ongoing need to maintain the safety and reliability of the network. The proposal has been assessed on this basis.

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146 *Electricity Safety Act 1998* (Vic), s. 99

147 *Electricity Safety Act 1998* (Vic), s. 106.

148 See, *Electricity Safety Act 1998* (Vic), ss. 113A, 113B and 113C.

149 *Electricity Safety Act 1998* (Vic), s. 113D.

150 *Electricity Safety Act 1998* (Vic), s. 141(4).

151 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of armour rods and vibration dampers*, 4 Jan 2011.

152 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of spacers*, 4 Jan 2011.

The mandatory safety obligations of United Energy relate to three project categories which we now assess:

United Energy Proposal

United Energy's BMP related obligations are contained in their Fire Protection Plan dated August 2014.[153]

What are armour rods, vibration dampers and spacers?

Armour rods are a fitting used to protect the power conductor from damage due to bending, compression, abrasion and fatigue due to wind-induced vibration and flashovers. They are helical rods wound over the conductor where it sits on an insulator. Vibration dampers are an additional device to reduce fatigue caused through wind-induced vibration. They are often helical rods wound over the conductor a short distance away from the cross arm. Spacers are insulated rods that are tied between the conductors to stop them from clashing in windy conditions.

Armour rods, vibration dampers and spacers

The obligations for armour rods, vibration dampers and spacers are contained in the Fire Prevention Plan at section 1.[154] Accordingly, United Energy has demonstrated it has an obligation to undertake this work in the next regulatory control period.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy. As United Energy was directed to undertake this work we are satisfied this is a discrete program of work that does not fall within United Energy's business as usual level of capex to manage asset fire safety.

We next assess whether the proposed allowance satisfies the capex criteria.[155] In response to an AER information request United Energy provided a copy of their Fire Prevention Plan.[156] The plan states:[157]

> As a result of the Victorian Bushfire Royal Commission and Recommendation 33, Energy Safe Victoria (ESV) has directed UE under section 141(2)(d) of the Electricity Safety Act and via letters dated 4 January 2011 to amend its Electricity Safety Management Scheme (ESMS) to include the development (or reinforcement) of plans and procedures in relation to the fitting of spacers/ spreaders, vibration dampers and armour rods. The current status of the progress of these programs are now reported through the UE ESMS reporting regime.

[153] United Energy, Fire Prevention Plan 2014–2019, August 2014 (provided in response to AER information request to United Energy 022, 7 August 2015).

[154] United Energy, Fire Prevention Plan 2014–2019, August 2014, p. 9.

[155] NER, cl. 6.5.7(c)(1) & (2).

[156] AER, *Information Request to United Energy IR# 022*, 7 August 2015.

[157] United Energy, Fire Prevention Plan 2014–2019, August 2014, p. 8.

United Energy has prepared forecasts for armour rods and vibration dampers (5,000), and spacers (1,680) based on based on consideration of its ESMS reporting regime and has provided these forecasts to ESV. We consider the survey methodology to be sound. As the basis of this forecast is the result of a survey to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period, we accept these forecasts.

The costs to be incurred for each activity are derived from actual contract rates used by United Energy. United Energy stated:

> Unitised rates are based on agreed rates from our existing contracts with the service providers Tenix and Zinfra.[158]

The unitised rate[159] for the installation of vibration dampers and armour rods negotiated by United Energy appears to be high. However, the unitised rates proposed by United Energy are derived from contracts with independent service providers. We are satisfied that the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. A major reason for differences in these rates for each distributor will reflect differences in the number of armour rods requiring treatment as a proportion of the total number of spans relative to the number of vibration dampers required on the same span. For this activity, there are likely to be significant differences in mobilisation, outage and traffic management costs between the United Energy rate and the CitiPower/Powercor rate. This is particularly so because the United Energy rate is based on a smaller program and thus is unlikely to achieve a similar scale economy. On this basis, we accept the United Energy unitised rate is efficient.

We calculate a unitised rate of $282.44 per spreader. This rate has been negotiated with the service providers Zinfra and Tenix. It is an 18 per cent reduction on the current rate. We accept this rate.

For armour rods and vibration dampers we accept United Energy's forecast of $4.779 million ($2015, including overheads & escalation).

For spreaders we accept United Energy's forecast of $ 0.475 million ($2015, including overheads & escalation).

Accordingly, the resultant cost estimates reasonably reflect the capex criteria.

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[158] United Energy, *Regulatory Proposal 2016–20*, *Attachment NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, p. 7.

[159] Throughout this section a reference to a unitised rate of United Energy is an amount derived from United Energy, *NET 449 AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, Table 8, p. 23.

Business as usual capex

United Energy has proposed significant bushfire mitigation capex for six activities which we consider should be assessed as BAU capex. These programs are the High Voltage Aerial Bundled Cable (HV ABC), Low Voltage Aerial Bundled Cable (LV ABC), connectors and conductors programs and the installation of four REFCL devices and the reconstruction of its SWER network. This is because we have not been able to identify a specific commitment to these six activities in either the approved United Energy Electrical Safety Management scheme or the United Energy Fire Prevention Plan 20142019. We note that the Fire Prevention Plan (FPP) contains United Energy's current Bushfire Mitigation Plan.

The FPP identifies roles and accountabilities of United Energy personnel in meeting their monitoring, operational response and reporting obligations under their ESMS. However, the approach taken in United Energy's FPP does not set firm targets for addressing specific defects in assets or asset categories. Rather, United Energy relies on monitoring of their network to identify defects as they arise. They respond to identified problems by setting in place programs to address the problem areas. These programs are reported to ESV and actioned appropriately.

We consider this approach is consistent with United Energy maintaining the safety and reliability of their network. However, there are no set targets for any of the six activities listed in this section in the FPP. For a regulatory obligation to be demonstrated we expect to be able to identify a target for a volume of work or a statement of milestones that need to be achieved by a certain date. On this basis we consider none of the six activities are necessary to meet a regulatory obligation or requirement. However, as United Energy has an ongoing commitment to maintaining the safety and reliability of its network, their overall approach to these activities is consistent with the capex objectives. We next consider whether each listed activity individually satisfies the capex objectives.

What are connectors?

As their name suggests, connectors are the device used to join two or more wires together. There are a wide variety of connector types. United Energy reports that it has a high failure rate detected in certain connector types due to incorrect installation.

Connectors

United Energy replaced 14,482 cable connectors in the current period. The forecast in the next period is a 24 per cent reduction in the volume to be treated to 11,040.[160] The expenditure explanation statement details the history of problems encountered with certain connector types. These manifest as outages, affecting reliability or as complete failure leading to potential safety concerns. Because of these concerns the expenditure

[160] United Energy, *Regulatory Proposal 2016–20: Attachment NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, Table 8, p. 23.

has not been assessed under the general replacement program of United Energy. It is a continuation of an established program. We accept this program is necessary to maintain the reliability and safety of the network.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy. Replacement of connectors is a program of work that falls within United Energy's business as usual level of capex to manage asset safety and reliability. We have taken this into account in determining an allowance for this work.

We next assess whether the proposed allowance satisfies the capex criteria.[161] United Energy has prepared a forecast for connectors of 11,040 units based on consideration of its asset management system and its historical rates of treatment. The basis of this forecast is the result of an survey to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period. We consider the forecast methodology to be sound. The forecast volume is 24 per cent less than the volume in the current period. We accept this forecast.

We calculate the unit rate of $424.57 per connector for this work. This rate has been renegotiated with the service providers Zinfra and Tenix. This is an increase in the unitised rate of 13 per cent. Although the increase in price is material, the unitised rate is derived from contracts with independent service providers. We are satisfied that the contracts were properly entered into on a competitive basis, based on a detailed work specification. Therefore, the unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. These differences are unique to this work specification and mean direct comparison of the rate for this activity with other utilities is not possible.

For connectors we accept United Energy's unitised rate and the forecast of $4.687 million ($2015, including overheads & escalation) is a reasonable estimate of the least cost necessary to satisfy the capex objectives.

What are conductors?

Conductors is a generic term that describes the wires and cables that carry electricity through a distribution network. The term can include bare steel, aluminium and copper wires as well as all types of insulated cables. In this proposal the term is applied to bare steel wires as are used in the overhead lines that exist in United Energy's distribution area.

Conductors

An ongoing need is for the replacement of conductors as they reach the end of their technical and economic lives. United Energy report they replaced 93,891 m of cable in the current period. The forecast is based on a Weibull analysis of the asset population.

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[161] NER, cll. 6.5.7(c)(1) & (2).

In the next period United Energy forecast a 58 per cent reduction in the volume to be treated to 39,520 m.[162] It is a continuation of an established program. We accept this forecast replacement is necessary to maintain the reliability and safety of the network.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy. Replacement of conductors is a program of work that falls within United Energy's business as usual level of capex to manage asset safety and reliability. We have taken this into account in determining an allowance for this work.

We next assess whether the proposed allowance satisfies the capex criteria.[163] United Energy has prepared a forecast for conductors of 39,520 m based on consideration of its asset management system and its historical rates of treatment. The basis of this forecast is the result of a Weibull analysis to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period. We consider the application of a Weibull analysis to this asset category is sound. The forecast is 58 per cent less than the volume in the current period. We accept this forecast.

We calculate the unitised rate of $108.73 per m for this work. This rate has been renegotiated with the service providers Zinfra and Tenix. Although the increase in price is significant, the unitised rate proposed by United Energy is derived from contracts with independent service providers. We are satisfied that the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. These differences are unique to this work specification and mean direct comparison of the rate for this activity with other utilities is not possible.

For conductors we accept United Energy's unitised rate and the forecast of $4.248 million ($2015, including overheads & escalation) reasonably reflect the capex criteria.

What is Low Voltage and High Voltage Aerial Bundled Cabling?

Aerial Bundled Cabling is a type of overhead power line. It may operate at low voltage (1 000 volts or less) or at high voltage (above 1 000 volts). It usually involves three insulated phase conductors bundled tightly together. It may include a fourth conductor for the neutral which may be bare or insulated, depending on local practice.

Low Voltage Aerial Bundled Cabling (LV ABC)

Another ongoing need under United Energy's ESMS is for the replacement of deteriorating Low Voltage Aerial Bundled Cable. The program replaced 15,381 m of cable in the current period. The forecast in the next period is a 14 per cent reduction in

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162 United Energy, *Regulatory Proposal*, *Attachment: NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, Table 8, p. 23.

163 NER, cll. 6.5.7(c)(1) & (2).

the volume to be treated to 13,191 m.[164] However, this forecast is greater than would be suggested by the asset age profile alone. Were this expenditure considered as general replacement expenditure a lower forecast would have resulted based on the application of the AER's repex model.

United Energy explain this higher forecast is because in treed areas it has determined that insulated cable will have lower faults.[165] We also note that this increase in the forecast is offset by the reduction in overhead conductor replacement noted above. Longer term, it will also reduce opex requirements as vegetation clearance requirements are reduced. It is a continuation of an established program. We consider the primary driver is to maintain the safety of the network. We also consider the effect on increasing reliability will be small. On this basis we accept this program is necessary to maintain the reliability and safety of the network.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy. This is a program of work that falls within United Energy's business as usual level of capex to manage asset fire safety. We have taken this into account in determining an allowance for this work.

We next assess whether the proposed allowance satisfies the capex criteria.[166] United Energy has prepared a forecast for LV ABC of 13,191 m based on consideration of its ESMS reporting regime and GIS data. The basis of this forecast is a survey to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period. We accept the forecasting methodology is sound. The forecast is 14 per cent less than the volume in the current period. We calculate the unit rate of $93.57 per m for this work. This rate has been negotiated with the service providers Zinfra and Tenix. It is a 63 per cent reduction on the current rate. We accept these forecasts.

Accordingly, the resultant cost estimate of $1.234 million ($2015, including overheads & escalation) reasonably reflects the capex criteria.

High Voltage Aerial Bundled Cabling (HV ABC)

An issue which has arisen in the current period for all the Victorian distributors is an increased need for early replacement of deteriorating High Voltage Aerial Bundled Cable. United Energy has replaced 2,026 m of cable in the current period. The forecast in the next period is a 1,349 per cent increase to 29,347 m.[167] This forecast is not consistent with the asset age profile for HV ABC. To support the increase in proposed

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[164] United Energy, *Regulatory Proposal 2016–20: Attachment NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, Table 8, p. 23.

[165] United Energy, *Regulatory Proposal 2016–20: Attachment* : *NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015, p. 25.

[166] NER, cll. 6.5.7(c)(1) & (2).

[167] United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 449 – AER Category Expenditure Explanation Statement: Asset Class – Connectors and Conductors*, April 2015 Table 8, p. 23.

replacements United Energy prepared a business case which outlines the rapid increase in failure rate.

> Investigations by external and internal experts reveal that the root cause for HV ABC failures which have occurred on UE's network, is the ongoing electrical discharge between the earthed catenary wire and the semi conductive core material around each phase. This leads to erosion of the semi conductive screen, creating high electric stress points on the insulation and ultimately insulation failure.[168]

This indicates that the design standard adopted when the cable was deployed commencing in the 1990's was deficient. This design standard was developed by the former State Electricity Commission Victoria based on the best available information at the time. It did not recognise the potential for early insulation failure when strung with an earthed catenary wire. This failure mode has only become apparent after an extended period in service. Consequently, we do not consider the need for this replacement results from an imprudent decision by United Energy. United Energy illustrate the impact on reliability by an example based on the Dromana sub-station.

> Taking DMA 13 as an example; the 14 sustained outages on DMA13 over the past ten years known to be caused by ABC failures have contributed 2.68 SAIDI minutes. UE intends to replace a 4.5 km section of HV ABC on feeder DMA 13 in 2015. Nine of the fourteen incidents are located on the section targeted to be replaced, impacting SAIDI by 1.91 minutes. Six out of these 9 HV ABC faults occurred in the past two years.[169]

The business case also states:

> The concerning consequence of HV ABC failure is the potential for a fire start in HBRA. So far, 7 out of 24 HV ABC faults across UE's network over the past ten years have resulted in fire starts in HBRA.[170]

We consider that the business case demonstrates that the replacement program for HV ABC is necessary to maintain the reliability and safety of the network.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy. This is a program of work that falls within United Energy's business as usual level of capex and opex to manage asset fire safety. We have taken this into account in determining an allowance for this work.

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[168] United Energy, *Regulatory Proposal 2016–20, Attachment: NET 618 High Voltage Aerial Bundled Cable Replacement Program - PJ 0131-0*, April 2015, p. 3.

[169] United Energy, *Regulatory Proposal 2016–20, Attachment: NET 618 High Voltage Aerial Bundled Cable Replacement Program - PJ 0131-0*, April 2015, p. 5.

[170] United Energy, *Regulatory Proposal 2016–20, Attachment*: *NET 618 High Voltage Aerial Bundled Cable Replacement Program - PJ 0131-0*, April 2015, p. 5.

We next assess whether the proposed allowance satisfies the capex criteria.[171] United Energy has prepared a forecast for HV ABC (29,347 m) based on consideration of its GIS data and resource availability. We accept the forecasting methodology is sound. As the basis of this forecast is the result of a survey to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period, we accept this forecast.

> The total cost of replacing all 60 km of 22 kV ABC is in the order of $38M. As this is unlikely to be possible in a short time frame, a program of prioritised replacements over 10 years is proposed. This will target replacement of approximately 5.6 km pa at an annual cost of $3.5M.[172]

We calculate the unit rate of $629.31 per m for this work. This rate has been renegotiated with the service providers Zinfra and Tenix. It is a 22 per cent increase on the current rate. Although the increase in price is significant, the unitised rates proposed by United Energy are derived from contracts with independent service providers. We are satisfied that the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. These differences are unique to this work specification and mean direct comparison of the rate for this activity with other utilities is not possible. We accept this forecast and the proposed unitised rate.

Accordingly, the resultant cost estimate of $18.468 million ($2015, including overheads & escalation) reasonably reflects the capex criteria.

Single Wire Earth Return (SWER) replacement

SWER is a low cost technology with a single conductor (usually steel) commonly used to supply small loads in remote and rural areas. United Energy stated they have committed to replacing all the SWER in their network.[173]

> UE has given a commitment to replace all its SWER systems by 2021 to comply with the recommendations of the Bushfire Royal Commission.[174]

The AER has not been able to identify a specific commitment to this activity in either the approved United Energy Electrical Safety Management Scheme or the United Energy Fire Prevention Plan 2014-2019. We note that the Fire Prevention Plan contains United Energy's current Bushfire Mitigation Plan.

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171 NER, cll. 6.5.7(c)(1) & (2).

172 United Energy, *Regulatory Proposal 2016–20, Attachment*: *NET 618 High Voltage Aerial Bundled Cable Replacement Program - PJ 0131-0*, April 2015, p. 1.

173 SWER operates at 12.7 kV and is used to supply small loads, usually in rural and remote areas.

174 United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 457 – AER Category Expenditure Explanatory Statement – Other Programs, April 2015,* pp. 31–32.

We note that the Victorian Bushfires Royal Commission made recommendations that relate to improving the safety of SWER systems. For AusNet Services and Powercor the ESV issued directions requiring specific actions to improve the safety of their SWER networks. However, as United Energy has not identified an existing regulatory obligation we have considered whether the expenditure is necessary to maintain the reliability and safety of the United Energy network.

The United Energy supporting information does not set out a business case for why expenditure will be necessary to maintain the reliability and safety of the network. The business case examines the options to achieve the outcome of total replacement of SWER.[175] The chosen option is the least cost option. The business case cites the high consequences of failures of SWER installations identified by the VBRC as justification for the expenditure. However, this does not establish that the United Energy SWER system is currently unsafe or likely to become unsafe or unreliable in the next regulatory control period. In the absence of evidence to suggest that the SWER network is currently unsafe or likely to become unsafe or unreliable we conclude this expenditure is not required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy.

For the capex criteria to be satisfied the capital expenditure must reasonably reflect the efficient cost of satisfying the capital expenditure objectives. If no capital expenditure objective is satisfied then the capex criteria cannot be met. On this basis we do not accept United Energy's cost estimate of $18.367 million ($2015, including overheads & escalation) reasonably reflects the capex criteria. Accordingly, we consider this project should not be funded.

We note that the Victorian Government is expected to implement a new regulatory obligation in response to recommendation 27 of the VBRC. In a later section we discuss our preferred approach to deal with these possible new regulations as they may affect United Energy's SWER systems in high bushfire risk areas.

What is Rapid Earth Fault Current Limiting (REFCL) Technology?

The Victorian Government is currently investigating technology solutions which reduce the cost of minimising the risk of a powerline fault igniting a fire. The REFCL is a relatively new technology which may have cost advantages. Its potential for bushfire mitigation is promising. It is an extension of resonant earth system technology, which is commonly used in Europe and elsewhere. The REFCL device is capable of detecting when a power line has fallen to the ground and can almost instantaneously shut off power on the fallen line.

[175] United Energy, *Regulatory Proposal 2016–20: Attachment: NET 233 – Single Wire Earth Return (SWER)*, ver 1.0, April 2015.

Rapid Earth Fault Current Limiting (REFCL) devices

United Energy proposes to install four REFCLs in the 2016–20 regulatory control period at: Frankston, Dromana, Rosebud and Mornington. Feeders leaving these substations each service areas of high bushfire risk when assessed against the criteria of the Victorian Government emergency services agencies.[176] The selection by United Energy of these four substations as sites for REFCLs is based on this criteria. United Energy previously installed a trial Ground Fault Neutraliser at the Frankston South sub-station during the 2011–15 regulatory control period. The Ground Fault Neutralizer is a specific form of REFCL technology.

The United Energy Fire Protection Plan does not include a firm commitment to install REFCLs at any of the four locations (Frankston, Dromana, Mornington and Rosebud). In the absence of a specific commitment to undertake these REFCL installations we do not consider that United Energy has demonstrated it has an obligation to undertake this work in the next regulatory control period.

As no regulatory obligation exists we do not consider that the proposed investment in Rapid Earth Fault Current Limiting (REFCL) technology is necessary to comply with applicable regulatory obligations or requirements. We next consider if the REFCLs are necessary to maintain the safety and reliability of the network.

United Energy submitted a detailed business case to justify the expenditure on safety and reliability grounds.[177] However, the business case does not establish that the technology is required to *maintain* the safety and reliability of the network. We consider the United Energy business case establishes that the REFCL technology will *enhance* network safety, especially if associated with other works to improve the safety of the SWER network. We discuss this further below.

When compared to the cost of undergrounding powerlines, new technologies offer the potential to significantly reduce the cost of reducing the risk of igniting a fire. However, until there are established standards for the design, construction and operation of these newer technologies it is a difficult task to assess whether investment in the new technology will be required to comply with applicable regulatory obligations or requirements and will be prudent and efficient. Our reason for this conclusion is that the Victorian Government may determine that different specific treatments are to apply in designated areas of the State. This creates a risk that the areas selected by United Energy for REFCL deployment may be subject to different technical requirements that make the deployment of a REFCL unnecessary or inappropriate.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by United Energy.

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[176] United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 224 - UE PL 2050 REFCL Strategic Plan v1.0.* April 2015*.*

[177] United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 224 - UE PL 2050 REFCL Strategic Plan v1.0,* April 2015.

We are satisfied this is a discrete program of work that does not fall within United Energy's business as usual level of capex and opex to manage asset fire safety.

The Victorian Government may proceed with a mandatory program of installing REFCLs in selected locations in the near future. However, this Victorian Government program is not yet in place. The locations to be mandated to be the subject of REFCL installations have yet to be determined. UE stated:[178]

> UE propose to install four REFCL schemes at zone substation[s] which supply its high bushfire risk networks in the forecast period. The justification is the reduced fire start risk in bushfire areas.

In developing the proposed regulations to support the REFCL technology the Victorian Government is developing a Regulatory Impact Statement (RIS). A key component of the RIS process is to calculate the relative costs and benefits of the installation of a REFCL device at each zone sub-station. Until this work is complete the identification of those United Energy substations suitable for treatment by a REFCL is speculative. The AER expects to rely on the RIS prepared by the Victorian Government to identify those locations which should be subject to the installation of a REFCL in the next regulatory control period.

United Energy has performed a separate cost-benefit analysis to demonstrate that the safety and reliability benefits of these installations warrant funding.[179] We accept their analysis demonstrates a net reliability and safety benefit. However, the approach adopted by the Victorian Government may require a different approach be used which achieves the mandated safety outcome. For example, the Victorian Government may determine that alternative treatments such as the fitting of enhanced capability automatic circuit reclosers or reconstruction of the SWER lines using a new insulated cable type is a sufficient treatment. The areas selected by United Energy may not meet the threshold set by the Victorian Government above which treatment with a REFCL is warranted. As a consequence, the deployment of a REFCL may be redundant at one or more of the nominated locations.

Accordingly, we consider the United Energy cost estimates for REFCLs do not reasonably reflect the capex criteria. We consider the decision to deploy REFCLs can best be addressed as a potential future regulatory obligation. We set out in the next section our preferred approach to potential future regulatory obligations, if they arise.

Future regulatory obligations

Following the Victorian Bushfires Royal Commission (VBRC) 67 recommendations were made, of which eight relate directly to the safety of electrical distribution networks in Victoria. Another relevant recommendation is recommendation 27:

[178] United Energy, *Regulatory Proposal 2016–20*, *Attachment: NET 457 – AER Category Expenditure Explanatory Statement – Other Programs,* April 2015, p. 28.

[179] United Energy, *Regulatory Proposal 2016–20: Attachment: NET 224 – UE PL 2050 REFCL Strategic Plan,* April 2015, Table 3, p. 24.

> The State amend the Regulations under Victoria's Electricity Safety Act 1998 and otherwise take such steps as may be required to give effect to the following:
>
> - the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
> - the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.

The Victorian Government is developing a regulatory requirement to give effect to recommendation 27. In particular, work is being undertaken by the Victorian Government to develop suitable regulatory standards for the use of new technologies such as Rapid Earth Fault Current Limiting (REFCL) devices and a new types of insulated line as major tools to reduce the risk of powerline faults igniting bushfires.

These regulations are expected to apply in High Bushfire Risk Areas (HBRA) of the State and will involve a mandatory program of installing REFCLs and a change to the design standards that apply to new line construction and the reconstruction of assets in certain areas (Codified Areas). However, this Victorian Government requirement is still being developed and is not yet in place. The timing and scope of the regulations are not currently known.

United Energy has not addressed this impending development in its regulatory proposal. AusNet Services proposed to apply a regulatory change pass through event to any regulatory change or changes that apply in the next regulatory control period. Powercor on the other hand proposed that the pending regulatory changes be dealt with as contingent projects. We have therefore, considered whether either approach is preferable (contingent project or pass through event) and the trigger event which should apply to a contingent project.

Having considered the respective proposals of AusNet Services and Powercor, we consider a contingent project approach is preferable. Our preference is to apply a common regulatory approach to all affected service providers. We prefer to deal with the costs of the Victorian government regulations consistently across distributors. This ensures that the cost of the regulation is recovered from customers in the same manner. It also allows us to compare the costs and impacts on customers more transparently so that we can ensure that consumers pay no more than necessary for the implementation of the regulation. This is particularly important because the cost and timing of the regulation are not yet known.

Until the Victorian Government regulations have been determined and are promulgated it will remain unclear whether there is likely to be an impact on United Energy. If, in their substitute determination regulatory proposal United Energy applies for one or more contingent projects in response to these impending regulations, our intention is to apply a common regulatory approach to that proposal, including the applicable trigger event.

B.6 Forecast non–network capex

The non-network capex category for United Energy includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment. United Energy proposed $194.6 million ($2015) for non-network capex, compared to $173.2 million in the 2011–15 regulatory control period.[180] It proposed $163.7 million for ICT capex, compared to $131.2 million in the previous period. It has also proposed $30.9 million for the other non-network capex categories, compared to $40.1 million in the previous period.

B.6.1 Position

We do not accept United Energy's forecast non-network capex. We have instead included an amount of $134.6 million ($2015) for non-network capex in our estimate of total capex which we consider reasonably reflects the capex criteria. This is a reduction of 31 per cent. This is comprised of $103.6 million for ICT capex and $30.9 million for other non-network capex

In coming to this view, we have found that United Energy's forecast non-network ICT capex of $163.7 million ($2015) does not reflect the efficient costs of a prudent operator. We consider that non-network ICT capex of $103.6 million ($2015) reasonably reflects United Energy's required capex for this category in the 2016–20 regulatory control period. This is a reduction of 37 per cent from United Energy’s forecast ICT capex.

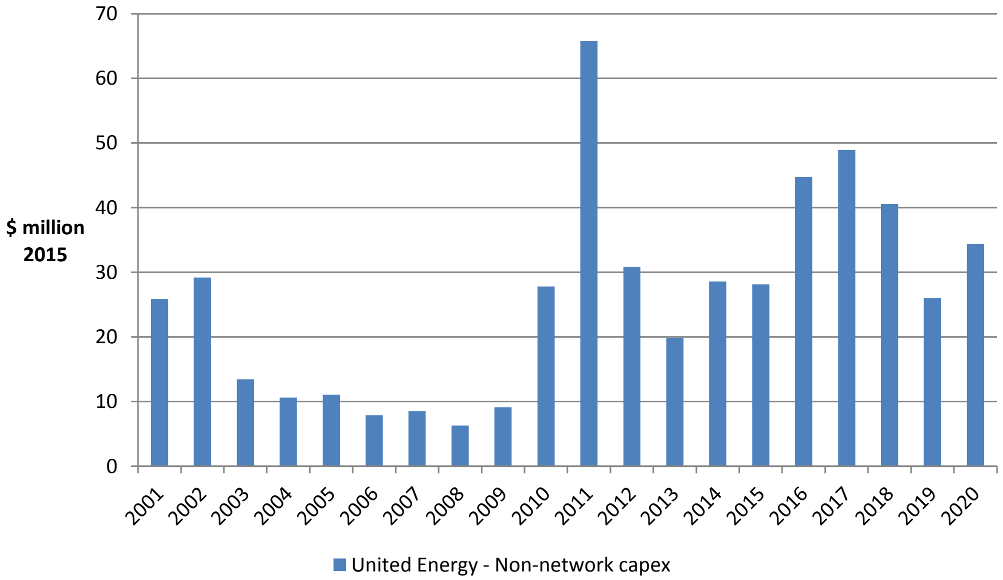
In modelling United Energy's required revenue for the 2016–20 regulatory control period, we have also accounted for forecast disposals of fleet assets which United Energy omitted from its regulatory proposal.

B.6.2 United Energy's proposal

Figure 6.17 shows United Energy's actual and expected non-network capex for the period from 2001 to 2015, and forecast capex for the 2016–20 regulatory control period.

180 United Energy, *Regulatory proposal 2016–20*, April 2015, pp. 76 and 80.

Figure 6.17 United Energy's non-network capex 2001 to 2020 ($million, 2015)



Source: United Energy, *Regulatory information notice*, template 2.6; United Energy, *Category Analysis RIN 2014*, template 2.6; United Energy, *RIN response for 2011-2015 regulatory control period, template 2.1.1*; AER analysis.

United Energy's forecast non-network capex for the 2016–20 regulatory control period is 12 per cent higher than actual and expected capex in the 2011–15 regulatory control period.[181]

Our analysis of longer term trends in non-network capex suggests that United Energy has forecast capex for this category at relatively high levels for most of the regulatory control period. Non-network capex in the first three years of the 2016–20 regulatory control period is forecast to be higher than expenditure in any year since 2001, with the exception of the 2011 year. We therefore consider that United Energy's forecast non-network capex program warrants further review to confirm the need for and timing of the proposed expenditure.

We have assessed forecast expenditure in each category of non-network capex. Analysis at this level has been used to inform our view of whether forecast capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.[182] Figure 6.18 shows United Energy's actual and forecast non-network capex by sub-category for the period from 2009 to 2020.

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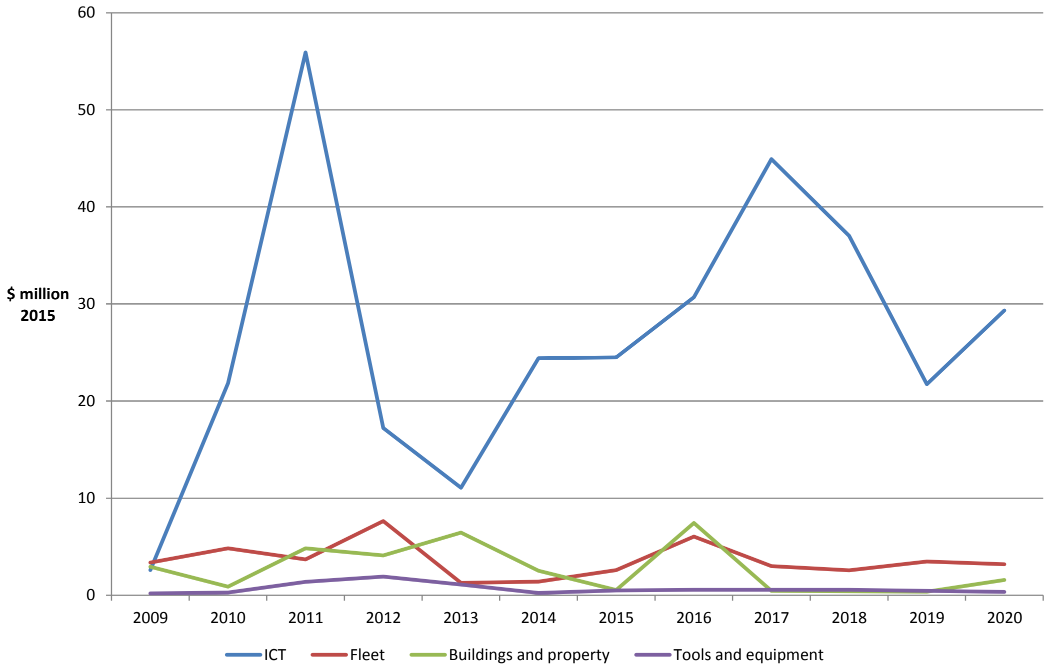
181 United Energy, *Regulatory information notice,* template 2.6; United Energy, *Category Analysis RIN 2014*, template 2.6; AER analysis.

182 NER, cl. 6.5.7(e)(5).

Figure 6.18 United Energy's non-network capex by category ($million, 2015)



Source: United Energy, *Regulatory information notice*, template 2.6; United Energy, *Category Analysis RIN 2014*, template 2.6; AER analysis.

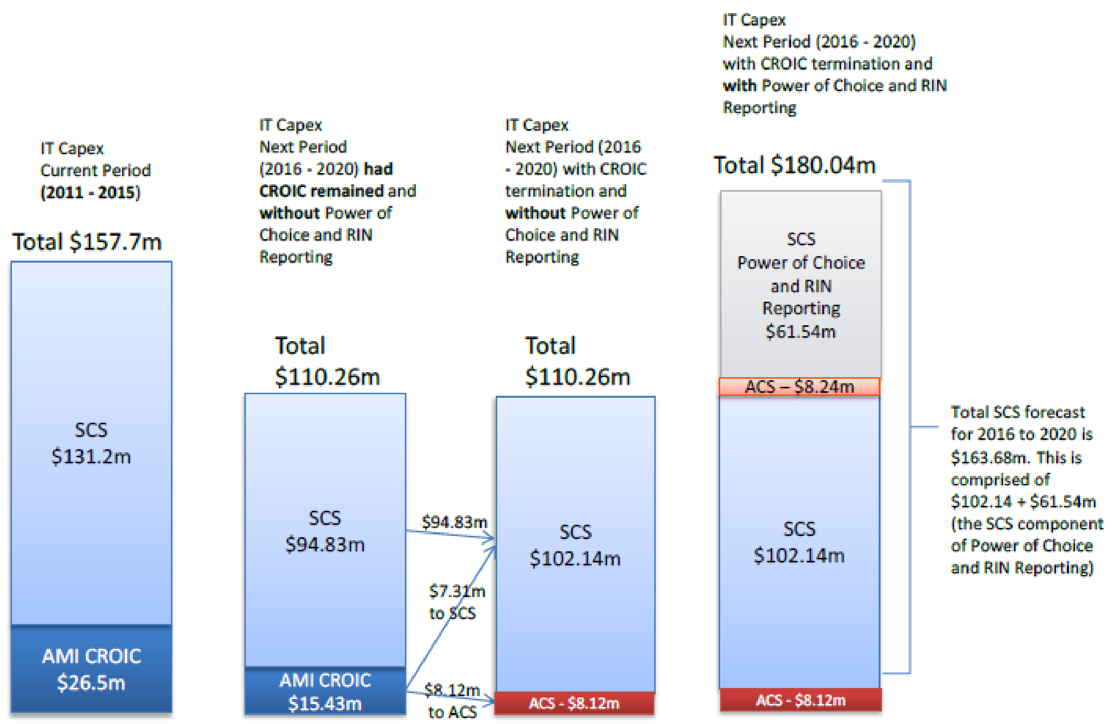
United Energy has forecast an increase in ICT capex in the 2016–20 regulatory control period of 25 per cent. Forecast capex for motor vehicles is generally consistent with historical levels of expenditure. United Energy has forecast both buildings and property capex, and tools and equipment capex to reduce substantially in the 2016–20 regulatory control period.

We therefore undertook a detailed review of the justification for United Energy's forecast ICT capex to confirm the need and timing of the forecast expenditure. We have assessed United Energy’s forecast ICT capex using both trend analysis and individual project review. In our trend analysis, we have compared the proposed expenditure to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure. In doing so, we have considered the underlying drivers of expenditure, including the investment lifecycle stage the business is in and its particular IT needs. Where we have decided to review individual projects or programs, we have examined any business cases and other supporting documentation provided by the business to assess whether the expenditure reasonably reflects the capex criteria. Our conclusions are summarised below.

B.6.3 Information and communications technology capex

United Energy has forecast non-network IT capex of $163.7 million ($2015) for the 2016–20 regulatory control period.[183] This is an increase of $32.5 million or 25 per cent from actual and expected expenditure in the 2011–15 regulatory control period. A comparison of United Energy's actual and forecast ICT capex for the 2011–15 and 2016–20 regulatory control periods is shown in Figure 6.19.

Figure 6.19 Comparison of United Energy's non-network ICT capex in the 2011–15 and 2016–20 regulatory control periods



Source: United Energy, *Capital expenditure overview – ICT*, 30 April 2015, p. 10.

United Energy submitted that three factors should be taken into account when comparing its historical and forecast ICT capex:[184]

- market reforms following from the AEMC's Power of Choice review will require significant ICT capex for system changes to meet the new requirements
- the AER's regulatory information notice (RIN) reporting requirements, in particular the need to report based on actual rather than estimated data, will also require significant ICT capex in the 2016–20 regulatory control period

[183] United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 96.

[184] United Energy, *Regulatory Proposal 2016–20, Capital expenditure overview – ICT*, 30 April 2015, p. 9.

- termination of the Advanced Metering Infrastructure Cost Recovery Order in Council (CROIC) at the end of 2015 – a portion of the recurrent ICT costs previously recovered under the CROIC will be included as standard control services capex in the 2016–20 regulatory control period.

United Energy submitted that a valid comparison of forecast and historical ICT capex would exclude the costs for Power of Choice and RIN reporting projects and account for the ongoing recovery of CROIC costs. On that basis, United Energy identified forecast ICT capex for standard control services of $102.1 million ($2015), a reduction in forecast ICT capex of approximately 29 per cent when the additional Power of Choice and RIN reporting projects are excluded.[185]

We consider that United Energy's base forecast for ICT capex of $102.1 million is likely to reflect the high level drivers of these costs, and reasonably reflect the efficient costs of a prudent operator. A majority of this expenditure is recurrent in nature, designed to maintain the currency or capability of ICT infrastructure, applications and services.[186] The forecast reduction in comparable ICT capex requirements reflects the substantial investment made by United Energy in the 2011–2016 regulatory control period, and its current stage in the ICT asset lifecycle. In the 2011–2016 regulatory control period, United Energy delivered several large ICT projects that were critical to its business transformation process. These included a major enterprise resource planning system replacement project, a system separation project, two data centre relocations, a major infrastructure refresh, updates of the distribution management system, and upgrades of market systems.[187] These major projects do not need to be replicated in the 2016–20 regulatory control period. Rather, continued investment is required to maintain and refresh existing ICT assets, and address remaining capability gaps as required. United Energy submitted that:[188]

> Having completed a major overhaul of our ICT systems in recent years, we will continue to invest in the systems to ensure these systems are refreshed to maintain the industry standard required to meet the needs of our customers.

This is consistent with the Consumer Challenge Panel's submission that levels of ICT capex in the 2011–2016 regulatory control period in part reflected 'one off' adjustments which do not necessarily need to be replicated in the 2016–20 regulatory control period. The Consumer Challenge Panel submitted that overall, capex for IT and communications should reflect a reduction from current levels in order to bring the amounts of capex back to 'reasonable' levels.[189] We consider the 29 per cent reduction in United Energy's base standard control ICT capex forecast is consistent with this view.

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185 United Energy, *Regulatory Proposal 2016–20, Capital expenditure overview – ICT*, 30 April 2015, p. 10.

186 United Energy, *Regulatory Proposal 2016–20, IT Capital Program 2016 to 2020*, April 2015, p. 30.

187 United Energy, *Regulatory proposal* 2016–20, 30 April 2015, p. 77.

188 United Energy, *Regulatory proposal* 2016–20, 30 April 2015, p. 79.

189 CCP Sub-Panel 3, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, pp. 58–59.

In reaching this conclusion, we have not attempted to re-examine United Energy's prioritisation of particular business needs, or approve investments for specific projects or programs. Rather, we have considered whether the proposed $102.1 million base ICT capex program, excluding new major projects, reasonably reflects a prudent and efficient level of capex that is deliverable in the 2016–20 regulatory control period. We are satisfied that this is the case.

The additional capex of $61.5 million proposed by United Energy for the Power of Choice and RIN reporting projects is considered separately below.

Power of Choice ICT capex

United Energy forecast ICT capex of $37.2 million ($2015) for nine projects related to forthcoming market reforms driven by the recommendations of the AEMC's Power of Choice review. The ICT projects provide for new or modified systems to deliver new or enhanced capabilities in the following areas:

- electricity customer switching
- distribution network pricing arrangements
- expanding competition in metering and related services
- enabling multiple trading relationships
- customer access to information about their electricity consumption
- management of embedded networks
- enabling the deployment of demand management
- delivery of demand side participation information to AEMO
- introduction of a market based demand response mechanism.

United Energy is the only Victorian DNSP to propose ex ante capex costs related to the full range of potential market reforms arising from the AEMC's Power of Choice review. The other four Victorian DNSPs have proposed to recover various Power of Choice related costs through the cost pass through arrangements of the NER rather than through the ex-ante capex allowance. This is because in most cases the nature of future regulatory obligations and the scope, timing and cost of system changes required to accommodate them remain uncertain. This uncertainty is reflected in the regulatory proposals submitted by AusNet Services, Jemena, CitiPower and Powercor, which include the following statements:

> there is a large degree of uncertainty with respect to the timing and quantum of Power of Choice related cost impacts[190]

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[190] AusNet Services, *Regulatory proposal 2016–20*, April 2015, p. 270.

> As the AEMC has only released a draft determination and certain procedures and guidelines are yet to be published, there is uncertainty as to JEN's role and responsibilities in respect of metering services, the scope of the systems changes it will have to implement (and the cost involved), and the need for additional operating and capital expenditure to ensure it is fully compliant[191]
>
> ****
>
> CitiPower considers there is still uncertainty as to the detail of the framework for metering contestability …. Having regard to that uncertainty, the cost implications of the expiration of the Victorian Metering Derogation and the introduction of metering contestability are not sufficiently certain such that they could be included in CitiPower's forecast expenditure in its regulatory proposal.[192]
>
> ****
>
> Powercor is unable to fully assess the impact of multiple trading relationships until after the rule change determination and/or retail market procedures have concluded.[193]

United Energy also acknowledges this uncertainty in the project justification documents submitted for each of the nine proposed Power of Choice related projects. These project justification documents all include a statement that: 'detailed requirements are not available at this stage'.[194]

We sought further information from United Energy to explain the rationale behind its preferred approach to managing the uncertainty surrounding future Power of Choice related ICT costs, in contrast to the approach adopted by the other Victorian DNSPs.[195] United Energy submitted that:[196]

> While the PoC Rules were not final at the time of submitting our Regulatory Proposal, we consider that quantifying the expected costs of meeting these new Rules, based on the information known at the time, improves transparency for stakeholders and is critical for informing the further development of the PoC Rules.
>
> As you would be aware, since submitting our Regulatory Proposal, further progress has been made on the development of the PoC Rules, albeit that they are still not final. We have been actively following these changes and will revise our forecast costs associated with meeting these Rules as part of our Revised Regulatory Proposal.

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191 Jemena, *Regulatory proposal 2016–20, Attachment 5–4: Risk Management Framework*, 30 April 2015, p. 15.

192 CitiPower, *Regulatory proposal 2016–20, Appendix L – Managing uncertainty*, April 2015, p. 21.

193 Powercor, *Regulatory proposal 2016–20, Appendix L – Managing uncertainty*, April 2015, p. 26.

194 The statement is made under the 'Assumptions' section of each project justification document. For example, refer to United Energy, *PJ20 Power of Choice Multiple Trading Relationships*, 16 March 2015, p, 8.

195 AER, *Information request to United Energy IR#016*, 30 July 2015.

196 United Energy, *Response to information request United Energy IR#016*, 6 August 2015, p. 1.

We agree with United Energy that attempting to quantify the expected costs of meeting the new Power of Choice related rules aids transparency and may contribute to the further development of the rule changes. However, in assessing United Energy's forecast capex, we must be satisfied that the capex reasonably reflects the capex criteria.

We are not satisfied that United Energy's forecast ICT capex for Power of Choice related projects reasonably reflects the capex criteria. Given the uncertainty that exists around the nature of the applicable regulatory obligations, the possible system changes required, and the quantum of costs which may be incurred, we are not satisfied that United Energy's forecasts reasonably reflect the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives.[197] Further, where a rule change process has commenced, or is expected to commence, but has not yet concluded, we do not consider that possible capex associated with a future rule change is required to meet an applicable regulatory obligation or requirement.[198]

On this basis, we have not included United Energy's forecast standard control capex of $37.2 million for the nine proposed Power of Choice related IT capex projects in our estimate of total capex for this preliminary decision. The scope, timing and cost of necessary IT system changes related to the various Power of Choice reforms remain uncertain. The regulatory change event pass through in the NER provides a mechanism for the recovery of costs associated with a regulatory change where those costs are material. We will review any updated or additional supporting information relating to these costs submitted by United Energy as part of its revised proposal.

RIN Reporting ICT capex

United Energy forecast ICT capex of $24.3 million ($2015) to achieve compliance with RIN reporting obligations in the 2016–20 regulatory control period.[199] This project is intended to deliver changes to nine IT systems resulting in:[200]

- an enhanced RIN reporting capability
- improved automation of RIN reporting processes
- integration with transaction-based and data warehousing and reporting applications.

The majority of the costs associated with the RIN reporting project are labour costs ($21 million) with relatively minor costs for IT hardware, software licences and project management ($3.3 million).[201]

[197] NER, 6.5.7(c).

[198] NER, r. 6.5.7(a)(2).

[199] United Energy, *Regulatory proposal 2016–20, Capital expenditure overview – ICT*, 30 April 2015, p. 9.

[200] United Energy, *PJ22 – RIN Reporting*, 15 March 2015, p. 26.

[201] United Energy, *PJ22 – RIN Reporting*, 15 March 2015, p. 27.

The AER's RIN reporting obligations apply to all network service providers in the NEM. However, United Energy is one of only a small number of service providers to identify significant compliance costs in their capex or opex forecasts. CitiPower, Powercor and SA Power Networks have also proposed IT capex for compliance with the RIN reporting obligations. In contrast, AusNet Services, Jemena, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Energex and Ergon Energy have either not proposed any ICT capex for this or only proposed very small amounts.

We use the data that is provided in response to our category analysis and benchmarking RINs to improve our regulation of the network businesses. For example, the information is used to conduct trend analysis and benchmarking, to better inform our assessment of forecast expenditure. This has benefits for consumers through ensuring forecast expenditure is efficient, and for all stakeholders in providing increased transparency and consistency in regulatory processes. In establishing the RIN reporting obligations, we acknowledged that there may be some upfront costs to businesses in order to comply with the new data requirements. We sought to minimise the scope and cost of data requirements so that the benefits of data collection outweigh the costs of collecting the data. We sought information from network service providers on the cost of compliance when we were consulting on RIN obligations, but were not provided with estimates.[202]

We sought further information from United Energy concerning the nature and quantum of the forecast RIN reporting project costs.[203] United Energy provided a breakdown of the labour resources required to deliver the three phases of the project. United Energy submitted that the total resources required equate to an additional 17 full time equivalent employees for the five years of the 2016–20 regulatory control period, or \$2.5 million for each of the nine systems affected by the project.[204] This compares to the quantified tangible benefit identified by United Energy of annual savings of \$0.65 million on external consultants and internal labour from 2018 onwards.[205] As such, the labour cost of the project equates to more than 32 years of the forecast internal and external labour savings provided by the project.

We recognise that each business is starting from a different position regarding its existing systems and data availability. However, we would not expect a prudent operator to require the extent of additional investment identified by United Energy. We have not seen similar requests for increased expenditure from businesses in New South Wales and Queensland, or from some other businesses in Victoria. We expect that network service providers would already likely collect much of the data required by the RIN reporting obligations in order to facilitate the efficient operation and

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[202] AER, *Better Regulation: Explanatory Statement: Final regulatory information notices to collect information for category analysis*, March 2014, pp. 1–2, 8: AER, *Better Regulation: Explanatory Statement: Regulatory information notices to collect information for economic benchmarking*, November 2013, p. 9.

[203] AER, *Information request to United Energy IR# 016*, 30 July 2015.

[204] United Energy, *Response to information request United Energy IR# 016*, 6 August 2015, pp. 3–5.

[205] United Energy, *PJ22 – RIN Reporting*, 15 March 2015, p. 21.

management of its network. United Energy appears to acknowledge this when it states that:[206]

> Since submitting our Regulatory Proposal to the AER on 30 April 2015, we have undertaken further analysis on what we require by way of information to effectively manage our network and bring us in line with good industry practice. We have found that in order to align with current industry practice and run our network more effectively we need to improve our Asset Management Systems (AMS) Information, to collect more and better data …. The investment set out in our RIN Reporting Project Justification is critical to the upgrade of our Asset Management Systems.

In relation to the specific systems to be upgraded as part of the RIN reporting project, United Energy submitted that all of these systems were recently replaced in the 2011–15 regulatory control period on a like for like basis. At the time of replacing these systems, United Energy did not upgrade them to enable better asset management capability. United Energy now proposes to improve the capacity of these systems to ensure its asset management capability is in line with good industry practice.[207] In our view, further investment of the quantum proposed, so soon after replacing the same systems in the 2011–15 regulatory control period, may reflect an inefficient approach to ICT investment. The cost of this inefficiency should not be borne by consumers.

In relation to the magnitude of costs required to achieve RIN reporting compliance, United Energy noted that:[208]

> The AER has clear expectations that future RIN reports will be largely based on actual data rather than estimates. However the exact nature of that expectation is unclear and different interpretations lead to very different estimates of expenditure.

The RIN reporting project justification also notes that the scope of work proposed reflects ‘United Energy’s interpretation of DNSP RIN requirements’ and is based on a ‘preliminary’ gap analysis of deficiencies to be addressed by the project.[209] On this basis, we have concerns about the magnitude of expenditure proposed for this project, which appears to reflect an initial, risk averse assessment of possible costs. As such, we are not satisfied that the scope and cost of the project proposed by United Energy necessarily reflect actual RIN compliance costs.

In summary, we do not accept that the forecast capex for the RIN reporting project proposed by United Energy reasonably reflects the efficient costs of a prudent operator. A significant driver for the project appears to be United Energy’s need to improve its asset management systems and data in line with good industry practice, rather than comply with the specific RIN reporting obligations. United Energy did not

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206 United Energy, *Response to information request United Energy IR# 016*, 6 August 2015, p. 2.
207 United Energy, *Response to information request United Energy IR# 016*, 6 August 2015, p. 2.
208 United Energy*, Regulatory Proposal 2016–20*, *Capital expenditure overview – ICT*, 30 April 2015, p. 9.
209 United Energy, *PJ22 – RIN Reporting*, 15 March 2015, p. 8.

upgrade the capability of these systems when they were replaced in the 2011–15 regulatory control period, which we are concerned may reflect an inefficient approach to ICT investment. The quantified labour savings provided by the project are minor compared with the significant labour costs proposed to deliver the project. On this basis, we have not included United Energy’s forecast standard control capex of $24.3 million for the RIN reporting project in our estimate of total capex for this preliminary decision. We will consider any revised estimate of RIN compliance costs in our assessment of United Energy’s revised proposal.

Conclusion on ICT capex

For the reasons set out above, we are not sufficiently satisfied that United Energy’s non-network ICT capex forecast reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.[210] Our alternative estimate of forecast standard control ICT capex is $103.6 million ($2015). This includes United Energy’s base forecast ICT capex of $102.1 million, plus a portion of United Energy’s forecast alternative control services ICT costs which we have reallocated to standard control services as discussed in attachment 16 of this preliminary decision. Our alternative estimate of forecast standard control ICT capex is a reduction of $60.1 million or 37 per cent from United Energy’s forecast capex. We will make allowance for it in our estimate of total capex for the 2016–20 regulatory control period.

B.6.4 Fleet asset disposals

United Energy did not account for any disposals of fleet assets in its regulatory proposal. In assessing United Energy's forecast non-network capex, we sought further information regarding United Energy's forecast disposals of fleet assets in the 2016–20 regulatory control period.[211]

In response to our information request, United Energy advised that it expected proceeds from the sale of fleet assets over the 2016–20 regulatory control period of $0.7 million.[212] We have accounted for these disposals in modelling United Energy's required revenue for the 2016–20 regulatory control period.

[210] NER, cl. 6.5.7(c).

[211] AER, *Information request to United Energy IR# 004*, 23 June 2015.

[212] United Energy, *Response to information request United Energy IR# 004*, 8 July 2015.

C Maximum demand forecasts

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure.[213] This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts. Hence accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network.

This attachment sets out our decision on United Energy's forecast network maximum demand for the 2016–20 regulatory control period. We consider United Energy's demand forecasts at the total system level and the more local level.

System demand represents total demand in the United Energy distribution network. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased network utilisation which may, once any spare capacity in the network is used up, lead to a requirement for growth capex. Conversely forecasts of stagnant or falling system demand will generally signal falling network utilisation, a more limited requirement for growth capex, and the potential for the network to be rationalised in some locations.

Localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments.

In our consideration of United Energy's demand forecasts, we have had regard to:

- United Energy's proposal
- independent maximum demand forecasts from the Australian Energy Market Operator (AEMO)[214]
- a report by our internal economic consultant, Dr Darryl Biggar, on the forecasting methodologies underlying each Victorian electricity distributor's demand forecasts for 2016–20 (this report will be published alongside this preliminary decision)[215]
- long-term demand trends and changes in the electricity market, and
- stakeholder submissions in response to United Energy's proposal (as well as submissions made in relation to the Victorian electricity distribution determinations more generally).[216]

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213 NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).

214 AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014

215 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015.

216 See AER, http://www.aer.gov.au/node/24446.

These are set out in more detail in the remainder of this appendix.

C.1 AER determination

We are not satisfied that United Energy's demand forecasts reflect a realistic expectation of demand over the 2016–20 regulatory control period. In determining a realistic expectation of demand over the 2016–20 period, we have had regard to the following factors:

- Recently observed changes in the electricity market and the way energy is consumed in recent years (e.g. strong uptake of solar PV, changing customer behaviours and energy efficiency measures) suggests that the strong positive demand growth seen in United Energy's network prior to 2009 is unlikely to return in the short to medium term. This is discussed in section C.3.
- United Energy's forecasting methodology uses observed historical patterns of peak demand, and the sensitivity of historical demand to temperature, to forecast future maximum demand. On this basis, United Energy forecasts a recovery of maximum demand levels from the previous flattening of demand. This is primarily due to a number of demand drivers such as impact of air conditioning penetration and expected growth rate, which have not been adequately supported. We are concerned that the model used to develop United Energy's forecasts does not allow for the potential changes that we may be observing for the electricity market in Victoria and recent declines in demand. This is discussed in section C.2 and C.4.
- Independent forecasts from AEMO better explain the actual demand pattern seen on all distributors' networks. This is because it does not assume a fixed structural relationship between demand and demand drivers over a long period and, instead, places greater reliance on industry knowledge and judgement. While not without its limitations, we consider that AEMO's forecasts better reflect recent changes in the electricity market. This is also discussed in section C.4.

We understand that United Energy (and the Victorian electricity businesses) are in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR). We also note that AEMO will publish updated connection point demand forecasts for Victoria. We are open to United Energy submitting an updated demand forecast that accounts for the factors listed above, including the most recent demand data and AEMO's updated forecasts.

We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will also consider updated demand forecasts and other information (such as AEMO's revised connection point forecasts) in the final decision to reflect the most up to date data.

We have also received a number of consumer submissions that raise concerns with United Energy's and the other Victorian distributors maximum demand forecasts. The CCP submitted that we should pay particular attention to the distributors maximum demand forecasts and whether they have been over estimated, given the following considerations:

- forecasts of maximum demand are key drivers of revenue requirements

- distributors' forecasts exceed and contrast with AEMO's forecasts, and
- distributors have consistently over forecast maximum demands in the past.[217]

The Ethnic Communities Council of Victoria (ECCV) also supported us further examining the Victorian distributors' forecasts that exceed forecasts by AEMO.[218]

The VECUA also submitted that the Victorian distributors have consistently over estimated their peak demand and energy delivered projections. VECUA put forward that network distributors are insulated from volume risk through revenue cap regulation, which allows them to pass that risk on to customers. Therefore if the actual energy delivered is lower than forecast by networks' then networks will increase their prices to recover their guaranteed revenues. VECUA also considered it important to note:[219]

> …that the Victoria distributors were rewarded with windfall profits for their forecasting errors, as their revenue allowances included returns and depreciation on load-driven capex which they did not incur.

As set out in this appendix, we have closely examined United Energy's maximum demand forecasts and drawn similar observations to these submissions. A key part of our work has been to analyse United Energy (and the other Victorian distributors) demand forecasts with reference to AEMO's independent maximum demand forecasts. However, the VECUA submitted that AEMO has consistently over estimated its energy forecasts in recent years and has not fully considered the influence of future factors in reducing demand (such as energy efficiency schemes, automotive closures, cost reflective price structures and battery storage technology).[220] We do not agree with the VECUA and consider that AEMO's explanation of its forecasting methodology reveals that it has considered a wide variety of information in its forecast, including predictions for energy efficiency and automotive closures in Victoria and this represents an enhancement and improvement to its previous forecast approach.[221]

Further, the CCP and VECUA referred to AusNet Services demand forecasts as the only Victorian distributor to forecast lower energy consumption in the future compared to the past.[222] VECUA has submitted that AusNet Services demand forecasting

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217 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 32–37.

218 Ethnic Community Council of Victoria, *Submission to the Australian Energy Regulator Victoria Electricity Pricing Review*, 15 July 2015, p. 4.

219 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 14–16.

220 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 17.

221 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 11.

222 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 35–37; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 15–16.

methodology incorporates actual interval metering data, which it considers may account for the differences between AusNet Services forecast growth and other Victorian distributors.[223] The CCP considered that the AusNet Services approach to developing its forecast demand is a significant enhancement in forecasting future demand and is a direct outcome from the decision to mandate the roll out of the AMI program in Victoria.[224] We consider there is merit to these views (and will be useful as distributors develop their information capacity). However we have not directly taken this into account for our assessment of United Energy's maximum demand forecasts because it has not been necessary due our assessment approach which is based substantially on comparison with AEMO’s demand forecasts.

C.2 United Energy's proposal

United Energy provided historical and forecast demand figures in their proposal and in the reset Regulatory Information Notice (RIN).[225] United Energy proposed approximately 2 per cent annual growth in maximum demand across the 2016–20 period. In its proposal, United Energy forecast an increase in peak demand in specific areas of its network to be driven by:[226]

- increasing penetration of air-conditioners by commercial businesses and residential households
- the contribution of solar PV remaining small at times of maximum demand, with growth in solar PV slowing in United Energy's service area over the past year and many energy efficiency programs influencing maximum demand winding down
- expected improvements in economic growth and stabilisation of electricity prices, and
- population and building stock growth, particularly in and around the developing suburbs from Keysborough through to Carrum Downs, and parts of the Mornington Peninsula.[227]

United Energy submitted that its forecast of peak demand growth is based on public information from the Victorian Government.[228]

United Energy's engaged the National Institute of Economic and Industry Research (NIEIR) to develop its demand forecasts.[229] United Energy's proposal also included a brief summary of NIEIR's demand forecasting method, including approaches to:

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223 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks’ 2016–20 Revenue Proposals*, 13 July 2015, p. 16.

224 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 35–37 and p. 44.

225 United Energy reset RIN; United Energy, *Regulatory Proposal 2016–20,* April 2015, pp. 27–39.

226 United Energy, *Regulatory Proposal 2016–20, Maximum demand overview paper,* April 2015, p. 24.

227 United Energy, *Regulatory Proposal 2016–20, Maximum demand overview paper,* April 2015, p. 11.

228 United Energy, *Regulatory Proposal 2016–20, Maximum demand forecasting method, Appendix A: NIEIR's PeakSim model,* April 2015.

- demand drivers
- accounting for economic conditions such as incomes and electricity prices
- projections of residential customer numbers by dwelling stock forecasts; non-residential customer number forecasts are derived from historic growth in energy consumption, historic customer growth and average usage by tariff class,[230] and
- post model-adjustments for changes in electricity prices, energy efficiency programs and embedded generation.[231]

United Energy submitted that it then undertakes a top down and a bottom up verification of the NIEIR demand forecast. The top down verification is reconciled with another economic model developed by AECOM (Architecture, Engineering, Consulting, Operations, and Maintenance). This model is described as a simplified version of NIEIR's model and reported to follow the approach adopted by AEMO. The bottom up verification reconciles zone substation and high voltage distribution feeder forecasts with NIEIR's forecast. United Energy submitted that the bottom up verification is then reconciled with the top down forecast in order to address any apparent bias in the bottom up forecasts.[232]

United Energy's forecasting methodology is described in detail in Dr Biggar's report.[233]

C.3 Demand trends

Our first step in examining United Energy's forecast of maximum demand is to look at whether the forecast is consistent with, or explained by, long-term demand trends and changes in the electricity markets.

Figure 6.20 shows that over the last few years, the path of electricity demand seems to be changing. From 2006 to 2009, actual maximum demand on United Energy's network was growing steadily. Then from 2009 to 2012, demand flattened and declined. The decline in 2009 from historical demand growth has also been recorded for Victoria (as shown in Figure 6.21) and for the NEM. While there was some growth in demand between 2013 and 2014, this does not necessarily indicate a return to longer-term growth in demand.

As shown further in Figure 6.20, United Energy's demand forecasts for the 2015–20 period are higher than the actual demand observed for its network during 2006–14 (in particular its PoE 10 forecasts). United Energy forecasts a return to demand growth on the network similar to that experienced prior to 2009. This contrasts with AEMO's

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229 United Energy, *Regulatory Proposal 2016–20,* April 2015, p. *27*.

230 United Energy, *Regulatory Proposal 2016–20,* April 2015, p. 39*.*

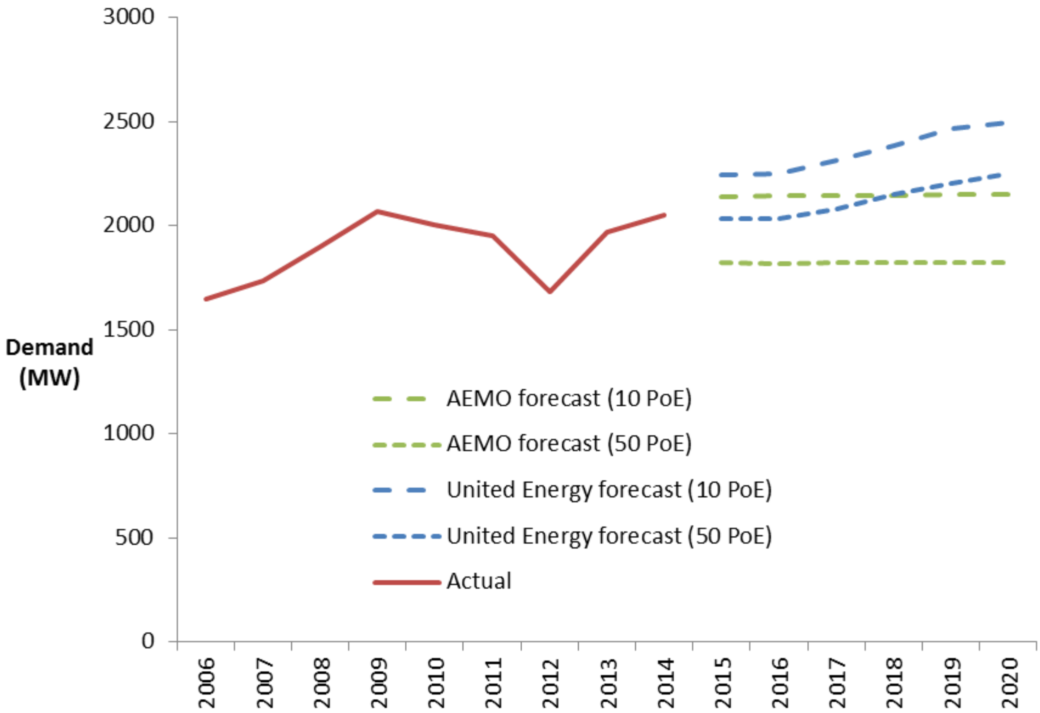
231 United Energy, *Regulatory Proposal 2016–20,* April 2015, pp. 37–38.

232 United Energy, *Regulatory Proposal 2016–20, April 2015,* pp. 34–36*;* United Energy, *Regulatory Proposal 2016–20, Maximum demand forecasting method*, pp. 7–8.

233 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 19–25.

Connection Point Forecasts, published in September 2014, which forecasts little or no growth in connection point demand on United Energy's network for the same period.[234]

Figure 6.20 Comparison of peak demand forecasts of United Energy and AEMO (MW, non-coincident, summated connection point forecasts)



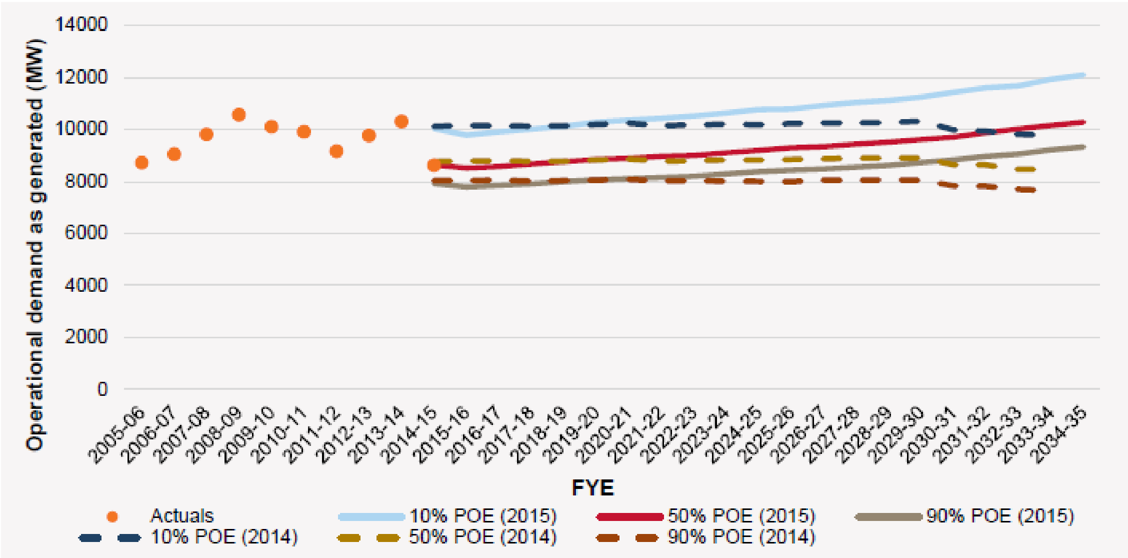
Source: United Energy regulatory proposal, AER analysis using AEMO data on transmission connection point forecasts; reset RIN; economic benchmarking RIN 2006-14.

Note: Actual demand over the 2006 to 2014 period reflects United Energy's actual maximum demand over this period (as reported in United Energy's economic benchmarking RIN data from 2006 to 2014). This is opposed to weather normalised historical maximum demand data.

Figure 6.21 shows AEMO's forecasts of maximum demand across Victoria. In its 2015 national electricity forecasting report, AEMO forecast a flattening of maximum demand for Victoria for 2015–2020. However, AEMO has forecast some growth in maximum demand over the next twenty years, which is a change from its 2014 national electricity forecasting report.

[234] AEMO, *Transmission Connection Point Forecasting Report for Victoria*, September 2014, pp. 12–13.

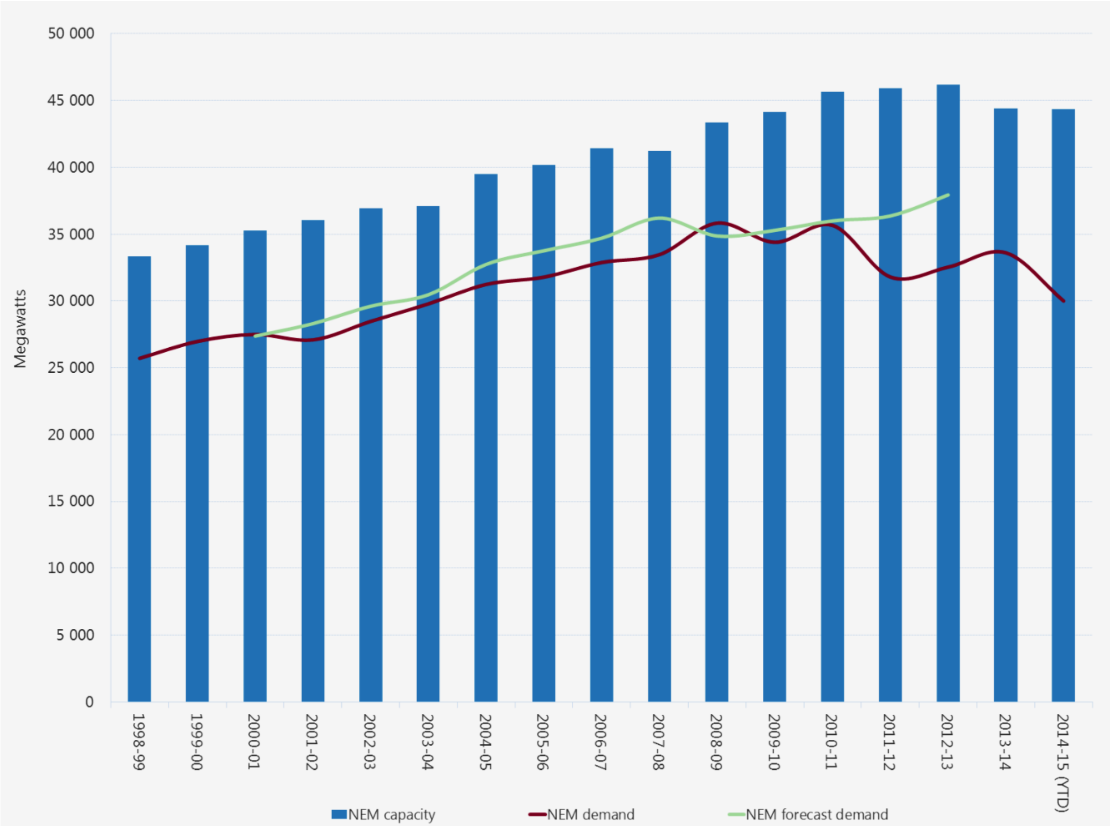
Figure 6.21 AEMO's maximum demand forecasts for Victoria



Source: AEMO, *2015 National Electricity Forecasting Report,* June 2015.

We see a similar change in peak demand patterns across the National Electricity Market (NEM). Figure 6.22 compares NEM peak demand together with the forecast peak demand two years ahead and total generation capacity, since the NEM began. It shows actual demand has been declining generally since 2008–09 across the NEM.

Figure 6.22 Comparison of historical generation capacity and peak demand across the NEM



Source: AER, accessed on 18 August 2015 at: https://www.aer.gov.au/node/9772.

Note: The step up in maximum demand in 2004–05 is as a result of Tasmania's entry to the NEM.

United Energy forecasts strong demand growth for 2015–20, whereas other independent forecasts from AEMO predict low or no growth over this period. While actual connection point demand increased on United Energy's network in 2013 and 2014 (see Figure 6.20), the observed changes in demand patterns within the span of nine years raises the question of whether the recent flattening of demand is an aberration (and demand will return to growth) or a realistic expectation of demand over the 2016–20 period.

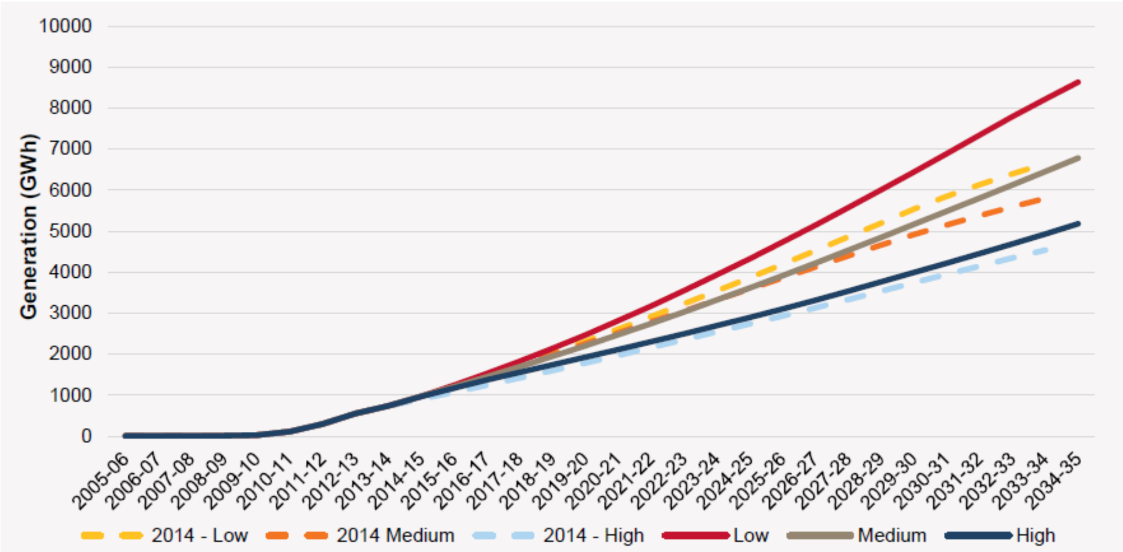
There have been some developments in the Australian and Victorian electricity markets over recent years that have influenced energy consumption and maximum demand patterns.

First, across the NEM, growth in rooftop solar generation (PV) and energy efficiency (through the uptake of energy efficient appliances and building efficiency) has reduced electricity drawn from the grid. Rooftop PV generation has had the long-term effect of reducing maximum demand and shifting the daily peak to later in the evening. Energy efficiency reduced overall energy consumption and has a downward impact on maximum demand.

In Victoria, AEMO reported that in the five years to 2014–15, consumption in the residential and commercial sector decreased due to rising prices and the uptake of rooftop PV.[235] AEMO forecasts that there will be continued uptake of rooftop PV in the residential and commercial sectors.

To demonstrate, Figure 6.23, drawn from AEMO's 2015 national electricity forecasting report for Victoria, shows the projected capacity of solar PV systems across Victoria. From this figure we observe a projected substantial increase in the volume of installed rooftop solar PV capacity can be observed from 2010 to 2015, with capacity expected to continue to grow strongly to 2020 and beyond.[236]

Figure 6.23 Projected capacity of solar PV systems in Victoria



Source: AEMO, *2015 National Electricity Forecasting Report*, June 2015.

However, we note that the impact of rooftop PV will likely have diminishing impacts on maximum demand over the longer-term as peak daily demand shifts to the evening. This is recognised in AEMO's forecasting report.[237] We note that electricity storage (e.g. batteries) has the potential to significantly enhance the impact of solar generation on maximum demand on the distribution network. However, wide-spread uptake of battery storage will probably not be significant over the 2016–20 period.

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[235] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 68.

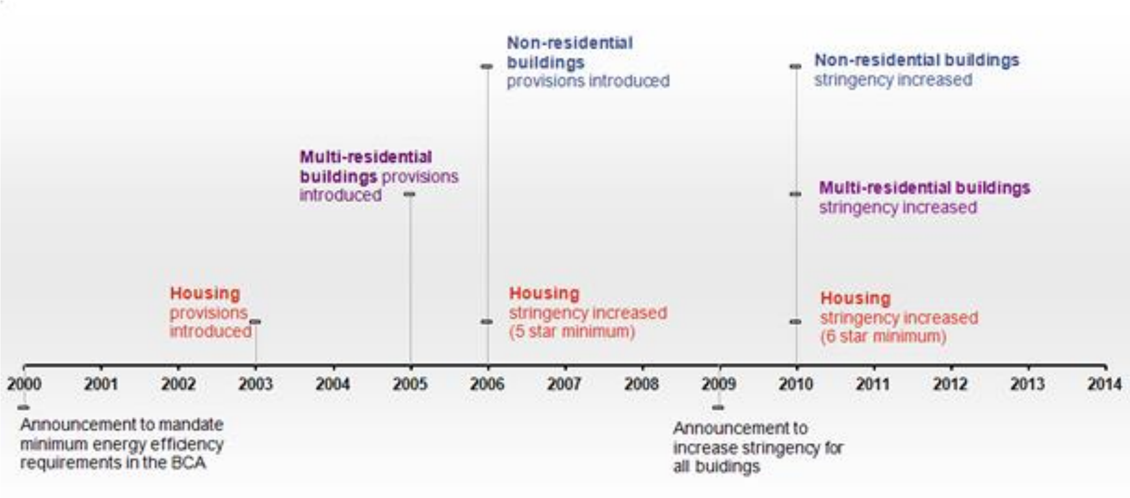
[236] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 73.

[237] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 77.

Second, energy efficiency also contributed to decreased consumption and AEMO forecasts that energy efficiency measures will continue.[238] Ongoing energy efficiency measures such as mandatory energy efficiency building requirements[239] and other government incentives[240] have created an accumulative effect in slowing down demand growth over time. In addition, greater customer awareness of energy usage, improving appliance efficiencies and replacement of aging appliances will likely continue to put downwards pressure on consumption and maximum demand.[241]

Figure 6.24 gives an overview of government energy efficiency requirements in building provisions. From this timeline it can be inferred that the increasing energy efficiency requirements in building regulation are likely to have a cumulative effect on demand in the future.

Figure 6.24 Timeline of Energy Efficiency Requirements in Building Regulation



Source: Australian Building Codes Board (ABCB), accessed on 27 August 2015 at: http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx.

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238 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

239 Australian Building Codes Board (ABCB), *National Construction Code energy efficiency requirements*, http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx , accessed on 27 August 2015.

240 Department of Industry and Science, *Your energy savings: Rebates*, http://yourenergysavings.gov.au/rebates?live_in%5B%5D=64&interested%5B%5D=82&=Search, accessed on 27 August 2015.

241 AEMO, *2015 National Electricity Forecasting Report: Overview*, June 2015, pp. 8–11.

Finally, AEMO also forecast that Victoria is not expected to recover to its historical high level of operational consumption (in 2008–09) until 2030–31, when population is projected to be 1.7 million higher than in 2014–15.[242]

We consider that the combination of these factors support forecast reductions or softening of maximum demand even in the presence of economic and population growth. In particular, based on our assessment of independent forecasts from AEMO, we consider the continuing presence of energy efficiency measures, improving appliance efficiencies and continued growth in rooftop PV will likely put downward pressure on demand, which may counteract any demand growth due to economic and population growth. Solar PV and energy efficiency are not transient or temporary phenomena, but rather fundamental changes in the way electricity is consumed.

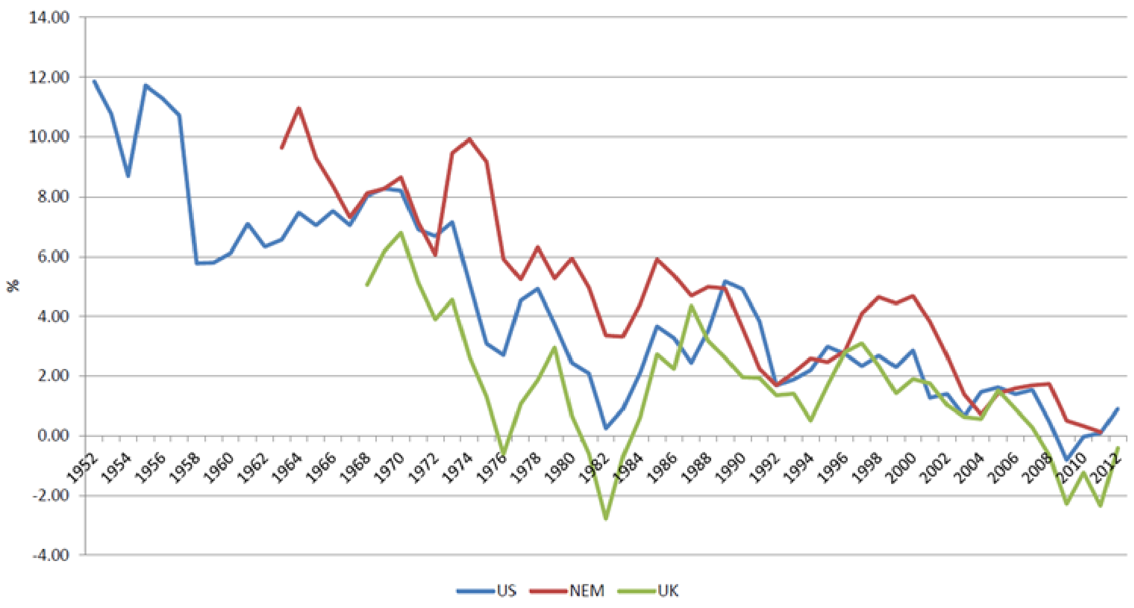
As set out in section C.4 below, we consider that United Energy's forecasting methodology does not adequately capture the changes we are observing for the electricity market in Victoria and recent declines in demand. This is because United Energy's methodology assumes that the structural model they have estimated using 2004–2015 data accurately and completely captures the key drivers of demand in Victoria and that the same relationships between demand and demand-drivers will continue to hold over the 2016–20 period. We are not satisfied that this reflects a realistic expectation of future demand over the 2016–20 period since we are not confident that the drivers used in United Energy's model are able to fully capture the changes in demand in recent years.

We note this is consistent with international trends. Figure 6.25 highlights the fact that growth in electricity demand is currently low or zero in the USA and UK despite the existence of continued population growth and economic growth. In other words, this chart suggests that the impact of economic growth and population growth on electricity demand is being offset by other factors (such as improving energy efficiency). On this basis, it is reasonable to argue that high growth is unlikely to return over 2016–20.[243]

242 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

243 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 11.

Figure 6.25 Long-term trends in electricity growth rates



Source: Energy Supply Association of Australia (ESAA).[244]

C.4 United Energy's forecasting methodology and assumptions

Our next step in examining United Energy's forecasts of maximum demand is to look at United Energy's methodology and whether it is likely to result in a realistic maximum demand forecast. We have relied on a report by our internal economic consultant, Dr Darryl Biggar, and some of our observations about recent trend in maximum demand.

Broadly, Dr Biggar stated that Untied Energy has drawn on sophisticated forecasting tools and has sought to validate its forecasts using a range of different approaches. However, Dr Biggar raised concerns that United Energy's forecasts, and the forecasting tools it uses, may not capture all of the relevant factors which may drive peak demand in the future. On this basis, Dr Biggar stated that he is concerned that the estimates put forward by UE are not a realistic expectation of future demand.

We consider that this position is supported by both recent trends in demand and consumption patterns, and AEMO's independent demand forecasts.

Assessment of NIEIR's demand forecasting methodology

United Energy forecasting methodology (from NIEIR) is segmented into two parts:

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244 Economic and Social Outlook Conference 2014, ESAA, 3 July 2014, p. 7, accessed on 18 August 2015 at: http://www.melbourneinstitute.com/downloads/conferences/Outlook2014/Outlook2014_slides/6_Warren,%20Matthew.pdf.

- Temperature insensitive (base) demand – the part of demand that would occur irrespective of the weather conditions. The projections of base demand are assumed to be strongly related to the estimated growth or decline in energy sales.
- Temperature sensitive demand – the part of demand that occurs due to prevailing weather conditions. NIEIR argued that the temperature sensitivity of electricity demand is primarily driven by the penetration of air conditioning load.

To estimate demand forecasts that are sensitive to temperature, NIEIR first estimated a long-term historical relationship between demand and temperature. It then used this observed historic pattern of peak demand to forecast future peak demand. NIEIR then made some various post modelling adjustments for changes in electricity prices, energy efficiency programs, and small scale embedded generation. Collectively these adjustments are relatively minor.

In Dr Biggar's report (2015), he observed that NIEIR's forecasting model forecast that temperature insensitive (or base) demand will recover from previous lows and that temperature sensitivity will increase. This relates to two key assumptions in NIEIR's forecast:[245]

- that energy volumes are no longer in decline and will recover to 2008 levels before flattening out again, and
- there will be increasing penetration of air conditioning at the rate of 2 to 3 percent per annum. This yields an increase in NIEIR's projections of maximum demand across its network.

Dr Biggar stated that NIEIR's forecast air conditioning penetration rate is insufficiently justified. In particular, Dr Biggar noted that where new air conditioner models are being used to replace older, less efficient models, an increase in air conditioner purchases could be expected to decrease (rather than increase) the impact on maximum demand. [246] Furthermore, Dr Biggar considered this approach ignores the plausible impact of solar PV on base level demand and temperature sensitivity.

We agree and consider that solar PV and energy efficiency measures could outweigh any expected increase in maximum demand from increased penetration of air conditioners. The NIEIR model appears to use long-term historical relationships between demand and temperature, which may not necessarily take into account increases in energy efficiency.

Taking into account Dr Biggar's observations, we are concerned that the assumptions in NIEIR's model do not sufficiently account for the recent decline in maximum demand. NIEIR's report is also more than one year old. Accounting for 2014/15 summer demand would likely further support a decline in maximum demand. Biggar's

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[245] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 19–25.

[246] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 19–25.

summary of NIEIR's approach is that while it appears sound in its estimates of historic peak demand, it appears less convincing when it comes to forecasting future peak demand levels.[247]

Assessment of AECOM's demand forecasting methodology

Our next step in examining United Energy's forecasts of maximum demand is to look at their process for validating the forecasts provided by NIEIR. We have reviewed United Energy's validation model developed by AECOM.

AECOM's forecasting methodology, like most forecasting models, assumes that there is a fixed and unchanging underlying relationship between demand and key demand drivers. It also assumes that this relationship can be accurately estimated using historic data and that these relationships that have been observed in the past will continue into the future. However, if there are changes in the market which are not captured in the forecasting model, the model will not provide a reliable guide to future outcomes.

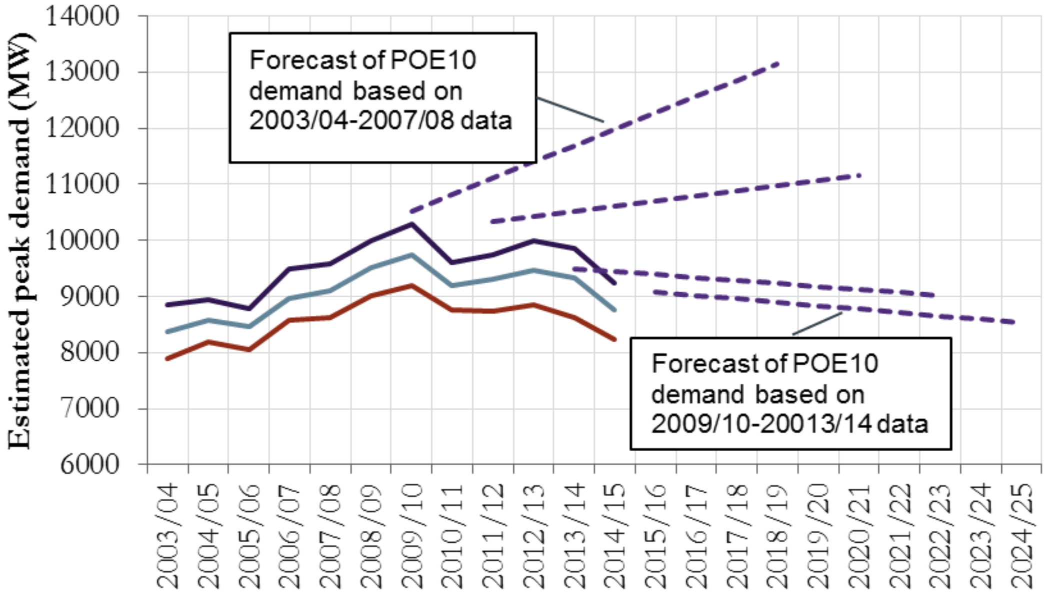
This is shown in Dr Biggar's 2015 report on the Victorian electricity distributors' demand forecasting methodologies.[248] Dr Biggar's analysis, replicated in Figure 6.26, provides a simple illustration which shows what can happen when the assumed drivers of demand do not capture a fixed and unchanging relationship between demand and the key drivers. In this example it is assumed that the primary driver of demand is time (a simple time trend). But as Figure 6.26 shows, there appears to be no fixed relationship between peak demand and time. In the first half of the last decade, peak demand growth was increasing rapidly. Since around 2009 it appears that peak demand has been declining. This illustrates that a model, which assumes a simple fixed relationship between peak demand and time would likely give unreliable forecasts of future peak demand.[249]

[247] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 19–25.

[248] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

[249] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

Figure 6.26 Illustration of future forecasts of POE10 levels based on the most recent five years of data



Source: Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 10.

Similarly, Dr Biggar observed that AECOM's modelling enforces a single relationship between maximum demand and weather and other key drivers historically which is assumed to continue to hold in the future. [250] After examining the drivers used by AECOM, Dr Biggar expressed concern that these drivers may not be able to capture the recent apparent change in demand drivers noted above (such as investment in solar PV and increasing energy efficiency).[251] This is supported by the evidence presented in section C.3 above which suggests that average demand growth is likely to be low, zero or negative in the near future.

AEMO's connection point demand forecasts

We have used AEMO's connection point demand forecasts as an independent comparison to United Energy's forecasts. In September 2014, AEMO published its report on connection point demand forecasts for each of the Victorian electricity distributors for the 2014–2023 period. As noted previously, AEMO forecasts low or zero demand growth over the 2016–20 period.

[250] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 22.

[251] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 24.

AEMO's connection point demand forecasts are based on a methodology developed by ACIL Allen, which was developed after consultation during 2012–13 with all distribution businesses.[252] This methodology does not assume a particular long-term structural relationship for demand over time. AEMO has decided to adopt a ‘cubic’ relationship with historical demand and adopts an “off-the-point approach” (which means that the demand forecast begins at the most recent point of actual demand).[253]

ACIL Allen's "off-the-point" approach is not without its criticisms. In particular, it relies on industry knowledge and judgement to adopt an alternative to a historical linear trend and to start the forecast at the most recent point, which can be arbitrary if not based on first principles or underlying economic phenomena.[254] However, we consider it is a better model for forecasting demand for United Energy's network for 2015–20 than NIEIR's models. This is because ACIL Allen's models do not assume a fixed structural relationship between long-term drivers of demand and certain economic factors across the entire period. In using the "off-the-point" approach ACIL Allen extrapolates the relationship between demand and the long-term underlying drivers based on the most recent actual demand value. Because of this, we consider that AEMO's forecast is more likely to reflect a realistic expectation of demand over the 2016–20 period.

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252 In December 2012, the Council of Australian Governments (COAG) released its energy market reform implementation plan. In this plan, AEMO will develop independent demand forecasts in 2013–14 to inform the AER's assessment of infrastructure investment plans submitted by Network Service Providers . Further detail is provided at http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

253 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 19–25.

254 This was a source of criticism in Frontier Economics’ peer review of AEMO’s demand forecasts. See Frontier, “High level review of transmission connection point forecasts: Victoria”, A report prepared for the Australian Energy Market Operator, September 2014.

D Real material cost escalation

Real material cost escalation is a method for accounting for expected changes in the costs of key material inputs to forecast capex. The capital expenditure real escalation forecast model submitted by United Energy includes forecasts for changes in the prices of commodities such as copper, aluminium, steel and crude oil, rather than the prices of the physical inputs it actually sources for its network services (e.g., poles, cables, transformers). United Energy has also escalated construction related costs in its cost of materials forecast.

D.5 Position

We are not satisfied that United Energy's proposed real material cost escalators (leading to cost increases above CPI) reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 period.[255] Instead we consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria. We consider this is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 period. We have arrived at this conclusion on the basis that:

- zero per cent real cost escalation is likely to provide a more reliable estimation of the price of input materials, given the potential inaccuracy of commodities forecasting;
- there is little evidence to support how accurately United Energy's real cost escalation model reasonably reflects changes in prices it paid for physical assets in the past. Without this supporting evidence, it is difficult to assess the accuracy and reliability of United Energy's real cost escalation model as a predictor of the prices of the assets used to provide network services, and
- United Energy has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that are not captured by its capex forecast model.

Our approach to real materials cost escalation discussed above does not affect the proposed application of labour and construction related cost escalators which apply to United Energy's standard control services capital expenditure. We consider that labour and construction related cost escalation as proposed by United Energy is likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria, given these are direct inputs into the cost of providing network services.

255 NER, cl. 6.5.7(a).

D.6 United Energy's proposal

United Energy stated that the escalators applied to materials were developed internally using raw-commodity level data provided by an independent expert, BIS Shrapnel, to forecast real material cost escalations for the 2016–20 regulatory period.[256] United Energy stated that it derived its material cost escalators by applying escalators at the raw-commodity level (i.e. wood, aluminium, copper, steel, oil, concrete etc.) to the estimated mix of these materials used to construct and/or maintain its distribution network (e.g. poles, cables, transformers).[257] United Energy then applied a weighted average escalator, including labour, for each asset class for each year to its capex forecast.[258]

Real cost escalation indices for the following material cost drivers were calculated for United Energy by BIS Schrapnel:[259]

- aluminium
- copper
- steel
- oil
- wood; and
- concrete.

Table 6.15 outlines United Energy's real materials cost escalation forecasts.

Table 6.15 United Energy's real materials cost escalation forecast—inputs (per cent)

	2016	2017	2018	2019	2020
Aluminium	8.0	8.2	5.1	-7.0	-5.2
Copper	3.5	7.7	2.1	-10.0	-6.1
Steel	4.7	3.0	2.7	-11.0	-3.4
Oil	-1.1	4.3	2.5	-7.7	-5.0
Wood	2.2	1.7	0.9	2.2	3.9
Concrete	-1.0	-2.0	-4.9	-3.2	1.3

Source: United Energy, Revenue proposal, Attachment FIN 583, BIS Schrapnel, *Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. iii.

256 United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 59.
257 United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 60.
258 United Energy, *Regulatory Proposal 2016–20*, April 2015, p. 60.
259 United Energy, *Revenue proposal Attachment FIN 583 BIS Schrapnel*, *Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014.

D.7 Assessment approach

We assessed United Energy's proposed real material cost escalators as part of our assessment of total capex under the National Electricity Rules (NER) requirements. Under the NER, we must accept United Energy's capex forecast if we are satisfied it reasonably reflects the capex criteria.[260] Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.[261]

We have applied our approach as set out in our Expenditure Forecast Assessment Guideline (Expenditure Guideline) to assessing the input price modelling approach to forecast materials cost.[262] In the Expenditure Guideline we stated that we had seen limited evidence to demonstrate that the commodity input weightings used by service providers to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the service providers paid for manufactured materials.[263] We considered it important that such evidence be provided because the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used.[264] As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast manufactured material cost changes is likely to reasonably reflect changes in raw material input costs.

In our assessment of United Energy's proposed material cost escalation, we:

- reviewed the BIS Schrapnel report commissioned by United Energy[265]
- reviewed the capex real escalation model used by United Energy[266]; and
- reviewed the approach to forecasting manufactured material costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.

We received no stakeholder submissions on this issue.

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[260] NER, cl. 6.5.7(c).

[261] NER, cl. 6.5.7(c)(3).

[262] AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline,* November 2013, pp. 50–51.

[263] AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

[264] AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

[265] United Energy, *Regulatory Proposal 2016–20: Attachment: FIN 583 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014.

[266] United Energy, *Regulatory Proposal 2016–20: Attachment: FIN 583 Real Escalation working (BIS Schrapnel) – LOCKED.*

D.8 Reasons

We must be satisfied that a forecast is based on a sound and robust methodology in order to accept that United Energy's proposed total capex reasonably reflects the capex criteria.[267] This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[268] In making our assessment, we do recognise that predicting future materials costs for electricity service providers involves a degree of uncertainty. However, for the reasons set out below, we are not satisfied that the materials forecasts provided by United Energy satisfy the requirements of the NER. Accordingly, we have not accepted it as part of our substitute estimate in our preliminary decision on total forecast capex. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this has been taken into account into our substitute estimate.

Capital expenditure forecast model

United Energy's capex real escalation model does not demonstrate how and to what extent material inputs have affected the cost of inputs such as cables and transformers. In particular, there is no supporting evidence to substantiate how accurately United Energy's materials escalation forecasts reasonably reflected changes in prices they paid for assets in the past to assess the reliability of forecast materials prices.

In our Expenditure Guideline, we requested service providers should demonstrate that their proposed approach to forecast materials cost changes reasonably reflected the change in prices they paid for physical inputs in the past. United Energy's proposal does not include supporting data or information which demonstrates movements or interlinkages between changes in the input prices of commodities and the prices United Energy paid for physical inputs. United Energy's capex real escalation model assumes a weighting for total material inputs for each asset class, but does not provide information which explains the basis for the weightings, or that the weightings applied have produced unbiased forecasts of the costs of United Energy's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable. In summary, United Energy has not demonstrated that their proposed approach to forecast materials cost changes reasonably reflects the change in prices they paid for assets in the past.

Materials input cost model forecasting

United Energy estimated cost escalators in order to assist in forecasting future operating and capital expenditure. These cost escalators include commodity inputs in the case of capital expenditure. United Energy adopted a high level approach, hypothesising a relationship between these commodity inputs and the physical assets it purchased. United Energy has not successfully attempted to explain or quantify this

267 NER, cl. 6.5.7(c).

268 NER, cl. 6.5.7(c)(3).

relationship, particularly in respect to movements in the prices between the commodity inputs and the physical assets and the derivation of commodity input weightings for each asset class.

We recognise that active trading or futures markets to forecast prices of assets such as transformers are not available and that in order to forecast the prices of these assets a proxy forecasting method needs to be adopted. Nonetheless, that forecasting method must be reasonably reliable to estimate the prices of inputs used by service providers to provide network services. United Energy has not provided any supporting information that indicates whether the forecasts have taken into account any material exogenous factors which may impact on the reliability of material input costs. Such factors may include changes in technologies which affect the weighting of commodity inputs, suppliers of the physical assets changing their sourcing for the commodity inputs, and the general volatility of exchange rates.

Materials input cost mitigation

We consider that there is potential for United Energy to mitigate the magnitude of any overall input cost increases. This could be achieved by:

- potential commodity input substitution by the electricity service provider and the supplier of the inputs. An increase in the price of one commodity input may result in input substitution to an appropriate level providing there are no technically fixed proportions between the inputs. Although there will likely be an increase in the cost of production for a given output level, the overall cost increase will be less than the weighted sum of the input cost increase using the initial input share weights due to substitution of the now relatively cheaper input for this relatively expensive input.

  We are aware of input substitution occurring in the electricity industry during the late 1960's when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do however recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies with which some inputs are not substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby potentially reducing the total expenditure requirements of an electricity service provider[269]

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.[270] For example, United Energy has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs

[269] NER, cl. 6.5.7(e)(7).

[270] NER, cl. 6.5.7(e)(6).

- the scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency, and
- increases in productivity that have not been taken into account by United Energy in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2016–20 period, we consider that there is potential for an upward bias in estimating material input cost escalation by maintaining the base year cost commodity share weights.

Forecasting uncertainty

The NER requires that an electricity service provider's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[271] We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. The following factors have assisted us in forming this view:

- recent studies which show that forecasts of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse[272]
- evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts;[273] and
- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $US to $AUS). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.[274]

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271 NER, cl. 6.5.7(c)(3).

272 R. Alquist, L. Kilian, R. Vigfusson, *Forecasting the Price of Oil*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1022, July 2011 (also published as Alquist, Ron, Lutz Kilian, and Robert J. Vigfusson, 2013, *Forecasting the Price of Oil*, in Handbook of Economic Forecasting, Vol. 2, ed. by Graham Elliott and Allan Timmermann (Amsterdam: North Holland), pp. 68–69 and pp. 427–508) and International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, pp. 25–31.

273 International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, p. 27, Chinn, Menzie D., and Olivier Coibion, *The Predictive Content of Commodity Futures*, Journal of Futures Markets, 2014, Volume 34, Issue 7, p. 19 and pp. 607–636 and T. Reeve, R. Vigfusson, *Evaluating the Forecasting Performance of Commodity Futures Prices*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1025, August 2011, pp. 1 and 10.

274 R. Meese, K. Rogoff, (1983), *Empirical exchange rate models of the seventies: do they fit out of sample?*, Journal of International Economics, 14, B. Rossi, (2013), *Exchange rate predictability*, Journal of Economic Literature, 51(4), E. Fama, (1984), *Forward and spot exchange rates*, Journal of Monetary Economics, 14, K. Froot and R. Thaler, (1990), Anomalies: Foreign exchange, the Journal of Economic Perspectives, Vol. 4, No. 3, CEG, *Escalation factors affecting expenditure forecasts*, December 2013, and BIS Shrapnel, *Real labour and material cost escalation forecasts to 2019/20, Australia and New South Wales*, Final report, April 2014.

Strategic contracts with suppliers

We consider that electricity service providers can mitigate the risks associated with changes in material input costs by including hedging strategies or price escalation provisions in their contracts with suppliers of inputs (e.g. by including fixed prices in long term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution possibilities between operating and capital expenditure,[275] we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.

Cost based price increases

Accepting the pass through of material input costs to input asset prices is reflective of a cost based pricing approach. We consider this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex. In taking into account the revenue and pricing principles, we note that this approach would be less likely to promote efficient investment.[276] It also would not result in a capex forecast that was consistent with the nature of the incentives applied under the CESS and the STPIS to United Energy as part of this decision.[277]

Selection of commodity inputs

The limited number of material inputs included in United Energy's capex real escalation model may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by United Energy. United Energy's capex forecast model may also be biased to the extent that it may include a selective subset of commodities that are forecast to increase in price during the 2016–20 period.

Commodities boom

The relevance of material input cost escalation post the 2009 commodities boom experienced in Australia when material input cost escalators were included in determining the approved capex allowance for electricity service providers. We consider that the impact of the commodities boom has subsided and as a consequence the justification for incorporating material cost escalation in determining forecast capex has also diminished.

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[275] NER, cl. 6.5.7(e)(7).

[276] NEL, s. 7.

[277] NER, cl. 6.5.7(e)(8).

D.9 Review of independent expert's reports

We have reviewed the BIS Schrapnel report commissioned by United Energy. We consider that this review, along with our review of two other reports detailed below, provides further support for our position to not accept United Energy's proposed materials cost escalation.

BIS Schrapnel report

- BIS Schrapnel acknowledge that as well as individual supply and demand drivers impacting on the forecast price of commodities, movements in the exchange rate also impact on the price of commodities. BIS Schrapnel stated that movements in the Australian dollar against the US dollar can have significant effects on the domestic price of minerals and metals.[278] BIS Shrapnel are forecasting the Australian dollar to fall to US$0.77 in 2018[279]. This is significantly lower than the exchange rate forecasts by Sinclair Knight Mertz (SKM, now Jacobs SKM) of between US$0.91 to US$0.85 from 2014–15 to 2018–19 submitted as part of our recent review of TransGrid's transmission determination for the 2015–18 regulatory period.[280] In its report submitted in respect to our review of Jemena Gas Networks access arrangement for the 2015–20 access arrangement period, BIS Schrapnel stated that exchange rate forecasts are not authoritative over the long term.[281]

  We consider the forecasting of foreign exchange movements during the next regulatory control period to be another example of the potential inaccuracy of modelling for material input cost escalation.

- BIS Schrapnel stated that for a range of items used in most businesses the average price increase would be similar to consumer price inflation and that an appropriate cost escalator for general materials would be the Consumer Price Index (CPI).[282] In its forecast for general materials such as stationary, office furniture, electricity, water, fuel and rent for Jemena Gas Networks, BIS Shrapnel assumed that across the range of these items, the average price increase would be similar to consumer price inflation and that the appropriate cost escalator for general materials is the CPI.[283]

  This treatment of general business inputs supports our view that where we cannot be satisfied that a forecast of real cost escalation for a specific material input is

278 United Energy, *Regulatory Proposal 2016–20: Attachment FIN 583 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 37.

279 United Energy, *Regulatory Proposal 2016–20: Attachment FIN 583 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 4.

280 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.

281 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A–7.

282 United Energy, *Regulatory Proposal 2016–20: Attachment FIN 583 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 43.

283 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019–20 - Australia and New South Wales*, April 2014, p. 48.

robust, and cannot determine a robust alternative forecast, zero per cent real cost escalation is reasonably likely to reflect the capex criteria and under the PTRM the electricity service provider's broad range of inputs are escalated annually by the CPI.

In addition to our review of the BIS Shrapnel Report, we have also received submissions from electricity service providers on other recent resets. We have considered the relevance of those submissions to the issues raised by United Energy in order to arrive at a position that takes into account all available information. Our views on these reports are set out below. Overall, both these reports lend further support to our position to not accept United Energy's proposed materials cost escalation.

Competition Economists Group report

A number of electricity service providers commissioned the Competition Economists Group (CEG) to provide real material cost escalation indices in respect to revenue resets for these businesses recently undertaken by us. These businesses included ActewAGL, Ausgrid, Endeavour Energy, Essential Energy and TasNetworks (Transend).

- CEG acknowledged that forecasts of general cost movements (e.g. consumer price index or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs (e.g. energy costs and equipment leases etc.).[284] This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity service provider's intermediary input costs.
- CEG acknowledged that futures prices will be very unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[285] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the material input cost models used by United Energy.
- CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:[286]

  > While futures prices are not accurate predictors of future spot prices, they nevertheless reflect current beliefs of market participants about forthcoming price developments.

  This supports our view that there is a reasonable degree of uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of assets used by electricity service providers to provide network services. Whilst the IMF may conclude that commodity futures prices reflect market beliefs

[284] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
[285] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.
[286] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

on future prices, there is no support from the IMF that futures prices provide an accurate predictor of future commodity prices.

- Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.[287] Analysis of this data shows that the longer the futures projection period, the less accurate are LME futures in predicting actual commodity prices. Given the next regulatory control period covers a time span of 60 months we consider it reasonable to question the degree of accuracy of forecast futures commodity prices towards the end of this period.

  Figures 1 and 2 also show that futures forecasts have a greater tendency towards over-estimating of actual aluminium and copper prices over the 20 year period (particularly for aluminium). The greatest forecast over-estimate variance was about 100 per cent for aluminium and 130 per cent for copper. In contrast, the greatest forecast under-estimate variance was about 44 per cent for aluminium and 70 per cent for copper.

- In respect of forecasting electricity service providers future costs, CEG stated that:[288]

  > There is always a high degree of uncertainty associated with predicting the future. Although we consider that we have obtained the best possible estimates of the NSPs' future costs at the present time, the actual magnitude of these costs at the time that they are incurred may well be considerably higher or lower than we have estimated in this report. This is a reflection of the fact that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.

  This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.[289]

- CEG also acknowledge that its escalation of aluminium prices are not necessarily the prices paid for aluminium equipment by manufacturers. As an example, CEG referred to producers of electrical cable who purchase fabricated aluminium which has gone through further stages of production than the refined aluminium that is traded on the LME. CEG also stated that aluminium prices can be expected to be influenced by refined aluminium prices but these prices cannot be expected to move together in a 'one-for-one' relationship.[290]

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287 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5–6.

288 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

289 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

290 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

CEG provided similar views for copper and steel futures. For copper, CEG stated that the prices quoted for copper are prices traded on the LME that meet the specifications of the LME but that there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.[291] For steel futures, CEG stated that the steel used by electricity service providers has been fabricated, and as such, embodies labour, capital and other inputs (e.g. energy) and acknowledges that there is not necessarily a 'one-for one' relationship between the mill gate steel and the steel used by electricity service providers.[292]

These statements by CEG support our view that the capex real escalation model used by United Energy has not demonstrated how and to what extent material inputs have affected the cost of intermediate outputs. We note, as emphasised by CEG, there is likely to be significant value adding and processing of the raw material before the physical asset is purchased by United Energy.

- CEG has provided data on historical indexed aluminium, copper, steel and crude oil actual (real) prices from July 2005 to December 2013 as well as forecast real prices from January 2014 to January 2021 which were used to determine its forecast escalation factors.[293] For all four commodities, the CEG forecast indexed real prices showed a trend of higher prices compared to the historical trend. Aluminium and crude oil exhibited the greatest trend variance. Copper and steel prices were forecast to remain relatively stable whist aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

Sinclair Knights Mertz report

Sinclair Knights Mertz (SKM, now Jacobs SKM) were commissioned by TransGrid to provide real material cost escalation indices in respect to the revenue reset for TransGrid recently undertaken by us.

- SKM cautioned that there are a variety of factors that could cause business conditions and results to differ materially from what is contained in its forward looking statements.[294] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the cost of assets that are not captured by United Energy's capex real escalation model.
- SKM stated it used the Australian CPI to account for those materials or cost items for equipment whose price trend cannot be rationally or conclusively explained by the movement of commodities prices.[295]
- In its modelling of the exchange rate, SKM has in part adopted the longer term historical average of $0.80 USD/AUD as the long term forecast going forward.[296]

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[291] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
[292] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.
[293] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, Figures 3, 4 and 5, pp. 23, 25 and 28.
[294] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.
[295] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.

This is consistent with our view that longer term historical commodity prices should be considered when reviewing and forecasting future prices. In general, we consider that long term historical data has a greater number of observations and as a consequence is a more reliable predictor of future prices than a data time series of fewer observations.

- SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.[297] SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.[298]
- SKM stated that in respect to the reliability of oil future contracts as a predictor of actual oil prices, futures markets solely are not a reliable predictor or robust foundation for future price forecasts. SKM also stated that future oil contracts tend to follow the current spot price up and down, with a curve upwards or downwards reflecting current (short term) market sentiment.[299] SKM selected Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.[300] The decision by SKM to adopt an economic forecast for oil rather than using futures highlights the uncertainty surrounding the forecasting of commodity prices.

Comparison of independent expert's cost escalation factors

To illustrate the potential uncertainty in forecasting real material input costs, we have compared the material cost escalation forecasts derived by BIS Schrapnel and CEG as shown in Table 6.16 SKM did not provide its real materials escalation forecasts in calendar years so were excluded from this comparison.

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296 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
297 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.
298 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 16.
299 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.
300 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.

Table 6.16 Real material input cost escalation forecasts (per cent)

	2015 (%)	2016 (%)	2017 (%)	2018 (%)	2019 (%)
Aluminium					
CEG	8.3	0.9	1.8	2.9	2.8
BIS Shrapnel	9.5	8.0	8.2	5.1	-7.0
Difference (%)	-12.6%	-88.8%	-78.0%	-43.1%	-140.0%
Copper					
CEG	-1.4	-1.5	-0.4	1.2	1.1
BIS Shrapnel	0.4	3.5	7.7	2.1	-10.0
Difference (%)	-450.0%	-142.9%	-105.2%	-42.9%	-111.0%
Steel					
CEG	-4.2	1.8	0.9	1.0	1.0
BIS Shrapnel1	4.8	4.7	3.0	2.7	-11.0
Difference (%)	-187.5%	-61.7%	-70.0%	-63.0%	-109.1%
Oil					
CEG	-9.0	1.2	1.0	0.9	1.0
BIS Shrapnel	-1.9	-1.1	4.3	2.5	-7.7
Difference (%)	373.7%	-209.1%	-76.7%	-64.0%	-113.0%

Source: CEG, *Updated cost escalation factors*, December 2014, pp. 6, 7, 9 and 10 and BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii. and BIS Shrapnel, Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales, April 2014, p. iii.

As Table 6.16 shows, there is considerable variation between the two consultant's commodities escalation forecasts. The greatest margin of variation is 12.0 percentage points for steel in 2019, where CEG has forecast a real price increase of 1.0 per cent and BIS Shrapnel a real price decrease of 11.0 per cent. These forecast divergences between consultants further demonstrate the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services. This supports our view that United Energy's forecast real material cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period.[301]

D.10 Conclusions on materials cost escalation

We are not satisfied that United Energy has demonstrated that the weightings applied to the intermediate inputs have produced unbiased forecasts of the movement in the prices it expects to pay for its physical assets. In particular, United Energy has not

301 NER, cl. 6.5.7(a).

provided sufficient evidence to show that the changes in the prices of the assets they purchase are highly correlated to changes in raw material inputs.

CEG, in its report to electricity distribution service providers, identified a number of factors which are consistent with our view that United Energy's capex real escalation model has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. BIS Schrapnel and CEG acknowledged that forecasts of general cost movements (e.g. CPI or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs.[302] CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[303] CEG also stated that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.[304]

Recent reviews of commodity price movements show mixed results for commodity price forecasts based on futures prices. Further, nominal exchange rates are in general extremely difficult to forecast and based on the economic literature of a review of exchange rate forecast models, a "no change" forecasting approach may be preferable.

It is our view that where we are not satisfied that a forecast of real cost escalation for materials is robust, and we cannot determine a robust alternative forecast, then real cost escalation should not be applied in determining a service provider's required capital expenditure. We accept that there is uncertainty in estimating real cost changes but we consider the degree of the potential inaccuracy of commodities forecasts is such that there should be no escalation for the price of input materials used by United Energy to provide network services.

In previous AER decisions, including our recent decisions for the New South Wales and ACT distribution networks as well as our decisions for Envestra's Queensland and South Australian gas networks, we took a similar approach. This was on the basis that as all of the New South Wales and ACT distribution businesses and Envestra's real costs are escalated annually by CPI under the PTRM and tariff variation mechanism respectively, CPI must inform the AER's underlying assumptions about energy service provider's overall input costs. Consistent with this, we applied zero real cost escalation and by default the New South Wales and ACT distribution businesses and Envestra's input costs were escalated by CPI in the absence of a viable and robust alternative. Likewise, for United Energy, we consider that in the absence of a well-founded materials cost escalation forecast, escalating real costs annually by the CPI is the

302 United Energy, *Regulatory Proposal 2016–20: Attachment: FIN 583 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 43 and CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.

303 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

304 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

better alternative that will contribute to a total forecast capex that reasonably reflects the capex criteria.

The CPI can be used to account for the cost items for equipment whose price trend cannot be conclusively explained by the movement of commodities prices. This approach is consistent with the revenue and pricing principles of the NEL which provide that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.[305]

D.11 Labour and construction escalators

Our approach to real materials cost escalation does not affect the application of labour and construction related cost escalators, which will continue to apply to standard control services capital and operating expenditure.

We consider that labour and construction related cost escalation reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[306] We consider that real labour and construction related cost escalators can be more reliably and robustly forecast than material input cost escalators, in part because these are not intermediate inputs and for labour escalators, productivity improvements have been factored into the analysis (refer to the opex attachment).

Further details on our consideration of labour cost escalators are discussed in Attachment 7.

305 NEL, s. 7(2).

306 NER, cll. 6.5.6(c)(3) and.6.5.7(c)(3).

E Predictive modelling approach and scenarios

This section provides a guide to our repex modelling process. It sets out:

- the background to the repex modelling techniques
- discussion of the data required to apply the repex model
- detail on how this data was specified
- description of how this data was collected and refined for inclusion in the repex model
- the outcomes of the repex model under various input scenarios

This supports the detailed and multifaceted reasoning outlined in appendix A.

E.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and National Gas Rules.[307] In light of these rule changes the AER undertook a “Better Regulation” work program, which included publishing a series of guidelines setting out our approach to regulation under the new rules.[308]

The expenditure forecast assessment Guideline (Guideline) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[309] It lists predictive modelling as one of the assessment techniques we may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009–10 review of the Victorian electricity DNSPs' 2011–15 regulatory proposals and have also used it subsequently.[310]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[311] At a basic level, the model predicts the volume of a distributor's assets that may need to be replaced over each of the next 20 years. This prediction is made by looking at the age of assets already in commission, and the time at which, on average, these assets would be expected to be replaced. The unit cost of replacing the assets is used to provide an estimate of replacement expenditure. The data used in the model is derived from the distributor’s regulatory information notice (RIN) responses and from the outcomes of the unit cost and

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307 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

308 See AER *Better regulation reform program* web page at http://www.aer.gov.au/Better-regulation-reform-program.

309 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

310 AER Determinations for 2011–15 for CitiPower, Jemena, Powercor, SP AusNet, and United Energy.

311 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

E.2 Data specification process

Our repex model requires the following input data on a distributor's network assets:

- the age profile of network assets currently in commission
- expenditure and replacement volume data of network assets
- the mean and standard deviation of each asset's replacement life (replacement life).

Given our intention to apply unit cost and replacement life benchmarking techniques, we defined the model's input data around a series of prescribed network asset categories. We collected this information by issuing two types of RINs:

1. "Reset RINs" which we issued to distributors requiring them to submit this information with their upcoming regulatory proposal

2. "Category analysis RINs" which we issued to all distributors in the NEM.

The two types of RIN requested the same historical asset data for use in our repex modelling. The Reset RIN also collected data corresponding to the distributors proposed forecast repex over the 2016–20 regulatory control period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

For background, we note that in past determinations, our RINs did not specify standardised network asset subcategories for distributors to report against. Instead, we required the distributors to provide us data that adhered to broad network asset groups (e.g. poles, overhead conductors etc.). This allowed the distributor discretion as to how its assets were subcategorised within these groups. The limited prescription over asset types meant that drawing meaningful comparisons of unit costs and replacement lives across distributors was difficult.[312]

Our changed approach of adopting a standardised approach to network asset categories provides us with a dataset suitable for comparative analysis, and better equips us to assess the relative prices of capital inputs as required by the capex criteria.[313]

When we were formulating the standardised network assets, we aimed to differentiate the asset categorisations where material differences in unit cost and replacement life existed. Development of these asset subcategories involved extensive consultation

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[312] The repex model has been applied in the Victorian 2011–15 and Aurora Energy 2012–17 distribution determinations; AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

[313] NER, cl. 6.5.7(e)(6).

with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.[314]

E.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what we require to deploy our assessment techniques. We consider that the data refinement and consultation undertaken after the RINs were received, along with the extensive consultation carried out during the Better Regulation process, provide us with reasonable assurance of the data's quality for use in this part of our analysis.

To aid distributors, an extensive list of detailed definitions was included as an appendix to the RINs. Where possible, these definitions included examples to assist distributors in deciding whether costs or activities should be included or excluded from particular categories. We acknowledge that, regardless of how extensive and exhaustive these definitions are, they cannot cater for all possible circumstances. To some extent, distributors needed to apply discretion in providing data. In these instances, distributors were required to clearly document their interpretations and assumptions in a “basis of preparation” statement accompanying the RIN submission.

Following the initial submissions, we assessed the basis of preparation statements that accompanied the RINs to determine whether the data submitted complied with the RINs. We took into account the shift in data reporting obligations under the new RINs when assessing the submissions. Overall, we considered that the repex data provided by all distributors was compliant. We did find a number of instances where the distributors’ interpretations did not accord with the requirements of the RIN but for the purpose of proceeding with our assessment of the proposals, these inconsistencies were not substantial enough for a finding of non-compliance with the NEL or NER requirements.[315]

Nonetheless, in order that our data was the most up to date and accurate, we did inform distributors, in detailed documentation, where the data they had provided was not entirely consistent with the RINs, and invited them to provide updated data. Refining the repex data was an iterative process, where distributors returned amended consolidated RIN templates until such time that the data submitted was fit for purpose.

E.4 Benchmarking repex asset data

As outlined above, we required the following data on distributors' assets for our repex modelling:

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[314] See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.

[315] NER, cl. 6.9.1.

- age profile of network assets currently in commission
- expenditure, replacement volumes and failure data of network assets
- the mean and standard deviation of each asset's replacement life.

All NEM distributors provided this data in the Reset RINs and Category analysis RINs under standardised network asset categories.

To inform our expenditure assessment for the distributors currently undergoing revenue determinations,[316] we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

In this section we explain the data sets we constructed using all NEM distributors' data, and the benchmark unit costs and replacement lives we derived for the standardised network asset categories.

E.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:[317]

- benchmark unit costs
- benchmark means and standard deviations of each asset's replacement life (referred to as "uncalibrated replacement lives" to distinguish these from the next category)
- benchmark calibrated means and standard deviations of each asset's replacement life.

Our process for arriving at each of the benchmarks was as follows. We calculated a unit cost for each NEM distributor in each asset category in which it reported replacement expenditure and replacement volumes. To do this:

- We determined a unit cost for each distributor, in each year, for each category it reported under. To do this we divided the reported replacement expenditure by the reported replacement volume.
- Then we determined a single unit cost for each distributor for each category it reported under. We first inflated the unit costs in each year using the CPI index.[318]

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316 Vic, SA and QLD distribution network service providers—AusNet Services, United Energy, Jemena, Powercor, Citipower, SA Power Networks, Energex and Ergon Energy.

317 We did not derive benchmark data for some standardised asset categories where no values were reported by any distributors, or for categories distributors created outside the standardised asset categories.

318 We took into account whether the distributor reported on calendar or financial year basis.

We then calculated a single unit cost. We did this by first weighting the unit cost from each year by the replacement volume in that year. We then divided the total of these expenditures by the total replacement volume number.

We formulated two sets of replacement life data for each NEM distributor:

- The replacement life data all NEM distributors reported in their RINs.
- The replacement life data we derived using the repex model for each NEM distributor. These are also called calibrated replacement lives. The repex model derives the replacement lives that are implied by the observed replacement practices of a distributor. That is, the lives are based on the data a distributor reported in the RIN on its replacement expenditure and volumes over the most recent five years, and the age profile of its network assets currently in commission. In this way, they can be said to derive from the distributors observed replacement practices. The calibrated lives the repex model derives can differ from the replacement lives a distributor reports.

We derived the benchmarks for an asset category using each of the three data sets above. That is, we derived a set of benchmark unit costs, benchmark replacement lives, and benchmark calibrated replacement lives for an asset category. To differentiate the two sets of benchmarked replacement lives, we refer to the benchmarks based on the calibration process as 'benchmarked calibrated replacement lives' and those based on replacement lives reported by the NEM distributors as 'benchmarked uncalibrated replacement lives'. We applied the method outlined below to each of the three data sets.

We first excluded Ausgrid's data, since it reported replacement expenditure values as direct costs and overheads. Therefore these expenditures were not comparable to all other NEM distributors which reported replacement expenditure as direct costs only. We then excluded outliers by:[319]

- calculating the average of all values for an asset category
- determining the standard deviation of all values for an asset category
- excluding values that were outside plus or minus one standard deviation from the average.

Using the data set excluding outliers we then determined the:

- Average value:
    - benchmark average unit cost

[319] For the benchmarked calibrated replacement lives we performed two additional steps on the data prior to this. We excluded any means where the distributor did not report corresponding replacement expenditure. This was because zero volumes led to the repex model deriving a large calibrated mean which may not reflect industry practice and may distort the benchmark observation. We also excluded any calibrated mean replacement lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years reportable in the asset age profile.

- benchmark average mean and standard deviation replacement life
- benchmark average calibrated mean and standard deviation replacement life.

- One quartile better than the average value:
  - benchmark first quartile unit cost (below the mean)
  - benchmark third quartile uncalibrated mean replacement life (above the mean)
  - benchmark third quartile calibrated mean replacement life (above the mean).
- 'Best' value:
  - benchmark best (lowest) unit cost
  - benchmark best (highest) uncalibrated mean replacement life
  - benchmark best (highest) calibrated mean replacement life.[320]

E.5 Repex model scenarios

As noted above, our repex model uses an asset age profile, expected replacement life information and the unit cost of replacing assets to develop an estimate of replacement volume and expenditure over a 20 year period.

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.[321] However, we have multiple data sources for replacement lives and unit costs, being the data provided by the distributors, data that can be derived from their performance over the last five years, and benchmark data from all distributors across the NEM. The range of different inputs allows us to run the model under a number of different scenarios, and develop a range of outcomes to assist in our decision making.

We have categorised three broad input scenarios under which the repex model may be run. These are explained in greater detail within our Replacement expenditure model handbook.[322] They are:

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[320] We did not determine quartile or best values for the uncalibrated standard deviation and calibrated standard deviation replacement lives. This is because we used the benchmark average replacement lives (mean and standard derivation) for comparative analysis between the distributors. However, the benchmark quartile and best replacement life data was for use in the repex model sensitivity analysis. The repex model only requires the mean component of an asset's replacement life as an input. The repex model then assumes the standard deviation replacement life of an asset is the square root of the mean replacement life. The use of a square root for the standard deviation is explained in more detail in our Replacement expenditure model handbook; AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

[321] It has been necessary for some distributors to make assumptions on the asset age profile to remove double counting. This is detailed at the end of this appendix.

[322] AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

(1) The Base scenario – the base scenario uses inputs provided by the distributor in their RIN response. Each distributor provided average replacement life data as part of this response. As the distributors did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years and the forecast unit cost from the upcoming regulatory control period in the base scenario.

(2) The Calibrated scenario – the process of "calibrating" the expected replacement lives in the repex model is described in the AER's replacement expenditure handbook.[323] The calibration involves deriving a replacement life and standard deviation that matches the distributor's recent historical replacement practices (in this case, the five years from 2011 to 2015). The calibrated scenario benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked scenarios – the benchmarked scenarios use unit cost and replacement life inputs from the category analysis benchmarks. These represent the observed costs and replacement behaviour from distributors across the NEM. As noted above, we have made observations for an "average", "first or third quartile" and "best performer" for each repex category, so there is no single "benchmarked" scenario, but a series of scenarios giving a range of different outputs.

The model can also take into account different wooden pole staking/stobie pole plating rate assumptions (see section E.3 for more information on this process). For the Victorian distributors, who exhibit high wooden pole staking rates relative to the rest of the NEM, we have not chosen to test different staking scenarios. A full list of the scenario outcomes is provided in Figure 6.27 and Figure 6.28 below.

Figure 6.27 Repex model outputs – replacement lives

Replacement lives	
Base case (RIN)	$914 million
Calibrated lives	$220 million
Benchmarked calibrated average	$361 million
Benchmarked calibrated third quartile	$320 million
Benchmarked calibrated best	$191 million

Source: AER analysis, using historic unit costs.

323 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013, pp. 20–21.

Figure 6.28 Repex model outputs − unit costs

Unit cost	
Benchmarked average	$227 million
Benchmarked first quartile	$147 million
Benchmarked best	$118 million

Source: AER analysis, using calibrated replacement lives.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the distributor did not incur any expenditure on an asset category in the 2011–15 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2016–20 regulatory control period (used to derive forecast unit costs). If both these inputs were not available, we used the benchmarked average unit cost as a substitute input.

In addition, we did not use a calibrated asset replacement life where the distributor did not replace any assets during the 2011−15 regulatory control period. This is because the calibration process relies on replacement volumes over the five year period to derive a mean and standard deviation, and using a value of zero may not be appropriate for this purpose. In the first instance, we substituted these values with the average calibrated replacement life of the broad asset group to which the asset subcategory belonged. Where this was not available, we used the benchmarked calibrated replacement life or the base case replacement life from the distributor.

While the majority of the data was provided in a form suitable for modelling, limited adjustments needed to be made for some of the data. For United Energy we converted some forecast underground cable replacement volumes metres to kilometres to match its historic reporting.

Un-modelled repex

As detailed in the AER's repex handbook, the repex model is most suitable for asset categories and groups with a moderate to large asset population of relatively homogenous assets. It is less suitable for assets with small populations or those that are relatively heterogeneous. For this reason, we chose to exclude certain data (or asset categories) from the modelling process, and did not use predictive modelling to directly assess these categories. However, where suitable data was available, we used predictive modelling to test our other findings on these categories. We decided to exclude SCADA repex from the model for this reason. Expenditure on pole top structures was also excluded, as it is related to expenditure on overall pole replacement and modelling may result in double counting of replacement volumes. Other excluded categories are detailed in appendix E.3 of this preliminary decision.[324]

E.6 The treatment of staked wooden poles

The staking of a wooden pole is the practice of attaching a metal support structure (a stake or bracket) to reinforce an aged wooden pole.[325] The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for like basis. To understand why this requires special treatment, we have described below the normal like-for-like assumption used in the repex model, why staked poles do not fit well within this assumption, and how we adapt the model inputs to take account of this.

E.6.1 Like-for-like repex modelling

Replacement expenditure is normally considered to be on a like-for-like basis. When an asset is identified for replacement, it is assumed that the asset will be replaced with its modern equivalent, and not a different asset. For example, conductor rated to carry low voltage will be replaced with conductor of the same rating, not conductor rated for high voltage purposes.

The repex model predicts the volume of old assets that need to be replaced, not the volume of new assets that need to be installed. This is simple to deal with when an asset is replaced on a like-for-like basis – the old asset is simply replaced by a new asset of the same kind. It follows that the volume of assets that needs to be replaced where like-for-like replacement is appropriate match the volume of new assets to be installed. The cost of replacing the volume of retired assets is the unit cost of the new asset multiplied by the volume of assets that need to be replaced.

E.6.2 Non-like-for-like replacement

Where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles.

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324 For AusNet Services, we ran a limited set of modelling scenarios on SCADA and other repex, as suitable data was available. This was used to test the findings from our other techniques. For Powercor, we ran limited scenarios on pole top structures to test the findings from our other techniques. For each of these, we relied more on other assessment techniques, as detailed in Appendix A.

325 The equivalent practice for stobie poles is known as "plating", which similarly provides a low cost life extension. SA Power Networks carries out this process. We applied the same process for modelling SA Power Networks' stobie pole plating data as we have for staked wooden poles. However, for simplicity, this section only refers to the staking process.

Staked and unstaked wooden poles

The life of a wooden pole may be extended by installing a metal stake to reinforce its base. Staked wooden poles are treated as a different asset in the repex model to unstaked poles. This is because staked and unstaked poles have different expected lives and different costs of replacement.

When a wooden pole needs to be replaced, it will either be staked or replaced with a new pole. The decision on which replacement type will be carried out is made by determining whether the stake will be effective in extending the pole's life, and is usually based on the condition of the pole base. If the wood at the base has deteriorated too far, staking will not be effective, and the pole will need to be replaced. If there is enough sound wood to hold the stake, the life of the pole can be extended, and a stake can be installed. Consequently, there are two possible asset replacements (and two associated unit costs) that may be made by the distributor – a new pole to replace the old one or nailing a stake to the old pole.

The other non-like-for-like scenario related to staking is where an in-commission staked pole needs to be replaced. Staking is a one-off process. When a staked pole needs to be replaced, a new pole must be installed in its place. The cost of replacing an in-commission staked pole is the cost of a new pole.

Unit cost blending

We use a process of unit cost blending to account for the non-like-for-like asset categories.

For unstaked wooden poles that need to be replaced, there are two appropriate unit costs: the cost of a new pole; and the cost of staking an old pole. We have used a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[326] We ran the model under a variety of different weightings – including the observed staking rate of the business and observed best practice from the distributors in the NEM.

For the Victorian distributors, we adopted their own observed staking ratio.

For staked wooden poles being replaced, in the first instance, we used historical data from the distributors on the proportion of different voltage staked wooden poles being replaced to approximate the volume of each new asset going forward.[327] The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the

326 For example, if a distributor replaces a pole with a new pole 50 per cent of the time, and stakes the pole the other 50 per cent of the time, the blended unit cost would be a straight average of the two unit costs. If the mix was 60:40, the unit cost would be weighted accordingly.

327 Poles with different maximum voltages have different unit costs. An assumption needs to be made to determine, for example, how many new ">1kv poles" and how many new "1kv-11kv" need to be installed to replace the staked wooden poles.

asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

E.7 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when determining calibrated replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced. Since the replacement of staked poles is not on a like-for-like basis, we make an adjustment for the calibration process to function correctly. That is, we need to know the number of staked poles that reach the end of their economic life so we can calibrate the model for when these assets are replaced. The category analysis RIN currently only provides us with information on how many new stakings have taken place, rather than how many were actually replaced. We sought, and were provided with this information directly from the distributors.