FINAL DECISION
United Energy distribution determination
2016 to 2020

Attachment 6 – Capital expenditure

May 2016

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Note

This attachment forms part of the AER's final decision on United Energy's distribution determination for 2016–20. It should be read with all other parts of the final decision.

The final 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

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

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Attachment 11 – Service target performance incentive scheme

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

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

Shortened form	Extended form
repex	replacement expenditure
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 United Energy's total revenue requirement.[1]

This attachment sets out our final 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 - Demand
- Appendix D - Network performance and implications for proposed capex.

6.1 Final decision

We are not satisfied United Energy's proposed total forecast capex of $1053.0 million ($2015) reasonably reflects the capex criteria. This is 6.8 per cent greater than actual/estimated capex for the 2011–15 period ($986 million). 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 $917.8 million ($2015) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

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

	2016	2017	2018	2019	2020	Total
United Energy's revised proposal	234.6	233.8	208.0	193.7	183.0	1053.0
AER final decision	209.7	204.8	178.2	167.1	157.9	917.8
Difference	-24.9	-29.0	-29.7	-26.6	-25.1	-135.2
Percentage difference (%)	-10.6	-12.4	-14.3	-13.7	-13.7	-12.8

Source: AER analysis.

Note: Numbers may not add due to rounding.

The figures above do not include equity raising costs and capital contributions. For our assessment of equity raising costs, see attachment 3.

1 NER, cl. 6.4.3(a).

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

These reasons include our responses to stakeholders' submissions on United Energy's revised 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 in some categories is likely to be higher than an efficient level, inconsistent with the NER. As a result of our testing, 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 final 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's proposed a total capex forecast of $1,053.0 million ($2015) in its revised proposal. We are not satisfied this forecast reasonably reflects the capex criteria. We are satisfied our substitute estimate of $917.8 million ($2015) reasonably reflects the capex criteria. Our substitute estimate is12.8 per cent lower than United Energy's revised 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	United Energy accepted our preliminary decision and proposed a revised augex forecast of $124.3 million ($2015). We have included this in our substitute estimate.
Customer connections capex	We have included United Energy's forecast for connections capex of $316.8 million ($2015) in our capex decision. United Energy's revised forecast is an increase on its initial proposal from $249.0 million to $316.8 million. This is due to increases in forecast volumes, project costs and existing committed projects. Consistent with our preliminary decision, we are satisfied that United Energy's forecast methodology is reasonable and the increased volumes and unit rates reflect the latest available data. As such we have included the amount United Energy forecast for connections capex in our substitute estimate.
Asset replacement capex	We have not included United Energy's proposed repex of $563.6 million ($2015) in our

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

Issue	Reasons and findings
(repex)	substitute estimate. In particular we do not accept United Energy's proposed repex for modelled categories of repex, and un-modelled categories of expenditure. However, we have accepted some additional capex to maintain safety and reliability. We have instead included in our substitute estimate of overall total capex an amount of $446.1 million ($2015).
Non-network capex	We have not included United Energy's proposed non-network capex of $184.3 million ($2015) in our substitute estimate. We have instead included an amount of $168.4 million ($2015). We accept United Energy's forecasts for motor vehicles, buildings and property, and plant and equipment capex as reasonably reflecting required expenditure in these categories. We do not accept United Energy's forecast for IT capex. In our view, United Energy's IT forecast does not reflect the efficient costs of a prudent operator. We consider that some elements of the Power of Choice program and RIN compliance program have not been justified.
Real cost escalators	United Energy accepted the AER's application of CPI indexation as a proxy for forecasts of escalation of materials costs in real terms over the 2016–20 regulatory control period. United Energy accepted the AER's approach to labour escalators in its preliminary decision. We have updated the labour escalation rates in our preliminary decision and those used by United Energy in its revised proposal. We discuss our assessment of forecast labour price growth for United Energy in attachment 7. The difference between the impact of the real labour cost escalations proposed by United Energy and those accepted by the AER in its capex decision is $1.8 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:[3]

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

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 final 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.

[3] NEL, s. 7A.

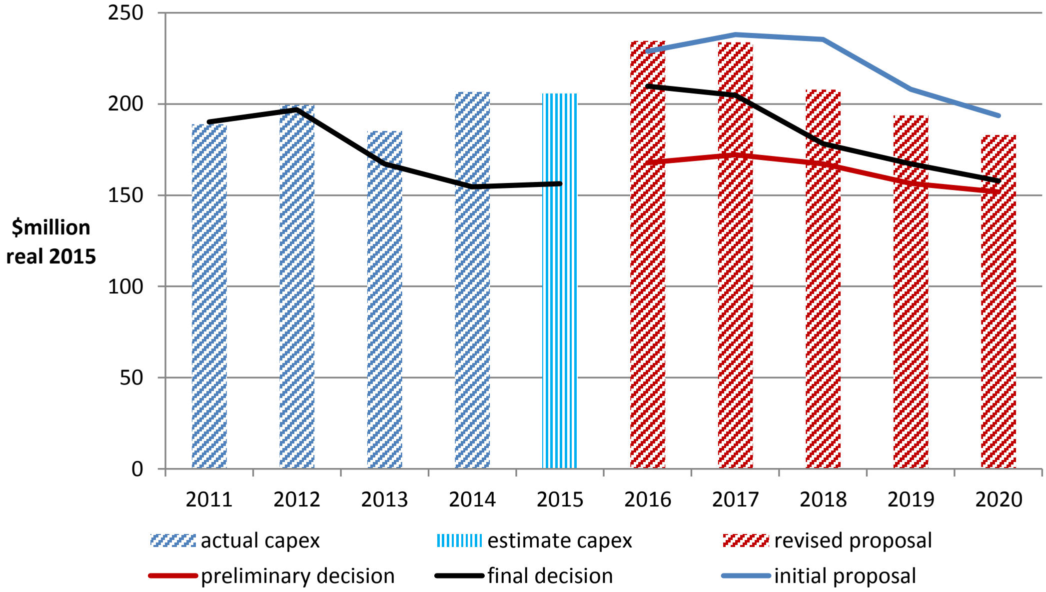
[4] NER, cl. 6.5.7(a).

6.2 United Energy's revised proposal

United Energy's revised proposal was for total forecast capex of $1053.0 million ($2015) for the 2016–20 regulatory control period. This is 29.2 per cent higher than our preliminary decision, and 4.6 per cent lower than United Energy's initial regulatory proposal.

Figure 6.1 shows the difference between United Energy's proposal, its revised proposal and our preliminary decision for the 2016–20 regulatory control period, as well as the actual capex that United Energy spent during the 2011–15 regulatory control period.

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



Source: AER analysis.

United Energy's revised forecast is higher than our preliminary decision due to:[5]

- increased Gross Customer Connections capex arising from increased volumes, project costs, and Horizon Projects
- increases in repex which United Energy considered is necessary to address deteriorating reliability and safety performance.

6.3 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

5 United Energy, *Revised regulatory proposal,* 6 January 2016, p. 10.

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 revised 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 revised regulatory proposal.[6] 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.[7] It also provides us with an 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, and this cannot be adequately explained, 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:[8]

- 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.

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6 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.

7 NER, cl. 6.5.7(c).

8 NER, cl. 6.5.7(a).

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.[9] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are: [10]

- 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]'.[11]

Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:[12]

> 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.[13] In taking the capex factors into account, the AEMC noted:[14]

> …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.[15] 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:[16]

- providing direct control network services; and

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9 NER, cl. 6.12.1(3)(ii).

10 NER, cl. 6.5.7(c).

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

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

13 NER, cl. 6.5.7(e).

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

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

16 NEL, s. 7A.

- complying with its regulatory obligations and requirements.

6.3.1 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).[17] We released our Guideline in November 2013.[18] 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.[19] 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.

We note that RIN data forms part of a distributor's regulatory proposal.[20] 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.[21] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.2 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.[22] 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.

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

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

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

[20] NER, cll. 6.8.2(c2) and (d).

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

[22] 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.

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.[23]

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.

As we explained in our Guideline:[24]

> 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 final decision on overall capex. Our final decision clearly sets out the extent to which 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 revised proposal.

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

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

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 cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[25]
- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[26]

6.3.3 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:[27]

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25 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 Energy Australia 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).

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

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

> 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 and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[28] 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 final decision

We applied the assessment approach set out in section 6.3 to United Energy. In this final decision, 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.

28 NER, r. 6.6.

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.

Table 6.3 Assessment of capex by capex driver 2016–20 ($2015, million)

Category	2016	2017	2018	2019	2020	Total
Augmentation	33.8	30.7	29.5	19.3	11.0	124.3
Connections	61.7	63.2	63.2	63.9	64.8	316.8
Replacement	91.9	92.7	92.5	88.4	80.6	446.1
Non-Network	41.4	45.7	23.0	25.9	32.4	168.4
Labour escalation adjustment	0.1	-0.2	-0.4	-0.6	-0.6	-1.8
Gross Capex (includes capital contributions)	**228.9**	**232.2**	**207.8**	**196.9**	**188.1**	**1,053.9**
Capital Contributions	19.2	27.4	29.5	29.8	30.2	136.1
Net Capex (excluding capital contributions)	**209.7**	**204.8**	**178.2**	**167.1**	**157.9**	**917.8**

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Our approved capex of $917.8 million is $103.0 million higher than our preliminary decision of $814.8 million. The key components of our capex decision that have changed include:

- increased replacement expenditure (repex) ($32.2 million), which includes expenditure to meet regulatory obligations associated with bushfire safety risks; public safety programs and programs to maintain network reliability and power quality
- increased net connection capex ($23.1 million) to reflect updated housing construction data; and
- increased non-network ICT capex for Power of Choice ($23.3 million) and RIN compliance ($11.0 million) to meet new regulatory obligations.

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 require United Energy to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex and a certification by its Directors that those key assumptions are reasonable.[29]

United Energy's key assumptions are set out in our preliminary decision.[30] We have assessed United Energy's key assumptions in the appendices to this attachment.

6.4.2 Forecasting methodology

The NER require United Energy to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[31] United Energy must include this information in its regulatory proposal.[32]

The key aspects of United Energy's forecasting methodology are set out in our preliminary decision. In our preliminary decision we considered that United Energy's forecasting methodology was generally reasonable.[33] We maintain this position in this final decision. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment.

Origin and VECUA maintained their support for applying a combination of top-down and bottom-up assessment techniques. They considered this is necessary to ensure that forecast costs, including unit rates, are not overstated. A combined approach ensures inter-relationships and synergies between projects or areas of work, which are more readily identified at a portfolio level, are adequately accounted for.[34] AGL also supported our use of benchmarking as an input into determining total capex (and opex) forecasts.[35]

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

29 NER, cll. S6.1.1(2), (4) and (5).

30 AER, *Preliminary decision, United Energy 2016 to 2020, Attachment 6: Capital expenditure,* October 2015, pp. 19–20.

31 NER, cll. 6.8.1A and 11.6.3(c).

32 NER, cl. S6.1.1(2).

33 AER, *Preliminary decision, United Energy 2016 to 2020, Attachment 6: Capital expenditure,* October 2015, pp. 20–21.

34 Origin, Submission to AER preliminary decision Victorian networks, 6 January 2016, p. 2; VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 27.

35 AGL, *Submission: AER preliminary decision on the Victorian electricity distribution network regulatory proposals*, 7 January 2016, p. 1.

projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency.[36]

Importantly, we do not limit our capex assessment to top-down methods. We utilise a holistic assessment approach that include techniques such as predictive modelling and detailed technical reviews (see section 6.3 and appendix A).

6.4.3 Interaction with the STPIS

We consider our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we should not set the capex allowance such that it would lead to United Energy systematically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient service provider in United Energy's circumstances 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 final decision, we specifically considered the impact our decision will have on the safety and reliability of United Energy's network.

In its submission, the Consumer Challenge Panel (CCP) noted the following explanation from the AEMC:[37]

> …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 distributor’s actual spending—

36 For example, see AER, *Final decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, October 2015, p. 21; AER, *Final decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, October 2015, pp. 20–21.

37 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.

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 spend particular capital expenditure differently, below or in excess of the total capex forecast in our decision. However, there is no additional expenditure 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 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.

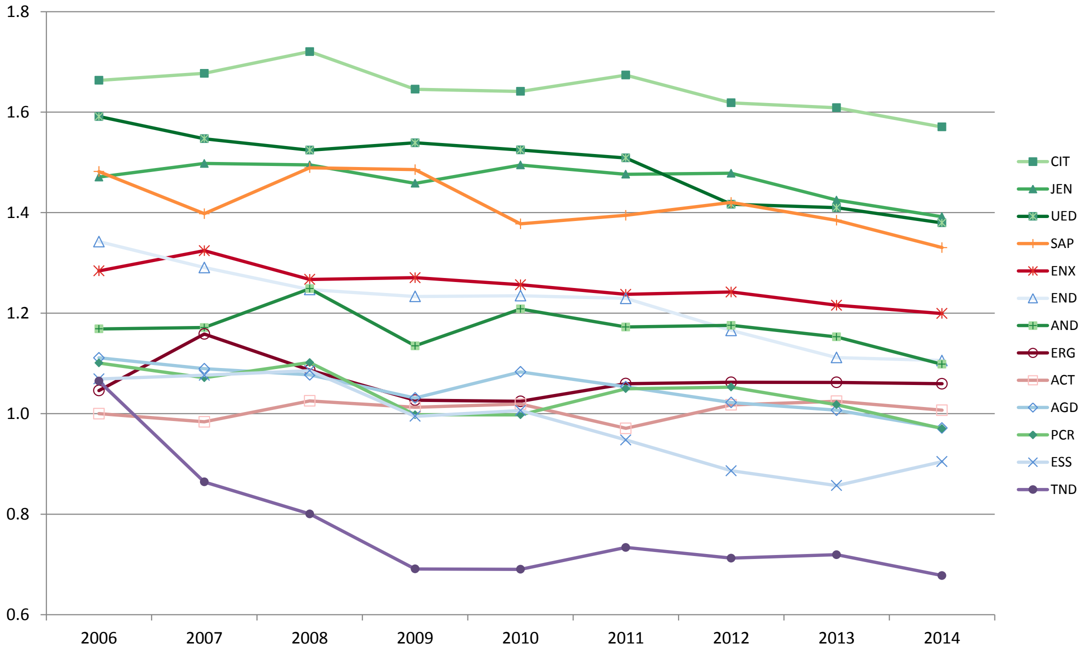
The NER sets out that we must have regard to our annual benchmarking report.[38] This section shows how we have taken it into account. We consider that this high level benchmarking at the overall capex level is suitable to gain an overall understanding of United Energy's proposal in a broader context. 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.

6.4.4.1 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. It simultaneously considers the productivity of each DNSP's use of overhead lines and underground cables (split into distribution and sub-transmission voltages) and transformers and other capital. United Energy performs relatively well on this measure falling behind only CitiPower, and Jemena from 2012 to 2014.

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

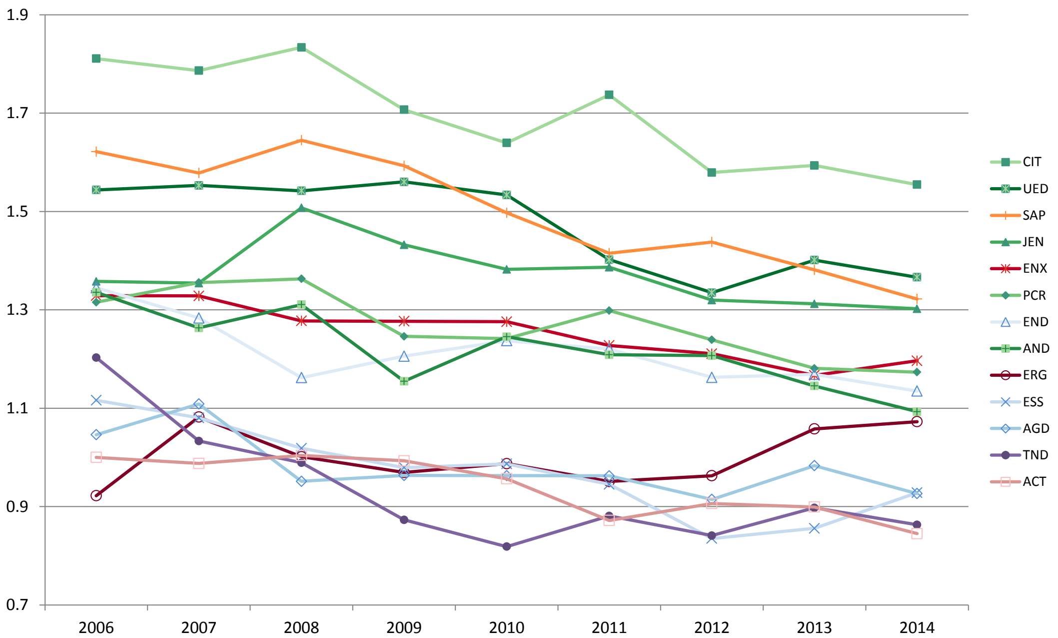
Figure 6.2 Capital partial factor productivity for 2006–14



Source: AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015, p. 11.

Figure 6.3 shows how United Energy ranks 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 also one of the highest performers on this metric.

Figure 6.3 Multilateral total factor productivity for 2006–14



Source: AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015, p. 8.

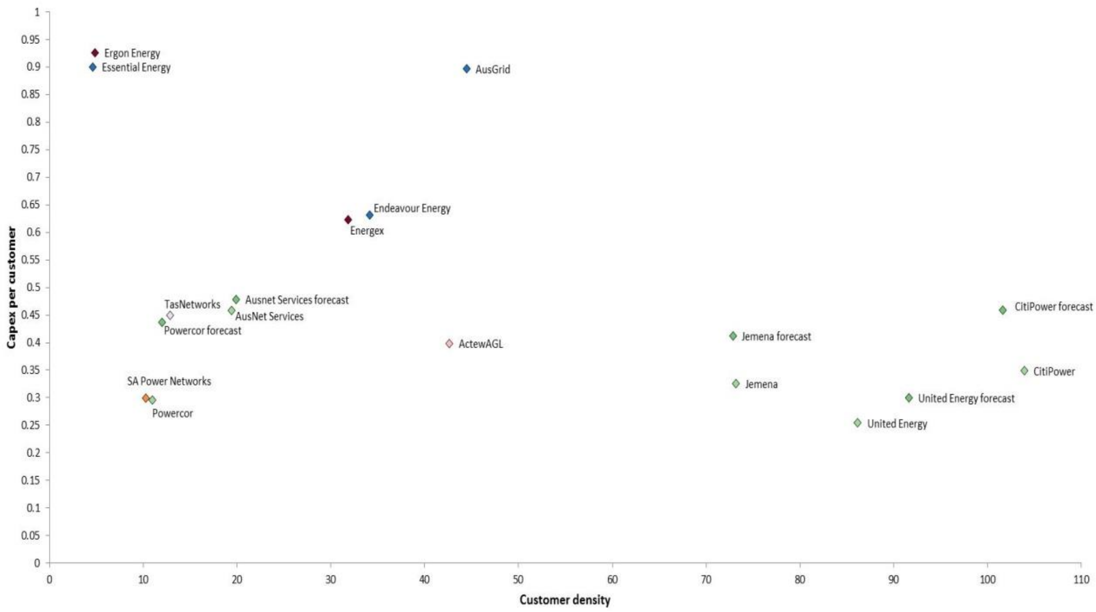
6.4.4.2 Relative capex efficiency metrics

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 distributors 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 that the Victorian distributors generally perform well in these metrics compared to other distributors in the NEM. For completeness, 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.

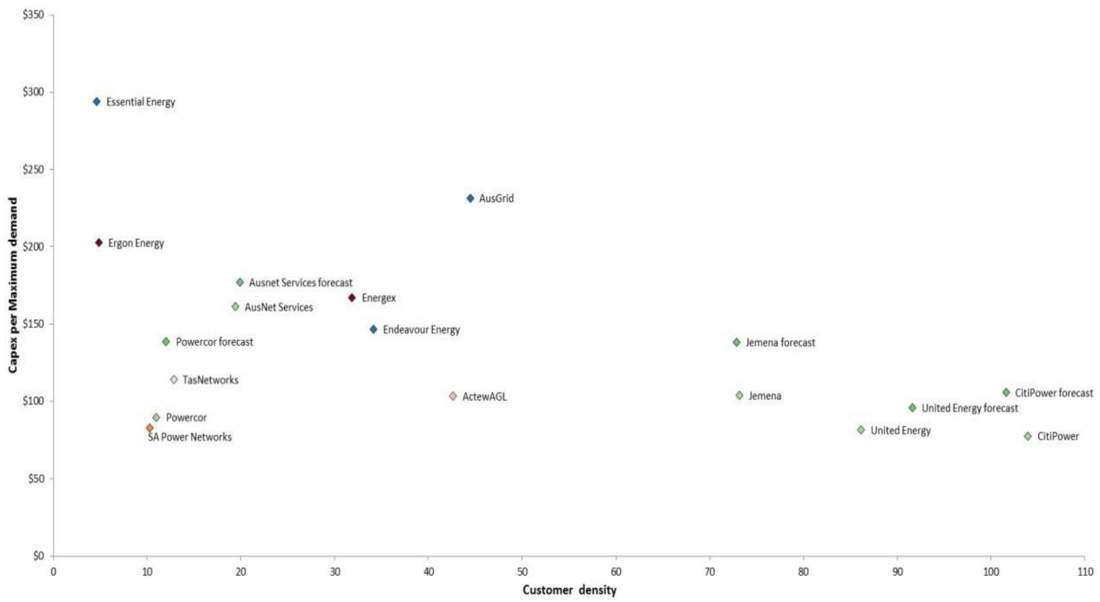
Figure 6.4 Capex per customer (000's, $2013–14), against customer density



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 (000's, $2013–14), against customer density



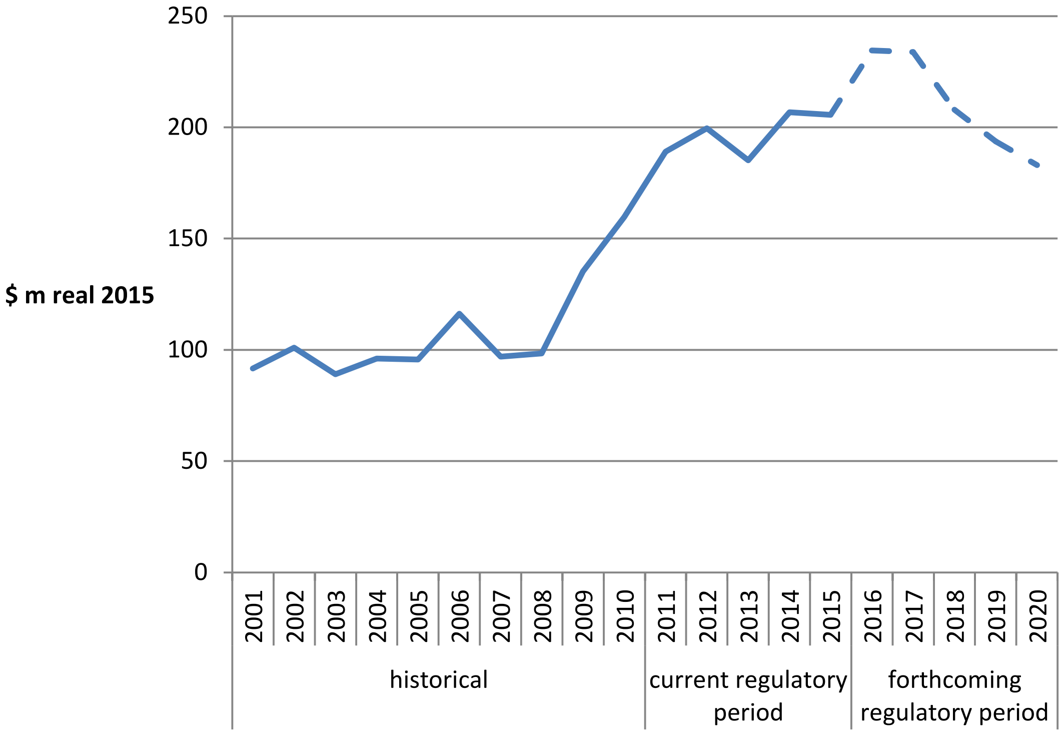
Source: AER analysis.

6.4.4.3 United Energy's historic capex trend

We 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 2 years of the regulatory control period. We note that United Energy's capex falls towards the end of the regulatory control period.

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



Source: AER analysis.

VECCUA noted the Victorian distributors' initial capex proposals, including United Energy's, are significantly higher than historical levels.[39] As we noted in section 6.2, United Energy's revised proposal is only 4.6 per cent lower than its initial proposal.

The CCP was concerned the Victorian distributors' capex in recent years has been excessive. The CCP noted capex has been reasonably constant historically and stated the total capex forecasts for the 2011–15 regulatory control period were 'aberrations'.[40]

The CCP further noted the Victorian distributors rejected our preliminary decisions, and as a group only marginally reduced their forecast capex from actual levels of the 2011–15 period.[41] We note United Energy's revised total capex forecast for the 2016–20 regulatory control period is approximately $67.0 million, or 6.8 per cent, higher than

[39] VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, pp. 23–24.

[40] CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 22 February 2016 p. 19.

[41] CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 22 February 2016 p. 19.

actual capex in the 2011–15 regulatory control period.[42] The CCP provided analysis showing the capex for the 2011–15 regulatory control period has resulted in a more expensive asset base, even when controlling for demand and customer numbers.[43]

We note Origin largely agreed with our reductions to the Victorian distributors' capex forecasts in the preliminary decisions.[44] On the other hand, VECUA stated our preliminary decisions provided excessive capex allowances to the Victorian distributors. VECUA considered the preliminary decisions predominantly based the allowances on expenditure in the 2011–15 regulatory control period.[45] VECUA noted several drivers that are putting downward pressure on the Victorian distributors' capex requirement in the 2016–20 regulatory control period, including:

- the downturn in electricity demand and consumption
- excess system capacity, declining asset utilisation and reducing network ages
- lower network reliability expectations

Hence, VECUA stated the Victorian distributors' capex forecasts should revert to historical levels.[46]

Our detailed assessment in appendix B takes into account points made in these submissions where relevant, for example network utilisation levels and its likely impact on network augmentation requirements. In appendix B we fully examine whether United Energy's revised proposal reflects its expected operating environment.

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.

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42 United Energy, *Reset RIN, Revised regulatory proposal,* January 2016; United Energy, *Regulatory proposal,* April 2015, p. 44.

43 CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 22 February 2016 pp. 19–20.

44 Origin, *Submission: Victorian networks revised proposals*, 4 February 2016, p. 1.

45 VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 8.

46 VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 20.

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 and capex forecast will provide United Energy with sufficient financial capacity to maintain the reliability of its network.
Forecast demand	Forecast demand is related to United Energy's total forecast capex. Specifically, augmentation capex is 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 augmentation 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 related 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 related 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.[47] Table 6.5 summarises how we have taken into account the capex factors.

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

Where relevant, we also had regard to the capex 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 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 proposed cost escalation rates for labour.
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 total 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:[48]

> 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.[49] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[50] 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.[51] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[52]

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

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

50 AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines*, November 2013, p. 78.

51 NER, cl. 6.5.7(c).

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

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 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.[53] 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.[54]

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.[55]

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 revised 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.[56] 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

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[53] 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.

[54] AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015.

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

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

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 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.[57] The models draw

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57 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.[58]

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.[59] 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.[60] 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.[61]

For our final 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 technical and other technical expertise within the AER to assist with our review of United Energy’s capex proposals.[62] These involved reviewing United Energy’s processes, and specific projects and programs of work.

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

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

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

61 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.

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

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 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: Forecast augex
- Section B.3: Forecast customer connections capex (including capital contributions)
- Section B.4: Forecast repex
- Section B.5: 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 Forecast augex

Augmentation capex (augex) is driven by a service provider's need to build or augment its network. The main driver of augex is forecast maximum demand and its effect on expected network utilisation. Augex can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

United Energy proposes $124.3 million ($2015) over the 2016–20 period (excluding overheads). We accept United Energy's forecast augex reasonably reflects the capex criteria and will enable it to achieve the capex objectives, and include it in our estimate of overall total capex.

United Energy originally proposed $166.4 million ($2015) in augex. In our preliminary decision, we accepted that a large proportion of United Energy’s augex proposal reasonably reflects the capex criteria. However, we considered that United Energy had overstated its forecasts of maximum demand and inputs into its network planning framework (notably its estimate of the value of customer reliability), which had the effect of inflating its augex forecast.[63]

Our preliminary decision estimated that a $127 million augex forecast reasonably reflected the capex criteria over the 2016–20 period. To determine our alternative estimate of augex, we estimated the effect of adopting AEMO’s Victorian VCR estimate, which we considered better reflected the willingness-to-pay of United Energy’s customers for reliability supply of electricity.[64] We also considered that this alternative estimate was consistent with independent maximum demand forecasts from the Australian Energy Market Operator's (AEMO), which we considered reflected a realistic expectation of demand.[65]

United Energy's revised proposal accepts our preliminary decision for augex and proposes $124.3 million ($2015) in its revised proposal.[66] United Energy's proposal is slightly less than our preliminary decision due to proposed change in material and labour cost escalators. United Energy also did not contest any of our reasoning in the preliminary decision and did not provide any new information.

We note that AEMO updated their most recent Victorian maximum demand forecast (which was too late to be considered as part of our preliminary decision). As we set out in Appendix C, AEMO's updated maximum demand forecasts are slightly higher than its initial forecasts, but also still support our position that United Energy's demand forecast does not reflect realistic expectation of demand. We continue to adopt our augex preliminary decision because United Energy accepted our decision and did not provide any new information.

63 AER, *Preliminary Decision 2016–20 United Energy*, Attachment 6, October 2015, p. 37

64 AER, *Preliminary Decision 2016–20 United Energy*, Attachment 6, October 2015, p. 38

65 AER, *Preliminary Decision 2016–20 United Energy*, Attachment 6, October 2015, p. 39

66 United Energy, *Revised Regulatory Proposal 2016-20*, p. 12.

We are aware that United Energy recently completed consultation on a draft regulatory investment test for distribution (RIT-D) on its proposal to build a new sub-transmission line between Hastings and Rosebud. United Energy's revised augex proposal includes $23.5 million in capex for this project.[67]

While the process is not yet complete, we note that the draft RIT-D recommends deferring the construction of this new sub-transmission line by two years. This deferment would be enabled by a demand management solution. United Energy has advised that its aim would be to defer half of the total $23.5 million capex from the 2016-20 period.[68] At this early stage of the process, the cost of any demand management solution has not yet been finalised with the potential providers.

We have not reduced United Energy's revised augex proposal to reflect the deferral of this sub-transmission line, or provided additional opex. Consistent with our position adopted in other revenue determinations, we will apply a specific capex and/or opex adjustment for demand management activities where it can be shown to meet the capex criteria.[69] Given that the final cost of the demand management solution is not known, it is not possible to make an assessment as to how much additional opex is required and whether this amount would meet the opex criteria.

In the event that United Energy proceeds with its proposal in the RIT-D to defer this project, consumers will share in these cost savings through the capital expenditure sharing scheme.

67 United Energy, *RIT-D Draft Project Assessment Report – Lower Morning Peninsula Supply Area*, 16 December 2015. United Energy completed consultation of this draft report on 2 February 2016.

68 United Energy, *Response to AER information request 042*, 17 February 2016, p. 2.

69 This is consistent with the approach we have previously adopted in our regulatory determinations. For example, see AER Final Decision 2014–19, Ausgrid: Attachment 6, pp. 89–92

B.3 Forecast customer connections capex

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 may provide 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. 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 calculation of United Energy's annual revenue requirement. That is, United Energy recovers net capex investment across the life of the asset through revenue received for the provision of standard control services.

B.3.1 AER Position

We are satisfied United Energy’s revised proposal for connections capex of $316.8 million reasonably reflects the capex criteria.[70] We have included this amount in our substitute estimate of forecast capex as shown in Table 6.6. Further, we accept United Energy’s revised proposal for customer contributions of $136.1 million ($2015).

Table 6.6 AER final decision connections capex ($2015) million excluding overheads)

	2016	2017	2018	2019	2020	Total
Connections capex	61.7	63.2	63.2	63.9	64.8	316.8
Customer contributions	19.2	27.4	29.5	29.8	30.2	136.1

Source: AER analysis.

This position is consistent with our preliminary determination. In determining this we considered:

- United Energy’s forecast methodology

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

- the trends in United Energy's connections capex across time.

B.3.2 Revised proposal

In its revised proposal, United Energy included a forecast of connections capex of $316.8 million ($2015) for 2016 to 2020. We note that this is an increase of $67.6 million ($2015) from its initial proposal.[71]

While retaining its forecasting methodology, United Energy has increased its forecasts of gross connections capex and capital contributions to reflect:[72]

- updated volumes for non-unitised and unitised projects
- updated project costs for non-unitised projects and unit costs for unitised projects
- updated forecasts of existing committed projects (horizon projects).

United Energy noted that it will recover two thirds of the $67.6 million increase through up-front customer contributions from developers, rather than through distribution use of system (DUOS) charges levied on all customers.[73]

United Energy stated that the volume increase is driven by increases in business supply and multi-occupancy projects sustained by extended periods of low interest rates and a high demand for housing.[74]

With respect to the project cost increase, United Energy noted:

> The project cost increase is driven by a change in the style of projects, with more rail crossings, road works, and building developments in built-up areas being undertaken. Also high customer requirements and the connection of large customers with new dedicated assets, will increase customer contributions and hence project costs. As these projects cost significantly more than the average in their category, the higher proportion of these projects increases the project cost. The relevant programs of works forecast over 2016 to 2020 indicates the recent increases will continue for the 2016 to 2020 regulatory period.[75]

United Energy updated its forecasts of existing committed projects to include projects which were not committed or confirmed by customers at the time of United Energy submitted its initial regulatory proposal.[76]

Further, United Energy's revised proposal also increased its forecast of customer contributions as a result of updating its forecast cash contributions model. United Energy notes that its revised proposal is consistent with both the Essential Services

[71] AER, *United Energy Preliminary Decision 2016-20 Attachment 6 Capital Expenditure*, p. 6-54.
[72] United Energy, *Revised regulatory proposal*, January 2016, p. 13.
[73] United Energy, *Revised regulatory proposal*, January 2016, p. 18.
[74] United Energy, *Revised regulatory proposal*, January 2016, p. 18.
[75] United Energy, *Revised regulatory proposal*, January 2016, p. 18.
[76] United Energy, *Revised regulatory proposal*, January 2016, p. 18.

Commission of Victoria (ESC) Guideline 14 and the AER's national Customer Contributions Guidelines.[77]

B.3.3 Reasons for AER Position

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.

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.[78]

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".[79] Unitised projects have lives of up to 12 months whereas non-unitised projects have lives that can extend to up to three years.

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.[80]
- The unitised projects are based on standardised contractual unit rates for unitised United Energy projects.

  For the unitised project unit rates United Energy has updated these to include the actual 2015 project costs.[81] Table 6.7 compares these unit rates.

[77] United Energy, *Revised regulatory proposal*, January 2016, p. 18.
[78] United Energy, *Revised regulatory proposal*, January 2016, p. 13.
[79] United Energy, *Revised regulatory proposal*, January 2016, p. 13.
[80] United Energy, *Revised regulatory proposal*, January 2016, p. 13.
[81] United Energy, *Revised regulatory proposal*, January 2016, p. 15.

Table 6.7 Project Costs by Activity Code between 2014 & 2015 ($, real 2015)

	2014	2015
Business supply	51 864	58 736
Urban residential supply	70 882	81 040
Recoverable works	35 642	72 423
Rural supply	32 313	28 164
Multi-occupancy supply	3160	3237

Source: United Energy, *Revised Regulatory Proposal*, Table 5-10.

United Energy notes the increases in project costs for 2015 have been driven by:

- Major road developments including the undergrounding of rail level crossings and building developments. These projects have high customer requirements and complexity in dense population areas and involve safety clearances, long asset relocation detours and street vegetation. United Energy expects this to continue across the 2016-20 regulatory period.[82]
- The connection of large customers such as data centres, hospitals, railway supply and major building developments requiring upstream connection works on the network. United Energy expects this to continue across the 2016-20 regulatory period.[83]
- Certain projects completed in 2014 were not capitalised until 2015. United Energy notes these costs were included in the 2015 project cost calculations rather than the 2014 calculations.

Consistent with our preliminary determination, we are satisfied that United Energy's updated unit rates are reasonable given they are based on verifiable historical actual data. We note that United Energy contracts with its service providers are competitively tendered on an arms' length basis.[84] With this in mind, we are satisfied that United Energy's updated unit rates reflect the efficient costs of meeting its obligations to connect customers to the network. Further, we note that the use of historical expenditure works in step with the regulatory framework to reveal efficient costs 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

[82] United Energy, *Revised regulatory proposal*, January 2016, p. 17.
[83] United Energy, *Revised regulatory proposal*, January 2016, p. 17.
[84] United Energy, Capex Overview Paper - Connections FINAL, 28 April 2015, Table 8, p. 27.

categorisation. These growth indices rely on economic and industry forecasts published by the Australian Construction Industry Forum (ACIF).[85]

For each connection type United Energy has updated these to use 2015 actual volumes as the baseline for preparing its connections capex forecasts for 2016-20.[86] Table 6.8 sets out the change in the baseline connection volume between 2014 and 2015.

Table 6.8 Actual connection volumes between 2014 and 2015

	2014	2015
Business supply	447	539
Urban residential supply	123	128
Recoverable works	308	244
Rural supply	34	35
Multi-occupancy supply	2807	4836

Source: United Energy, *Revised Regulatory Proposal*, Table 5-8.

In its revised proposal United Energy notes:

> The increase in Business supply (CB) actual volume is due to a recent increase in mixed developments (residential/commercial) and an increase in business park developments. The increase in multi occupancy (CD) actual volume is due to recent increases in small residential developments for additions and alterations. The ACIF forecast demonstrates that these increases are likely to be sustained for 2015-2020. We consider that it is more appropriate to use our 2015 actual volumes to forecast our gross connections capex than our 2014 actual volumes because they are more recent and therefore more likely to be representative of our future requirements. [87]

In its submission, CCP3 supports the AER's use of historical data as the basis for the cost of high volume connections. CCP3 considers that just as opex and capex trends provide powerful arguments for assessing realistic future cost allowances, so too do the historic costs for providing new connections. [88]

We are satisfied it is appropriate to use the latest available volumes of connection activity. As such we agree with United Energy that the latest available year, the 2015

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85 United Energy, *Revised regulatory proposal*, January 2016, p. 15.

86 In its initial proposal United Energy relied on using 2014 actual volumes as the baseline to which it applied the ACIF growth indices.

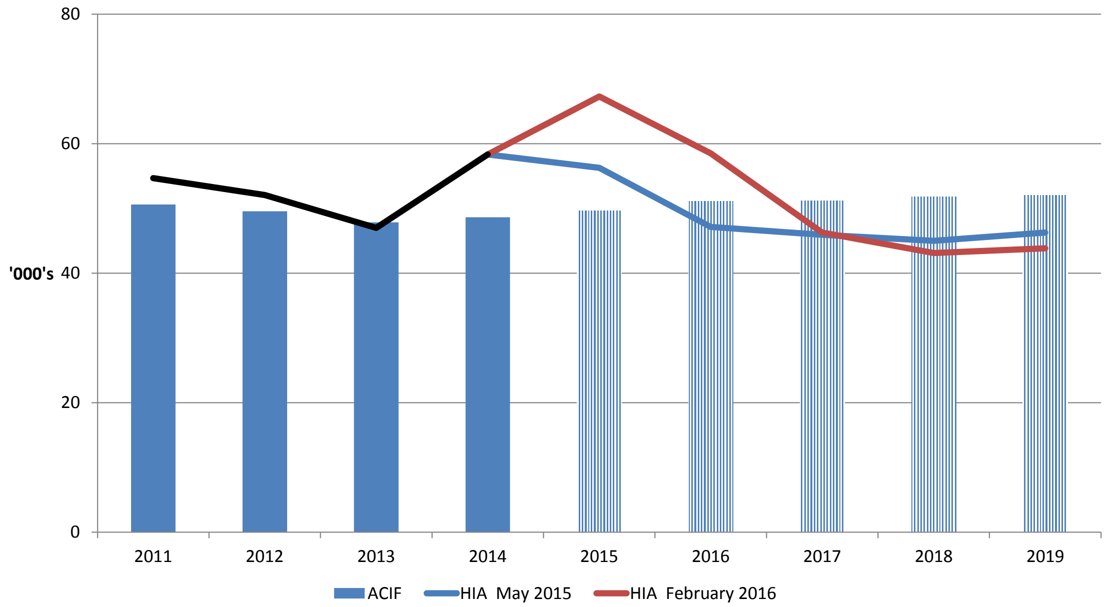
87 United Energy, *Revised regulatory proposal*, January 2016, p. 15.

88 CCP3, *Report on AER Preliminary Decisions and DNSPs' Revised Proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 56.

actual volumes, is the appropriate starting point for the forecast of customer connections.

CCP3 notes the increases in the DNSPs' revised forecasts of new connections and considers that any variations to future growth need to be based on fully independent assessments. Consistent with our preliminary determination we have compared this growth rate to other available data on the rate of residential construction and found they follow a similar trend. Figure 6.7 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).[89] 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.[90]

Figure 6.7 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 and February 2016.

We note that in its latest forecast the HIA increased its forecasts for housing construction. On this basis we are satisfied that the increase in United Energy's forecast connection activity represents a realistic expectation of the volume connection

89 HIA Housing Forecasts https://hia.com.au/en/BusinessInfo/economicInfo/housingForecasts.aspx.

90 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/.

activity United Energy will be required to undertake over the 2016–20 regulatory period.

With respect to the large recoverable works we have also cross checked United Energy's reasoning against material published by the Level Crossing Removal Authority. [91] We are satisfied that many of these large projects will occur in United Energy's distribution area and will require United Energy to undertake above average expenditure.

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 revised 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, and
- assessing the reasonableness of United Energy’s forecasting methodology.

In our preliminary determination we noted that the relevant guideline for calculating customer contributions may be subject to change:

> 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.[92]

[91] http://levelcrossings.vic.gov.au/crossings.

[92] AER, *United Energy Preliminary Decision 2016-20 Attachment 6 Capital Expenditure*, p. 6-60.

United Energy's forecast of customer contributions comprises both cash contributions and gifted assets.[93]

In its initial proposal, United Energy forecast cash contribution through 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.[94] In its revised proposal United Energy has back-cast these contributions assuming:

- marginal cost of reinforcement (MCR) to reflect current actual costs
- an X factor of zero
- 2016 tariffs, and
- opex so that it is excluded from both incremental revenue and incremental cost.

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. United Energy considers this forecast is consistent with both the Essential Services Commission of Victoria (ESC) Guideline 14 and the AER’s national Customer Contributions Guidelines.

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.[95] 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.[96]

CCP3 considers that although there is forecast legislative change to alter the capital contribution assessment process, the basis of the calculations should continue on current rules (ESCV guidelines) until the change comes into effect and there should be a pass through change triggered to reflect the difference in approach.[97] Further, CCP3 notes that the different DNSPs have different outcomes, in percentage terms, for the amount of capex recovered from each customer. This implies that they have differing approaches to calculating the customer contributions despite them apparently applying the same guideline.

We compared the ESC Guideline 14 with the AER's Connection charge guidelines we note that both these guidelines prescribe similar methods for calculating customer contributions. In simple terms, both guidelines calculate the contribution as the

93 United Energy, *Revised regulatory proposal*, January 2016, p. 13.

94 United Energy, *Revised regulatory proposal*, January 2016, p. 19.

95 United Energy, *Revised regulatory proposal*, January 2016, p. 19.

96 United Energy, *Revised regulatory proposal*, January 2016, p. 19.

97 CCP3, *Report on AER Preliminary Decisions and DNSPs' Revised Proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 55.

difference between the cost to the distributor of connecting the customer to the distribution network and the revenue the distributor will receive from that connection. Therefore we consider any differences between the two guidelines must relate to the assumed future incremental revenue or the assumed incremental cost for each forecast connection.

Incremental revenue

Both the ESC and AER guidelines rely on assumptions on the revenue that the distributors will receive for each connection. Under ESC guideline 14 the calculation of the revenue the distributor will earn from each connection relies on assuming that the price path for the last year of the price determination continues over the 30 years for domestic customers and 15 years for all other customers.[98] The AER's connection policy uses a flat real price path after the end of the relevant distribution determination, for the remaining life of the connection, when estimating the incremental revenue.[99]

Incremental cost

Similar to incremental revenue discussed above, both the ESC and AER guidelines rely on assumptions on the costs of the connection requiring a customer contribution. These costs, or incremental costs, represent the expenditure that the distributors will incur as part of the connection. We view the method to calculate the incremental cost of connections to be similar under both guidelines. That is both factor in the impact the connection has on the network and downstream augmentation in determining incremental cost. We do consider a difference exists between the two guidelines regarding the treatment of operating, maintenance and other costs. That is the ESC Guideline 14 includes opex in its calculation of incremental cost whereas the AER's connection policy does not include these costs.

We consider that accounting for the differences between the ESC Guideline 14 and the AER connection policy would be immaterial to the forecast of customer contributions. Further, we consider it is likely that Chapter 5A will be adopted in Victoria over the course of the 2016-20 regulatory control period under the AER’s Connection Charge Guideline under Chapter 5A of the NER.

Consistent with our preliminary determination, 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. Noting the adjustments made to back-cast the contribution rate we are satisfied that United Energy has demonstrated that its forecast is appropriate under either ESC Guideline 14 and AER’s connection charging guideline under Chapter 5A of the NER. On this basis, we are

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98 Essential Services Commission, Guideline No. 14 Provision of Services by Electricity Distributors.

99 AER, Connection charge guidelines for electricity retail customers Under chapter 5A of the National Electricity Rules.

satisfied that United Energy's forecast reflects a realistic expectation of customer contributions it will receive over the 2016-20 regulatory control period.

B.4 Forecast repex

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. [100]

Replacement can occur for a variety of reasons, including when:

- an asset fails while in service, or presents a real risk of imminent failure
- a condition assessment of the asset[101] determines that it is likely to fail soon (or degrade in performance, such that it does not meet its service requirement) and replacement is the most economic option
- the asset does not meet the relevant jurisdictional safety regulations, and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

The majority of network assets will remain in efficient use for far longer than a single five year regulatory control period (many network assets have economic lives of 50 years or more). As a consequence, a distributor will only need to replace a portion of its network assets in each 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 capital expenditure.

United Energy's forecast also includes additional expenditure which is predominately driven by network reliability and safety (our consideration of United Energy's network performance and the implications for proposed expenditure is discussed in Appendix B). United Energy’s proposal also 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 assessment of United Energy's specific repex programs related to bushfire mitigation is also discussed below (see page 91).

B.4.1 Position

We do not accept United Energy's proposed repex of $564 million ($2015), excluding overheads. We have instead included in our alternative estimate of overall total capex, an amount of $446.1 million ($2015) for repex, excluding overheads. This is 20.9 per cent lower than United Energy’s revised proposal, but is 8 per cent higher than what was determined in our preliminary decision. We are satisfied that this amount reasonably reflects the capex criteria.[102]

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

[101] A condition assessment may relate to assessment of a single asset or a population of similar assets. High value/low volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

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

Table 6.9 Final decision on United Energy’s total forecast repex ($2015, million)

	2016	2017	2018	2019	2020	Total
United Energy's initial proposal	118.9	125.6	124.8	113.8	101.9	585.1
AER preliminary decision	82.0	85.7	86.9	83.3	76.1	413.9
United Energy's revised proposal	113.3	114.4	119.1	113.6	103.2	563.6
AER final decision	91.9	92.7	92.5	88.4	80.6	446.1
Total difference b/w final and revised ($m)	-21.4	-21.7	-26.6	-25.2	-22.6	-117.5
Percentage difference b/w final and revised (%)	-18.9	-19.0	-22.4	-22.2	-21.9	-20.9

Source: AER analysis.

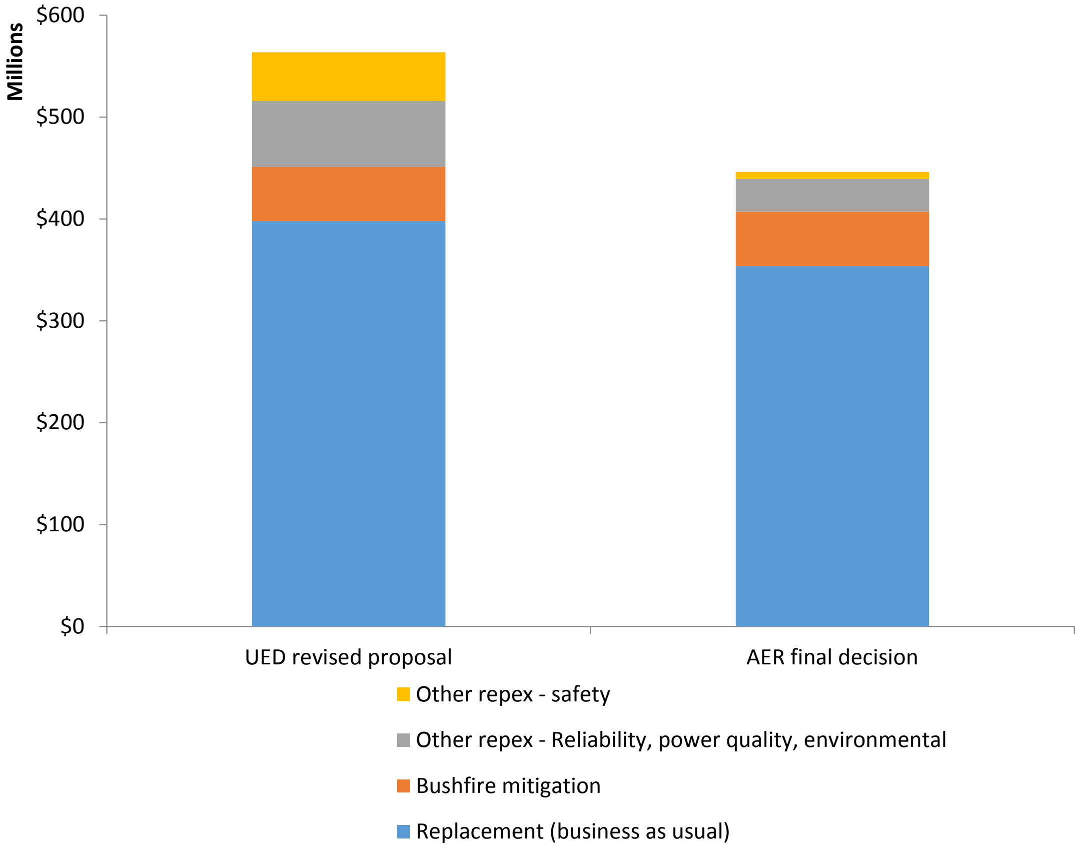
Note: Numbers may not add up due to rounding.

Our final decision on repex includes:

- $257 million for business as usual replacement of poles, overhead conductor, underground cable, service lines, switchgear, transformers, SCADA and network protection, which is $44 million or 15 per cent lower than United Energy's revised proposal (see section B.4.4)
- $97 million for business as usual pole top structures replacement, which is also aimed at minimising fire starts, consistent with United Energy's proposal (see section B.4.4)
- $53 million for specific safety programs related to bushfire mitigation, consistent with United Energy's proposal (see section B.4.4)
- $7 million related to public safety, which is $41 million or 86 per cent lower than United Energy's revised proposal (see section B.4.4); and
- $32 million to maintain network reliability, power quality, environmental requirements and other repex, which is $32 million or 50 per cent lower than United Energy's revised proposal (see section B.4.4).

Figure 6.8 compares United Energy's revised proposal with our final decision.

Figure 6.8 United Energy's revised proposal and our final decision



Source: United Energy revised proposal, AER analysis.

B.4.2 United Energy's revised proposal

United Energy's revised proposed repex forecast of $564 million was 4 per cent lower than its forecast of $585 million in its initial proposal.

In its revised proposal, United Energy accepted the following parts of our preliminary decision:[103]

- repex for the proposed pole top structures and SCADA
- repex for the proposed installation of dampers, armour rods and spacers in the network; and
- the rejection of the proposed SWER line removal expenditure.

The issues United Energy raised in its revised proposal where it did not agree with our preliminary decision were: [104]

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[103] United Energy, *Revised Regulatory Proposal*, 6 January 2016, pp. 22–23.

[104] United Energy, *Revised Regulatory Proposal*, 6 January 2016, pp. 22–23.

- United Energy raised issues with our predictive modelling. In particular, it noted that we should have used unit costs based on its forecast costs rather than historical expenditure. It also noted some issues with the input data and interpretation of the model results.
- United Energy did not accept our preliminary decision in relation to the category "other" repex. United Energy submitted that this category of repex is required to allow it to maintain its safety and reliability. United Energy acknowledged that much of the expenditure may be considered to be augex. [105]
- United Energy sought a revised amount of $53.3 million for bushfire mitigation programs.

B.4.3 AER approach

We have applied several assessment techniques to assess United Energy's forecast of repex against the capex criteria. [106] These techniques include:

- analysis of United Energy's long term total repex trends
- predictive modelling of repex based on United Energy's assets in commission
- consideration of various network health indicators; and
- review of United Energy's business cases.

We use our predictive modelling to assess approximately 47 per cent of United Energy's proposed repex. Where our predictive modelling has differed from United Energy's revised proposal, we have considered the reasons for this before choosing whether it is appropriate to arrive at an alternative estimate of repex that reasonably reflects the capex criteria. [107]

For those aspects of our assessment where we have not used predictive modelling, we have relied on the assessment of expenditure trends, the consideration of asset health indicators and project reviews, involving an assessment of supporting material such as business cases to assess United Energy's revised proposal. Our findings from these assessment techniques are consistent with our overall conclusions.

We have not used predictive modelling for the remaining 53 per cent of United Energy's proposed amount. This amount included capex for:

- bushfire mitigation
- pole top structures
- SCADA and network protection

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105 United Energy, *Revised Regulatory Proposal*, 6 January 2016, pp. 22.
106 NER, cl. 6.5.7(c).
107 NER, cl. 6.5.7(c).

- expenditure on assets not captured within the eight standard asset groups used in our predictive modelling (referred to as "other repex")

United Energy disagreed with our view in the preliminary decision that the actual repex spent in the 2011–15 regulatory control period was sufficient to allow it to maintain the safety and reliability of its network.[108] United Energy provided further information on its safety and reliability performance in support of its proposal. United Energy submitted that much of the increase in expenditure proposed in the 2016–20 regulatory control period is to allow it to maintain its safety and reliability. We have assessed United Energy's proposed "other" expenditure and bushfire mitigation repex on whether it is required for United Energy to maintain the safety and reliability of its network or to meet a jurisdictional safety obligation, such that it reasonably reflects the capex criteria.[109] Our findings regarding United Energy's safety and reliability are discussed in this appendix and further supporting analysis is detailed in appendix D of the capex attachment.

Trend analysis

We have used trend analysis (historical expenditure) to draw general observations from the historic trend analysis in relation to total repex. 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). However, for some aspects of our assessment where we have not relied on predictive modelling, we have used historical expenditure levels of expenditure to reject United Energy's forecast of repex or to develop our alternative estimate. In particular, where past expenditure was sufficient to meet the capex criteria[110], we are satisfied that it can be a reasonable indicator of whether forecast repex is likely to reflect the capex criteria.

Predictive modelling

Our predictive model, known as the repex model, allows us 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 control period. Using what we refer to as calibrated replacement lives (derived from the last five years of repex volumes), the repex model gives an estimate that reflects United Energy's 'business as usual' asset replacement practices.

As part of the 'Better Regulation'[111] 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

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108 United Energy, *Revised Regulatory Proposal*, 6 January 2016, p. 22.

109 NER, cl. 6.5.7(c).

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

111 AER, Better Regulation, www.aer.gov.au

implemented it in a number of revenue determination processes including the recent NSW/ACT and Qld/SA decisions. It builds on repex modelling we undertook in previous Victorian and Tasmanian distribution pricing determinations.[112]

The repex model provides both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and a well-founded high level assessment of that data (top-down analysis). The model can also be calibrated using data on United Energy's entire stock of network assets, along with its recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that predictive modelling cannot perfectly predict United Energy's necessary replacement volumes and expenditure over the next regulatory control 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 explain our reasons for this in Appendix F of our preliminary decision. We also 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.[113]

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. We use our qualitative techniques to assess whether there is any such evidence. In this way, we consider that the repex model serves as a 'first pass' test, as set out in our Expenditure Guideline.[114]

We recognise there are reasons why some assets may be better assessed outside of the repex model. Where we considered it was justified, we separately assessed such assets outside the model using techniques other than predictive modelling.

[112] 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.

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

[114] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

Network health indicators

We have used a number of network health indicators with a view to observing network asset health. Asset utilisation is one such indicator. We have had regard to changes in asset utilisation to provide an indication as to whether United Energy's assets are likely to deteriorate more or less than would be expected given the age of its assets. Asset utilisation in some circumstances is a useful check on the outcomes of our predictive modelling in that unlike the other indicators, and the predictive modelling itself, it is not age based.

The remaining indicators we have used are aged based. We acknowledge that these are less useful for providing a check on the outcomes of our predictive modelling because the model also assumes age is a reasonable proxy for asset condition. While providing some context for our decision, we have not relied on these age-based indicators to inform our alternative estimate. However, these indicators have provided context for our decision and the findings are consistent with our overall conclusion.

B.4.4 AER repex findings

Trends in historical and forecast repex

We have conducted a trend analysis of United Energy's repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.[115] We use trend analysis to gauge how United Energy's historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.9 shows United Energy's repex spend has been steadily increasing across time. United Energy is forecasting this trend to continue for the first part of the 2016–20 regulatory control period before tapering off in the latter two years. Figure 6.9 also shows that the replacement of the eight repex asset groups[116] specified in the category analysis RIN[117] grew between 2011 and 2014, but have since reduced slightly and are forecast to be relatively consistent over the next regulatory control period. We can observe from Figure 6.9 that the expenditure driving the increasing repex trend over time is in the "other" repex[118] (which is not captured by predictive modelling) and in repex for bushfire mitigation. These are considered separately in our analysis below.

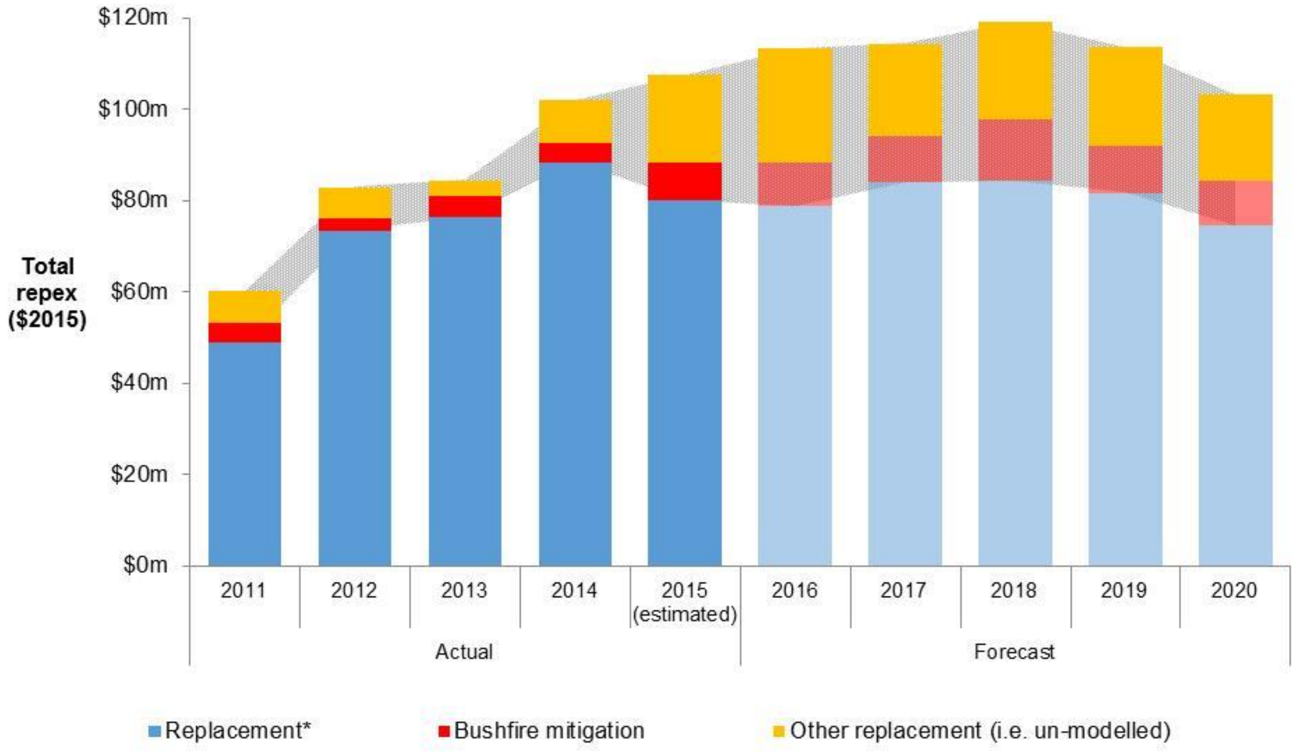
115 NER, cl. 6.5.7(e)(5).

116 The eight asset groups are poles, pole top structures, overhead conductor, underground cable, service lines, transformers, switchgear and "SCADA and protection systems". These are captured in the "replacement category in Figure 6.9.

117 Regulatory Information Notice.

118 "Other" repex is expenditure not captured in the eight asset groups specified in the category analysis RIN. We note that United Energy's proposed expenditure in other predominately does not relate to the replacement of existing assets.

Figure 6.9 United Energy - Actual and forecast repex ($2015)



* see footnote on page 52

Source: Reset United Energy - RRP 5-30 CA RIN Other Un-modelled corrected

We acknowledge there are limitations in long term year on year comparisons of replacement expenditure. However, a comparison of historical trends and forecasts provides context when considering United Energy's proposed expenditure.

Predictive modelling

We use predictive modelling to estimate how much repex United Energy is expected to need in future, given the age of its current assets, and based on when it is likely to replace the assets. We modelled five asset groups using the repex model. These were poles, underground cables, service lines, transformers and switchgear.[119] To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories. Pole top structures and SCADA were not modelled, nor were the specialised categories of capex defined by United Energy that were not classified under the eight asset groups prescribed in the category analysis

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119 For the final decision we have chosen not to model overhead conductors. The majority of United Energy's proposed expenditure on this asset (as well as its past expenditure) is driven by its obligations under its bushfire mitigation plan. Only 2 per cent of the expenditure is separate to this plan. Consequently, predictive modelling was not considered appropriate to model the small residual amount that was not related to bushfire mitigation works. We are satisfied that United Energy's proposed repex of $1.4 million for overhead conductor reflects its business as usual repex and have included this in our alternative estimate.

RIN.[120] In total, the assets modelled represent 47 per cent of United Energy's proposed repex.[121] Our predictive modelling calculation process is described at appendix F of the preliminary decision.

As discussed in our preliminary decision 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 historical expenditure. This estimate uses United Energy’s own historical 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 set out below our views on their suitability for use in our assessment.

We have had regard to United Energy's revised proposal and 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 beyond business as usual requirements in the next period.

As noted above, United Energy has not accepted our predictive model findings from our preliminary decision. United Energy has raised a number of issues with our predictive modelling process. Our assessment of United Energy's revised proposal is outlined below.

Differences between modelling conducted by Nuttall Consulting and the AER

United Energy submitted a report from Nuttall Consulting as part of its initial proposal. Nuttall Consulting populated a series of predictive model scenarios for United Energy and detailed its observations in its report. For those models where both we and Nuttall Consulting used similar input assumptions, the outcomes were similar, however, our models tended to predict lower replacement volumes than those of Nuttall Consulting. United Energy provided a further report from Nuttall Consulting as part of their revised proposal. This report commented on several data and interpretation issues that may explain the differences between our predictive modelling and the modelling undertaken by Nuttall Consulting.

The main issues raised were:

- certain categories of underground cable should not be scaled [122]

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120 Our reasons for excluding these assets were detailed at Appendix F of our preliminary decision.

121 We have used predictive modelling to assess 47 per cent of United Energy's proposed repex. However, a proportion of capex classified by United Energy as "repex" is actually for the installation of new assets, not replacements. Because of this, the proportion of asset replacements assessed is actually higher than suggested by the 47 per cent figure above.

122 United Energy provided age profile and expenditure data for underground cable by metre, rather than by kilometre. Other distributors have used kilometres. In order to compare the results of modelling across distributors, it was necessary to convert United Energy's conductor assets into kilometres by dividing the assets by 1000. However, a small set of underground cable assets were expressed as single units, rather than as a length. The scaling had the

- using estimates from 2015 as the start of the estimation period rather than estimates from 2016
- our preliminary decision to use historical unit costs rather than forecast unit costs.

We agree with the first two points. That is, that some underground cable assets should not be scaled when used in the model and that using estimated outputs starting at 2016 is appropriate. Once these issues are addressed, the volumes from our predictive model and Nuttall Consulting's model align for most asset categories. However, there are still some remaining volume differences with the switchgear asset group.

The third issue is whether it is appropriate to use historical or forecast unit costs. Of the five asset categories modelled, the choice of unit cost only affects the switchgear asset group to a material extent. We have considered the outstanding differences between our predictive modelling and United Energy's proposal in detail below, including whether it is appropriate to adopt historical or forecast unit costs. As part of this, we have examined the remaining differences between our modelling and Nuttall Consulting's modelling.

Differences between United Energy's proposal and the AER's predictive model

Table 6.10 shows the outcome of our predictive model (using historical and forecast unit) and the expenditure proposed by United Energy.

Table 6.10 Outcome of predictive modelling ($million, 2015)

	AER model			United Energy proposal and historical	
	Historical unit costs	Historical unit costs (United Energy switchgear categories)	Forecast unit costs (United Energy switchgear categories)	United Energy Proposal	United Energy 2011-15
Poles	45.1	45.1	44.9	38.7	35.8
Underground cables	52.4	52.4	51.0	43.5	38.4
Service lines	9.8	9.8	10.3	33.6	69.2
Transformers	44.2	44.2	43.6	69.2	31.9
Switchgear	52.6	67.0	81.2	80.4	59.2
Total modelled	**204.2**	**218.6**	**231.0**	**265.3**	**234.5**

Source: AER analysis

effect of minimising the size of these assets, and, consequently, their values were not appropriately captured by the predictive model used in the preliminary decision.

Our predictive model estimates higher repex than United Energy's revised proposal for poles ($6.6 million higher) and underground cables ($9 million higher). It estimates lower repex for switchgear ($29 million lower), service lines ($23 million lower) and transformers ($25 million lower). In the following section, we have examined the reasons for the difference and whether we are satisfied that United Energy has justified expenditure above the business as usual estimate provided by our predictive model.

Switchgear

United Energy has proposed expenditure of $81 million on switchgear replacement. Our predictive model, when calibrated, estimates replacement of $52.6 million (using historical unit costs). This outcome was achieved by modelling the prescribed switchgear asset categories in the category analysis RIN.

There are two factors that explain the difference between our model outcome and the predictive models prepared for United Energy by Nuttall Consulting:

- Nuttall Consulting used a different set of asset categories for switchgear than those prescribed in the category analysis RIN.
- United Energy has proposed a higher unit cost for this asset group (on average) for the forecast period than observed during the last five years (historical unit cost).

We have assessed these two points of difference in order to determine whether our predictive model properly represents an estimate of business as usual repex.

We are not satisfied that United Energy's forecast reasonably reflects the capex criteria, and have included an amount for business as usual requirements in our alternative estimate. In particular, we consider United Energy's historical, rather than forecast unit cost, is reflective of its future replacement cost. However, we have adopted United Energy's switchgear asset categories in our predictive modelling, and consider a business as usual amount of $67 million (based on these categories) reasonably reflects the capex criteria.

Disaggregated asset categories

The first difference is Nuttall Consulting's use of a different set of assets categories in the switchgear group. These different asset categories map to the prescribed asset categories in the category analysis RIN, and could be characterised as being disaggregated (i.e. more granular) versions of the category analysis RIN assets.[123] If the predictive model is recalibrated using United Energy's disaggregated asset categories, the new estimate is $67 million, approximately $14 million higher than our preliminary decision estimate. Applying the disaggregated asset categories, results in

[123] For example, the prescribed RIN category "< = 11 kV ; Switch" is disaggregated into five asset categories: "< = 1 kV ; SWITCH GEAR"; "< = 1 kV ; SWITCH; POLE MOUNTED"; "O/H Isolators -HV - 11kV"; "O/H Load Break Switches - HV - 11kV"; and "Ring Main Unit - 11kV".

the volume estimates from our model aligning with those volumes estimated by Nuttall Consulting.

We consider the use of United Energy's more granular asset categories is likely to provide a more accurate representation of United Energy's business as usual replacement volumes in the switchgear asset group. The disaggregated data allows for higher and lower value asset populations to be considered separately, which assists in modelling accuracy.

Choice of unit cost

Given that our modelling agrees with the switchgear volumes estimated by Nuttall Consulting's modelling, the remaining difference can be explained by the choice of unit cost. The difference between using historical and forecast unit costs is approximately $13 million.

United Energy has identified 17 asset categories within the switchgear asset group. Closer examination of the categories within the switchgear asset group shows that the difference in outcomes is driven by the unit cost of a single asset category. The selection of unit cost has a minimal effect on 16 of the 17 switchgear asset categories in this group. For these assets, applying historical unit costs results in an estimate of $54.5 million, while using United Energy's forecast unit costs gives an estimate of $57.2 million.

The asset category that is most affected by the application of forecast unit costs is the category named by United Energy ">= 11 KV & < = 22 KV; LINE CAPACITORS; CONTROLLERS AND VACUUM SWITCHES" (LCCVS). United Energy has proposed repex of $4.9 million for this asset category. For this asset category, the choice of unit cost results in estimates of:

- $12.6 million when historical unit costs are used
- $24 million when forecast unit costs are used.

Relevantly, the adoption of either unit cost exceeds the amount of repex that United Energy has sought for this asset category. This is because predictive modelling has estimated a higher volume of replacement than proposed by United Energy.

Generally, we consider the use of recent historical unit costs (escalated for inflation) to provide a better estimate of the cost of replacement than forecast costs.[124] Historical unit costs reflect the cost that a distributor has been able to achieve in the recent past in undertaking its replacement programs.

For the majority of United Energy's modelled asset groups, there is little difference between the adoption of historical or of forecast unit costs. We note that estimated

[124] If the application of forecast unit costs is materially lower than the application of historical unit cost, we may consider applying forecast costs to carry through potential efficiencies identified by the distributor arising from the lower expected unit costs going forward.

repex is lower for three of the five modelled asset groups when forecast unit costs are used, while it is materially higher for the switchgear group.[125] As noted above, the difference in the switchgear group can mostly be attributed to a single asset category.[126]

Given the difference in estimates can be explained by a difference in cost for one asset category, and given the repex model has already estimated a higher amount of repex for that asset based on historical unit cost, we maintain that the use of United Energy's historical unit costs is consistent with the capex criteria. [127]

On this basis, we estimate $67 million to be the business as usual estimate of repex for the switchgear group, using historical unit costs.

Service Lines

United Energy has proposed $34 million for service line replacements over the 2016-20 regulatory control period, which is $24 million higher than our business as usual estimate of $10 million. United Energy's proposal includes funding for its bulk replacement of neutral screened services in 2016 and ongoing replacement of service lines. In total, United Energy has proposed the replacement of around 66 000 service lines over the regulatory control period, 20 724 in 2016 (including 15 360 neutral screened services), and an average of around 11 000 a year for the remainder of the period.

We are not satisfied that United Energy forecast reasonably reflects the capex criteria, and have included an amount for business as usual requirements in our alternative estimate. In particular, we are not satisfied that United Energy has established that it needs to continue the bulk replacement of service lines in order to meet the capex objectives.

Predictive modelling

Predictive modelling conducted by both us and by Nuttall Consulting does not support the volume of replacement proposed by United Energy. The predictive modelling (using calibrated replacement lives) estimates around 20 000 service replacements over the regulatory control period. This is around 46 000 fewer replacements than proposed by United Energy.

United Energy replaced 145 000 service lines in the 2011–15 regulatory control period, (around 40 per cent of its asset fleet of 368 000 overhead service lines). As a result, United Energy has the youngest overhead service line assets of all distributors in the

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[125] The adoption of forecast costs for Service Lines increases the forecast by about $0.5 million compared with historical costs. All other asset categories are lower using forecast unit costs.

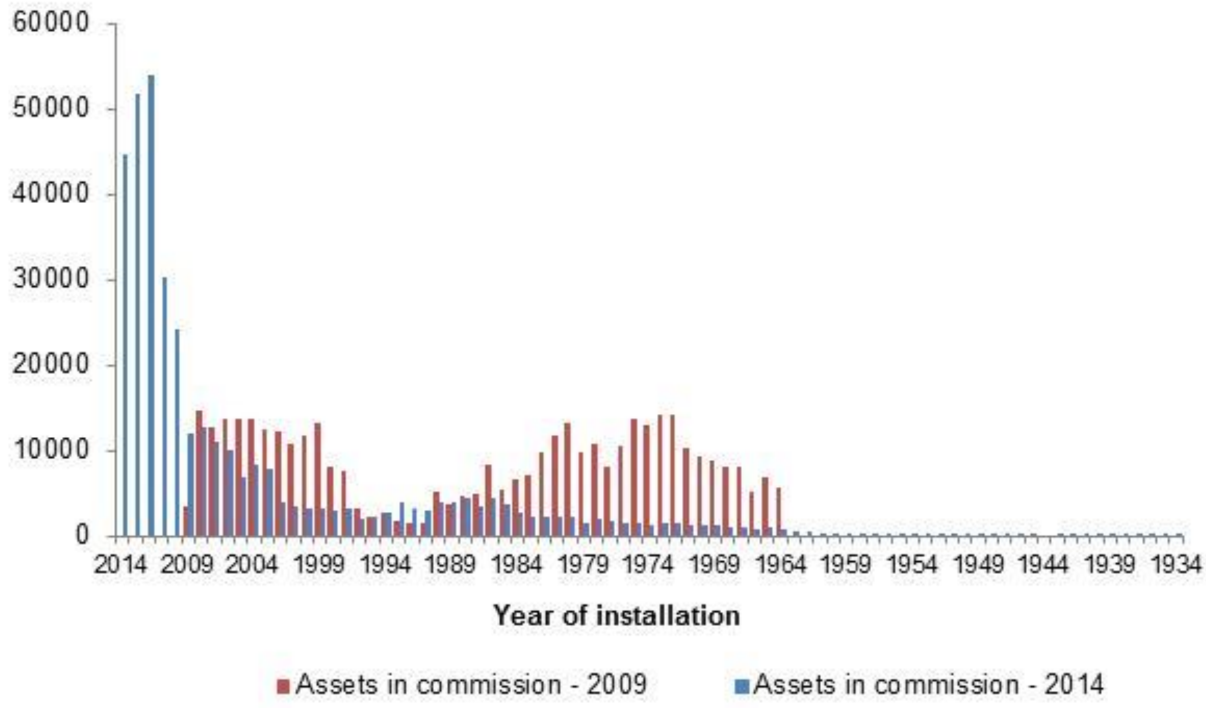
[126] When the LCCVS asset category is excluded from the repex model, the difference in total estimated repex (i.e. all modelled asset categories) between the adoption of either historical or forecast unit costs is less than one per cent, $207 million for forecast unit cost and $206 million for historical unit cost.

[127] National Electricity Rules, cl. 6.5.7(c)

National Electricity Market. In particular 257 000 (or 70 per cent) of its service lines are less than 10 years old, while 297 000 (0r 81 per cent) are less than 20 years old. United Energy's asset replacement over the past five years has had a significant impact on the average age of its service line fleet. The average age of a service line on United Energy's distribution network is currently 10 years, while at the time of the last reset in 2010, the average was 23 years. United Energy estimated that service lines last 40 years. This is also the average replacement age predicted by our calibrated predictive model and models used by Nuttall Consulting.

United Energy has replaced most of its older service line assets over the last five years. Figure 6.10 compares the installation date of assets in commission in 2009 with assets in commission in 2014.

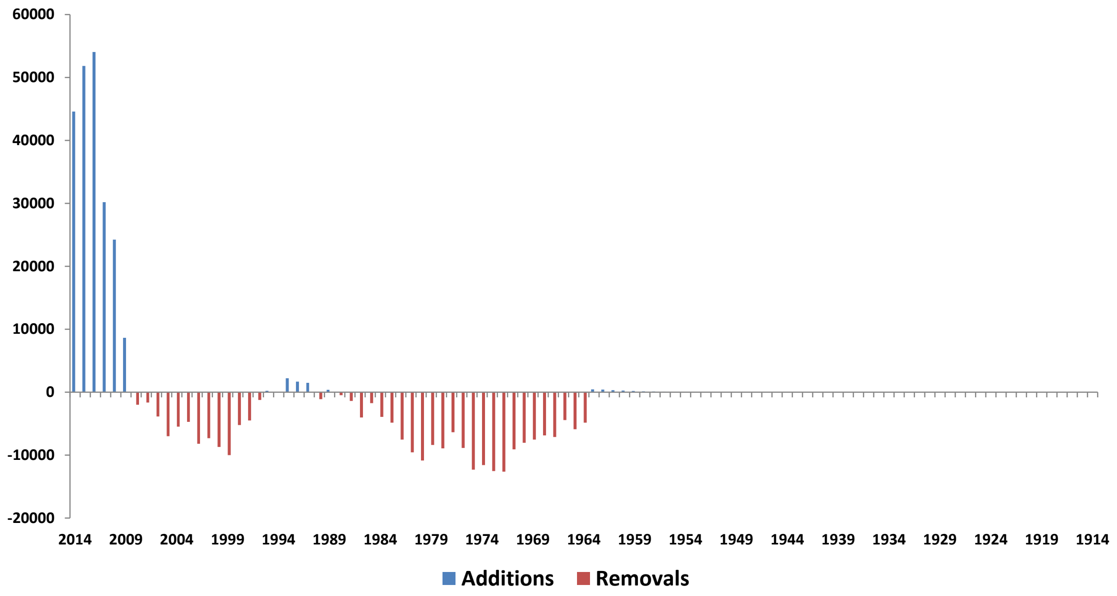
Figure 6.10 United Energy - Service line age profile



Source: Reset RIN 2010 & CA RIN 2014

Figure 6.11 shows net additions and removals from United Energy's service line fleet over the 2009–14 period. This illustrates that United Energy has replaced most of the older assets in its fleet. United Energy has also estimated that it will have replaced 20 000 service lines in 2015 (which is not captured within the latest available age profile data). This could be expected to further reduce the number of older assets in United Energy's service line asset fleet and further reduce the average age of its assets.

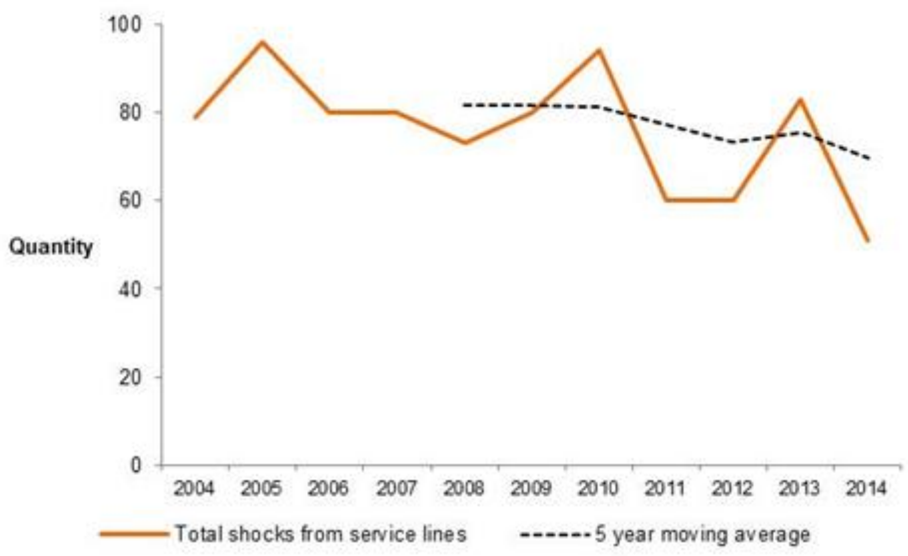
Figure 6.11 United Energy - Net additions and removals of assets between 2009 and 2014



Source: Reset RIN 2010 & CA RIN 2014

We note that United Energy's replacement of service lines has coincided with an improvement in the safety and failure performance of this asset. Electric shocks caused by service lines have fallen over the 2011–15 regulatory control period. Figure 6.12 shows that the number of electric shocks caused by service lines have, on average, decreased since 2005.

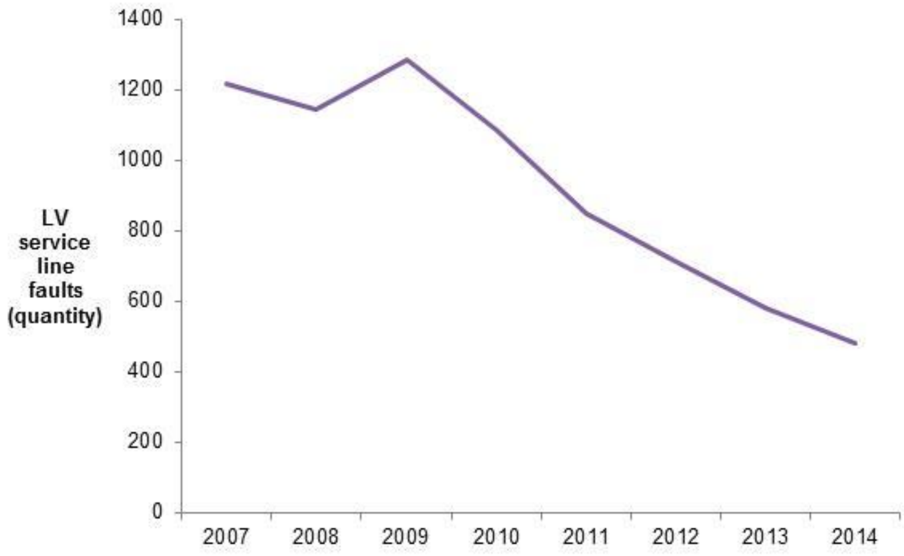
Figure 6.12 United Energy - Electric shocks from service lines



Source: United Energy, revised regulatory proposal, January 2016

United Energy's service lines failures performance has also improved significantly over the last regulatory control period. Figure 6.13 shows total asset failures of service lines over the 2007–14 period. Over this time, service line failures have more than halved.

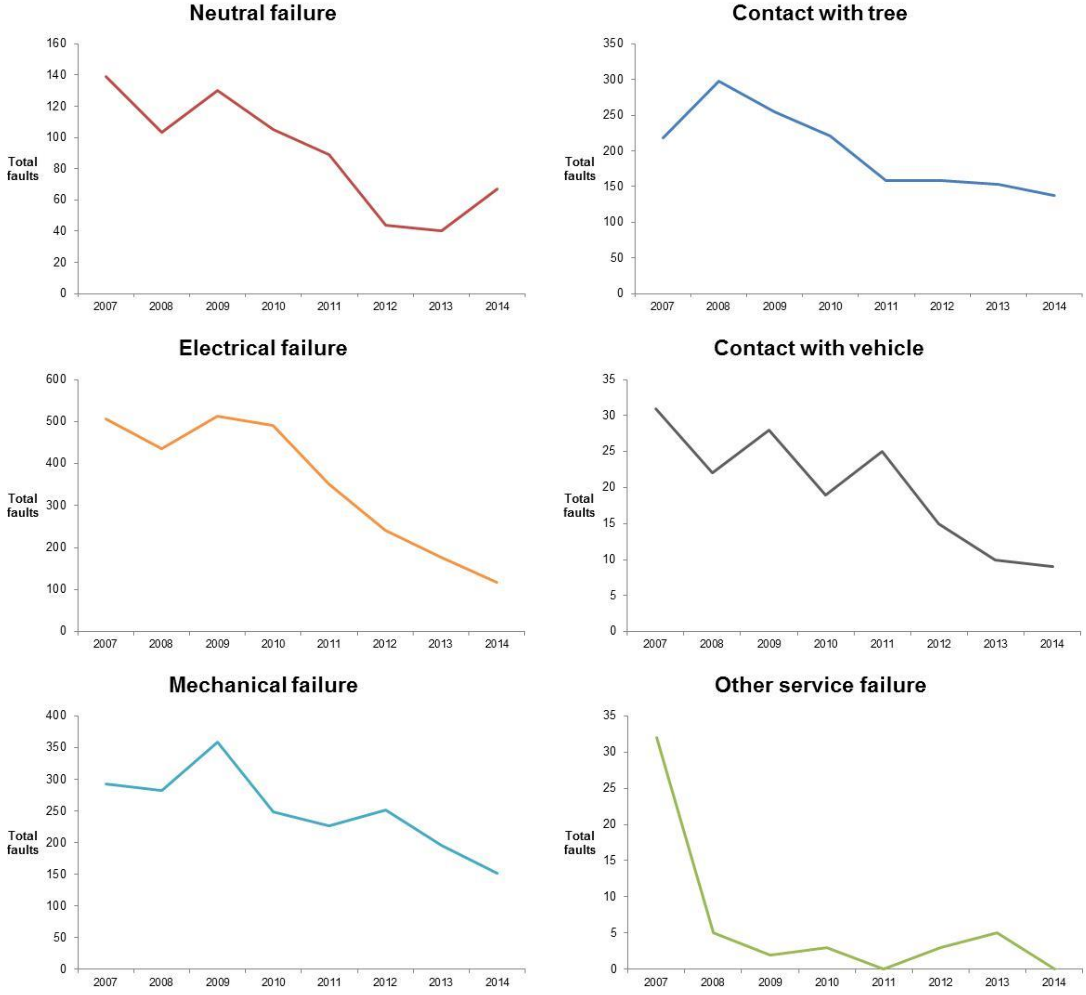
Figure 6.13 United Energy - low voltage service line faults



Source: United Energy, revised regulatory proposal, January 2016

Figure 6.14 show the breakdown of this data into various failure causes. In each case, there is a downward trend in asset failures over the period.

Figure 6.14 United Energy - Service line faults by type



Source: United Energy, revised regulatory proposal, January 2016.

As a result we consider that United Energy has not demonstrated that it requires repex above the business as usual estimate in order to reasonably reflect the capex criteria on the basis of:

- the small number of older assets in commission
- the high volume of new assets in the network
- the improving failure trend over time, where failures are decreasing; and
- the overall improvement in the safety performance of these assets over the 2011-15 regulatory control period.

However, United Energy has also submitted that part of its replacement volume is driven by safety obligations, which are not captured by predictive modelling.[128] We have examined this issue below.

Neutral Screen Replacement Program

United Energy submitted that the Neutral Screen Replacement Program is part of its Electricity Safety Management Scheme (ESMS), and therefore it is required to carry out the replacement to comply with a jurisdictional safety obligation.[129]

United Energy has proposed to replace 15 360 neutral screened service lines in 2016 as part of its Neutral Screen Replacement Program.[130] United Energy's stated that the bulk replacement program is due to be finalised in 2016. United Energy's forecast for neutral screened service line repex for 2016 is $9 million, while our predictive model estimate of business as usual repex is $2.3 million.

In reviewing the ESMS synopsis document that was submitted to Energy Safe Victoria (ESV) the Neutral Screen Replacement Program is not referenced within the document.[131] United Energy provided further information on the interaction between the ESMS and the Neutral Screen Replacement Program.[132] United Energy referenced our final decision for United Energy in the 2011–15 regulatory control period[133]. It noted that, following our decision to include the Neutral Screen Replacement Program in its forecast of capex in that decision, it amended its LV Services and Terminations Management Plan (referenced in the ESMS) to include this safety driven capex project.[134]

We do not consider that United Energy has demonstrated that the completion of the Neutral Screened Replacement Program is a regulatory obligation. The program does not appear within the ESMS material provided to us. Further, the ESMS does not establish that compliance with lifecycle plans (in this case the LV Services and Terminations Management Plan) is a requirement under the ESMS.

As discussed above, United Energy has replaced a significant number of service lines on its network over the last five years. We would expect that this program of replacement would have targeted the highest risk assets, leaving lower risk assets in commission. This appears to be supported by the evidence as electric shocks caused by neutral screened services have fallen substantially since the introduction of the program in 2011 as shown in Figure 6.15 below. We also note this is consistent with

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128 United Energy, *AER Category Expenditure Explanatory Statement - Asset Class Services and Terminations*, p. 22.

129 United Energy, *LV Services and Terminations Life Cycle Strategy*, p. 46.

130 United Energy, *LV Services and Terminations Life Cycle Strategy*, p. 46.

131 United Energy, *ESMS synopsis version 1.1*, 30 September 2011.

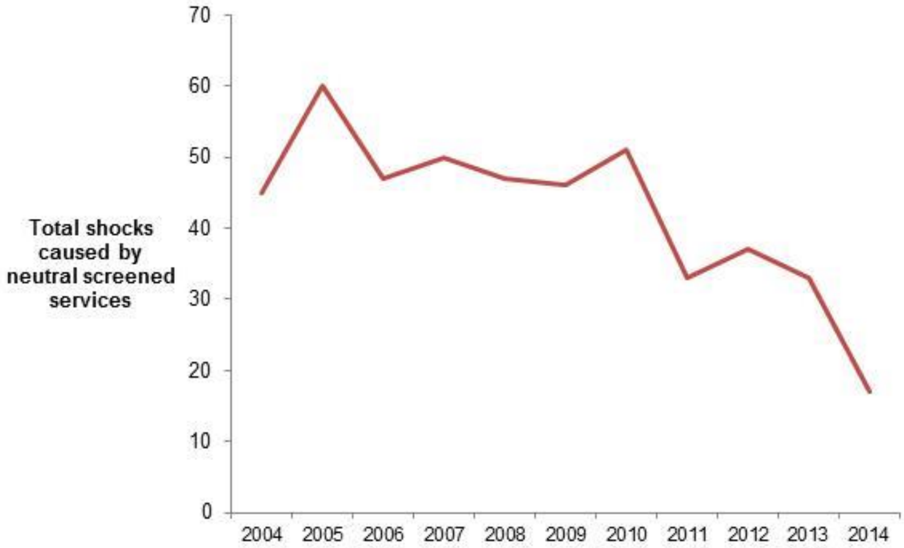
132 AER, *Information request 051*, 3 March 2016.

133 AER, *Final decision, Victorian electricity distribution network service providers - Distribution determination 2011-2015*, October 2010, p. 469.

134 United Energy, *Response to AER Information request 051*, 7 March 2016.

Figure 6.10 and Figure 6.11 (above), which show a similar improvement in performance for the entire service line fleet.

Figure 6.15 United Energy - Electric shocks caused by neutral screened services



Source: United Energy, revised regulatory proposal, January 2016.

We note that United Energy is required by the Electricity Safety Act to undertake neutral screened testing.[135] We have also provided an amount in our alternative estimate for improving Neutral Integrity Testing proposed by United Energy to:[136]

- improve Neutral Integrity Testing safety governance by automating and recording Neutral Testing issues; and
- improve the safety for its workforce, customers and the public who could be impacted by related Neutral Integrity issues.

As discussed in section B.4.2 we consider this expenditure will improve the targeting of service line replacements, such that United Energy should be able to better manage these associated risks.

United Energy also submitted that that:

> … In the forecast period, OT [Operational Technology] projects have been proposed to continuously monitor services and alert the control room as soon

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135 United Energy, *LV Services and Terminations Life Cycle Strategy*, p. 43

136 See section B.4.2.

> as the service has failed. This is expected to halve the number of electric shocks experience by the general public in the forecast period …[137]

And:

> United Energy has three OT projects that will materially affect the safety performance of our services:-
>
> - Service mains deterioration
> - In-meter capabilities
> - Intelligent Network Device
>
> Taken together these three projects will enable the monitoring of service cables, including their neutrals so that if a fault occurs it will be detected immediately. The benefit is that the fault can then be rectified promptly before it causes an incident like an electric shock. This is a great improvement on the present practice of manually testing services every 10 years, **and on the bulk replacement of services by deteriorating cable type instead of just those that have failed**. [emphasis added] [138]

Accordingly, United Energy considers that new methods of service line testing will reduce shocks and be superior to the previous method of bulk service line replacement. However, United Energy has not proposed to amend its asset management approach of bulk replacement of neutral screened service lines to take advantage of the benefits of a more targeted approach from more efficient neutral testing. Instead, United Energy has sought to continue a bulk replacement program it commenced five years ago, notwithstanding its improved safety performance and improved risk management approach, without demonstrating that this is required to maintain the safety of the network.

In summary, we are not satisfied that United Energy requires repex to continue its bulk replacement of neutral service lines, given that:

- The majority of the program replacements have already taken place and electric shocks have fallen
- United Energy has not established that there is a regulatory obligation to replace these service lines
- United Energy's proposed investment in operational technology will allow a replacement program that is more targeted towards any remaining high risk assets, rather than entire populations of assets.

Given the above, we consider the business as usual estimate identified by our predictive modelling of service line repex reasonably reflects the capex criteria. [139]

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137 United Energy, *Network Safety Assessment*, December 2015, p. 46.

138 United Energy, *Network Safety Assessment*, December 2015, p. 46.

139 NER, cl. 6.5.7(c)

Transformers

United Energy has proposed $69.2 million for transformer replacement over the 2016-20 regulatory control period. This includes funding for around $41 million to replace 15 power transformers operating at 66/11kv or 66/22kv. United Energy spent $31.9 million on transformer repex in the last regulatory control period. United Energy's proposal is $37.3 million higher, or more than double its expenditure in the 2011–15 regulatory control period.

We are not satisfied that United Energy forecast reasonably reflects the capex criteria, and have included an amount for business as usual estimate requirements in our alternative estimate. In particular, we are not satisfied that United Energy has established that its proposed increase in repex above historical expenditure is required to meet the capex objectives. Our alternative estimate includes an amount for replacement of transformers that is above United Energy's historical expenditure, but below its proposal.

Difference between our business as usual estimate and United Energy's proposal

Our predictive modelling estimate of business as usual repex for transformers is $44.2 million. United Energy also proposed $3.7 million of repex in the transformer group on assets that were not captured by the predictive modelling. This expenditure is largely in line with historical expenditure. When these assets are included with the modelled amount, the business as usual amount is estimated to be approximately $48 million, around $12 million more than United Energy's historical expenditure, but $21 million lower than its proposed expenditure.

The main difference between the business as usual estimate from the predictive model and United Energy's proposal is the volume of work it seeks to undertake over the 2016–20 regulatory control period.[140] l. We discuss the main driver of the remaining difference between our business as usual estimate and United Energy's proposal below.

Power transformers

The main difference between United Energy's revised proposal and our predictive modelling volume outcomes is the number of power transformers operating at 66/22kv or 66/11kv predicted to be replaced over the next five years. [141] Power transformers are situated in zone substations and are among the most expensive assets on the distribution network. United Energy currently has 105 of these assets in service, and the replacement cost of a single unit is estimated at between $3.1 million (based on

[140] The selection of unit cost makes a small difference to the forecast for the transformer asset group. The adoption of forecast unit costs result in an estimate of $43.6 million, while historical unit costs give an estimate of $44.2 million.

[141] United Energy has proposed higher repex for some other transformer asset categories, but these are not as material as its estimate for 66/22 kV and 66/11 kv power transformers.

historical cost) and $2.7 million (based on United Energy's forecast cost). United Energy estimates that each zone substation services around 10 000 customers.[142]

Our predictive model is calibrated using United Energy's replacement practices over the last five years of actual data. During this time, United Energy reported four power transformer replacements due to condition. The calibrated repex model predicts a replacement of nine power transformers over the next five years.[143] This is the same modelled outcome as achieved by Nuttall Consulting when using this calibrated input.

United Energy submitted that the four replacements in the last period did not reflect its actual condition based replacement practice over the last regulatory control period.[144] It noted that, over the 2011-15 regulatory control period, it had used augmentation expenditure to replace a further four power transformers that had reached the end of their economic life. United Energy submitted that it will not have the opportunity to use augex to replace end of life power transformer assets in the 2016–20 regulatory control period.[145] Given this, it has submitted that our predictive model should be calibrated using these (higher) volumes. [146][147]

We have considered whether our estimate of nine replacements over the next five years is sufficient to allow United Energy to maintain its business as usual approach to asset replacement, by considering whether this estimate is likely to maintain the current level of asset risk. Figure 6.16 compares the age profile of United Energy's power transformer assets in 2009 with the age profile in 2014. It can be seen that the oldest transformers in the network form the majority of the assets taken out of commission during the last regulatory control period (whether due to a repex or augex driver). This indicates that United Energy's replacement strategy focused on the oldest assets in the network.

[142] United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 11.

[143] The actual output from the repex model, which allows for decimals, is 9.18 units.

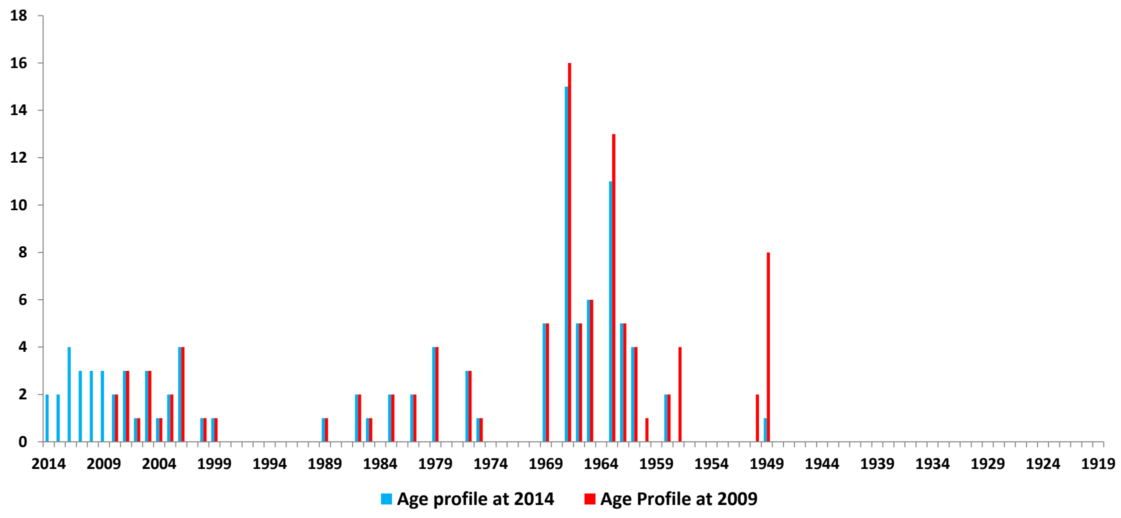
[144] United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 14.

[145] United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 35.

[146] United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 35.

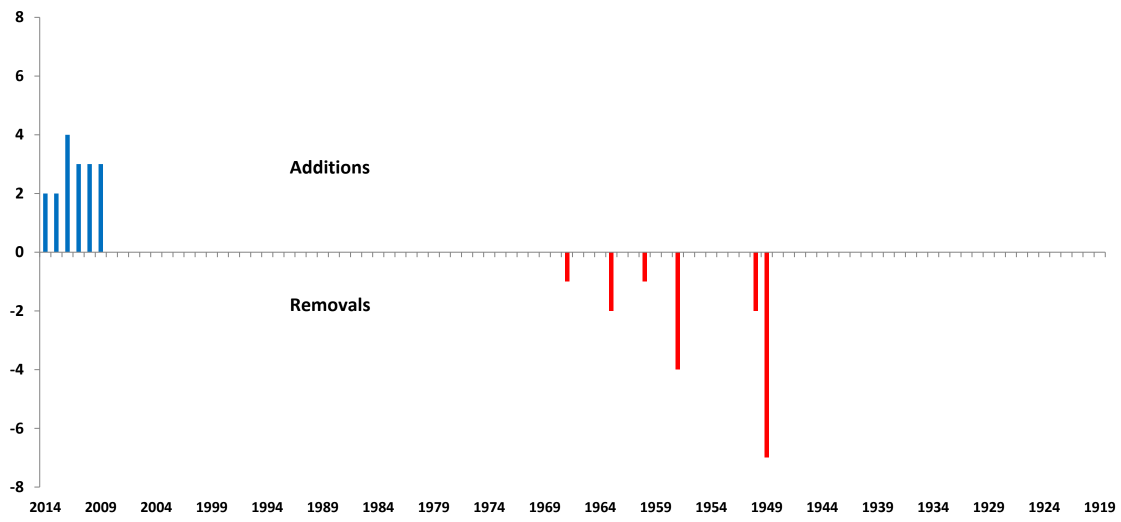
[147] Nuttall consulting used predictive modelling based on historical repex volumes (which match our predictive modelling outcome of nine replacements) and predictive modelling using augex and repex (which predicts 15 replacements).

Figure 6.16 United Energy - changes in power transformer age profile



Source: United Energy, Reset RIN 2010 & CA RIN 2014.

Figure 6.17 United Energy - power transformer additions and removals from the network between 2009 and 2014



Source: United Energy, Reset RIN 2010 & CA RIN 2014x.

The average age of United Energy's power transformer fleet at the end of 2014 is 33.6 years. This is a reduction from the average age observed in 2009, before the last regulatory control period. At that time, the average age of United Energy's power transformers was 37.9 years. United Energy has substantially reduced the average age of its assets over the 2011–15 regulatory control period, leaving fewer old assets in commission.

This health indicator provides a check on whether United Energy's risk has increased over the 2011–15 regulatory control period. As the average age has fallen (and United Energy has concentrated predominantly on replacing the oldest assets in the network), we consider that the risk of failure is likely to have decreased over the last regulatory control period. We note that, since 2004, United Energy has not had a failure of a power transformer or their associated systems leading to the interruption of customers or any significant safety incidents.[148] In 2020, the average age of these assets will be largely consistent with the 2014 observation, at 34.5 years (based on the replacement volume estimated by our repex model). This is not significantly different from the current average age of United Energy's assets, and remains much lower than the average age in 2009. It is also similar to the average age of the power transformer asset fleets for other Victorian distributors, which range between 33 and 40 years. As such, we consider the replacement of approximately nine power transformers over the 2016–20 regulatory control period will allow United Energy to maintain its current approach to managing the risk associated with the operation of its power transformer fleet. Consequently, we consider this volume reasonably reflects the capex criteria[149] and have included it in our alternative estimate of efficient repex.

We have also reviewed United Energy's forecasting method for transformer replacement. United Energy's replacement methodology uses demand to estimate the degradation of its transformers over time.[150] We note that United Energy's forecasts are based on an earlier, higher forecast of demand growth in the 2016–20 regulatory control period, that were submitted with United Energy's initial proposal. United Energy has since accepted a lower forecast of demand in its revised proposal. However, it has not revised its replacement forecast for transformers based on these lower demand forecasts, even though, under its methodology, which is linked to demand, the degradation would be expected to be lower over the 2016–20 regulatory control period. Further, while United Energy stated that it has performed sensitivity analysis on its forecast[151], it has not used demand as part of the sensitivity test[152], despite information from the 2011–15 regulatory control period that demonstrates a link between demand and the output of United Energy's forecasting model.[153] Given the lower demand forecasts, we are not satisfied that United Energy's estimated degradation of its transformer assets supports asset replacement higher than our business as usual estimate.

148 United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 16.

149 NER, cl. 6.5.7(c).

150 United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 13.

151 United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 25.

152 United Energy, *ZSS Transformers Life Cycle Strategy*, p. 53.

153 United Energy indicated that its forecasting model used for the 2011–15 regulatory control period (which is the same prediction model used for the 2016–20 regulatory control period) had overestimated replacement need because demand was not as high as predicted in that period, United Energy, *AER Category Expenditure Explanation Statement –ZSS Transformers*, p. 20.

Un-modelled - Other

In its Revised Regulatory Proposal United Energy proposed $112.2 million for un-modelled other repex. In our Preliminary Decision we provided our alternative estimate of $28 million[154] for un-modelled other repex on the basis that:

- this amount was consistent with the level of expenditure in the 2011–15 regulatory control period; and
- United Energy did not provide business cases to support expenditure above historical expenditure.

We have considered United Energy's proposed expenditure in relation to the categories of expenditure listed in Table 6.11 in the context of the capex criteria and objectives.[155] We are not satisfied that United Energy's proposed $112.2 million for un-modelled other repex reasonably reflects the capex criteria and objectives. We have instead included in our alternative estimate of un-modelled other expenditure an amount of $39 million. We are satisfied this amount reasonably reflects the capex criteria.[156]

Table 6.11 Final decision on United Energy's total forecast un-modelled repex ($2015, million)

Program/project	United Energy Revised Regulatory Proposal	AER Final Decision
ZSS Primary Asset Replacement	10.1	5.3
Non VBRC Safety Projects	6.4	0.0
Operational Technology		
OT Safety	24.5	6.6
OT Reliability	6.8	0.0
OT Other	10.2	0.0
Network Reliability	35.8	9.5
Environment	5.2	4.3
Power Quality	8.0	8.0
Terminal Station Redevelopment	5.2	5.2
Total Un-modelled Repex	**112.2**	**39.0**

Source: United Energy, revised regulatory proposal, January 2016; AER analysis

154 AER, *Preliminary Decision - United Energy distribution determination 2016 to 2020 - Attachment 6 Capital Expenditure*, p. 6-78.

155 NER, cll. 6.5.7(a) and (c).

156 NER, cl. 6.5.7(c).

Our consideration of United Energy's proposed expenditure shown in Table 6.11 is detailed below.

Reliability related expenditure

We have assessed any proposed expenditure that is expected to result in a reduction (i.e. an improvement) in the duration (SAIDI) and/or frequency (SAIFI and MAIFI) [157] of United Energy's interruptions to supply in the context of the capex objectives.[158]

As is discussed in Appendix D.6, United Energy's system wide SAIFI remained relatively stable over the 2010 to 2014 period. We have, however, observed that United Energy’s system wide SAIDI deteriorated over the 2010 to 2014 period.

We recognise that the capital intensive nature of distribution networks makes it prohibitively expensive, and consequently inefficient, to build sufficient capacity to avoid all interruptions to supply. Interruptions to supply on distribution networks should be kept to efficient levels—based on the value of reliability to customers, and the willingness of customers to pay—rather than by a distributor trying to eliminate every possible interruption to supply. We note that the impact of an interruption to supply on a distribution network tends to be localised to part of the network, compared with the potentially widespread impact of a generation or transmission outage.[159]

Our Service Target Performance Incentive Scheme (STPIS)[160] is intended to balance a distributor's incentive to reduce expenditure with its need to maintain or improve service quality. The STPIS achieves this by providing financial incentives to distributors to maintain and improve service performance where customers are willing to pay for these improvements. Under the 'reliability of supply' component of the scheme, a distributor's revenue is increased (or decreased) based on changes in service performance, in accordance with the STPIS. In determining whether United Energy's proposed expenditure reasonably reflects the capex criteria we have considered the network reliability performance targets to be applied through our STPIS.

We note that United Energy's relatively stable system wide SAIFI, and the deterioration in its system wide SAIDI have been reflected in our revised STPIS performance targets to be applied over the 2016–20 regulatory control period (see Appendix D.6, p. 6-121). In particular, we have eased United Energy's SAIDI targets to reflect its deteriorating average SAIDI performance over the past five regulatory years[161]. Notwithstanding the revised SAIDI targets, we consider that there is evidence to suggest that United Energy's declining system wide SAIDI requires some additional expenditure in order for it to meet our revised STPIS performance targets. As such, we have focused our

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[157] We note that all references to SAIDI, SAIFI, MAIFI and CAIDI refer to unplanned interruptions to supply. See AER, *Electricity distribution network service providers - Service Target Performance Incentive Scheme*, November 2009, p. 22 for our standard definitions of these performance measures.

[158] NER, cl. 6.5.7(a)

[159] AER, *Electricity distributors 2011-13 performance report*, June 2015, p. 34

[160] AER, *Service Target Performance Incentive Scheme*, November 2009.

[161] AER, *Service Target Performance Incentive Scheme*, November 2009, s. 3.2.1(a)

assessment of United Energy's proposed reliability related projects and programs on those that are projected to specifically address the duration of interruptions to supply (SAIDI) as opposed to the frequency in which these interruptions occur (SAIFI and MAIFI).

United Energy proposed specific programs and projects that are designed to have a positive impact on network reliability. United Energy's proposed programs/projects and the projected impact on system wide reliability are shown in Table 6.12.

Table 6.12 Summary of United Energy's proposed reliability related programs/projects[162]

Program/project	Projected unplanned SAIDI improvement over reg. period	Projected unplanned SAIFI improvement over reg. period	Projected unplanned MAIFI improvement over reg. period	Proposed capex (Real $2015m)[163]
ACRs and RCGSs[164]	18.39	0.138	-0.138	9.5
Fuse Savers	0.90	0.010	0.000	1.7
Rogue Feeders	0.00	0.000	0.000	5.6
Animal Proofing	4.78	0.021	0.000	10.4
Clashing	3.00	0.000	0.000	4.0
Communication Upgrades	1.80	0.000	0.000	4.5
Operational Technology	3.10	0.000	0.000	6.8
Information Technology	3.10	0.000	1.300	6.0

Source: United Energy, *Network Reliability Assessment*, December 2015.

We have assessed any proposed expenditure that would result in a reduction (i.e. an improvement) in United Energy's SAIDI, SAIFI or MAIFI[165] in the context of the capex objectives and criteria. [166]

[162] We note that the projected SAIDI, SAIFI and MAIFI values have not been summed to provide a 'total' proposed improvement. This is because the respective proposed SAIDI, SAIFI and MAIFI impacts of the individual programs/projects may not mutually exclusive.

[163] We note there are a number of inconsistencies in the proposed capex values provided in United Energy's Network Reliability Assessment (UE PL 2304) and in the supporting project/program documents. For presentation purposes we have displayed the values as they appear in the Network Reliability Assessment (UE PL 2304); however, we have considered the values in the supporting project/program documents.

[164] Automatic Circuit Recloses and Remote Control Gas Switches

[165] We note that all references to SAIDI, SAIFI, MAIFI and CAIDI refer to unplanned interruptions to supply. See *AER, Service Target Performance Incentive Scheme*, November 2009, p. 22 for our standard definitions of these performance measures.

[166] NER, cll. 6.5.7(a) and (c)

As such, it would not be appropriate for us to include proposed expenditure that is expected to improve United Energy's system wide SAIFI (i.e. reduce the frequency of interruptions to supply). This is because the average frequency of sustained interruptions to supply was relatively stable over the 2010 to 2014 period.

We have, however, included a portion of United Energy's proposed reliability expenditure that specifically addresses its declining SAIDI performance as we consider some of this expenditure is appropriate when considered in the context of the capex objectives and criteria.[167] In addition, we consider this expenditure would be seen as appropriate to allow United Energy to meet its revised (albeit lower) SAIDI targets. While we have accepted some of this expenditure, we note that United Energy has proposed multiple projects to address its declining SAIDI performance. While we may consider certain projects and programs in forming a view on our alternative estimate, 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[168] that the AER does not approve specific projects. This means United Energy, during the regulatory control period, may undertake other projects and programs or a different mix of programs identified in its revised proposal to address its declining SAIDI performance.

Our assessment of each reliability focused program and project can be found below.

Network Reliability

Automatic Circuit Recloses (ACRs) and Remote Control Gas Switches (RCGSs)

We have included in our alternative estimate an amount of $9.5 million for the replacement of Automatic Circuit Recloses (ACRs) and Remote Control Gas Switches (RCGSs). We consider this expenditure will allow United Energy to address its worsening SAIDI performance and enable it to meets its revised STPIS performance targets for the 2016-20 regulatory control period. We are satisfied that United Energy's proposed expenditure of $9.5 million for the replacement of ACRs and RCGSs reasonably reflects the capex objectives and criteria. [169]

United Energy indicated that installing ACRs will sectionalise its network into smaller segments, thereby reducing the impact of faults by reducing the number of customers impacted. [170] United Energy also indicated that installing RCGSs will enable a faulted section to be more easily identified by network control so that customers that can be isolated from the faulted part of the network and improve restoration time. [171]

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[167] NER, cll. 6.5.7(a) and (c).

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

[169] NER, cl. 6.5.7(a) and (c)

[170] United Energy, *Network Reliability Assessment*, December 2015, p. 49.

[171] United Energy, *Network Reliability Assessment*, December 2015, p. 49.

We note that United Energy's revised network SAIDI target, to be applied through the STPIS during the course of the 2016-20 regulatory control period, is approximately 67.6 minutes per customer (see Attachment 11). United Energy has projected an improvement of 18.39 minutes per customer over the 2016–20 regulatory control period through its proposed $9.5 million investment in its ACRs and RCGSs program[172]. Relevantly, this level of improvement is expected to enable United Energy to achieve the revised STPIS targets.[173]

As previously mentioned, the STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service quality, including network reliability. It achieves this by providing financial incentives to distributors to maintain and improve service performance where customers are willing to pay for these improvements. As such, we consider this expenditure is consistent with the capex objectives and criteria.[174]

We consider that given the expected SAIDI improvement as a result of our inclusion of United Energy's proposed expenditure on ACRs and RCGSs in our forecast allowance, the inclusion of the following additional reliability related expenditure, totalling nearly $39 million, does not meet the capex criteria.

The following programs/projects have not been included in our assessment of United Energy's capex requirements over the 2016–20 regulatory control period:

- Animal Proofing ($10.4 million)
- Communication Upgrade ($4.5 million)
- Clashing ($4 million)
- Distribution Fault Anticipation, Data Collection & Analytics (DFADCAA) ($3.9 million)
- OMS Smart Grid Gateway Extension ($3 million)
- DMS LV Management ($3 million)
- Fault Location Identification and Application Development (FLIAD) ($2.8 million)
- Fuse Savers ($1.7 million). [175]

As previously discussed (see page 73), the inclusion in our alternative estimate of United Energy's proposed ACRs and RCGSs expenditure is expected to address its deteriorating SAIDI performance and assist it to meet its STPIS performance targets for the 2016–20 regulatory control period. It follows that United Energy's proposed expenditure on the programs/projects identified above, in conjunction with the

[172] United Energy, *Network Reliability Assessment*, December 2015, p. 49.
[173] See attachment 11.
[174] NER, cll. 6.5.7(a) and (c).

approved ACRs and RCGSs expenditure, would result in improving, rather than maintaining network reliability. As such, we are not satisfied that United Energy's proposed expenditure on these programs/projects meets the capex objectives and criteria. [176] Any additional capex that results in improvements to network reliability that are valued by customers will be funded through the STPIS.

Rogue Feeders

United Energy's revised proposal of $5.6 million for its 'Rogue Feeders' program has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy's 'Rogue Feeder' program focuses on those feeders and customers that experience a high volume of faults when compared to the network average and thereby manages some of the financial risk associated with Guaranteed Service Levels (GSLs). [177]

We note United Energy's operating expenditure includes a component that accounts for the payment of GSLs to its worst served customers. As this opex does not take into account any reliability improvements to worst served customers, we consider the approval of capital expenditure for United Energy's 'Rogue Feeder' program would provide United Energy with a GSL allowance that is likely to be overstated.

For these reasons, along with the reasons identified in our assessment of the programs/projects above, we are not satisfied that United Energy's proposed expenditure on its 'Rogue Feeders' program meets the capex objectives and criteria. [178]

Safety related expenditure (Non-VBRC safety projects)

We have assessed any proposed expenditure that would result in an improvement to United Energy's network safety in the context of the capex objectives and criteria. [179]

Intelligent secure substation management

United Energy's revised proposal of $6.4 million for its 'Intelligent Secure Substation Asset Management' (ISSAM) program has not been included in our assessment of its capex requirements over the 2016-20 regulatory control period.

United Energy submitted that under its proposed 'ISSAM program', CCTV will be installed at zone substations over the five year period ending in June 2021. United Energy submitted that the principal driver behind its 'ISAAM' project is to maintain safety and security in the face of increased security risks. [180]

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176 NER, cll. 6.5.7(a) and (c)

177 United Energy, *Network Reliability Assessment*, December 2015, p. 54.

178 NER, cll. 6.5.7(a) and (c)

179 NER, cll. 6.5.7(a) and (c)

180 United Energy, *Intelligent Secure Substation Asset Management (ISSAM) (UE PL 2401),* p. 10.

We do not consider that United Energy has provided sufficient justification for its proposed expenditure on its 'ISAAM' project. United Energy has not provided any evidence of existing, or increasing security risks at zone substations, nor has it quantified any potential benefits to the proposed installation.

Absent such justification we are not satisfied that the proposed expenditure for the 'ISAAM' project meets the capex objectives and criteria. [181]

Operational Technology (Safety)

Service Mains Deterioration Field Works

United Energy's revised proposal of $4.2 million[182] for its 'Service Mains Deterioration Field Works' project has been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy submitted that its 'Service Mains Deterioration Field Works' consists of upgrading the Advanced Metering Infrastructure (AMI) communications network to provide sufficient bandwidth to satisfy the mandated AMI requirements. United Energy has indicated that it does not consider that its current AMI network is able to meet the additional bandwidth requirements that will be imposed. However, the AMI Communications network can be modified to meet the mandated smart meter requirements and cater for the additional meter data required. [183]

United Energy submitted that the expected benefits of its 'Service Mains Deterioration Field Works' project include:

- improving Neutral Integrity Testing safety governance by automating and recording Neutral Testing issues, and
- improving safety for its workforce, customers and the public who could be impacted by related Neutral Integrity issues. [184]

United Energy stated:

> The Service Mains Deterioration Field Works Project performs the field works component for automated Neutral Integrity Testing. It delivers benefits in conjunction with the In Meter Capability Project (described below) and the Network Analytics (IT) Project. [185]

We consider that this proposed expenditure will improve the targeting of service line replacements such that United Energy may be able to better manage these associated

[181] NER, cll. 6.5.7(a) and (c).
[182] Not discounted.
[183] United Energy, *Service Mains Deterioration Field Works (UE PJ 1385)*, p. 4.
[184] United Energy, *Service Mains Deterioration Field Works (UE PJ 1385*), p. 4.
[185] United Energy, *Network Safety Assessment*, December 2015, p. 48.

risks (see page 58). We note that United Energy's revised proposal of $2.3 million[186] to allow it to meet its regulatory inspection and testing obligations[187] has also been included in our assessment of its opex requirements (see Attachment 7) over the 2016-20 regulatory control period.

As such we consider United Energy's proposed capex will allow it to continue to meet its regulatory inspection and testing obligations, while avoiding the need to undertake bulk replacements of service lines as acknowledged by United Energy.[188]

As such, we are satisfied that United Energy's proposed expenditure for its 'Service Mains Deterioration Field Works' project is consistent with the capex objectives and criteria. [189]

In Meter Capabilities

United Energy's revised proposal of $2.4 million[190] for its 'In Meter Capabilities' (IMC) project has been included in our assessment of its capex requirements over the 2016-20 regulatory control period.

United Energy submitted that the key driver for the proposed 'IMC' project is the requirement to satisfy its statutory obligation to minimise as low as reasonably practicable (ALARP) the safety risks arising from its electricity network. [191]

United Energy's proposed 'IMC' project enables IMC applications to be implemented via the AMI network wireless communication without the need for site visits. [192] United Energy submitted that the objectives of 'IMC' project are to take advantage of the underutilised AMI meter capability and expand functionality to provide greater real-time insights of network issues at or near customers' premises. Relevantly, United Energy stated that one specific initiative is to use IMC to provide a more effective risk management associated with neutral integrity at customers' premises. [193]

As stated above, United Energy submitted that the IMC projects will deliver benefits in conjunction with the Service Mains Deterioration Field Works project related to the effective risk management of neutral integrity issues. [194] In particular, we consider that this expenditure will improve the targeting of service line replacements such that United Energy may be able to better manage these associated risks (see page 58).

186 United Energy, *Project Justification - Network Analytics (UE PJ 12)*, p. 26.
187 *Electricity Safety (Network Assets) Regulations 1999*, r. 27(2).
188 *Electricity Safety (Network Assets) Regulations 1999*, r. 27(2).
189 NER, cll. 6.5.7(a) and (c).
190 Not discounted.
191 United Energy, In Meter Capabilities (IMC) (UE PJ 1386), p. 4.
192 United Energy, In Meter Capabilities (IMC) (UE PJ 1386), p. 4.
193 United Energy, In Meter Capabilities (IMC) (UE PJ 1386), p. 4.
194 United Energy, *Network Safety Assessment*, December 2015, p. 48.

As such, we are satisfied that United Energy's proposed expenditure for its 'IMC' project is consistent with the capex objectives and criteria. [195] Accordingly, we have included in our alternative estimate an amount of $2.4 million for United Energy's 'IMC' project.

DNSP Intelligent Network Device

United Energy's revised proposal of $5.2 million[196] for its 'DNSP Intelligent Network Device' project has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy's proposed 'DNSP Intelligent Network Device' project is focused on ensuring its customers do not experience deterioration in safety following the introduction of metering competition. [197]

We do not consider that United Energy has provided sufficient evidence to support its view that there will be an increased safety risk following the introduction of metering competition. United Energy stated that:

> This project is focused on maintaining safety. It ensures that customers do not experience a deterioration in safety following the introduction of metering competition.
>
> The following projects will deliver a combined reduction of 50% in the number of shocks experienced by our customers:
>
> - PJ1385 Service Mains Deterioration Field Work; and
> - PJ1386 In Metering Capability.
>
> The forecast 50% reduction in the number of electric shocks can be achieved by these two projects with relatively low levels of capital expenditure. [198]

We note that United Energy's business case forecast that metering contestability will impact on less than one per cent of its existing AMI meters. While United Energy has not substantiated this safety risk, this indicates that any negative impact on United Energy's safety risk as a result of metering contestability would be expected to be negligible over the 2016–20 regulatory control period.

As such, we are not satisfied that the proposed expenditure for the 'DNSP Intelligent Network Device' project is consistent with the capex objectives and criteria. [199]

195 NER, cll. 6.5.7(a) and (c).

196 Not discounted

197 United Energy, *DNSP Intelligent Network Device (UE PJ 5002),* p. 4

198 United Energy, *DNSP Intelligent Network Device (UE PJ 5002),* p. 4

199 NER, cll. 6.5.7(a) and (c).

Light Detection and Ranging Asset Management

United Energy's revised proposal of $6.8 million[200] for its 'Light Detection and Ranging' (LiDAR) Asset Management project has not been included in our assessment of its capex requirements over the 2016-20 regulatory control period.

United Energy's proposed 'LiDAR' project utilises technology and associated software to perform targeted surveys of the network to identify poles and conductor spans that represent a risk to safety. It also identifies vegetation encroachment issues in high risk areas and updates and verifies United Energy's Geographic Information System and asset databases. [201]

United Energy submitted that its proposed LiDAR project will improve network safety by augmenting the current audit processes relating to physical assets, as well as mitigating the bushfire risks arising from currently undetected network issues. It will also provide secondary benefits in the form of future capital expenditure efficiencies. [202]

United Energy also stated that the 'LiDAR' project will deliver capex efficiencies by increasing planned replacement and minimise the need for physical survey work for some planned distribution works.[203]

We note that the primary driver for this project is to improve safety. However, we note United Energy's business case indicates that this project will not provide a net benefit to customers.[204] This means that the expected benefit or avoided costs (in terms of the value of any reduced risk) is expected to be less than the proposed expenditure.

As there is not a positive business case to support the safety improvements we are not satisfied that the proposed expenditure for the 'LiDAR' project is consistent with the capex objectives and criteria. [205]

Operational Technology Security

United Energy's revised proposal for its Operational Technology Security[206] project has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy submitted that the principal driver for this project is to maintain safety in accordance with its regulatory obligations.[207] United Energy noted that the proposed

200 Not discounted.
201 United Energy, *Project Justification Light Detection and Ranging (LiDAR) Asset Management*, p. 4.
202 United Energy, *Project Justification Light Detection and Ranging (LiDAR) Asset Management*, p. 5.
203 United Energy, *Project Justification Light Detection and Ranging (LiDAR) Asset Management*, p. 15.
204 United Energy, *Project Justification Light Detection and Ranging (LiDAR) Asset Management*, p. 4.
205 NER, cll. 6.5.7(a) and (c).
206 United Energy, *OT Security (UE PJ 1500)* (confidential), p. 4.
207 United Energy, *OT Security (UE PJ 1500)* (confidential), p. 4.

expenditure on its Operational Technology Security project provides no offsetting benefits in terms of reliability improvements or expenditure efficiencies.[208]

We note that the proposed Operational Technology Security project is not supported by any evidence in its business case to demonstrate a history of actual or increasing security risks related to its network. In particular, United Energy has not provided any evidence to support its view that this project is necessary to maintain safety.

As such, we are not satisfied that United Energy's proposed expenditure for its Operational Technology Security project is consistent with the capex objectives and criteria. [209]

Zone Sub-Station Primary Replacement

Zone Sub-station Capacitor Banks

United Energy's revised proposal of $4.8 million for its 'Zone Substation capacitor banks' program has not been included in our assessment of its capex requirements over the 2016-20 regulatory control period. We are not satisfied that United Energy's proposal of $4.8 million for its 'Zone Substation capacitor banks' program reasonably reflects the capex objectives and criteria.[210] We have instead included an amount of $0.7 million in our alternative estimate for the reasons explained below.

We note United Energy's revised proposal of $4.8 million represents a large increase from $0.7m of actual expenditure over the 2011–15 regulatory control period.

United Energy has historically installed capacitor banks at various zone substations throughout its network in order to correct power factor[211] and improve the utilisation of the capacity of the network. [212]

United Energy submitted that under its proposed 'Zone Substation capacitor banks' program it proposes replacing five capacitor banks over the 2016–20 regulatory control period. [213] In 2012 United Energy initiated a program wherein it proactively replaces capacitor banks aged 50 years or older, prioritised by condition. Under the program, the first capacitor bank replacement occurred during 2014–15 with annual replacements to be undertaken throughout the 2016–20 regulatory control period. United Energy has submitted that that it has no way of determining the condition (in this case oil levels) of these assets.[214]

United Energy stated:

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208 United Energy, *OT Security (UE PJ 1500)* (confidential), p. 11.

209 NER, cll. 6.5.7(a) and (c).

210 NER, cll. 6.5.7(a) and (c).

211 Improves energy efficiency.

212 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 8.

213 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 14.

214 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 11.

The replacement strategy is based on the average life span of 60 years for large Ducon capacitors and 40 years for small capacitors. A large number of these Ducon capacitors are showing age related degradation problems and need to be replaced in a timely manner before failure … When opportune UE will also align capacitor bank replacements with other related capex replacement programs/projects e.g. capacitor bank circuit breaker replacements. UE believes this strategy maximises project efficiencies and minimises cost duplication. [215]

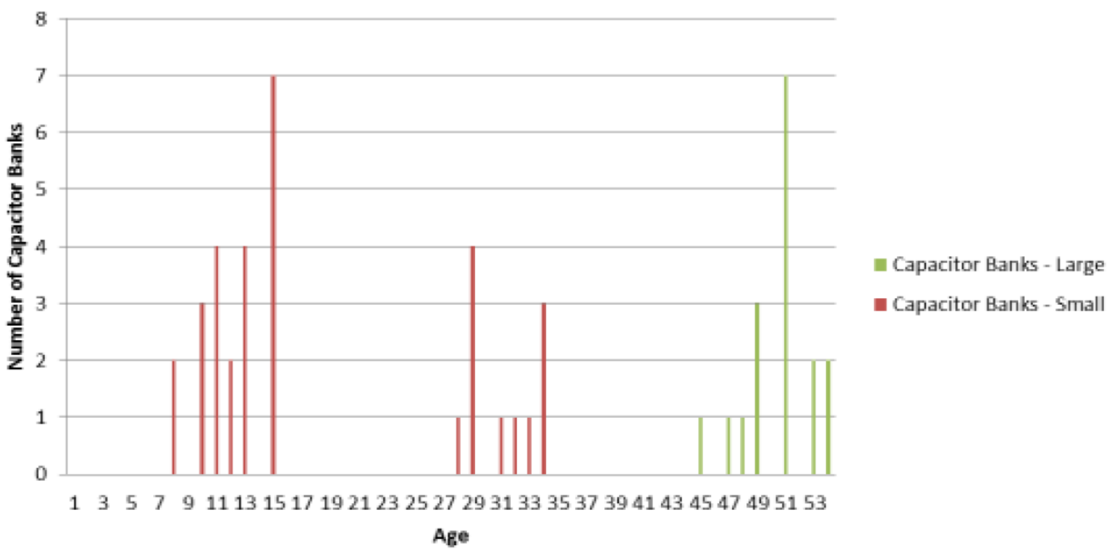
and:

Capacitor banks are non-critical network components; however the consequences of failure can be significant. At best, a failure causes the substation transformation capacity to be marginally reduced during times of peak load; at worst, the above effects are combined with a significant release of PCB-contaminated oil, and plant fire. [216]

We also note that United Energy has submitted that it has on average three capacitor bank failures per annum.[217] However, United Energy did not indicate whether these failures include large capacitor banks.

As shown in Figure 6.18, United Energy has an age profile for its large capacitor banks of between 45 and 50 years of age.

Figure 6.18 Zone Substation Capacitor Banks - Age Profile



Source: United Energy, Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors, Figure 3, p. 8

[215] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 9.

[216] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 8.

[217] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 11.

This age profile indicates that the oldest assets in commission will still be below their expected average asset life by the end of the 2016–20 regulatory control period. Further, while United Energy refers to the 'significant consequences of asset failure' it has not quantified the project risk (avoided costs) from implementing its proposed proactive replacement program.

We note that the unit cost of a large capacitor bank replaced in in 2014–15 was around $0.5 million. [218] However, United Energy forecast a unit cost of around $1 million for its proposed five large capacitor bank replacements over the 2016–20 regulatory control period.

Given the age profile of United Energy's assets, the lack of risk analysis and the likelihood the proposed costs are overstated (see previous paragraph) we are not satisfied that the step increase in expenditure is likely to reasonably reflect the capex criteria for the achievement of the capex objectives and criteria.[219] We have instead included United Energy's business as usual expenditure of $0.7 million in our alternative estimate.

Zone Sub-Station Earth Grids

United Energy's revised proposal of $1 million for its 'Zone Substation Earth Grids' program has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period. We are not satisfied that the proposal of $1 million for its 'Zone Substation Earth Grids' program reasonably reflects the capex objectives and criteria.[220] Instead we have included an amount of $0.7 million based on United Energy's estimated spend in the last regulatory control period. [221]

United Energy submitted that under its proposed 'Zone Substation Earth Grids' program, earth grids will be inspected over the 2016–20 regulatory control period. Replacement/augmentation works will be undertaken after completion of the audits at the various locations.[222] We note that zone substation earth grids are installed at the time of construction of the zone substation and generally match the installation age.

United Energy stated:

> The earth grids in zone substations are considered to be in good condition/performance. Failures are primarily due to third party damage from excavations or vehicles, and changes in ground conditions. [223]

We note that additional expenditure on the 'Zone Substation Earth Grids' program will not impact on failures caused by third parties.

[218] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 10.
[219] NER, cll. 6.5.7(a) and (c)
[220] NER, cll. 6.5.7(a) and (c)
[221] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 13.
[222] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 7.
[223] United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 14.

United Energy also stated that:

> Overall, UE is satisfied with the asset performance in the current period, indicating that the level of expenditure on this asset class [Zone Substation Earth Grids] is appropriate. [224]

While the findings from earth grid inspections is not yet known[225] United Energy submitted that its proposed amount is significantly lower than its previous expenditure of $1.5 million in the last five years.[226]. However, we note that the relative data provided by United Energy reflects that its actual expenditure was about $0.7 million over the 2011–15 regulatory control period[227]. We are satisfied that expenditure of $0.7 million for the 'Zone Substation Earth Grids' program reasonably reflects the capex criteria for the achievement of the capex objectives and criteria[228] on the basis that:

- existing asset performance does not indicate that there are likely to be safety related issues; and
- recent historical expenditure has been sufficient to maintain existing levels of performance.

Zone Sub-Station Neutral Earthing Resistor

United Energy has proposed capital expenditure to replace a single neutral earthing resistor in the 2016–20 regulatory control period at a cost of $0.1 million. [229] United Energy submitted that it is already undertaking this work. We are satisfied that United Energy's proposed repex of $0.1 million for replacing a single neutral earthing resistor in the 2016–20 regulatory control period reasonably reflects the capex objectives and criteria.[230]

United Energy indicated that the project was scheduled to commence in 2015 and is expected to be completed in 2016. United Energy submitted that due to the small value of the project, and because it was to be commenced in the 2011-15 regulatory control period, no further comment was provided'. [231]

While limited information has been provided, we note that the proposed expenditure is lower than United Energy's expenditure over the 2011-15 regulatory control period. As

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224 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 13.
225 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 12.
226 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 13.
227 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, Figure 6, p. 13.
228 NER, cll. 6.5.7(a) and (c)
229 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 7.
230 NER, cll. 6.5.7(a) and (c)
231 United Energy, *Expenditure Justification - ZSS Capacitor Banks, Earthing and Neutral Earthing Resistors*, p. 7.

such, we are satisfied that United Energy's proposed expenditure for replacing a single neutral earthing resistor reasonably reflects the capex objectives and criteria. [232]

Zone Sub-Station Transformer Instrumentation

United Energy's Revised Regulatory Proposal made reference to, but did not provide documentation or propose a cost for its 'Zone Sub-Station Transformer Instrumentation' project. [233]

Zone Substation Buildings

We are satisfied United Energy's revised proposal of $3.8 million for 'Zone Substation Buildings' reasonably reflects the capex criteria[234], and therefore has been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy has submitted that it is proposing replacing one building at Springvale Zone Substation, and decommissioning another building at Dandenong Zone Substation following a number of civil engineering reports assessing the structural integrity and safety of the buildings.[235]

United Energy's total forecast expenditure is comparable to its expenditure of $4.0 million over the 2011–15 regulatory control period.[236] As such, we are satisfied that United Energy's proposed expenditure for the 'Zone Substation Buildings' program reasonably reflects the capex criteria for achieving the capex objectives and criteria. [237]

Operational Technology (Other)

Dynamic Rating Monitoring Control Communication

We are not satisfied that United Energy's revised proposal of $2.2 million[238] for its 'Dynamic Rating Monitoring Control Communication' (DRMCC) is consistent with the capex criteria and objectives. [239] As such, United Energy's proposed expenditure has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy's principal driver behind its 'DRMCC' project is to increase capex efficiency through the provision of comprehensive transformer monitoring and control solution for Zone Substation power transformers. [240]

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[232] NER cll. 6.5.7(a) and (c)

[233] United Energy, *2016 to 2020 Revised Regulatory Proposal*, 6 January 2016, Table 5-21 p. 39.

[234] NER, cll. 6.5.7(c).

[235] United Energy, *AER Category Expenditure Justification - Zone Substation Other Buildings*, April 2015, p. 10.

[236] United Energy, *AER Category Expenditure Justification - Zone Substation Other Buildings*, April 2015, p. 4.

[237] NER, cll. 6.5.7(a) and (c).

[238] Not discounted.

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

[240] United Energy, *Dynamic Rating Monitoring Control Communication (DRMCC) (UE PJ 1413),* p. 4.

We note that United Energy has submitted that this project is a pilot scheme to determine the net benefits from wider deployment of the scheme. United Energy considers that the net benefits, which are uncertain and not quantified, include:[241]

- avoidance of transformer augmentation
- avoidance of catastrophic failure; and
- transformer life extension.

In reviewing these benefits we note that United Energy stated that there is limited transformer augmentation over the 2016–20 regulatory control period. As such it is expected that there would be limited benefits in terms of any deferred transformer augmentation. We also note that United Energy considers that the likelihood of catastrophic failure is not likely.[242] As noted on page 6-68, United Energy has not experienced a power transformer failure since 2004. Finally, we note that United Energy has not proposed any life extension for its power transformers and we have provided a business as usual allowance on the basis of no life extensions. In particular, United Energy has projected capex efficiencies (albeit uncertain) from undertaking the proposed 'DRMCC' project. As these efficiencies are not reflected in United Energy's forecast, we consider the costs of the project should not be funded by customers.

Pilot Schemes

United Energy's revised proposal of $7 million for its 'Pilot New and Innovative Technologies' project and $1 million for its 'Test Harness' project (pilot schemes) has not been included in our assessment of its capex requirements over the 2016–20 regulatory control period.

United Energy's pilot schemes are intended to develop the automation of meter testing.[243]

We note that the benefits of conducting the proposed 'Pilot New and Innovative Technologies' project have not been quantified. United Energy's Project Justification document stated that the potential benefits are 'to be determined'.

We do not consider that United Energy has provided sufficient justification or evidence to support the proposed 'Pilot New and Innovative Technologies' project. United Energy considers the benefits of conducting the scheme will include:

- avoidance of costs of transformer failure
- extended transformer life; and
- lower transformer testing costs.

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241 United Energy, *Dynamic Rating Monitoring Control Communication (DRMCC) (UE PJ 1413)*, p. 5.

242 United Energy, *Dynamic Rating Monitoring Control Communication (DRMCC) (UE PJ 1413)*, Table 2, p. 5.

243 United Energy, *Test Harness (UE PJ 1398)*, p. 4

However, we consider United Energy has not provided evidence to support these expected benefits from undertaking the project. We consider these benefits appear to be uncertain, and, we note that United Energy does not appear to have assumed any life extensions in terms of its proposed transformer replacement which appears to confirm our assessment. Therefore, our estimate for business as usual transformer replacement (see page 65) does not reflect any expected efficiencies. As this project is expected to provide capex efficiencies by reducing business as usual transformer expenditure below business as usual requirements, this project should not be funded by customers.

We do not consider that United Energy has provided sufficient justification for its proposed expenditure on its 'Test Harness' project. In particular, we consider United Energy's expected benefits (e.g. capex efficiencies from expected increases in future capitalised labour costs) from undertaking the project are uncertain with no supporting evidence to support its expectations.[244] We also note that United Energy has projected capex efficiencies from undertaking the proposed 'Test Harness' project.

As such, we are not satisfied that United Energy's proposed expenditure on its pilot schemes is likely to reflect the capex objectives and criteria.

Environment

We have included in our alternative estimate an amount of $4.3 million for United Energy's 'Environment' program over the 2016–20 regulatory control period. We consider our alternative estimate amount of $4.3 million is consistent with United Energy's historical expenditure and is likely to reasonably reflect the capex criteria for the achievement of the capex objectives. [245]

United Energy submitted that its environmental projects are driven by requirements of legislation related to environmental protection and to provide a safe workplace for its staff and contractors, customers and stakeholders. United Energy's proposed environmental expenditure of $5.2 million [246] covers initiatives for:

- oil containment ($1.7 million)
- noise abatement ($1.9 million)
- asbestos removal ($0.6 million)
- land management ($0.3 million); and
- climate resilience ($0.7 million).

United Energy submitted that:

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244 United Energy, RRP 5-25a - Test Harness PJ1398 - Jan 2016.

245 NER, cll. 6.5.7(a) and (c).

246 United Energy, *Expenditure Justification - Environment*, December 2015, p. 9.

> UE's forecast is based on continuing the [substation oil containment] program of works by installing fully compliant oil and water separation technology at the five highest priority risk sites over the next 5 years. [247]

As United Energy has stated that this expenditure relates to a continuation of its 'Oil substation and containment' program, this program is expected to be consistent with its 'business as usual' asset replacement expenditure. Given this program should be consistent with its business as usual expenditure we consider that this proposed expenditure is reasonably likely to satisfy the capex criteria and objectives.[248]

United Energy submitted that:

> The implementation of the [current] noise [Environmental Improvement Plan] EIP is an ongoing program which has achieved positive environmental results to date (reduction of noise emissions at 14 zone substations which previously exceeded EPA Guidelines. [249]

Again, as United Energy has stated that this expenditure relates to an ongoing application of its 'Noise Environmental Improvement Plan', this program is expected to be consistent with its 'business as usual' asset replacement expenditure. As such, we consider that this proposed expenditure is reasonably likely to satisfy the capex criteria and objectives.[250]

United Energy submitted that:

> UE has forecast for the next regulatory period a modest amount of $110K per annum, to address the removal of asbestos from some of the medium risk assets and/or those assets that become friable as a consequence of age or disturbance. [251]

Given United Energy's safety obligations related to asbestos removal remain unchanged, we consider that United Energy's proposed expenditures on its 'Asbestos Removal' project should be consistent with its 'business as usual' expenditure. As such, we consider this proposed expenditure is reasonably likely to satisfy the capex criteria and objectives. [252]

United Energy proposed expenditure for its 'Climate Resilience' program so as to change design standards to enhance the resilience of its network. United Energy stated its proposed approach is to:

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[247] United Energy, *Expenditure Justification - Environment,* December 2015, p. 10.

[248] NER, cll. 6.5.7(a) and (c).

[249] United Energy, *Expenditure Justification - Environment*, December 2015, p. 10.

[250] NER, cll. 6.5.7(a) and (c).

[251] United Energy, *Expenditure Justification - Environment*, December 2015, p. 11.

[252] NER, cll. 6.5.7(a) and (c).

> …continue investigations and assessments in the first few years of the next regulatory period before considering the appropriate capital investment strategy to manage risks posed on the network by a changing climate. [253]

United Energy also stated:

> Climate resilience is to be addressed in the forthcoming regulatory period [2016-20] for the first time. [254]

We note United Energy has not provided a positive business case to quantify the expected benefit or avoided costs (in terms of the value of any reduced risk) of the proposed expenditure on its 'Climate Resilience' program. We also note that United Energy stated it will continue to investigate strategies to improve the resilience of the network. This statement suggests that this activity is already embedded in its business practices.

As such, we are not satisfied that United Energy's proposed $0.7 million expenditure for the 'Climate Resilience' program is consistent with the capex objectives and criteria. [255]

United Energy submitted that:

> In line with the updated National Environment Protection (Assessment of Site Contamination) Measure 1999 (NEPM), UE have developed a program to undertake detailed site investigations at potential high risk sites to determine the required environmental management measures and remediation assessments to meet the NEPM requirements. The land management program is a continuation of detailed site assessment works undertaken at 3 selected higher risk sites in 2014/15 in response to the amended regulatory guidelines for contaminated sites. [256]

We note that United Energy's refers to updated regulatory obligations and United Energy expects to incur modest expenditure in 2015. United Energy has proposed site assessments for 10 zone substations and four distribution sites over the 2016–20 regulatory control period. However, United Energy has not provided evidence to support the impact (number of site investigations) of any updated obligations. As a result we have provided United Energy with an amount which reflects its estimated historical expenditure of $0.2 million over five year period. On the basis that three sites were undertaken in 2014–15, our alternative estimate is expected to cover a similar number of sites (but assumes a lower cost per site as proposed by United Energy). We

[253] United Energy, *Expenditure Justification - Environment*, December 2015, p. 10.

[254] United Energy, *Expenditure Justification - Environment*, December 2015, p. 8.

[255] NER, cll. 6.5.7(a) and (c).

[256] United Energy, *Expenditure Justification - Environment*, December 2015, p. 11.

are satisfied that our alternative estimate will reflect the capex criteria and objectives.[257]

Power quality

We have included in our alternative estimate United Energy's revised proposal of $8 million[258] for its 'Power Quality Maintained' program over the 2016–20 regulatory control period. This expenditure, with the exception of its forecast for its Low Voltage Regulators project, is consistent with its historical 'Power Quality maintained' expenditure.

United Energy submitted that its 'Power Quality Maintained' program for the 2016–20 regulatory control period includes power quality initiatives to prevent deterioration in the quality of supply performance predominantly due to uptake of solar photovoltaic (PV) systems and increased use of power electronic appliances.[259]

United Energy has submitted that the objective of the 'Power Quality Maintained' program is to identify and target particular areas of its network where known or emerging power quality regulatory compliance issues have been identified, particularly those identified by our recently installed smart meters. Following detailed modelling and analysis of measured data, United Energy plans to apply corrective measures to enable it to maintain power quality.[260]

United Energy's 'Power Quality Maintained' program includes proposed expenditure on the installation of:

- Harmonic Filters ($3.9 million)
- Low Voltage Regulators ($2.6 million)
- Bus-Tie Open Schemes (BTOS) ($0.7 million), and
- 'Other' Power Quality meters ($0.8 million).[261]

United Energy submitted that the proposed 'Low-Voltage Regulator' program involves installing self-automated voltage regulators on its LV system to contribute to the maintenance of its quality of supply levels.[262] The 'Low-Voltage Regulator' program targets problems such as flicker and voltage excursions.

United Energy stated:

> … with the introduction of AMI, UE has better knowledge of the quality of supply issues on the LV network. Some LV systems have been identified as

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257 NER, cl. 6.5.7(a).

258 Not discounted.

259 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 6.

260 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 8.

261 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 14.

262 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 14.

> operating beyond the limits specified in the Distribution Code and a new program of work has been initiated and will be continued in the forecast period, to install electronic LV regulator equipment to provide localised LV regulation so that the networks comply with the Code.[263]

United Energy also stated:

> UE plans to install LV regulators at 60 sites at a rate of completing 10 sites every year over the 2016-2020 regulatory control periods. Installation will commence at the 10 worst performing. The site selection is carried out based on the analysis of data from AMI meters. [264]

United Energy submitted that the LV regulators installed over the 2011-15 regulatory control period have demonstrably tightened-up the voltage regulation window and provided faster response to sudden changes in voltage. [265] We accept United Energy's 'step change' increase in capex for its 'Low-Voltage Regulator' program on the basis that it has identified quality of supply issues in the context of meeting its regulatory obligations as specified in the Code.[266]

As such, we are satisfied that United Energy's proposed expenditure on its 'Power Quality Maintained' program of $8 million is consistent with the capex objectives and criteria. [267]

Terminal Station Redevelopments

We have included in our alternative estimate United Energy's revised proposal of $5.2 million[268] for its 'Terminal Station Redevelopments' program [269] [270] over the 2016–20 regulatory control period. We are satisfied that United Energy's proposed repex of $5.2 million for its Terminal Station Redevelopments reasonably reflects the capex criteria.[271]

Subsequent information provided by United Energy[272] indicated that it has already spent a combined $2.2 million (of the total $7.4 million gross capex[273]) on the terminal station redevelopment projects during the 2011–15 regulatory control period. United

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263 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 17.

264 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 17.

265 United Energy, *Expenditure Justification - Power Quality Maintained*, December 2015, December 2015, p. 9.

266 Electricity Distribution Code.

267 NER, cll. 6.5.7(a) and (c)

268 Not discounted.

269 United Energy, Richmond Terminal Station (RTS) Redevelopment - 66kV Line & Secondary Works, EDPR Business Case.

270 United Energy, Heatherton Terminal Station (HTS) Redevelopment - 66kV Line & Secondary Works, EDPR Business Case.

271 NER, cll. 6.5.7(a) and (c).

272 In response to AER Information request #53, 21 March 2016.

273 United Energy net capex plus AusNet Transmission Group contribution of $3.3 million.

Energy submitted that the AusNet Transmission Group has committed to pay a combined $3.3 million of the remaining $5.2 million.

As this program is necessary given the Richmond Terminal Station and Heatherton Terminal Station rebuilds, we are satisfied that United Energy's 'Terminal Station Redevelopments' program reasonably reflects the capex objectives and criteria. [274]

Bushfire Mitigation Expenditure

Forecast bushfire safety capex - overview

In our preliminary decision, we did not accept United Energy's proposed $74.8 million ($2015) for its bushfire mitigation and safety program. Our alternative allowance was instead set at $34.8 million ($2015).

In its revised proposal United Energy set out $53.3 million for bushfire mitigation and other safety measures. This amount included some business as usual capex. [275] This amount reflects a decrease of $21.5 million from the expenditure United Energy submitted in its initial proposal.

United Energy's revised proposal included:

- $7.5 million for two rapid earth fault current limiters (REFCLs)
- $30.2 million for the accelerated replacement of defective HV ABC cable; and
- $15.5 million for armour rods, vibration dampeners, spacers, connectors, LV ABC cable and other conductors.

United Energy's revised amount reflected its acceptance of our preliminary decision to reject its SWER replacement program. This resulted in a substantial decrease in the total proposed expenditure for its bushfire mitigation and safety program.

United Energy's revised amount included an increase in expenditure on its proposed HV ABC program. This increase was associated with recent amendments to its regulatory obligations. [276] We note that under the Victorian electrical safety framework, when an Electrical Safety Management Scheme (ESMS) or Bushfire Mitigation Plan is accepted by Energy Safe Victoria (ESV), the components set out in that plan become regulatory obligations.

United Energy's revised amount also included a decrease in expenditure on its proposed REFCL program.

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[274] NER, cll. 6.5.7(a) and (c).

[275] United Energy, *Revised Regulatory Proposal*, Table 5-20, item 4, VBRC projects, p. 40.

[276] United Energy's revised 2014/19 Fire Prevention Plan, Version 3 and Bushfire Mitigation Plan and Electrical Safety Management Scheme (ESMS) were accepted by Energy Safe Victoria (ESV). The accepted amendments to the Plan and ESMS relate to the accelerated program of replacement of defective HV ABC cable and the installation of two REFCL devices, which are the subjects of our analysis.

Our assessment of United Energy's revised REFCL and HV ABC programs is detailed in the following sections. We note United Energy has accepted our preliminary decision for armour rods, vibration dampeners, spacers, connectors, LV ABC cable and other conductors.

Based on our assessment, we find that United Energy's proposed capex reasonably reflects each of the capex criteria. Our alternative estimate of $53.3 million for bushfire safety capex includes all programs previously approved in the preliminary decision with the exception of HV ABC and REFCL, which is amended by this final decision.

Bushfire mitigation program

In its revised proposal, United Energy proposed an amended amount of $53.3 million ($2015) for bushfire mitigation programs. In addition, to the measures previously approved in our preliminary decision, the revised bushfire mitigation program focused on the following two key programs:

- REFCLs ($7.5 million)
- HV ABC replacement ($30.2 million).

We are satisfied that the additional capex for the proposed bushfire mitigation program is efficient capex that a prudent operator would require to maintain the reliability and safety of the network, and to comply with relevant regulatory obligations. We are also satisfied that proposed capex to replace overhead conductors is consistent with the capex criteria. As such, we accept United Energy's capex proposal to spend $53.3 million ($2015) on its bushfire mitigation program.

We have assessed:

- United Energy's compliance with its safety related obligations; and
- the prudency and efficiency of the two amended programs within the proposed bushfire mitigation program which are in addition to programs approved in the preliminary decision, including complete replacement of faulty HV ABC cables and installation of two REFCL devices.

In undertaking these reviews, we have drawn on engineering and other technical expertise within the AER.

In summary we consider that:

- the information submitted satisfies us that section 106 of the *Electricity Safety Act* (Victoria) requires United Energy to incur bushfire mitigation capex, in addition to capex that it may be required to incur in order to comply with other, more specific requirements under the *Victorian Electricity Industry Act*.
- The proposed bushfire mitigation expenditure for armour rods, vibration dampeners and spacers is in response to a mandatory program of work required under a compulsory ESMS and is required to comply with applicable regulatory obligations (refer to our preliminary decision).

- The proposed expenditure on low voltage aerial bundles cable , connectors and conductors is considered to be consistent with business as usual capex to maintain asset safety and network reliability (refer to our preliminary decision).
- the proposed HV ABC replacement program is efficient capex that a prudent network operator would need to incur to achieve the capex objectives as this is required under the ESMS.
- the proposed REFCL installation projects are efficient capex that a prudent network operator would incur to achieve the capex objectives as this is required under the ESMS.

As such, we are satisfied that United Energy's proposed capex for the revised bushfire mitigation program reasonably reflects the capex objectives. Our detailed reasoning is discussed below by reference to the capex criteria.

Reliability and safety of the network

In Victoria, the safety obligations of major electricity companies are contained in the *Electricity Safety Act 1998 (Vic)*. Each of the five Victorian distributors is classed as a 'major electricity company' under this Act. Section 99 of this Act mandates that major electricity companies must submit an ESMS to the safety regulator, Energy Safe Victoria (ESV) for acceptance.[277]

It is compulsory for United Energy to comply with the accepted ESMS for its network.[278] Further, the Act requires that each major electricity company must submit a Bushfire Mitigation Plan for its network to ESV and must comply with that Plan, once this is approved or accepted by ESV.[279] The Bushfire Mitigation Plan forms part of an accepted ESMS.[280]

The United Energy Bushfire Mitigation Plan has been amended since our preliminary decision to incorporate the installation of REFCL devices at two locations, Mornington and Dromana. In our preliminary decision we did not accept that United Energy had an obligation to install REFCL devices in the 2016-20 regulatory control period. By subsequently incorporating a commitment to install two devices in their approved ESV Bushfire Mitigation Plan, United Energy now has a regulatory obligation to undertake this investment. Energy Safe Victoria advised United Energy that it accepted the amended plan, which includes this commitment.[281] As the two installations are now a regulatory obligation, we are satisfied that these installations are necessary for the reliability and safety of the network and will meet the capex objectives.

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

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

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

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

281 Energy Safe Victoria, *Acceptance of Bushfire Mitigation Plan 2014-2019*, 19 February 2016.

In our preliminary decision we found the United Energy business case supported the replacement of 30km of defective HV ABC cable. In their revised proposal United Energy proposed replacing all 60km of HV ABC installed in its network.[282] The revised remediation plan arose because the ESV was concerned that an unacceptable safety hazard would remain if the remediation plan was not completed sooner.[283] United Energy has modified this work program in their ESMS to address ESV's concerns. Energy Safe Victoria advised it accepted the amended plan.[284]

As the work required for both these projects falls within an ESMS accepted by ESV as necessary to maintain the reliability and safety of the network, we consider these projects are required to meet the capex objectives.

Prudent and efficient investment

Rapid Earth Fault Current Limiting (REFCL) devices

We examined the United Energy business case to assess its proposed investment in two REFCL devices against the capex criteria.[285] This included a breakdown of the major cost elements which make up each project. We also compared the United Energy costings to the costs indicated by the Victorian Government in the draft Regulatory Impact Statement (RIS) published on 17 November 2015.[286]

The RIS stated that the average cost per installation to be $9 million if all existing surge diverters require replacement or $6.6 million on average, if only one-third of the surge diverters require replacement.[287] The submission by the Victorian Government draws particular attention to these estimates.[288] We note that some submissions in response to the RIS challenge those costings, particularly in relation to the assumptions concerning the cost and number of surge diverters (surge arresters or lightning arresters) that would require replacement when a REFCL is installed.

United Energy estimated the cost for the Mornington installation at $3.99 million ($2015), whilst the Dromana installation is estimated to be $3.51 million ($2015). Apart from the surge diverters, we consider each of the other cost elements as identified by United Energy to be reasonable. The material and site preparation costs are generally consistent with the RIS. The project management and design costs accord with our expectations for similar activities associated with capital works of a similar scale.

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282 United Energy, *HV Aerial Bundled Cable Strategic Analysis Plan - UE PL 2053*, Table 17, p. 34

283 United Energy, *RRP 5-20b ESV letter re HV ABC replacement - 20151223.*

284 Energy Safe Victoria, *UE HV aerial bundle cables strategy letter - 20160219*, 19 February 2016.

285 United Energy, *RRP 5-21 - DMA and MTN ZSS REFCL Installation.pdf.*

286 Victorian Government, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015.

287 Victorian Government, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 70.

288 Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20*, p. 2.

The replacement of surge diverters is the largest cost element of each project, at 29 per cent and 24 per cent respectively, of total estimated costs. In relation to the surge diverters United Energy stated that: [289]

> The above cost estimates are based on UE's experience installing its REFCL at Frankston South and from up to date estimates using 2015 dollars from equipment suppliers and design and construction service providers. UE has estimated the number of surge arrester replacements for MTN and DMA based on the number that needed replacement found from surveys of Frankston, Frankston South and Langwarrin areas. The exact number will not be known until the MTN and DMA feeders are surveyed.
>
> The cost per project estimated by UE is very efficient when compared to the costs listed in the regulatory impact statement for the amendments to the Electricity Safety (Bushfire) Regulations 2013 in tables 14 and 20. The average cost of the projects listed is $6.26M compared to United Energy's price of $3.75M. The only zone substation which has lower cost is Coolaroo and it does not require any works to replace surge arresters because all surge arresters have already been replaced.

This statement addresses a key uncertainty surrounding the installation of REFCLs which directly affects project cost. The REFCL device when operating will introduce temporary line voltages that exceed the common ratings of current equipment. This necessitates a detailed survey of every affected line to identify assets which do not have a sufficiently high voltage rating. Some assets will be sufficiently rated such that they do not require replacement or modification. However, a number of assets may require replacement or modification to operate safely with a REFCL installed. This uncertainty is generally referred to as 'hardening cost uncertainty' within the industry.

Although the costs contained in the RIS suggest an average cost of $6.6 million, there is considerable variability in cost from a low of around $2 million to $13 million in current project estimates by other distributors. This variability is recognised in the RIS. As the feeders originating at the Mornington and Dromana substations are relatively short the hardening costs proposed by United Energy are likely to be at the lower end of the expected cost range.

The approach adopted by United Energy to estimate the likely surge diverter replacement need is based on their direct experience of a detailed investigation of a similar feeder with a REFCL installed in the general vicinity of the two other planned installations. Although this is not a detailed survey of the affected feeders, it is otherwise a reasonable approach to determining an indicative budget at the early stages of the development of a capital budget. In all other regards the project costs are at the low end of the range.

On balance, we accept that the United Energy estimating approach is reasonable, but only for these two projects. For all other REFCL projects, including projects by other

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289 United Energy, *RRP 5-21 - DMA and MTN ZSS REFCL Installation.pdf,* p. 12.

distributors we intend to impose a higher standard on the preliminary investigations before funding is approved in order to better mitigate this cost uncertainty, which affects both consumers and the distributors installing these devices.

As such, we consider the resultant cost estimates totalling $7.5 million ($2015) reasonably reflect the capex criteria. [290]

HV ABC

In their revised proposal United Energy has submitted a revised forecast for replacement of 60km HV ABC.[291] The basis of this forecast is a detailed, line-by-line survey to establish a program to complete the works to an accelerated timetable which has been sought and accepted by ESV. We have reviewed United Energy's revised forecast and accept it is accurate as it is consistent with what the ESV has approved.

In our preliminary decision we noted that, based on currently contracted rates, the total cost of replacing all 60km of 22 kV ABC would be in the order of $38 million. The unit rate of the revised program has been estimated at $500/m, based on the actual costs of stage 1, which commenced in the previous regulatory control period.[292] This rate is lower than the rate accepted by us in our preliminary decision. However, as the rate is consistent with revealed costs for past work of a similar nature, we accept this amended forecast of the proposed unitised rate.

As such, we consider the resultant cost estimate of $30.2 million reasonably reflects the capex criteria. [293]

Network health indicators

As noted on page 6-52, and in our Preliminary Decision, we looked at network health indicators to determine whether United Energy' past replacement practices have allowed it to achieve the capex objectives in a manner that reasonably reflects the capex criteria. [294] While this method has not been directly used to reject United Energy' repex proposal, or to produce at an alternative estimate, we note our 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's network have been relatively stable or declining across time with the exception of 2014 which saw a sharp increase (see section D.6)
- measures of United Energy' network assets residual service lives and age show that the average overall age of the network is being maintained. Using age as a high level proxy for condition, this suggests that historical replacement

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

[291] United Energy, *HV Aerial Bundled Cable Strategic Analysis Plan - UE PL 2053*, Table 17, p. 34.

[292] United Energy, *HV Aerial Bundled Cable Strategic Analysis Plan - UE PL 2053*, table footnote, p. 12.

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

[294] NER, cll. 6.5.7(a) and (c).

expenditures have been sufficient to maintain the condition of the network (see Figure 6.19)

- 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.

Further, we noted that the value of customer reliability has recently fallen.[295] 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.

We considered that the above indicators generally suggested that replacement expenditure in the past period has been sufficient to allow United Energy to meet the capex objectives. [296] This is consistent with our overall findings on repex from our other assessment techniques.

United Energy raised some concerns with our use of estimated residual asset life as an indicator of network health. United Energy proposed the use of a model to reveal the underlying health of its network. The primary function of United Energy's model is to make top-down assessment of the total repex needed to maintain reliability and network safety. United Energy's model uses an age threshold based on 'typical Weibull characteristics' and Conditions Based Risk Management (CBRM) health index methodology to predict the age at which the rate of asset failure will rapidly increase.[297]

We have maintained our use of average estimated residual service life as a measure of network health provides as we consider it provides a reasonable, high level indication of United Energy's historical replacement practices. We do not consider United Energy's proposed methodology is sufficiently robust for the purpose of determining efficient replacement needs. Our reasons for maintaining our use of estimated residual asset life as an indicator of network health as well as our reasons for not accepting United Energy's proposed alternative are discussed below.

Trends in the remaining service life and age of network assets

In our preliminary decision we assessed the estimated residual life of United Energy's assets across time.

In its revised proposal United Energy questioned our use of estimated residual life as a suitable measure of asset condition.[298] We have considered United Energy's view of our methodology, however, we maintain the use of estimated residual service life to be a relevant measure of the age of United Energy's assets as a high level check as to whether past replacement practices have allowed it to meet the capex objectives.

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[295] AEMO, *Value of Customer Reliability Review - Final Report*, September 2014.

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

[297] United Energy, *Revised Regulatory Proposal*, p. 35.

[298] United Energy, *Revised Regulatory Proposal*, p. 34.

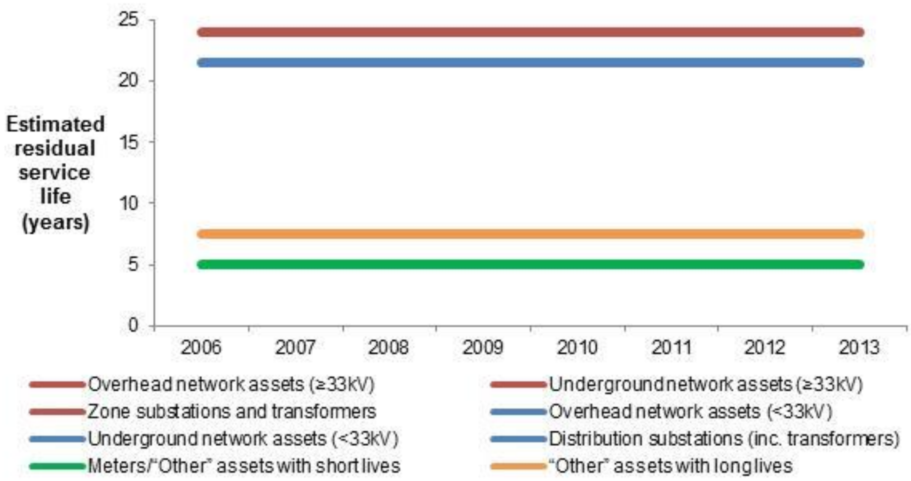
As stated in our preliminary decision we acknowledge there are limitations in using estimated residual service life to assess the condition of network assets. However, we note the use of average estimated residual service life considers the age of all assets, thereby providing a reasonable high level indication of United Energy's historical replacement practices.

As acknowledged in our preliminary decision, large volumes of network augmentation and connections may result in a disproportionately large quantity of new assets being installed on the network.[299] As a result the residual service life of the assets may increase without necessarily addressing any underlying asset condition deterioration.

However, we note that the information provided by United Energy in the Economic Benchmarking RIN captures multiple years of residual life data (Figure 6.19).[300] Consequently, any evidence of new assets being installed on United Energy's network has been considered in this data, as well as the replacement of existing assets.

Figure 6.19 shows that the estimated residual lives of United Energy’s assets have been flat over the period 2006–2013. This indicates that, on average, the age profile of United Energy’s network assets has remained unchanged.

Figure 6.19 United Energy - Estimated residual service life of network assets



Source: United Energy - Economic Benchmarking RIN - 4. Assets (RAB) - table 4.4.2 Asset Lives - estimated residual service life (Standard Control Services)

We maintain our view that the flat trend in the residual lives of United Energy's assets (where age is a proxy for asset condition) suggests that past replacement practices have been consistent with maintaining network performance. That said we have

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299 AER, *Preliminary Decision - United Energy distribution determination 2016 to 2020 - Attachment 6 Capital Expenditure*, p. 6-84.

300 United Energy 2006-13 Economic Benchmarking RIN, Table 4.4, https://www.aer.gov.au.

considered United Energy's network reliability and safety performance and it implications for proposed expenditure in Appendix B.

United Energy's proposed methodology of determining assets at a high risk of failure

In support of its revised proposal United Energy submitted that it considers the proportion of its assets entering the “wear out” phase is increasing. United Energy developed a 'threshold based' methodology to determine the most appropriate time of an asset's life to take corrective action (primarily asset replacement) in order to maintain reliability and safety on its network. [301]

United Energy's preferred method uses asset age as a proxy for condition and purely focuses on assets at the end of the life cycle (i.e. entering the wear out phase). United Energy submitted that it uses Weibull[302] lives for an asset class where available; otherwise the economic life is used.

United Energy stated that:

> The relationship between asset age and the probability of asset failure is well known. Assets typically have a long period of serviceable life with negligible failures, followed by a period of deterioration or the ‘wear out phase’ which leads to increasing failure. This is reflected by the Weibull probability density function, which can be used to depict the distribution of failure rates for a particular asset class. [Figure 6.20] shows a typical Weibull probability density function for an asset with an effective life of 55 years. [303]

United Energy's proposed method predicts that asset failures will rapidly increase once an asset has reached 85 per cent of its nominal life (refer to Figure 6.20).United Energy indicated that this corresponds with an independently developed Condition Based Risk Management (CBRM) health index threshold where risk of failure is said to be escalating. [304]

United Energy stated that:

> Analysis of the Weibull distribution identified that the inflection point of a nominal Weibull curve, where failures are predicted to rapidly increase, occurs where assets have reached 85% of their nominal life. It also corresponds to a CBRM health index threshold where risk of failure is said to be escalating. Therefore, the HROF threshold was selected to be 85% of useful life. Sensitivity analysis also shows that there is a linear relationship between the percentage threshold used and the volume or value of assets beyond the HROF threshold. As the metric is used for comparative purposes only (from

301 United Energy, *Asset High Risk of Failure Assessment*, December 2015.

302 Weibull distribution is a continuous probability distribution. It is used to attempt to make predictions about the life of all products in the population by fitting a statistical distribution to life data from a representative sample of units.

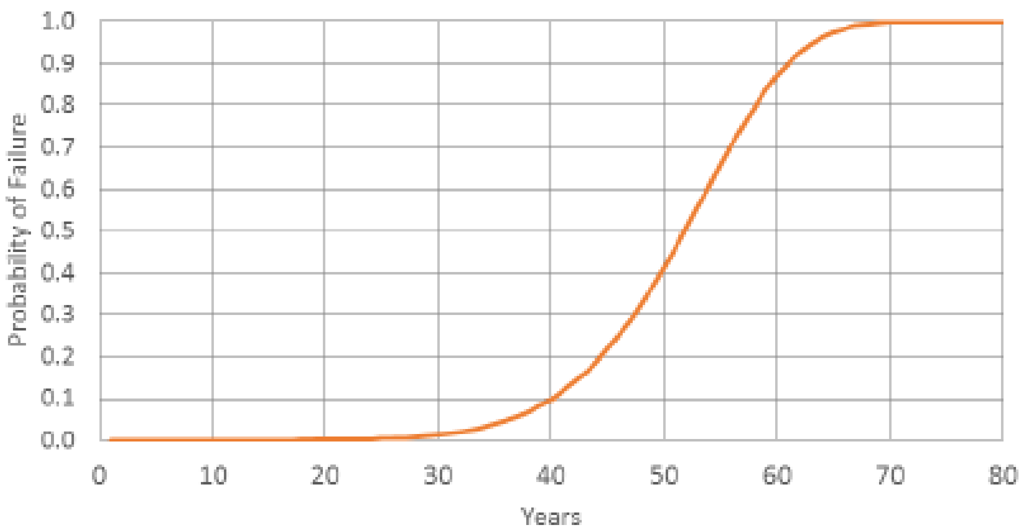
303 United Energy, *Asset High Risk of Failure Assessment*, December 2015.

304 Application of CBRM with United Energy Report (EA Technology report no. J000151-1) (not provided).

year to year or for each regulatory period), the actual percentage selected will not have a material impact on the outcome. The sensitivity analysis concluded that 85% can be used as a reasonable measure of assets at high risk of failure based on asset age. [305]

Figure 6.20 (reproduced below) was provided by United Energy to show a typical Weibull probability density function for an asset with an effective life of 55 years. [306]

Figure 6.20 Typical Weibull distribution for an asset with 55 years of expected life - United Energy analysis [307]



Source: United Energy, Asset High Risk of Failure Assessment, December 2015 (p. 17).

We do not consider United Energy's methodology is sufficiently robust for the purpose of determining efficient replacement needs. We note the following limitations in United Energy's assessment of its assets:

- the data used to plot the 'typical Weibull distribution for an asset with 55 years of expected life' was not validated.[308]
- the method of calculating the 'typical Weibull distribution for an asset with 55 years of expected life' has not been identified.[309]

United Energy's scenario analyses only provides for the following two scenarios:

- the proportion of assets at high risk of failure when considering United Energy's 'proposed repex'; and

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305 United Energy, *Asset High Risk of Failure Assessment*, December 2015, p. 12.
306 United Energy, *Asset High Risk of Failure Assessment*, December 2015, p. 17.
307 United Energy, *Asset High Risk of Failure Assessment*, December 2015, p. 17.
308 United Energy, *Revised Regulatory Proposal*, p. 17.
309 United Energy, *Revised Regulatory Proposal*, p. 17.

- the proportion of assets at high risk of failure when spending $0 on asset replacement.

We note that United Energy did not present any scenarios that forecast the impact of the replacement expenditure amount included in our preliminary decision. This is despite the fact that this amount reflected an amount we considered to be sufficient to allow United Energy to meet the capex objectives.[310]In referring to the verification steps taken to assess the functionality of its network health model, United Energy stated:

> The sensitivity analysis found that the output trends identified were relatively insensitive to changes in asset lives and unit rates, and were largely independent to the threshold chosen to represent the start of the asset wear out phase. [311]

This was despite the key function of the model being to quantity the number of assets deemed to be at a higher risk of failure using various assets passing an age threshold.

United Energy submitted that:

- its CBRM risk profile aligns with the standard Weibull Distribution curve; and
- that the Weibull characteristics of an asset that has reached 85 per cent of its useful life aligns with CBRM Health Index (HI) level 4. [312]

However, it can be seen in United Energy's 'Table 3' (reproduced in Figure 6.20 below) that the Weibull curve/characteristics attributed to the various 'risk stages' do not align with the CBRM HI profile submitted by United Energy. 'Figure 2-3' as submitted by United Energy (reproduced below) shows that the probability of asset failure remains constant in until it reaches CBRM HI level 4 and does not indicate that the asset has reached 'maximum acceleration of failure rate'. United Energy's Health Index boundaries (see footnote) defines assets in the HI level 4 category as 'low risk'. However, United Energy's 'Table 3' classes CBRM HI level 4 assets as 'escalating risk'. The disconnection between these conflicting definitions is best seen in Figure 6.22.

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[310] United Energy, *Revised Regulatory Proposal*, p. 34.

[311] United Energy, *Asset High Risk of Failure Assessment*, December 2015, p.13.

[312] The CBRM methodology centres on the principle of checkpoints changing an asset from green (low risk), yellow (escalating risk) to red (highest risk). These are defined as Health Index (HI) bounds 0-4 for green, 4-7 for yellow ('End of Life' at 5.5), and 7+ for red. - United Energy, *Asset High Risk of Failure Assessment*, December 2015, p. 23.

Figure 6.21 United Energy - Asset risk of failure assessment

Table 3: Correlation between CBRM and Standard Weibull Curve

Risk Stage	CBRM HI1	% of Useful Life based on Std Weibull Curve	Weibull Characteristic
Escalating Risk	4	85%	Maximum acceleration of failure rate
CBRM defined 'End of Life'	5.5	100%	Peak failure density (most failures expected)
Highest Risk	7	108%	>80% chance of failure

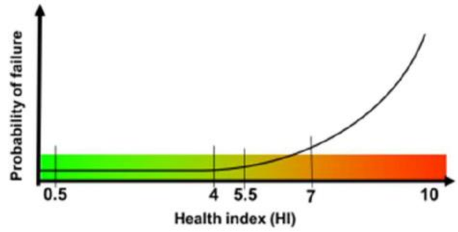

Figure 2-3 Relationship between Health Index and Probability of Failure

Source: CBRM Report for UE

Source: United Energy, Asset High Risk of Failure Assessment, December 2015.

We have assessed that if United Energy's '85 per cent' methodology were to be applied to an asset with an effective life of 55 years, the asset would be considered to have a 'high risk of failure[313]' once it has reached 47 years of age[314]. However, United Energy's Weibull distribution shows that an asset with an effective life of 55 years only has a 26 per cent probability of failure once it has reached 47 years of age (see Figure 6.22).

In addition, an asset with an expected effective life of 55 years would be 'more probable than not probable' to fail (i.e. >50 per cent chance of failure) once it had reached approximately 52 years of age, which equates to approximately 95 per cent of its effective life.

Figure 6.22 provides our analysis of United Energy's proposed '85 per cent' methodology to an asset with an effective life of 55 years.

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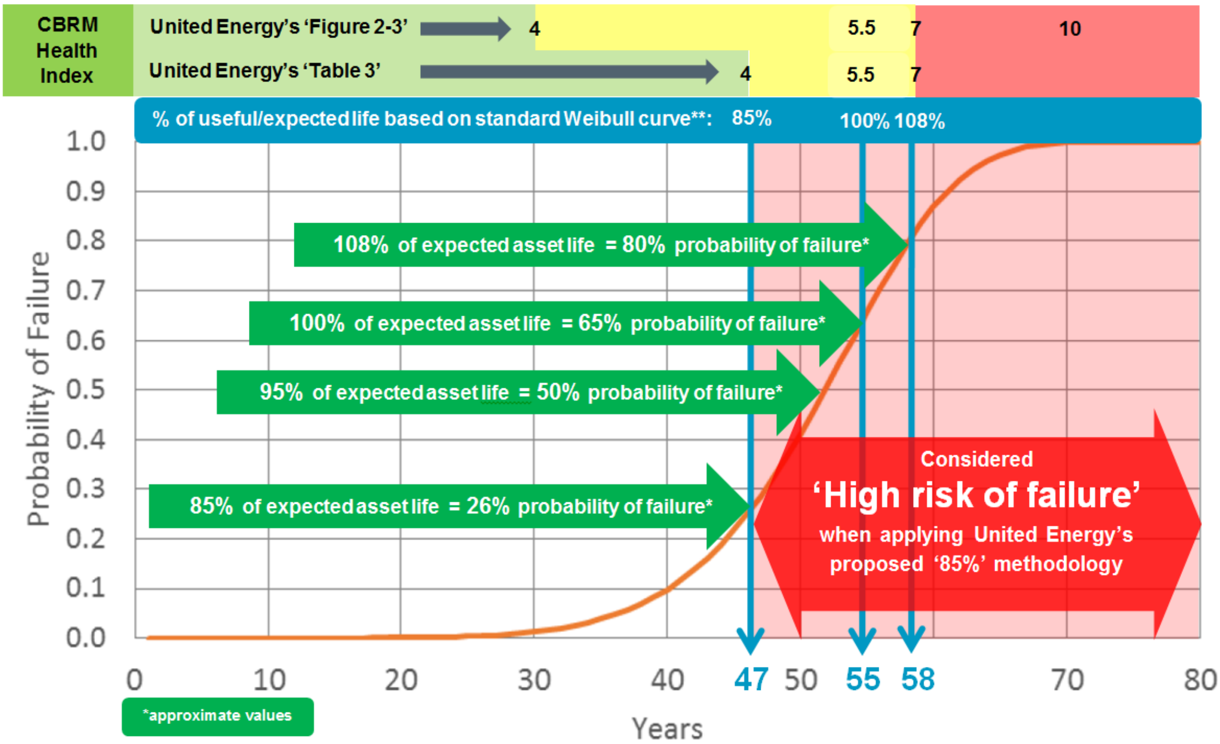
[313] United Energy, *Asset High Risk of Failure Assessment*, December 2015, p. 12

[314] 85% x 55 years (expected life) = approximately 47 years

Figure 6.22 United Energy's typical Weibull distribution for an asset with 55 years of expected life - AER analysis



** See Figure 6.21 for United Energy's definitions of these values.

Source: AER analysis - United Energy, Asset High Risk of Failure Assessment, December 2015

In summary, if United Energy's proposed methodology were to be used to determine the most appropriate time of an asset's life to take corrective action (primarily asset replacement), an asset may be targeted for replacement when it has only a 26 per cent probability of failure.

As such, we consider United Energy's application of the '85 per cent threshold' methodology is likely to understate the age of the asset in which it may be necessary to undertake corrective action. Relevantly, applying the '85 per cent threshold' methodology may result in assets being refurbished or replaced before it is necessary.

Finally, we note that our predictive modelling outcome is based on United Energy's recent replacement practices. This means that replacement drivers, including drivers related to deterioration in asset condition and United Energy's tolerance to asset risk have been taken into account in our estimate derived from our predictive modelling (refer to section B.4.4).

B.5 Forecast non–network capex

Non-network capex for United Energy includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment. United Energy's revised proposal includes forecast non-network capex of $184.3 million ($2015) (excluding overheads). This is a reduction of $10.3 million or 5 per cent from United Energy's initial proposal of $194.6 million, but an increase of $49.8 million or 37 per cent from our preliminary decision for non-network capex of $134.6 million.[315]

B.5.1 Position

We do not accept United Energy's revised proposal for non-network capex. We have instead included an amount of $168.4 million ($2015) for forecast non-network capex. As discussed below, we are not satisfied that United Energy's forecast non-network ICT capex for Power of Choice related projects and RIN compliance reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives.[316]

In coming to this view:

- We are not satisfied that United Energy's forecast ICT capex for the Power of Choice related projects reasonably reflects the prudent and efficient costs required to meet its regulatory obligations. We consider that forecast capex of $23.2 million ($2015) is likely to reasonably reflect a prudent and efficient level of ICT capex for the Power of Choice projects in the 2016–20 regulatory control period.
- We are not satisfied that United Energy's forecast ICT capex for RIN reporting compliance reflects a reasonable estimate of the efficient costs of a prudent operator to achieve RIN reporting compliance. We consider that forecast capex of $11.0 million ($2015) is likely to reasonably reflect a prudent and efficient level of ICT capex necessary to achieve compliance with RIN reporting obligations in the 2016–20 regulatory control period.
- We are satisfied that United Energy's forecast capex for the motor vehicles, buildings and property, and plant and equipment categories of non-network capex, consistent with our preliminary decision, reasonably reflects the efficient costs of a prudent operator.

B.5.2 Revised proposal

In its revised proposal, United Energy accepted our preliminary decision on forecast non-network capex for motor vehicles, buildings and property, and tools and equipment. However, United Energy sought additional ICT capex of $33.5 million

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[315] United Energy, *Revised regulatory proposal*, 6 January 2016, p. 51.

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

($2015) to comply with the AEMC's rule changes relating to the Power of Choice review, and $16.3 million ($2015) for system upgrades to meet RIN reporting obligations.[317] These two elements of non-network ICT capex are discussed below.

We received a submission on ICT capex from the Consumer Challenge Panel. The CCP submitted that it is concerned about the high level of ICT capex being sought by all the Victorian distributors.[318] We note the CCP's general concern about the high levels of ICT capex sought but take the view that the historic spending from 2001–2010 is not necessarily the best guide to the prudent and efficient level of ICT spending for the 2016–20 regulatory control period. In our assessment, we recognise that IT expenditure is typically lumpy in nature and its timing is dependent on necessary system upgrades, technology obsolescence, as well as other requirements such as new regulatory obligations.

B.5.3 Information and communications technology capex

Power of Choice projects

In our preliminary decision, we rejected United Energy's proposed $37.2 million ($2015) for ICT capex for Power of Choice projects. In its revised proposal, United Energy instead proposed $33.5 million. We do not accept this proposed forecast for additional ICT capex and instead substitute an amount of $23.27 million ($2015).

Since 2014 the AEMC has made several rule changes relating to its Power of Choice review, including, in November 2015, rules for the introduction of metering contestability. These various rule changes give rise to new regulatory obligations for distributors. Following assessment of the various projects proposed by United Energy, we accept that there is evidence that some will be required to ensure compliance with certain of these regulatory obligations. Under the capital expenditure objectives, we must allow sufficient capex to allow a distributor to comply with regulatory obligations or requirements.[319]

As noted above, the CCP submitted that it was not convinced that there is a need to increase ICT costs to accommodate the Power of Choice rule changes, noting that the AEMC did not explicitly identify any costs that it expected to be incurred as a result of the changes.[320] However, following our assessment, we are satisfied the distributors, including United Energy, have demonstrated that they will need to modify their ICT systems to address certain new obligations. We note the CCP is concerned also by the

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[317] United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 51–55.

[318] Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 61.

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

[320] Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 63.

difference in costs proposed by each distributor in relation to the Power of Choice rule changes.[321] We address these differences in our assessment below.

Assessment approach

In assessing United Energy's Power of Choice program, we have examined the proposed projects and identified which are in response to regulatory obligations.

We evaluated the projects proposed by each distributor as set out in its proposal. Where a distributor's project costs were not fully supported by a detailed business case with sufficiently supported cost estimation, we also sought further information from the distributor in relation to how the capex forecast was derived. We recognise that the Victorian distributors for the most part have not been able to provide detailed assessment of the capex required or completed a detailed business case for these projects. This is understandable given that these rule changes are recent and there is still time to complete more detailed project plans before implementation is required.

As part of our assessment, we also had regard to information provided by all of the Victorian distributors given that each must meet the same regulatory obligations and are subject to the same operating environment. The fact that the obligations and the operating environment apply to all the Victorian distributors allows for a degree of comparability in assessing proposed costs. Accordingly, where the distributor's justification for forecast costs did not justify the capex proposed, we considered the distributor's proposed capex compared to what other Victorian distributors proposed to address that particular regulatory obligation. We then examined the distributor's proposal in order to assess any factors that might explain the need for different capex requirements.

United Energy's Power of Choice program

United Energy included $37.2 million for the ICT capex costs for Power of Choice in its initial proposal. In our preliminary decision, we rejected this proposed capex because the scope, timing and costs of ICT changes relating to Power of Choice changes was too uncertain, noting that it may be possible to recover costs by way of a pass through.[322] In its revised proposal, United Energy proposed $33.5 million for the ICT capex costs of Power of Choice changes.[323]

United Energy proposed the additional ICT capex for projects to address the following initiatives from the Power of Choice review:

- Consumer Data Access ($2.5 million)

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[321] Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 63.

[322] AER, *Preliminary decision - United Energy distribution determination 2016–2020 - Attachment - 6 - Capital expenditure*, October 2015, p. 6-109.

[323] United Energy, *Revised regulatory proposal*, 6 January 2016, p. 52.

- Metering Competition ($17.9 million)
- Network Pricing ($2.8 million)
- Customer Switching ($1.2 million)
- Demand Response Mechanism ($1.8 million)
- Demand Management AEMO Reporting ($1.4 million)
- Demand Management ICT Platform ($5.4 million)
- Embedded Networks ($0.8 million).

Our assessment of these projects is detailed below.

Consumer Data Access

United Energy's consumer data access project is to comply with the new Metering Data Provision Procedures developed by AEMO which came into effect on 1 March 2016.[324] These Procedures make it easier for customers to get their electricity consumption data from their distributor. These Procedures introduce new regulatory obligations that United Energy must comply with resulting in potential compliance costs. Given that the implementation date was 1 March 2016, we considered it unlikely that this capex (or a significant proportion of this capex) will be spent during this regulatory control period. However, United Energy, in response to our information request, submitted that to date it has spent $0.8 million, with $300,000 spent in 2015 which will be capitalised in 2016. United Energy will spend the remaining $1.7 million during the rest of 2016.[325] We understand that from 1 March 2016, Victorian distributors will be testing 'format 8', a new file format for Victorian Energy Compare (VEC), which is compatible with the AEMO requirements. This format is to be tested for six months until 1 September 2016, when it will become a standard file format for VEC.

Given these requirements, we are satisfied that some expenditure for consumer data access is reasonably likely to meet the capex criteria. We discuss our estimate for this project below.

Metering competition

The metering competition rule change will introduce competition in metering and facilitate a market led deployment of advanced (smart) meters. The AEMC made a final rule change for metering competition in November 2015.[326] This rule change places new regulatory obligations on United Energy and will require that United Energy make changes to its ICT systems to comply with the new rules.

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[324] AEMO, *Metering Data Provision Procedures*, September 2015.

[325] United Energy, *AER United Energy info request #53 — IT capex – Power of Choice*, 21 March 2016, pp. 1–2.

[326] *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12*.

In its metering competition project, United Energy has included $3.69 million for shared market protocol (SMP). The SMP will provide a standard form of communication for energy companies seeking access to services enabled by advanced (smart) meters. For SMP, the AEMC has released a final advice on how an SMP could be implemented, but the final form of the required changed is not entirely known.[327] However, these obligations are intended to have the same implementation date as metering contestability (1 December 2017) and United Energy (and other distributors) submitted that the SMP requirements are inextricably linked to the metering contestability changes and that implementing them together will provide efficiencies.[328] Given SMP is closely linked to the metering requirements, United Energy will need to meet these regulatory obligations.

Network Pricing

The AEMC made a final rule change for distribution network pricing arrangements in November 2014. The proposed network pricing project is to address the requirement that network prices reflect the efficient costs of providing network services to individual consumers so that they can make informed decisions about their electricity usage.[329] This rule change introduces new regulatory obligations for distributors from 2017.

We also note the Victorian Minister for Resources and Energy issued a Ministerial direction specifying changes to the proposed tariff structure statements of the Victorian network businesses to ensure customers can opt in to new network tariffs from their current tariffs, rather than opt out as specified in the businesses' initially proposed tariff structure statements.[330] While this is likely to reduce the volume of transactions and may result in lower ongoing costs during the 2016–20 regulatory control period as customer take up may be less than initially estimated, we are satisfied that these obligations will still require United Energy to make changes to its ICT systems and processes.

Assessment of consumer data access, metering competition, and network pricing estimate

Having accepted that the consumer data access, metering competition, network pricing, and SMP are relevant in determining ICT capex required to meet Power of Choice reforms, we now consider whether United Energy's forecasts for these projects are likely to reasonably reflect the efficient costs that a prudent operator would incur.

In its revised proposal, United Energy provided short project justifications for each of the projects which included the headline cost of each project which provided some

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[327] AEMC, *Final advice: Implementation advice on the shared market protocol*, 8 October 2015. AEMC, *Consultation paper: National Electricity Amendment (Updating the electricity B2B framework) Rule 2015*, 17 December 2015.

[328] United Energy, *AER United Energy info request #043 - IT capex for Power of Choice*, 18 February 2016, pp. 5–6.

[329] *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9.*

[330] Advanced Metering Infrastructure (AMI Tariffs) Amendment Order 2016, Victorian Government Gazette G15, 14 April 2016.

breakdown of the forecast costs.[331] We sought further information from United Energy on the details and justification for its Power of Choice expenditure on three occasions.[332]In assessing United Energy's forecast costs, we compared its forecasts to those of the other Victorian distributors for projects to meet the same regulatory obligations. United Energy's costs were in line with those of Jemena and CitiPower/Powercor,[333] with AusNet Services forecasting significantly higher costs, as can be seen in Table 6.13. United Energy and Jemena were the only distributors to propose consumer data access projects.

Table 6.13 Range of forecast costs for Power of Choice projects

Project	United Energy	AusNet Services	Jemena	CitiPower/Powercor[a]	Average[c]
Network pricing	$2.79 million	$5.86 million	$2.71 million	$0[b]	$2.75 million
Metering competition	$14.29 million	$27.80 million	$17.50 million	$14.25 million	$15.41 million
SMP	$3.69 million	$6.57 million	$2.89 million	$2.08 million	$2.89 million
Consumer data access	$2.5 million	$0[b]	$1.9 million	$0[b]	$2.20 million
Total	$23.27 million	$40.23 million	$25 million	$16.33 million	$23.25 million

Source: AER analysis.

Notes: (a) CitiPower and Powercor's costs were considered together as they share ICT systems.

(b) These distributors did not propose projects to address these rule changes.

(c) Where a distributor did not propose an amount for a project, this was not included in the calculation of the average. AusNet Services forecasts were excluded from the average.

We note that United Energy has provided us with only high level information and has not yet undertaken a detailed business case for these projects. However, we further observe that the proposed costs for meeting the same obligations are similar to the average costs in aggregate compared for these projects to those proposed by the other distributors, with the exception of AusNet Services.

Excluding AusNet Services' higher estimates, which we found to be unsupported, United Energy's proposed estimate was comparable to the other distributors' estimates

[331] United Energy, *Project Justification - Power of Choice - Metering competition*, 17 December 2015. United Energy, *Project Justification - Power of Choice - Network Pricing*, 17 December 2015.

[332] United Energy, *AER United Energy info request #043 - IT capex for Power of Choice*, 18 February 2016. United Energy, *AER United Energy info request #048 - IT capex for Power of Choice*, 3 March 2016. United Energy, *AER United Energy info request #053 - IT capex for Power of Choice*, 21 March 2016.

[333] For these purposes we have considered CitiPower/Powercor as one entity because they share these ICT systems.

where they proposed capex for a comparable project to address the same regulatory obligation.[334]

We have had regard to the circumstances of the other Victorian distributors which are subject to a similar operating environment (e.g. all of the Victorian distributors have similar metering arrangements and business process obligations). Further, from the information provided by United Energy, we have assessed that the majority of United Energy's costs are capitalised labour costs to amend existing systems and processes. This is similar to the nature of the costs that the other Victorian distributors expect to incur. This provides for a degree of comparability for assessing the proposals submitted by all of the Victorian distributors.

Given United Energy's forecast capex of $23.27 million was similar to the average of $23.25 million (excluding AusNet Services) we are satisfied that this amount is reasonably likely to reflect the capex criteria. We have included this amount in our alternative capex estimate.

Customer Switching

United Energy's customer switching project is in response to an April 2014 report by the AEMC which made recommendations to the Standing Council on Energy and Resources, which have not yet been implemented.[335] The report made recommendations to improve the timing and accuracy of customer transfers. As these recommendations have not yet been implemented:

- there no new regulatory obligation; and
- we do not consider that any requirements are sufficiently certain to include an amount in United Energy's ex-ante forecast.

Once the recommendations are implemented, we expect that the pass through arrangements in the NER will provide United Energy with an opportunity to recover any associated expenditure, subject to materiality of costs.

Demand response mechanism

The demand response mechanism project is in response to a rule change request by the COAG Energy Council to create a mechanism that would allow the demand side to participate in the wholesale market. The AEMC issued a consultation paper on this in November 2015.[336] This rule change is therefore still at an early stage and we do not consider that any obligations are sufficiently certain. Therefore we have not included an amount for this proposed rule change in our alternative estimate. When this rule

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[334] All the Victorian distributors proposed comparable projects for metering contestability and SMP/B2B projects; all distributors, excepting Powercor/CitiPower, proposed comparable projects for network pricing arrangements.

[335] AEMC, *Final Report: Review of Electricity Customer Switching*, 10 April 2014.

[336] AEMC, Consultation Paper: *National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling)*, 5 November 2015.

change is finalised, we expect that the pass through arrangements in the NER should allow United Energy to recover any associated expenditure, subject to materiality of costs.

Demand Management AEMO reporting

United Energy submitted that the demand management AEMO reporting initiative is to comply with yet to be determined AEMO reporting guidelines regarding demand side participation.[337] These guidelines are to be published by 26 September 2016 and are required by a recent AEMC rule.[338] As these guidelines have not been finalised, we do not consider that there is sufficient certainty to determine United Energy's obligations and associated expenditure. Once the guidelines are finalised, we expect that the pass through arrangements in the NER should provide United Energy with an opportunity to recover any associated expenditure, subject to the materiality of costs.

Demand Management IT platform

United Energy submitted that this project provides the ICT capabilities to enable the deployment of demand management as a cost effective alternative to traditional network investment.[339] United Energy also submitted that its demand management IT platform project is justified on the basis of deferring and replacing traditional network investment with non-network options. It also submitted that it is necessary to support its demand management AEMO reporting and demand response mechanism projects.[340]

We note this proposed project is not required to address a new regulatory obligation and we would expect a robust business case to support United Energy's proposal. United Energy provided a short project justification in support of this project which included a high level cost breakdown.[341] United Energy submitted in the project justification that this project would be NPV positive on the basis of allowing the deferral of capex in the 2016–20 regulatory control period and the subsequent period.[342] However, there is no evidence that these capex savings have been reflected elsewhere in the capex forecast. Relevantly as this project is expected to provide capex efficiencies, we do not consider that these costs should be funded by customers. On the basis of the information provided, we are not satisfied that this this

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337 United Energy, *Project Justification - Demand Management AEMO Reporting*, 17 December 2015, p. 5.

338 *National Electricity Amendment (Improving demand side participation information provided to AEMO by registered participants) Rule 2015 No. 4*.

339 United Energy, *Project Justification - Power of Choice - Demand Management IT platform*, 17 December 2015, p. 5.

340 United Energy, *Project Justification - Power of Choice - Demand Management IT platform*, 17 December 2015, p. 5.

341 United Energy, *Project Justification - Power of Choice - Demand Management IT platform*, 17 December 2015, pp. 8 and 13.

342 United Energy, *Project Justification - Power of Choice - Demand Management IT platform*, 17 December 2015, p. 8.

capex would be incurred by a prudent operator acting efficiently. Therefore we have not included an amount for this project in our alternative estimate.

Embedded Networks

For embedded networks, while the AEMC did make a final rule change in December 2015, the market procedures have not yet been made.[343] As noted by AusNet Services the final market procedures relating to embedded networks, which are not expected until August 2016, must be available before the design phase can be completed and implementation can commence.[344] Therefore, we consider that the regulatory obligation is not sufficiently certain at this time for this project to be included in the forecast capex. Again, we expect that once these obligations are finalised, United Energy may be able to apply for a cost pass through to recover any expenditure, subject to materiality.

RIN reporting compliance

In our preliminary decision, we acknowledged that RIN compliance is a new regulatory obligation that may give rise to compliance costs. However, on the basis of the information provided by United Energy, we were not satisfied that the magnitude of United Energy's proposed capex for RIN compliance costs of $24.3 million ($2015) was prudent and efficient. We invited United Energy to provide additional information and evidence in support of its forecast RIN compliance costs.[345]

In its revised proposal, United Energy proposed an alternative RIN compliance solution involving a mix of both capex and opex. United Energy proposed reduced RIN compliance capex of $16.3 million ($2015) for ICT system changes, together with an opex step change of $4.6 million.[346] United Energy's total revised RIN compliance ICT costs of $20.9 million ($2015) reflect a reduction of $5.0 million or 19 per cent from its initial proposal.

Origin Energy submitted that it does not support the inclusion of expenditure for system upgrades associated with regulatory reporting obligations. Origin Energy recognised that the businesses may incur some costs to enhance systems to map data from existing systems into the RIN format. However, Origin Energy submitted that these costs would not be material as the majority of information would be captured as a matter of course and the mapping into the AER format would not be onerous.[347]

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[343] *National Electricity Amendment (Embedded Networks) Rule 2015 No. 15*.

[344] AusNet Services, *Electricity Distribution Price Review 2016–20: Revised Regulatory Proposal: Power of Choice program*, 6 January 2016, p. 47.

[345] AER, *Preliminary decision - United Energy distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, pp. 6-109 to 6-112.

[346] United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 55 and 66.

[347] Origin Energy, *Re: Submission to AER Preliminary Decision Victorian Networks*, 6 January 2016, p. 2.

United Energy identified a number of issues requiring action to achieve compliance, including:[348]

- collection of additional asset information to remove the estimated component of items of reported information, including:
    - operating voltage for poles, pole top structures, overhead conductors, underground cables, service lines, transformers and switchgear
    - material type for poles
    - number of phases for overhead conductors and transformers
    - customer type and connection complexity for service lines
    - ampere rating for transformers
    - feeder type for poles, overhead conductors and underground cables
    - total MVA replaced and disposed for transformers
- changing ICT systems to accept additional information
- establishing new reports
- revising business processes to provide information that meets RIN requirements.

In our view, these issues reflect both the need to re-map existing data as identified by Origin Energy but also the need for new data acquisition, storage and manipulation processes and capabilities. We acknowledge that RIN compliance, including the requirement to report 'actual' rather than 'estimated' data, is a new regulatory obligation that may give rise to compliance costs. While it is possible that RIN compliance costs may be relatively immaterial for some businesses, in other cases they may be more significant. In assessing the need for any RIN compliance costs, we must be satisfied that they reflect the efficient costs that a prudent operator would require to comply with its regulatory obligations.[349] This will maximise the net benefits of RIN reporting to consumers in terms of enhanced industry efficiency, transparency, governance and data availability.

United Energy submitted a business case in support of its revised forecast RIN compliance costs.[350] This business case addressed some of the factors relevant to assessing the prudence and efficiency of a proposed capex project, including.

- a description of the need for investment, with some supporting evidence as to the current state of ICT and business systems and RIN reporting information gaps[351]
- evidence that a range of alternative options, including a 'do nothing' option, has been considered[352]

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[348] United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 55–56.
[349] NER, cl. 6.5.7(c).
[350] United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015.
[351] United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, pp. 6–10 and 19.

- evidence that the lowest cost option which meets regulatory requirements has been selected.[353]

In our preliminary decision, we expressed concern that the scope and magnitude of costs proposed for RIN compliance appeared to reflect a risk averse assessment of possible costs.[354] United Energy's revised proposal for the RIN compliance project reflects a new approach to meeting RIN reporting obligations. United Energy reduced the scope of the project by retaining some manual processes, only capturing data that is essential for RIN reporting, and deferring some ICT changes until required for asset management purposes.[355] United Energy described this option as a 'risk based approach' to RIN compliance. United Energy identified that this approach carries some risk of misreporting and may result in inaccuracies in the reported data that would make the information 'estimated' rather than 'actual.[356]

In our view, while United Energy's revised approach is a lower cost option, it is not clear that it carries any material increase in compliance risk. United Energy has not provided evidence that it has formally analysed or quantified the additional risk arising from its 'risk based approach'. Nonetheless, United Energy considers the risk of misreporting occurring is rendered 'unlikely' by a negligible ($0.05 million) increase in quality assurance costs.[357] The extent of any actual increase in compliance risk associated with this 'risk based approach' is therefore not clear, but appears minimal. Equally, it is not clear that costs could not be further reduced without a material increase in compliance risk. The 'risk based approach' reduces compliance costs by maintaining current practices in relation to the reporting of information for two asset types: conductors and services.[358] In our view, it is possible that the same approach could be similarly applied to other asset categories without a material increase in compliance risk. As a result, we maintain the concern expressed in our preliminary decision that United Energy's forecast costs for RIN compliance appear to reflect a risk averse assessment of possible costs, and are therefore likely to be overstated.

In our preliminary decision, we expressed concern that 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.[359] In this regard, United Energy's revised business case for the RIN compliance project stated that:[360]

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352 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, pp. 10–12.

353 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 15.

354 AER, *Preliminary decision - United Energy distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, pp. 6-109 to 6-112.

355 United Energy, *Revised regulatory proposal*, 6 January 2016, p. 56.

356 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 12.

357 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 12.

358 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 12.

359 AER, *Preliminary decision - United Energy distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, p. 6-111.

360 United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 13.

> While some benefits to asset management practices are expected, these have not been quantified and have not been included in the evaluation.

It is important that both the costs and benefits of an investment are quantified and accounted for in determining the overall net cost. In our view, the RIN compliance project may provide efficiencies in asset management practices, resulting in real cost savings that have not been accounted for in the business case justification for this investment. The justification for the quantum of proposed costs is therefore not fully supported by the project business case.

In assessing United Energy's proposed RIN compliance costs, we sought clarification of an apparent inconsistency between United Energy's forecast capex for RIN compliance and the cost estimate set out in the supporting business case.[361] United Energy's business case identified RIN compliance capex of $14.7 million, compared to capex of $16.3 million included in United Energy's total capex forecast. United Energy submitted that the $16.3 million figure included in its revised regulatory proposal was a typographical error.[362] As a result, and for the other reasons expressed above, we are not satisfied that United Energy's revised regulatory proposal reasonably reflects the efficient costs that a prudent operator would require to comply with the RIN reporting obligations.

In considering the efficient costs that United Energy would require to meet its RIN reporting regulatory obligations, we have considered the proposed RIN compliance costs in the context of similar costs proposed by other distributors. While we recognise that each business is starting from a different position regarding its existing systems, processes and data availability, we would expect some consistency in the magnitude of costs required by distribution service providers to meet the same regulatory obligations. Table 6.14 shows that United Energy's forecast ICT costs for achieving RIN compliance are higher than those of other distributors in Victoria and South Australia.

361 AER, *Information request 046 – RIN reporting ICT capex*, 16 February 2016.

362 United Energy, *Response to AER information request 046*, 23 February 2016.

Table 6.14 Forecast RIN compliance expenditure ($2015)

Distributor	RIN compliance ICT capex	RIN compliance ICT opex	Total RIN compliance expenditure
United Energy	14.7[a]	4.6	19.3
CitiPower / Powercor[b]	10.6	5.0	15.5
AusNet Services	-	-	-
Jemena	2.1	5.9	8.0
SA Power Networks[v]	8.6	6.4	15.0
Average (excluding United Energy)	5.3	4.3	9.6

Source: United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 20; CitiPower, *Attachment 1.56 RIN compliance expenditure*, January 2016; Jemena, *Attachment 8–11 - Business case for RIN actuals*, 6 January 2016, p. 31; AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 6 - Capital expenditure*, October 2015, p. 6-124; and AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 7 - Operating expenditure*, October 2015, p. 7-75.

Notes: Totals may not add due to rounding.

a. accounts for the error in United Energy's forecast RIN compliance capex discussed above.

b. assessed as a single project across the two businesses.

c. SA Power Networks is included as the only previous decision on RIN compliance costs made by the AER.

The total capex and opex RIN compliance costs for United Energy of $19.3 million ($2015) are 24 per cent higher than the next highest estimate (CitiPower/Powercor) and approximately double the average of the other businesses shown in Table 6.14. United Energy's proposal is 29 per cent higher than the allowed costs for RIN compliance included in our final regulatory determination for SA Power Networks following a review of prudent and efficient RIN reporting costs by our ICT consultant Nous Group.[363] The disparity between total forecast costs is driven by the capex component, given that United Energy's forecast opex step change is in line with the average of the other service providers.

We sought further information from United Energy to justify its comparatively higher forecast RIN compliance costs.[364] United Energy submitted that the key drivers of the difference in required expenditure between businesses are the differences in existing asset management practices, information systems and the ICT investment lifecycle. For example, United Energy noted that AusNet Services had upgraded its enterprise resource planning systems after the RIN reporting requirements were finalised in 2014. United Energy also noted that some distributors had proposed additional ICT projects closely related to RIN reporting which would assist them to meet their reporting

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363 AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 6 - Capital expenditure*, October 2015, p. 6-124; and AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 7 - Operating expenditure*, October 2015, p. 7-75.

364 AER, *Information request 046 – RIN reporting ICT capex*, 16 February 2016.

requirements. United Energy submitted that seeking to apply the lowest cost to all distributors ignores key differences between them and would not allow United Energy to recover its efficient costs of meeting the RIN requirements.[365]

As discussed above, we are not satisfied that United Energy's forecast RIN compliance costs reasonably reflect the efficient costs that a prudent operator would require to meet the capex objectives. In determining efficient costs, we agree with United Energy that applying the lowest proposed costs for meeting RIN reporting obligations to all distributors is unlikely to allow for the recovery of efficient costs in all cases. We recognise that some variation in compliance costs is expected due to differences in existing systems and practices. However, we consider that a forecast of costs which is more consistent with the forecasts of other service providers subject to the same RIN reporting requirements is likely to reflect a more reasonable estimate of the efficient costs required by United Energy. This is because, despite some differences, there are many similarities between the circumstances of the Victorian distribution businesses. For example, like AusNet Services, United Energy's general ICT capex requirement (excluding RIN reporting and Power of Choice related costs) is forecast to decline in the 2016–20 regulatory control period following significant investment in the 2011–15 regulatory control period. Also, like other businesses, United Energy has proposed additional expenditure on related ICT projects which will assist in meeting the RIN reporting requirements.[366]

In summary, having reviewed the information submitted by United Energy, we are not satisfied that United Energy's revised proposal capex for the RIN reporting compliance project reflects a reasonable estimate of the efficient costs of a prudent operator.[367] The business case submitted by United Energy does not fully support the efficiency of the forecast costs. United Energy's proposed RIN compliance capex of $16.3 million ($2015) significantly exceeds the investment requirements identified by other service providers, and in any case was made in error as acknowledged by United Energy.[368]

In our view, forecast capex of $11.0 million reasonably reflects the efficient costs for United Energy to achieve RIN reporting compliance. This level of capex aligns United Energy's total (capex and opex) RIN compliance costs with those of other Victorian distributors (specifically CitiPower/Powercor) which we consider to be efficient. We consider that this level of capex, although higher than other distributors, is commensurate with United Energy's need for significant system investment given past asset management practices. It also represents an efficient trade-off between capex and opex given United Energy's comparatively small opex step change. We will make allowance for our substitute estimate of RIN compliance capex in our estimate of United Energy's total capex. We have accepted United Energy's forecast RIN compliance opex step change, as discussed in attachment 7 of this final decision.

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365 United Energy, *Response to AER information request 046*, 23 February 2016, pp. 2–3.

366 The asset data collection project and asset management system capability project. Refer to United Energy, *Attachment 5-39 - PJ22 RIN reporting*, 22 December 2015, p. 5.

367 NER, cl. 6.5.7(c).

368 United Energy, *Response to AER information request 046*, 23 February 2016, p. 1.

C Maximum demand

The expected maximum demand is a key input into a distributor's forecast capex and opex and to our assessment of that forecast expenditure.[369] This attachment sets out our decision on United Energy's forecast maximum demand for the 2016–20 period.

In this section, demand refers to summer peak demand (MW), unless otherwise indicated. The demand data reviewed in this section are non-coincident summer peak demand data with probability of exceedance (POE) of 10 percent and has been weather adjusted and summated at the transmission connection point level.

In our preliminary decision, we were not satisfied that United Energy's maximum demand forecast was a realistic expectation of demand over the 2016–20 regulatory control period.[370] We considered that independent forecasts from the Australian Energy Market Operator (AEMO) more likely reflected a realistic expectation of demand over the 2016–20 period.[371] We subsequently reflected AEMO's forecasts in our preliminary decision on United Energy's augex proposal.

At the time of our preliminary decision, United Energy (and the Victorian electricity businesses) were in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR) process. In addition, AEMO updated their most recent Victorian maximum demand forecast, which was too late to be considered as part of our preliminary decision. Hence, we stated that we would consider updated demand forecasts and other information (such as AEMO's most recent demand forecasts) in our final decision.

United Energy did not contest our preliminary decision about its maximum demand forecasts and did not provide us with updated forecasts in its revised decision. We maintain our preliminary decision that United Energy's original maximum demand forecast does not reflect a realistic expectation of demand because:

- it remains significantly above AEMO's updated maximum demand forecasts in terms of both the level and growth in maximum demand, and
- it proposes a significant step-up in maximum demand when compared to the recent flattening of demand since 2010, which is not adequately explained.

Figure 6.23 shows AEMO's updated maximum demand forecast, and United Energy's initial maximum demand forecast for comparison. AEMO's has increased the level of its maximum demand forecast since its original 2014 forecast. AEMO attributes the increased demand forecast to population and economic growth in Victoria, as well as

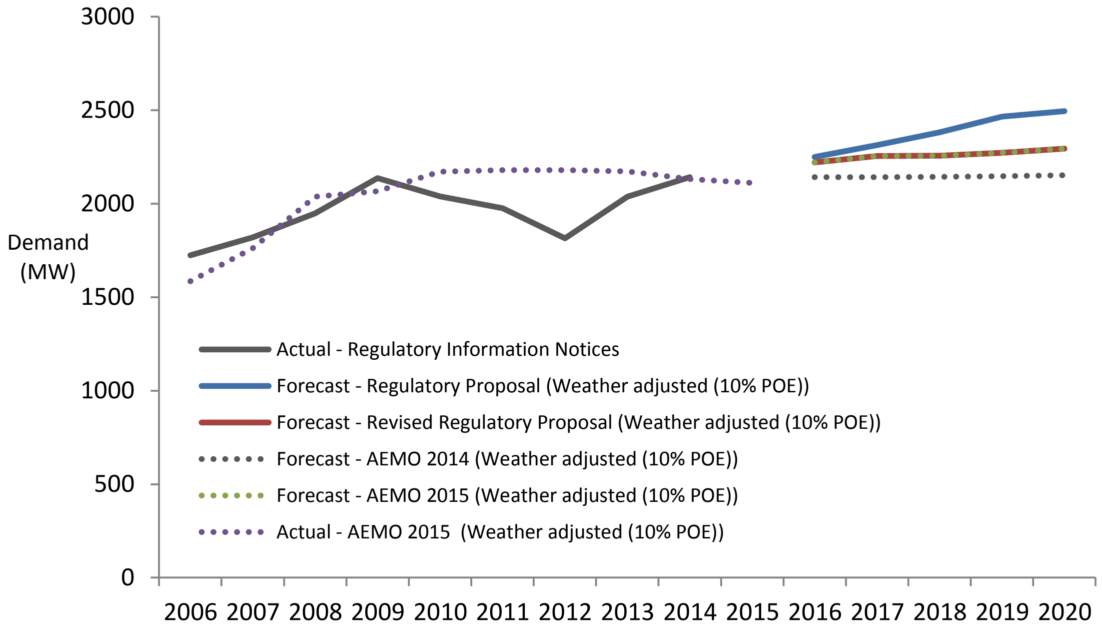
[369] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).

[370] AER, *Preliminary Decision 2016–20, United Energy: Attachment 6: Capital expenditure*, p. 114.

[371] AER, *Preliminary Decision 2016–20, United Energy: Attachment 6: Capital expenditure*, p. 114, 128.

improvements to its forecasting methodology through adjustments for historical rooftop PV and the reconciliation process.[372]

Figure 6.23 United Energy and AEMO maximum demand forecasts



Source: AER analysis, United Energy, Reset RIN 2016–20, April 2015; AEMO, Dynamic interface for connection points in Victoria, September 2014; AEMO, Dynamic interface for connection points in Victoria, 22 December 2015; United Energy, Economic Benchmarking RIN (Actual) for 2006–13; United Energy Economic Benchmarking RIN (Actual) for 2014.

Note: The actual raw demand for 2015 is not yet available from United Energy.

As shown in Figure 6.23, United Energy's weather adjusted historical demand shows a flattening of maximum demand growth from 2010.[373] United Energy's original maximum demand forecast reflected a significant step-up in demand growth that is inconsistent with this recent trend. In contrast, AEMO's demand forecasts are more consistent with recent trends. While AEMO's updated demand forecasts is slightly above the recent trend, it incorporates the most up-to-date data and revisions to its methodology such that we consider it currently reflects a realistic expectation of demand. As we explain in section B.2, we continue to adopt our preliminary decision for United Energy's demand-driven capex because United Energy accepted our preliminary decision and did not provide any further information.

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[372] AEMO, 2015 AEMO transmission connection point forecasting report for Victoria, September 2015, pp. 4, 8.

[373] In our preliminary decision, we compared United Energy's demand forecast with United Energy's actual demand during the 2006 to 2015 period. For our final decision we have enhanced this analysis by using weather adjusted demand data. Weather adjustment of actual demand data removes the effect of random weather factors on observed electricity demand. This enables us to draw more robust inferences about changes in the underlying level of demand for electricity from the historic data.

In two separate submissions, Origin Energy and AGL express support for our use of the latest AEMO connection point forecast in our assessment process.[374]

In its submission on our preliminary decisions for the Victorian electricity distributors, the Victorian Government notes that the electricity distributors may seek additional expenditures through revised demand forecasts.[375] We discuss the impact of United Energy's demand forecast on forecast augex in section B.2.

[374] Origin Energy, *submission to AER preliminary decision Victorian networks*, 6 January 2016, p.2. AGL, *submission to AER preliminary decision on the Victorian electricity distribution network regulatory proposals*, 7 January 2016, p. 1.

[375] The Victorian Government, *Submission to the AER on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20*, January 2016, p.1.

D Network performance and implications for proposed capex

D.6 Network reliability and safety performance

In its revised regulatory proposal, United Energy submitted that it considered our preliminary repex forecast amount of $413.9 million to be insufficient to enable it to meet its Service Target Performance Incentive Scheme (STPIS) targets and to satisfy its compliance obligations, including safety. United Energy submitted that as a consequence, the AER's preliminary forecast would not satisfy the capex objectives and criteria in the NER. [376]

United Energy submitted that its reliability performance deteriorated despite substantially increased expenditure on replacing assets over the 2011 to 2015 regulatory control period. [377] United Energy noted that it incurred STPIS penalties of approximately $40 million for its reliability performance over the 2011 to 2014 regulatory years.[378]

In its revised regulatory proposal, United Energy submitted the following four drivers were responsible for its increase in actual replacement expenditure:[379]

- deteriorating reliability
- deteriorating network safety
- ageing assets, whereby an increasing proportion of assets are entering their "wear out" phase; and
- increased investment in response to the findings of the Victorian Bushfire Royal Commission (VBRC).

These drivers, with the exception of 'VBRC' related capex and assets entering their wear out phase are discussed in section D.6 and in section D.7 respectively. We discuss United Energy's consideration of aging assets entering their wear out phase and proposed 'VBRC' related expenditure in appendix B.4.

D.6.1 Trends in reliability performance and asset failure

In our preliminary decision we assessed that United Energy's outages due to asset failures and network SAIFI[380] had both, on average, been flat across time. We

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376 NER, cll. 6.5.7(a) and (c).

377 United Energy, *2016 to 2020 Revised Regulatory Proposal*, 6 January 2016, p. 22.

378 United Energy, *2016 to 2020 Revised Regulatory Proposal*, 6 January 2016, p. 22.

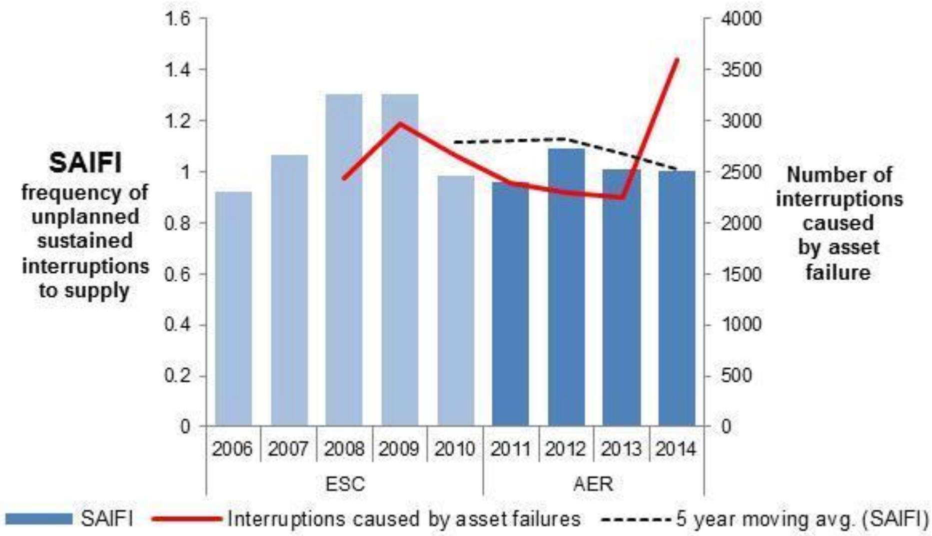
379 United Energy, *2016 to 2020 Revised Regulatory Proposal*, 6 January 2016, p. 22.

considered that the overall stability in both of these measures indicated that the replacement practices from the last period were sufficient for United Energy to meet the capex objectives.

Frequency of sustained interruptions to supply (SAIFI)

Figure 6.24 shows our initial assessment of United Energy's system wide SAIFI using audited data provided by United Energy in the AER's Economic Benchmarking RINs.

Figure 6.24 System wide unplanned SAIFI



Source: Economic Benchmarking RINs and Category Analysis RINs.

Subsequent to our initial assessment (in our preliminary decision) United Energy provided alternative data[381] to assess both system wide SAIFI, and the impact of asset failure on system wide SAIFI.[382] United Energy provided the alternative data it considered the data it provided in the Economic Benchmarking RINs was not appropriate for conducting a comparative assessment of SAIFI over time as it did not apply the AER's existing exemption criteria[383] to years prior to 2011.[384]

In its Revised Regulatory proposal United Energy stated:

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380 System Average Interruption Frequency Index (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).

381 Unaudited.

382 United Energy, *2016 to 2020 Revised Regulatory Proposal*, Attachment C, pp.139–160.

383 Certain events may be excluded when calculating the revenue increment or decrement under s3.3 of the Service Target Performance Incentive Scheme.

384 United Energy, *2016 to 2020 Revised Regulatory Proposal*, Attachment C, pp. 139–160.

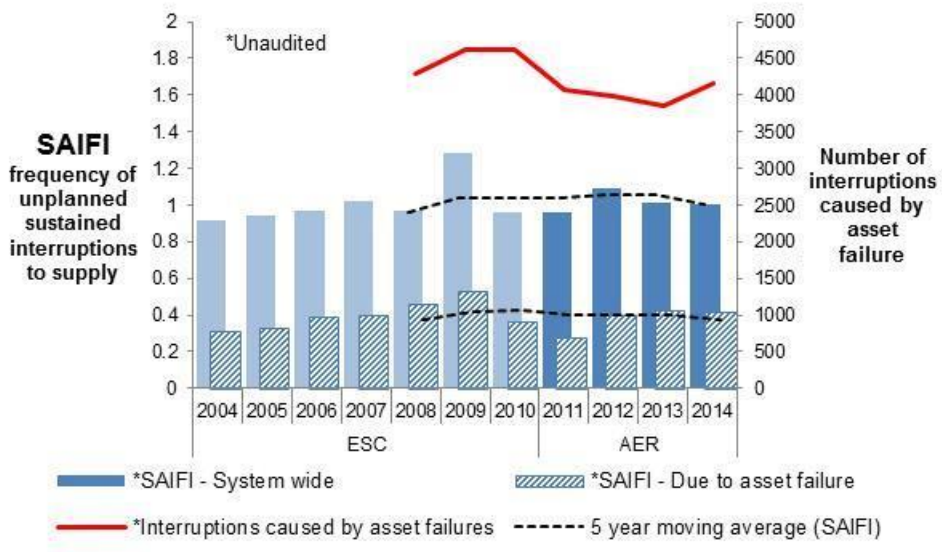
The data for 'unplanned sustained interruptions caused by asset failure' is missing some equipment failure data during 2008-13.[385]

In support of this statement United Energy also provided alternative data relating to unplanned sustained interruptions caused by asset failure.[386]

While we are not in a position to verify the accuracy of United Energy's unaudited alternative data, we have considered this information in the context of United Energy's reliability performance that is relevant to the capex objectives.

Figure 6.25 shows our assessment of United Energy's system wide SAIFI, the impact of asset failure on system wide SAIFI, and the number of unplanned sustained interruptions caused by asset failure using United Energy's alternative data.

Figure 6.25 System wide unplanned SAIFI and interruptions caused by asset failure



Source: AER analysis of (unaudited) data provided in United Energy's letter to AER dated 11 December 2015.

The alternative data provided by United Energy indicated that:

- system wide SAIFI has remained relatively constant across time
- system wide SAIFI as a result of asset failure has remained relatively constant across time, and
- the number of interruptions caused by asset failure has remained relatively constant across time.

385 United Energy, *2016 to 2020 Revised Regulatory Proposal*, p. 31.

386 United Energy, *2016 to 2020 Revised Regulatory Proposal*, - Table 3, Attachment C, p. 142 (unaudited).

Duration of sustained interruptions to supply (SAIDI)

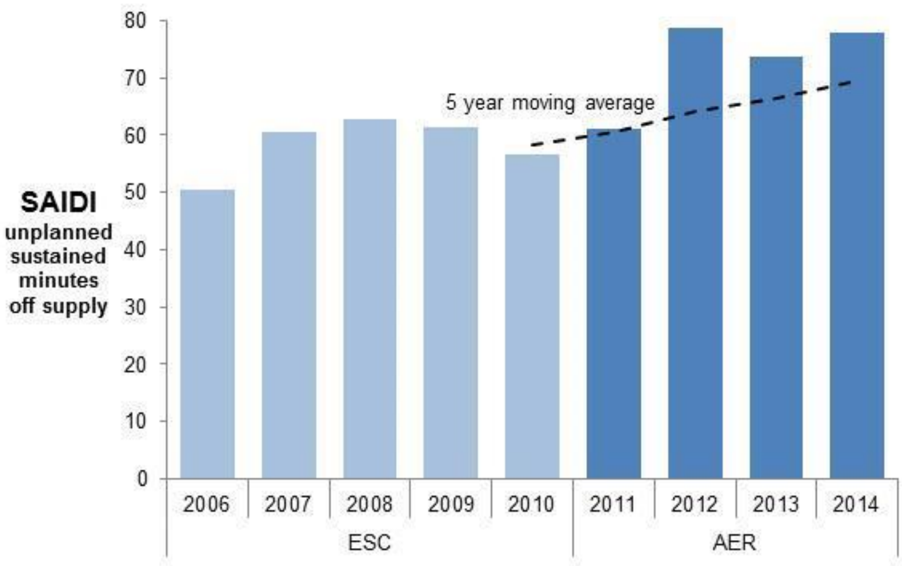
We observe in Figure 6.26 that United Energy's system wide SAIDI[387] performance deteriorated over the 2010 to 2014 period. This deterioration in system wide SAIDI has been reflected in our revised STPIS targets to be applied to United Energy over the 2016–20 regulatory control period.[388]

In its Revised Regulatory Proposal United Energy submitted that the deterioration in system wide SAIDI is important to its repex forecast because:

- it was driven by a trend increase in the number of assets approaching end of life; and
- it is facing a gap between its current level of reliability performance and the AER's STPIS target.

Our consideration United Energy's proposed expenditure to address network reliability is outlined in section B.4.4.

Figure 6.26 System wide unplanned SAIDI and interruptions caused by asset failure



Source: Economic Benchmarking RINs

387 System Average Interruption Duration Index (SAIDI): The sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).

388 See Chapter 11.

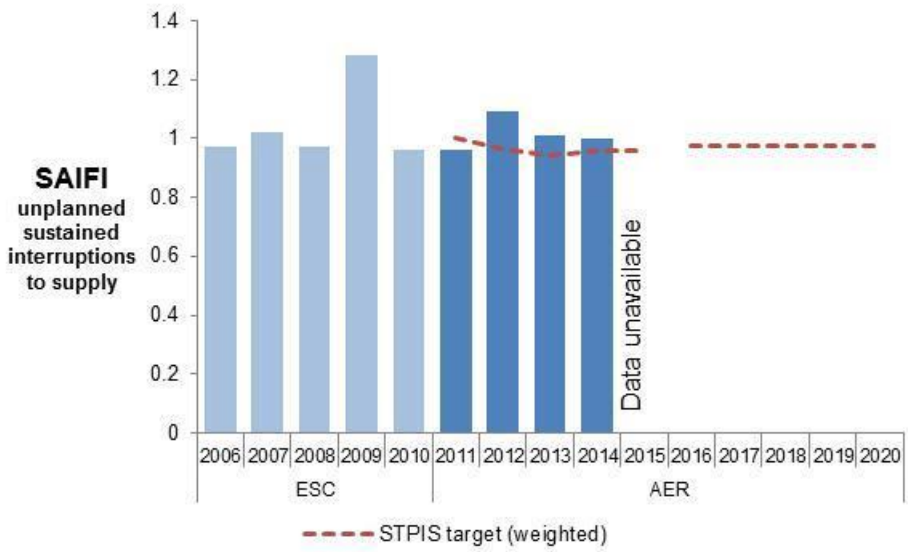
Correlation with STPIS targets

In its Revised Regulatory Proposal United Energy submitted that our STPIS targets for the 2016–20 regulatory control period contradicted our view that it has maintained its reliability performance. [389]

In response we note that our view regarding United Energy's network reliability performance was made in reference to United Energy's system wide SAIFI performance. As previously discussed, we maintain our view that United Energy has maintained its network SAIFI reliability performance.[390]

We observe that United Energy's reliability targets, as shown in Figure 6.27, Figure 6.28 and Figure 6.29 have been determined based on the criteria set out in the STPIS.[391]

Figure 6.27 STPIS targets - SAIFI[392]



Source: AER analysis of (unaudited) data provided in United Energy's letter to AER dated 11 December 2015

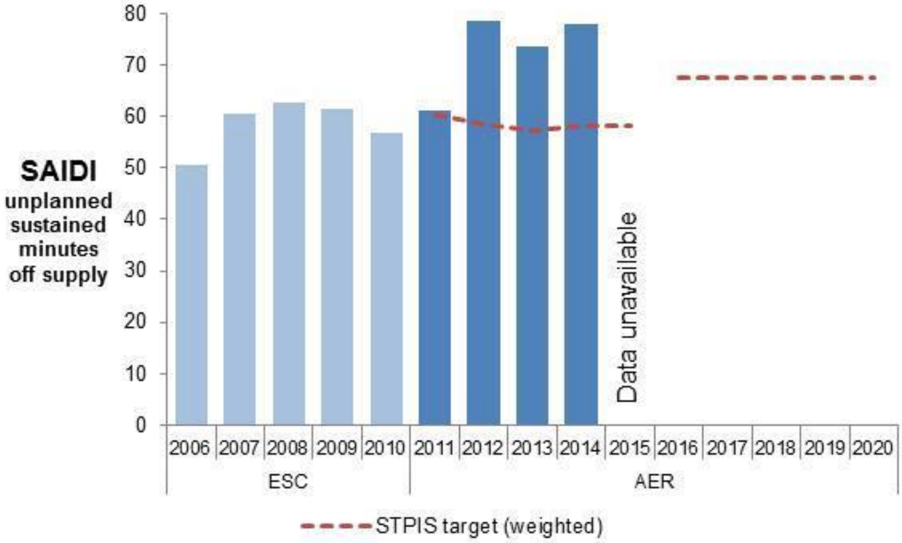
389 United Energy, *2016 to 2020 Revised Regulatory Proposal*, 6 January 2016, p. 28.

390 See page 6-127.

391 AER, *Service Target Performance Incentive Scheme*, s. 3.2.1(a)

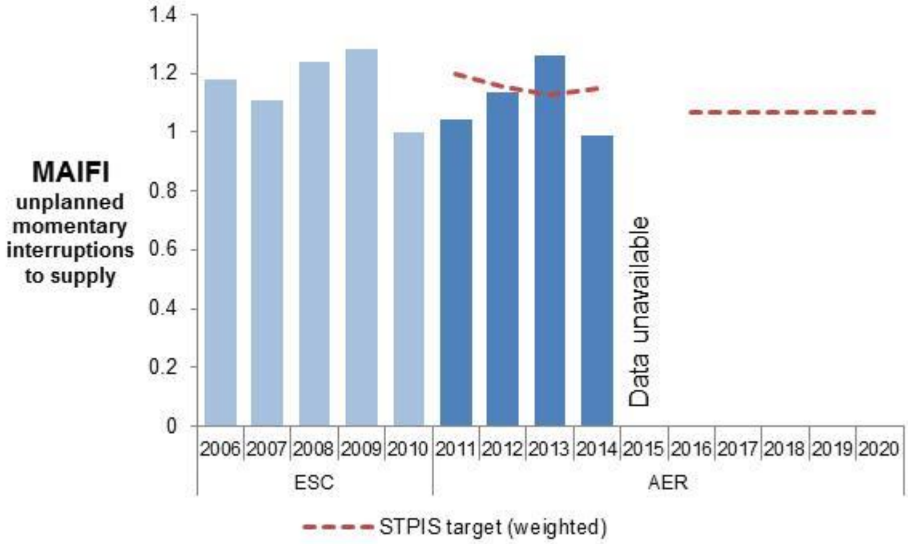
392 The STPIS targets shown in Figure 6.27 reflect weighted, system wide targets that have been calculated by multiplying the respective feeder targets by the proportion of networks customers on each feeder type.

Figure 6.28 STPIS targets - SAIDI[393]



Source: Economic Benchmarking RINs

Figure 6.29 STPIS targets - MAIFI[394]



Source: AER, Victorian Electricity Distribution Network Service Providers Annual Performance Report 2010 (May 2012) (2006-2010), Annual RINs (2011-14),

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393 The STPIS targets shown in Figure 6.28 reflect weighted, system wide targets that have been calculated by multiplying the respective feeder targets by the proportion of networks customers on each feeder type.

394 The STPIS targets shown in Figure 6.29 reflect weighted, system wide targets that have been calculated by multiplying the respective feeder targets by the proportion of networks customers on each feeder type.

In its Revised Regulatory Proposal United Energy stated:

> SAIDI is an important performance metric as it encompasses changes in fault frequency, the number of customers impacted, and restoration times.[395]

We note that this is not correct. SAIDI measures the average duration of unplanned sustained interruptions per customer. It does not measure the frequency of interruptions to supply. The frequency of interruptions to supply is measured by SAIFI and MAIFI.

As discussed above, United Energy's network SAIFI performance has remained relatively constant over time.[396]

United Energy also provided an assessment of its system wide CAIDI[397] to support its view that its network reliability has deteriorated.[398] For the reasons outlined in section (page) of this final decision we do not consider that CAIDI is an appropriate measure for considering whether past replacement practices are consistent with meeting the capex objectives.

The standard definitions of SAIDI, SAIFI and MAIFI can be found in our Service Target Performance Incentive Scheme (STPIS). [399] The STPIS also provides a definition of CAIDI despite it not featuring as a parameter in the scheme.

We use SAIDI, SAIFI and MAIFI to measure reliability performance, and to set performance targets.[400] These parameters measure the average duration and average frequency of interruptions to supply for each customer served. In particular:

- SAIDI is reported as the average duration of all sustained interruptions per customer over a regulatory year (i.e. total number of distribution customers ÷ the sum of the minutes of each unplanned sustained customer interruption)
- SAIFI is reported as the average number of sustained interruptions per customer over a regulatory year (i.e. total number of unplanned sustained customer interruptions ÷ the total number of distribution customers)
- MAIFI is reported as the average number of momentary interruptions per customer over a regulatory year (i.e. total number of unplanned momentary[401] customer interruptions ÷ the total number of distribution customers)

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395 United Energy, *2016 to 2020 Revised Regulatory Proposal*, p. 28.

396 United Energy's substantial deterioration in service performance on its short rural feeders has been given a seven per cent weighting in the system wide SAIDI shown in Figure 6.27, Figure 6.28, and Figure 6.29. This is because approximately seven per cent of United Energy's total network customers are on short rural feeders.

397 Customer Average Interruption Duration Index (CAIDI): The sum of the duration of each sustained customer interruption (in minutes); divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions (one minute or less duration).

398 United Energy, *2016 to 2020 Revised Regulatory Proposal*, Attachment C, pp. 139–160.

399 AER, *Electricity distribution network service providers - Service Target Performance Incentive Scheme,* November 2009, p. 22.

CAIDI differs from these measures as it does not strictly provide a 'per customer' measure. Instead, CAIDI provides a measure of the average duration of each individual interruption experienced by the average customer. As such, CAIDI is more reflective of a 'per interruption' measure than it is a 'per customer' measure.

The (hypothetical) examples in the example tables below demonstrate that fluctuations in CAIDI can be misleading as a measure of customer reliability.

Example: Ambiguous properties of CAIDI

When examining the (hypothetical) CAIDI figures in Example Table 1 in isolation, it appears as though there has been a consistent decline in the level of reliability in each year. However, both the frequency of interruptions (SAIFI) and the duration of interruptions (SAIDI) have decreased in each successive year (i.e. reliability has improved).

Example Table 1: Example of worsening CAIDI (hypothetical)

	Year 1	Year 2	Year 3	Year 4	Year 5
SAIDI	50	43	36	31	26
SAIFI	2	1.4	0.98	0.69	0.48
CAIDI	25	30	37	45	54

Source: AER Analysis.

Conversely, when examining the (hypothetical) CAIDI figures in Example Table 2 in isolation, it appears as though there has been a consistent improvement in the level of reliability in each year. However, both the frequency of interruptions (SAIFI) and the duration of interruptions (SAIDI) have increased in each successive year (i.e. reliability has deteriorated)

Example Table 2: Example of improving CAIDI (hypothetical)

	Year 1	Year 2	Year 3	Year 4	Year 5
SAIDI	50	60	72	86	104
SAIFI	2	2.5	3.13	3.91	4.88
CAIDI	25	24	23	22	21

Source: AER Analysis.

401 One minute or less.

An increase in CAIDI could mean that the distributor is doing a progressively worse job of restoring power to its customers. However, it is also possible that a higher (worse) CAIDI means that the distributor was simply experiencing less frequent outages.

Conversely, a decrease in CAIDI could mean that the distributor is doing a better job of restoring power to its customers. However, it is also possible that a lower (better) CAIDI means that the distributor was experiencing more short duration outages.

Example Table 3 provides an additional exaggerated (hypothetical) example that can be used to further highlight this point.

Example Table 3: Exaggerated example of maintaining CAIDI (hypothetical)

	Year 1	Year 2
Total number of distribution customers	100	100
Sum of the duration of each unplanned sustained customer interruption (in minutes)	5 000	51 564 706
Total number of unplanned sustained customer interruptions	100	1 031 294
SAIDI	50	515 647
SAIFI	1	10 313
CAIDI	50	50

Source: AER Analysis

In year 1 the average customer only experienced one interruption to supply which lasted 50 minutes. As there was only one interruption to supply for the year the average duration of all sustained interruptions (SAIDI) and average duration of each interruption (CAIDI) are the same, that being '50'.

In year 2 the average customer experienced 10 313 sustained interruptions to supply (SAIFI) and experienced a total of 515 647 minutes off supply (SAIDI). This example demonstrates an extremely unlikely scenario wherein the customer is, for the entirety of year 2, in a repetitive cycle of having electricity supplied for one minute, then being off supply for fifty minutes. Despite what is clearly a disastrous year, the CAIDI is again 50 minutes. Note this is the same CAIDI as year 1 when the average customer only experienced one interruption to supply.

These examples, in particular the exaggerated example provided in the box above demonstrate that changes in CAIDI can be misleading when used as a measure of customer reliability.

In short, CAIDI is mathematically equal to SAIDI divided by SAIFI. Therefore, CAIDI will increase if SAIFI improves more quickly than SAIDI. Thus, if the change in SAIFI is proportionately greater than the change in SAIDI, then CAIDI will move in the opposite direction of SAIDI and SAIFI.

As was evidenced in section , a distributor's reliability could be improving on both SAIFI and SAIDI; however, CAIDI could still be getting worse. This worsening level in CAIDI could easily be misinterpreted as a decline in the level of reliability. When putting this in the context of the STPIS, a distributor could receive significant financial rewards for continually improving and outperforming its SAIDI and SAIFI targets, whilst simultaneously the CAIDI would indicate a decline in service performance.

The most effective initial activities for a distributor embarking on reliability improvement initiatives may involve focusing on faults that occur frequently but are relatively quick and easy to repair. Once these relatively quick and easy faults are addressed, the causes of the remaining interruptions on the network may take longer to repair, causing CAIDI to increase.

In summary we note that CAIDI may be appropriate as a measure of operational efficiency. However, for the reasons discussed above we do not consider CAIDI to be an appropriate measure for considering whether past replacement practices are consistent with meeting the capex objectives.[402]

D.6.2 Network reliability drivers

In its Network Reliability Assessment United Energy stated:

> CAIDI has increased at 2.2 minutes per year over the last ten years; this was predominately driven by:
>
> - reductions in traffic flow speeds which means our response crews take longer to reach site
> - increasing number of HV events, which typically take longer to repair than faults on the LV network
> - increasing number of HV simultaneous events, and a shortage of resources; and
> - increasing percentage of faults caused by equipment failure which take longer to repair. [403]

These drivers are discussed below.

Reductions in traffic flow speed

In its Revised Regulatory Proposal United Energy stated that:

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402 CAIDI may be more relevant to measuring a distributor's operational efficiency on the basis that when the distributor responds more quickly after an interruption to supply, CAIDI may improve (decrease).

403 United Energy, *Network Reliability Assessment*, December 2015, p. 58.

> … our CAIDI performance had deteriorated predominately due to increased traffic resulting in longer times for response crews to reach site.[404]

As previously discussed we do not consider CAIDI to be an appropriate measure for determining whether proposed capex is consistent with the capex objectives. However, we note the driver of the duration component of CAIDI (i.e. the numerator) is directly correlated with the driver of the duration (i.e. 'minutes') component for SAIDI.[405] It follows that United Energy considers that the main reason for its deteriorating SAIDI is also due to the increase in road traffic congestion impacting on response times.

Sub-transmission, HV and LV asset failures

In its Revised Regulatory Proposal United Energy stated that:

> … HV and sub-transmission equipment failure is increasing at approximately 5 per cent per annum. This rate increases to nearly 10 per cent per annum if the data series commences in 2004. The increasing HV and sub-transmission equipment failure rate is consistent with our increasing network wide SAIFI. [406]

Our analysis of United Energy's data does not support this view.

Despite appearing to propose otherwise, United Energy's statement (above) suggests that the rate of increase in the frequency of its HV and sub-transmission equipment failures is decreasing. We note that a 5 per cent rate of increase over a specified time period when compared to a 10 per cent rate of increase over a longer time period indicates that the rate of increase is actually decreasing. We note, however, that United Energy did not provide data extending back to 2004 to support its statement.

Figure 6.30 shows that, as previously stated[407], system wide SAIFI has remained relatively constant across time despite the increase in the total number of HV and sub-transmission asset failures. An example of why we consider SAIFI to be a more relevant measure of performance than total number of events is provided in section on page .

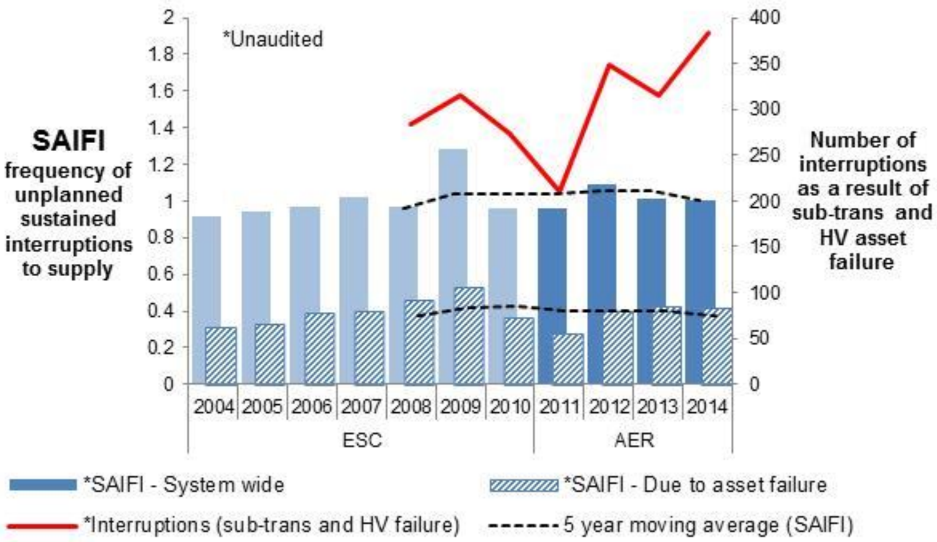
[404] United Energy, *Revised Regulatory Proposal*, p. 27.

[405] CAIDI = SAIDI ÷ SAIFI

[406] United Energy, *Revised Regulatory Proposal*, p. 27.

[407] Frequency of sustained interruptions to supply (SAIFI), p. 6-25.

Figure 6.30 System wide unplanned SAIFI and interruptions caused by sub-transmission and HV asset failure



Source: AER analysis of (unaudited) data provided in United Energy's letter to AER dated 11 December 2015

Figure 6.30 also shows that SAIFI as a result of sub-transmission and HV asset failure has remained relatively constant across time despite the increase in the total number of HV and sub-transmission asset failures.

This indicates that although the total number of HV and sub-transmission asset failures has increased, the total number of customers impacted by these failures has remained relatively constant. It is important to remember that SAIFI is reported as the average number of sustained interruptions per customer over a regulatory year. For example, one interruption to supply that affects 1000 customers will have the same SAIFI impact as two separate interruptions to supply that affect 500 customers each.[408]

Our assessment of system wide SAIFI, and the impact of asset failure on system wide SAIFI using United Energy's alternative data supports our preliminary decision that the trend in both interruptions to supply due to asset failures and system wide SAIFI have, on average, been flat across time. United Energy's alternative data shows that the impact of asset failure on system wide SAIFI has also been consistent across time.

The overall stability in both of these measures suggests that United Energy's replacement practices from the previous period have been sufficient to meet the capex objectives.

In its Network Reliability Assessment [409] United Energy submitted that its increasing CAIDI has been driven by:

[408] Given the distributor has same total number of distribution customers in each scenario.

[409] United Energy, *Network Reliability Assessment (UE PL 2304),* December 2015, p. 58.

- an increasing number of HV events, which typically take longer to repair than faults on the LV network, and
- an increasing number of HV simultaneous events, and a shortage of resources.

United Energy stated that

> … the AER should use only the information for sub-transmission and HV asset failures to draw conclusions in its assessment of reliability trends. [410]

United Energy provided the following information in support of this view:

- LV equipment failure accounts for 93 per cent of total equipment failure, but only accounts for 11 per cent of equipment failure SAIFI
- Sub-transmission and HV equipment failure accounts for only 7 per cent of total equipment failures, but account for 89 per cent of equipment failure SAIFI.

We do not agree with United Energy's view that we should exclude LV asset failures when measuring reliability performance. SAIFI measures the frequency of sustained interruptions to supply per customer. The type of failed asset responsible for an interruption to supply (i.e. sub-transmission, HV or LV) is of no relevance as the calculation of SAIFI affords no singular outage any greater weighting than the next. This is illustrated in the example below.

[410] United Energy, *Revised Regulatory Proposal*, January 2016, p. 27.

Example: Calculation of SAIFI

As previously mentioned, SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers on the distribution network. The SAIFI impact of interruptions to supply caused by a specific class of asset (e.g. asset 'A') is calculated by dividing the total number of unplanned sustained customer interruptions resulting from asset failures on 'asset A' by the total number of distribution customers.

The numerator in the calculation of SAIFI is 'number of unplanned sustained customer interruptions' not 'number of unplanned sustained interruptions'. Therefore, if United Energy's LV asset failures account for 89 per cent of its asset failure SAIFI, the calculation of SAIFI will automatically afford it an 89 per cent weighting. The fact that LV asset failures only account for 7 per cent of total asset failures is irrelevant to the calculation of SAIFI.

Example Table 4 highlights the point that the calculation of SAIFI considers the impact on customers. It is not impacted by the quantity of specific types of asset failures (i.e. sub-transmission, HV or LV).

Example Table 4: Allocation of asset failure SAIFI to system wide SAIFI

	Proportion of total asset failures	Proportion of asset failure SAIFI	Proportion of system wide SAIFI	Contribution to system wide SAIFI
System wide	-	-	100%	2.00
Asset failure - Total	100%	100%	50%	1.00
Sub-transmission and HV	7%	89%	44.5%[411]	0.89
LV	93%	11%	5.5%[412]	0.11

Source: AER analysis.

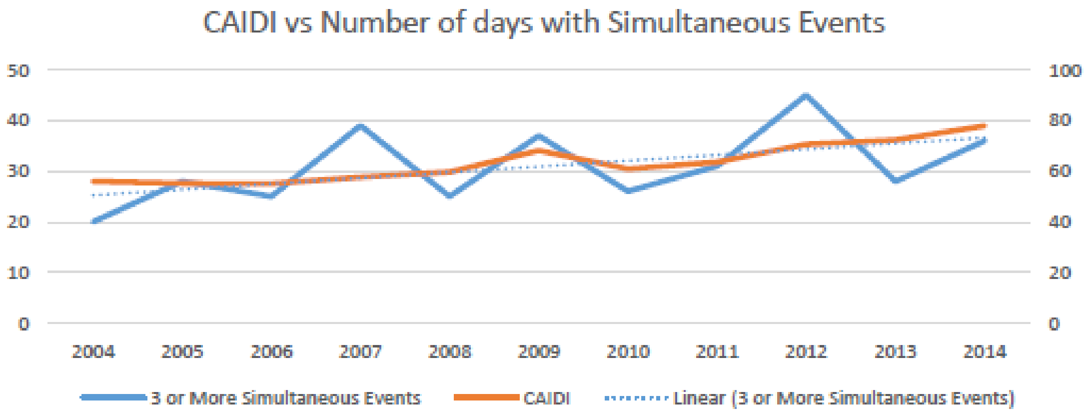
The example in Example Table 4 simply implies that a (hypothetical) 10 per cent reduction in the number of failures on sub-transmission and HV assets will have a more substantial impact on system wide SAIFI than a (hypothetical) 10 per cent reduction in the number of failures on LV assets. This is due to the SAIFI calculation accounting for the fact that customers are more greatly impacted by sub-transmission and HV asset failures than they are by LV asset failures. In summary, we acknowledge that assessing the proportional SAIFI impact of each type of asset failure can be used to provide insight into which types of assets contribute the most to SAIFI. However, for the reasons explained above, we see no reason to adopt United Energy's recommendation of only using sub-transmission and HV asset failures to draw conclusions on reliability trends.

Simultaneous HV failure events

In its Network Reliability Assessment United Energy noted that the deterioration in CAIDI has been driven by an increase in the number of HV simultaneous events[411], and a shortage of resources.

United Energy proposed that the trend increase in the number of days with simultaneous events has risen from 25 days per year to over 60 days per year over a 10 year period (Figure 6.31).[412]

Figure 6.31 Simultaneous events and unplanned CAIDI - United Energy assessment



Source: *United Energy, Network Reliability Assessment*, December 2015 (p. 61).

Our assessment of United Energy's data (presented in Figure 6.31) found that with the exception of the unusually high number of days with simultaneous events in 2012 the trend in simultaneous events has remained relatively constant since 2006. As such, this relatively constant trend in simultaneous events should be reflected in United Energy's 'business as usual' replacement expenditure which we have assessed in our Predictive modelling section (see page 50). That said, we have considered United Energy's proposed capex related to network reliability (see page 6-72).

D.7 Network safety

In its Revised Regulatory Proposal United Energy submitted that, in making our Preliminary Decision, we misunderstood matters relating to its safety performance. [413] United Energy submitted that we were incorrect in determining that its safety performance had been maintained during the 2011 to 2015 regulatory control period.

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[411] Events that have a start and finish time that overlap.

[412] United Energy, *Network Reliability Assessment (UE PL 2304)*, December 2015, p. 58.

[413] United Energy, *Revised Regulatory Proposal*, p. 25.

United Energy submitted that our initial assessment of its network safety performance failed to consider non-asset failure metrics. United Energy's Network Safety Assessment provided further information in support of its safety performance and the Repex needed to meet our network safety obligations.[414]

United Energy grouped its key 'safety metrics' into the following broad categories: [415]

- asset failures
- fire starts; and
- incidents involving the public.

United Energy also made reference to a set of metrics developed by Energy Safe Victoria (ESV) designed to manage network safety performance. [416] United Energy indicated its source for these metrics was the ESV's 'Distribution Business Electrical Safety Performance Reporting Guidelines (the Guidelines)'. [417] [418]

United Energy also referred to the following assessments from the ESV Safety Performance Report on Victorian Electricity Networks (the ECV Report)[419]:

- asset performance is either stable or improving for four out of five businesses
- the number of fires caused by network assets declined for four out of five businesses
- an overall increase in fire numbers and asset failures was driven principally by one company – United Energy.

United Energy submitted that we should have regard for the independent assessment of the safety regulator (the ESV) in our Final Decision.

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414 In its Network Safety Assessment (p. 7) United Energy states that:

> 'The (Electricity Safety) Act imposes an obligation to not only maintain present levels of safety but to reduce it "as far as practicable".'

We observe that this is not an exact representation of the obligations imposed by the Act.

s. 98 of the *Electricity Safety Act (1998)* specifies:

> A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable -
>
> (a) the hazards and risks to the safety of any person arising from the supply network; and
>
> (b) the hazards and risks of damage to the property of any person arising from the supply network; and
>
> (c) the bushfire danger arising from the supply network.

415 United Energy, *Network safety Assessment*, p. 7.

416 United Energy, *2016 to 2020 Revised Regulatory Proposal*, January 2016, p. 31.

417 Energy Safe Victoria, Distribution Business Electrical Safety Performance Reporting Guidelines.

418 We note the Guidelines provide distribution businesses with guidance on the application of both the Electricity Safety Act and the Electricity Safety (Management) Regulations when reporting incidents involving their assets. However, we note that the Guidelines do not provide any metrics designed to manage the distribution businesses' safety performance.

419 Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks 2014.

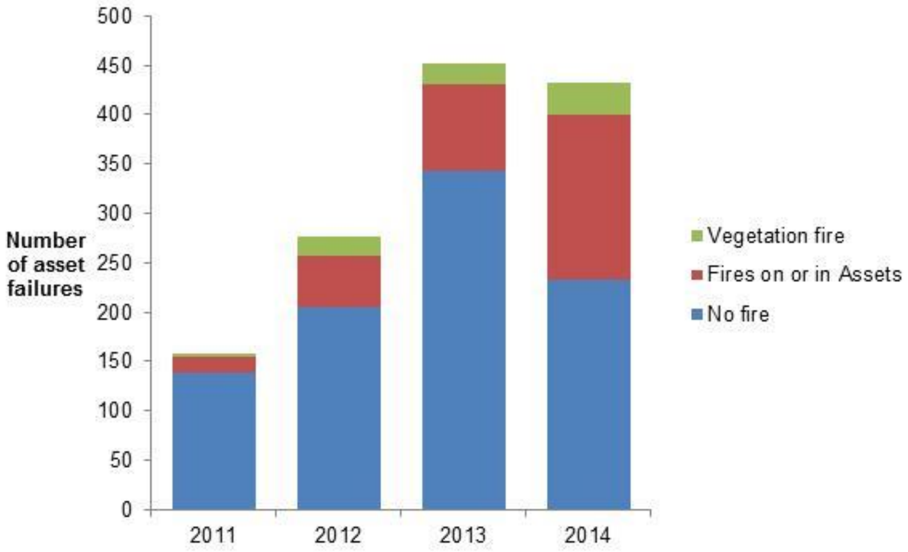
Asset failures

In its Revised Regulatory Proposal United Energy stated that:

> …the vast majority of “unplanned sustained outages due to asset failure” are not relevant to network safety. Therefore, the AER should revise its assessment of network safety using only asset failure data that is relevant to network safety.[420]

United Energy provided data (Figure 6.32) and supplementary commentary to support its view that its safety performance has deteriorated[421]. United Energy also referenced the ESVs 'Safety Performance Report on Victorian Electricity Networks' (the Report) [422] as a supporting document.

Figure 6.32 Asset failures relevant to network safety[423]



Source: United Energy, Network Safety Assessment, December 2015 (pp. 15–17).

We note that United Energy defines an asset failure as being 'relevant for network safety' if it complies with the set of metrics developed by the ESV to manage network safety performance. [424]

The ESV provided the following assessment of United Energy's asset failures in its Report:

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[420] United Energy, *Revised Regulatory Proposal*, January 2016, p. 31.

[421] United Energy, *Revised Regulatory Proposal*, January 2016, p. 30.

[422] Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks, 2014.

[423] See footnote on p. 37 for United Energy's definition of 'relevant to network safety'.

[424] United Energy, 2016 to 2020 Revised Regulatory Proposal, January 2016, p. 31.

> Even though there was a significant reduction in the number of failures of crossarms and LV assets in 2014 compared to 2013, these still remain the main assets that fail. These failures can lead to serious consequences such as bushfire, serious injury or death. ESV recommends that United Energy reviews its asset programs and addresses the root cause of these failures.

The ESV Report also stated the following in reference to the 2010–13 period:

> United Energy contends that it was incorrectly reporting crossarms as failed when they had been noted as requiring urgent replacement. This would mean the failure rates reported may be overstated. United Energy will not attempt to correct the historical quantities reported, but will in future only report crossarm failures when they actually fail. [425]

In its Network Safety Assessment United Energy stated:

> … [internal] targets for network safety have been set firstly by considering the average performance of the 2011 -2014 period. For some of the metrics, reliable data is not available for 2011 [426]

United Energy did not submit that the relevant data presented in its Revised Regulatory Proposal, and presented as the basis of its assertion that its safety performance has deteriorated, is potentially inconsistent.

We note that the ESV made a number of recommendations to United Energy in its Report, most of which related to reporting, program assessments, processes and procedure, and stakeholder engagement. Of these recommendations, only the replacement of crossarms due to age and condition and to mitigate pole-top fires is directly relevant to United Energy's replacement expenditure:

In its Report the ESV stated:

> The evidence is that United Energy's crossarm replacement program is not keeping pace with the rate of incidents, and this is likely to seriously impact safety. Replacement rates need to be increased to reverse the upward trend as failure to do so will increase the safety risk; both age and condition should be used as criteria for replacement. [427]

We note that we included United Energy's proposed replacement expenditure for Pole Top Structures[428] in our Preliminary Decision[429]. In its Revised Regulatory Proposal United Energy stated that:

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425 Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks, 2014, p. 128.

426 United Energy, *Network Safety Assessment*, December 2015, p. 21.

427 Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks, 2014, p. 128.

428 Pole Top Structures = Crossarms.

429 AER, *Preliminary Decision - United Energy distribution determination 2016 to 2020 - Attachment 6 Capital Expenditure*, p. 6-79.

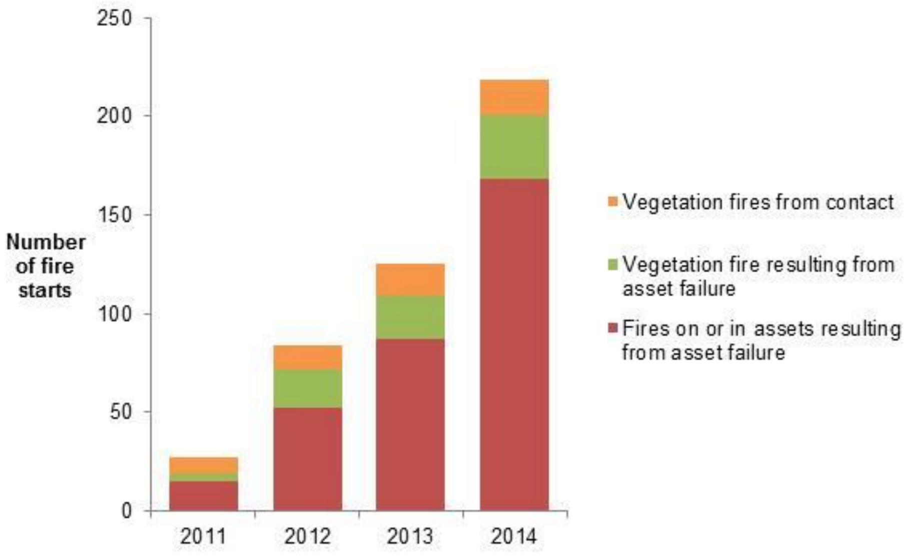
> The AER accepted our Repex forecasts for Pole Top Structures and SCADA, except for our forecast cost escalation. We accept the AER's Preliminary Decision on Pole Top Structures and SCADA. [430]

As such the amount in our alternative estimate has adopted United Energy's proposals in relation to crossarms.

Fire starts

United Energy provided data (Figure 6.33) and commentary to support its view that its safety performance has deteriorated[431]. United Energy also referenced the ESVs 'Safety Performance Report on Victorian Electricity Networks' (the Report) [432] as a supporting document.

Figure 6.33 Fire starts



Source: United Energy, Network Safety Assessment, December 2015 (pp. 16–18).

United Energy stated that:

> The increase [in fire starts since 2011] is largely due to the larger numbers of fires on assets and in particular to the number of pole and cross arm fires.

As previously mentioned we included United Energy's proposed replacement expenditure for Pole Top Structures[433] in our preliminary decision[434]. In its Revised Regulatory Proposal United Energy submitted that:

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[430] United Energy, *Revised Regulatory Proposal*, January 2016, p. 22.

[431] United Energy, *Revised Regulatory Proposal*, January 2016, p. 30.

[432] Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks, 2014.

[433] Pole Top Structures = Crossarms.

The AER accepted our Repex forecasts for Pole Top Structures and SCADA, except for our forecast cost escalation. We accept the AER's Preliminary Decision on Pole Top Structures and SCADA. [435]

As such the amount in our Final Decision has adopted United Energy's proposals in relation to addressing these risks.

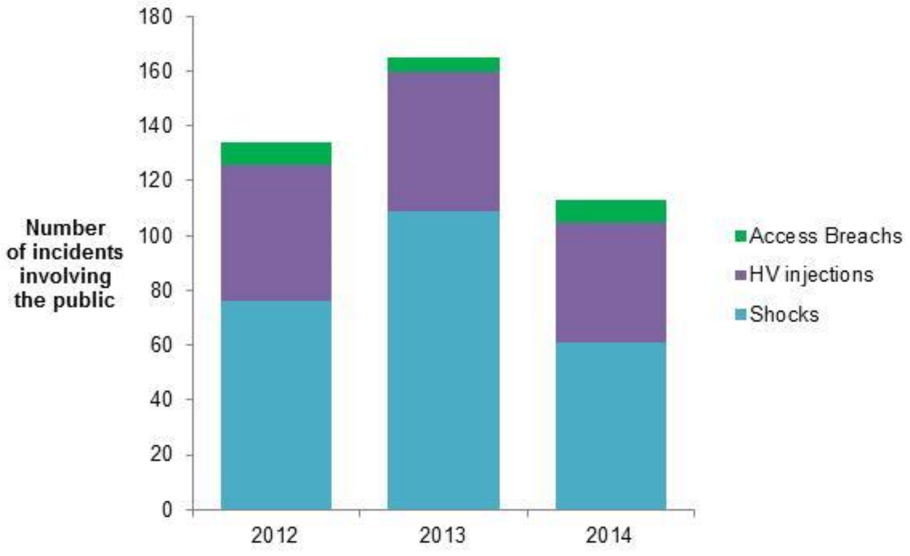
We note that United Energy has decided not to proceed with the replacement of SWER lines to mitigate bushfire risk, based on the outcome of its bushfire mitigation ALARP (as low as reasonably practicable) risk assessment.[436]

We have considered proposed expenditure related to bushfire mitigation measures in section B.4.4 (page 91).

Incidents involving the public

United Energy provided data (Figure 6.34) and commentary to support its view that its safety performance has deteriorated[437]. United Energy also referenced the ESVs 'Safety Performance Report on Victorian Electricity Networks' (the Report)[438] as a supporting document.

Figure 6.34 Incidents involving the public



Source: United Energy, Network Safety Assessment, December 2015, p. 20.

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[434] AER, *Preliminary Decision - United Energy distribution determination 2016 to 2020 - Attachment 6 Capital Expenditure*, October 2015, p. 6-79.

[435] United Energy, *Revised Regulatory Proposal*, January 2016, p. 22.

[436] United Energy, *Asset High Risk of Failure Assessment*, December 2015.

[437] United Energy, 2016 to 2020 Revised Regulatory Proposal, January 2016, p. 30

[438] Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks, 2014

In its Revised Regulatory Proposal United Energy stated that:

> Our safety performance for both asset failures and fire starts is clearly deteriorating, whilst our performance for incidents involving the public is relatively constant.

The ESV provided the following assessment of United Energy's incidents involving the public in its Report:

> Pole-top fires, crossarm failures, lightning strikes and other asset failures are the main cause of high voltage injections. High voltage injections reported to ESV by United Energy during 2014 are mostly due to crossarm fires causing failure of the crossarm and subsequent contact with the lower voltage conductors. This further reinforces the recommendation … that crossarms should be replaced based on both age and condition, and that United Energy needs to increase the rate at which it replaces crossarms.

As previously mentioned we accepted United Energy's proposed replacement expenditure for Pole Top Structures[439] in our Preliminary Decision.[440]

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439 Pole Top Structures = Crossarms

440 AER, *Preliminary Decision - United Energy distribution determination 2016 to 2020 - Attachment 6 Capital Expenditure*, October 2015, p. 6-79.