DRAFT DECISION

United Energy
Distribution determination
2021 to 2026

Attachment 5
Capital expenditure

September 2020

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to United Energy for the 2021–26 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

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

Attachment 12 – Not applicable for this distributor

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

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Attachment A – Victorian f-factor incentive scheme

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5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS). Generally, these assets have long lives and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).[1]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[2] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the National Electricity Objective (NEO)).[3]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[4] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Appendix A outlines further detailed analysis of our draft decision.

Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our ex-ante incentive-based regulatory framework and is often referred to as the 'capex bucket'.

Once the ex-ante capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. This incentive-based framework recognises that distributors should have the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

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1 NER, cl. 6.5.7(a).

2 NER, cl. 6.5.7(c).

3 NEL, ss. 7, 16(1)(a).

4 AER, *Capex assessment outline for electricity distribution determinations,* February 2020.

Distributors may need to undertake programs or projects that they did not anticipate during the reset. Distributors also may not need to complete some of the programs or projects proposed if circumstances change. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs. As noted previously, distributors may spend more or less than our forecast in response to unanticipated changes.

We use real $2020–21 unless otherwise noted.

5.1 Draft decision

We do not accept United Energy's updated net capex forecast of $1127.6 million for the 2021–26 regulatory control period.[5] We are not satisfied that its total net capex forecast reasonably reflects the capex criteria. Our substitute estimate of $833.3 million is 26 per cent below United Energy's initial proposal. We are satisfied that our substitute estimate reasonably reflects the capex criteria. Table 5.1 outlines our draft decision.

Table 5.1 Draft decision on United Energy's total net capex for the 2021–26 regulatory control period ($ million, $2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's updated proposal	243.0	229.0	231.5	227.0	197.0	1127.6
AER draft decision	165.5	161.2	165.8	165.6	175.2	833.3
Difference ($)	-77.5	-67.8	-65.7	-61.4	-21.9	-294.3
Difference (%)	-32	-30	-28	-27	-11	-26

Source: United Energy's initial PTRM and subsequent update and AER analysis.

Note: Numbers may not sum due to rounding.

5.2 United Energy's initial proposal

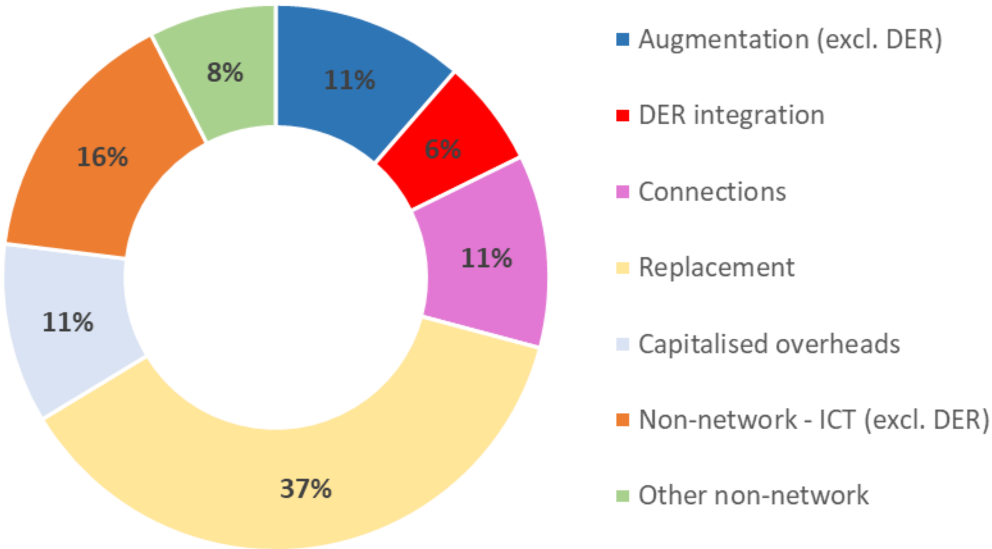
United Energy forecast $1212.6 million for net capex in its initial capex proposal for the forecast regulatory control period. This included $82.7 million ($2020–21, unescalated) of replacement capital expenditure (repex) to address its regulatory obligations under the *Environment Protection Amendment Act 2018*. In May 2020, the Victorian Government announced the deferral of the *Environment Protection Amendment Act 2018* to 1 July 2021. Consequently, United Energy wrote to us on 15 May 2020 stating

[5] United Energy's initial proposal included $1212.6 million for net capex, but we have assessed its updated net capex forecast of $1127.6 million. See section 5.2 for further details.

that it was withdrawing most of its environmental management repex and reverting to its historical repex of $1 million for this program.[6] As a result of this change we have assessed United Energy's updated net capex forecast of $1127.6 million. This is 40 per cent higher than its actual capex of $807.8 million in the 2016–20 regulatory control period.[7]

Figure 5.1 outlines United Energy's updated net capex forecast by capex driver. Repex makes up the largest share of net capex at 37 per cent, followed by information and communications technology (ICT). Distributed energy resources (DER) integration capex includes augex and ICT capex programs.

Figure 5.1 United Energy's updated net capex forecast



Source: United Energy's initial proposal and AER analysis.

United Energy's updated gross capex forecast is $1370.2 million and includes $240.0 million for capital contributions and $2.6 million for asset disposals.

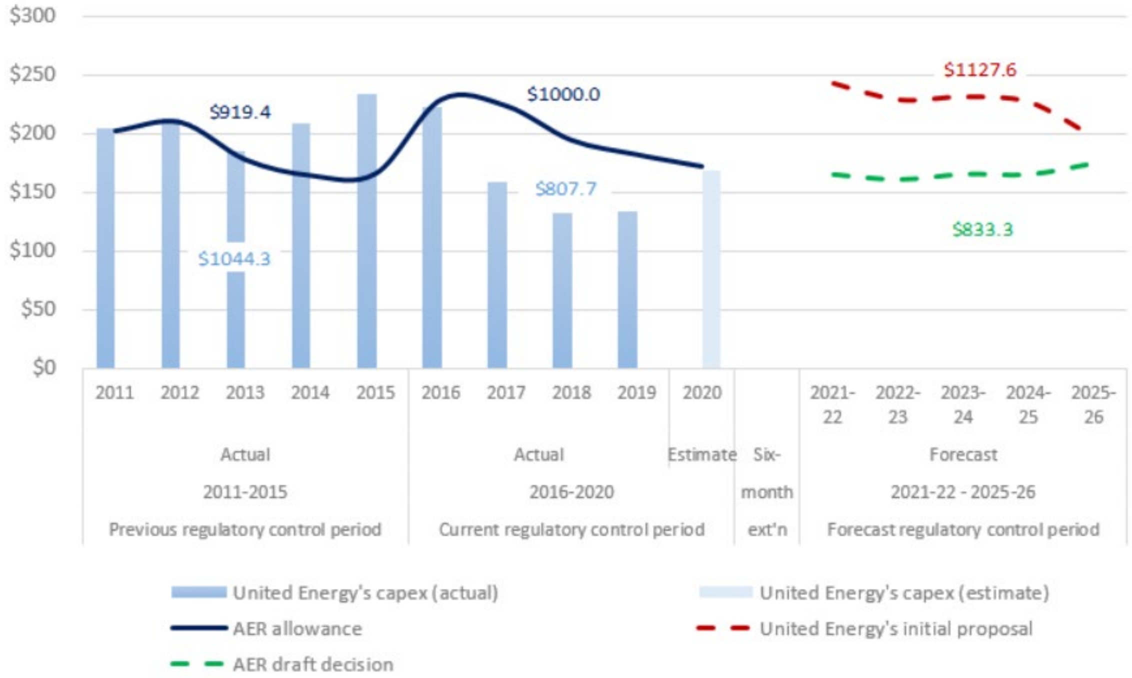
Figure 5.2 outlines United Energy's historical net capex performance compared with its proposal and our draft decision. United Energy expects to spend $815.3 million in the current regulatory control period (i.e. including 2020 estimated capex), which is 22 per cent lower than the 2011–15 regulatory control period. It estimates that it will

6 United Energy, *Re: Amendments to select step changes and capital programs in our 2021–2026 regulatory proposals*, 15 May 2020.

7 In this attachment we compare forecast capex with actual capex in the current period; i.e. calendar year 2016 to 2019 pro-rated to five years. The impact of the COVID-19 pandemic and the derivation of calendar year 2020 estimate as the average of two financial year estimates creates uncertainty regarding the validity of the estimate.

underspend its regulatory capex forecast in the current regulatory control period by $205.6 million (20 per cent).[8]

Figure 5.2 United Energy's net capex snapshot ($ million, $2020–21)



Source: United Energy's initial proposal and subsequent update and AER analysis.

Note: Numbers on the chart represent total net capex for the respective regulatory control period. Current period actual capex includes 2016 to 2019 capex, pro-rated to five years.

5.3 Reasons for draft decision

We are not satisfied that United Energy's total capex forecast reasonably reflects the capex criteria. We are therefore required to set out a substitute estimate.[9] Our substitute estimate is broadly in line with its current regulatory control period spend. We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and forms part of an overall distribution determination that contributes to achieving the NEO to the greatest degree. In coming to our draft decision, we asked United Energy many questions across multiple information requests. United Energy was very receptive to our questions and in most cases provided useful responses within the requested timeframes. We acknowledge that our questions are likely to have presented additional resourcing challenges, particularly due to COVID-19, and appreciate United Energy's cooperation and assistance.

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8 The capex underspend for the 2016–20 regulatory control period includes actual capex for 2016 to 2019 and an estimate of capex for 2020. This is consistent with our PTRM and RFM.

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

We typically analyse a distributor's total capex forecast from a top-down perspective. This top-down review forms the starting point of our capex assessment to determine whether further detailed analysis is required, but is also used throughout our review process to test the results of our bottom-up assessment. We apply both top-down and bottom-up reviews so that our decision is fully informed. In this case, we are not satisfied that United Energy's forecast capex is prudent and efficient under both reviews.

From a top-down perspective, several metrics indicate that United Energy's forecast is not prudent and efficient. We note that:

- The capital expenditure sharing scheme (CESS) applies in the current regulatory control period. We therefore place significant weight on United Energy's forecast capex being 40 per cent higher than its actual capex over the first four years of the current regulatory control period. In addition, its forecast is 20 per cent higher than its longer-term actual capex trend, going back to the start of the 2011–15 regulatory control period.
- United Energy's materially higher forecast relative to the current regulatory control period is combined with a current regulatory control period underspend of 20 per cent. This is reflected in its CESS payment of $49.7 million. This highlights that United Energy has demonstrated in the current regulatory control period that it can manage and maintain its network at an efficient level.
- Over the current regulatory control period United Energy has performed well on a number of network health indicators. Its safety impact public incidents have decreased significantly and incidence of unplanned outages, as measure via the system average interruption frequency index (SAIFI), have trended down. United Energy currently has one of the lowest outage frequencies in the National Electricity Market (NEM). This shows that current levels of historical capex are sufficient to support the safe and reliable provision of network services.
- We are therefore satisfied that our substitute estimate which is in line with current regulatory control period spend will provide United Energy with sufficient funding to meet its capex objectives, including supporting safe and reliable provision of network services, under the NER.
- Several stakeholders did not support aspects of United Energy's capex forecast. For instance, the AER's Consumer Challenge Panel (CCP17) and the Victorian Community Organisations (VCO) do not support United Energy's poles repex, with CCP17 highlighting its excellent network performance in the current regulatory control period.
- Energy Consumers Australia (ECA), CCP17 and the VCO all highlighted that affordability was the priority for consumers. ECA noted that, 'Reliability is also valued but the majority of customers were happy with existing levels of reliability

and did not want to pay for reliability improvements'.[10] The VCO raised concerns that Victorian businesses are overinvesting in capacity and reliability leading to their regulatory asset base (RAB) 'expanding in excess of consumer requirements'.[11]

- We observed limited top-down challenges to United Energy's forecast. United Energy refers to top-down measures that it has considered, such as the repex model. However, it does not appear to have made any adjustments to its forecast to account for these top-down measures or conducted sensitivity analysis to test its forecast. Our consultant Energy Market Consulting associates (EMCa) raised similar concerns and has found that a lack of top-down challenge at the capex driver or overall capex level has likely led to overstated capex requirements for the forecast regulatory control period. It noted the lack of evidence showing the link between United Energy's capex forecast and 'intended benefit to consumers – including as measured by network performance outcomes and network risk indices'.[12]
- Maximum demand, which is the key driver of augmentation capital expenditure (augex), has remained flat in Victoria over the last decade. United Energy has overstated its demand forecasts to support its augex proposals. In the past, United Energy has forecast strongly rising demand in its initial proposals for the previous and current regulatory period forecasts, which has not eventuated. United Energy predicates its continued optimistic forecast of rising maximum demand on a return to a strong relationship between gross domestic product (GDP) and demand. It also chose or adjusted key inputs based on judgement rather than a neutral, evidence-based approach. It prepared its forecasts prior to the emergence of the COVID-19 pandemic. We have applied the Australia Energy Market Operator's (AEMO) latest demand forecasts because AEMO's recent demand forecast accuracy has been closer to actual demand and is widely accepted by industry and understood by stakeholders.

To corroborate the outcomes of the top-down review, we thoroughly assessed the bottom-up material United Energy provided in support of its capex forecast. Our bottom-up review confirmed the findings of our top-down assessment. Specifically, United Energy did not provide convincing bottom-up evidence to support its forecast increase of 40 percent compared with actual capex in the current regulatory control period.

Table 5.3 summarises, and Appendix A outlines, our detailed bottom-up assessment by capex driver, including how we have applied our assessment techniques and how we came to our position. Our assessment highlighted that United Energy's initial augex, repex, DER capex, connections and ICT capex forecasts would not form a total capex forecast that reasonably reflects the capex criteria, taking into account the capex

10 Spencer&Co, *Advice to ECA on Victorian submissions*, June 2020, p. 5.
11 Victorian Community Organisations, *2021-2026 Victorian EDPR – Joint submission*, May 2020, p. 8.
12 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 32.

factors and the revenue and pricing principles. We had regard to the following considerations in forming our position:

- United Energy provided risk monetisation models to support some elements its forecast, and these were consistent with our *Industry practice application note for asset replacement planning*.[13] We commend United Energy for taking this approach and providing transparency around its asset planning. However, we agree with EMCa's observations that many assumptions in these models are not explained, untested, or are likely to overstate risk.
- While United Energy provided reasonable cost-benefit analysis for some projects and programs, there was a lack of supporting cost-benefit analysis, particularly options analysis, for other asset projects and programs in the regulatory proposal. For instance, United Energy did not provide economic analysis in support of its forecast wood poles repex of $90 million despite the 69 per cent step-up from its current regulatory control period spend.
- EMCa noted that United Energy forecast projects above the base level of capex with limited evidence of portfolio optimisation, leading to a bias to overstate capex requirements.[14] For example, United Energy proposed a number of proactive programs to address safety risks. However, it did not account for how these programs will impact its business-as-usual volumes due to the reduced network risks delivered through these proactive programs.
- We acknowledge the cost efficiencies achieved by United Energy in the current regulatory control period, leading to capex savings of $200 million.[15] However, like EMCa we think that these efficiencies may not be fully reflected in the costs relied upon for developing United Energy's capex forecast. Customers therefore will not receive the full benefits of these efficiencies.
- For United Energy's DER integration capex, we are highly supportive of United Energy facilitating solar photovoltaic (PV) growth on its network. However, its solar enablement program forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program. Specifically, its analysis includes investments that would be more prudent to undertake in subsequent regulatory control periods.
- In addition, many stakeholders highlighted concerns with how United Energy valued solar PV exports in its modelling, suggesting the attributed value over the life of the investment did not consider there might be zero or negative benefits into the future, and the proposal tended to overstate the value of solar export.[16] The

[13] AER, *Industry practice application note for asset replacement planning*, January 2019.

[14] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 94.

[15] United Energy, *APP02 What we have delivered*, January 2020.

[16] DELWP, *Victorian Government submission on the electricity distribution price review 2021–26*, May 2020, p. 2; CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106; EnergyAustralia, *Submission to VIC DNSP proposals*, June 2020, p. 1; Energy Users' Association of Australia, *EDPR submission*, June 2020, p. 11.

final Value of DER (VaDER) study report, due in early October 2020, will help to address some of these stakeholder concerns.

Table 5.2 outlines the amounts by driver that we have included in our substitute estimate of $833.3 million for net capex.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or for individual projects and programs. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

Table 5.2 Net capex substitute estimate by driver ($ million, $2020–21)

Driver	United Energy's proposal	AER draft decision	Difference ($)	Difference (%)
Repex[17]	420.1	304.4	-115.7	-28
DER integration capex	71.3	39.3	-32.0	-45
Augex (excluding DER)	129.7	89.3	-40.4	-31
Gross connections	369.2	294.1	-75.2	-20
ICT capex (excluding DER)	174.1	153.4	-20.8	-12
Other non-network capex	85.4	61.6	-23.8	-28
Capitalised overheads	120.4	91.6	-28.8	-24
Gross capex	**1370.2**	**1033.6**	**-336.6**	**-25**
less capital contributions	240.0	194.8	-45.2	-19
less asset disposals	2.6	5.5	2.8	107
Net capex	**1127.6**	**833.3**	**-294.3**	**-26**

Source: United Energy's initial PTRM, subsequent information request responses and AER analysis.
Note: Numbers may not sum due to rounding.

Table 5.3 summarises the reasons for our substitute estimate by capex driver. This reflects the way we have assessed United Energy's total capex forecast.

Table 5.3 Summary of our findings and reasons

Issue	Findings and reasons
Total capex	United Energy has not provided sufficient information to demonstrate that its forecast capex is prudent and efficient. We

17 The repex forecast assessed is lower than initially proposed as United Energy removed its environmental capex.

Issue	Findings and reasons
	have therefore substituted its forecast with a substitute estimate that better reflects the capex criteria. We invite United Energy to address our concerns in its revised proposal. Our draft decision provides a substitute estimate that is broadly in line with United Energy's current period spend.
Repex	United Energy has not demonstrated that a 33 per cent step-up in repex is required to maintain safety and reliability. In particular, the 69 per cent increase in wood poles repex is unsupported by sound quantitative analysis. Where a business proposes a large increase in repex relative to current regulatory control period spend we expect that it will provide clear evidence of the need for the investment.
DER capex	United Energy has adequately supported most aspects of its DER integration capex proposal. However, it has overstated its solar enablement program by including investments that would be more prudent to undertake in subsequent regulatory control periods. We also have concerns with the use of a 30-year period in the net present value (NPV) analysis. We are supportive of United Energy facilitating solar PV growth on its network. However, its forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program.
Augex	United Energy has not established that significant growth in maximum demand is realistically likely to occur on its network, to support the increase in traditional augex it has proposed. We expect flat maximum demand to continue, as it has over the current regulatory control period, and as AEMO has forecast. Accordingly, we have used revealed cost over the current regulatory control period (historicals) as the basis for our substitute traditional augex forecast.
Connections capex	United Energy's forecasts were produced before COVID-19 affected connections volumes, and it has not justified the use of historicals under its previous connections policy as the basis for aspects of its forecast. We have used historicals under its current policy as the basis for forecasting connections and capital contributions, and applied an approximate adjustment for COVID-19's effects on construction.
ICT capex	We have assessed recurrent ICT primarily through a top-down assessment. Top-down trend and benchmarking analysis reveals that United Energy's recurrent ICT capex forecast is likely to be reasonable. United Energy has adequately supported most of its non-recurrent ICT capex forecast, except its customer enablement and intelligent engineering programs.
Other non-network capex	United Energy has demonstrated the prudency of its property forecast but it has not selected the most efficient options to

Issue	Findings and reasons
	undertake its work. Its fleet capex is reasonable, however we have made an adjustment for fleet disposals in our substitute estimate.
Capitalised overheads	We have updated United Energy's base and trend component of its capitalised overheads forecast. We have also adjusted capitalised overheads for a lower level of forecast direct capex.
Demand	United Energy's demand forecast is overstated, likely due to the way key variables have been applied as post-modelling adjustments rather than incorporated within its regression model. United Energy's past forecasts have materially overstated demand, and its current forecasts do not adjust for the effects of COVID-19. In our draft decision, we have adopted AEMO's most recent demand forecasts for United Energy's network, which have historically been more accurate.
Modelling adjustments	Modelling adjustments relate to United Energy's consumer price index (CPI) and real price escalation assumptions. We have updated United Energy's labour price escalators to be consistent with our operating expenditure (opex) decision. Consistent with our standard approach, we have assumed real contract labour escalation to be in line with CPI.

A Capex driver assessment

This appendix outlines our detailed analysis of United Energy's capex driver category forecasts for the current regulatory control period. These categories are repex, DER integration capex, augex, connections capex, ICT capex, other non-network capex and capitalised overheads. We use real $2020–21 unless otherwise stated.

We used various qualitative and quantitative assessment techniques to assess the different elements of United Energy's proposal to determine whether it reasonably reflects the capex criteria. More broadly, we seek to promote the NEO and take into account the revenue and pricing principles set out in the NEL.[18] In particular, we take into account whether our overall capex forecast will provide United Energy with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[19]

A.1 Repex

Repex must be set at a level that allows a distributor to meet the capex criteria. 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 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[20]
- 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 result, a distributor will only need to replace a portion of its network assets in each regulatory control period.

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[18] NEL, ss. 7, 7A and 16(1)-(2).

[19] NEL, s. 7A.

[20] 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.

A.1.1 Draft decision

United Energy has not satisfied us that its updated forecast of $420.1 million is prudent and efficient.[21] We have included $304.4 million in our substitute estimate, which is a 28 per cent reduction (Table A.1). We are satisfied this forms part of a total capex substitute estimate that reasonably reflects the capex criteria.

A.1.2 United Energy's initial proposal

United Energy's updated repex forecast is $420.1 million for the forecast regulatory control period. This forecast is $103.7 million, or 33 per cent, higher than its actual repex of $316.4 million in the current regulatory control period.

In its initial capex proposal United Energy forecast $505.1 million for repex. This included $86.1 million to address its regulatory obligations under the *Environment Protection Amendment Act 2018*. In May 2020, the Victorian Government announced the deferral of the *Environment Protection Amendment Act 2018* to 1 July 2021. United Energy wrote to us on 15 May 2020 stating that it was withdrawing most of its environmental management repex and reverting to its historical repex of $1 million for this program.[22] As a result of this change, we have assessed United Energy's updated repex forecast of $420.1 million.

United Energy explained the basis for its repex forecast:[23]

> Our replacement investment in the 2021–2026 regulatory period is to continue to provide a resilient network has been informed by insights from our ongoing stakeholder engagement program:
>
> - we are ensuring the long-term sustainability of our pole replacement program by proposing additional risk-based pole replacements, focused on lower durability poles in high bushfire risk areas
> - we are leveraging our smart meters to reduce safety risks as far as practicable, including using analytics to proactively detect hazardous service lines
> - we are continuing to effectively reduce the risk of bushfires from our network by replacing assets in high bushfire risk areas, such as removing expulsion drop-out fuses—our customers hold strong views that safety should be a top priority, and our fire prevention plan has been accepted by Energy Safe Victoria.

Table A.1 shows United Energy's forecast repex by asset group for the forecast regulatory control period. The largest asset group by forecast expenditure is poles

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21 United Energy's initial proposal included $505.1 million for net capex, but we have assessed its updated repex forecast of $420.1 million. See section A.1.2 for further details.

22 United Energy, *Re: Amendments to select step changes and capital programs in our 2021–2026 regulatory proposals*, 15 May 2020.

23 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 51.

($94 million or 22 per cent of total repex), followed by pole-top structures ($78 million or 19 per cent) and switchgear ($74 million or 18 per cent).

Table A.1 United Energy's forecast repex by asset group, 2021–26 ($ million, $2020–21)

Asset group	Forecast	Percentage of total repex
Poles	94.0	22
Pole-top structures	77.7	19
Switchgear	73.7	18
Transformers	47.8	11
SCADA	43.7	10
Underground cables	30.6	7
Services lines	24.9	6
Overhead conductors	15.2	4
Other	12.4	3
Total Repex	**420.1**	

Source: AER analysis and United Energy.

Note: Numbers may not add up due to rounding.

A.1.3 Reasons for draft decision

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

- trend analysis
- repex modelling
- bottom-up program and project-level economic and engineering review
- technical review from our consultant EMCa
- network health indicators
- stakeholder submissions.

Overall, we conclude that United Energy has not been able to provide sufficient evidence to demonstrate that its forecast repex is prudent and efficient.

United Energy's proposed 33 per cent increase in repex relative to current regulatory control period actual repex is not adequately justified. It forecast increases for eight out of nine asset groups, with five asset groups forecast to increase by more than 50 per cent compared with actual repex in the current regulatory control period.

Our repex model outcomes show that United Energy's modelled repex forecast is 86 per cent above the modelled threshold. Where a distributor proposes a large increase in repex relative to current regulatory control period spend we expect that it will provide clear evidence of the need for the investment. For example, a distributor should demonstrate why it expects additional risks above those in the current period. For compliance obligations it should demonstrate that the proposed capex is not grossly disproportionate to the benefits, and explain how it is addressing the compliance obligation in the current regulatory control period.

Our bottom-up review found that United Energy did not support many of its forecast programs and projects with business cases, cost-benefit analysis or other quantitative supporting evidence. EMCa noted that the supporting material was not sufficient to justify the proposed volume and cost assumptions that United Energy has included in its proposed forecast. Furthermore, United Energy has assumed a continuation of current expenditure trends with insufficient consideration of current and expected asset performance.[24] For example, its wood poles repex forecast is 69 per cent higher than actual repex in the current regulatory control period, largely driven by United Energy applying a linear trend to its historical repex.

United Energy provided good models in support of some of its repex forecast, although this was not in the majority of cases. Its risk monetisation models are an example where the basis of the forecast is consistent with our *Industry practice application note for asset replacement planning*.[25] However, we agree with EMCa that United Energy appear to overstate some risk assumptions, and it did not support some assumptions with evidence of historical failures and consequence costs. Therefore, we have doubts that United Energy's forecast repex to mitigate these risks is prudent and efficient.

United Energy did not provide sufficient evidence to support its forecast for number of proactive programs to address safety risks. Consistent with our previous decisions, we forecast funding for distributors to mitigate network safety risks. However, United Energy did not provide sufficient evidence to demonstrate a change in network conditions between the current and forecast regulatory periods would require a step-up in repex. In addition, United Energy did not adequately consider the impact of these safety programs on business-as-usual replacement volumes. We think that this contributes to duplication of some repex. We therefore agree with EMCa's findings that United Energy has generally not justified that further forecast funding above and beyond its business-as-usual program is required.

Stakeholder views on United Energy's repex proposal were mixed. VCO noted United Energy's large underspend of its repex allowance in the current period.[26] CCP17 noted that customers were generally satisfied with reliability but expressed a preference for underground power lines and prioritising the service wire safety

[24] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 44.

[25] AER, *Industry practice application note for asset replacement planning*, January 2019.

[26] Victorian Community Organisations, *2021–26 Victorian EDPR – Joint submission*, May 2020, p. 41.

programme (dog bones).[27] Spencer&Co expressed support for United Energy's switchgear and transformer programs, and in particular greater use of mobile transformers to manage risk and consequence of failure.[28] CCP17 and the VCO both raised concerns about United Energy's wood poles repex forecast.

We acknowledge United Energy's excellent safety and reliability performance in the current regulatory control period. United Energy noted that:[29]

> Our network is one of the most reliable in Australia, being available for over 99.99% of the year, or less than 45 minutes off supply per annum on average for our customers. Since 2013, we have also reduced the number of ground fire starts from our assets by 34%, and driven a 71% reduction in public safety incidents, consistent with our obligation to reduce safety risk as far as practicable.

Figure A.1 shows that United Energy outperformed its service target performance incentive scheme (STPIS) feeder targets over the current regulatory period, whilst underspending its regulatory capex forecast by 20 per cent. SAIFI performance is also forecast to further improve in the forecast regulatory control period.

Figure A.1 United Energy's historical and target SAIFI performance from 2006 to 2026

Source: AER analysis.

27 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals*, June 2020, p. 91.

28 Spencer&Co, *Advice to ECA on Victorian submissions*, June 2020, p. 19.

29 United Energy, *Regulatory proposal 2021–2026*, January 2020, p. 51.

As United Energy has successfully maintained the health of its network at its current spend levels, including safety risk, we are not convinced that United Energy's proposed 33 per cent step up in repex relative to its current regulatory control period spend is required over the forecast regulatory control period.

Given our overall concerns with United Energy's proposed forecast, we have included in our substitute estimate repex of $304.4 million. We are satisfied that this forms part of a capex forecast that is prudent and efficient and sufficient for United Energy to meet its capex objectives consistent with s. 6.5.7 of the NER. However, there were several information gaps that contributed to this draft decision. We therefore invite United Energy to provide further evidence to support its forecast repex in its revised proposal having regard to the findings in this draft decision.

Trend analysis

We must have regard to actual and expected capital expenditure during any preceding regulatory control period.[30] Trend analysis of a distributor's past expenditure allows us to draw general observations about how a distributor is performing and provides a sanity check against our predictive modelling results. For some repex categories, where past expenditure was sufficient to achieve the capex objectives, this can be a reasonable indicator of whether the forecast repex is reasonable.[31]

Figure A.2 shows annual repex by asset group. United Energy has forecast an increase for all repex asset groups except for overhead conductors compared with the current regulatory control period. United Energy’s total forecast for repex is 33 per cent higher than its actual repex for the current regulatory control period (or 31 per cent higher if we include United Energy's 2020 estimate in the current regulatory control period repex) and 9 per cent lower than its actual repex for the previous regulatory control period.

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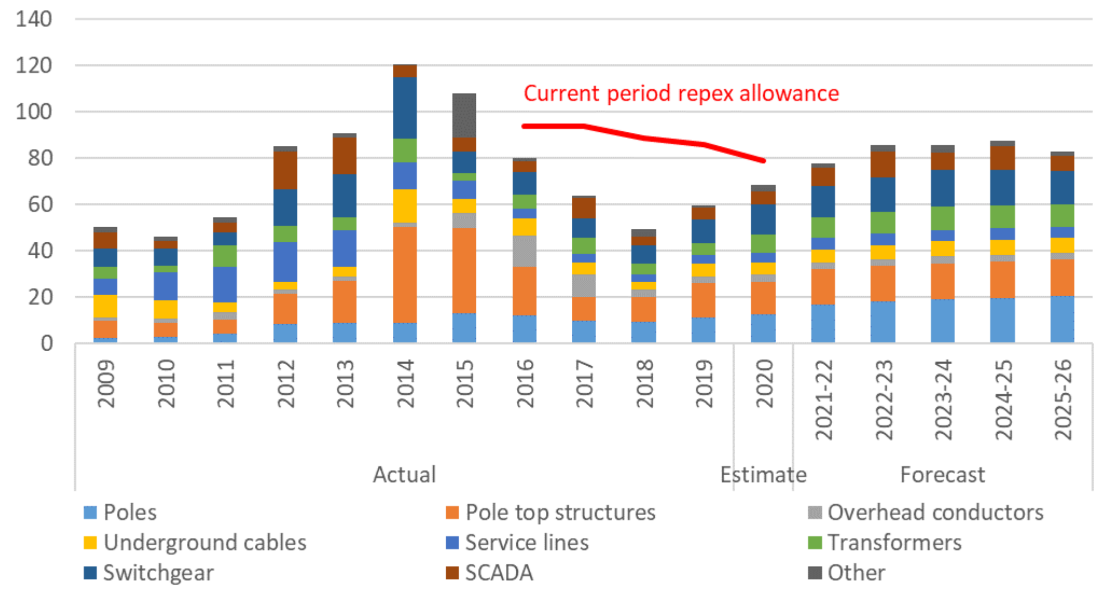
30 NER, cl. 6.5.7(e)(5).

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

Figure A.2 United Energy's historical and forecast repex by asset group ($ million, $2020–21)



Source: RIN data and AER analysis.

Investments in pole-top structures, service lines and automatic circuit reclosers in the previous regulatory control period drove the improvements in reliability and safety over the current regulatory control period.

We estimate that United Energy's actual and estimated repex in the current regulatory control period is around 35 per cent lower than its regulatory repex forecast. Energy Australia, the VCO and CCP17 each raised concerns about the underspending by United Energy (or by the Victorian businesses more broadly). They questioned whether the large underspends were due to the businesses over-forecasting and the AER setting overly conservative allowances, as opposed to real efficiency gains.

Repex modelling

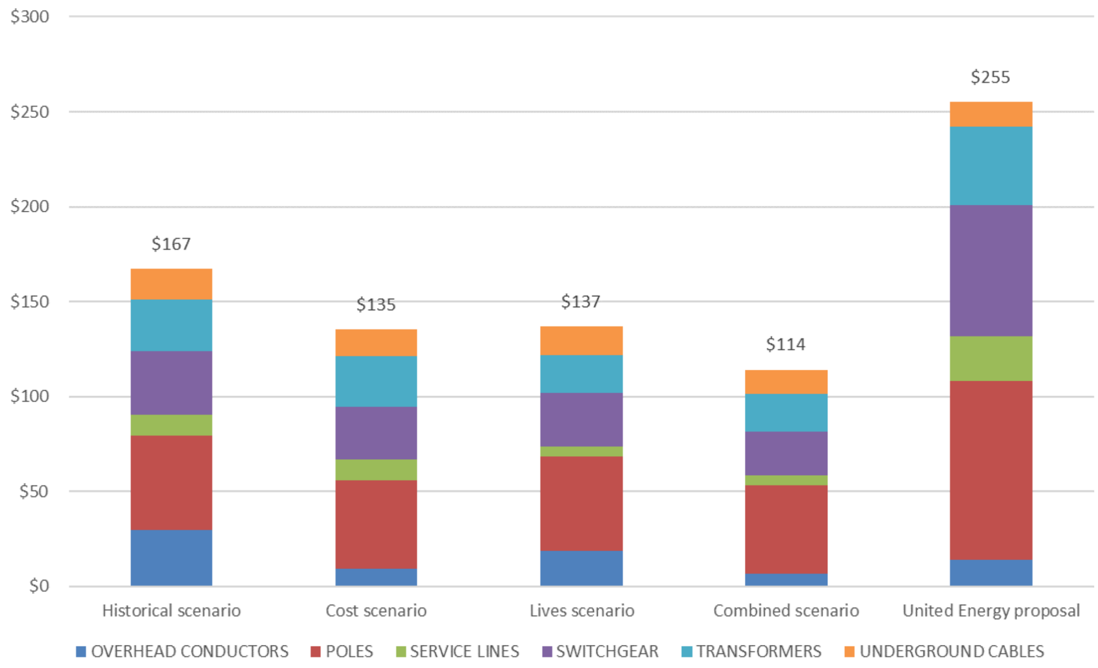
The repex model is a statistical tool used to conduct a top-down assessment of a distributor's repex forecast. We analyse discrete asset categories within the following six broader asset groups: poles, overhead conductors, underground cables, service lines, transformers and switchgear. We use the repex model to advise and inform us where to target a more detailed bottom-up review, and as a starting point for our substitute repex forecast if necessary.[32]

United Energy's modelled repex contributes 61 per cent ($255 million) to its total forecast repex. Figure A.3 shows our repex modelling results. United Energy's

[32] For a description of the repex model see AER, *AER repex model outline for electricity distribution determinations*, February 2020.

modelled repex forecast is $118 million (86 per cent) higher than the repex model threshold (lives scenario).[33] Our substitute estimate includes an allowance of around $183 million for modelled repex.

Figure A.3 Repex model results ($ million, $2020–21)



Source: AER analysis of RIN data from all businesses in the NEM.

United Energy's forecast exceeds the repex model results for all asset groups except overhead conductors. The asset groups with the largest difference in dollar terms between the repex model results and United Energy's forecast are:

- poles—$44 million (89 per cent) difference
- switchgear—$45 million (159 per cent) difference
- transformers—$28 million (139 per cent) difference.

The repex model results led us to carrying out further assessment for each of the modelled asset groups.

Poles

United Energy's forecast for poles repex is $94 million, which is 76 per cent higher than actual repex in the current regulatory control period. United Energy has not justified its forecast for wood poles. Our substitute estimate includes $57 million for poles repex, which is 39 per cent lower than United Energy's forecast. Our substitute is in line with

[33] We compare a DNSP's proposal against the higher of the lives scenario or cost scenario. This takes into account interrelationships between cost and lives.

United Energy's actual repex in the current regulatory control period and includes United Energy's proposed proactive concrete poles program.

United Energy's poles forecast consists of:

- Condition-based wood pole interventions—$79 million
- Risk-based wood pole replacement program—$11 million
- Proactive concrete pole replacement program—$4 million.

Wood poles

Figure A.4 shows historical and forecast repex and annual failures. United Energy’s wood poles forecast of $90 million is $37 million or 69 per cent higher than current regulatory control period actual repex. The figure shows an increasing trend in repex from 2009 through to 2025–26 (including United Energy's forecast), although the trend is flat or decreasing over the current regulatory control period.

United Energy’s wood pole performance is excellent: failure rates peaked in 2015 and have decreased steadily through to 2019, reflecting the higher level of repex over the current regulatory control period compared with previous regulatory years. Even at their peak in 2015 failure rates were only 0.4 per 100,000 poles, which is well below the NEM average of around 0.7 failures per 100,000 poles. We have seen no evidence that any pole failures have resulted in serious incidents. This suggests that current risk levels are very low and United Energy is managing the network well. United Energy stated that its current practices ‘has delivered low numbers of pole failures for our network that to date, have satisfied both ESV [Energy Safe Victoria] and our customers’ expectations’.[34]

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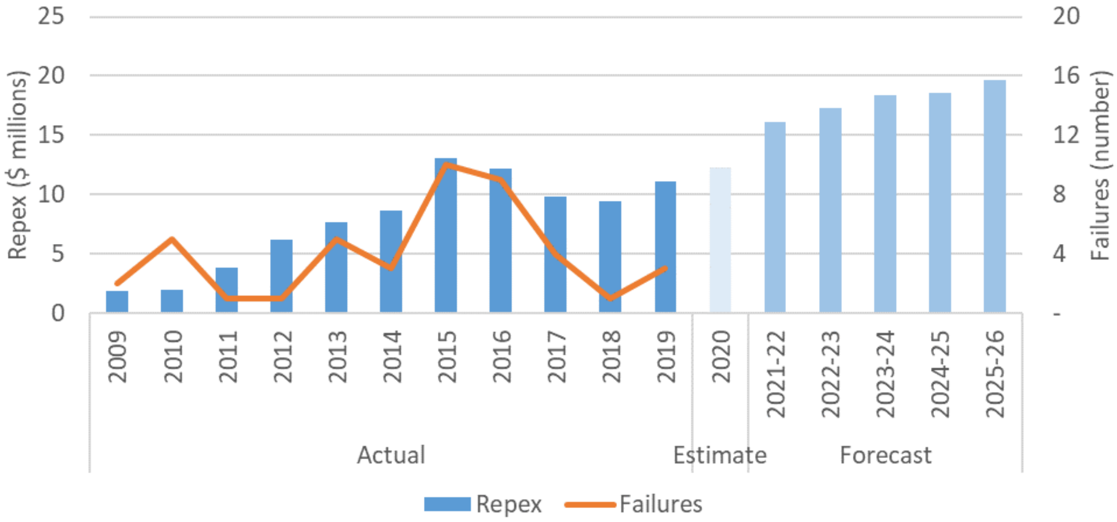
[34] United Energy’s response to information request 009. ESV is Energy Safe Victoria.

Figure A.4 Wood poles repex and failures



Source: AER analysis of RIN data and *CP PAL and UE - letter to AER in response to poles discussion*.

United Energy has not demonstrated a need for the increase in wood poles repex over its historical spend. We consider that current regulatory control period repex reasonably reflects efficient costs to maintain safety and reliability, as demonstrated by its very low and falling failure rates over the current regulatory control period.

Condition-based pole interventions

United Energy's condition-based program represents business-as-usual reactive replacement or reinforcement. United Energy applied an upward linear trend to forecast its condition-based usual volumes. This is a main driver of the increase in forecast poles repex.

We are not satisfied that United Energy's forecast for its condition-based poles program is prudent and efficient:

- United Energy has not provided any cost-benefit analysis or a quantified risk assessment to support a step-up in intervention volumes.
- Its application of nine years of historical data to create an upward trend in intervention volumes is not justified. Using nine years of data is inconsistent with the majority of repex programs that United Energy has forecast using its unitised model, which generally use five years of data or less.[35] United Energy argues that a longer term trend improves the coefficient of determination (i.e. provides a better fit). However, this does not account for the improvements in the performance of the pole population over the nine-year period or the expected performance in the forecast period.

[35] United Energy’s unitised volume model uses historical data to forecast repex volumes. This makes up roughly half of United Energy’s repex forecast.

In coming to our position, we also had regard to EMCa's findings:[36]

- United Energy has not demonstrated that the underlying pole condition or associated network risk is increasing, undermining its justification for increased pole repex.
- United Energy's reliability performance is actually good and improving, and fire start events are declining. In the absence of better information, EMCa concludes that network risk is not escalating exponentially or otherwise.
- There is limited evidence of United Energy's attempt to moderate the expenditure, including using top-down review methods to estimate the forecast outcomes in terms of network risk.

Risk-based pole replacement program

United Energy states that its 'incremental risk-based program is targeted at lower durability poles in high bushfire risk areas'.[37] It applied a serviceability index to its current pole population in high bushfire risk areas (HBRA) to estimate forecast volumes. The serviceability index takes into account wood fibre strength degradation, and forms part of Powercor and CitiPower's 'enhanced pole calculator' which these businesses proposed for the forecast regulatory control period.

We agree in principle that United Energy should seek to make improvements to its asset management practices where practical, such as taking into account different factors when assessing pole condition. We also agree that it is prudent to consider consequence risks when determining the serviceability of a pole. However, we do not agree that the risk-based program is prudent:

- The proactive program is not supported by adequate cost-benefit analysis or risk assessment, and the evidence before us suggests that there is no need to proactively decrease risk in the forecast period.
- We have analysed United Energy's pole failure data over the last ten years. Failures in hazardous bushfire risk areas represented fewer than 10 per cent of total failures, and only a low proportion of failures were low durability (class 3) poles, which this program is intended to target. Furthermore, we have seen no evidence that any of these failures resulted in safety or property damage.

Based on our analysis, we do not see there is a significant or emerging risk that United Energy needs to address through a proactive replacement program above and beyond business-as-usual intervention volumes.

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[36] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, pp. 44–53.

[37] United Energy's response to information request 009.

Concrete poles

United Energy forecast $4 million for a proactive program to address concrete poles not connected to its common-multiple earth neutral network. United Energy has justified this program.

The concrete poles proposal is a good example of the evidence we seek from United Energy to justify its proposed step-increases in forecast repex. It provided evidence that these poles can become live, posing serious safety risks, and discussed compliance with the updated Australian Standard (AS) 2067 and 7000. It provided reasonable cost-benefit analysis of credible options. The CCP17 and EMCa noted their support for this program.[38]

Transformers

United Energy's forecast for transformers repex is $48 million, which is 65 per cent higher than actual repex in the current regulatory control period. United Energy has not satisfied us that its forecast for zone substation (ZS) transformers is prudent and efficient. Our substitute estimate includes $33 million for transformers repex. This is 32 per cent lower than United Energy's forecast.

United Energy's forecast consists of:

- replacement of 16 ZS transformers ($32 million)
- replacement of distribution transformers ($16 million).

Figure A.5 shows that annual average transformers repex was around $7 million between 2011 and 2020. United Energy forecasts transformers repex to increase to around $10 million per year in the forecast regulatory control period.

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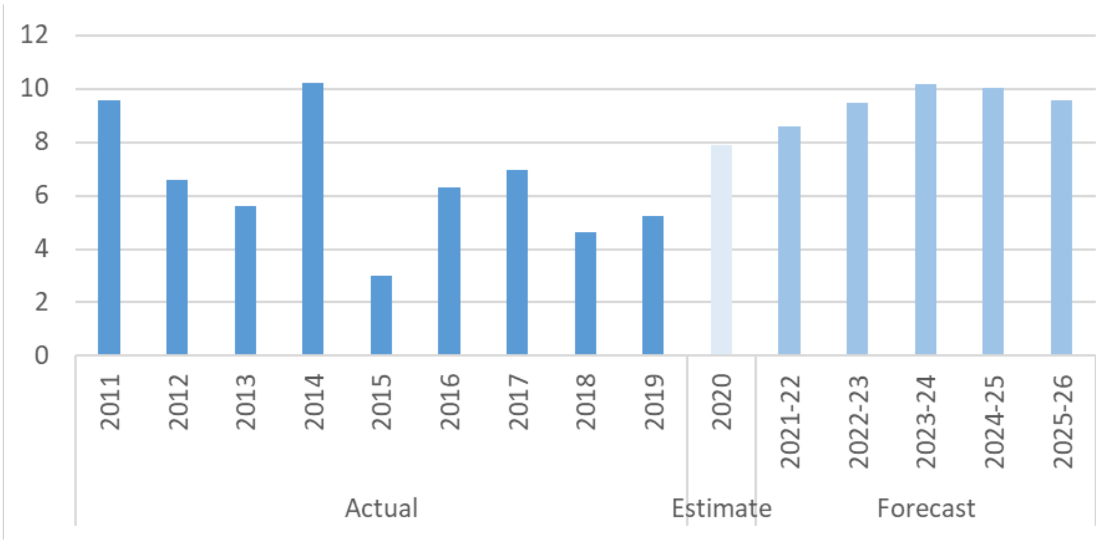
[38] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals,* June 2020, p. 95; and EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 51.

Figure A.5 Transformers repex ($ million, $2020–21)



Source: AER analysis of RIN data.

Zone substation transformers

United Energy submitted that:[39]

> The forecast increases in our transformer replacement volumes over the 2021–2026 regulatory period…reflects the rising risk of failure based on our experience as our transformer population continues to deteriorate over time. It also reflects the increased consequence of failure due to higher zone substation demand.

Energy Consumers Australia noted its support for United Energy's replacement programs for larger asset types, including their readiness program to enable greater use of mobile transformers to manage risk and consequence of transformer failure.[40]

United Energy used a risk monetisation model to identify the optimal timing of replacement of ZS assets. In addition, United Energy is undergoing a 'mobile readiness' program which reduces consequence of failure and allows for efficient deferral of ZS asset replacement.

United Energy's risk monetisation approach is consistent with good industry practice and we commend it for adopting this approach to asset management. Notwithstanding, we consider that the model produces inflated repex forecasts. Like EMCa, we have found that several assumptions, including network risk, are overstated in its model. We note the following:

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39 United Energy, *UE BUS 4.04 Zone substation transformer replacements: forecast method overview*, January 2020, p. 14.

40 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26 Submission – Attachment 1*, June 2020, p.19.

- United Energy's calculation of unserved energy may be overstated due to its weighting of 10% PoE and 50% PoE peak demand. We raised this issue with United Energy and it submitted that in Victoria this weighting is the norm for network planning purposes, and has been used for around 20 years.[41]
    - EMCa noted that the use of this demand treatment in the context of assessing asset replacement timing may not be appropriate:[42]

> We consider the key issue here is the application of a planning methodology to estimate the expected value of unserved energy. We consider that United Energy is incorrect in stating that the 50% PoE does not represent a realistic expectation of demand. However, the expected value of unserved energy is not a function of the peak demand alone. It should take account of the Load Duration Curve, since the amount of energy unserved (if any) as a result of an equipment outage depends on the load during the time of the outage, and this also is influenced by any mitigation measures…United Energy has not demonstrated that its 70:30 assumption is valid for DNSP planning purposes.

- EMCa raised concerns about the deliverability of the ZS transformer program. It acknowledged that United Energy provided further information regarding its delivery strategy and plan but concluded that a number of transformers will likely roll-over into the next [regulatory control period]'.[43]
- United Energy's demand forecasts appear to be overstated, which may bring forward the optimal timing of replacement of some transformers. We have been unable to substitute AEMO's demand forecasts into the model. However, by applying a flat demand forecast from 2018 we find that the prudent timing of replacement for a number of transformers falls beyond the forecast regulatory control period. We have similar concerns with the values of customer reliability (VCR) and consider that the relevant VCR is that published by us in 2019.[44]
- United Energy's model predicts that prudent timing for 12 out of the 16 proposed transformer replacements is in the current regulatory control period. However, United Energy has elected to delay these replacements until the forecast regulatory control period. The model's outcomes raise questions about the extent to which United Energy relies on its own risk analysis in its replacement planning decisions, why it is electing to be exposed to risks that its model has assessed to be uneconomical, or whether the risk assumptions in the model are overstated.
- We query why the probability of major failure is three-fold higher than for minor failure. We understand that United Energy derived these probabilities from University of Queensland research. Although we do not have access to the

41 We met with United Energy on 17 June 2020 to discuss this matter, and received a response to information request 041 on 8 July 2020.

42 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 27. EMCa's reference to the "70:30 assumption" relates to United Energy's weighting of 10% PoE and 50% PoE peak demand.

43 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 77.

44 AER, *Values of Customer Reliability - Final report on VCR values*, December 2019.

publication we suspect the research identifies causes of asset transformer retirements, as opposed to all failures including repairable failures. This is because the research identifies a very high occurrence of winding failures (56 per cent) and a very low occurrence of bushing failures (4 per cent). As a result, the probability of major failure appears to be overestimated.

- We have not seen evidence of actual failure consequence costs—United Energy reports that there have been nine failures in the current regulatory control period. The actual costs of recent transformer failures may be used to test the validity of the model and its assumptions and allow United Energy to calibrate its risk assumptions. We would also expect the mobile readiness program would reduce failure consequence costs further than what United Energy has incurred. We invite United Energy to provide this analysis with its revised proposal.

Given our concerns, we include in our substitute estimate an allowance for ZS transformers in line with current regulatory control period repex.[45] We encourage United Energy to review our findings on its risk monetisation model ahead of its revised proposal.

Distribution transformers

United Energy's forecast of $16 million is estimated using historical repex and is consistent with actual repex in the current regulatory control period. We do not have any concerns about this approach.

Switchgear

United Energy's forecast for switchgear repex is $74 million, which is 62 per cent higher than actual repex in the current regulatory control period. United Energy has not satisfied us that its forecast for distribution switchgear is prudent and efficient. Our substitute estimate includes $55 million for switchgear repex. This is 25 per cent lower than United Energy's forecast and 20 per cent higher than actual repex in the current regulatory control period.

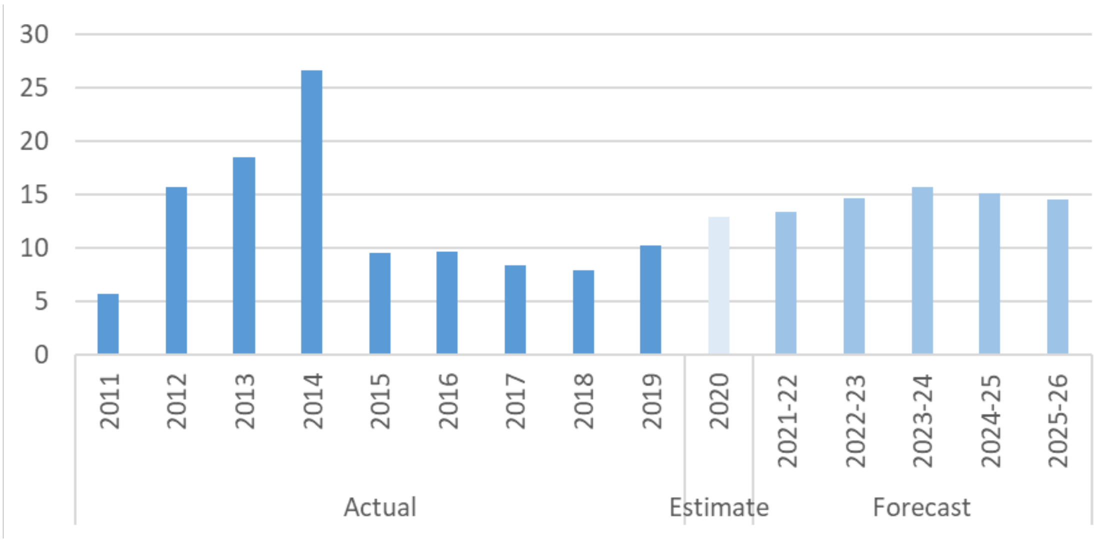
United Energy's forecast consists of:

- replacement of 10 ZS switchboards/switchgear ($20 million)
- replacement of distribution switchgear ($54 million).

Figure A.6 shows that United Energy invested heavily in switchgear repex in 2012 to 2014. Between 2015 and 2019 annual average repex was around $9 million. United Energy proposed around $15 million per year for switchgear repex in the forecast regulatory control period.

[45] This includes adjustments to underground cables, switchgear, other repex and SCADA, network control and protection systems asset groups associated which the ZS transformer programs.

Figure A.6 Switchgear repex ($ million, $2020–21)



Source: AER analysis of RIN data.

Zone substation switchgear

We accept that United Energy's ZS switchgear forecast is reasonable and we include it as part of our substitute estimate.

United Energy stated that, ‘Our forecast replacement volumes reflect refinements to our risk quantification method, where previously unquantified risks were not well understood’.[46]

United Energy used the same risk monetisation model as it did for ZS transformers to identify the optimal timing of replacement of ZS assets. As such, some of our concerns about the ZS transformers forecast are relevant for the ZS switchgear forecast. However, we have relied on EMCa's findings to come to our position to accept the forecast. It noted that:[47]

> We have some residual concerns with the models provided to demonstrate the prudent timing of the proposed projects…However, the assumptions and sensitivity testing appeared to deliver logical results.
>
> When we tested the concerns we expressed in the transformer category to the switchgear category of expenditure, we found that the optimal date for replacement was deferred, however the input assumptions needed to be unreasonably modified to shift the projects beyond the next RCP.

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46 United Energy, *UE BUS 4.04 Zone substation switchgear replacements: forecast method overview*, January 2020, p. 15.

47 EMCa, *Review of aspects of United Energy’s regulatory proposal 2021–26*, September 2020, pp. 81–82.

EMCa also noted that its concerns about project delivery are not as significant for ZS switchgear as they are for ZS transformers. Based on these observations we accept United Energy's forecast for ZS switchgear.

Distribution switchgear

United Energy forecast an increase in distribution switchgear repex. We asked United Energy to provide further details, and it submitted that the increase was due to 'an upward trend in gas switch replacements, and the replacement of expulsion drop-out fuses'.[48]

Gas switches

In response to follow-up questions United Energy noted that it based its initial forecast on an incomplete set of data. It provided revised data and an alternative forecast of $10 million based on average volumes over six years to 2019.[49] We observe a declining trend in gas switch replacement volumes since 2014 and a decrease in failures since 2017. We consider that United Energy's forecast likely overstates requirements and have included $7 million in our substitute estimate, which is based on average actual repex in the current regulatory control period.

Expulsion drop-out (EDO) fuses

United Energy submitted that EDO fuses pose a safety risk as they may cause fires upon failure. It proposed a proactive program to replace all EDO fuses over the forecast regulatory control period ($4 million).

Our analysis of the data suggest that United Energy is currently managing risks effectively, with an average failure rate of less than two per year over the current regulatory control period. We expect that the EDO fuse population will be replaced over time as part of United Energy's business-as-usual reactive program. We do not consider it prudent to include the proactive program in our substitute estimate.

Service lines

United Energy's service lines forecast of $25 million is $6 million (35 per cent) higher than current regulatory control period spend. United Energy has not sufficiently demonstrated that its proactive replacement program is prudent and efficient. We include $18 million for business-as-usual service lines repex in our substitute estimate (with adjustments to real labour escalation).

United Energy's forecast consists of:

- business-as-usual replacements ($19 million)—this is around the same as current regulatory control period repex

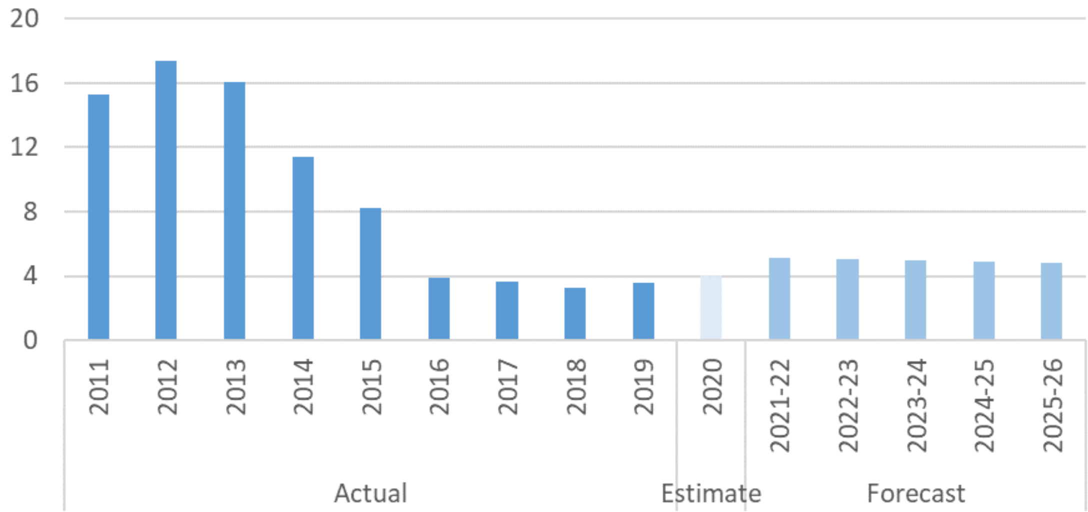
48 United Energy's response to information request 013.

49 United Energy's response to information request 052.

- proactive safety program ($6 million).

Figure A.7 shows that United Energy spent $68 million on service lines repex in the previous regulatory control period. The high level of repex was due to a proactive program to replace neutral screen service lines, which United Energy apparently halted at the beginning of the current regulatory control period. As a result of this proactive program, United Energy has a very young population of service lines.

Figure A.7 Service lines repex ($ million, $2020–21)



Source: AER analysis of RIN data.

Service line failure rates decreased from more than 1200 in 2009 to less than 400 in 2015, and have since remained at that level.[50] This suggests that current regulatory control period spend is sufficient to maintain low failure rates.

Proactive service line replacement

United Energy's proactive replacement program aims to remove neutral screen and PVC twisted wire service lines over ten years. These are old technologies that carry a significantly higher probability of failure compared with the newer aerial bundled cable service lines. As noted above, United Energy proactively replaced a large proportion of its neutral screen service lines in the previous regulatory control period. We did not provide a regulatory forecast to continue the program in the current regulatory control period because there was no regulatory obligation and we considered that the service line population overall was in good health.

United Energy provided a business case and a risk monetisation model to support the forecast. Our analysis found that:

50 United Energy, *UE BUS 4.05 Services: replacement forecast method*, January 2020, p. 7.

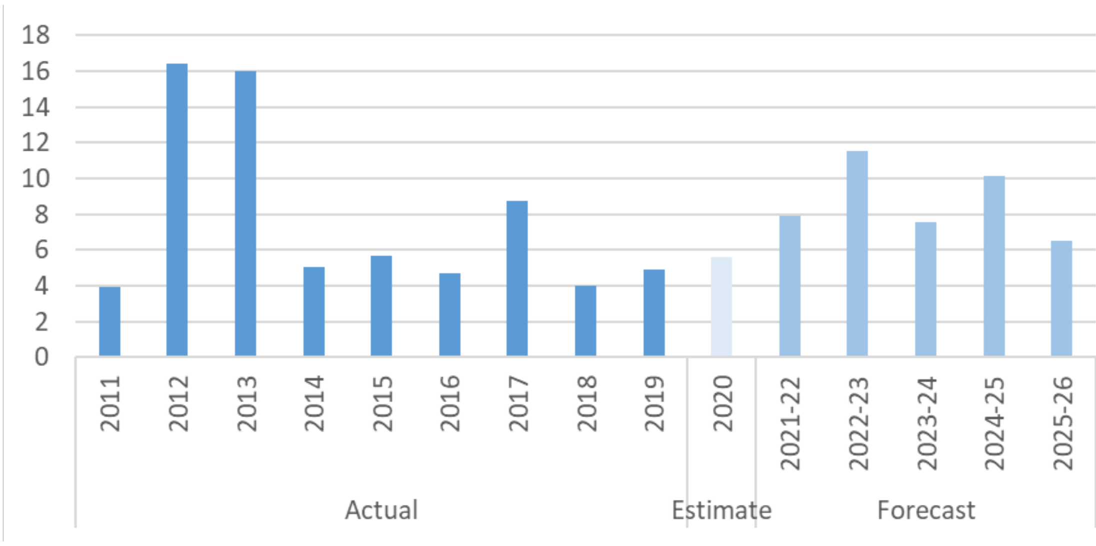
- Safety risks are likely to be overstated. In its estimate of shock consequence costs United Energy multiplies probability of shock consequence, a disproportionality factor and average cost of a serious injury (derived from a Safe Work Australia report). We consider that the overwhelming majority of public shocks will not result in any significant consequence. In its revised proposal we invite United Energy to provide details including consequence costs of public shocks in its network that have led to personal injury.
- United Energy's risk model shows that a 10-year proactive replacement program is only marginally preferable to the standard condition monitoring approach. Even small adjustments of the assumptions would make business-as-usual reactive replacement the preferred option.
- United Energy did not account for the proactive program in its business-as-usual forecast, despite neutral screen and PVC twisted wire service lines contributing to the majority of service line failures.

SCADA, network control and protection systems (SCADA)

United Energy's forecast for SCADA repex is $44 million, which is 56 per cent higher than actual repex in the current regulatory control period. United Energy has not satisfied us that its forecast is prudent and efficient. Our substitute estimate includes $29 million for SCADA repex, which is 34 per cent lower than United Energy's forecast. Our forecast is in line with current regulatory control period actual repex, plus United Energy's forecast for SCADA repex related to ZS switchgear replacements.

Figure A.8 shows United Energy's historical and forecast SCADA repex. Except for higher repex in 2012 and 2013, forecast SCADA is higher than historical trends.

Figure A.8 SCADA, network control and protection systems repex ($ million, $2020–21)



Source: AER analysis of RIN data.

United Energy noted that the drivers of its forecast SCADA repex are the condition of SCADA assets and the replacement of primary assets, i.e. proposed ZS switchboard replacements.

Relays replaced on condition

United Energy provided a risk monetisation model to support its condition-based replacements of ZS relays. United Energy's risk monetisation approach is consistent with good industry practice and we commend it for adopting this approach to asset management. Notwithstanding, we consider the model produces inflated repex forecasts. This is because we have found that some of the model assumptions are overstated and unsubstantiated. We note the following:

- It appears that the model only compares 'do-nothing' with a pre-determined replacement of all relays at nine substations. We would expect consideration given to a replace on failure approach or a targeted replacement volume. In addition, we have identified that United Energy's planned replacement timing in some cases is many years later than the model's prudent timing. These observations raise doubt whether United Energy is, in fact, relying on its cost-benefit analysis to determine its replacement decisions.
- The probability of failure numbers are unsubstantiated with historical evidence. Furthermore, they appear to be based on age alone, with the same probability of failure applied to all relays independent of their location, utilisation or environmental factors.
- United Energy assumes unit rates for unplanned replacements are more than 200 per cent higher (on average) than planned unit costs. This assumption is likely to overstate the cost of consequence of running its assets to failure (despite being United Energy's replacement strategy over the current regulatory control period). We encourage United Energy to demonstrate, by way of historical evidence, how it arrived at its unit rates estimates.

EMCa also raised concerns with the model, stating that:[51]

> We observe that United Energy's modelling approach in this group is similar to the approach undertaken for substation replacement projects. Accordingly, we consider that the input assumptions relied upon in the model are likely to be subject to similar concerns, leading us to conclude that some of the input assumptions may be overstated.

Other SCADA repex

We accept United Energy's forecast for SCADA repex related to ZS switchgear replacements. We agree with United Energy that it is standard industry practice to

[51] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 90.

replace protection systems when primary ZS assets are replaced, because the cost efficiencies will generally outweigh the costs of premature replacement.

United Energy has not provided any additional supporting evidence for its remaining SCADA programs. In the absence of further information, we consider current regulatory control period actual repex is reasonable to include in our substitute estimate.

Pole-top structures

United Energy's pole-top structures forecast of $78 million is 9 per cent higher than current regulatory control period spend. The forecast consists of:

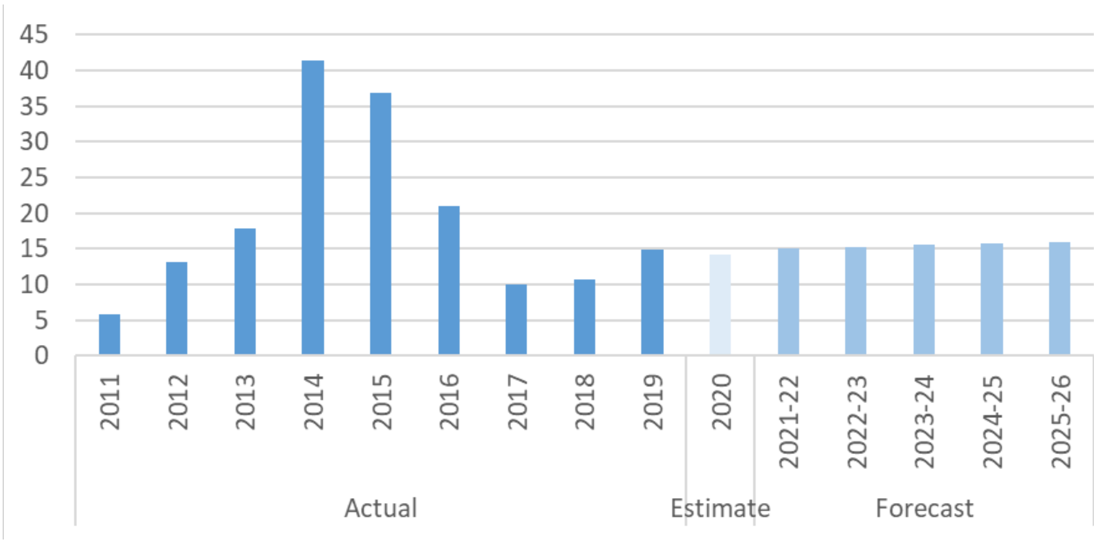
- reactive business-as-usual program ($71 million)—this is around the same as current regulatory control period spend
- proactive safety program ($7 million)
- offset adjustment to reflect higher poles repex forecast (-$1 million).

United Energy has not demonstrated a need for this level of pole-top structures repex. We include $60 million in our substitute estimate, which is equal to actual repex in the current regulatory control period but excluding 2016 due to a change in asset management policy.

Figure A.9 shows United Energy's historical and forecast pole-top structures repex. United Energy noted that it 'invested heavily in pole top structures in the period up to 2016. As a result of this investment, we observed a reduction in pole top failures.' It also noted that, 'Since May 2017, we have also applied a comprehensive condition-based risk management (CBRM) model to manage cross-arm inspection and replacement'.[52]

[52] United Energy's response to information request 013.

Figure A.9 Pole-top structures repex ($ million, $2020–21)



Source: AER analysis of RIN data.

Reactive program

United Energy's forecast business-as-usual program is 30 per cent higher than actual repex since 2017 (before accounting for the offset adjustment). It noted that it had applied a multiplier to 2017 and 2018 actual volumes 'to account for lower than sustainable replacement volumes observed in 2017 and 2018 as our CBRM management was being implemented.' It also noted that it will 'update our forecasts for the revised regulatory proposal to include our actual 2019 data'.[53]

Given United Energy's significant improvements in asset failures and fire starts we are not satisfied that it requires a step-up in repex. Instead, we include in our substitute estimate pole-top structures a forecast based on actual repex from 2017 to 2019, which is consistent with United Energy's stated approach to the revised proposal.

Proactive program

United Energy proposed to proactively replace all high-voltage wood cross-arms in hazardous bushfire risk areas. It says that the program is consistent with its safety obligations to minimise risk as far as practicable.[54] We have not seen evidence to demonstrate that the costs of the program are not grossly disproportionate to the safety risk reduction benefits, and therefore constitute a safety obligation.

United Energy submits that its CBRM model targets higher risk assets, including those identified in this proactive program. To the extent that the higher-risk assets are replacement under the CBRM program, we consider that it is not necessary to

53 United Energy's response to information request 013.

54 United Energy's response to information request 013.

proactively replace the lower-risk assets. This is reinforced by the reduction in failures and fire starts in recent years under the CBRM model. United Energy stated that:[55]

> A significant driver for the reduction of asset failures has been the reduction in pole top failures.

and

> The main driver for the reduction in fire starts was the reduction in pole top fires, reduction in LV [low voltage] asset failures and a revision to the vegetation management system in CY15/16.

United Energy provided cost-benefit analysis to support the proactive program. We have some concerns with some assumptions in the model, including:

- Status quo volume assumptions are not intuitive and not explained. The status quo option assumes low risk (and therefore low replacement volumes) in the forecast regulatory control period, and thereafter volumes increase sharply until all cross-arms are replaced by 2028. Furthermore, the low volumes assumed in the current period suggests that the CBRM model is not identifying high voltage (HV) cross-arms in HBRA for replacement in large numbers. This implies that these assets are not a significant safety risk.
- EMCa notes, 'From the model, it indicates that this program targets replacement of 1,825 cross-arms only. However, there is insufficient information provided to ascertain the risk reduction that relates to this subset of HV crossarms for replacement relative to the population of HV cross-arms'.[56]
- United Energy has not accounted for the impact of the proactive program on its reactive business-as-usual program. To the extent the proactive program is removing higher-risk cross-arms from the network we would expect to see a reduction in reactive volumes.

For these reasons we do not see a need for an increase in pole-top structures repex in the forecast regulatory control period compared with its current period spend.

Underground cables and overhead conductors

Together, United Energy's forecast for these asset groups is $46 million. Although this is higher than the repex model result of $36 million it is substantially lower than current regulatory control period repex of $64 million. We do not have concerns about the forecast.

Other repex

United Energy's initial capex proposal included $97 million for other repex. It subsequently withdrew the majority of its proposed environmental capex program so

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55 United Energy, *UE PL 2034 Strategic Asset Management Plan*, January 2020, p. 24.

56 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 57.

we assessed the residual forecast other repex of $12 million. While forecast other repex is around one-third higher than current regulatory control period spend, this translates to an increase of only around $3 million. The forecast includes recurrent repex such as substation repairs and capacitor banks. We have included United Energy's forecast for other capex in our substitute estimate.

A.2 DER integration capex

DER includes solar PV, energy storage devices, electric vehicles (EVs) and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that are placed on networks.

DER integration expenditure addresses increasing DER penetration on the network. This includes managing voltage within safety standards and allowing solar customers to dynamically export back onto the grid. DER integration capex includes:

- augmenting the network to physically provide greater solar PV export capacity
- ICT capex to develop greater visibility of the LV network and manage changes being driven by technological developments (batteries and EVs).

A.2.1 Draft decision

United Energy has not demonstrated that its initial DER integration capex forecast is prudent and efficient. We include $39.3 million for this category in our substitute estimate of total capex, which is $32.0 million (45 per cent) lower than United Energy's initial proposal.

A.2.2 United Energy's initial proposal

United Energy's initial DER integration capex forecast includes the following programs:

- solar enablement (augex)—augmenting distribution transformers to increase capacity
- digital network (ICT capex)—ICT capex technology upgrades
- digital network devices (augex)—targeted rollout of network devices to facilitate the two programs above.

For this draft decision, these programs have been grouped together to form the DER integration capex category. The relevant forecasts have also been subtracted from United Energy's respective augex and ICT capex forecasts, ensuring the forecasts are not double-counted and the total net capex amounts reconcile.

A.2.3 Reasons for draft decision

United Energy has adequately supported most aspects of its DER integration capex proposal. However, United Energy has overstated its solar enablement program by including investments that would be more prudent to undertake in subsequent regulatory control periods. In addition, United Energy has not fully explained how its solar enablement program interrelates with other aspects of its DER integration capex forecast, particularly its digital network program, as well as its tariff structure statement proposal. Stakeholders such as CCP17 raised similar concerns.[57]

Solar enablement

United Energy stated that it proposed this program because it is forecasting large increase in solar PV penetration during the forecast regulatory control period.[58] This is expected to cause localised network voltages to rise, which may cause solar inverters to trip off as a safety measure that prevents the solar PV system from producing and exporting.[59] United Energy is also forecasting an associated solar enablement step change, which includes tapping and an ongoing compliance program. Transformer tapping is an operational practice that helps to regulate network voltages. Our opex decision (Attachment 6) outlines further detail.

We are supportive of United Energy facilitating solar PV growth on its network. However, its forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program. Specifically, its analysis includes investments that would be more prudent to undertake in subsequent regulatory control periods. Secondly, the solar enablement program business case uses a 30-year NPV analysis period, unlike the standard 20-year NPV period United Energy uses for other repex and augex projects.

For this reset we think capex required to increase DER export capacity is SCS and consistent with the capex objectives. In assessing the solar enablement program, consistent with EMCa's advice, we are guided by two principles: timeliness and proportionality. Considering timeliness ensures that investments are undertaken as they are needed and not before they are required. Considering proportionality requires that, given the substantial amount of network augmentation proposed, possible lower cost solutions are exhausted and each augmentation is individually justified.

EMCa stated that considering these principles will help facilitate the most appropriate actions being taken to accommodate distributed solar and to enable customers to achieve the benefits of their own investments.[60] As a result, overall our draft decision better reflects the costs needed for customers to export energy and ensures that customers are not overcharged.

Timeliness – optimal investment timing

EMCa's review of United Energy's solar enablement program identified that distribution transformer upgrades that would be more prudent to undertake in subsequent

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57 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals,* June 2020, p. 105.

58 Solar customers as a proportion of total customers.

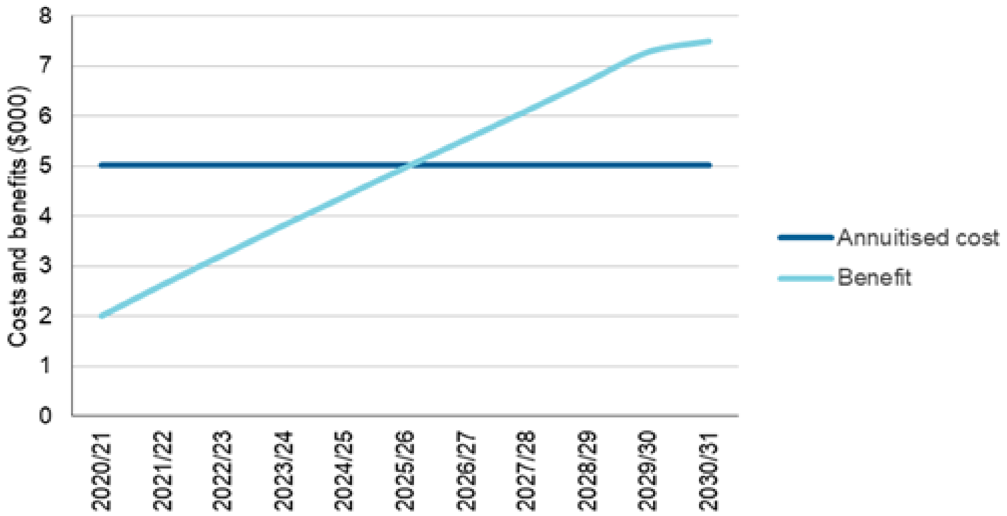
59 United Energy, *Solar enablement business case,* January 2020, p. 4.

60 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 143.

regulatory control periods have been included in United Energy's initial proposal. United Energy sought to determine a time profile for its proposed expenditure as the year when the cost-benefit analysis model first produces a positive NPV. This is erroneous and also inconsistent with the method United Energy (and other distribution businesses) apply in seeking to determine the appropriate timing for other augex projects.

The applied approach brings forward augmentations when they are still uneconomic, but have a positive NPV only because their forecast of distant future positive net benefits is offsetting the still negative net benefits within the forecast period. The standard approach is to identify when the annual benefits exceed the annual costs, in this case represented by the annuitised cost of the upgrade being considered. EMCa's analysis highlighted that the net benefits to customers are far smaller if United Energy undertakes these augmentations before this time. Figure A.10 outlines an example of this analysis and highlights that the optimal investment timing for this specific transformer is 2025–26.

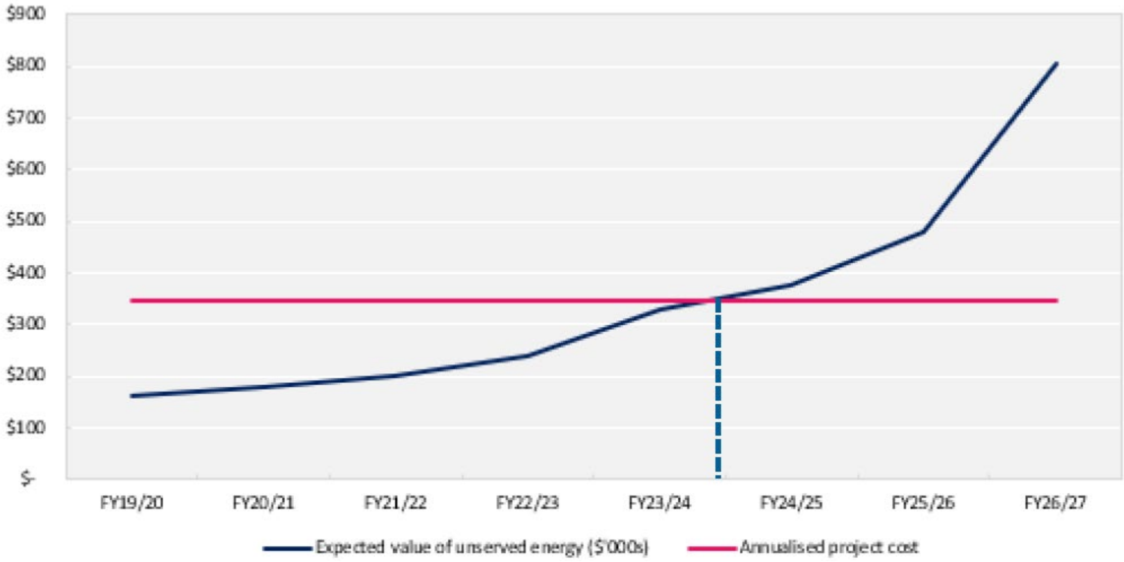
Figure A.10 Annuitised costs and modelled benefits of one transformer upgrade ($ thousand, $2020–21)



Source: EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 149.

Figure A.10 highlights that the annual benefits of this distribution transformer upgrade will not exceed the annualised costs until 2025–26. This type of analysis is consistent with how some distributors propose and we typically assess repex and traditional augex proposals. Figure A.11 outlines the analysis United Energy undertook for its Doncaster area augex project. It used this approach to ascertain the optimal timing of each of its traditional augex proposals but has not done so for DER.

Figure A.11 United Energy's assessment of the energy not served vs the annualised option cost ($ thousand, $2020–21)



Source: EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 106.

EMCa applied the same analysis approach to all proposed distribution transformers. Conducting the analysis over the proposed 30-year period produces 183 distribution transformers that are economic to upgrade in the forecast period, compared with United Energy's proposal of 533 transformers. In other words, a large proportion of the proposed transformers have an optimal investment timing trigger point (where the expected benefits exceed the expected costs) outside the forecast regulatory control period (2026–27 or later). Therefore, EMCa's analysis highlights that it is not prudent and efficient to upgrade these transformers in the forecast regulatory control period.

To further support this position, EMCa conducted both NPV analysis and optimal investment timing analysis for a sample of distribution transformers. EMCa's NPV analysis showed that the upgrades should be triggered around the same time as determined by the optimal investment timing analysis method. In other words, the net benefit is low if the upgrade is done prematurely, but increases significantly if the timing is deferred. In addition, EMCa's analysis shows that if the upgrade is deferred even further beyond this point, the net benefit reduces, which further supports the assertion that the selected timing is optimum.

Proportionality – NPV analysis period

United Energy's solar enablement business case is based on a 30-year NPV analysis. Standard approaches to this type of analysis for other augex and repex projects use a 20-year NPV period. EMCa noted that United Energy had not adequately considered the uncertainty inherent in justifying capex based on a 30-year model of assumed PV export benefits.[61] EMCa advised that using a 20-year NPV period aligns with United Energy's cost-benefit analysis approach for its augex and repex programs.

United Energy stated that a 30-year analysis period is appropriate because it had already factored uncertainty into its analysis by using conservative assumptions for forecast PV uptake and installed inverter capacity.[62] However, this response indicates that United Energy has not placed weight on the potential for battery technology to develop and consumer behaviour to change in response to cheaper and developing technologies.

United Energy also submitted that shortening the NPV analysis period would require the time over which assets are depreciated to be shortened as well.[63] However, we do not agree with this assertion. There are many examples of other expenditure where the economic analysis period does not align with the depreciation life. For example, the standard approach to conduct NPV analysis is generally over 20 years, including for repex and augex. However, these assets are not depreciated over 20 years. For example, United Energy's distribution system assets have a standard life of 51 years. In addition, United Energy's ICT assets have a standard life of six years, but the economic analysis is not conducted over this same period.

EMC also came to the same conclusion. It did not agree that the NPV analysis period must equal the depreciation life of the relevant asset. EMCa stated that:[64]

> LV assets may well have economic lives of 45 years or more and are typically depreciated accordingly. Similarly, we would expect that an LV asset that is installed as part of an LV augmentation, whether for SE purposes or for other reasons, would have a similar expected life in service. The question at issue here is not the life of the asset, but the analysis period for which it is reasonable to consider benefits to justify the LV augmentation investment, in this case for solar enablement purposes. This requires consideration of a reasonable forecasting horizon, within which a reasonable estimate of costs and benefits can be made.

Other considerations

United Energy conducted forums, surveys, a deep dive workshop, and published and consulted on an options paper to develop options for enabling solar. It contends that customer feedback from these engagement activities was pivotal in shaping its approach and noted that its customers can tolerate reasonable constraints but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. However, CCP17 submitted that the way the investment proposal

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61 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 143.

62 United Energy's response to information request 044, July 2020, p. 9.

63 United Energy's response to information request 044, July 2020, p. 12.

64 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 147.

was presented to customers may have led to United Energy overstating its customer's expectations.[65]

United Energy concluded that allowing some (reasonable) level of solar constraint and removing it when the cost of continuing to allow the constraint outweighs the cost of removing was the only option that is capable of maximising the net benefits of solar. A key component of this assessment is the value United Energy attributes to the additional solar proposed to be added to its network.

Many stakeholders highlighted concerns with how United Energy valued solar PV exports in its solar enablement modelling:

- The Victorian Department of Environment, Land, Water and Planning (DELWP) submitted that the Victorian Government is committed to helping Victorians take control of their energy bills, create jobs and take strong and effective action on climate change via the Solar Homes program, and United Energy's proposed solar enablement program will support the delivery of its program over the forecast period.[66] However, DELWP acknowledged that assessing the proposed investment is challenging due to lack of agreed methodology and limitations of transparency in assumptions and approaches.[67]
- CCP17 submitted that the assumed value of rooftop solar exports used in the modelling does not consider that over the life of the investment there might be zero or negative pool prices.[68]
- EnergyAustralia submitted that there are some aspects in the treatment of DER that warrant closer attention, particularly the value of solar export, and noted that generally the DER integration proposals tended to overstate the value of solar export.[69]
- The Energy Users' Association of Australia stated that the value of DER may be overstated, highlighting that in both South Australia and Queensland in the last 12 months, at times in the middle of the day increased solar PV can have no value or a negative value with the incidence of negative pool prices increasing.[70]
- The VCO supported a standard approach for valuing exported generation that reflects the expected changes in the value of DER exports over time.[71]

Similar concerns were raised in response to our consultation paper on Assessing DER Integration Expenditure,[72] in addition to a lack of consistency across distributors in

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65 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106.

66 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 2.

67 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 3.

68 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106.

69 EnergyAustralia, *Submission to VIC DNSP proposals,* June 2020, p. 1.

70 Energy Users' Association of Australia, *EDPR submission,* June 2020, p. 11.

71 Victorian Community Organisations, *2021–26 Victorian EDPR – Joint submission*, May 2020, p. 10.

72 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/initiation.

valuing the benefits associated with investing in DER integration. In response we and the Australian Renewable Energy Agency commissioned the VaDER study earlier this year.[73] Commonwealth Scientific and Industrial Research Organisation and Cutler-Merz were engaged to conduct a study into potential methodologies for valuing DER and have extensively engaged with stakeholders, including United Energy, as part of the study.

The final report of the VaDER study is due to us in early October 2020, which will help to address some of the stakeholder concerns outlined above. We will publish the final report as soon as practicable. We will then consider the report's recommendations and formally implement them as we consider appropriate as part of our DER integration expenditure guideline, now due for completion in 2021. Given the extensive stakeholder engagement in forming the VaDER study's recommendations, we anticipate that consumers will expect Victorian distributors to prepare their revised proposals in the spirit of these recommendations.

Substitute estimate

Our substitute estimate conducts the optimal investment timing analysis discussed above over a 20-year analysis period, rather than the 30-year period that United Energy proposed. This is consistent with our standard assessment approaches for more traditional types of expenditure, such as repex and augex. This approach reduces the number of distribution transformers that are economic to upgrade in the forecast regulatory control period from 533 to 167 and contributes $13.8 million[74] to our substitute estimate of total capex.

Digital network

United Energy's DER integration capex forecast includes a digital network program. It outlined that its network is going through a large transformation. It has good visibility of its HV network, but changing customer requirements such as demand management programs and EVs and battery uptake require it to develop greater visibility of its LV network.[75] United Energy expects this program will allow it to manage the network more efficiently in real-time, through better forecasting, monitoring, diagnosis and eventually through automation.[76]

The listed benefits of its digital network program are promoting EVs uptake, optimising load control of customer appliances, enhancing cost-reflective pricing, detecting electricity theft, proactively managing asset failures, avoiding overblown fuses, looking after vulnerable customers and keeping customers safe.[77] United Energy proposes to

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73 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/consultation.

74 Excluding real price escalation.

75 United Energy, *Digital network business case,* January 2020, p. 5.

76 United Energy, *Digital network business case,* January 2020, p. 4

77 United Energy, *Digital network business case,* January 2020, p. 6.

implement more advanced technological capabilities and extend its AMI coverage to type 1–4 contestable metering customers (large customers) and unmetered supply customers in a targeted rollout.

CCP17 acknowledged that a level of investment is needed to establish a data gathering and analytics capability to explore some of the benefits identified. However, it questioned why United Energy could not draw reasonable advantages regarding energy theft, customer energy profile modelling and EVs charging analysis from its existing systems, noting that Victorian customers have already spent a significant amount on advanced metering at most customer supply points.[78]

Therefore, CCP17 submitted that it did not support the digital network programs because other simpler and less costly alternatives exist to achieve similar outcomes; many expectations of customer acceptance of these initiatives are untested; and the benefits to customers are not clear, are over a long time period subject to exogenous factors that may or may not change.[79]

EMCa's review highlighted that digital network may have merit but that the investments may be premature for the forecast regulatory control period. EMCa noted the needs analysis for real-time data to support digital network has not been fully justified.[80] EMCa considered that the claimed positive net benefit is strongly dependent of benefit streams continuing for ten to 20 years and there is considerable uncertainty in these benefit streams beyond five to ten years.[81]

However, United Energy has provided quantified benefits for its digital network program to improve the capabilities regarding EVs uptake, cost-reflective pricing and customer appliance load control. As highlighted above, the distributors' solar enablement proposals did not account for these aspects. It is inconsistent for United Energy to not account for these considerations in its solar enablement program, but then to account for them in the complementary ICT proposals that aim to facilitate these capabilities.

While we agree with EMCa's assessment and stakeholder submissions that highlighted that the digital network programs may be marginally overstated, we consider it is more critical for United Energy to account for the capabilities outlined above, particularly EVs uptake and cost-reflective pricing, in its revised solar enablement proposal. Therefore, we have included United Energy's initial digital network forecast in our substitute estimate of total capex. As noted above, United Energy has flagged that it intends to reconsider the intended outcomes and output measures of its DER integration capex forecast, and test alternative options in light of additional stakeholder engagement on the proposal.

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78 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 100.

79 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 100.

80 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 165.

81 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 168.

A.3 Augex

The need to build or upgrade the network to address changes in demand and network utilisation typically triggers augex. The need to upgrade the network to comply with quality, safety, reliability and security of supply requirements can also trigger augex.

A.3.1 Draft decision

We do not accept United Energy's proposed non-DER augex forecast of $129.7 million, due to United Energy's overstated demand forecasts. Our substitute forecast includes $88.6 million for non-DER augex. This is based on our alternative forecast for flat maximum demand, and the augex United Energy has incurred over the current regulatory control period where maximum demand on its network has been flat.

A.3.2 United Energy's initial proposal

United Energy proposed $128.7 million for non-DER augex. We have divided this between the following categories, based on the different drivers involved and whether the expenditure is recurrent or non-recurrent:

- $104.3 million for traditional augex
- $8.5 million for rapid earth fault current limiters (REFCL) and bushfire-related augex
- $16.9 million for other augex.[82]

Traditional Augex

The major projects United Energy proposed in this category are:

- Doncaster Supply Area ($6.4 million)
- Malvern Supply Area ($7.5 million)
- Keysborough Supply Area ($6.6 million)
- Mornington Supply Area ($7.5 million)
- HV Feeders Augmentation ($12.8 million).
- United Energy identified growing maximum demand as a key driver of the need for these projects.

United Energy also proposed $67.3 million for 75 smaller projects not supported by business case analysis. Based on descriptions United Energy provided, 58 per cent of capex for these smaller projects is driven by forecast demand growth, leaving the remainder driven by other requirements (such as regulatory compliance).[83]

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82 These figures and those below are after applying United Energy's higher rate of real escalations.

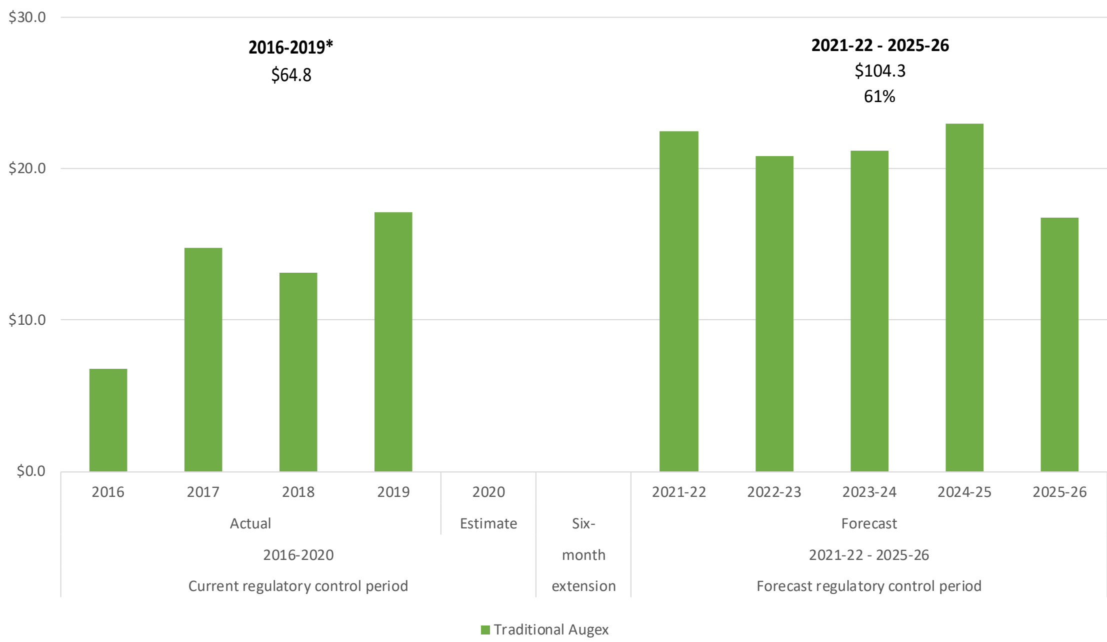
83 United Energy’s response to information request 011, Q3, 29 April 2020, p. 1.

A.3.3 Reasons for draft decision

Traditional Augex

United Energy proposed a largely demand-driven increase of 40 per cent compared with 2016–19 actuals (Figure A.12). As discussed in Section B (Forecast Demand), United Energy's maximum demand forecasts are materially overstated. We have adopted AEMO's 2019 Transmission Connection Point forecasts as our alternative demand forecast. We do not accept United Energy's forecast for this category of augex as the need for many projects does not arise under these alternative forecasts during the forthcoming regulatory control period.

Figure A.12 United Energy's historical and forecast traditional augex ($ million, $2020–21)



Source: AER analysis based on United Energy's RIN data.

Note: Traditional augex is defined as augex excluding 'communications', 'VBRC' and DER capex. No estimate was made for 2020 or the six-month extension period.

Stakeholders also expressed concern that overstated demand forecasts could lead to over-building or windfall CESS benefits, including after accounting for the effects of COVID-19.[84]

[84] Victorian Community Organisations, *2021–26 Victorian EDPR - Joint Submission,* May 2020, p. 4; CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, pp. 59-62; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* May 2020, p.3.

In the absence of new compliance obligations, we expect forecast traditional augex will be similar to historical costs where we reasonably expect maximum demand to grow (or not to grow) at a similar rate as the current regulatory control period. Therefore, we treat United Energy's traditional augex as a recurrent category where revealed costs are a reasonable estimate of future requirements.

To apply this approach, for calendar years 2016–19 we have included all non-DER augex reported in United Energy's RIN except augex it identified as 'VBRC' (Victorian Bushfires Royal Commission) and 'other augex' which includes communications augex.[85] This produces a substitute forecast for traditional augex of $74.5 million, compared with United Energy's forecast $104.3 million.

This substitute does not rely on apportioning our alternative demand forecasts to the zone substation level, and assessing the need for individual projects. For 58 per cent of augex in this category, United Energy did not supply business cases, and EMCa found there was not sufficient evidence to support this part of United Energy's forecast.[86] We nevertheless sought to check the reasonableness of our substitute forecast through bottom-up analysis for the projects for which we had sufficient information. To do this, we reconciled United Energy's original bottom-up zone substation forecasts with AEMO's 2019 forecasts at the terminal station level by changing forecasts for all zone substations connected to each terminal station by the same ratio each year. This is similar to the procedure United Energy describes for reconciling its bottom-up zone substation forecasts to its top-down network forecast, except applied at the terminal station level.[87]

For zone substations where United Energy forecasted a need for demand driven augex to begin in a given year, we took the demand forecast in that year as the threshold for augmentation. We then calculated which projects met this threshold during the forthcoming regulatory control period, based on our substitute zone substation demand forecasts (prior to any use of demand management). This led to reductions of $37.2 million for the 58 per cent of expenditure we were able to assess, which is greater than our substitute estimate based on historicals ($29.7 million in reductions).

However, although our substitute demand forecasts are usually lower, this is not the case at every geographical level. Hence our demand forecasts could imply the need for new projects that United Energy has not proposed, and we have not examined this. On the other hand, we have included significant capex for non-demand driven projects in our bottom-up substitute without assessing it individually. On balance, we therefore consider our bottom-up analysis supports our top-down substitute.

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85 To validate this comparison, we asked United Energy to identify augex for these categories historically, as United Energy's proposed augex model encompass all categories of augex reported in its RIN. United Energy*, Response to Information request 52 - Question 15,* July 2020, pp.6-7.

86 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 96.

87 United Energy, *United Energy Maximum Demand Forecasting Method,* October 2019, p. 19.

EMCa assessed projects in this category primarily from an engineering perspective. It was not within EMCa's scope to assess United Energy's demand forecasts, as we consider AEMO's demand forecasts are robust as inputs to our assessment. EMCa's demand forecasting sensitivity analysis was limited to adjusting for one consideration: whether to use a blend of POE10 and POE50 forecasts (as United Energy and AEMO do) or a POE50 forecast only.[88]

REFCL and Bushfire Augex

United Energy’s list of augex projects identifies $8.5 million for augex related to reducing fire starts and maintaining and enhancing its existing REFCLs. Although United Energy has not supplied business cases for these projects, the overall value of this forecast appears reasonable and is relatively low, so we have included this aspect of United Energy's forecast.

Other augex programs

United Energy proposed other augex programs including network communications device upgrades and other technology upgrades. EMCa's review highlighted that United Energy did not provide information to support some of this communications augex forecast.[89] We encourage United Energy to include further supporting information including business cases and cost models for these aspects of its forecast in its revised proposal.

Consistent with our alternative control services (ACS) capex draft decision, we have reallocated a proportion of United Energy's proposed network communications expenditure to ACS capex. United Energy allocated 100 per cent of its 3G shutdown network communications program to SCS capex. However, as outlined in our ACS metering draft decision (Attachment 16), some 3G shutdown capex should be allocated to ACS metering. The 3G systems that United Energy proposes to replace are used to backhaul bulk data from AMI meters. This data is used for both metering and standard control network services. Therefore, United Energy should share this cost between SCS and ACS. Based on our analysis, we have allocated 72 per cent of this program to SCS capex and the remaining 28 per cent to ACS capex.

Similarly, United Energy allocated 88 per cent of its annual communication devices program to SCS capex. Our ACS metering analysis has determined that this allocation should be 25 per cent SCS capex and 75 per cent ACS capex. Our substitute estimate of total capex is consistent with these reallocations. Our metering draft decision (Attachment 16) outlines further analysis of these reallocations.

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88 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 134. Implicitly, our alternative zone substation forecasts retain United Energy's blended method, assuming the ratio of POE50 to POE10 forecasts remains constant.

89 EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 135.

A.4 Connections capex

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet new customer demand.

A.4.1 Draft decision

We do not accept United Energy's connections and capital contributions forecasts, as it has not justified the increase involved compared to historical expenditure under its current contributions policy, and COVID-19 has since affected construction activity. Our substitute forecast includes $294.1 million for gross connections, which is a reduction of 20 per cent. We include $194.8 million for customer contributions, which is a reduction of 19 per cent. This is based on historical expenditure under United Energy's current customer contributions policy, adjusted for COVID-19 based on a dwelling construction forecast by the Housing Industry Association (HIA).

A.4.2 United Energy's initial proposal

United Energy proposed $369.2 million for gross connections, and $240.0 million for capital contributions. For high volume connections (typically residential and smaller connections) United Energy forecast volumes based initially on their average by type over the period 2015–16 to 2018–19, then applied growth rates for construction activity taken from the Australian Industry Construction Forum for regions in its network. It similarly averaged unit rates by type over the period 2015–16 to 2018–19.[90]

For 'low volume' connections, United Energy has used a combination of 'bottom-up build' and 'historical average' methods.

United Energy has forecast contributions, gifted assets and rebates based on 2016–17 to 2018–19 averages. It stated that it used this shorter period due to the change to its connections policy from July 2016.[91]

A.4.3 Reasons for draft decision

For categories where historical unit rates and volumes are key inputs to a forecast, it is important to select appropriate years from which to calculate these averages. Generally, selecting a different range of years over which to calculate gross connections and customer contributions is unlikely to be appropriate, or at least requires justification. Otherwise, 'cherry picking' from different samples to arrive at a higher forecast is possible.

United Energy's decision to limit the years used to calculate its capital contributions until after its policy changed is reasonable. Since its customer contributions increased

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90 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 82.

91 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 83.

materially after the policy change, including earlier data would bias its net connections forecast downwards.

However, United Energy has not justified its decision not to use the same range of years to calculate average volumes and gross connections unit rates. Even when broken down by category, unit rates and volumes are an average across connections with different requirements. So from year to year, these averages can move due to essentially random fluctuations. Using the same periods for averaging for gross connections and customer contributions means that the same projects are used as samples for both. Unit rates from a time closer to the forecast regulatory control period will also generally be more reflective of future unit rates, especially if a trend is evident. Average unit rates across high volume connection declined by 3.5 per cent per year on average over the period United Energy used.[92]

United Energy has also used a financial year of estimates (2018–19) as part of the average used to make its forecast. Forecasts should be based on actuals wherever possible.

To test the materiality of these issues, we compared United Energy's average yearly forecast net connections (prior to real cost escalation) with average yearly net connections between calendar years 2016 and 2019. To address the impact of United Energy's different connections policy prior to July 2016 we weighted the 2016 data by half (noting that excluding 2016 entirely would have produced a lower average). United Energy's net connections forecast is 13 per cent higher based on this comparison. This indicates United Energy's choice of years for averaging purposes has a material effect on its forecast.

For these reasons we do not accept United Energy's relatively higher volume connections and capital contributions forecasts prior to the effects of COVID-19.

United Energy has not updated its forecast to take into account the effects of the COVID-19 pandemic. The pandemic has strongly affected the construction industry, and is likely to continue to reduce activity due to its effect on net migration and overall output.

To produce a substitute estimate that estimates both COVID-19 pandemic effects and uses more appropriate years as the basis for averaging, we have first adopted the yearly average for gross connections and for capital contributions over calendar years 2016–19, with 2016 data weighted by half, for every year of the forthcoming period. We have then applied a COVID-19 adjustment to this historicals based forecast, based on HIA forecasts released in April. We have used these forecasts as they provide a Victoria-specific forecast and extend one year into the forthcoming regulatory control period.[93]

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92 This takes unit rates by United Energy's function codes, weighted by average volumes over 2015–16 to 2018–19, where meaningful unit rates could be calculated for every year.

93 Housing Industry Association, *HIA Housing Forecasts - April 2020 COVID-19 Update*, April 2020.

To estimate the effects of the COVID-19 pandemic over 2021–22, we compared forecast dwelling starts with actual yearly dwelling starts prior to COVID-19 over the current regulatory period (calendar years 2016–19). This gives a ratio of 0.58. This is an approximate measure of the forecast effects of the COVID-19 pandemic, as this is the major factor the HIA sought to account for in producing these forecasts. We then applied this ratio to the yearly averages for gross connections and capital contributions described above for 2021–22. This results in a further 8 per cent reduction to both.

The COVID-19 pandemic is also likely to affect low volume connections due to its impact on economic activity. United Energy has used a 'bottom-up build' to forecast some of these projects, and whether and when these projects will now go ahead needs to be reconsidered. As we do not have sufficient information to assess COVID-19 effects for each project, we have combined low volume connections and high volume connections together for the purposes of our substitute forecast based on historicals and a COVID-19 adjustment.

Currently, the duration of the main consequences of the COVID-19 pandemic is highly uncertain. The Reserve Bank of Australia's August Statement on Monetary Policy assumes international border restrictions will ease from the middle of 2021 in its baseline scenario.[94] Net migration and construction activity will likely then take time to recover. This indicates it is reasonable to assume the effects of the pandemic on construction will have ended by July 2022. Therefore for years after 2021–22, we have not adjusted our historicals based substitute estimate.

The combined effect of these adjustments reduces gross connections by 20 per cent to $294.1 million, and capital contributions reduces by 19 per cent to $194.4 million.

For our final decision, we will incorporate any new information that is likely to materially affect the forecast. This could include:

- updated construction forecasts for Victoria (including those that would allow us to distinguish effects by type of connection)
- any actual 2020 capex data from United Energy
- updated information about the likely length of the impacts of the COVID-19 pandemic.

A.5 ICT capex

ICT relates to all devices, applications and systems that support business operation. ICT capex is categorised broadly as either replacement of existing infrastructure for reasons due to end of life, technical obsolescence or added capability of the new system) or the acquisition of new assets for a business need.

94 Reserve Bank of Australia, *Statement on Monetary Policy*, August 2020, Section 6 (Economic Outlook).

A.5.1 Draft decision

We do not accept that United Energy's initial non-DER ICT capex forecast of $174.1 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $154.1 million for this category in our substitute estimate of total capex, which is $20.0 million (12 per cent) lower than United Energy's initial proposal.

A.5.2 United Energy's initial proposal

United Energy's initial proposal includes an ICT capex forecast of $174.1 million, which is split into $107.8 million in recurrent ICT and $66.3 million in non-recurrent ICT. Table A.2 summarises United Energy's initial proposal and our draft decision. As noted above in Section A.2, we have included United Energy's digital network program in the DER integration capex category. This program is therefore excluded from the numbers and analysis presented below.

Table A.2 Draft decision on United Energy's ICT capex forecast ($ million, $2020–21)

Category	Initial proposal	Draft decision	Difference ($)	Difference ($)
Recurrent ICT	107.8	103.5	-4.3	-4[95]
Non-recurrent ICT	66.3	50.6	-15.7	-24
Total ICT capex	**174.1**	**154.1**	**-20.0**	**-12**

Source: AER analysis.

Note: Numbers may not sum due to rounding.

A.5.3 Reasons for draft decision

We have had regard to all the information before us, including EMCa’s independent review and stakeholder submissions. We received several submissions that raised questions or concerns about United Energy's ICT capex, including from ECA, CCP17 and Origin Energy. The submissions noted that the:

- benefits were not always clear and opex benefits/savings appeared relatively low
- duplication of retailer provided services should not be included within regulated revenue.

Consistent with the approach outlined in our ICT expenditure assessment guideline, we have assessed recurrent ICT capex separately to non-recurrent ICT capex.[96]

[95] We accept United Energy's recurrent ICT capex forecast. These minor reductions relate to United Energy's CPI and real price escalation assumptions.

[96] AER, *ICT capex assessment review*, May 2019.

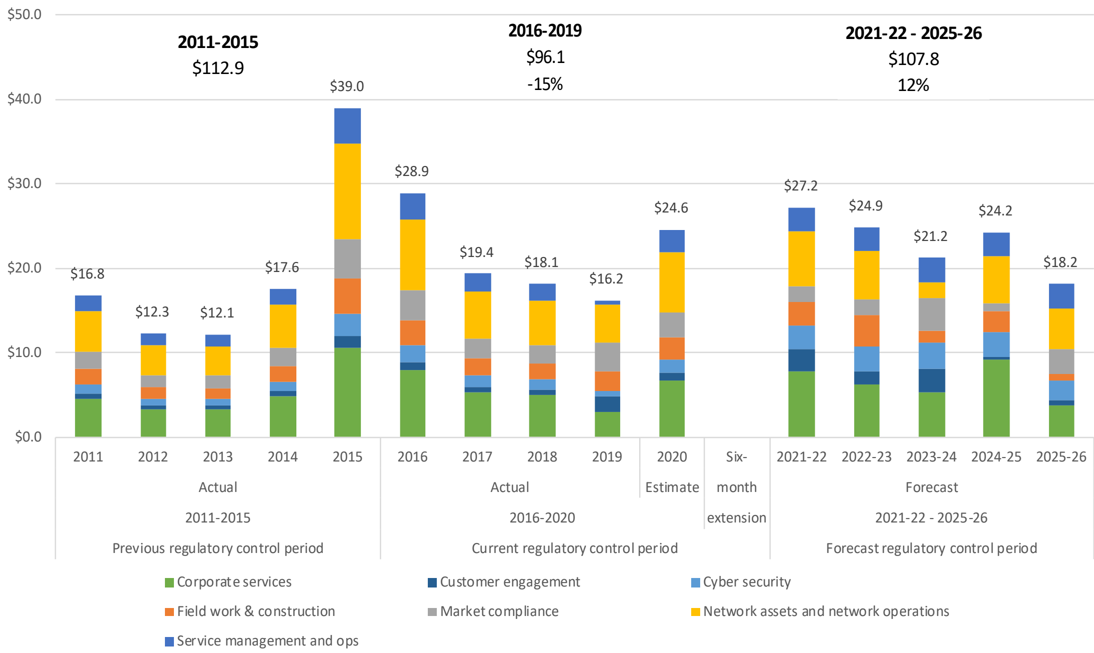
Recurrent ICT

Our draft decision accepts United Energy proposed recurrent ICT of $107.8 million. We have assessed this aspect of the forecast primarily through a top-down assessment. This is because historical costs are a likely indicator of future costs for this ICT capex category given the recurrent nature of these investments. We also had regard to benchmarking analysis of recurrent ICT total expenditure (totex) to assess United Energy's recurrent ICT capex forecast.

Top-down assessment

United Energy is forecasting a 12 per cent increase in its recurrent ICT capex over the forecast regulatory control period. However, its forecast is broadly in line with its longer term trend, as highlighted in Figure A.13.

Figure A.13 United Energy's historical vs forecast recurrent ICT snapshot ($ million, $2020–21)



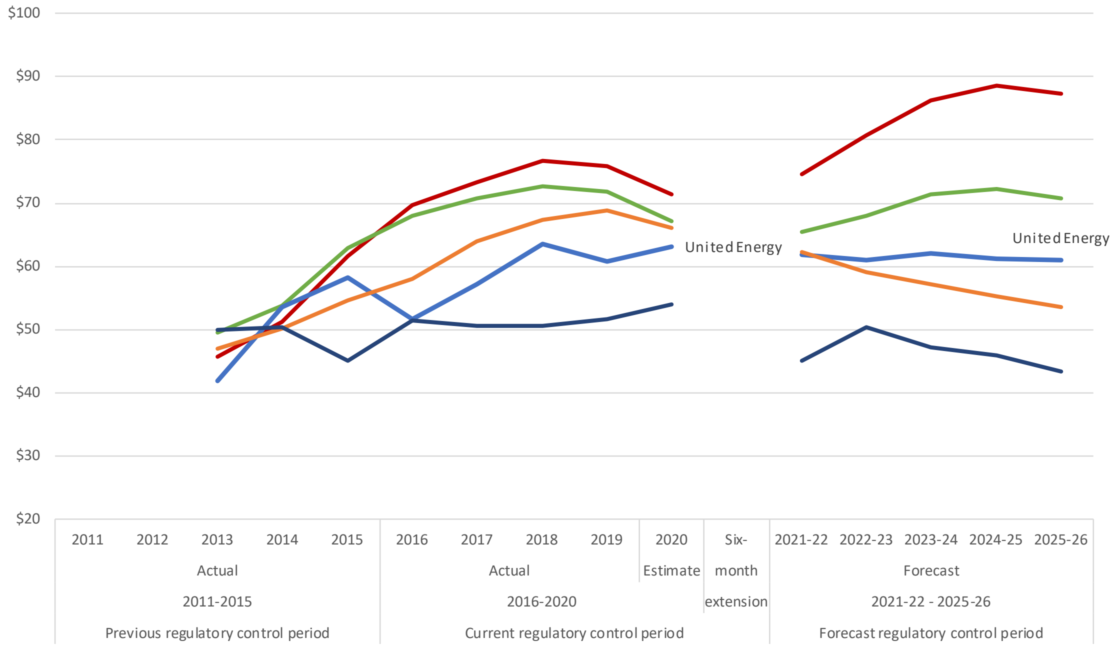
Source: United Energy's initial proposal and AER analysis.

Note: The labels under each regulatory control period show total ICT capex over the period and change from previous period. The four years of actual data from the current period (2016–19) have been prorated to a five-year period.

Figure A.14 highlights United Energy's actual recurrent ICT totex per customer ranged from $40 to $63 per customer, and it is just above $60 per customer for the forecast regulatory control period. This places United Energy in the middle of the five Victorian distributors for recurrent ICT totex per customer both in terms of historical revealed expenditure and forecast expenditure.

Figure A.15 illustrates United Energy's actual recurrent ICT totex per end user has varied 2013 to 2019. Since 2017, the five Victorian distributors have spent between approximately $30 000 and $45 000 in ICT totex per end user. United Energy's forecast places it at the mid-point compared with the other distributors, particularly by the end of the forecast regulatory control period.

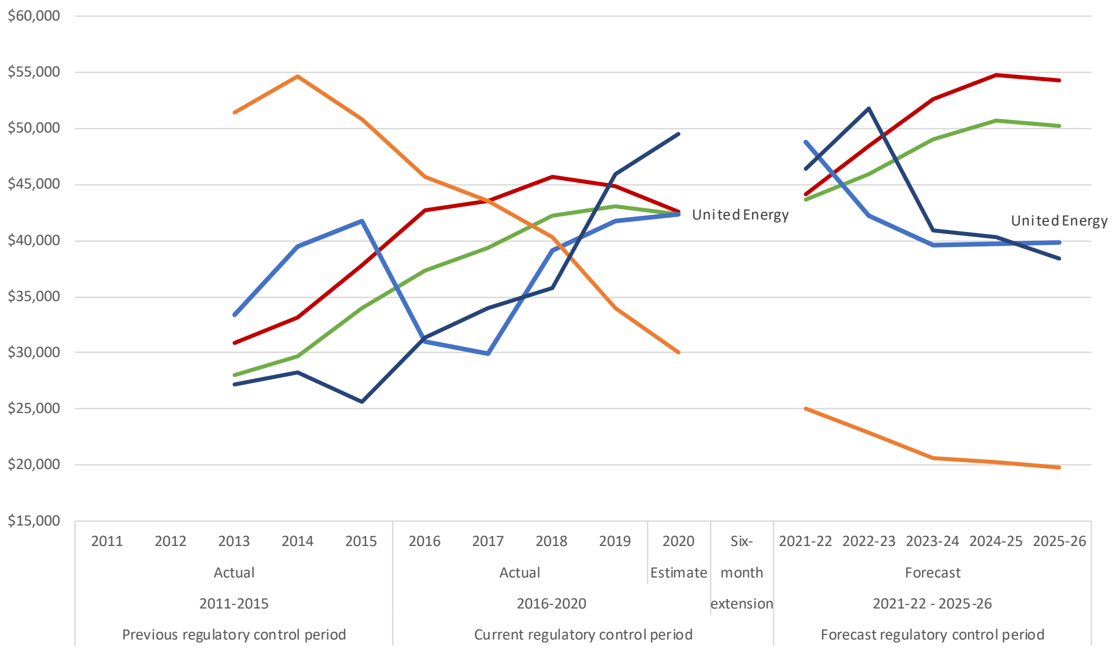
Figure A.14 Victorian ICT benchmarking: recurrent ICT totex per customer ($ million, $2020–21)



Source: AER analysis.

Note: Data presented is a five-year moving average.

Figure A.15 Victorian ICT benchmarking – Recurrent ICT totex per end user ($ million, 2020–21)



Source: AER analysis.

Note: Data presented is a five-year moving average.

Based on our top-down trend and benchmarking analysis, United Energy's recurrent ICT capex forecast appears to be reasonable. We have therefore included its initial forecast in our substitute estimate of total capex. The reduction noted above in table A.2 relates to our assessment of United Energy's CPI and real price escalation assumptions and therefore does not relate to our category assessment.

Non-recurrent ICT

United Energy has not justified its $66.3 million forecast for non-recurrent ICT capex. Our substitute estimate does not include United Energy's customer enablement program and adjusts the forecast for its intelligent engineering program. We have not identified any material issues in United Energy's remaining non-recurrent ICT programs.

We have reviewed the information United Energy provided in support of its non-recurrent ICT capex forecast, including the business cases and cost-benefit models. Where required, we have sought further information from United Energy through information requests. We have also had regard to the findings of EMCa from their bottom-up review.

Customer enablement

United Energy proposed to implement apps and other data platforms that will facilitate customer communication in relation to network services such as connections and outages. The program also aims to facilitate customers' understanding of their energy usage.[97] Our assessment sought to identify if the proposed investment was likely to be prudent and efficient, providing a positive expected value to consumers.

The first claimed benefit provides an additional means of accessing information in relation to network connections. While we consider this relevant, convenience is the only additional value the proposed app is likely to provide. In addition, the added value is likely to be quite low, as it may be slightly more convenient to use the app than using the identical web page facility.

The second claimed benefit provides improved availability and customer access to information. Given energy retailers already provide their customers with access to information on their energy usage, this benefit duplicates services that are inefficient in a monopoly network context. EMCa also does not consider that real-time data is required to extract the claimed benefits and therefore does not consider United Energy has fully justified the proposed costs of this project. EMCa concluded that United Energy could achieve some of the benefits through a combination of price signals through tariff reform and third-party providers.[98]

The third claimed benefit provides a reduction in call centre time. As consumers already have access to these same services through the web page, the choice of an app would not make a material difference to calls. We think that United Energy's approach to valuing savings in customer time through the use of these additional services overstates customer benefits. United Energy used an apportioned time saving between using an app versus a website and the average consumer wage rate as a proxy. We think the time saved from using an app compared to a website is immaterial[99] and the use of the average consumer wage rate as a proxy for enquiry time overvalues the time customers invest in following up a connection or outage enquiry.

Red Energy and Lumo Energy submitted that the provision of competitive services or duplicating services already provided by energy retailers must not form part of the revenue cap or regulated services provided. They considered that duplicating these costs across both networks and retailers is not in the long-term interests of consumers.[100]

Based on our assessment, stakeholder submissions and EMCa's analysis, we do not consider that United Energy has established that its customer enablement program is prudent and efficient. Any realised benefits are likely to be insignificant. Once these benefits are removed, United Energy's preferred option becomes NPV negative. Therefore, we have not included this program in our substitute estimate of total capex.

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[97] United Energy, *Customer enablement business case,* January 2020, p. 5.

[98] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, pp. 165–166.

[99] We think the difference in time spent on an app versus a website is relatively immaterial given the frequency with which customers would actually use either interface.

[100] Red Energy and Lumo Energy, *Victorian electricity distribution determination, 2021 to 2026,* June 2020, p. 1.

Intelligent engineering

United Energy proposed a program to correctly map its network assets with physical earth of the Global Positioning System (GPS). It explained that coordinates between its own assets are correct, but because they are not correctly mapped to GPS, the discrepancy can result in higher costs and higher risk of safety incidents through working around its underground assets.[101] United Energy stated that the benefits of this program are:

- conflating its geospatial information system (GIS) records to the physical earth
- introducing a master data management system
- enhancing map Insights
- improving Dial Before You Dig (DBYD) accuracy and access to information.[102]

EMCa indicated that it has concerns the benefits of this project may be overstated because United Energy could not necessarily have 100 per cent confidence in the revised mapping. However, it considers it is prudent for United Energy to remap the network, and noted that these issues appear to be of such significance that there is a case for undertaking some of this work in the current regulatory period rather than waiting until the next regulatory period.[103] United Energy responded to this query in an information request that there is no work underway on this project in the current regulatory period.[104]

However, we do not think the inclusion of the DBYD application is prudent and efficient under preferred option 2. Consistent with our concerns regarding the customer enablement program, we consider this app may only provide a degree of convenience over an identical web page facility. In addition, an official DBYD application already exists, which suggests that it is not the role of a monopoly network to duplicate an application, particularly if it is only applicable to a few Victorian electricity networks.

We do not have material concerns with option 1. Based on EMCa's advice, we recognise United Energy's proposal to remap its network is prudent and efficient. We have therefore included the capex forecast under option 1 for intelligent engineering in our substitute estimate of total capex.

CCP17 and Spencer&Co both submitted that although the program would streamline internal business operations, it was unclear how United Energy had taken these savings into account in its forecast.[105] United Energy explained that it had not incorporated the expected savings into its opex forecast, but it had also not included

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[101] United Energy, *Intelligent engineering business case,* January 2020, p. 5.

[102] United Energy, *Intelligent engineering business case,* January 2020, p. 5.

[103] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, pp. 173–175.

[104] United Energy, *Response to Information request 20,* May 2020, p. 4.

[105] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals,* June 2020, pp. 79, 93; Spencer&Co, *Advice to ECA on Victorian submissions,* June 2020, p. 22.

some additional operational costs it expects to incur through the digital network program in its forecast.[106]

We have found that the two operational benefits, first from the intelligent engineering program and second the additional cost of the digital network program not included in United Energy's forecast, are comparable. We have therefore not made an adjustment for this in our draft decision.

Other non-recurrent ICT programs

United Energy has justified its other non-recurrent ICT programs— systems applications and products (SAP) S/4 HANA, five-minute settlement and cyber security, which we have included in our substitute estimate of total capex. AusNet Services and Jemena have similar proposals, and we have seen other distributors outside Victoria require similar SAP upgrades and increasing cyber security ICT capex requirements, including SA Power Networks, Ausgrid and TasNetworks. We are also satisfied that the Australian Energy Market Commission’s decision to delay the commencement of the five-minute settlement rule by three months will not materially affect the proposed capex program.[107]

Stakeholder submissions on these programs were limited. CCP17 suggested that we consider the economies of scale and customer impact of the proposed parallel upgrade by CitiPower, Powercor and United Energy to SAP S/4 HANA. We are satisfied that the proposed capex for each of the three programs is efficient. United Energy explained that internal staff with expertise in the SAP systems implementation developed the cost breakdown for the SAP S/4 HANA upgrade.[108]

EMCa concluded that based on the number of SAP modules and the organisational business process complexity and migration from a legacy SAP platform to a modern SAP platform, the proposed implementation cost for a single instance for the preferred option is reasonable.[109] United Energy also provided evidence that 90 per cent of recent ICT projects have been delivered within budget and underspends that have occurred have not been substantial.[110]

A.6 Other non-network capex

Other non-network capex includes property, fleet, plant, tools and equipment. Property expenditure relates to the maintenance, refurbishment and optimisation of offices, operational depots, warehouses, training facilities and other specialist facilities. We

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106 United Energy’s response to information request 029, June 2020, pp. 5–6.

107 Australian Energy Market Commission, *Rule determination: National electricity amendment (delayed implementation of five minute and global settlement) rule 2020*, July 2020, p. i.

108 United Energy's response was provided in the response to a Powercor information request. Powercor, *Response to information request 30,* June 2020, pp. 4–5.

109 EMCa, *Review of aspects of United Energy’s regulatory proposal 2021–26*, September 2020, p. 179.

110 United Energy’s response to information request 020, May 2020, pp. 1–2.

have assessed the indirect costs associated with property assets as part of overheads and the costs below refer to 'direct' capital costs only.

Fleet includes expenditure for purchasing new vehicles and related items, including mounted plant. This can be divided between light fleet (passenger and light commercial vehicles) and heavy fleet (elevated work platforms, crane borers and other heavy commercial vehicles).

A.6.1 Draft decision

United Energy has not demonstrated the efficiency of its property forecast, and has not adequately accounted for property and fleet disposals. We include $61.6 million in our substitute estimate, which is 28 per cent lower than United Energy's forecast. This is based on selecting the most efficient options to carry out United Energy's property work. We have also added $2.8 million to United Energy's capex disposals forecast, as United Energy did not account for the sale of its used vehicles in the forecast regulatory control period.

A.6.2 United Energy's initial proposal

Property

United Energy's $68.8 million (unescalated) forecast comprises three new or refurbished depot works at Mornington, Keysborough and Burwood. Following a change in ownership, United Energy considered its current depots were inadequate to address expected demand. United Energy noted its depots, although compliant with the standards required at the time it was built, must be brought up to current standards if the sites are altered.

United Energy also identified occupational health and safety concerns such as a lack of female change rooms. United Energy also forecast $0.9 million for facilities security upgrades.

Fleet and other

United Energy forecast $14.5 million (unescalated) for motor vehicles and other non-network capex. Its fleet forecast is based on a bottom-up build using replacement dates in line with its policy. Its general equipment forecast is based on average historical expenditure over 2016–19.[111]

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[111] United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 135.

A.6.3 Reasons for draft decision

Property

We include in our substitute estimate $38.7 million for property capex. This is $31.0 million (44 per cent) lower than United Energy's forecast. United Energy has demonstrated the prudency of its property forecast but it has not selected the most efficient options to undertake its work.

We note that United Energy's forecast property capex is 443 per cent higher than its current regulatory control period actual and estimated property capex of $13.1 million in the current regulatory period.

However, United Energy noted that low historical property capex has resulted in insufficient storage areas and inadequate space to service its fleet. United Energy considers it is necessary to expand and upgrade its depots to ensure it can maintain network reliability and meet its health and safety obligations.[112]

We engaged EMCa to assess the prudency and efficiency of each option presented by United Energy.

For each of the depots, United Energy identified the following three options:

- redevelop existing site
- purchase greenfield site
- purchase brownfield site.

United Energy would then select the highest NPV option. Following a response to our information request for the quantification of its options analysis, United Energy also provided a minimum spend option to address structural issues. [113]

We typically examine property forecasts based on historical practice and trend. We consider, in these circumstances, United Energy's historical trend is not indicative of its forecast requirements as we are satisfied that United Energy, through expanding its depots, must meet current safety standards.

We recognise that United Energy's forecast is addressing issues and bringing it in line with CitiPower and Powercor's property works. Based on this, we considered historical trend was not reasonable and we have undertaken a bottom-up assessment.

We engaged EMCa to assess the business case for each of the depots. EMCa found the following issues with United Energy's cost-benefit analysis:

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[112] United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 131.

[113] United Energy's response to information request 003, May 2020.

- Overstated fatality risk, its risk assumptions indicated that there would be a 45 per cent probability of fatality at its depots over the forecast regulatory control period. There is no data to support this probability.
- Many productivity gains are unsupported and appear to be double-counted.
- Reduced customer unserved energy costs are not supported by evidence. [114]

EMCa undertook additional NPV analysis and adjusted the benefit calculations for the issues identified above. It found that United Energy's proposed capex for Mornington depot was prudent and efficient. However, the minimum spend option was the highest NPV option for Keysborough and Burwood depots.[115] This results in a forecast of $9.0 million and $13.4 million, respectively.

We agree with EMCa's analysis and have adopted the highest NPV options based on EMCa's analysis. We also considered whether any depot works should be deferred. However, NPV analysis indicates that the differences are marginal and United Energy has identified why it must address depot issues as soon as possible.

We have also consider United Energy's facilities security upgrade which includes $0.9 million in property capex and $4.7 million in ICT capex is prudent and efficient. This is consistent with EMCa's findings.[116]

Fleet and other

United Energy's $12.4 million fleet forecast aligns with fleet capex over 2009–19 on an annualised basis ($12.5 million). United Energy's fleet replacement policies are in line with our benchmarks for efficient service lives, and the forecast is a small component of its overall capex.[117] United Energy's method for forecasting general equipment capex ($2.1 million) based on historicals is reasonable.

United Energy stated that it did not explicitly forecast disposals from the sale of used vehicles, but it did not explain how it accounted for fleet disposals implicitly.[118] Accordingly, we have included in our substitute estimate $2.8 million for fleet disposals, based on applying our substitute estimate of disposals as a percentage of vehicle capex for Powercor (23 per cent, in turn based on SA Power Networks' disposals values) to United Energy's motor vehicles forecast.

A.7 Capitalised overheads

Overhead costs include business support costs not directly incurred in producing output, and shared costs that the business cannot directly allocate to a particular

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[114] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 208.
[115] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, pp. 211–213.
[116] EMCa, *Review of aspects of United Energy's regulatory proposal 2021–26*, September 2020, p. 205.
[117] United Energy, *Motor Vehicle Policy*, July 2019, p. 8.
[118] United Energy, *Information request 11 – Q4*, 29 April 2020, p. 1.

business activity or cost centre. The Australian Accounting Standards and the distributor's cost allocation methodology determine the allocation of overheads.

A.7.1 Draft decision

We are not satisfied that United Energy's capitalised overheads forecast of $120.4 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $91.6 million in our substitute estimate of total capex. We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria.

A.7.2 United Energy's initial proposal

United Energy forecasts $120.4 million in capitalised overheads for the forecast regulatory control period.

United Energy applied a base step trend methodology to arrive at its forecast, involving:

1. adopting its 2018 SCS capitalised overheads as the base year
2. step increases in the base year, to reflect United Energy’s forecast opex rate of change for the next regulatory control period.

A.7.3 Reasons for draft decision

To arrive at our substitute we have adjusted the overheads to reflect our change to the base year, our substitute for United Energy’s rates of change and our lower substitute for direct capex. The net effect of these adjustments results in a substitute estimate of capitalised overheads that is $28.8 million lower than United Energy's forecast.

Adjusting for our lower estimate of direct capex

We consider that reductions in United Energy's forecast expenditure should result in the reduction in the size of its total overheads. Our assessment of United Energy's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in United Energy's regulatory proposal. It follows that we would expect some reduction in the size of United Energy's capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the capex program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

As a result, in the absence of alterative information and consistent with our previous determinations, we have adopted a 75 per cent fixed and 25 per cent variable ratio to adjust overheads.

Other adjustments

We have also adjusted United Energy’s model to adjust the base year from 2018 to the average of the overheads expenditure between 2016 and 2019. We consider the average reflects a more accurate representation of current regulatory control period overheads as it is less affected by annual variation.

We then substituted the forecast rates of change used to escalate the overheads to maintain consistency with our own substitute forecast of United Energy's opex rate of change. Further analysis on our assessment of United Energy's rates of change can be found in Attachment 6 of our draft decision.

B Forecast demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure.[119] This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts. Therefore, reasonable demand forecasts based on the most current information are important inputs to ensuring efficient levels of investment in the network. This section sets out our decision on United Energy's forecast network maximum demand for the forthcoming regulatory control period.

B.1 Draft decision

We are not satisfied that United Energy’s demand forecasts reasonably reflect a realistic expectation of demand over the forthcoming regulatory control period. We consider AEMO's 2019 Transmission Connection Point forecasts for United Energy's network are reasonable, based on information currently available.

B.2 United Energy's initial proposal

United Energy’s consultant, the NIEIR, has forecast growth in non-coincident maximum demand of 1.3 per cent per year between 2021 and 2026. United Energy has used this to forecast its demand driven augex projects, after reconciling them with its bottom-up zone substation forecasts.

The NIEIR's top-down forecasts are based on a combination of modelling for using variables such as gross state product, electricity prices, and temperature, and post-modelling adjustments for the effects of solar PV, EVs, battery storage, demand response programs, and energy efficiency improvements for appliances and buildings.[120] The NIEIR reported state-wide regression coefficients, and produced maximum demand forecasts at the terminal station level. Independently, United Energy forecast maximum demand at each of its zone substations. United Energy then adjusted these bottom-up forecasts to reconcile with its consultant's (the Centre for International Economics) top-down terminal station forecasts. United Energy used these reconciled zone substation forecasts to determine the need for demand driven augmentation, as summarised in Figure B.1.

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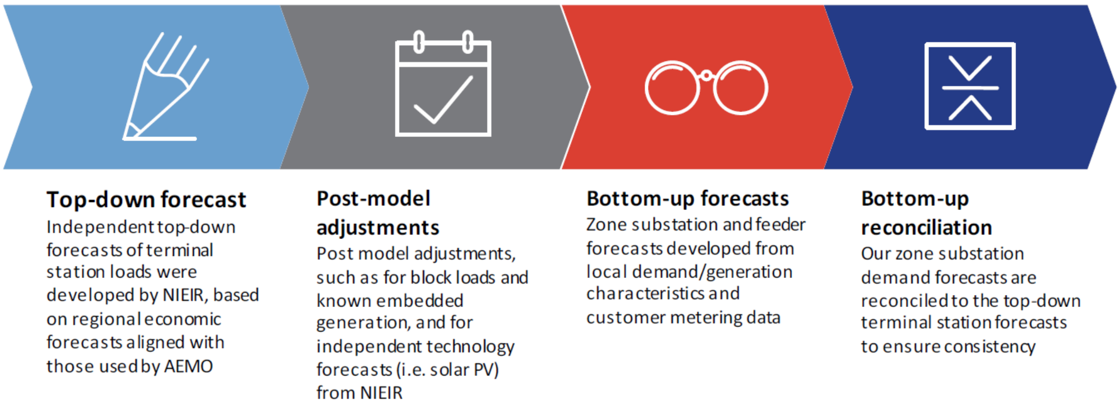
119 NER, cll. 6.5.6(c)(1)(iii) and 6.5.7(c)(1)(iii).

120 NIEIR, *Maximum Demand Forecasts for United Energy Terminal Stations to 2030*, July 2018, p. 50; Oakley Greenwood, *Post-Model Adjustments for Terminal Station Forecasts*, 7 December 2018, p. 50.

Figure B.1 United Energy's demand forecasting approach



Source: United Energy's regulatory proposal, p. 106.

B.3 Reasons for draft decision

We are not satisfied that United Energy's demand forecasts are reasonable, based on considering:

- historical trends in demand
- a comparison of results with AEMO's 2019 Transmission Connection Point Forecasts
- United Energy's past demand forecasting performance, compared to AEMO's
- specific assumptions and methods used in United Energy's demand forecasts.

Consumers have expressed concern at overstated demand forecasts leading to windfall CESS benefits, and the potential for this to reoccur.[121] We share these concerns and have looked at United Energy's demand forecasts in detail.

Traditionally, the key driver of augex has been growing maximum demand. However since 2008 system peak demand has remained relatively flat in Victoria and other states except Queensland.[122]

As shown in Figure B.2, United Energy forecast strongly rising maximum demand in its 2011–15 proposal and its 2016–20 proposal. In both cases this increase did not eventuate.

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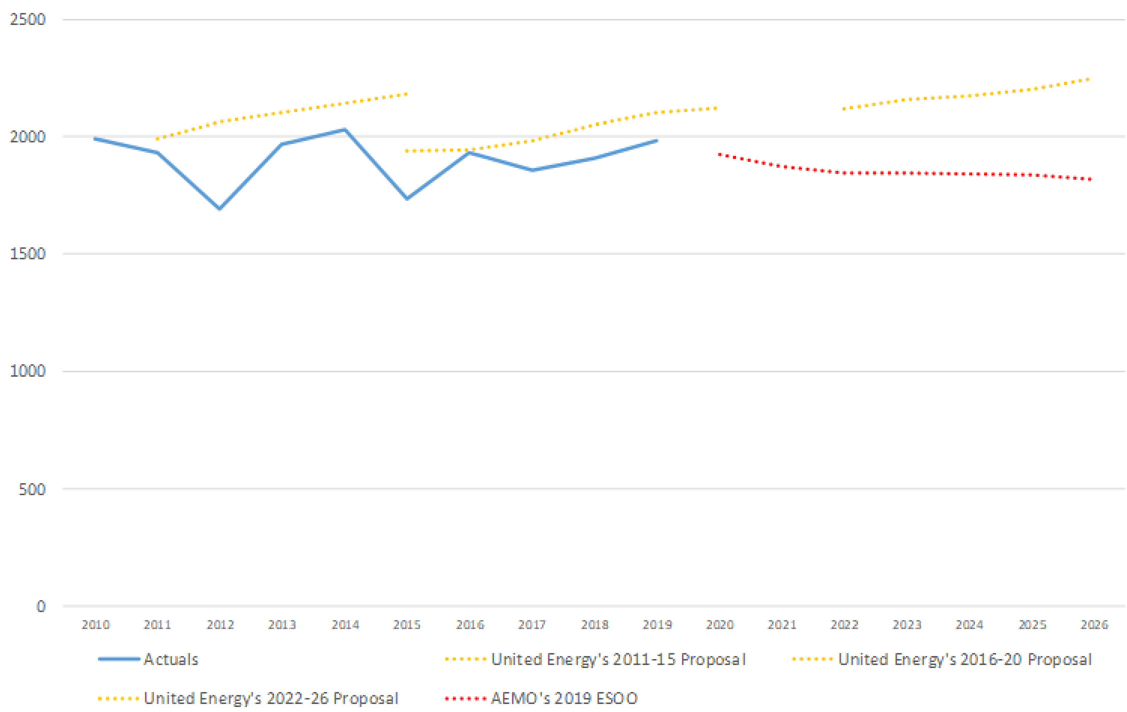
[121] Victorian Community Organisations, *2021–2026 Victorian EDPR - Joint Submission,* May 2020, p. 4; CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, pp. 59–62; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* May 2020, p.3.

[122] AER, *State of the Energy Market*, 1 July 2020, pp. 71–72.

Figure B.2 United Energy's historical and forecast maximum coincident demand (MW, PoE50) [123]



Source: AER analysis based on past proposals.

United Energy's consultant, the NIEIR, has again forecast strong growth in maximum demand compared to historical trends. From summer 2015–16 until 2018–19, AEMO's weather corrected non-coincident actuals show average annual growth of 0.7 per cent (PoE50). The NIEIR forecast demand growth at almost double this rate for 2020–21 until 2025–26: an increase of 1.3 per cent per year.

The NIEIR's forecasts use econometric regression modelling. Typically regression modelling is sensitive to choices made by the researcher. Hence we consider that internal consistency alone may not be sufficient to establish that a forecast reasonably reflects a realistic expectation of demand. A forecast involving a substantial increase compared to historical trends also needs to be justified by comparing its results with any other authoritative forecasts, and where there are material differences, clearly demonstrate why the chosen methods and assumptions are superior. We have also given weight to the accuracy of past forecasts.

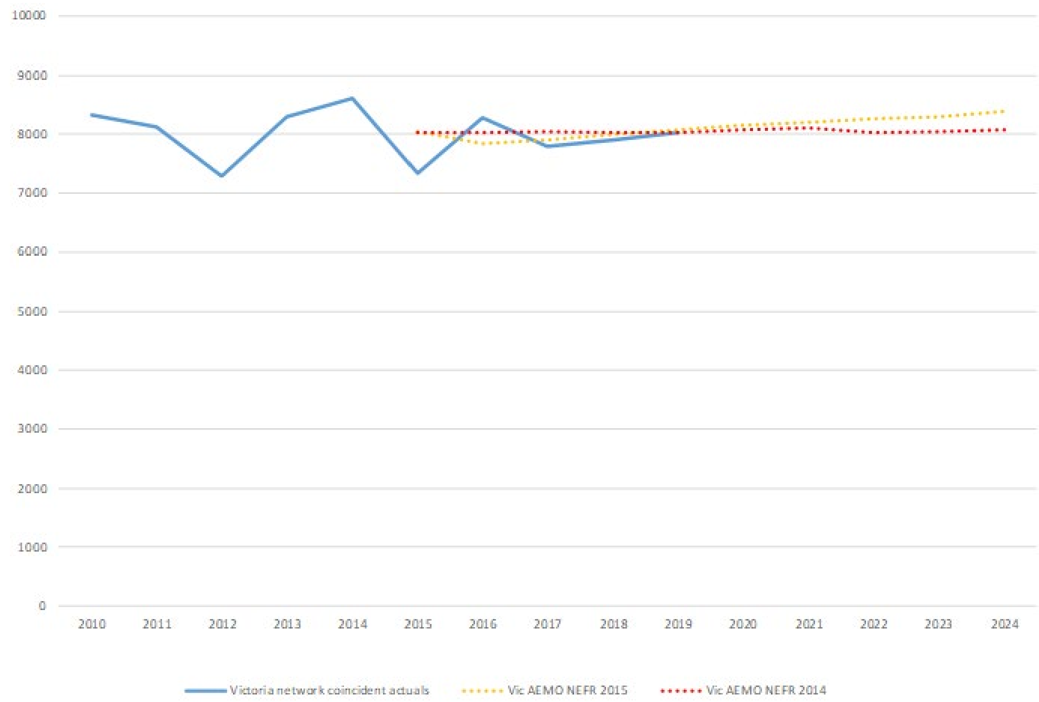
We consider AEMO's Transmission Connection Point forecasts should be the main basis for comparison. For transmission planning, AEMO's role in producing demand

[123] The forecasts are based on the higher maximum demand forecasts United Energy included in its RIN. United Energy, *2016–20 Regulatory Proposal*, July 2015, page 36; United Energy, *2011–15 Regulatory Proposal*, p. 100; AEMO, *Transmission Connection Point Forecasts for Victoria*, November 2019.

forecasts is mandated by the NER, and it has no strong incentive to over- or under-forecast. AEMO also consults widely with stakeholders in producing its forecasts through its standing Forecasting Reference Group. In contrast to the NIEIR's forecasts, AEMO's 2019 forecasts are for flat non-coincident maximum demand in United Energy's network over the forthcoming period: an average decline of 0.04 per cent per year.

AEMO's forecasts for Victoria that were available during the previous decision process have proven relatively unbiased (Figure B.3). Unbiased PoE50 forecasts should be above or below actuals by roughly equal and cancelling amounts over a number of years.

Figure B.3 AEMO's historical forecasts vs actuals in Victoria (MW, Network Peak, PoE50)



Source: AEMO National Electricity Forecasting Reports 2014 and 2015; AEMO Transmission Connection Point Forecasts 2019; AER Analysis.

In the previous regulatory control period, United Energy forecast 2.3 per cent average annual coincident maximum demand growth in its draft proposal.[124] AEMO's 2014 forecasts were for flat demand growth.[125] AEMO's 2014 forecasts were broadly consistent with actual maximum demand growth so far (0.7 per cent per year, weather

[124] United Energy, *Regulatory proposal 2016–2020*, July 2015, page 36.

[125] Darryl Biggar, *2015 Victorian Electricity Distribution Pricing Review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, 25 September 2015, p. 19.

corrected). United Energy did not contest our substitute demand forecasts in its revised proposal.[126]

We asked United Energy to explain why it considers its forecasts for the forthcoming regulatory control period superior to AEMO's. United Energy criticised AEMO's forecasts for failing to adequately consider bottom-up drivers of demand growth. In this respect, United Energy's modelling differs from AEMO's in two ways. First, the NIEIR applied its regression coefficients at the terminal station level, whereas AEMO constrains its forecasts based on a blend of its terminal station results and its state-wide forecasts.[127] Second, United Energy has produced bottom-up demand forecasts at the zone substation level.

Regarding United Energy's zone substation level forecasts, United Energy has used a method that includes extrapolations from past trends, rather than building up specific small area forecasts.[128] Regardless, United Energy's own demand forecasting procedure appropriately depends on reconciling its bottom-up zone substation forecasts to its top-down network level forecasts, which take precedence. Therefore, United Energy has not demonstrated that its forecasts are superior to AEMO's on methodological grounds. Bottom-up, we have used United Energy's forecasts at the zone substation level to produce an alternative set of demand forecasts that reconcile to AEMO's (as discussed in the non-DER augex section).

We also examined specific methods and assumptions used by the NIEIR. We found the following issues:

- United Energy's post-modelling adjustments for solar PV take-up do not align with its solar enablement business case, as they were made before the Victorian government announced details of its Solar Homes policy. Although United Energy states that this effect of this difference is likely to be immaterial, it has not demonstrated this, and it did consider the effect sufficiently material to update its proposed DER augex.[129]
- Assumed uptake of batteries may be conservative, given recent declines in battery prices.
- Our draft tariff structure statement decision is for EVs owners to be subject to time of use tariffs, which will incentivise charging at non-peak times: see Attachment 19. The NIEIR's model does not appear to incorporate any adjustment for increased take-up of time-varying tariffs.

Overall, the NIEIR describes its methodological approach as 'similar to the methodological approach used by AEMO'.[130] However United Energy has not

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[126] AER, *United Energy distribution determination final decision 2016–20,* May 2016, page 6-118.

[127] AEMO, *AEMO Connection Point Forecasting Methodology*, July 2016, p. 28.

[128] United Energy, *Maximum Demand Forecasting*, October 2019, p. 15.

[129] United Energy's response to information request 001*,* Q3 (b), 18 March 2020, p.3.

[130] NIEIR, *Maximum Demand Forecasts for United Energy Terminal Stations to 2030*, July 2018, p. 32.

explained why these similar approaches yield substantially different results, beyond its argument that its forecasts incorporate more bottom-up information. Structurally, the key difference appears to be that the NIEIR has used population and economic growth in its regression model, whereas AEMO's 2019 terminal station forecasts rely to a greater extent on fitting curves based on historical trends (after weather correction) at the terminal station level.

While regression modelling based on underlying drivers of demand can be a useful tool, its success depends on specifying the model correctly, to incorporate all significant drivers. The poor historical performance of all Victorian distributors' demand models indicates that a key variable or variables are missing, such as energy efficiency, solar PV uptake or reduced industrial consumption.

While United Energy has sought to address this using post-modelling adjustments, these do not necessarily appropriately correct for the error introduced by model misspecification. Post-modelling adjustments are intended to capture the real effect of changes in a variable on demand. However, the bias introduced by omitting a variable itself is likely to be significantly different from this. The NIEIR did not report testing whether instead adopting additional variables for solar PV and energy efficiency within the model improved its explanatory power.

In the absence of a well-specified model, AEMO's forecasts are likely to be more accurate. AEMO's 2020 state-wide forecasts do not first regress demand on variables such as GDP growth and prices, and then account for effects such as solar PV and energy efficiency afterwards. Instead, for residential demand, they model the effect of all variables on demand per customer as part of a single process. [131] This is less likely to cause misspecification bias.

Moreover, given the NIEIR argues for a strong relationship between demand and GDP growth, even if this method were to be accepted, it would need to update its forecasts for the effects of COVID-19. United Energy has indicated that it is working on revisions to its demand forecasts to take account of these effects.

AEMO's 2020 Victoria-wide forecasts are for an initial decline in maximum demand due to COVID-19, and then flat maximum demand over the forthcoming period.[132] Overall, maximum demand declines by 0.5 per cent per year until 2025–26 (compared to average maximum demand over 2015–16 to 2019–20), which is similar to its 2019 transmission connection point forecasts. Hence, using AEMO's approach (which does not depend as strongly on GDP as an input) COVID-19 does not sufficiently affect demand across Victoria to be likely to change our conclusions for opex and capex. We note this reduction may be conservative, as AEMO's central scenario models COVID-19 as a temporary shock, rather than assuming a permanent effect due to lower migration and population growth. We will also consider AEMO's final

[131] AEMO, *Electricity Demand Forecasting Methodology Information Paper*, August 2020, pp. 27–28.

[132] AEMO, *2020 Electricity Statement of Opportunities*, August 2020, p. 106

transmission connection point forecasts due in November as part of our final decision, as these will provide data for each network.

C Repex modelling

This attachment details the repex modelling results, it describes the general repex modelling approach for the Victorian distributors and details specific adjustments for United Energy during our engagement. Inputs and outputs of the model, including the NEM median data, are published alongside this decision.[133] Further detail on our repex modelling approach is detailed in the Repex Model Outline. [134]

General repex modelling approach for all Victorian electricity distribution determinations

Our assumptions on the most representative calibration period and the conversion from financial year to calendar year are consistently for all Victorian distributors.

Transition from calendar year to financial year

The Victorian regulatory control periods are transitioning from a calendar to financial year basis. We have relied on as reported calendar year as our input data.[135] In order to estimate the forecast repex requirements in financial year basis, we have taken the average of the 2021 and 2026 calendar years, along with the full calendar year forecast for 2022 through 2025. The approach ensures that we capture a distributor's most recent replacement practices via its most recent actual reported and audited information.

Calibration period

The calibration period refers to the historical time period used to analyse a distributor's historical replacement practices.[136] For the Victorian electricity distribution determinations, we have relied on the four most recent calendar years (2016–2019 inclusive) as our calibration period. Due to the six-month transition from calendar year basis to financial year basis, we have four full years of current regulatory control period data available for the draft decision.

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133 AER, *Draft Decision - United Energy Distribution Determination - Repex model*, September 2020.

134 AER, *Repex Model outline for electricity distribution*, February 2020.

135 Data reported as part of the annual Category Analysis RINs.

136 The time period that is most representative of a distributor's expected future repex requirements is selected as the calibration period. In doing so, we have regard to changes in legislative obligations or other factors that may affect our analysis or a distributor's historical replacement practices. AER, Review of repex modelling assumptions, December 2019, p.7

Specific modelling adjustments for United Energy – review of regulatory proposal

After reviewing United Energy's proposal and supporting documentation, including United Energy's consultant (GHD) report on repex modelling.[137] We have made further adjustments to our standard modelling approach.

Recast data

United Energy proposed to reclassify 'minor repairs' from capex to opex as it noted that the reclassification better reflects the nature of the work.[138] The reclassification affected a number of categories within the underground cables and overhead conductor asset groups and was reflected in its recast RINs.[139] No other asset groups' volumes or expenditure were recast. In order to forecast repex, while excluding the impact of minor repairs, we have relied on the recast category analysis RIN, as the basis of the input expenditure and volumes for the relevant asset categories.[140]

Specific modelling adjustments for United Energy – engagement with United Energy

During the review process, we have engaged with United Energy on its repex model inputs through a number of information requests and meetings.[141] In July 2020, we provided United Energy its preliminary repex modelling outputs. In response, United Energy questioned some of the repex modelling assumptions and provided us an alternative view on some of the repex model input data and assumptions. We discuss United Energy's concerns, suggestions and our response below.

Service lines volumes

In August 2020, due to the reclassification of some service line replacements to opex, United Energy provided some suggested recast volumes for its service line assets. The reclassification was part of its minor repairs base adjustment but had not been outlined as part of its capex proposal. We do not accept the reclassification of service lines minor repairs to opex in our draft decision.[142] As such, we have not made any adjustments to our repex model to take into account the revised service lines volumes. We will have regard to United Energy's revised proposal and its position on service lines minor repairs in determining our final decision repex model input data, assumptions and the necessary adjustments.

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137 United Energy, *UE ATT097 - GHD - Repex modelling review,* January 2020.

138 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 153.

139 United Energy, *RIN003 - Workbook 3 - Recast CAT - January 2020*, public and United Energy, *RIN001 Workbook 1 - Reg determination* - January 2020, public.

140 Recast volumes were provided as part of information request. See United Energy, *Response to Information Request #047 - Repex model input data*, 02 July 2020.

141 United Energy's response to information requests 041 and 047.

142 AER, *Draft Decision - United Energy distribution determination - Attachment 6 - Opex*, September 2020.

Concrete pole unit rate

United Energy did not replace any concrete poles in the calibration period so there were no historical unit rates available. Our initial substitute was the blended wood pole unit rate.[143] United Energy submitted that the correct substitute was the unblended wooden pole unit rate, because it does not stake concrete poles. Figure C.1 shows the substitute unit rates derived from blended (our initial substitute) and unblended (United Energy's proposed substitute) wooden poles.

Figure C.1 Our initial substitute and United Energy's substitute unit rates for concrete poles ($ thousand, $2020–21)

Asset group	Asset category	AER	United Energy
Poles	<= 1kV; concrete	3.88	8.56
Poles	> 1kV & <= 11kV; concrete	6.01	14.33
Poles	> 11kV & <= 22kV; concrete	5.94	14.15
Poles	> 22kV & <= 66kV; concrete	8.21	20.28

Source: United Energy, repex model response - AER preliminary analysis, 31 August 2020.

After reviewing and considering the information before us, we agree with United Energy and have made the suggested adjustments.

Other repex

We excluded the 'other' asset categories from the repex model because of the heterogeneity of the reported assets within those categories and the inability to adequately obtain a consistent set of historical and NEM median data. This approach is in line with previous decisions where unique assets, or assets that cannot be benchmarked, are excluded from the modelling.

United Energy submitted that the exclusion of these asset categories compromises the usefulness and the accuracy of the repex analysis, diminishes the coverage of a key regulatory tool and adopts the principle of the 'lowest common denominator'. It submitted that its preferred approach is to model the other asset categories, while relying on the distributors' own calibrated historical performance, given that there are readily available asset information.

We considered United Energy's submission but have maintained our modelling approach of excluding unique assets. Our approach ensures the integrity of the comparative analysis, where the model tests a consistent set of asset categories.

[143] If an asset is a common asset in the NEM, but due to data reporting issues is not reported in the distributor's category analysis RIN over the calibration period, we may utilise similar assets' unit costs and estimated replacement lives as a substitute for missing data.

The repex model benchmarks a distributor’s asset unit cost and calibrated lives against the median unit cost and calibrated life of each asset across the NEM. This comparison function is key to testing the prudency and efficiency of proposed modelled repex. Therefore, we exclude from the repex model any unique assets that cannot be meaningfully compared with other distributors.

It is important to note that, irrespective of whether a particular asset category is considered modelled or unmodelled repex, we expect distributors to provide robust cost-benefit analysis to support their forecast. We discuss our assessment of United Energy's repex forecast in Appendix A.

D Ex-post prudency and efficiency review

We are required to provide a statement on whether the roll forward of the RAB from the previous regulatory control period contributes to the achievement of the capital expenditure incentive objective.[144] The capital expenditure incentive objective is to ensure that, where the RAB is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in the value of the regulatory asset base.[145]

As the Victorian distribution network service providers are moving from calendar regulatory years to financial regulatory years, this ex-post assessment will apply to the 2014 to 2019 calendar regulatory years. The NER require that the last two years of the current regulatory control period are excluded from past capex ex-post assessment. The ex-post prudency and efficiency will exclude calendar regulatory control year 2020 and the first half of calendar year 2021.[146]

The NER states that we may only make a determination to reduce inefficient past capex if any one of the following requirements is satisfied where the distributor has:

- spent more than its capex allowance (the 'overspending' requirement)
- incurred capex that represents a margin paid by the distributor, where the margin referable to arrangements that, in our opinion, do not reflect arm's length terms (the 'margin' requirement)
- included capex that should have been treated as opex (the 'capitalisation' requirement).[147]

D.1 Draft decision

We are satisfied that United Energy's capex over the regulatory control years 2014 to 2019 should be rolled into the RAB.

D.2 Reasons for draft decision

We have reviewed United Energy’s capex performance for the regulatory years from 2014 to 2019. This assessment has considered United Energy’s actual capex relative to the regulatory forecast provided and the incentive properties of the regulatory regime for a distributor to minimise costs. United Energy’s incurred total capex is below its forecast for each of those regulatory control years.

We have also had regard to some measures of input cost efficiency as published in our latest annual benchmarking report.[148] We recognise that there is no perfect

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144 NER, cl. 6.12.2(b).

145 NER, cl. 6.4A(a).

146 The first half of the calendar year will be considered a regulatory year for the purpose of this review.

147 NER, cl. S6.2.2A(b) to (i).

benchmarking model, but our benchmarking models are robust measures of economic efficiency and we can use this measure to assess and compare a distributor's efficiency.

The results from our most recent benchmarking report highlights that United Energy increased to the second most efficient distributor out of the 13 NEM distributors with a multilateral total factor productivity score of 1.351 for 2018.[149] This represents a 7.5 per cent increase from its 2017 multilateral total factor productivity value, and a continuation of its upward trend since 2012. While this provides relevant context, we have not used our benchmarking results in a determinative way for this capex draft decision, including in relation to this ex-post prudency and efficiency review.

Based on our review, we consider that the 'overspending' and 'margin' requirements are not satisfied.[150]

However, we consider that 'reclassification of minor repairs' opex step-change has met the 'capitalisation' requirement. As part of a proposed opex step-change, United Energy has informed us that it had incurred capex of approximately $18.3 million in the current regulatory control period that should have been classified as opex.[151] It noted this treatment better reflects the nature of the work as the costs are incurred to maintain the age of the asset, and that the work does not result in the creation of a new asset.[152] While we accept that a subset of the proposed expenditure can be expensed in the forecast regulatory control period,[153] we find:

- The incurred expenditure does not appear to be included in United Energy's opex regulatory forecast for the current regulatory control period; therefore, it would be unreasonable to penalise United Energy by treating the expenditure as opex for the purpose of calculating the EBSS carryovers.
- Similarly, as the amount was included in United Energy's capex regulatory forecast for the current regulatory control period, it would be unreasonable to exclude it from United Energy's RAB as it was treated as such throughout the regulatory control period.

Our analysis suggests that there has not been any consumer detriment as a result of capitalising this expenditure over the current regulatory control period. Therefore, we do not consider that it is necessary to remove this expenditure from the RAB.

For the reasons set out above, we are satisfied that the entirety of United Energy's capex in the regulatory control years from 2014 to 2019 should be rolled into the RAB.

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148 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2019.

149 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Annual Benchmarking Report*, October 2019, p.17.

150 NER, cl. S6.2.2A(c).

151 AER Analysis of recast RIN as compared to the category analysis RIN.

152 United Energy, *Regulatory Proposal 2021–2026*, January 2020, p. 153.

153 See AER, *Draft Decision - United Energy distribution determination - Attachment 6 - Opex*, September 2020.

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
augex	augmentation capital expenditure
capex	capital expenditure
CBRM	condition based risk management
CCP17	Consumer Challenge Panel (sub-panel 17)
CESS	capital expenditure sharing scheme
CPI	consumer price index
DBYD	Dial Before You Dig
DELWP	Victorian Department of Environment, Land, Water and Planning
DER	distributed energy resources
ECA	Energy Consumers Australia
EDO	expulsion drop-out
ESV	Energy Safe Victoria
EVs	electric vehicles
GDP	gross domestic product
HBRA	high bush fire risk areas
HV	high voltage
ICT	information and communications technology
LV	low-voltage
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value

Shortened form	Extended form
opex	operating expenditure
PV	photovoltaic
PVC	polyvinyl chloride
RAB	regulatory asset base
REFCL	rapid earth fault current limiters
repex	replacement capital expenditure
RIN	regulatory information notices
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAP	systems applications and products
SCADA	supervisory control and data acquisition, network control and protection systems
SCS	standard control services
STPIS	service target performance incentive scheme
totex	total expenditure
VaDER	value of distributed energy resources
VCO	Victorian Community Organisations
VCR	values of customer reliability