energy market consulting associates

United Energy 2026 - 2031 Regulatory Proposal

REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX AND VEGETATION MANAGEMENT

Public Version

Report prepared for:

AUSTRALIAN ENERGY REGULATOR (AER)

August 2025

Preface

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be allowed for the prescribed distribution services of United Energy from 1st July 2026 to 30th June 2031. The AER's determination is conducted in accordance with its responsibilities under the National Electricity Rules (NER).

This report covers a particular and limited scope as defined by the AER and should not be read as a comprehensive assessment of proposed expenditure that has been conducted making use of all available assessment methods nor all available inputs to the regulatory determination process. This report relies on information provided to EMCa by United Energy. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose. In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments.

EMCa's opinions in this report include considerations of materiality to the requirements of the AER and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

Except where specifically noted, this report was prepared based on information provided to us prior to 1 June 2025 and any information provided subsequent to this time may not have been taken into account. Some numbers in this report may differ from those shown in United Energy's regulatory submission or other documents due to rounding.

Enquiries about this report should be directed to:

Paul Sell

Managing Director
psell@emca.com.au

Prepared by

Gavin Forrest, Mark de Laeter, Paul Sell and Eddie Syadan

Date saved

26/09/2025 10:01 AM

Version

Final v1

Energy Market Consulting associates

ABN 75 102 418 020

Sydney Office

L25, 100 Mount Street, North Sydney NSW 2060
PO Box 592, North Sydney NSW 2059
+(61) 2 8923 2599
contact@emca.com.au
www.emca.com.au

Perth Office

L28, 140 St Georges Terrace, Perth WA 6000
contact@emca.com.au
www.emca.com.au

TABLE OF CONTENTS

ABBREVIATIONS VI

EXECUTIVE SUMMARY VIII

1 INTRODUCTION 1
- 1.1 Purpose of this report 1
- 1.2 Scope of requested work 1
- 1.3 Our review approach 1
- 1.4 This report 5

2 REVIEW OF GOVERNANCE, MANAGEMENT AND FORECASTING METHODS 7
- 2.1 Introduction 7
- 2.2 Background and context 7
- 2.3 Presentation of submission information 8
- 2.4 Assessment of governance arrangements and forecasting methods for the next RCP 10
- 2.5 Our findings and implications for our expenditure review 19

3 REVIEW OF PROPOSED AUGMENTATION EXPENDITURE (AUGEX) 21
- 3.1 Introduction 21
- 3.2 What United Energy has proposed 21
- 3.3 Assessment of demand-driven projects 23
- 3.4 Assessment of CER customer-driven electrification augex project 29
- 3.5 Findings and implications of proposed augex 37

4 REVIEW OF PROPOSED OPEX - VEGETATION MANAGEMENT 40
- 4.1 Introduction 40
- 4.2 What United Energy has proposed 40
- 4.3 Assessment of the proposed step change 43
- 4.4 Findings and implications of the proposed opex step change 55

APPENDIX A – CITIPOWER, POWERCOR AND UNITED ENERGY'S ECONOMIC MODELLING OF PROPOSED ELECTRIFICATION PROGRAM 59

APPENDIX B – ECONOMIC ASSESSMENT METHODOLOGY ISSUES 63

APPENDIX C – REVIEW OF HISTORICAL PERFORMANCE 66

LIST OF TABLES

Table 2.1: Summary of information provided ... 10

Table 2.2: Summary of CPU steps in regulatory proposal development ... 12

Table 2.3: Summary of United Energy expenditure iterations ($m, 2006) ... 12

Table 2.4: United Energy's forecasting approach for augex ... 14

Table 3.1: United Energy's proposed augex by driver - $m, real FY2026 ... 22

Table 3.2: EMCa scope of United Energy's proposed demand augex - $m, real FY2026 ... 23

Table 3.3: Mornington Peninsular supply area - options summary ($m, 2026) ... 25

Table 3.4: United Energy's proposed Shoreham zone substation augex - $m, real FY2026 ... 27

Table 3.5: United Energy's proposed Customer-driven electrification augex - $m, real FY2026 ... 29

Table 3.6: United Energy - complaints conversion to network rectification projects ... 32

Table 3.7: Summary of United Energy's comparative options analysis ... 33

Table 3.8: Nature and net cost of proposed electrification works - $m, real 2026 (unescalated) ... 33

Table 3.9: Options cost analysis – reactive projects, $m, 2026 ... 36

Table 4.1: United Energy total proposed vegetation management step change - $m, real FY2026 ... 40

Table 4.2: United Energy's bottom-up build of its vegetation management opex - $m, real FY2026 ... 41

Table 4.3: United Energy's proposed total vegetation management opex - $m, real FY2026 ... 41

Table 4.4: United Energy changes to vegetation management opex step change - $m, real FY2026 ... 42

Table 4.5: Comparison of vegetation management opex across CPU businesses - $m, real FY2026 ... 42

Table 4.6: Comparison of vegetation management opex unit rates CPU businesses - $m, real FY2026 ... 42

Table 4.7: Build-up of United Energy's vegetation management program, $m FY2026 ... 45

Table 4.8: Comparison of base program and uplift cutting volumes ... 47

Table 4.9: Real price escalation (percentage) ... 51

Table 4.10: United Energy LiDAR cost assumptions ... 54

LIST OF FIGURES

Figure 1.1: Scope of work covered by this report ... 1

Figure 1.2: NER capital expenditure criteria ... 2

Figure 1.3: NER capital expenditure objectives ... 3

Figure 1.4: NER operating expenditure criteria ... 3

Figure 1.5: NER operating expenditure objectives ... 4

Figure 2.1: Summary of United Energy's approach to ensuring efficient delivery 17
Figure 3.1: UE proposed augex compared with current RCP and historical by driver - $m, real FY2026 23
Figure 3.2: Sub-transmission network in the Mornington Peninsula 24
Figure 3.3: Seasonal load profile of LMP (MW) 25
Figure 3.4: Undervoltage non-compliance of Victorian DNSPs (%) 30
Figure 3.5: United Energy projection of voltage compliance forecast - 'do nothing' scenario (%) 31
Figure 4.1: Historical and forecast expenditure - $m FY2026 44
Figure 4.2: Historical and forecast expenditure for base program only - $m FY2026 45
Figure 4.3: Historical and forecast vegetation management spans that are required to be cut 46
Figure 4.4: Annual inspection and cutting plan – LBRA and HBRA 47
Figure 4.5: Historical completion volumes 48
Figure 4.6: Volume of HBRA spans over the period 2022 to 2024 49
Figure 4.7: Trend of average vegetation management unit rates - $, FY2026 50
Figure 4.8: Vegetation management opex per km of overhead length ($2023) - average 2019-23 51
Figure 4.9: Average vegetation management opex per maintenance span km versus customer density 52
Figure 4.10: Average vegetation management unit rate versus customer density 53
Figure 4.11: Comparison of 3-year vegetation management unit rates (FY22-FY24) - $, FY2026 53

ABBREVIATIONS

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	Augmentation expenditure
BCR	Benefit to Cost Ratio
BAU	Business As Usual
BESS	Battery Energy Storage System
BST	Base-Step-Trend
CAP	Customer Advocacy Panel
CBA	Cost Benefit Analysis
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resources
CPU	CitiPower, Powercor and United Energy
DMA	Dromana zone substation
DNSP	Distribution Network Service Provider
DSS	Distribution Substation
DVM	Dynamic Voltage Management
ELCMP	Electric Line Clearance (Vegetation) Management Plan
ESV	Energy Safe Victoria
EV	Electric Vehicle
HBRA	High Bushfire Risk Area
HGS	Higgins zone substation
HV	High Voltage
ICT	Information Communication Technology
IR	Information Request
IT	Information Technology
LBRA	Low Bushfire Risk Area
LDC	Load Duration Curve
LiDAR	Light Detection and Ranging
LMP	Lower Mornington Peninsular
LV	Low Voltage
MTN	Mornington

Term	Definition
MW	Mega Watt
NER	National Electricity Rules
next RCP	2026-2031
NNS	Non-Network Solution
NPV	Net Present Value
NSP	Network Service Provider's
PAL	Powercor
PQ	Power Quality
RBD	Rosebud zone substation
RCP	Next Regulatory Control Period
repex	Replacement expenditure
RIN	Regulatory Information Notice
RIT	Regulatory Investment Test
RP	Regulatory Proposal
SCS	Standard Control Service
SHM	Shoreham
TBTS	Tyabb Terminal Station
TNSPs	Transmission Network Service Providers
UE	United Energy
VCR	Value of Customer Reliability
VER	Value of Emissions Reduction
VNR	Value of Network Resilience
YTD	Year to Date

EXECUTIVE SUMMARY

Introduction and context

1. The AER has engaged EMCa to undertake a technical review of aspects of the augmentation expenditure (augex) and opex step changes that United Energy has proposed in its regulatory proposal (RP) for the 2026-31 Regulatory Control Period (next RCP).
2. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed capex and opex allowances as an input to its draft determination on United Energy's revenue requirements for the next RCP.

Expenditure under assessment

Proposed augex

3. United Energy has proposed $180.3 million for augex over the next RCP. This represents a 70% increase from the $106 million that United Energy expects to incur in the current RCP.
4. We have been asked to review projects and programs with aggregate proposed capex of $138.4 million including an Electrification/CER project with proposed capex of $40.9 million. These projects comprise approximately 77% of United Energy's proposed augex.

Proposed opex step change for vegetation management

5. United Energy has proposed an opex step change for its vegetation management program of $72.3 million for the next RCP. United Energy proposes the opex step change to meet its compliance obligations commencing in the current period, and which is above that included in the base year opex of FY25.
6. We have assessed the proposed opex step change based on the same methodology applied to each of the Powercor, CitiPower and United Energy networks.

Assessment and findings

Assessment of governance, management and forecasting methods

7. In considering United Energy's expenditure governance, management and forecasting methodologies, we focus primarily on matters which we consider impact the forecast expenditure requirements that we have been asked to review, as detailed in the subsequent sections of this report.
8. We found that Victorian DNSPs' regulatory proposals, including United Energy, reflect changes impacting the industry; however, we found that the way in which each DNSP proposes to respond to these changes differs and which was a feature of our review.
9. In our review of the governance, management and forecasting methods that United Energy applied in determining its forecast expenditure, we found examples of the following issues:
   - United Energy's initial submission lacked quality information
   - United Energy's reliance placed on economic modelling outcomes was overstated and the conclusions that it drew from it were not always valid, and
   - Cost estimates that were higher than an efficient level.
10. We saw evidence of many of these issues in the projects and programs that we were asked to review and have considered the implications of these findings in our determination of an

alternate estimate of the forecast expenditure requirements. We understand that in determining an overall expenditure allowance for capex and opex, the AER will have regard to these matters more generally.

Assessment of proposed augex

Demand forecasts

11. Our assessments of the proposed augex forecasts take United Energy's demand forecasts as a given, noting that review of demand forecasts was not within our scope.

Lower Mornington Peninsular supply upgrades

12. We are satisfied that United Energy needs to prudently manage the risk of voltage collapse in the Lower Mornington Peninsular (LMP). However, instead of its proposed new sub-transmission line to be completed prior to the summer of FY32, we consider that a modest expansion of the existing non-network solution is likely to be the prudent approach, at least within the next RCP.

13. In forming this view, we are cognisant of certain challenges with expanding the existing non-network solution, but also that establishing a new 54 km overhead transmission line through the LMP would not be without its own environmental and other societal challenges.

New Shoreham zone substation

14. The new Shoreham substation (SHM) is proposed to take advantage of the proposed new 66kV LMP subtransmission line, cutting into the line. It is a reliability/resilience-driven initiative taking into account the impacts of major weather events (in particular). However, United Energy has not adequately demonstrated that building SHM is the prudent economic solution.

15. We consider that if at some time in the future, it is economic to construct the proposed LMP 66kV line, the economic prudency of also establishing SHM should be reconsidered. In the interim, we are of the view that the proposed 66kV line and SHM substation should be deferred beyond the next RCP.

The proposed CER – Customer-driven electrification project is not sufficiently justified

16. We are satisfied that forecast demand and the expected trend to electrification will tend to increase instances of voltage non-compliance over time. We also accept that United Energy will need to incur expenditure to functional compliance in a dynamic system and we are directionally supportive of selective proactive augmentation to address under-voltages, offsetting reactive responses to complaints, where the latter is less cost effective.

17. However, we have significant concerns with United Energy's forecasting methodology that we consider has led to an overstatement of the expenditure that it will require in the next RCP. We found issues with the modelling, and the use of input assumptions. These include the use of VCR to value energy served to customers at less than 216 volts which we do not consider to be a valid application of the VCR. The jump from four voltage complaints in FY24 to United Energy's forecast of 185 voltage complaints in FY27, is also not credible from the information provided and affects the assumed quantum of augmentation required.

Assessment of proposed vegetation management opex step change

There has been no change to regulation obligations that apply to United Energy

18. We firstly considered whether the proposed step change met the requirement of the opex step change criteria for a change in regulatory obligations. Based on CPU's submission, there has been no change to its regulatory obligations. The electric line clearance requirements have not changed since the commencement of the current RCP, and CPU has not advised of any change to its electric line clearance obligations that are likely to positively or negatively impact the expenditure requirements in the next RCP.

19. However, LiDAR data used as part of improvements to vegetation management has identified a volume of spans to be treated that exceeds the current program to meet its compliance obligations.

Basis of forecast step change is likely to overstate the required expenditure

20. We reviewed the assumptions proposed by United Energy, and its modelling methods and found that:

- The ultimate size of the vegetation management program will likely be lower than it has assumed after taking into account additional factors
- United Energy has not sufficiently demonstrated that the proposed increases to its vegetation management costs are prudent, or that the unit cost assumptions are efficient; we base this on our own analysis of the historical and forecast costs incurred by the CPU businesses
- United Energy has not correctly taken account of the BST forecasting method for opex in the calculation of the required step change, and
- Our benchmarking of United Energy's historical costs indicates that it is higher than other NEM DNSPs. United Energy has not provided rationale for why it is incurring costs that are materially higher, why these higher rates are reflective of an efficient level or what measures are in place, or being put into place, to reduce the costs to an efficient level.

Adjustment for a range of uncertainty and efficiency factors is likely to reduce the need for an opex step change

21. We consider that whilst the CPU businesses are building capacity and capability to meet their compliance requirements, the opportunities for competitive forces to apply downward pressure on prices from the market are lessened. However, over time, we consider there should be opportunities for pricing to moderate, and then to improve. This is also supported by our own benchmarking analysis which indicates that United Energy is currently incurring costs that are materially higher than other NEM DNSPs, including other Victorian DNSPs.

22. We further consider that the program, once stabilised, offers United Energy an ability to reduce not only the costs but potentially the volume of spans to be treated through greater targeting of maintenance cutting practices. United Energy has not taken account of these potential efficiency factors.

23. Our analysis indicates that the need for additional opex is very sensitive to relatively small changes in the factors we identified, meaning that relatively small reductions to volume or costs (towards the benchmark cost) or increases in efficiency removed the need for the proposed step change.

Implications for expenditure allowances

Our approach

24. We were asked to consider an alternate expenditure forecast for the projects and programs that we reviewed based on the issues that we identified. Where a project was reasonably justified in accordance with the NER, we included this in our alternate expenditure forecast. On other cases, our proposed alternative expenditure forecast for the categories of expenditure we were asked to review involves one or more adjustments, to the extent that the adjustment factors formed the basis of United Energy's forecast and which we consider to be not justified or overstated.

25. Since the scope of our review did not in all cases comprise all projects within a 'category' of proposed expenditure, our alternative forecasts necessarily apply only to the aggregate of the projects within the scope of our review.

26. To the extent we found evidence of systemic issues in its application of governance, management and forecasting issues to the projects and programs that we reviewed, we have taken account of these in our proposed alternate forecast.

Alternative forecasts for reviewed projects

United Energy’s proposed forecast for the augex projects that we reviewed is higher than a prudent and efficient level

27. We consider that a reasonable alternative forecast for United Energy for the augmentation projects within our scope, and which includes its proposed CER-related augex, would be between 90% and 95% less than United Energy has proposed.

United Energy’s proposed vegetation management opex step change forecast is not a reasonable forecast of its requirements

28. We are satisfied that additional improvement to vegetation management activities is required for United Energy to achieve compliance in the next RCP, however we consider that a number of factors in United Energy’s forecast are not reasonable assumptions and leads us to conclude that United Energy does not require an opex step change.

1 INTRODUCTION

The AER has asked us to review and provide advice on aspects of United Energy's proposed expenditures over the 2026-31 Regulatory Control Period (next RCP) relating to replacement expenditures (repex), augmentation expenditures (augex) and operating expenditures related to vegetation management. Our review is based on information that United Energy provided and on aspects of the NER relevant to assessment of expenditure allowances.

1.1 Purpose of this report

29. The purpose of this report is to provide the AER with a technical review of aspects of the expenditure that United Energy has proposed in its regulatory proposal (RP) for next RCP'

30. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed expenditures allowance as an input to its Draft Determination on United Energy's revenue requirements for the next RCP.

1.2 Scope of requested work

31. Our scope of work, covered by this report, is as defined by the AER. Relevant aspects of this are as summarised in Figure 1.1: .

Figure 1.1: Scope of work covered by this report

Scope of work covered by this report

The scope of this review, as requested by the AER, covers the following.

- Capex (ex-ante)
  - Augex (selected projects, including CER and electrification)
- Opex
  - Vegetation management step change

32. Other aspect of United Energy's expenditures, including ICT and cybersecurity, are covered in other reports.

1.3 Our review approach

1.3.1 Approach overview

33. In conducting this review, we first reviewed the RP documents that United Energy has submitted to the AER. This includes a range of appendices and attachments to United Energy's RP and certain Excel models which are relevant to our scope.

34. We next collated several information requests. The AER combined these with information request topics from its own review and sent these to United Energy.

35. In conjunction with AER staff, our review team met with United Energy at its offices on 2 – 4 April 2025. United Energy presented to our team on the scoped topics, and we had the opportunity to engage with United Energy to consolidate our understanding of its proposal.

36. United Energy provided the AER with responses to information requests and, where they added relevant information, these responses are referenced within this review.

37. We have subjected the findings presented in this report to our peer review and Quality Assurance processes and we presented summaries of our findings to the AER prior to finalising this report.

1.3.2 Conformance with NER requirements

38. In undertaking our review, we have been cognisant of the relevant aspects of the NER under which the AER is required to make its determination and relevant AER Guidelines.

Capex Objectives and Criteria

39. The most relevant aspects of the NER in this regard are the 'capital expenditure criteria' and the 'capital expenditure objectives.' Specifically, the AER must accept the Network Service Provider's (NSP) capex proposal if it is satisfied that the capex proposal reasonably reflects the capital expenditure criteria, and these in turn reference the capital expenditure objectives.

40. The NER's capital expenditure criteria and capital expenditure objectives are reproduced in Figure 1.2: Figure 1.2 and Figure 1.3..

Figure 1.2: NER capital expenditure criteria

NER capital expenditure criteria

The *AER* must:

(1) *subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (**the capital expenditure criteria**):*

- *(i) the efficient costs of achieving the capital expenditure objectives;*
- *(ii) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
- *(iii) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the capital expenditure objectives*

Source: NER 6.5.7(c) Forecast capital expenditure, v230

Figure 1.3: NER capital expenditure objectives

> ***NER capital expenditure objectives***
>
> *(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to do each of the following **(the capital expenditure objectives**):*
>
> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> *(i) the quality, reliability or security of supply of standard control services; or*
>
> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>
> *to the relevant extent:*
>
> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services;*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services; and*
>
> *(5) contribute to achieving emissions reduction targets through the supply of standard control services.*

Source: NER 6.5.7(a) Forecast capital expenditure, v230

Opex Objectives and Criteria

41. The most relevant aspects of the NER in this regard are the 'operating expenditure criteria' and the 'operating expenditure objectives.' The NER's opex criteria and opex objectives are reproduced below.

Figure 1.4: NER operating expenditure criteria

> **NER operating expenditure criteria**
>
> *(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (**the operating expenditure criteria**):*
>
> *(1) the efficient costs of achieving the operating expenditure objectives;*
>
> *(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and*
>
> *(3) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the operating expenditure objectives.*

Source: NER 6.5.6(c) Forecast operating expenditure, v230

Figure 1.5: NER operating expenditure objectives

NER operating expenditure objectives

(a) *A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to do each of the following (**the operating expenditure objectives**):*

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services; and

(5) contribute to achieving emissions reduction targets through the supply of standard control services.

Source: NER 6.5.6(a) Forecast operating expenditure, v230

How we have interpreted the capex and opex criteria and objectives in our assessment

42. We have taken particular note of the following aspects of the capex and opex criteria and objectives:

- Drawing on the wording of the first and second criteria, our findings refer to efficient and prudent expenditure. We interpret this as encompassing the extent to which the need for a project or program or opex item has been prudently established and the extent to which the proposed solution can be considered to be an appropriately justified and efficient means for meeting that need
- The criteria require that the forecast '*reasonably reflects*' the expenditure criteria and in the third criterion, we note the wording of a '*realistic expectation*' (emphasis added). In our review we have sought to allow for a margin as to what is considered reasonable and realistic, and we have formulated negative findings where we consider that a particular aspect is outside of those bounds
- We note the wording '*meet or manage*' in the first objective (emphasis added), encompassing the need for the NSP to show that it has properly considered demand management and non-network options
- We tend towards a strict interpretation of compliance (under the second objective), with the onus on the NSP to evidence specific compliance requirements rather than to infer them, and
- We note the word '*maintain*' in objectives 3 and 4 and, accordingly, we have sought evidence that the NSP has demonstrated that it has properly assessed the proposed

expenditure as being required to reasonably maintain, as opposed to enhancing or diminishing, the aspects referred to in those objectives.

43. The DNSPs subject to our review have applied a Base Step Trend approach in forecasting their aggregate opex requirements. Since our review scope encompasses only proposed expenditure for certain purposes, we have sought to identify where the DNSP has proposed an opex step change that is relevant to a component that we have been asked to review. Where the DNSP has not proposed a relevant opex step change, then we assume that any opex referred to in documentation that the DNSP has provided is effectively absorbed and need not be considered in our assessment.

1.3.3 Technical review

44. Our assessments comprise a technical review. While we are aware of stakeholder inputs on aspects of what United Energy has proposed, our technical assessment framework is based on engineering considerations and economics.

45. We have sought to assess United Energy's expenditure proposal based on United Energy's analysis and United Energy's own assessment of technical requirements and economics and the analysis that it has provided to support its proposal. Our findings are therefore based on this supporting information and, to the extent that United Energy may subsequently provide additional information or a varied proposal, our assessment may differ from the findings presented in the current report.

46. We have been provided with a range of reports, internal documents, responses to information requests and modelling in support of what United Energy has proposed and our assessment takes account of this range of information provided. To the extent that we found discrepancies in this information, our default position is to revert to United Energy's RP documents as provided on its submission date, as the 'source of record' in respect of what we have assessed.

1.4 This report

1.4.1 Report structure

47. In section 2 we provide our observations on United Energy's application of its governance framework and forecasting methodology to the expenditure category, along with the derived forecasting inputs.

48. In the assessment sections 3 and 4, we have presented our assessment of projects within our scope, respectively for:

- Proposed augex projects
- Proposed vegetation management step change.

49. In each of these assessments sections we include:

- an overview of the proposed expenditure and a summary of United Energy's justification for that expenditure
- our assessment of individual expenditure categories and/or projects, and
- our findings for each expenditure category and the implications of these findings for the expenditure allowances determined by the AER in its Draft Determination.

50. We also provide the following appendices:

- Appendix A - CPU economic modelling issues specific to CPU's proposed electrification program
- Appendix B - Economic assessment methodology issues, and
- Appendix C – United Energy's historical performance.

51. We have taken as read the considerable volume of material and analysis that United Energy provided, and we have not sought to replicate this in our report except where we consider it to be directly relevant to our findings.

1.4.2 Information sources

52. We have examined relevant documents that United Energy has published and/or provided to the AER in support of the areas of focus and projects that the AER has designated for review. This included further information at onsite meetings and further documents in response to our information requests. These documents are referenced directly where they are relevant to our findings.

53. Except where specifically noted, this report was prepared based on information provided by AER staff prior to 1 June 2025 and any information provided subsequent to this time may not have been taken into account.

54. Unless otherwise stated, documents that we reference in this report are United Energy documents comprising its RP and including the various appendices and annexures to that proposal.

55. We also reference responses to information requests, using the format IRXX QYY being the reference numbering applied by the AER to IRs and to specific Question numbers within that IR. Noting the wider scope of the AER's determination, the AER has also provided us with IR documents that it considered to be relevant to our review.

1.4.3 Presentation of expenditure amounts

56. Expenditure is presented in this report in $2025-26 real terms, unless stated otherwise. In some cases, we have converted to this basis from information provided by the business in other terms.

57. While we have endeavoured to reconcile expenditure amounts presented in this report to source information, in some cases there may be discrepancies in source information provided to us and minor differences due to rounding. Any such discrepancies do not affect our findings.

2 REVIEW OF GOVERNANCE, MANAGEMENT AND FORECASTING METHODS

The focus of our assessment has been the material changes to the governance and forecasting methods applied by United Energy to determination of its expenditure requirements for the next RCP. Specifically, we considered whether the changes made by United Energy are likely to have led to a higher or lower estimate of expenditure than would otherwise have been the case, for those items of expenditure we have been asked to review.

The extent to which the expenditure forecast requirements meet NER requirements is, in part, dependent on how its investment governance and management framework has been applied.

2.1 Introduction

58. In this section we provide some context from the historical performance of United Energy and make observations relating to the service performance and expenditure performance leading into the next RCP.

59. We then consider the materials provided by United Energy and how they align with the requirements as defined in the AER guidance materials. The extent to which we have a complete set of information to undertake our assessment is critical to a determination that the proposed expenditure is prudent and efficient.

60. We next consider whether United Energy has made any material changes to its governance arrangements during the current RCP, that have impacted its investment decision making and impacted either the nature or completeness of the information available to us. Following this we consider the governance, management and forecasting methods applied to the development of expenditure requirements for the next RCP, and whether these are likely to have led to a prudent and efficient forecast of requirements.

61. Our assessment of the governance, management and forecasting methods is not intended to be a comprehensive review, nor does it purport to represent all methods that United Energy has applied for the next RCP. Rather we focus primarily on matters which we consider impact the forecast expenditure requirements, detailed in the subsequent sections of this report.

2.2 Background and context

2.2.1 Summary

62. Common to our review of Victorian DNSPs, United Energy's expenditure incurred during the current RCP has differed from the allowance. Common drivers are delays to the onset of demand compared with the forecast prepared at the time of the previous determination and also uplifts in the price of goods and services incurred during the current period. We comment on key reasons for the changes in expenditure profile and composition of the projects and programs that make up the expenditure profile in our assessment of the corresponding expenditure.

63. For the next RCP, Victorian DNSPs like other NSPs across the NEM are responding to macro-economic changes including electrification and change in demand. In Victoria there are specific policy settings that impact demand and are embedded into the demand forecasts that each of the NSPs have relied upon. By agreement with the AER, a separate review of the demand forecast is being undertaken by the AER. For this review, we rely on the demand forecast and assumptions prepared by and submitted with the DNSP regulatory proposal.

64. In Appendix C, we provide a summary of the historical trends in service delivery and expenditure as context for our review. The trends are based on published materials from the AER and ESV, which apply to each DNSP that we have been asked to review.

65. We have not been asked to consider the broader performance for each DNSP or take account of all factors that may be contributing to the service of expenditure performance indicated by these trends. We also recognise that the measures applied by the AER and ESV are not comprehensive or exhaustive, but act as context for our assessment of specific projects and programs.

2.2.2 General observations relating to service performance

66. We observe that United Energy's network performance has generally been improving, along with asset performance despite the impact of several major weather events across Victoria. For United Energy's network:

- Average reliability performance is generally improving, which suggest that United Energy's asset management process has improved service levels
- According to the safety regulator ESV, the number of all asset failure incidents are lower than the long-term average, but the number of fires is higher
- The rate of line clearance non-compliance has increased, and the regulator is concerned by a worsening long-term trend
- Network utilisation has been slightly decreasing over the last 10 years, and remains higher than the DNSP average, and
- Voltage compliance has been well within the functional compliance limit set under the EDCoP.[1]

2.2.3 General observations relating to expenditure performance

67. United Energy's actual expenditure has historically tracked lower than the forecast expenditure. Issues such as increasing labour and material costs, and deferral of works that occurred during the current RCP also have implications for the forecast in the next RCP, and we consider the implications in the projects and programs that we have reviewed. For United Energy's network:

- Capex delivery performance is subject to a range of factors, with actual capex lower than forecast capex
- United Energy expects the net capex to marginally exceed the capex allowance for the current RCP, and
- Over the last 5 years, actual opex is lower than forecast opex resulting in an overspend against the opex allowance, however much closer in last two years.

2.3 Presentation of submission information

68. In this section we consider the degree to which United Energy has adhered to the expenditure assessment guidelines.

[1] Victorian Electricity Distribution Code of Practice

2.3.1 AER guidance on expectations

69. Drawing on the relevant parts of the Rules as detailed in section 1, and the guidance materials published by the AER, the AER has outlined four expectations of a network business' capital expenditure proposals in the Better Resets Handbook. These are:

1. Top-down testing of the total capital expenditure forecast and at the category level
2. Evidence of prudent and efficient decision-making on key projects and programs
3. Evidence of alignment with asset and risk management standards, and
4. Genuine consumer engagement on capital expenditure proposals.

70. In our technical review, we have regard to the first three of these expectations as they apply to the scope of our review and which target categories or sub-categories of capex. More specifically, expectation 2 includes demonstration of prudency and efficiency in its decision-making by:

- Identification and evidence of the network need
- Quantitative cost-benefit analysis (CBA), demonstrating that customers are likely to receive a net economic benefit from the proposed scope and timing of the work, and
- Where relevant, evidence of fully accounted for capex-opex or other trade-offs.

71. The AER's expectations are also accompanied by a range of guidelines to assist DNSPs, including the expenditure forecast assessment guidelines. With regard to the capital expenditure assessment approach, the expenditure forecast assessment guidelines emphasise the need for economic justification of the proposed expenditure:

> *'Where businesses do not provide sufficient economic justification for their proposed expenditure, we will determine what we consider to be the efficient and prudent level of forecast capex. In assessing forecasts and determining what we consider to be efficient and prudent forecasts we may use a variety of analysis techniques to reach our views.'*[2]

72. When considered together, and also drawing from relevant parts of other AER guidelines,[3] we interpret this to mean that the AER places material weight on demonstration of economic analysis to support the proposed expenditure. We have therefore considered demonstration of the economic justification in our assessment.

2.3.2 AER guidance on information that is expected to support the regulatory proposal

73. This is further supported by the summary of information that is expected to accompany the regulatory proposal, whereby the guidelines state:

> *'We will require a range of data to support our assessment of total forecast capex. We expect DNSPs to submit regulatory proposals that include:*
>
> – *economic analysis demonstrating the forecast expenditure is prudent and efficient. This should include documentation and underlying data sufficient to support the economic analysis*
>
> – *reasons for costs for given expenditure categories and types of work differing from their historical expenditure*
>
> – *explanations of trade-offs between capex and opex expenditure that show that the choices chosen (for example to undertake a capex IT program to reduce opex) are prudent and efficient. Firms will also need to demonstrate these choices are fully accounted for in capex and opex forecasts.'*[4]

---

2 AER Expenditure forecast assessment guidelines – Electricity distribution – October 2024

3 Including the asset replacement guidelines

4 AER Expenditure forecast assessment guidelines – Electricity distribution – October 2024

2.3.3 Summary of information provided for its expenditure forecast

74. In terms of the scope of our review, we summarise the information that has been provided to support the forecast expenditure in Table 2.1.

Table 2.1: Summary of information provided

Expenditure category	Sub-category	Evidence of need	Quantitative analysis
Augmentation capex	Selected projects	Summary business case for each project summarising the need	Economic analysis model for each project
Opex step change	Vegetation management	Summary business case	Cost model based on historical spend, and not economic analysis

75. The information provided initially by United Energy was not conducive to a review in accordance with the capex assessment guidelines, as the models and supporting information were incomplete, or the workings and assumptions relied upon by United Energy were not in every case transparent. We made requests for the models and supporting information that United Energy had relied upon in preparing its expenditure forecast and we were subsequently provided with this information. We have taken account of this information in our review.

76. In some instances, we did not find that justification documentation that was provided to us was robust, and that areas of expenditure were largely unexplained, or not sufficiently supported by evidence of observed performance. We are aware that similar matters were raised during the previous determination process, and which indicates that these matters have not been adequately addressed.

77. Where United Energy has proposed to change the expenditure included in the submission from its initial proposal, we have noted this in our assessment.

2.4 Assessment of governance arrangements and forecasting methods for the next RCP

78. Consistent with the overarching purpose, we focus primarily on matters which we consider impact the forecast expenditure requirements, detailed in the subsequent sections of this report.

2.4.1 Summary of material changes to the governance arrangements from the current RCP

79. In the context of the investment governance framework, forecasting methods and risk management approaches ('governance methods') we asked United Energy to detail any changes to the governance methods applied by each of the DNSPs and in common during the current period, and that impact the development of the expenditure forecast for the next period. In its response, United Energy referred to strengthening the role of stakeholder engagement:[5]

> *'Strengthening the role of stakeholder engagement, including enhancing the governance and independence the Customer Advisory Panel, represents a material changes (sic) in*

5 United Energy response to IR004 Question 2

> *the governance and external oversight of the development of our expenditure forecasts for the 2026–31 regulatory period.'*

80. We consider that an effective stakeholder engagement process is critical to ensuring that the expenditure proposed by a DNSP meets the criteria and objectives of the NER. However, we have not been asked to assess the stakeholder engagement processes employed by United Energy or the extent to which the proposed expenditure responds to feedback provided by stakeholders to United Energy. Where we discuss stakeholder feedback, it is included to assist an understanding of what United Energy has proposed.

81. United Energy also refers to changes, including the following updates: [6]

   – *'our customer values work was refreshed to challenge/validate any changes in customer priorities*

   – *updated our value framework to reflect with AER values of VCR, and added the new AER values of VER and VNR for quantifying emissions reduction and resilience benefits*

   – *updated our value framework to reflect the Value of Statistical Life (VSL) data regularly published by the Department of the Prime Minister and Cabinet*

   – *updated and refreshed our ICT risk monetisation framework, as set out in UE ATT 7.02.'*

82. Notwithstanding the strengthening of stakeholder engagement in its governance arrangements, we concluded that United Energy's investment planning processes within our scope of review had not materially changed from the time of the previous determination by the AER.

2.4.2 Top-down review and portfolio optimisation

CPU has applied a top-down review of its forecast expenditure

83. We consider that application of a top-down review and portfolio optimisation are two critical methods in determining a prudent and efficient expenditure forecast.

84. The respective CPU regulatory proposals state that: [7]

> *'The development of our expenditure forecasts also occurred through multiple expenditure iterations that progressively refined our investment portfolio. This process continually challenged and limited expenditure to those investments that deliver clear value for our customers.'*

85. We requested that CPU describe the process and steps taken to refine the investment portfolio, which we summarise in Table 2.2.

[6] CitiPower response to IR006 Question 2

[7] CitiPower Regulatory proposal 2026-31 – Part B – Explanatory statement, page 9

Table 2.2: Summary of CPU steps in regulatory proposal development

Step	Elaboration
Strategic framework	A key deliverable in the early works program was the development of a strategic framework for the 2026–31 regulatory proposals. This framework sought to identify the key strategic challenges that CPU need to 'get right' in its proposals.
Understanding service level expectations	In addition to the strategic framework, the development of CPU regulatory proposals was based on and supported by considerable effort to understand the service level expectations of its customers. This was particularly relevant in the context of relatively new issues, including electrification.
Expenditure iterations	The development of CPU expenditure forecasts occurred through multiple expenditure iterations that progressively refined our investment portfolio. The timing of these iterations was structured to support key milestones.

Source: United Energy – IR004 – general capex – 20250320 question 3

The portfolio review process has included three expenditure iterations

86. United Energy describes three expenditure iterations:[8]

- Preliminary iteration, December 2023
- Draft proposal, April 2024, and
- Regulatory proposal, December 2024.

87. In a further request, we asked for details of the three iterations and evidence of the investments removed from the forecast. The iterations are reproduced in Table 2.3.

Table 2.3: Summary of United Energy expenditure iterations ($m, 2006)

Category	Pre-draft proposal	Draft proposal	Regulatory proposal
Augmentation	167	181	168
Net connections	156	108	89
Replacement	489	474	480
ICT	235	312	293
Non-network assets (other	39	54	81
Total	**1,086**	**1,129**	**1,111**

Source: CitiPower response to IR012 question 1

88. We had expected to see demonstration of intermediate iterations, and evidence of the decision-making process being applied by the governance layers that demonstrate the movement up or down of the expenditure forecast in response to changing inputs or output scenarios.

89. CPU describes the process of challenge and review that it has applied as:[9]

> *'The design of our iteration process meant that top-down assessments were considered throughout the development of our forecasts. All else equal, we consider challenging and refining key input assumptions is preferable to higher-level or arbitrary assessments at total portfolio or category level (where it is more difficult to robustly understand the impacts of subsequent adjustments).'*

8 United Energy response to IR004 Question 3

9 United Energy response to IR004 Question 3

90. We consider that effective top-down reviews go beyond this description to test for changes in service levels, risk and deliverability. Notwithstanding comments by CPU, its response describes the consideration of additional top-down considerations, including:

- Affordability
- Equity
- Deliverability
- Acceptability (to customers, regulators and government), and
- External review and challenge of assumptions (e.g. challenge by the CAP).

91. Often this includes a prioritisation or ranking of investments, and which may include ranking against differing criteria. CPU states that the '*prioritisation of investments included in our regulatory proposal were not assessed based on a consolidated whole-of-business portfolio*.'[10] Rather:[11]

> *'the prioritisation of economic projects was determined through balancing bottom-up inputs and top-down principles (which are broader than just economic value), and repeatedly challenging these outcomes through internal and external governance processes. We consider this better recognise the varying drivers of the different projects (including stakeholder and customer service level expectations), the limited discretion associated with many of our proposed programs and the absence of a known financial constraint (such as an approved regulatory allowance, which may otherwise be used in our portfolio optimisation approach within a regulatory period).'*

92. Whilst our scope of review did not extend to considering whole expenditure categories, for our purposes, we did not see evidence of how CPU made the trade-offs to determine that the projects and programs it had included were reflective of a prudent and efficient expenditure forecast. Nor did we receive a satisfactory explanation as to why the current lower level of expenditure in the current RCP and the higher level in the next RCP are both considered to reflect prudent requirements, given the proposed step increase in proposed expenditure requirements.

The $50 million of projects removed from its forecast is offset by project additions

93. In its regulatory proposal, United Energy refers to $50 million of investments removed from the forecast expenditure.[12] We asked United Energy to describe the nature of the investments removed from the forecast expenditure, and which we summarise as:[13]

- refinements to project options
- Updated demand forecasts, including lower forecasts for both CER and electrification uptake
- Updated asset and cost data, and
- Reliance on uncertainty framework - projects that could be treated as contingent or managed through a pass-through applications.

94. In United Energy's provided worksheet,[14] the aggregate reduction is shown as $216 million from changes to 16 projects, with $67 million attributed to a lower connection forecast. United Energy states that due to project additions, the reduction is not visible in the totals.

---

10 United Energy response to IR012 Question 2

11 United Energy response to IR012 Question 2 (and IR004)

12 United Energy Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025, page 9 but which does not align with information provided in United Energy - IR012 - Q1 - iteration changes.xls

13 United Energy response to IR004 Question 3

14 United Energy - IR012 - Q1 - iteration changes.xls

2.4.3 Activity forecasting methods

Augex activity forecasting

95. Augex is typically forecast using bottom-up methods, as United Energy has done, and responds to specific drivers which may vary from one regulatory period to another. Table 2.4 summarises United Energy's expenditure forecasting approach for demand-driven and non-demand-driven works.

Table 2.4: United Energy's forecasting approach for augex

Augmentation Demand driven works to meet localised growth and demand at peak times, and non-demand driven works to maintain reliability, security and quality of supply	• Augmentation projects to resolve demand-driven constraints are identified by forecasting load growth and voltage levels and comparing these to available network capacity and voltage compliance obligations. Our augmentation forecast only includes capital works where the value of alleviating a constraint exceeds the cost • Non-demand driven works are forecast by considering the potential risk and consequence of adverse events, and to meet stipulated regulatory obligations where relevant

Source: EMCa extract from Table 1, United Energy - Expenditure forecasting methodology - 2026-31 - June 2024

96. CPU undertakes network planning in accordance with its Network Planning Framework, which sets out the process CPU follows to identify the need for physical and operational changes in the network over time. CPU states that this contributes to the network management objectives[15] described in its Network Planning Framework. The documents and content are consistent with what we would expect to see.

97. United Energy (with Powercor, CitiPower and consultants) has recently developed a Customer Electrification Forecasting Methodology (and related documents) which it applied to derive forecast expenditure to respond to the expected impacts of customer-driven electrification. We consider the application of these methodologies in our assessment of the relevant projects within our scope of review.

Opex step change forecasting

98. CPU has provided a bottom-up build of its vegetation management opex requirements, drawing from its historical expenditure as recorded in the RIN, and which it has used to determine the proposed opex step change with reference to a base year of FY25 to meet its compliance obligations.

2.4.4 Economic assessment

High level of reliance placed on model outcomes

99. CPU has placed significant emphasis on economic modelling of the proposed projects and programs as justification for proposed projects. In response to our questions surrounding management of uncertainty and preservation of option value, CPU stated that:[16]

> *'All projects and programs included in our regulatory proposal are economically justified, and/or based on defect trends consistent with our revealed asset management practices. As noted above, our reference to least regrets indicates that while projects are economically justified, even if our modelling is wrong, it is likely these projects would otherwise be undertaken in the near future, such that investing now is a least or no-regrets action.'*

100. Proposals that are economically justified and/or can be demonstrated as arising from a regulatory obligation are central precepts to the assessment of expenditure proposals under

15 Which relate to safety, reliability, asset management, compliance obligations, continuous improvement, and customers' input, interests, and needs.

16 United Energy response to IR004 Question 7

the NER. We have reviewed the basis of the proposals presented by CPU, including the economic models that CPU has relied upon.

Key modelling input assumptions impact the timing of expenditure requirements

101. In its regulatory proposal, CPU has updated its assumptions for final demand assumptions (e.g. incorporating most recent AEMO reports) and AER values, including VCR, CECV, VNR and VER. We have reviewed the models as presented and tested the sensitivity of the outcome to changes in these input assumptions.

102. The AER has advised us that it will assess United Energy's demand forecast separately and will consider our findings accordingly. For the purpose of our augex assessment, we have therefore taken United Energy's demand forecasts as a given. However, we have where relevant commented on the sensitivity of the proposed projects' optimal timing to negative variance in the demand forecast. If not considered by CPU in its sensitivity analyses, we include consideration of a 'low demand case scenario', which is a demand forecast of 100% 50PoE[17] rather than the 70%:30% weighted 50PoE/10PoE forecast used by United Energy for planning purposes.

103. We understand the forecast expenditure is based on the AER's 2019 VCR study, escalated in accordance with the AER's specified methodology. In the latest AER VCR study published in 2024, the values were materially changed including a reduction to the business customer VCR.

104. CPU has stated that it is yet to assess the impact of these changes but will consider these through the development of its revised regulatory proposal.

105. We have reviewed the potential impact of changes to the VCR assumption on the proposed expenditure for the next RCP and note that many of the substation VCRs appear to reflect a higher value of VCR than may be derived from AER's most recent 2024 VCR study. We come to this view by application of the customer weightings that CPU has applied, and when applied to the latest value of VCR by customer, result in reduction to the VCR assumption used in the economic analysis. In our assessment of the proposed expenditure, we consider that the timing for some projects is deferred beyond the end of the next RCP.

106. In addition to the value used for VCR, for several of the augex programs within our scope, we found issues with:

- Other input assumptions, including apparent lack of correlation with RIN data, inappropriate application of the VCR, and
- Inappropriate benefit derivation, including benefit timing and benefit sources.

2.4.5 Cost estimation and cost forecasting

CPU has applied its cost estimation methodology

107. To assist our understanding of how CPU prepared its cost estimate for the projects and programs that it had proposed for the next RCP, we asked for a copy of the cost estimation methodology and/or procedure used to develop project cost estimates in the capex forecast. In its response, CPU provided a summary of its typical cost estimation process.[18]

108. In a follow-up request, we asked for the approved and documented cost estimation methodology and/or cost estimation standard and/or cost estimation procedure used to develop project cost estimates in the capex forecast. We would expect that this is a standard management system document that outlines the requirements, quality and accuracy of cost estimates that applied to projects and programs, treatment of costs and risk allowances to be included in project cost estimates. We were provided with a network

17 Probability of exceedance, so 50PoE is shorthand for 50% probability of exceedance, for example

18 United Energy's response to IR004

project estimation process document that describes CPU's standard cost estimation methodologies that it uses for business-as-usual project delivery purposes.[19]

109. The methodology nominates that final project cost estimates for major projects are based on P50 estimates,[20] and do not include contingency amounts. The methodology is consistent with what we had expected to see. CPU referred to provisions for risk allowances for known risks, however we were not provided with evidence of the process to determining or quantifying the risk allowance, or evidence of its inclusions in the projects and programs we reviewed.

We did not see sufficient evidence of estimation accuracy and review

110. We also requested evidence of the estimation accuracy of a sample of projects delivered, and where available, any reviews of the estimating accuracy of projects. We were provided with a sample of five projects totalling approximately $27 million.[21] We do not consider this sample representative of the capex program that allows any meaningful conclusions to be drawn.

111. We therefore looked for considered the reasonableness of cost estimates in the specific projects and programs that we reviewed.

We found examples of costs that are higher than an efficient level

112. CPU refers to recent price uplifts, as well as ongoing inflationary pressure to explain the increases in unit rates that are included in its proposed expenditure.

113. Whilst we accept the current market conditions are adding cost pressures we sought to understand the reason for real increases in unit rates. We reviewed the unit cost information provided by CPU and found that the unit rates for volumetric programs appeared high. Based on our own benchmarking against RIN data, the unit costs for United Energy vegetation management activities were at the high end of DNSPs across the NEM – more information on our assessment is provided in section 4.

2.4.6 Deliverability

United Energy applies an outsourced operating model

114. As shown in Figure 2.1, United Energy applies an outsourcing model, with all capital works delivered by external resources. It further advises that its key delivery partners have been engaged under long term contracts to provide 'stable and readily available access' to resources for the next RCP.[22]

---

19 United Energy's response to IR012 Question 6

20 P50 represents the project cost to provide a 50% level of confidence in the outcome; there is a 50% likelihood that the final project cost will not exceed the P50 value

21 United Energy - IR004 – Q11(b) - completed projects – public.xls

22 UE RIN 24 - Governance, forecasting and deliverability overview - Jan2025 – Public, page 19

Figure 2.1: Summary of United Energy's approach to ensuring efficient delivery

United Energy's deliverability measures

External workforce

The delivery of our network capital program reflects our outsourced operating model, where all capital works are undertaken by independent, third-party service providers following an open, competitive tender. For example, we have a network services agreement with Zinfra to undertake all maintenance and fault responses across our network. For major projects, we have an approved panel of suppliers who compete for capital works. To ensure we achieve efficient, market-based rates, we package our works program to enable benefits to be obtained through tendering significant sized projects. Projects that are suitable to be tendered as turn key projects are identified at conception stage, and detailed scopes of works are prepared as the basis for tender documents.

De-risking procurement

In response to heightened procurement risks, we have evolved our procurement practices to actively manage this environment. Our approach includes:

- *multiple suppliers for each material and equipment*
- *period orders with multi-year contracts*
- *pricing mechanisms and hedging*
- *further improvements on longer term forecasting of procurement requirements and stockholding.*

Enabling resources

Our fleet and property resources enable the delivery of our works program. As set out in our regulatory proposal, we have plans in place to ensure these enabling resources grow with our underlying works program requirements. In the current period, for example, we have completed major depot upgrades that accommodate for future growth. We are also proposing to insource fleet in the 2026–31 regulatory period.

Source: Extracts from UE RIN 24 pages 20-21

115. The decision to insource or outsource is strategic to the goals of the network business and should take into account multiple factors. Many DNSPs operate a combination of internal and external resources, with key minimum resourcing retained for strategic reasons. Where competitive markets exist, the costs of outsourced services are often lower.

116. Our benchmarking of volumetric work indicates that United Energy is amongst the highest cost DNSPs.[23]

117. Whilst benchmarking can provide a basis to compare across businesses or jurisdictions, it cannot capture the operating context of the businesses. Sourcing should however seek to provide maximum value to consumers, and one measure is the cost efficiency of the delivered services. United Energy should be able to demonstrate why its delivery arrangements reflect highest value to customers.

United Energy has taken some steps to lessen the delivery challenge

118. We asked CPU to confirm the steps that have been undertaken to confirm the deliverability of the proposed increase in capex forecast, particularly the increases in substation-related replacement. In its response, CPU referred to:

- The ability to scale up using a combination of in-house and external provider

23 Refer to information in section 4 for benchmarking of vegetation management (opex) costs

- Distribution line works - moderated forecasts for overhead conductor and network hardening (i.e. it did not propose all works that were identified as economic), and extended the compliance timeframe for its vegetation management program (as well as offering longer-term contracts to provide greater certainty for contractors to build resources), and
- Substation related works - staggered projects across the regulatory period, increased internal workforce and delivery partners capacity to seven companies, and established robust period contracts for key materials.

United Energy has demonstrated an ability to uplift the resource capacity

119. United Energy outlines broad actions it has taken to build capacity across its internal workforce, flexible external workforce, de-risking the procurement supply chain, and enabling resources in its Governance, forecasting and deliverability overview document, RIN 24. Whilst these are important elements of the deliverability of the portfolio of work and will contribute to its ability to increase is delivery capacity, the description is not an assessment of the deliverability of the forecast expenditure, or changes in the composition of skills or project types.

120. We asked how United Energy had assured itself of its delivery capability and capacity for the next RCP, at a total level and by resource type. For example:
    - To understand the extent to which the deliverability assessment is informed by a resource and delivery strategy/plan and/or a workforce plan that identifies the current and future demand by work group and/or resource type, and
    - Outlines strategies to address any gap including growing the internal or external workforce, and steps to achieve this.

121. United Energy's response[24] refers to:
    - Annual assessments and project level assessment of workforce capability being regularly reviewed by its Executive, and
    - Its forecast works program being comparable to its historical work program
        - It therefore does not expect to require material uplifts in field delivery
        - Recent engagement with our external maintenance panel indicated that resources are readily available should United Energy require them.

122. Given the proposed similar activity across the industry and overseas (i.e. targeting a similar resource market, materials, and equipment), we expected a more granular assessment of the skills required, risks and strategies to address those risks.

123. The actual impact of the energy transition, and specifically increased pressure placed on the supply of key electricity sector resources across the state of Victoria remains uncertain. However, we consider that United Energy has taken reasonable steps to develop the required capacity to deliver its proposed works program.

[24] CitiPower's response to IR012 Question 10

2.5 Our findings and implications for our expenditure review

2.5.1 Summary of findings

Presentation of submission information

Lack of compelling information for our review

124. The Better Resets Handbook published by the AER nominates four expectations of a network business' capital expenditure proposal:[25]

- Top-down testing of the total capital expenditure forecast and at the category level
- Evidence of prudent and efficient decision-making on key projects and programs
- Evidence of alignment with asset and risk management standards, and
- Genuine consumer engagement on capital expenditure proposals.

125. Except for consumer engagement, which is beyond our scope of review, we find that CitiPower's submission had not in all cases fully achieved the remaining three expectations.

Additional information was necessary to complete our review

126. Additional information was provided in response to our requests, and this was largely helpful. However, as explained in our assessment of the proposed expenditure, we found instances where the justification was insufficient to support the expenditure that was proposed. We expand on this further in our assessment of the expenditure proposed for each of the projects and program in the subsequent sections of this report.

127. The supporting information has focussed on the projects and programs that result in expenditure for the next RCP. Whilst supporting the expenditure, it does not in all instances allow interrogation of the broader planning and prioritisation processes, or confirmation that the business has adequately prioritised the highest risk / benefits areas for consumers

Governance arrangements and forecasting methods

High level of reliance placed on model outcomes

128. CPU has placed significant emphasis on economic modelling of the proposed projects and programs. Proposals that are economically justified and/or can be demonstrated as arising from a regulatory obligation are central precepts to the assessment of expenditure proposals under the NER.

The economic analysis relies heavily on the input assumptions that United Energy has applied

129. Across the capex and opex forecast that we reviewed, we found examples of inadequately supported input assumptions, including for both the estimation of costs and for benefits. For example, in the case of the electrification-driven capex we consider that United Energy's use of VCR to attribute an economic cost to undervoltage supply considerably overstates this cost, leading to a considerable overstatement of the economic benefits of rectification.

130. We have reviewed the potential impact of changes to the VCR assumption on the proposed expenditure for the next RCP and note that many of the substation VCRs appear to reflect a higher value of VCR than may be derived from AER's most recent 2024 VCR study. In our assessment of the proposed expenditure, we consider that the timing for some projects would be deferred beyond the end of the next RCP as a result of correcting for this.

---

25 AER. Better Reset Handbook - December 2021.

131. Some input assumptions adopted by United Energy have led to the development of a higher program of expenditure than is prudent. Adoption of more reasonable inputs results in deferral of some projects beyond the next RCP.

We found examples of cost estimates that are higher than an efficient level

132. Whilst current market conditions are adding cost pressures we sought to understand the reason for real increases in unit rates. Unit costs proposed by United Energy are high. In comparing vegetation management costs of United Energy with other DNSPs, we found the costs were materially higher than the bulk of its peers and with no apparent explanation for the higher costs.

133. Whilst United Energy has a cost estimation methodology in place, we did not see sufficient evidence of review processes.

2.5.2 Implications for the expenditure forecast

134. We consider the implications of these findings in our review of the specific projects and programs in the subsequent sections of this report.

3 REVIEW OF PROPOSED AUGMENTATION EXPENDITURE (AUGEX)

The AER has asked us to assess a subset of United Energy's proposed $180 million augex program for the next RCP. United Energy has submitted eleven augex projects/programs of which we review three, which in aggregate represent $138 million capex.

For the three projects that we have reviewed, we consider that United Energy's proposed expenditure is significantly overstated. The reasons include (i) instances of conservative, inappropriate, or unsupported assumptions in the cost-benefit analyses, (ii) insufficient consideration has been given to use of non-network solutions, and (iii) insufficiently supported cost estimates.

3.1 Introduction

135. We have been asked by the AER to assess three of the eleven augmentation projects/programs that United Energy has submitted in its Proposal for the next RCP.

136. We reviewed the information provided by United Energy to support each of the three projects and programs and as necessary asked clarifying questions, both in writing and at a face-to-face meeting with United Energy representatives. We sought to confirm the need, quantum, and optimal timing of each project that we were asked to review.

137. In the sections that follow, we identify the projects we have been asked to review from United Energy's full list, and then we present our assessment of the individual projects.

3.2 What United Energy has proposed

3.2.1 Proposed augex

138. United Energy proposes $180.3 million augmentation capex in the next RCP, as shown in Table 3.1.

Table 3.1: United Energy's proposed augex by driver - $m, real FY2026

Augex by driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand						
Customer-driven electrification	11.7	6.1	13.4	17.5	21.6	**70.4**
Mornington Peninsula upgrades	0.0	0.0	0.0	20.5	20.6	**41.1**
Subtotal	11.7	6.1	13.4	38.0	42.2	**111.5**
Non demand						
Communications	3.0	2.3	3.0	0.7	0.4	**9.4**
Network innovation	1.2	1.2	0.8	0.8	0.8	**4.8**
Operational technology	1.4	1.4	1.1	1.1	1.1	**6.2**
System security	5.5	2.3	2.3	1.7	1.5	**13.2**
HV feeder program	1.6	0.7	0.2	0.2	0.2	**2.9**
Metering	0.8	0.8	0.9	0.9	0.9	**4.3**
Power quality	0.1	0.1	0.1	0.1	0.1	**0.6**
Sub transmission upgrades	0.2	0.3	0.0	0.0	0.0	**0.5**
Subtotal	13.8	9.2	8.4	5.6	5.0	**41.9**
Resilience						
Shoreham zone substation	0.0	0.0	0.0	13.4	13.5	**26.9**
Total	**25.5**	**15.3**	**21.8**	**57.0**	**60.7**	**180.3**

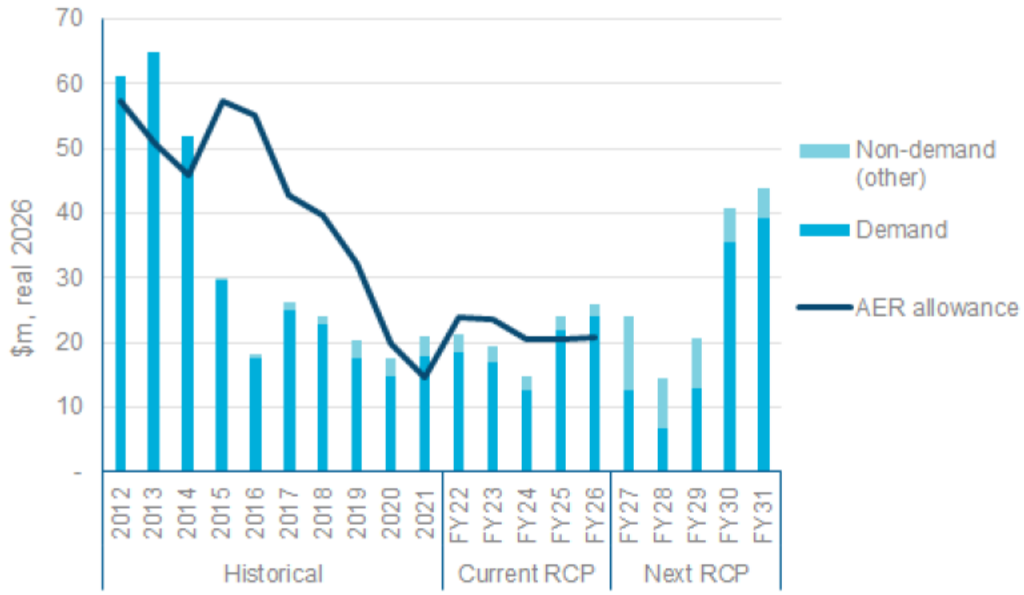
Source: EMCa table derived from United Energy SCS capex model

139. Figure 3.1 shows a comparison between United Energy's proposed, current and historical augex. United Energy's allowance for augex in the current RCP is $133 million and it anticipates spending $106m, a 21% underspend. United Energy advises that the reasons for the underspend include:[26]

- More efficient management of customer energy resources (CER) driven by the stronger than expected performance of its dynamic voltage management system (DVMS), identifying and addressing incorrect customer solar settings
- Partially deferred works in the Doncaster area due to the impact of increased costs on revised benefits analysis, and
- More general impacts associated with the pandemic, including the significant demand uncertainty and supply chain disruptions that impacted project timelines.

[26] UE RIN 11 - Expenditure transparency - Jan2025 – Public, Table 1 and page 2

Figure 3.1: UE proposed augex compared with current RCP and historical by driver - $m, real FY2026



Source: CPU response to IR#006

3.2.2 EMCa's Scope of Augex Review

140. The AER has asked us to assess the projects/programs listed in Table 3.2, which at $138 million in total represent 78% of the total forecast augex. We provide our assessment of each project in the subsequent sections.

Table 3.2: EMCa scope of United Energy's proposed demand augex - $m, real FY2026

Augex by driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand						
Customer-driven electrification[27]	11.7	6.1	13.4	17.5	21.6	**70.4**
Mornington Peninsula upgrades	0.0	0.0	0.0	20.5	20.6	**41.1**
subtotal	**11.7**	**6.1**	**13.4**	**38.0**	**42.2**	**111.5**
Resilience						
Shoreham zone substation	0.0	0.0	0.0	13.4	13.5	**26.9**
Total	**11.7**	**6.1**	**13.4**	**51.4**	**55.7**	**138.4**

Source: EMCa table derived from United Energy SCS capex model

3.3 Assessment of demand-driven projects

3.3.1 Lower Mornington Peninsula supply upgrades

What United Energy has proposed

141. United Energy proposes capex of $41.1 million, incurred over the next RCP, as shown in Table 3.2, to provide reliable supply of electricity across the Lower Mornington Peninsula area (LMP) as forecast demand continues to increase. The avoided risk is voltage collapse which could lead to widespread outages across the LMP. The proposed project involves

27 Reviewed in section 3.5

construction of a 54km 66kV sub-transmission line from Higgins zone substation (HGS) substation to Rosebud zone substation (RBD) by FY31.

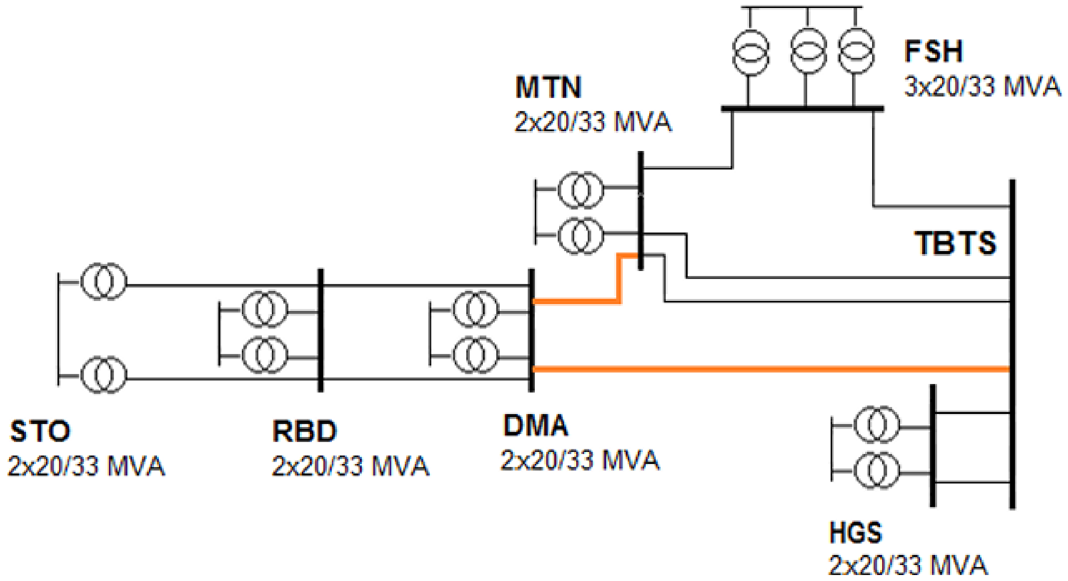
Assessment

The driver of the project is possible voltage collapse

142. Figure 3.2 shows the sub-transmission network in the LMP comprising the DMA, RBD, and STO[28] zone substations and the connecting sub-transmission lines.

> *'The LMP is vulnerable to voltage collapse if one of the sub-transmission lines supplying the LMP zone substations fails if combined demand at DMA, RBD and STO exceeds 123MW. Voltage collapse would lead to a widespread outage across all of the LMP zone substations.'*[29]

Figure 3.2: Sub-transmission network in the Mornington Peninsula



Source: UE BUS 3.04 – Lower Mornington Peninsula supply area – Jan2025 – Public, Figure 3

143. United Energy's 50PoE forecast shows that the maximum demand will exceed the 123MVA voltage collapse limit in 2026, which would lead to system security challenges if one of the sub-transmission lines fails (i.e. N-1 event in the summer peak 'window').

The likelihood of a sub-transmission outage during peak load is small but possible

144. As shown in Figure 3.3 there are four pronounced peaks in demand per year (during the holiday peak period over Christmas to late January) at which the demand can be up to double the standard summer peak load. The likelihood of a coincident outage of one of either the TBTS[30] to DMA or Mornington (MTN) to DMA sub-transmission lines during the summer holiday period at a time of extreme load is very small but possible. This probability of occurrence limits the exposure of the LMP to voltage collapse.

The risk of voltage collapse has been mitigated by a non-network solution (NNS) but the contract expires in 2025

145. United Energy has a NNS contract for 9 MW of diesel generators with 1MW of battery energy storage (BESS). The BESS cannot be relied upon in practice, so United Energy

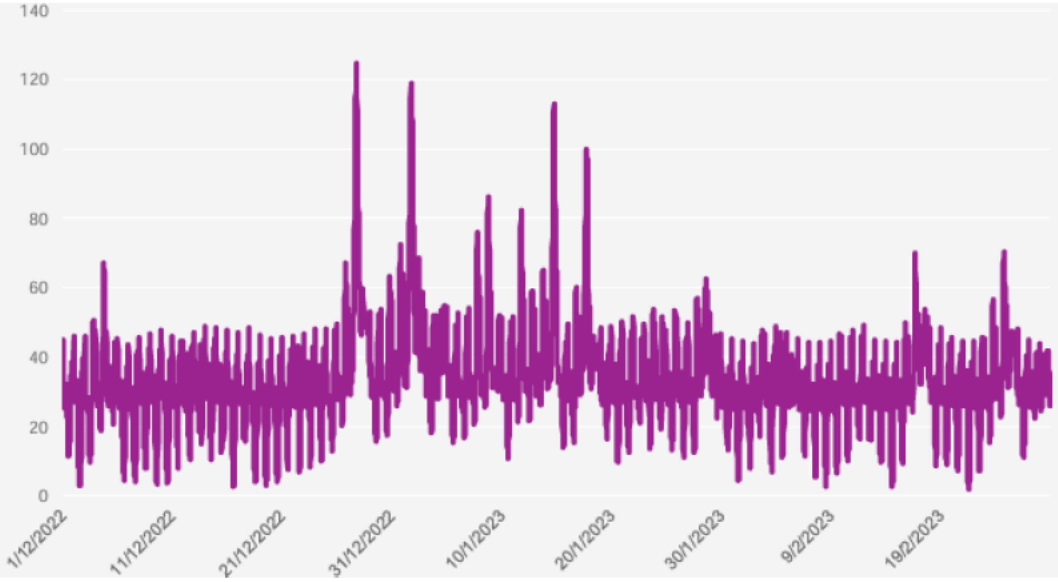
[28] Dromana, Rosebud, and Sorrento

[29] UE BUS 3.04 – Lower mornington peninsula supply area – Jan2025 – Public, page 5

[30] Tyabb Terminal Station

assumes only 9MW demand reduction at a cost of $600k p.a. for availability across the 8-10 weeks holiday period. The current contract expires in 2025, and United Energy expects the cost to renew the contract to increase (if it were renewed – an option United Energy has considered but with expanded service, as discussed below).

Figure 3.3: Seasonal load profile of LMP (MW)



Source: Insert-source-details

United Energy considered four options and proposes constructing a new sub-transmission line to address the voltage collapse risk

146. United Energy puts forward four options in its business case, summarised in Table 3.3.

Table 3.3: Mornington Peninsular supply area - options summary ($m, 2026)

Option	Cost in next RCP	PV cost	PV benefits	Net benefit	Establish by
1. Maintain status quo	-	-	-	-	
2. Construct HGS-RBD sub-transmission line	33.3*	-19.1	22.1	3.0	FY31
3. Construct HGS-RBD sub-transmission line and new Shoreham zone substation	55.1*	-31.6	37.6	6.0	FY31
4 Expanded non-network solution	0.0**	-5.7	-2.0	-7.7	FY32

*Source: UE BUS 3.04 - Lower Mornington Peninsula supply area – Jan2025 – Public, Table 2 and UE MOD 3.01 - Lower Mornington Peninsula supply area - Jan2025 – Public; * capex, ** the first year of expanded operation is FY32*

147. United Energy's preferred option is Option 3, to construct the HGS-RBD sub-transmission line and build a new Shoreham zone substation because it considers that this option has the highest net benefit.

148. The business case explains the rationale for the Shoreham substation, which is to address a different supply issue. We draw on the business case in considering the merits of the proposed substation in section 3.3.2. In this section, we focus on United Energy's options for addressing the identified need – voltage collapse if peak demand on the LMP exceeds 123MVA and if there is a coincident outage of either the MTN-DNA or TBTS-DNA sub-transmission lines.

149. Option 1 would require pre-contingent load shedding when demand exceeds the voltage collapse limit to maintain system security. This option assumes the current 10MW NNS remains available. This is not a prudent long-term approach.

150. Option 2 requires a 54km line plus work at the two end-point substations (e.g. new 66kV bays). It will resolve the voltage collapse constraint beyond 2050 and support long-term demand growth across the LMP. From the CBA model,[31] it appears that the economically optimum timing is to commission the sub-transmission line prior to the summer of FY32. We make the following observations regarding Option 2:

- The inference is that Option 1 will suffice until FY32 (albeit at an expected higher annual cost of operating the NNS)
- The Option 2 NPV is relatively small (i.e. given the capital cost) - the benefit to cost Ratio (BCR) of 1.16 indicates that the economic viability is susceptible to even relatively small negative variances of key inputs:
  - the sensitivity analysis provided[32] shows a negative NPV if the capex is 10% higher and the benefit is 10% lower than assumed
  - given the qualifications about the cost estimate in the business case[33] and the inherent uncertainty in demand forecasting, this is a realistic scenario, and
- The Load Duration Curve is based on 2019 data – a more recent LDC would give more confidence about the energy at risk calculations.

151. Option 4 is described in the business case as requiring an additional 10MVA of demand response for 90 minutes longer than the current 3 hours and 25 minutes. United Energy's assessment is based on the 10PoE demand forecast.[34] United Energy also states that it expects the new contract for NNS to cost more than $90k per MW. We make the following observations regarding Option 4:

- The cost in the CBA model[35] for this option is $111k per year commencing in FY32 and increasing by about $111k per year every second year, indicating that:
  - the cost is incremental to the Base Case, which is appropriate
  - the current 10MW power station is sufficient until 2032
  - thereafter the power station capacity is increased by about 1MW every two years, and this appears to be inconsistent with the business case requirements
- Using the 10PoE demand forecast rather than the 50PoE (or even the blended 50PoE/10PoE demand forecast) appears to be overly conservative in establishing the run times of the NNS diesel units
- The cost estimate does not appear to have been derived with input from the NNS 'market' – there are multiple suppliers of diesel generators and temporary leases are generally available; these could readily be factored into the cost-benefit analysis ahead of the RIT-D process, and
- If United Energy chooses to submit a RIT-D for its preferred project, the NNS market will have the opportunity to respond to the opportunity to provide network support.

Another option should have been considered by United Energy

152. United Energy does not appear to have countenanced expansion of the power station for one or more years to defer the need for the HGS-RBD 66kV line (i.e. until it is uneconomic to keep doing so). We suggest that this option is explored before any commitment is made to the new 66kV line.

31 UE MOD 3.01 - Lower Mornington Peninsula supply area - Jan2025 - Public

32 UE MOD 3.01 - Lower Mornington Peninsula supply area - Jan2025 - Public

33 For example, the amount of undergrounding required is uncertain, the line route is unlikely to be a fixed matter, and recent experience with powerline projects is substantial cost overruns

34 UE BUS 3.04 – Lower mornington peninsula supply area – Jan2025 – Public, pages 12-13

35 UE MOD 3.01 - Lower Mornington Peninsula supply area - Jan2025 - Public

153. Based on the information at hand, we consider that this option may prove to be the most economic approach and it 'buys' option value to test whether the new sub-transmission line is required (i.e. for example depending on peak demand and energy growth).

154. We note that continued operation of the diesel power station may not be welcomed by some,[36] but it may be the case that a new 54 km sub-transmission line stretching the length of the LMP is also opposed by a significant number of community members due to the environmental and amenity impacts.

Findings

155. We consider that the augex for the proposed Lower Mornington Peninsula project has not been sufficiently justified.

156. The identified need for the proposed new sub- transmission line is to eliminate the risk of voltage collapse across the LMP for a low probability by high impact event. It has the highest NPV of the options considered according to United Energy's analysis which indicates that optimal timing of the new line is FY32 (i.e. to meet the forecast summer FY32 peak demand).

157. However, given the peak demand occurs in four (or so) 'spikes' over the Christmas/January holiday period each year (and are therefore somewhat predictable), continuation of the current NNS or perhaps expanding it in FY30-31 may well be the optimal solution to enable the proposed new line to be deferred. This option has not been explicitly or adequately considered by United Energy and, absent such assessment, we consider that United Energy has not provided sufficient justification for engaging in this significant network augmentation.

3.3.2 Shoreham zone substation

What United Energy has proposed

158. In its Mornington Peninsular Supply Area business case, United Energy proposes building a new Shoreham (SHM) substation by cutting into and out of the proposed new 66kV sub-transmission line proposed between Higgins substation (HGS) and Rosebud (RBD) in the Lower Mornington Peninsular (LMP).

159. As shown in Table 3.4, the cost of the SHM is estimated at $26.9 million, to be constructed at the same time as the proposed HGS-RBD sub-transmission line.

Table 3.4: United Energy's proposed Shoreham zone substation augex - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Shoreham zone substation	-	-	-	13.4	13.5	**26.9**

Source: EMCa table derived from United Energy SCS capex model

Assessment

The identified need is improvement of supply reliability to 8,000 customers

160. United Energy advises that customers on the LMP '*have some of the poorest reliability experiences across our entire network, with several of our worst performing feeders located in the area. These feeders are typically longer than other feeders and span through denser, more vegetated areas, which means they are more impacted during major events such as storms.*' Four feeders deliver on average 608 minutes off supply to customers and over four times higher than the average number of outages.[37]

[36] At the on-site meeting we were advised of customer and parliamentary members' complaints about the use of diesel generators (EMCa onsite workshops - forecasting and augex – final, slide 67)

[37] UE BUS 3.04 – Lower Mornington Peninsula supply area – Jan2025 – Public, page 7

161. Based on this advice, we consider it reasonable that United Energy considers cost-effective means of improving supply reliability and resilience to the affected customers.

United Energy considered only one option for improving reliability and resilience for LMP customers

162. United Energy bundled this project with the proposed construction of the new HGS – RBD 66kV line as part of its option analysis which we describe in section 3.3.1. See Option 3 in Table 3.3. Construction would proceed in parallel with the proposed new line in FY30 and FY31.

163. United Energy advises that the construction of SHM would halve the length of several feeders supplying the area by providing another point of supply for customers, improving reliability, resilience and the quality of supply for around 8,000 customers.

164. The proposed investment is assumed to reduce the number of customers impacted by each fault by 50% and receive 45% less faults.[38]

165. Reference is made to improving supply to customers on the DMA15, DMA23, MTN32 and RBD21 feeders. The cost estimate does not appear to include proposed new feeders *'to be added to the network that would allow [United Energy] to improve outcomes…'*[39] and may not therefore represent the full cost of improving supply to the quoted 8,000 customers.

166. For completeness, United Energy should have identified a range of alternative options for improving supply reliability and resilience in the LMP – such as adding sectionalisers, automation schemes, increasing vegetation management, and/or addressing the most vulnerable line sections (e.g. with covered or bundled conductor). Whilst it may be the case that these options have already been implemented or are not as cost-effective as the proposed option, we are unable to assess whether the SHM substation option is superior.

The derivation of energy at risk is clouded by hard-coded numbers and lack of explanation

167. The provided model was unhelpful in understanding the derivation of the energy at risk. We therefore requested a more detailed model,[40] which although still containing links to other spreadsheets allowed us to see that according to United Energy's analysis, the largest historical contributor to unreliability is outages of the MTN32 feeder, with millions of customer minutes off supply in 2021. Outages on feeders DMA15 and DMA23 in 2021 also contributed significantly to minutes lost. The RBD21 feeder, by contrast has been relatively reliable. We assume that there was a major storm event in 2021.

168. United Energy has mitigated the impact of the 2021 event on overall results by averaging the annual minutes off supply over 10 years,[41] nonetheless, the impact of this event has a significant influence on the average results and which United Energy uses to project performance into the future.

169. Whilst it is a reasonable approach to use historical performance to forecast future performance, at $26.9 million, the proposed SHM substation presents as a relatively expensive means of mitigating the impact of a once-in-a-decade major event. This is borne out by:

- The additional capital cost of $26.9 million ($21.8 million PV) which provides $15.5 million in benefits (PV), and
- The BCR for the SHM component is 1.24,[42] which is typically considered to be marginal (i.e. the project can become uneconomic for relatively small unfavourable variances).

170. United Energy did not present a sensitivity analysis for SHM alone, however, with negative variances in cost and benefits, it is likely the NPV would be negative and the BCR less than

---

[38] CPU, EMCa on-site workshops – forecasting and augex – final, slide 73

[39] CPU, EMCa on-site workshops – forecasting and augex – final, slide 72

[40] United Energy - IR006 - Q4 - SHM individual assessment, Working_risks - Shoreham

[41] United Energy - IR006 - Q4 - SHM individual assessment, Working_risks – Shoreham, row 54

[42] From Table 3.4

one. Given the uncertainties in the estimates of both costs and benefits, we consider this to be a credible scenario.

Findings

171. We consider that the augex for the proposed Shoreham substation project has not been sufficiently justified. United Energy has not demonstrated that building SHM is the best economic solution, having not presented a range of lower-cost alternatives to address supply reliability and resilience in the LMP.

172. We consider that when it is economic to construct the NGS-RBD 66kV line the economic prudency of also establishing SHM should be reconsidered. In the interim, we are of the view that the proposed 66kV line and SHM substation should also be deferred beyond the next RCP.

3.4 Assessment of CER customer-driven electrification augex project

3.4.1 Introduction

173. United Energy proposes an augex customer driven electrification program as part of its Electrification and CER strategy. This strategy is common across the three CPU entities, and we describe it in our associated report.[43]

174. In aggregate, United Energy proposes $106.9 million (totex) for CER and Electrification. We assess its proposed ICT capex of $17.6m and ICT opex of $18.9m in our associated report. In the current report, we therefore review its proposed customer-driven electrification augex program.

3.4.2 What United Energy has proposed

175. As shown in Table 3.5, United Energy proposes a $70.4 million program to improve its steady-state voltage compliance over the duration of the next RCP by investing in:[44]

- Proactive LV augmentation, and
- Reactive augmentation.

176. It also recognises a small capex reduction of $0.8 million from avoided augmentation from non-network solutions, which it has accounted for in its proposed capex.

Table 3.5: United Energy's proposed Customer-driven electrification augex - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer-driven electrification	11.7	6.1	13.4	17.5	21.6	**70.4**

Source: EMCa table derived from United Energy SCS capex model

[43] EMCa review of CitiPower, Powercor and United Energy (CPU) proposed ICT, Cyber security, CER and Electrification expenditure for 2026-31 regulatory period

[44] UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 1

3.4.3 Assessment

Victorian DNSPs have voltage compliance obligations under the Australian Standards and Electricity Distribution Code of Practice (EDCoP)

177. The EDCoP obligates Victorian DNSPs to maintain voltage levels between 216 and 253 volts at least 99 per cent of the time.[45] Functional compliance is met if these limits are maintained for at least 95 per cent of our customers. United Energy advises that:

> *Voltage breaches are considered a tier one EDCoP breach, which carry civil penalties of up to $11,855,400 for periods in which we are non-compliant.[46]*

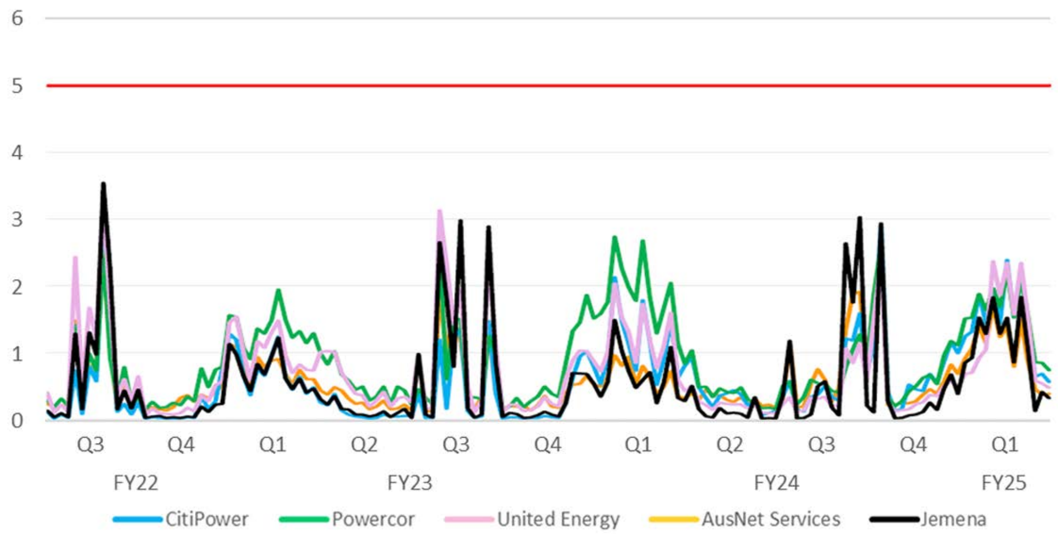
United Energy's focus is on undervoltage compliance

178. United Energy's reports that largely remediated voltage non-compliance by 2022 by implementing a dynamic voltage management system (DVMS), adjusting distribution substation (DSS) tap settings, phase balancing, and by shifting voltage settings across its network.

179. United Energy also reports that it receives customer complaints that must be addressed if they are receiving non-compliant power quality (or service level) that can only be addressed through network solutions and expects these to increase in volume (and cost) as more customers 'electrify' their homes.[47]

180. United Energy's undervoltage performance is shown in Figure 3.4, with its current service level at 97.5%. However, with the extent of electrification forecast over the next RCP, United Energy's new time-series modelling capability[48] indicates that undervoltage issues will increasingly arise. United Energy claims that this will lead to malfunctioning appliances, EVs not charging, flickering lights, curtailed PV export, increased energy costs, and reductions in the lifespans of electrical equipment.

Figure 3.4: Undervoltage non-compliance of Victorian DNSPs (%)



Source: UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 5

181. United Energy claims that the result of a modelled 'do nothing' scenario is for a level of non-compliance at 96.4% by FY31, as shown in Figure 3.5. United Energy claims that this

45 ESC, Electricity Distribution Code of Practice (V2), 2023, clause 20.4.1 and note to Table 2, page 82

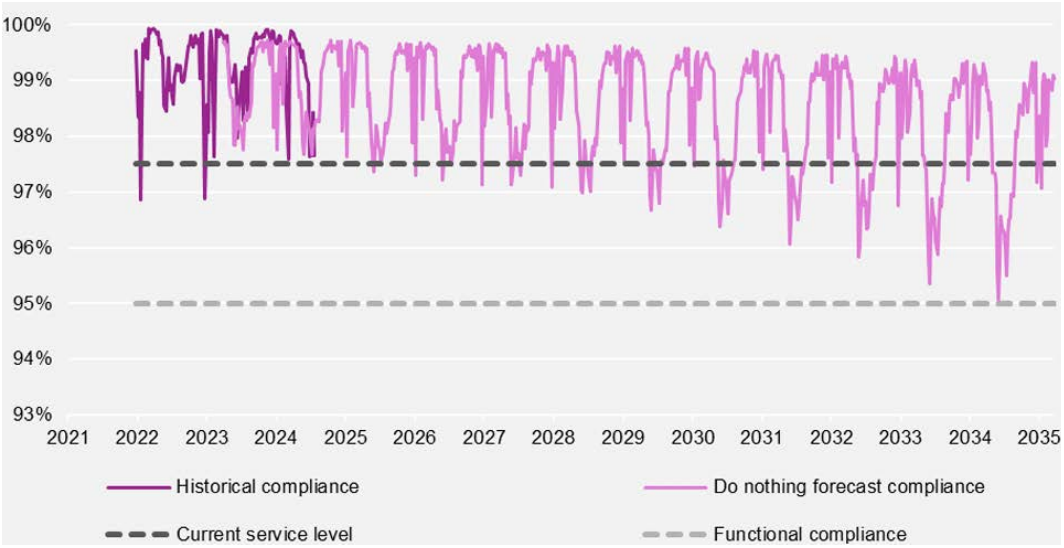
46 UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public– Public, page 7

47 UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, page 7

48 UE ATT 2.04 – Zepben – Detailed customer electrification forecasting methodology – Jan2025 – Public; developed using AMI data to simulate power flows at each customer connection every 30 minutes over 10 years

approach will inevitably and progressively lead to more customer complaints related to undervoltage during the next regulatory period, despite technically not breaching the functional limit (at least according to the modelling) either within this period or, it appears, until sometime beyond 2035.

Figure 3.5: United Energy projection of voltage compliance forecast - 'do nothing' scenario (%)



Source: UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 8

182. The combination of the description of its methodology and the methodology report itself are sufficient to satisfy us the methodology is a reasonable basis from which to forecast future LV voltage performance. However, as with all modelling, a crucial aspect is the quality of the inputs and other parameter assumptions. Such assumptions are challenging because there is little historical information available so far, given that the electrification journey is only beginning. However, with this caveat over the outcome of applying the methodology, we consider that there is a prima facie case for United Energy to at least consider options to ensure that it will remain compliant with its power quality obligations through the next RCP and beyond, with the focus on undervoltage management.

183. United Energy estimates that there will be 1,055 customer voltage complaints over the next RCP under the base case, each of which will need to be rectified.[49]

Proactive versus reactive upgrades

184. United Energy is required to rectify all power-quality related complaints (provided the issue is from the supply side) and therefore the less complaints it receives, the lower its 'reactive' voltage management cost over time. In turn, this means that forecasting the number of non-compliant sites and the undervoltage complaints from them is a key aspect of United Energy's cost forecasting modelling for voltage management costs.

185. Proactive investments include DSS offloads and reconductoring LV feeder sections. United Energy's analysis leads it to conclude that:

- Proactive upgrades are more efficient over the long-term because United Energy can optimise investment location and timing and deliver higher long-term service levels for a given cost, reducing the number of complaints over the duration of the next RCP compacted to a purely reactive approach, but that
- Proactive upgrades are more expensive in the short term because some sites would be upgraded in advance of customers complaining (despite these customers receiving poor and/or non-compliant service levels).

49 UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 5

186. This is the premise of its proposed 'proactive-first' investment in two of the three options it presents in its business case, as discussed below.

There is a significant disconnect between UE's historical power quality complaints and its forecast under-voltage complaints that 'require projects'

187. United Energy states in its business case that it received 146 complaints in FY24.[50] It does not specifically state that these are voltage-related complaints (or even PQ complaints), but this is inferred in the text.

188. We requested further information from CPU, with the response advising that:[51]

> *'The Customer complaints figures…are a projection of the expected undervoltage complaints received per year under the base case…Consistent with historical trends, a proportion of these complaints will be driven by network issues, which would require expenditure to resolve the undervoltage issue under jurisdictional compliance obligations. We have applied a Reactive Conversion Factor to the complaints forecast, based on historical rates, which gives us the forecast of complaints that are related to network-caused undervoltage issues and will require network expenditure.'*

189. We have summarised the numerical aspects of the response in Table 3.6, which shows that the number of complaints projected in the business case are assumed to be voltage-driven complaints but that only a proportion of them result in network projects (to rectify the issue).

Table 3.6: United Energy - complaints conversion to network rectification projects

	FY27	FY28	FY29	FY30	FY31	Total
# complaints in Table 5 of business case	185	195	209	224	242	**1,055**
Conversion factor derived by CPU	0.33	0.35	0.37	0.38	0.40	
# complaints forecast to require network projects*	62	68	76	86	97	**389**

Source: UE per PAL response to IR006, question 3(a)

190. However, only ***four*** of the 143 complaints in United Energy's FY24 RIN are identified as being related to technical quality of supply.[52] The equivalent number in the FY23 RIN is two technical complaints.

191. The gap between the RIN and the inputs to United Energy's model is not credible. It would appear that either UE's RIN data is incorrect or the forecast number of 'technical quality of supply complaints' forecast from 2027 onwards is massively overstated.

192. This is of fundamental importance because United Energy forecast a substantial increase in the number of non-compliant sites and voltage complaints over the next RCP, both of which informs its proposed augmentation program:

- Non-compliant sites are targeted through the proactive augmentation program, and
- The forecast number of complaints requiring network projects drive the reactive program.

193. If the staring number is wrong, then United Energy's projections and forecast expenditure to maintain or improve voltage compliance performance will also be wrong. This undermines confidence in United Energy's options analysis and proposed expenditure, which we consider below.

50 UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 2

51 CPU per PAL response to IR006, question 3(a)

52 United Energy 2023-24 - Annual - RIN Response - CONSOLIDATED - 31 October 2024 - PUBLIC(17468107.1)

United Energy considered three options and proposes to 'maintain' service levels

194. United Energy presents the three options identified in Table 3.7. Option 2 is recommended by United Energy as the best balance between cost and service level.

Table 3.7: Summary of United Energy's comparative options analysis

Option	FY31 voltage compliance	Total # forecast customer complaints (next RCP)	Cost ($m 2026)
1. Base Case – do not breach functional limit	96.5%	1,055	$42.2
2. Maintain service levels (recommended)	97.5%	848	$65.7*
3. Improve service levels	97.6%	692	$85.8

Source: UE BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Tables 5-11
** as recorded in Table 6 of the business case which is different to the capex model*

195. The Base Case is premised on responding to complaints reactively, and only utilising proactive investments to achieve functional compliance, investing as late as possible. The result of this approach is that no proactive expenditure would be incurred.[53, 54]

196. Whilst Option 3 is, as modelled, expected to result in 363 less voltage complaints over the duration of the next RCP, it comes at a high incremental cost compared to Option 2. In our view (and United Energy's) it is not representative of a good cost-benefit trade-off.

197. United Energy's modelling for Option 2 is designed to proactively target sites based on the highest number of customers that would become compliant and only to the level required to maintain the service level at 97.5% across the next RCP. According to United Energy's business case, it proposes the following Option 2 capex included in Table 3.8.

Table 3.8: Nature and net cost of proposed electrification works - $m, real 2026 (unescalated)

	Cost ($m)
Proactive LV augmentation	41.6
Reactive augmentation (to respond to a forecast 848 complaints)	25.0
Less avoided augmentation from non-network solutions	-0.8
Total	**65.7**

Source: PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 6

United Energy's proposed proactive program represents a very high cost per complaint addressed

198. As shown in Table 3.7 and Table 3.8, the cost of United Energy's proposed proactive option (option 2, at $65.7m) is $23.5m more than its 'base case' reactive option (at $42.2m). We consider it more reasonable to assess United Energy's program from the viewpoint of addressing underlying voltage degradation than solely as a means of reducing complaints. Nevertheless, an observation from Table 3.7 is that the cost to proactively reduce United Energy's forecast number of complaints from 1,055 over the five-year period, to 848 – a difference of 207 complaints (or 41 per year) – is around $113.5k per complaint. Intuitively, it seems unlikely that a customer would 'value' their complaint at this level.

53 PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 6

54 The Base case gives very similar results to the 'do nothing' case described above, however 'doing nothing' is a misnomer, as Powercor still needs to respond to non-compliances. We therefore expect the cost of the 'do nothing proactive' case to be close to that indicated for the Base Case.

United Energy's proactive investment methodology is highly sensitive to the assumed target service level

199. United Energy has relied on a simulation model to forecast the extent to which it expects undervoltage to occur. We provide an overview of this modelling in Appendix A. In brief, this model relies on voltage profile simulations for each feeder for each 30-minute interval, for the next 10 years. From this, it derives a set of 'economic' interventions to maintain an assumed target service level over the period and derives the cost of this program and an estimate of its economic value.

200. As we show in Appendix A, the model is highly sensitivity to the target service level, which is a model input assumption. United Energy's target service level setting is 97.5% over the period. In Powercor's equivalent model, the setting is 97%. From Powercor's model, we find that if it was to set a target of 96%, which is still above its Functional Compliance obligations of 95%, the model defines an augmentation program requirement that is only around 20% of the cost that Powercor has proposed.

201. We do not have access to an equivalent United Energy model,[55] however as the methodologies are identically applied, we consider it reasonable to assume that the outcome would be similar for United Energy's augmentation program. Furthermore, as we show in Figure 3.5, United Energy forecast is that even if it 'does nothing', it would remain well above its functional compliance limit through to the end of the next regulatory period and beyond.

202. Noting that United Energy's simulations indicate that (under a 'do-nothing' scenario) it would risk breaching its functional compliance obligations only well beyond the end of the next RCP, we consider that there are approaches that are considerably less costly than investment in long-lived augmentations in the next RCP. As with all Victorian DNSPs, United Energy will have the benefit of comprehensive AMI data to deploy a mix of focused HV, LV, proactive and reactive interventions where and when required. We consider that these needs will reveal themselves with better precision close to the time when they are required, as feeder-level variations in electrification uptake and accompanying customer behaviours become evident.

203. United Energy will also be able to gauge the extent to which it can rescue voltage decline through non-network approaches, including the Flexible Services that it will be rolling out during this period. United Energy may find, for example, that it can allow voltage service levels to decline slightly in the short term, with confidence that it can arrest and potentially reverse this decline through (preferably) non-network solutions, but with augex solutions as a backstop option.

Voltage service level decline due to electrification may be less than forecast

204. While the simulation modelling of voltage levels that has been undertaken for United Energy is relatively sophisticated and of considerable value in helping to assess its future needs, as with all forecasting models it is dependent on a range of assumptions.

205. An aspect that we do not observe in the modelling is to explore geographical variation in the uptake of electrification. For example, we consider it a reasonable hypothesis that EV uptake and at-home EV charging and charging behaviours may well vary at the 'postcode' level and for many feeders may have only a slow impact.

206. It is also a reasonable hypothesis that home electrification rates will vary considerably across the service area. New suburbs in Victoria will be fully electrified, in which case we assume that United Energy will design its networks accordingly from the outset and will not require a subsequent 'electrification augex' program for them. By contrast, it is in existing suburbs that United Energy will need to address decline in compliance due to electrification, but electrification in these suburbs may occur far more gradually than average, as appliances are replaced. Even if United Energy's overall assumptions regarding EV and electrification demands are reasonable at the aggregate level, this variation could significantly affect the scale of work needed.

55 Powercor provided a more detailed version of its model PAL MOD 3.31 which allowed the service level target to be varied

207. We have not seen evidence that such factors have been considered and, if they have not, then both could lead to lower levels of undervoltage than United Energy has relied on as the basis for its proposed augex program.

United Energy's proactive investment methodology is based on using VCR to value forecast energy supplied to customers at non-compliant undervoltages

208. In its modelling, the customer benefit from addressing undervoltage supply is derived from the assumed alleviation of energy supplied to customers below 216V by network augmentation. United Energy values energy supplied to customers at non-compliant voltages using the VCR. It linearly weights application of the VCR between 0% of the VCR at 216V (the 'soft' compliance limit) rising to 100% of the VCR at 207V (or lower).

209. EV charging interruption is the main example given for valuing curtailment at VCR. Other impacts from undervoltage that United Energy assumes will intensify over the next RCP to the extent that voltage service levels decline are heating, cooling, cooking malfunction, and appliance lifespan degradation.

210. United Energy models the impact of augmentation options on reducing the amount of energy supplied at non-compliant voltages. It assesses the customer benefit from an upgrade as the difference between pre- and post-augmentation supply, valued at VCR.

It is an overestimate to assert that supply will be curtailed at the levels that United Energy assumes, and to value undervoltage supply at VCR

211. Whilst United Energy (with CitiPower and Powercor) has put considerable effort into developing the models underpinning their analyses, using the VCR to assign value to energy supplied with non-compliant voltages is not consistent with the AER's intended application of it, even for curtailment of EV charging. The impact of not being able to charge an EV for some time is not the same as the impact of being entirely without supply within the household. We expect that the VCR is much higher than the economic cost of an undervoltage excursion and much higher than what people would be prepared to pay, given what we assume to be modest impacts. For example:

- There may be an inconvenience factor in an EV charger tripping off, which may be for minutes or for a few hours. In most circumstances, and assuming that the charger resets when voltage is restored, we consider that the pause in charging will have minimal consumer impact and may not even be noticed; we consider that assigning a VCR value of the order to $43/kWh to this inconvenience grossly overstates the likely economic value
- Tripping of air-conditioning due to under/overvoltage protection settings again may cause temporary inconvenience, though this depends for how long it trips, and
- The impact on other appliances is, in our view, unlikely to lead to major inconvenience or widespread damage individually or collectively and for the most part would not be noticed.

212. We asked United Energy to explain its rationale for the choice of VCR and in summary, its response was (i) that it is the closest measure currently available, and (ii) customer feedback is that they do not distinguish between reliability and power quality.[56] We consider that its customer feedback is likely explainable largely because those customers that have been supplied at times under voltage, may well be unaware of it, providing more indication of the minor impact that for the most part this has had. For example, we have already referred above to the very small number of voltage complaints that CitiPower receives.

213. In summary, we consider that from a technical perspective undervoltage below 207V for the most part does not lead to a supply outage and that valuing such supply at VCR is a significant overstatement of the economic cost.

[56] Powercor response to IR014, question 3(b), which covers CitiPower and United Energy's response as well

United Energy's reactive investment methodology

214. In addition to proactive investments, United Energy is required to respond to customer power quality complaints and remediate the issue as soon as practicable. Despite the proactive investment under its preferred option, it forecasts receiving 313[57] complaints which will require remediation work. United Energy advises that it remediates at the lowest cost rather than highest possible value.

215. Applying the conversion factors and average costs for minor and major rectification projects supplied by CPU to the proposed number of reactive projects under the Base Case and the Maintain option gives the results shown in Table 3.9. We sought to verify these costs using the costs per major and per minor project given in the business case, however the values that we derive from United Energy's stated assumptions differ from those that United Energy has proposed.

216. As shown in the table, we find that the $42.2m cost of the Base Case is materially overstated, and the business case proposed cost of $25.0m for the reactive project cost component of Option 2 is also overstated.

Table 3.9: Options cost analysis – reactive projects, $m, 2026

: <Title text> Option	Number of Complaints from Business Case	Business case + UE ATT 2.01			Reactive projects cost	
		# network projects	# major projects*	# minor projects*	Business case	EMCa analysis**
Option 1: Base Case	1,055	389	152	237	$42.2	$26.0
Option 2: Maintain	848	313	122	191	$25.0	$20.9

Source: EMCa analysis of information in UE BUS 3.01 and PAL ATT 2.01 Table 22
** ratio is 39% major projects and 61% minor projects*
*** Major project cost is $129k and Minor project cost is $27k*[58]

217. Overall, the average cost per reactive project is $108.5k for the Base case and $79.9k for the Maintain option (using the business case data). This material difference is not explained. However, the more significant issue, as explained earlier, is that both cost forecasts are based on United Energy's forecast of the number of voltage complaints, but which appears to be significantly overstated relative to other data that it provided.

Sensitivity analysis is not sufficient

218. United Energy included only one form of sensitivity analysis in its business case (and none in its provided model): modelling the non-compliance forecast for the Base Case using the 10PoE demand forecast. This shows that the proposed level of 'improve' investment would 'hold' compliance above the functional limit until 2033, rather than a date much further into the future with the base demand assumption (which is not apparent, but which we assume is 50PoE).

219. This analysis is not an adequate substitute for a thorough sensitivity analysis to test the robustness of the proposed expenditure, particularly given the issues that we have described with the methodology for deriving economic proactive augmentation projects. We consider that there is considerably more productive scope for sensitivity analysis around the impacts of electrification itself, than only varying the underlying demand forecast.

3.4.4 Findings

220. United Energy has not sufficiently justified the proposed customer electrification program and the proposed augex is materially overstated.

57 Based on the conversion factor applied to the 848 forecast complaints over the next RCP

58 UE ATT 2.01 – Customer electrification forecasting methodology – Jan2025, Table 22

221. We are satisfied that forecast demand and an expected trend to electrification will, other things being equal, tend to result in a decrease in voltage service levels over the regulatory period and that some 'PQ' expenditure will be required to manage this. United Energy's modelling indicates that it is likely to maintain functional compliance until well beyond the end of the next regulatory period and we consider it more likely that the impact will be less than United Energy has forecast.

222. However, we have four significant concerns with United Energy's forecasting methodology that we consider has led to a significant overstatement of the expenditure that United Energy will require in the next RCP. We consider that:

- United Energy has overstated the need and justification to maintain voltage service at current levels throughout the period. From a risk perspective, a slight decline would have considerably less impact on customers than United Energy is assuming, may be arrested by non-network solutions such as United Energy intends to deploy in any case, and would void the need for the proposed very substantial network augex investment
- United Energy can remain within its Functional Compliance obligations with a considerably lower level of proactive intervention and, through utilisation of its extensive AMI data, can monitor PQ at the LV level, utilising its DVM system and taking account of the impact of Flexible Services, and target any augmentation-based interventions as may be required, when required
- United Energy's use of VCR to value energy served to customers at less than 216 volts is not a valid application of the VCR. It leads to a significant overstatement of the economic cost of undervoltage supply and therefore to a significant overstatement of the economic benefits of United Energy's proposed proactive program, and
- United Energy's information on voltage complaints is highly inconsistent and cannot be relied on as a factor in considering the scale of reactive work required under any of the options that United Energy has considered.

223. On this basis, we consider that United Energy has not justified the considerable increase in augex that it has proposed to enable a proactive electrification program

3.5 Findings and implications of proposed augex

224. We consider that collectively and individually the projects/programs that we have reviewed significantly overstate United Energy's proposed capex for the next RCP.

3.5.1 Summary of findings

Context

225. We have assessed only three projects/programs out of eleven projects/programs presented by United Energy in its Proposal for the next RCP. Therefore, our findings may not be broadly applicable to the balance of the program.

226. We have not commented on demand forecasts. The AER has advised us that it will assess United Energy's demand forecast separately and will consider our findings accordingly. However, we have, for demand-driven projects, commented on the sensitivity of the proposed project optimal timing to negative variance in the demand forecast. Our 'low demand case scenario' is a demand forecast of 100% 50PoE rather than the 70%:30% weighted 50PoE/10PoE forecast used by United Energy for planning purposes.

General

227. United Energy has presented business cases and supporting cost-benefit analysis (CBA) models that provide foundational material to support assessment. However, we needed to ask a number of clarifying questions, primarily because the CBA models provided were not fully transparent, containing hard-coded data, for example.

228. United Energy responded to our clarifying questions, and this enhanced our understanding of each project and program.

229. The business cases provided to support the projects/programs (together with the CBA models) present a reasonable range of options to respond to generally well-articulated needs.

230. United has selected the highest NPV option in each case and the business case present both the optimal timing and sensitivity analyses focussed on the NPV.

231. Sensitivity analyses are presented in each case with the emphasis on demonstrating the robustness of the NPV of the selected option against negative variances (i.e. NPV remains positive) and superiority to the other options. This is good practice, however the sensitivity analyses did not encompass changes to the optimal timing.

LMP supply upgrade and new Stoneham Substation

232. We are satisfied that United Energy needs to prudently manage the risk of voltage collapse in the Lower Mornington Peninsular. However, instead of the proposed new sub-transmission line to be completed by FY31, we consider that a modest expansion of the existing non-network solution is likely to be the prudent approach, at least in the next RCP.

233. The new Stoneham substation is proposed to take advantage of the proposed new 66kV transmission line between HGS and RBD to improve quality of supply from a number of feeders and collectively 8,000 customers in the LMP. However, United Energy has not demonstrated that building SHM is the prudent economic solution.

234. We consider that when it is economic to construct the NGS-RBD 66kV line the economic prudency of also establishing SHM should be reconsidered. In the interim, we are of the view that the proposed 66kV line and SHM substation should be deferred beyond the next RCP.

CER - Customer Driven Electrification

235. We consider that the proposed expenditure is significantly overstated because of the following issues:

- United Energy has overstated the need and justification to maintain voltage service at current levels throughout the period – a slight decline would void the need for the majority of the proposed proactive augmentation
- United Energy has not fully explored the impact of alternatives to augmentation, such as flexible services, over time
- The use of VCR to value energy served to customers at less than 216 volts is not a valid application of the VCR in our opinion and significantly overstates the economic value of proactive interventions
- The apparent sudden increase in assumed undervoltage complaints is not credible from the information provided, and
- All other things being equal, the cost for United Energy's preferred Option 2 (Maintain) reactive project component appears to be overstated.

3.5.2 Implications for proposed capex allowance

236. We have been asked to review projects with aggregate proposed capex of $138.4million, including an Electrification/CER project with proposed capex of $70.4 million.[59] These projects comprise part of United Energy's aggregate proposed augex of $180.3 million.

Alternative forecast methodology

237. For projects within our scope in the demand augex category, we consider that the proposed capex for the three projects is not reasonable. Our proposed alternative forecast for the

59 Customer driven electrification

other projects involves one or more of the following adjustments, to the extent that it formed the basis of United Energy's forecast and which we consider to be not justified or to be overstated:

- Adjustments to correct modelling issues and/or unsupported or incorrect model input assumptions, and/or
- Adjustment to the timing of the proposed expenditure, resulting in deferment beyond the end of the next RCP.

Alternative forecast of expenditure

238. We consider that a reasonable alternative forecast for the projects within the augex categories that we reviewed, would be between 90% and 95% less than United Energy has proposed.

239. We stress that our advice on an alternative forecast relates only to the projects within the augex category of expenditure within the scope of our review and does not necessarily have any implication for augex that was not within the scope of our review.

4 REVIEW OF PROPOSED OPEX - VEGETATION MANAGEMENT

United Energy has proposed an opex step change of $72.3 million in its initial submission for vegetation management, reflecting the additional expenditure that it proposes as being required for a pathway to compliance with its electric line clearance obligations that commence in the current period. United Energy subsequently updated its submission, and increased its proposed opex step change to $76.8 million, with a corresponding increase in the number of spans to be cut from 37,300 spans to approximately 43,000 spans p.a.

We have identified a number of issues with United Energy's modelling of the proposed vegetation management opex relating to the proposed volume of spans to be treated and costs to treat the identified spans and which result in an opex forecast that is materially overstated.

We consider that United Energy's proposed opex step change for vegetation management is not a reasonable forecast of its expenditure requirements for the next RCP. We are satisfied that additional improvement to vegetation management activities is required for United Energy to achieve compliance in the next RCP, however we consider that a number of factors in United Energy's forecast are not reasonable assumptions. Adjustment of United Energy's assumptions, which we applied in various combinations, leads us to conclude that United Energy does not require an opex step change.

4.1 Introduction

240. In this section, we present our assessment of forecast opex step change that United Energy has proposed in the next RCP. We reviewed the information provided by United Energy to support its proposed opex step change for vegetation management, and its responses to our information requests on the topic.

4.2 What United Energy has proposed

4.2.1 Vegetation management opex step change

241. United Energy has proposed an opex step change for its vegetation management program of $72.3 million for the next RCP as shown in Table 4.1.

Table 4.1: United Energy total proposed vegetation management step change - $m, real FY2026

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation	5.3	8.8	15.8	16.1	16.4	**62.3**
Hazard trees	1.8	2.0	2.0	2.0	2.1	**9.9**
Total vegetation management step change	**7.1**	**10.8**	**17.8**	**18.1**	**18.4**	**72.3**

Source: EMCa table derived from UE MOD 9.02 – Vegetation Management

242. United Energy claims that a change in the 'standard of compliance'[60] is required by the safety regulator, as a result of its enhanced approach to vegetation management (including adoption of LiDAR) and evidenced by an increased level of enforcement of the requirements of the governing regulations and electric line clearance management plan. United Energy claims that these requirements in turn require additional expenditure for vegetation management activities.

4.2.2 Understanding the build-up of the forecast

243. United Energy calculates its step change by first calculating a bottom-up build of its vegetation management opex requirements and reducing that by the opex included in its base year to determine the proposed step change. It does this by projecting forward its existing program and applying an uplift to the base level of expenditure. We show the total opex in Table 4.2

Table 4.2: United Energy's bottom-up build of its vegetation management opex - $m, real FY2026

Total	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation cutting program	26.5	30.0	37.0	37.3	37.6	168.3
Hazard tree program	2.7	2.9	2.9	2.9	2.9	14.3
Total	**29.2**	**32.8**	**39.9**	**40.2**	**40.5**	**182.6**

Source: EMCa table derived from UE MOD 9.02 Vegetation management

244. Next, United Energy subtracted the vegetation management opex that it expects to incur in its proposed base year opex as shown in Table 4.3.

Table 4.3: United Energy's proposed total vegetation management opex - $m, real FY2026

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation:						
Forecast	26.5	30.0	37.0	37.3	37.6	168.3
minus Base	*21.2*	*21.2*	*21.2*	*21.2*	*21.2*	*106.0*
step change	**5.3**	**8.8**	**15.8**	**16.1**	**16.4**	**62.3**
Hazard trees:						
Forecast	2.7	2.9	2.9	2.9	2.9	14.3
minus Base	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*4.4*
step change	**1.8**	**2.0**	**2.0**	**2.0**	**2.1**	**9.9**
Total step change	**7.1**	**10.8**	**17.8**	**18.1**	**18.4**	**72.3**

Source: EMCa table derived from UE MOD 9.02 Vegetation management

4.2.3 Update to forecast opex step change

245. Subsequent to our discussions with United Energy at our onsite meeting, we asked United Energy to update the opex step change based on more recent actuals incurred in the program. United Energy increased its proposed opex step change as shown in Table 4.4.

[60] UE ATT 9.02 – Vegetation management step change – Jan2025 – Public

Table 4.4: United Energy changes to vegetation management opex step change - $m, real FY2026

Step changes	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial submission	7.1	10.8	17.8	18.1	18.4	**72.3**
Updated in response to IR014	12.7	15.8	16.0	16.1	16.2	**76.8**

Source: EMCa table derived from UE MOD 9.02 and IR014

246. We have relied on the more recent data provided in response to IR014 as the basis for our assessment.

4.2.4 Comparison of CPU businesses

247. The proposed opex step change has been based on the same methodology applied to each of the CitiPower, Powercor and United Energy networks. We show the proposed opex step change for each business in Table 4.5

Table 4.5: Comparison of vegetation management opex across CPU businesses - $m, real FY2026

Step changes	CitiPower	Powercor	United Energy
Base program	20.3	432.4	138.8
Base uplift program	27.4	197.3	66.9
Total vegetation management opex	47.7	629.7	205.8
Proposed vegetation management opex step change	**32.1**	**230.0**	**76.8**

Source: EMCa table derived from updated vegetation management step change models provided with PAL IR016, CP IR017 and UE IR014

248. In Table 4.6 we show the unit rates assumed in FY25 for each of the summary categories.

[redacted]

249. We have examined each step change on its own merit and whether the proposal meets the requirements of a step change as set out in the Expenditure Forecast Assessment Guideline.

4.3 Assessment of the proposed step change

4.3.1 Methodology

AER guidance materials outline how opex step changes are assessed

250. As outlined in the AER's Better Resets Handbook, the AER assesses the efficiency of a business's proposed opex forecast at a total level, using the top-down 'base-step-trend' approach described in the AER's Expenditure assessment guideline.

251. In the Better Resets Handbook, the forecasting of the step change component of the base-step-trend approach is described as follows:

> *'Forecasting step changes in costs that are not compensated by base operating expenditure and trend, and are required to ensure the operating expenditure forecast meets the criteria in the Rules. Examples include cost increases associated with new regulatory obligations and trade-offs between capital expenditure and operating expenditure.'*[61]

252. The AER has set out its expectations for forecasting step changes, in that they are limited to a few in number, or none at all. Our understanding is that step changes should present material additional efficient costs to the business that are not provided for in the base or trend component of the opex forecast:

'New regulatory obligation step change

- *It is clearly linked to the new regulatory obligation and represents a major upward step to comply with it.*
- *It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex through in-built provisions under output, price and productivity growth.*
- *No double counting of costs.*

Capex/opex substitution step change

- *It is supported by thorough cost-benefit analysis.*
- *The avoided capex is estimated accurately and it more than offsets the increase in opex in net present value terms (that is, efficient substitution).*
- *No double counting of costs.*

Step change driven by major external factor(s) outside the control of a business

- *It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth.*
- *Where it involves incurring costs in complex areas or markets, it is accompanied by an expert report (including analysis of options, market outlook and opinion on the reasonableness of the proposed step change).*
- *No double counting of costs.'*[62]

Step change derived from the requirements minus the expenditure incurred in its base year

253. CPU describes the forecasting method as a bottom-up build of requirements, based on its historical activities to inform its base level volume of work. CPU has added an uplift for each of the businesses, with the objective of moving to compliance by FY29.

---

61 AER Better Resets Handbook July 2024, page 23

62 AER Better Resets Handbook, July 2024, page 26

254. In its updated submission included, CPU estimates compliance is achieved one year earlier in FY28.

255. United Energy has proposed the base year as the penultimate year of the current regulatory period (i.e. FY25). The rationale is based on FY25 being the most recent year where audited actual data will be available at the time of the AER's final decision.

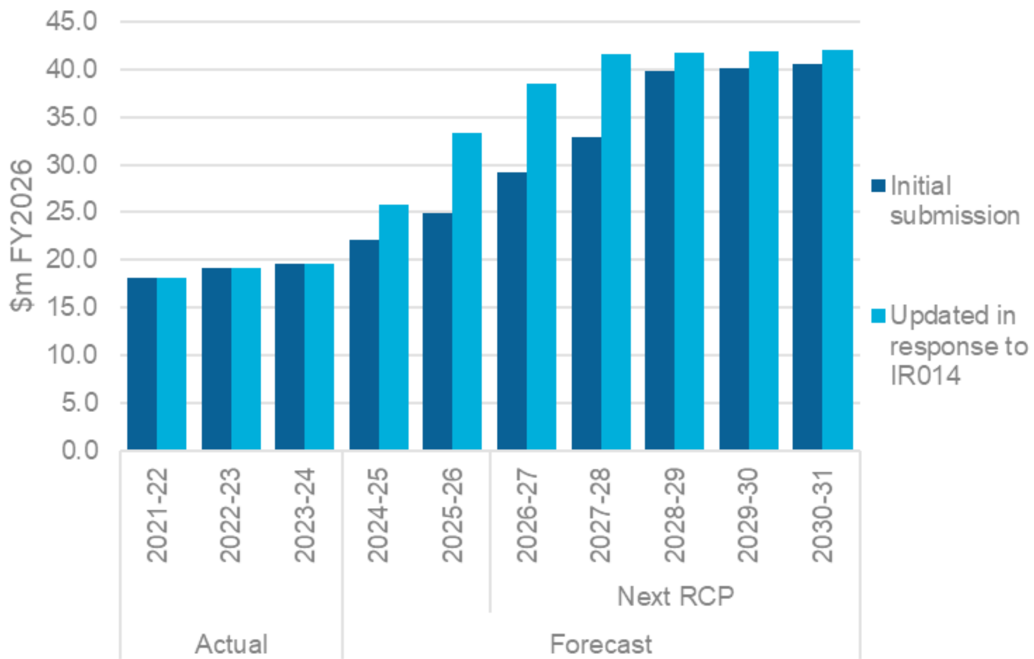
256. However, audited actual data is not available at the time of this assessment and the use of FY25 remains an estimate of the volume and expenditure that United Energy expects to incur.

Historical expenditure and volumes show an increasing vegetation program

257. The historical expenditure shows a rapid increase from FY22 based on the RIN as shown in Figure 4.1. This increase is forecast to continue into the next RCP, before leveling out in FY29 when United Energy considers that it will have achieved its line clearance obligations, and thereafter will move into maintaining compliance.

258. As a part of its response to IR014, United Energy states that it can achieve compliance one year earlier, in FY28.

Figure 4.1: Historical and forecast expenditure - $m FY2026



Source: EMCa analysis of MOD 9.02, and United Energy's response to IR014

259. The profile to achieve compliance is as United Energy has described, with the total expenditure having reduced at the time of compliance in its response to IR014, levelling at approximately $42 million p.a.

260. The revised response indicates a higher opex requirement than United Energy had included in its initial submission. This is due to a higher estimate of cut volumes and unit rates.

CPU has made a number of modelling errors in its presentation of its base program

261. In Table 4.7 we show how United Energy has presented the calculation of its required step change. The calculation of the step change includes growth in the base program.

Table 4.7: Build-up of United Energy's vegetation management program, $m FY2026

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	RCP Total
Base program	18.2	19.2	19.6	25.8	27.9	27.7	27.7	27.8	27.8	27.8	**138.8**
Uplift program	0.0	0.0	0.0	0.0	5.5	10.8	13.9	14.0	14.1	14.2	**66.9**
Total	18.2	19.2	19.6	25.8	33.4	38.5	41.6	41.8	41.9	42.0	**205.8**
Step change						**12.7**	**15.8**	**16.0**	**16.1**	**16.2**	**76.8**

Source: EMCa analysis of MOD 9.02, and IR014

262. We show United Energy's base program in Figure 4.2.

[redacted]

263. The base program expenditure does not reflect how the overall opex allowance is calculated using the BST methodology, and which includes vegetation management opex in its application of the base year, which already includes output and trend factors that are applied over the next RCP as part of the opex roll-forward.

264. We consider that the opex required for its base program is effectively contained within its base year opex to which it has nominated the year FY25 and is an input to the BST methodology. As discussed previously, under the BST methodology the opex is rolled forward to account for output, price and productivity factors. This includes provision for real price escalation.

265. We have not seen sufficient justification of the need for any base year adjustments to the base year to account for increases that would not be expected to be captured under this methodology.

4.3.2 Assessment of volume of vegetation management spans that require cutting

The updated estimate reflects an increase to the estimated cut volume

266. Based on information provided in response to IR007, we observe an increase in cut volumes for CY2024, and which suggests that a higher cut volume may be achieved (in part due to higher resources) than is indicated in the FY25 estimate in UE's initial submission (based on historical average). We asked each of the CPU business to provide an updated

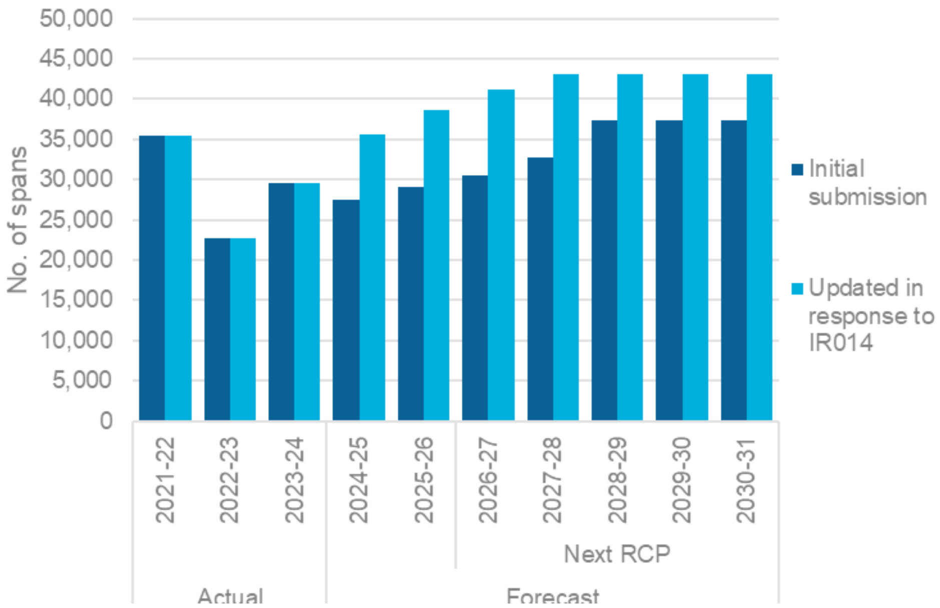
estimated base program cut volume for FY25, using the span category descriptions included in its model and indicate the data relied upon to update the estimate.

267. United Energy stated that:

> *'CY24 and CY25 March YTD cut volumes and FY25 unit rates were not available for the submission of the regulatory proposal. They are now available and MOD 9.02 has been updated to include FY25 estimated cut volumes (and FY25 unit rates).*
>
> *The estimated total base cut volume for FY25 comprises July 2024 to March 2025 actuals plus an estimate for April 2025 to June 2025 based on April 2024 to June 2024 actuals. See table below of estimated FY25 base cut volume by span category which have been sourced from the April 2025 weekly status report.'*[63]

268. In Figure 4.3 we show the trend in volumes. We had expected to see a similar profile on the basis that the cutting volumes are a large driver of the costs. However, we observe a higher increase in volumes in IR017 than has been included in the initial submission, and a slightly lower starting volume in FY25.

Figure 4.3: Historical and forecast vegetation management spans that are required to be cut



Source: EMCa analysis of MOD 9.02, and United Energy's response to IR014

269. Based on the initial submission we observe the total volumes converge around 37,300 spans p.a. once compliance is achieved. In the information provided in IR014, this number has increased to 43,000 without explanation.

270. As the response updated the FY25 estimated volumes and therefore the base program volumes for future years, United Energy does not appear to have taken sufficient account of the increase in calculating the total spans to be cut, as shown in Table 4.8.

63 United Energy response to IR014 Question 5

Table 4.8: Comparison of base program and uplift cutting volumes

	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Initial submission:							
Base program (Actual/estimate)	27,517	27,586	27,556	27,553	27,565	27,558	27,558
Uplift program (Forecast)	0	1,462	3,022	5,240	9,748	9,748	9,748
Total	**27,517**	**29,048**	**30,578**	**32,792**	**37,313**	**37,306**	**37,307**
IR014 updated submission:							
Base program (Actual/estimate)	35,635	35,654	35,617	35,635	35,635	35,629	35,633
Uplift program (Forecast)	0	2,980	5,588	7,450	7,450	7,450	7,450
Total	**35,635**	**38,634**	**41,204**	**43,085**	**43,085**	**43,079**	**43,083**

Source: EMCa analysis of MOD 9.02, and IR014

Proposed program is not aligned with United Energy's ELCMP

271. The ELCMP includes the annual inspection and forecast cutting plan in Figure 4.4. For United Energy this indicates an annual cutting program of 16,000 spans. This figure is not aligned to either the historical cutting program or the forecasting cutting program in either the current or forecast RCP.

Figure 4.4: Annual inspection and cutting plan – LBRA and HBRA

LBRA	Total number of spans to be inspected (estimated) (100%)	Forecast number of spans with vegetation to be cut (annual)
CP	~61,000	16,000
PAL	~220,000	40,700
UE	~171,000	39,400

HBRA	Total number of spans to be inspected (estimated) (100%)	Forecast number of spans with vegetation to be cut (annual)
CP	-	-
PAL	~288,000	46,700
UE	~19,000	8,850

Source: CPU ELCMP Figure 9

272. United Energy states that the annual works program is developed each year and outlines the target inspection and cutting timeframes for each campaign region and remains subject to variations from year to year. However, the differences between each of the sources of information are not explained.

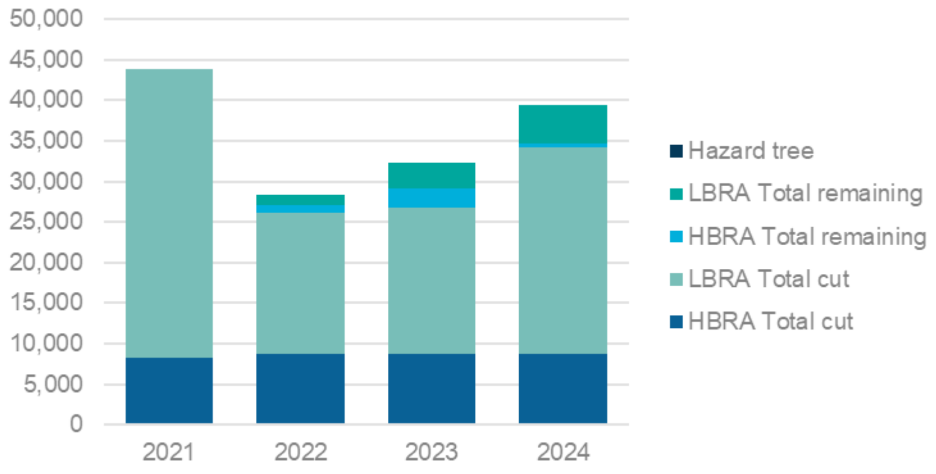
273. We have not placed any weight on the volumes included in the ELCMP as we understand that these are indicative, and do not reflect the output of the vegetation management system (VMS) or CPU's assessment of compliance.

The introduction of LiDAR has identified additional clearance issues, and which we consider provides a reasonable basis for the spans to be cut

274. In response to our request for information, CPU provided data of its vegetation program for each of the businesses. In Figure 4.5 we have separated the data into United Energy's

completed cutting (HBRA and LBRA), hazard trees and remaining. In this way we can see the total volume of work identified for United Energy's network.

Figure 4.5: Historical completion volumes



Source: EMCa analysis of United Energy data provided in Powercor's response to IR007 question 4g

275. Based on information provided in response to IR007, the total cutting program is estimated as 39,368 spans, with 34,157 cut and 5,211 remaining. We consider that this volume closely approximates the volume provided in response to our questions from its LIDAR survey,[64] and reflects a reasonable estimate of the total spans to be cut.

The total cutting volume in the updated response overstates the requirements as it does not reflect the FY25 estimate

276. The increase in cutting volumes of HBRA plus LBRA from 2022 to 2024 is presumably as a result of the introduction of additional resource capacity. Notwithstanding there may be a timing difference, we would expect to see and did not see a similarly increasing trend in the initial submission.

277. In the updated model provided in response to IR014 United Energy included an increase to the cutting volume from 27,517 to 35,635 in 2024-25. We therefore expected to see a reduction in the incremental cutting volumes to achieve compliance. However, this does not appear to have been the case, and which leads to an overstatement of the required cutting volumes.

278. A more reasonable estimate, is a program adjusted to reflect a base program of approximately 36,000 spans (as reported by United Energy) then increasing to achieve approximately 39,000 spans p.a.

The basis for the classification applied to the estimated uplift cutting volume has not been adequately demonstrated

279. CPU has assigned a classification of the cutting volume to its priority clearance codes, being 'VP1' (highest priority), 'VP2' (medium priority) and VP3 (lowest priority). CPU has also assigned categories of rectification and remaining cuts, which when considered together make up the vegetation management program. We were not provided with the rationale for the classifications and categorisations.

280. Whilst the unit rates assigned for the LBRA-rural[65] and HBRA zones were the same, and LBRA-urban were lower, independent of the priority clearance codes, we were not clear how the volumes assigned to rectification versus remaining were determined. The assumption

64 United Energy data provided in Powercor's response to IR007 question 4g

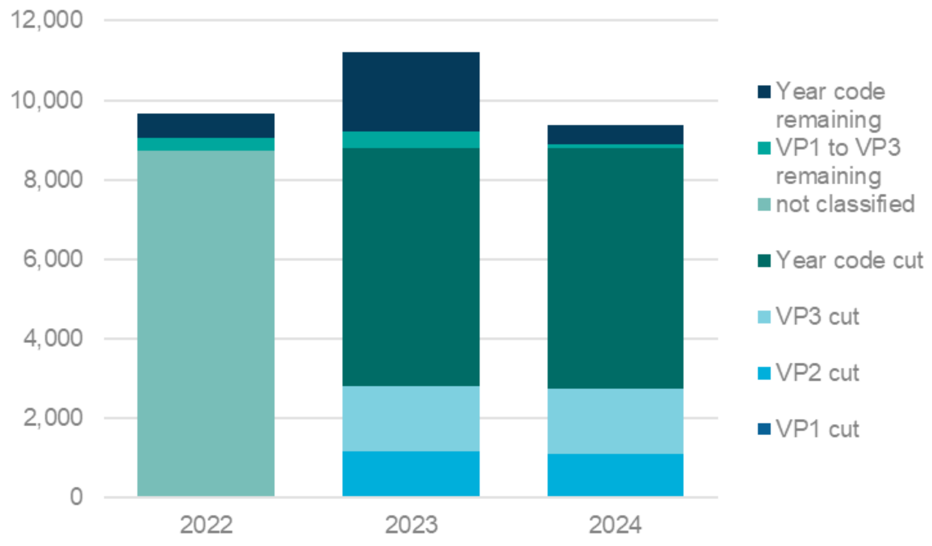
65 LBRA Rural is viewed as the same risk profile level as HBRA Rural and requires the same level of experience, labour and machinery to complete

applied by CPU is that the volume of rectification spans, attracting a higher unit rate due to the tight rectification timeframes involved,[66] will continue to increase over time.

281. As discussed previously, we would expect VP rectification cuts to decrease over time once compliance has been achieved.

282. In Figure 4.6 we illustrate the impact of United Energy's priority focus on vegetation management in the HBRA region, which shows that whilst the maintenance cutting (year code cutting) has increased over this time, the number of spans requiring VP rectification cutting has not. In fact, overall, the total number of HBRA spans have been decreasing slightly.

Figure 4.6: Volume of HBRA spans over the period 2022 to 2024



Source: EMCa derived from PAL IR007 Question 4g

283. Secondly, on the basis that CPU has prioritised HBRA first, then LBRA rural and finally LBRA urban, we would expect that remaining cutting volumes in HBRA would be low and may have been addressed in the current year.

284. Lastly, there is also an increasing trend of cuts attributed to the 'liveline' category which are some of the most expensive, and which is not explained. The classification and categorisation adopted by United Energy has not been adequately explained.

The ultimate size of the vegetation management program will be the result of additional factors, that United Energy does not appear to have taken into account

285. Whilst the 39,000 spans p.a. arising from its latest LiDAR survey provide a reasonable basis for a starting estimate, United Energy has not yet achieved compliance. This means that there are a proportion of spans identified for cutting that are not completed in any year. Whilst these may be determined as being a lower priority, they remain a compliance obligation and indicate that the program is unlikely to be optimised for resource, time or location. This means that the program effectiveness is not likely to optimal, and contractors may not be used efficiently, which impacts the costs incurred and the frequency to which a contractor may return to a span to undertake maintenance versus priority cuts. For example, whilst the growth patterns of vegetation are subject to a range of factors, in principle preventative maintenance cuts should avoid the need for a proportion of priority cuts, thereby reducing the overall program size and cost.

66 Contractors typically work in a different manner when cutting to rectification timeframes. This type of cutting is usually less efficient than planned cutting, including because contractors cannot travel down a line on the network, cutting spans sequentially to deliver economies of scale. Instead, they must program cutting to cut to the timeframes set out in the ELCMP, which does not allow for the same economies of scale.

286. Whilst United Energy appears to recognise the potential for changes to its program as a result of increasing capability, no adjustment was made to the program:

> *'We note that our forecast of incremental span volumes, and accordingly, our step change amount, does not include an allowance for any change in span volumes that may occur as a result of us continuing to increase our vegetation management capabilities to reflect changes in technology or our use of AI, such that we identify more or less spans that require cutting for compliance with the Code.'*[67]

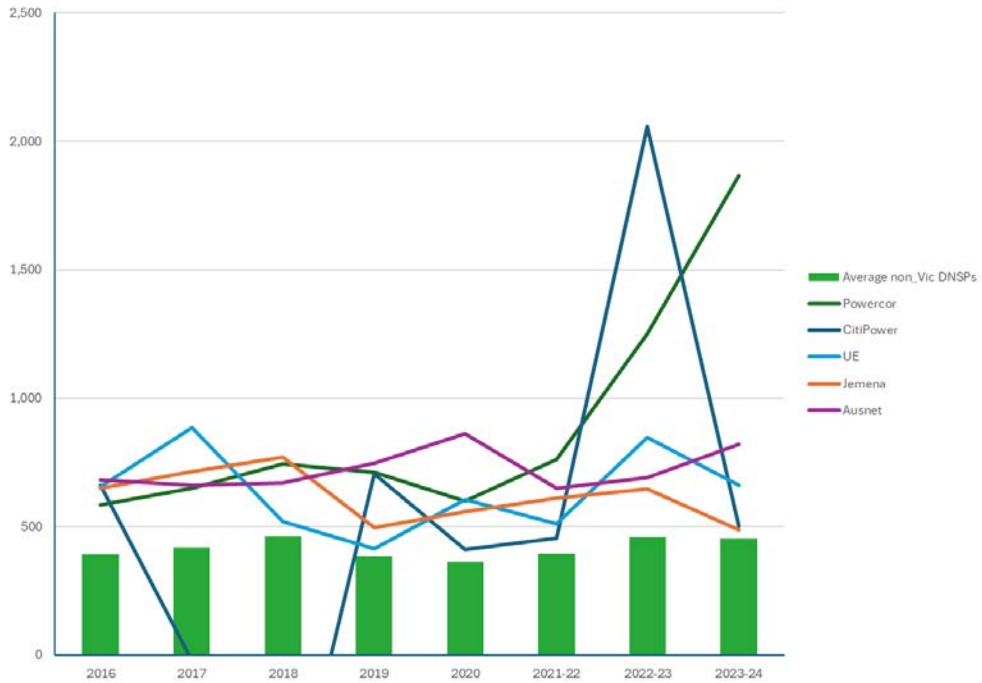
287. Given the current period of transition to compliance, it is not possible to estimate with a high degree of accuracy the likely reduction to the size of the vegetation management program, nor is this reduction likely to follow a linear trend. However, we expect that a reduction to the volume of spans estimated is likely once compliance has been achieved.

4.3.3 Assessment of unit rates

Historical unit rates have been increasing

288. We considered unit rates over time in Figure 4.7 and noticed that the Victorian DNSP unit rates were largely flat in real terms, with United Energy showing an increasing rate in the recent years.

Figure 4.7: Trend of average vegetation management unit rates - $, FY2026



Source: EMCa analysis of RIN data

289. If the cost increases that UE proposes were to be included in this analysis, the differences compared to other NEM businesses would be greater still.

CPU has applied real price escalation to its base program and uplift program

290. The build-up of CPU's modelling shows a small increase in unit rates applied to the base program expenditure. In the calculation of the expenditure required for vegetation management, we consider that as the base year expenditure is rolled-forward, the trend

[67] UE ATT 9.02 – Vegetation management step change – Jan2025 – Public, page 14

component of the opex BST methodology includes real price escalation. Therefore, including real cost escalation results in double counting of this cost.

291. The same real price escalation is also applied to the unit rates included in UE's uplift program, but as this is not included in the base year expenditure or the roll-forward, addition of real cost escalation is reasonable for this component.

292. The real price escalation applied by CPU is shown in Table 4.9.

Table 4.9: Real price escalation (percentage)

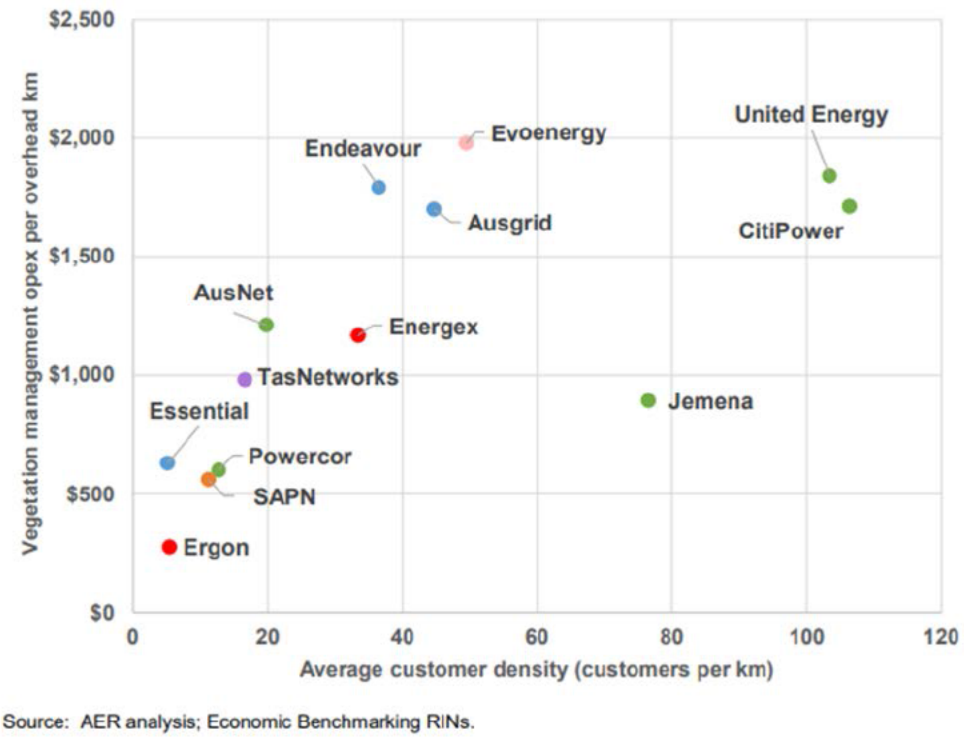
Real price escalation p.a (average)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Powercor	0.49	1.93	2.23	1.21	0.69	0.85	0.98	0.92
CitiPower	0.46	1.79	2.07	1.13	0.64	0.79	0.91	0.85
United Energy	0.41	1.61	1.87	1.01	0.58	0.71	0.82	0.77

Source: EMCa table derived from updated vegetation management step change models provided with PARL IR016, CP IR017 and UE IR014

Updated industry benchmarking places CitiPower and United Energy amongst the highest cost businesses in the NEM for vegetation management

293. In the AER's 2024 annual benchmarking report, CitiPower and United Energy are identified as having amongst the highest vegetation management expenditure per kilometre of overhead circuit line length in the NEM, whilst Powercor is identified as having one of the lowest. We reproduce the analysis relied upon by the AER in Figure 4.8.

Figure 4.8: Vegetation management opex per km of overhead length ($2023) - average 2019-23



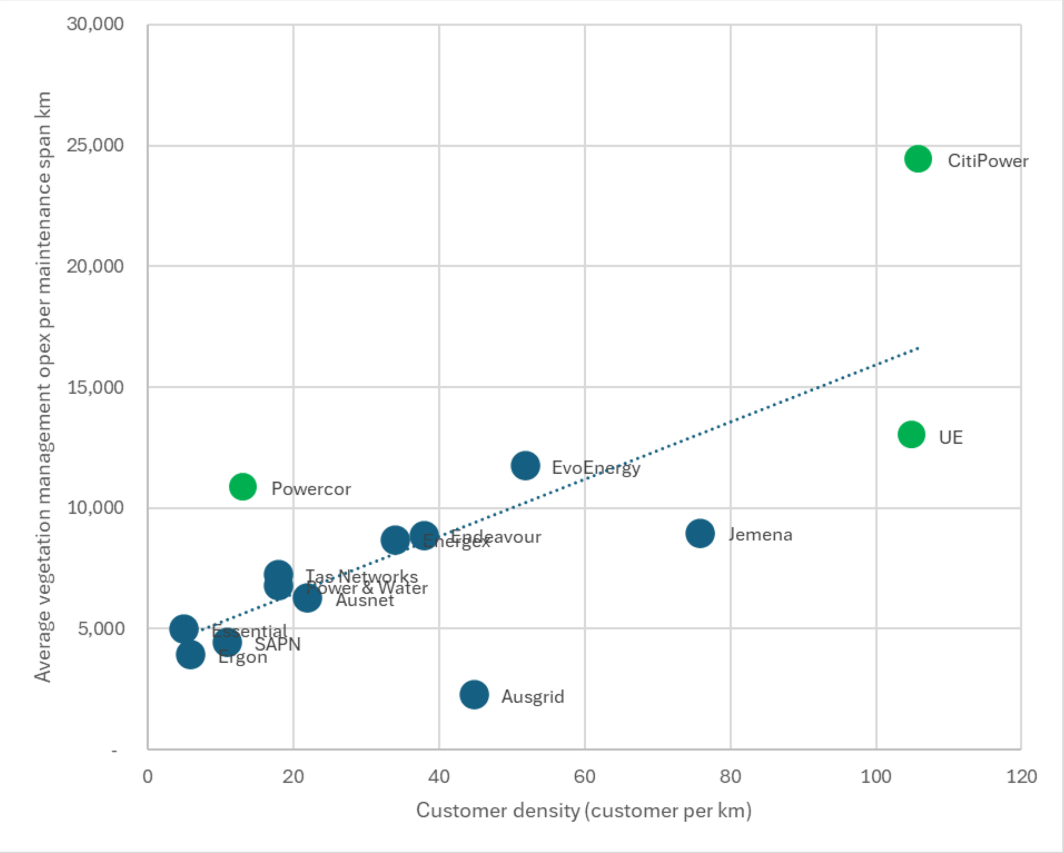
Source: AER, 2024 Annual Benchmarking Report – Distribution network service providers, Figure 19

294. The Annual benchmarking report noted difficulties in analysis into the quantity and quality of data related to vegetation management due to concerns regarding the comparability and consistency of some of the data. The report also refers to intensified vegetation

management arising from bushfire risk related regulatory obligations being a contributing factor to higher costs for Victorian DNSPs.

295. We undertook our analysis of the RIN data to understand the relationship between the three-year average vegetation management opex per maintenance span km. The results are shown in Figure 4.9. Whilst the results are similar for many of the DNSPs, the results for CPU businesses indicate a higher opex per maintenance span than as indicated in the AER benchmarking for overhead line length. We consider that this is due to a lower number of spans identified as requiring vegetation maintenance for the CPU businesses.

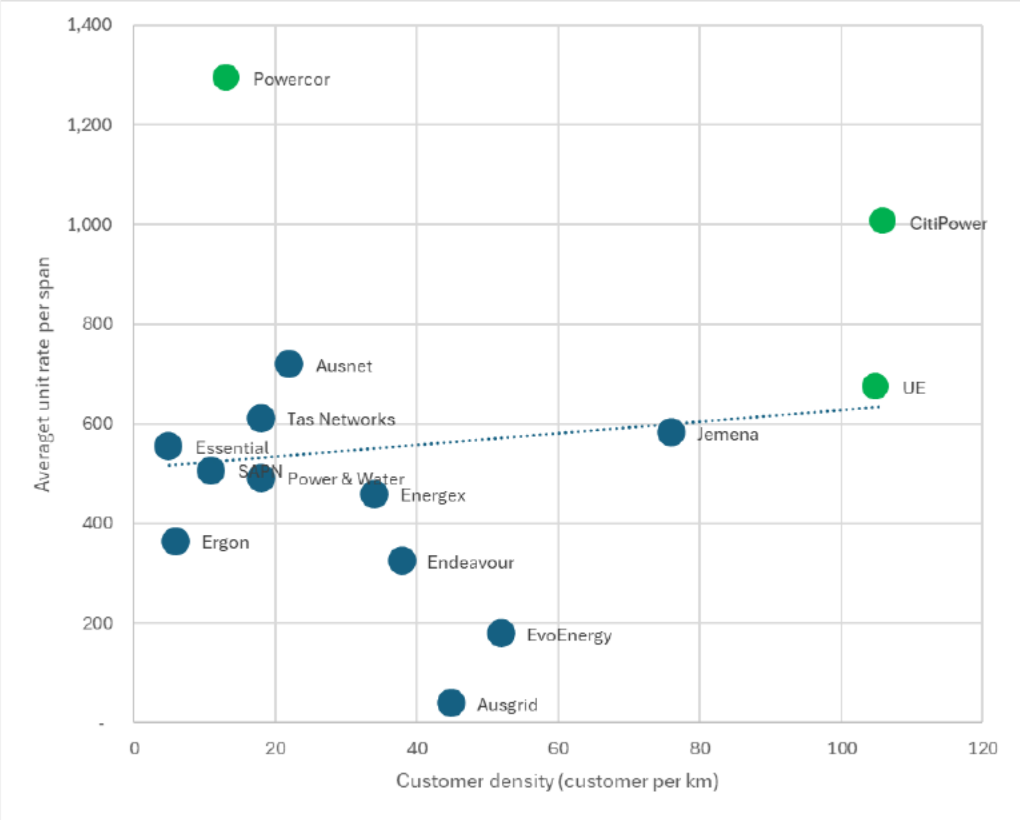
Figure 4.9: Average vegetation management opex per maintenance span km versus customer density



Source: EMCa analysis of RIN data

296. We also considered the average unit rates over the same period as shown in Figure 4.10.

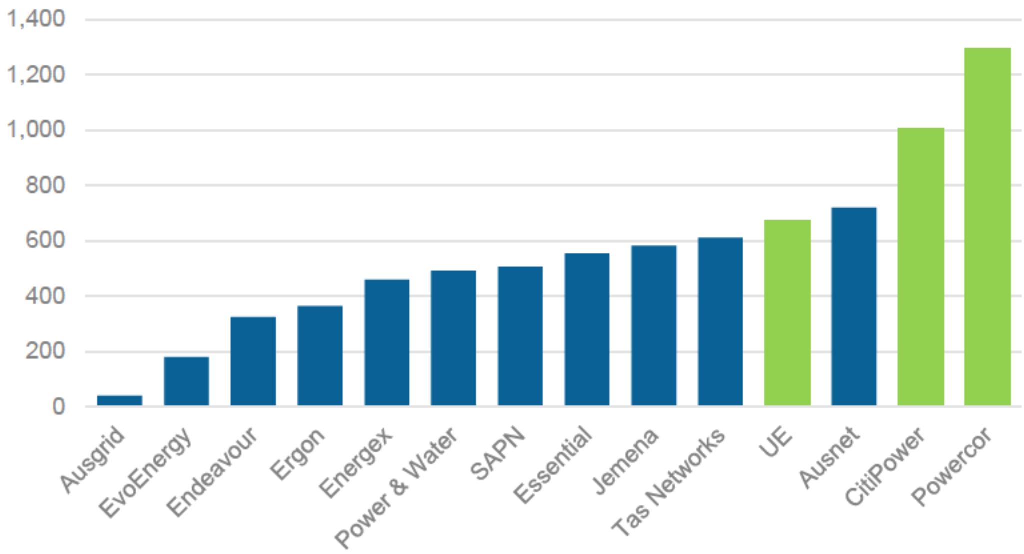
Figure 4.10: Average vegetation management unit rate versus customer density



Source: EMCa analysis of RIN data

297. Using another representation, using the same three-year averages, we see in Figure 4.11 that United Energy are at the top-end of historical unit rates.

Figure 4.11: Comparison of 3-year vegetation management unit rates (FY22-FY24) - $, FY2026



Source: EMCa analysis of RIN data

4.3.4 Assessment of additional matters

United Energy has included an increase to its hazard tree program

298. United Energy states that it has included additional expenditure of $10 million to increase the hazard tree inspection cycle from every five years to every three years. United Energy states that it is currently non-compliant with its ELCMP regarding hazard tree inspection cycles, which requires a three-year cycle.

299. Within its model, United Energy calculate the uplift in its hazard tree program (in addition to its base program) as being the difference between a hard coded value of $3 million p.a. and the BAU hazard tree program in 2022-23, then increased for real price escalation since that time to 2026-27, then increased for the remainder of the next RCP by real price escalation. A comment in the model refers to the $3 million value as being an *uplift by 2 times the 2022/23 actual Hazard tree cutting cost of $1.4m (CAT RIN 2.7.2)* without further explanation.

300. The basis for this calculation method is not provided, and we consider this is insufficient justification for the proposed step increase.

United Energy has included an increase in its LiDAR costs

301. United Energy states that it has not proposed an increase in its forecast contractor liaison costs to manage its contractors, in fact, it has not recorded this as a separate line item in its historical costs.

302. United Energy refers to an increase in the LiDAR inspection costs of $2 million to reflect the fact that United Energy will be utilising increased capabilities to a greater extent than previously. The LiDAR costs are hard-coded, proposed to commence in FY25 based on the assumptions as shown in Table 4.10, and are increased annually using price escalation.

Table 4.10: United Energy LiDAR cost assumptions

Cost item	Cost ($m Dec23)	Cost assumptions
LiDAR capture	1.96	Costs include pilot wages, helicopter maintenance, helicopter fuel, rental of hanger
LiDAR data classification	Nil	Costs include LiDAR lab, consultancy
Total	**1.96**	

Source: CP MOD 8.02

303. The costs for LiDAR are already included in the base year expenditure, and United Energy has not adequately justified any further increase. We consider the annual increases using price escalation are already included in the productivity growth factors of the opex BST methodology, when applied to the base year expenditure and do not need to be applied separately.

We consider that additional efficiencies are likely to come from new delivery capability, systems and processes

304. With the increased data available from LiDAR, we expect CPU to leverage greater efficiency in delivery of its vegetation management program. During our onsite discussions, we heard of examples where CPU was seeking to mitigate the highest risk areas first, as it increased capability to meet a higher volume of vegetation spans requiring treatment that it had previously undertaken. This will lead to a level of inefficiency as the work schedule may not be optimised.

305. As the program stabilises, and the delivery capability increased, there is greater potential to increase the efficiency of work scheduling. As cutting volumes are increased, there may be spans identified that require less frequent cutting than CPU has assumed. The introduction of Artificial Intelligence (AI) may also result in reductions to the cutting volume. Whilst these factors are not certain, it is more likely than not that efficiencies in program delivery will be made over the duration of the program, and which United Energy has not made provision for in its opex step change forecast.

306. It is generally recognised that the introduction of LiDAR and advanced analytics increases compliance and reduces opex related to vegetation management.[68] United Energy states that it has already delivered benefits from LiDAR and which we would expect to continue to be realised in the next RCP including:

> *'The introduction of LiDAR, and our advancements in its application, have significantly improved our vegetation management practices and processes over the course of the 2021–26 regulatory period. These improvements have greatly enhanced our ability to identify existing non-compliances with the Code clearance requirements or non-compliances that are expected to arise prior to the next inspection and cutting cycle (necessitating cutting in order to maintain compliance at all times), and our ability to do so in a timely manner.'*[69]

307. Sources state that '*Optimising these works programs by leveraging emerging technologies and advanced analytics can save utilities 10 – 15 per cent of their annual vegetation management spend.*'[70] We estimate that the efficiencies that CPU can achieve are likely to be of a similar order, and may be reflected across multiple regulatory periods recognising the current focus on compliance.

4.4 Findings and implications of the proposed opex step change

4.4.1 Summary of findings

Assessment against step change criteria

There has been no change to regulation obligations

308. We firstly considered whether the proposed step change met the requirement of the opex step change criteria. Based on CPU's submission, there has been no change to its regulatory obligations. The electric line clearance requirements have not changed since the commencement of the current RCP, and CPU has not advised of any change to its electric line clearance obligations that are likely to positively or negatively impact the expenditure requirements in the next RCP.

An increase in enforcement does not constitute a change to obligations

309. CPU argues there has been a change in 'accepted practice' of the current electric line clearance requirements, as evidenced by the increase in enforcement by Energy Safety Victoria. Given there has been no change to the obligations, we do not consider that changes to enforcement practices meet the opex step change criteria.

---

68 ENA 2020, Data opportunities for smarter networks accessed at https://www.energynetworks.com.au/resources/reports/data-opportunities-for-smarter-networks/

69 UE ATT 9.02 – Vegetation management step change – Jan2025 – Public, page 2

70 Based on an article from ESRI accessed at https://esriaustralia.com.au/blog/how-landscape-vegetation-management-changing

Assessment of the need for a material increase in expenditure

LiDAR data used as part of improvements to vegetation management has identified a volume of spans to be treated that exceeds the current program to meet its compliance obligations

310. The primary driver of United Energy's proposed increase arises from new information provided through the application of LiDAR technology that has identified vegetation encroaching the minimum clearance space for a large number of spans, and which exceeds the number of spans requiring cutting previously identified under its visual inspection method. United Energy has been progressively addressing a higher volume of vegetation spans with the view of achieving a state of compliance (based on its LiDAR data) with the electric line clearance regulations by FY29. United Energy has subsequently advanced the target year of compliance by one year, to FY28.

United Energy has already achieved a material increase to its cutting volumes in FY25

311. In responding to our request to update its estimate for the program to be completed in FY25, United Energy stated that the completed vegetation management spans had increased from around 28,000 to 36,000.

The ultimate size of the vegetation management program will be the result of additional factors, that United Energy does not appear to have taken into account

312. Whilst the 39,000 spans p.a. arising from its latest LiDAR survey provide a reasonable basis for a starting estimate, United Energy states that it has not yet achieved compliance. Therefore, the program effectiveness is not likely to optimal, and contractors may not be used efficiently, which impacts the costs incurred and the frequency to which a contractor may return to a span to undertaking maintenance versus priority cuts.

313. Given the current period of transition to compliance, it is not possible to estimate with a high degree of accuracy the likely reduction to the size of the vegetation management program, nor is this likely to be a linear trend. However, we expect that a reduction to the volume of spans estimated is likely once compliance is achieved.

United Energy has not correctly taken account of the BST forecasting method for opex

314. We consider that a bottom-up build of its requirements is an appropriate forecasting method to understand the vegetation management expenditure, however United Energy's application of the forecasting method does not adequately consider the BST method for forecasting overall opex when considering whether a step change is required. This includes taking account of existing provisions for output, price and productivity factors.

Basis of forecast step change is likely to overstate the required expenditure

315. United Energy has not demonstrated that the proposed forecast of its expenditure requirements is efficient as the proposed volume and unit costs are overstated. We base this on:

- Indications from data provided by CPU that the LiDAR program has identified a vegetation management program that is smaller than CPU has proposed to achieve compliance,
- The estimated cutting for 2024-25 is higher than the estimate relied upon by United Energy to establish the requirements for each of the businesses, and when combined with a smaller total volume to achieve compliance results in a reduced total expenditure,
- Inadequate justification for proposed uplifts in hazard trees and slashing,
- Unit rates are amongst the highest in Victoria, and higher than the revealed costs, without sufficient justification,

- Relatively new application of LiDAR technology and spatial analytics, which amongst other things will require several years to be refined including updating of the VMS to establish a stable vegetation management program, and
- Once stabilised the program can be expected to enable efficiencies to be realised and which are not currently included in the forecast of its opex requirements, and which we consider can be material.

316. As a consequence of the issues we have identified, we consider that the opex that United Energy considers that it will require is materially overstated.

Benchmarking of United Energy’s historical costs indicate that it is higher than other NEM DNSPs

317. In our review of vegetation management costs at a total level, as a proportion of total opex and average unit costs, the historical costs for United Energy indicate that it is amongst the highest in the NEM.

318. Using these measures, accounting for potential differences between Victorian and non-Victorian businesses, the costs are higher than an efficient level. If the proposed increases are included in this analysis, as are being proposed by the CPU businesses, the differences to other NEM businesses will widen further.

319. CPU has not provided a rationale for why it is incurring costs that are materially higher, why these higher rates are reflective of an efficient level or what measures are in place, or being put into place, to reduce the costs to an efficient level.

Adjustment for a range of uncertainty and efficiency factors is likely to reduce the need for an opex step change

320. We consider that whilst CPU businesses are building capacity and capability to meet their collective compliance requirements, the opportunities for competitive forces to apply downward pressure on prices from the market are lessened. However, over time, we consider there should be opportunities for pricing to moderate, and then to improve. This is also supported by our own benchmarking analysis.

321. We further consider that the program, once stabilised, offers United Energy an ability to reduce not only the costs but potentially the volume of spans to be treated through greater targeting of maintenance cutting practices.

Application of sensitivity analysis reduces the need for additional opex to zero

322. After moderation for the modelling issues that we found, and which reduced the required opex significantly, we also subjected the program to changes to the volume, unit rates and efficiency factors. The goal was to understand whether, given the uncertainty of these factors and materiality of the issues we found (such as identified in the benchmarking) would remove the need for additional opex.

323. We found that the need for additional opex was very sensitive to relatively small changes in these factors, meaning that relatively small reductions to volume or costs (towards the benchmark cost) or increases in efficiency removed the need for the step change. The analysis indicated to us that United Energy had a reasonable allowance for vegetation management opex included in the application of the FY25 base year to the BST methodology, taking account of trend factors.

4.4.2 Implications for proposed opex step change allowance

324. We consider that United Energy’s proposed opex step change for vegetation management is not a reasonable forecast of its expenditure requirements for the next RCP.

325. We are satisfied that additional improvement to vegetation management activities is required for United Energy to achieve compliance in the next RCP, however we consider that a number of factors in United Energy’s forecast are not reasonable assumptions.

326. We made adjustments to United Energy's forecasting methodology, to the extent that it formed the basis of United Energy's forecast and which we consider to be not justified or overstated, including:

- Adjustments to correct modelling of the base year opex
- Adjustment to the forecast volume of tree cutting and hazard tree programs that has been proposed, including to remove those elements that have not been sufficiently justified
- Adjustment to the unit cost basis for the proposed forecast
- Adjustment to align the forecast with the estimated 2024-25 volumes as included in information provided by United Energy, and
- Adjustment to account for a productivity and efficiency benefit each year following from the application of LiDAR and delivery efficiencies to be realised from the year in which compliance is achieved.

327. Adjustment of these assumptions, which we applied in various combinations, leads us to conclude that United Energy does not require an opex step change.

APPENDIX A – CITIPOWER, POWERCOR AND UNITED ENERGY'S ECONOMIC MODELLING OF PROPOSED ELECTRIFICATION PROGRAM

A.1 Introduction

328. CitiPower, Powercor and United Energy have each provided a model that they have used to (a) define a program of work to address the forecast voltage impact of electrification and (b) to support their claims that this program is economic.[71] These models are common in approach. For illustrative purposes, we refer here to the Powercor model, noting that our findings apply to all three.

329. Powercor provided an initial model along with its regulatory submission, in January 2025. While this model purports to be based on identifying a program of economic interventions, it does not provide an overall economic assessment, for example, in the form of an NPV for the proposed program. Further, the model is largely comprised of sheets of hard coded data, one of which is over 80,000 rows, but which provide little insight as to how the model identifies such economic interventions or their net economic benefits.

330. We asked for a version of the model that includes formula that would then allow us to trace the modelling relationships and Powercor provided such a model in April 2025. Our observations here apply to the later version of the model.

A.2 Summary of electrification model objectives and approach

A.2.1 Model descriptive information

331. Powercor provided a document that describes its *Customer Electrification Forecasting Methodology* (PAL Att 2.01) and we rely largely on this document for our understanding of its approach and its associated customer-driven electrification model.

332. Powercor also provided a document with its regulatory submission with a file name '*Detailed customer electrification forecasting methodology.*'[72] However the cover title of this document is '*Hosting Capacity Study – Network wide HV & LV Scenario based Hosting Capacity Analysis*.' We find that this document essentially describes the process by which technical hosting capacity and voltage have been simulated and forecast for ten years at a feeder level. This model provides outputs which include the forecast amount of energy supplied at over- and under-voltage levels and which it values at CECV (for over-voltage) and VCR (for under-voltage)[73]

333. Our summary description of the electrification model is based on our review of Powercor's methodology report (att 3.01) and from examining the model itself. We focus our description on the elements that appear to drive the output that Powercor has relied on, and our summary description is also therefore not a complete description of the model.

A.2.2 Our summary understanding of the model

71 PAL MOD 3.31

72 PAL attachment 2.04

73 As above, page 10: Definition of '*load_exceeding_normal_een_vcr*'

334. The model seeks to establish a program of LV augmentation works, that meets a target level of service. For this purpose, the model establishes and undertakes calculations for three options: to improve, maintain, or reduce service levels.

335. In the model, an HV clustering intervention is assumed as a given, and the cost and avoided LV augmentation from this are hard coded. Assumed benefits of avoided LV augmentation from non-network solutions (which we assume to be primarily flexible imports) and from DSS overlap are similarly hard coded.

336. The model then undertakes a feeder-level assessment to calculate the most economic proactive LV augmentations in each year, to maintain the target level of service, choosing from the options of DSS offload or reconductoring.

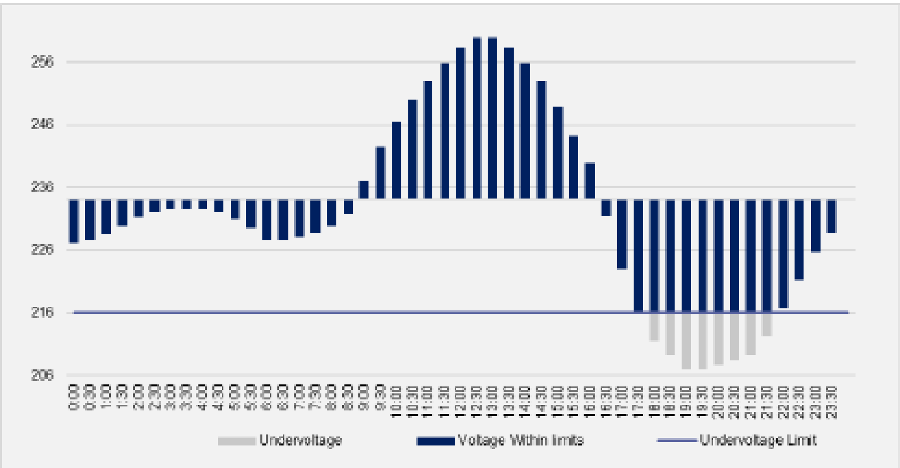
337. The model calculates an economic value for the alleviated supply resulting from the 'chosen' interventions, as the product of the modelled supply that is brought back within the compliant voltage levels and the VCR.

A.2.3 Powercor's modelling of the economic value of undervoltage supply

338. Powercor provides the diagrams shown in figure A.1 to illustrate how its half-hourly simulation of voltage is transformed to an assessment of 'energy at risk'.

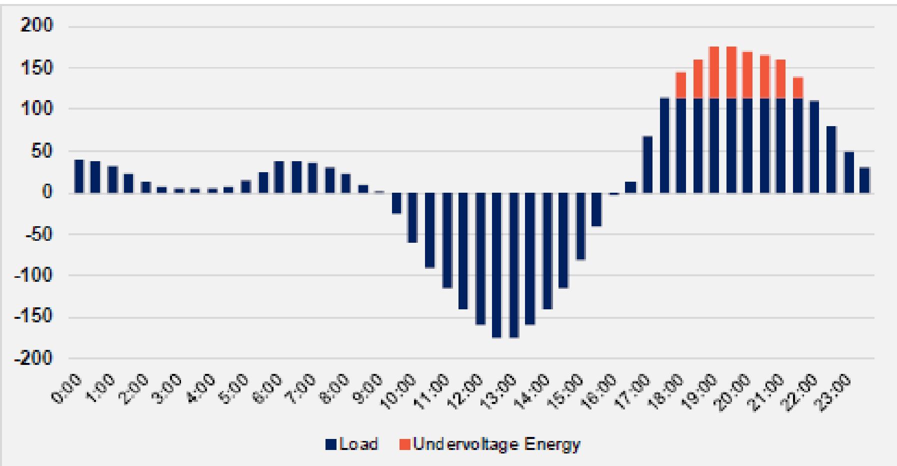
Figure A.1: Powercor example of voltage simulation and assumed 'energy at risk'

FIGURE 18 EXAMPLE VOLTAGE FLOW (V)



To calculate energy at risk, results are produced in kWh of load, shown in Figure 20

FIGURE 19 EXAMPLE UNDERVOLTAGE ENERGY AT RISK (KWH)



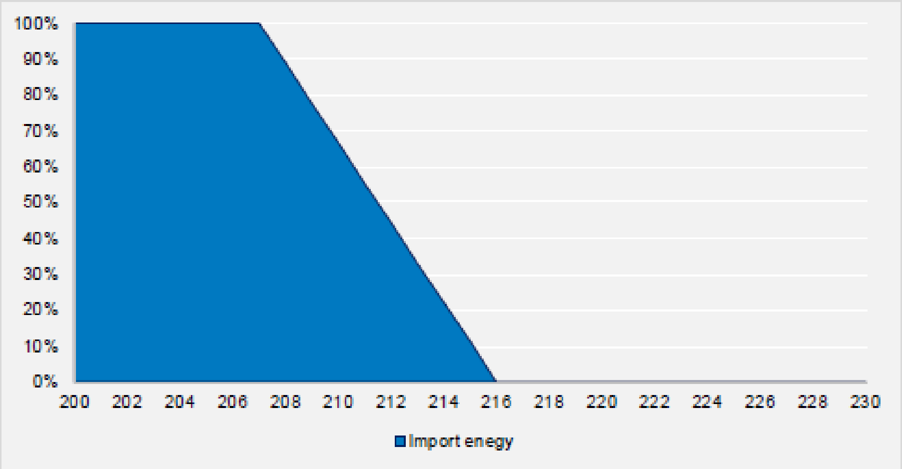
Source: PAL Att 2.01, figures 18 and 19

339. In Powercor's modelling, the value of the energy at risk is scaled linearly from 216V to 207V, below which it is assumed to be entirely curtailed, with this curtailment valued at VCR.

Figure A.2: Scaling of assumed energy lost to undervoltage

FIGURE 20 SCALING OF ENERGY LOST TO UNDERVOLTAGE (V)

This scaling is applied to the load_undervoltage_normal_kwh as described in section 5.1



Energy at risk is then multiplied by the Value of Customer Reliability (VCR) to provide a total dollar cost, at Equation 1.

Source: Pal Att 2.01, figure 20

340. Powercor's model simulates these forecast outcomes at the interval-level for each feeder, for 10 years

A.3 Sensitivity analysis

341. After investigating model logic, to the extent that it is present in the model provided, we undertook sensitivity analysis on two assumptions that we observed to be key drivers of model output.

342. The main driver in the model is, as expected, the target (voltage) service level. We tested for sensitivity to this input and, as we show in Table A.1, we find that for Powercor if this parameter is changed to target a 96% rather than the current 97%, then the required proactive program size would reduce from $72.7m to $15.4m. With this change, almost all of the required expenditure would be in the final two years of the next regulatory period.

343. As we describe in section 3.4, Powercor has not justified the use of VCR to value the cost to consumers of supply at a voltage below the lower voltage limit. We consider that this significantly overstates this cost, and therefore significantly overstates the benefits of alleviating such supply. While we are not aware of any well-founded estimate for such a value, we tested the sensitivity of the model by applying a scaling factor of 0.1 to this value. As shown in Table A.1, this marginally increases the model's estimate of the required LV augmentation cost but reduces the NPV result to less than one-tenth of its previous value.

Table A.1: Sensitivity analysis from Powercor economic modelling of proposed customer-driven electrification program. Capex and NPV ($m real 2026)

	FY27	FY28	FY29	FY30	FY31	TOTAL	*NPV*
Powercor analysis	5.5	18.4	7.9	20.0	20.9	**72.7**	*1,196.4*
EMCa sensitivity analysis 1: Reduce compliance from 97% to 96%	-0.3	-0.3	1.1	6.3	8.6	**15.4**	*524.2*
EMCa sensitivity analysis 2: As for (1) plus VCR scaling factor of 0.1	-0.3	-0.3	1.2	6.8	10.0	**17.4**	*48.4*

Source: EMCa sensitivity analysis, from PAL MOD 3.31

344. As a further observation, the model as provided by Powercor calculates approximately twice the amount of benefit occurring in the four years modelled after the end of the next period, compared with the benefits modelled within the next period.

A.4 Our conclusion on Powercor's electrification program economic model

345. Our investigation of the model shows its extreme sensitivity to the following assumptions:

- The 'required' size of the program is highly sensitive to the target level of compliance. While Powercor has defined its preferred option as maintaining the current level of compliance, we find that a small relaxation of this assumption (while still within its Functional Compliance obligations) would reduce the scale of the program that the model suggests, to one-fifth of the amount that Powercor proposes, and
- The economics of the program are highly sensitive to the assumed per-kWh benefit to customers of alleviating undervoltage supply, for which Powercor uses VCR.

346. Finally, we note that the economic model is based on input from the feeder-level voltage simulation technical modelling that has been conducted for Powercor. As we note in section 3.4, the methodology described for this appears reasonable, however it too is based on significant assumptions regarding electrification uptake and future customer usage behavioural patterns in an evolving sector that presents a challenge to any such forecasting to 2031.

APPENDIX B – ECONOMIC ASSESSMENT METHODOLOGY ISSUES

B.1 Introduction

347. For projects that CitiPower, Powercor and United Energy have sought to justify on economic grounds, they provided supporting economic models. In a number of instances, we find one or other of the following issues, which appear to be systemic.

B.2 Economic assessment utilisation annuitised capex as a proxy for capex

348. Whereas a standard Discounted Cashflow (DCF) analysis assesses the NPV of a project over a given analysis period, taking account of the forecast capex, opex and benefits in that period, we find that the CPU businesses have commonly applied an approach in which the capex is first annuitised, and then the NPV for the project is assessed taking account of this annuitised value as a proxy for capex, rather than the capex itself.

349. Where the life of the relevant asset is the same as the analysis period, it can be shown that this alternative method yields the same result. However, in instances where the asset life is longer than the analysis period, this alternative method overstates the economic benefit and this is typically the case in models provided by the CPU businesses.

350. In table B.1 we illustrate this result with an example in which the assumed life of the proposed asset is 50 years. With the assumptions we have applied, the project would have a negative NPV (minus $3.68m). However, under the 'annuitised cost' method that has been commonly used in CPU economic models, the project presents as having a positive NPV (in this example, $6.17m).

Table B.1: Illustrative example of overstatement bias for NPV calculated with annuitised capex

Parameters	***Value***	***Unit***
Capex	25	*$m*
Asset life	50	*years*
Assumed benefit	1.5	*$m/year*
Analysis period	20	*years*
Discount rate	3.50%	*%*

Summary results	**PV capex**	**Annuitised capex**	**PV annuitised capex**	**PV Benefits**	**NPV**
Discounted cashflow method	-$25.00	N/A	N/A	$21.32	**-$3.68**
Annuitised capex method	N/A	-$1.07	-$15.15	$21.32	**$6.17**

Source: EMCa

351. We find that CPU's common application of this method for calculating the NPV of the projects that it proposes, results in a systemic overstatement of their net economic benefit.

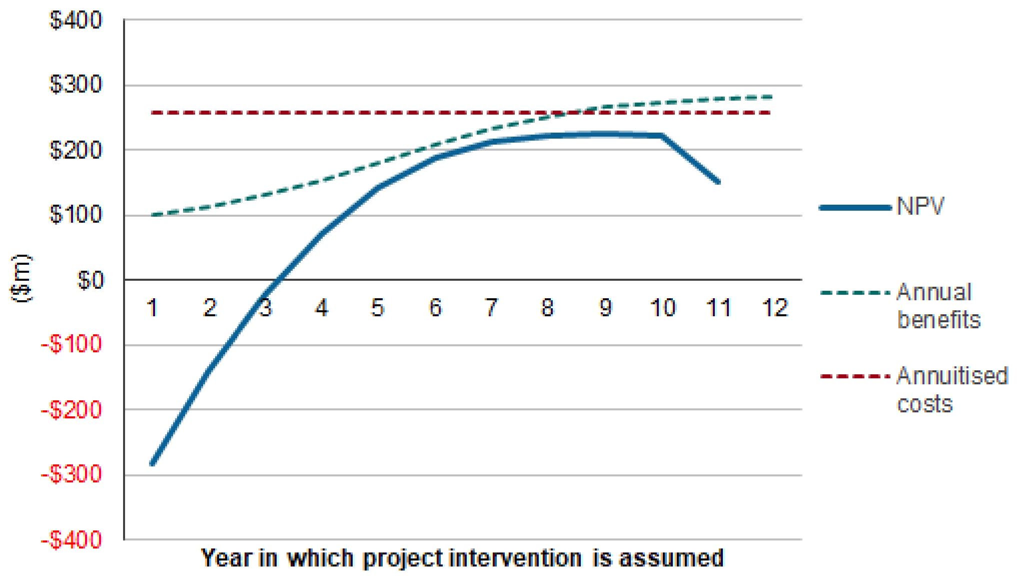
B.3 Economic timing

352. It is frequently the case in economic assessments in support of electricity infrastructure investments, that there is an escalating counterfactual economic cost (including an escalating risk-cost), and which the proposed investment is intended to address. This increasing cost for the counterfactual therefore defines the benefit that can be achieved by the proposed solution.

353. The question of identifying the optimum economic timing for the solution was addressed by AER in an industry practice application note.[74] In short, under microeconomic theory, it can be shown the optimum timing occurs when the annual benefits exceed the annuitised cost.

354. The illustration in figure B.1 shows a project for which benefits (green) increase over time. The annuitised cost of the project is shown in red. The blue NPV line shows the NPV for this project as a function of when the project is assumed to be undertaken – that is, it reflects a series of timing options for the project, if undertaken in any year up to the eleventh year.

Figure B.1: Illustration that defines the optimum timing for an investment[75]



Source: EMCa (illustrative example only)

355. As can be seen from the graph:

- If undertaken prior to year 3, the project would have a negative NPV.
- If the project was undertaken in any year from year 3 to year 7, the annual benefits are less than the annuitised cost and it would therefore not be economic to undertake the project.
  - This is the case despite the project having a positive NPV if undertaken after year 3. This result occurs because the net benefits beyond year 7 in this example more than offset the net costs before that (in the NPV calculation). But it remains the

74 AER, Industry practice application note; Asset replacement planning, January 2019. See Figure 1 (page 37)

75 Analysis in this worked example is based on an asset that is assumed to last, and therefore provide benefits for, 20 years from the date that it is commissioned. Benefits therefore continue beyond year 12 but are shown only to that year in order to focus on the timing decision.

case that the project is not economic if undertaken in the period up to year 7 because the benefits do not exceed the cost ***in that period***.

- From around year 8, the example shows that the annual benefits exceed the annuitised cost, demonstrating that the project is then justified. The graph shows that this timing also provides the highest NPV of the timing options considered.
- If the project was deferred beyond year 8, the NPV declines, because the net benefit of undertaking the project (as evidenced by the green benefits line exceeding the red annuitised cost line) is lost.

356. We provide this refresher on economic timing as we observed in the course of our assessments numerous instances in which a positive NPV was presented as evidence that a proposed project was justified within the next regulatory period, without having tested optimum timing in accordance with the AER practice note.

357. We consider this especially problematic where economic modelling of hundreds or thousands of potential interventions are simulated to determine a scope of work by applying a logic goal that progressively tests each potential intervention year-by-year for a positive NPV. If the modelled goal is set only to identify when each potential intervention would first have a positive NPV, and then to include each such intervention in the proposed work program, then the modelling will almost certainly be biased towards including such interventions prematurely and therefore over-estimating the extent to which such interventions are economically justified within the period.

APPENDIX C – REVIEW OF HISTORICAL PERFORMANCE

C.1 Summary

358. We observe that the network performance has generally been improving, along with asset performance despite the impact of several major weather events across Victoria. For United Energy's network:

- Average reliability performance is generally improving, which suggest that United Energy's asset management process has improved service levels
- According to the safety regulator ESV, the number of all asset failure incidents are lower than the long-term average, but number of fires are higher
- Rate of line clearance non-compliance has increased, and the regulator is concerned by a worsening long-term trend
- Network utilisation has been slightly decreasing over the last 10 years, and remains higher than the DNSP average

359. We observe that the actual expenditure has historically tracked lower than the forecast expenditure. Issues such as increasing labour and material costs, and deferral of works that occurred during the current RCP also have implications for the forecast in the next RCP, and we consider the implications in the projects and programs that we have reviewed. For United Energy's network:

- Capex delivery performance is subject to a range of factors, with actual capex lower than forecast capex
- United Energy expects the net capex to marginally exceed the capex allowance for the current RCP
- Over the last 5 years, actual opex is lower than forecast opex resulting in an overspend against the opex allowance, however much closer in last two years

C.2 Current period service performance

Average reliability performance is generally improving, which suggest that United Energy's asset management process has improved service levels

360. The AER noted that, on average, reliability had been improving for customers. Figure C.1 shows average outage duration and outage frequency data for United Energy based on the AER network performance report data. This indicates a decreasing outage duration and outage frequency.

Figure C.1: Comparison of United Energy historical outage duration and outage frequency

Source: AER Network performance report

361. Outage frequency may be considered to be an indicator of the effectiveness of asset management, to the degree that the trend is linked to preventable events and not actions of extreme weather or third parties. We make further observations as it relates to the scope of our assessment of the expenditure as relevant.

According to the safety regulator ESV, the number of all asset failure incidents are lower than the long-term average, but number of fires are higher

362. ESV publish the number of serious electrical incidents reported to Energy Safe by United Energy during the 2022–23 period, in its 2023 safety performance report on Victorian Electricity networks. The 2024 report was not available at the time of our review.

363. According to ESV, the most common incidents on the United Energy network in 2022–23 were:

> *'vehicle impacts, connection faults, other contact events and tree contact. One of these items is within the full control of the United Energy (connection faults), tree contacts are partially within its control and the other two are outside its control.'* [76]

364. The asset failure incidents are decreasing for most asset types with material reductions in connection assets as shown in Figure C.2. ESV state that is commencing a review of the conductor and connection management practices of all distribution networks in 2023–24.

365. The number of fires were higher than the long-term average. The most common causes of fire incidents as shown in Figure C.3 were:

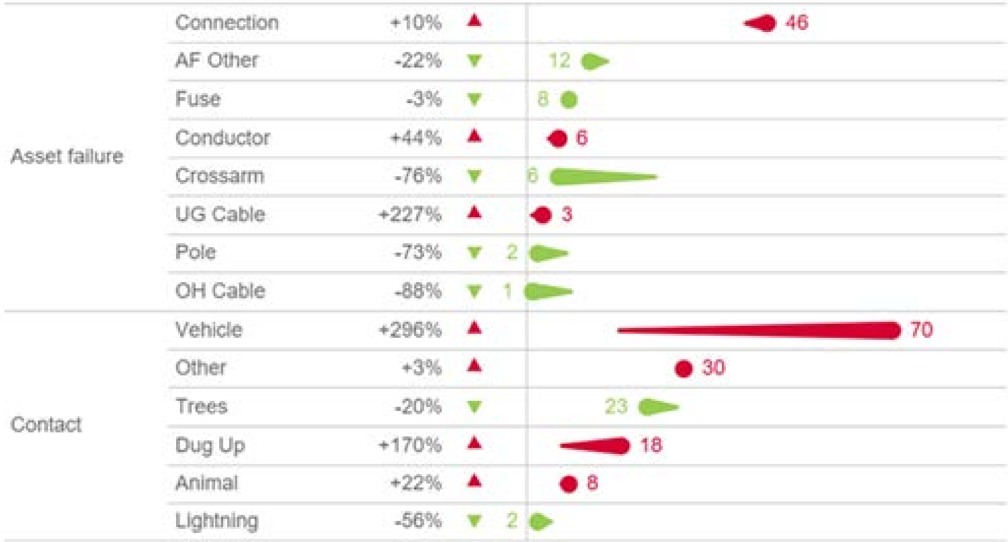
> *'Connection faults, tree contact, animal contact and vehicle impacts were the most common causes of network-related fires. One of these is within the full control of United Energy (connection faults), two are partly within its control (tree and animal contact) and vehicle impacts are largely outside of its control. Fires are higher than the long-term average in six categories and lower (or zero) in eight categories.'* [77]

---

[76] ESV, 2023 Safety Performance report on Victorian Electricity Networks

[77] Ibid

Figure C.2: Incidents on the United Energy network



Source: Source: ESV report, Figure 49

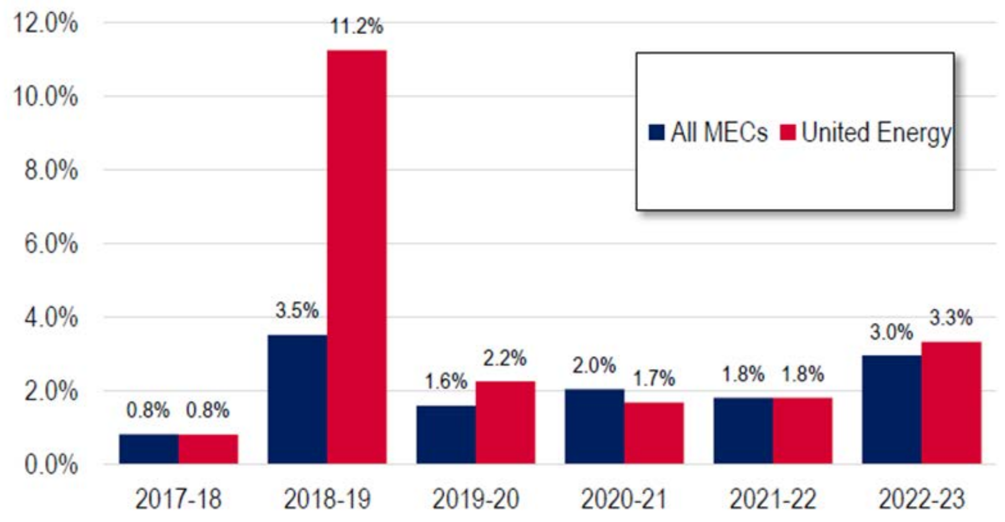
Figure C.3: Incidents on the United Energy network resulting in ground fires

Source: ESV report, Figure 50

Rate of line clearance non-compliance has increased, and the regulator is concerned by a worsening long-term trend

366. ESV also undertake inspections of the network to determine any spans that may not be compliant with the electricity line clearance regulations. The trend in major non-compliances is shown in Figure C.4. A major non-compliance is regarded as a high-risk situation where vegetation is touching, is growing through, or could soon touch, uninsulated conductors. This has resulted in greater use of ESV's enforcement option to issue infringement notices and fines.

Figure C.4: Rate of United Energy major non-compliances (HBRA and LBRA)



Source: ESV report, Figure 48

367. We observe an increase in the most recent rate of major non-compliances in United Energy, and an increasing trend over time. ESV state that it is concerned that:

> *'Since 2017–18, the overall rate of non-compliant vegetation on the United Energy distribution network has been getting progressively worse in HBRA (Figure 9). While the rate of major non-compliances in HBRA improved between 2020–21 and 2021–22, in 2022–2023 United Energy recorded its worst major non-compliance rate since Energy Safe commenced compiling electric line clearance inspection data in 2017–18 (Figure 9).*
>
> *The rates of non-compliance and major non-compliance in LBRA has increased for two consecutive years (Figure 10).*
>
> *Significant improvement is needed to address the rates of non-compliance affecting the United Energy HBRA network. We are closely monitoring the performance of United Energy through its safety regulation programs.'*[78]

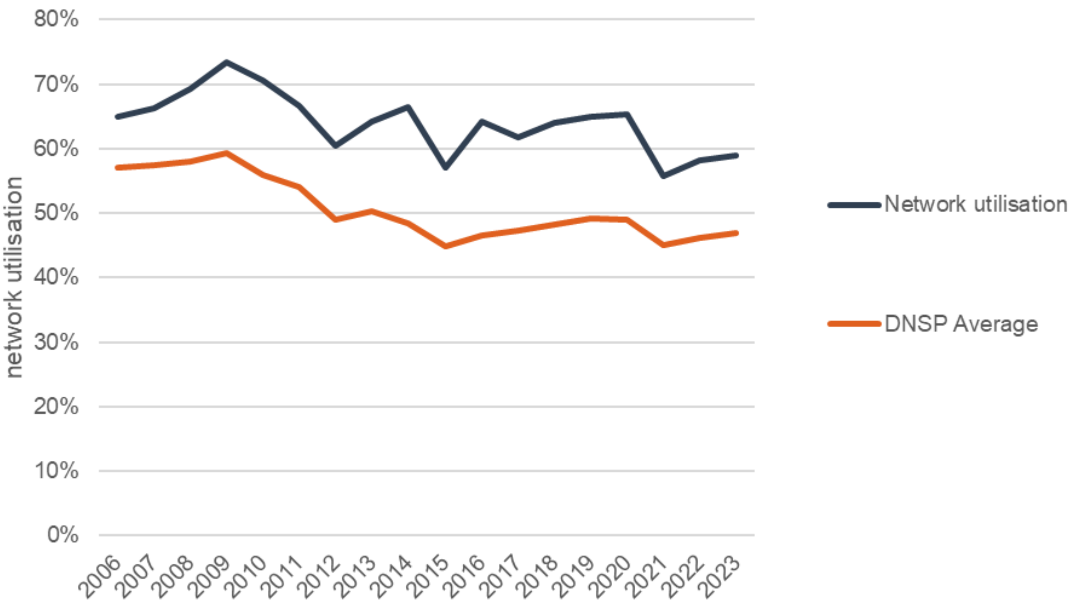
Network utilisation has been slightly decreasing over the last 10 years, and remains higher than the DNSP average

368. Network utilisation is an indicator of the capacity of the electricity network, and whilst does not account for localised constraints or complexities associated with the two-way flow of energy, is a coarse measure of the ability for networks to make greater use of the network assets.

369. Figure C.5 shows that United Energy's network utilisation has been decreasing over time and continues to have a network utilisation above the DNSP average.

[78] Ibid

Figure C.5: Comparison of United Energy historical network utilisation versus DNSP average



Source: AER Network performance report

C.3 Current period expenditure performance

Capex delivery performance is subject to a range of factors, with actual capex lower than forecast capex

370. In its 2024 network performance report,[79] the AER considered the aggregate over/under-spend and the timing of capex across the regulatory period. Whilst the over/under spend in any one year may not be instructive, the AER concluded from its analysis that

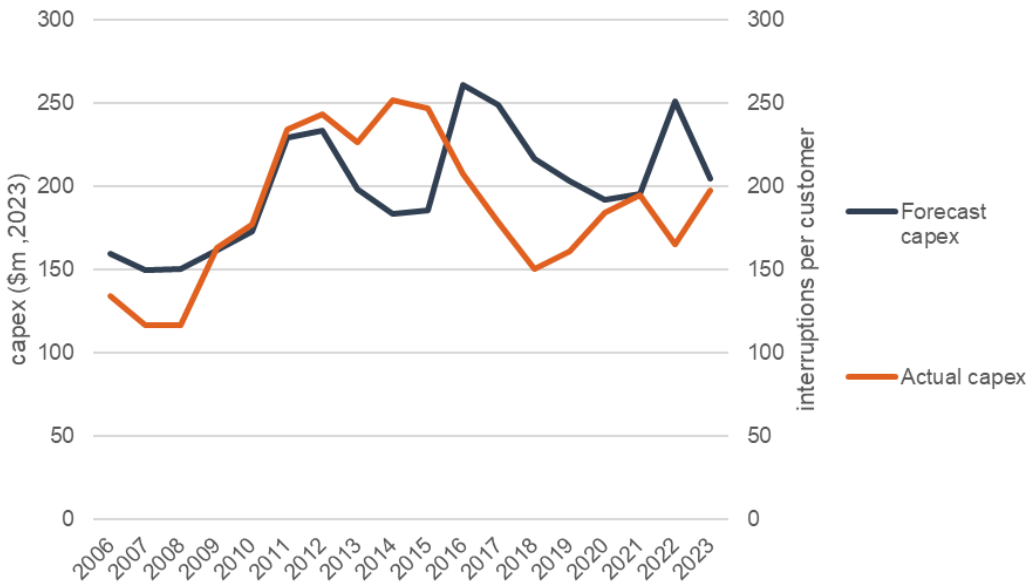
> *'Our first report looked at the timing of capex and concluded that NSPs tend to:*
>
> *• underspend by a greater extent early in regulatory periods*
>
> *• spend closer to, or above capex forecasts later in regulatory periods*
>
> *In our analysis we noted that there are different factors that can determine patterns of capex, and that one of the issues may be that capex incentives, financial or otherwise, vary through the course of the regulatory period.'*[80]

371. Figure C.6 shows the forecast vs actual capex for United Energy based on the AER network performance report data. Closer analysis is required of the drivers of the capex delivery performance in any regulatory period and year to year. We make further observations as it relates to the scope of our assessment of the expenditure as relevant.

[79] AER, 2024 Electricity and gas network performance report

[80] AER, 2024 Electricity and gas network performance report, page 29

Figure C.6: Comparison of United Energy historical actual with forecast capex



Source: AER Network performance report

United Energy expects the net capex to marginally exceed the capex allowance for the current RCP

372. Overall, United Energy state that it expects the net capital expenditure to marginally exceed the AER's allowance (and will further exceed this allowance after one-off asset disposals are excluded).

373. United Energy is expecting to underspend the component of the allowance allocated to augex, and materially exceed the component of the allowance allocated to repex. For augex, factors such as lower peak demand and consumption, deferred projects and lower expected costs (including efficient management of CER) have contributed to the underspend. For repex, the expenditure reflects rising input costs, noting the impacts of the pandemic and ongoing global supply chain pressures have limited the ability for contract management to mitigate these uplifts.

Over the last 5 years, actual opex is lower than forecast opex resulting in an overspend against the opex allowance, however much closer in last two years

374. In its 2024 network performance report,[81] the AER also considered totex and opex each year and across the regulatory periods:

> *'There has been a cumulative underspend by NSPs of their opex allowance for 6 consecutive regulatory years, with both DNSPs and TNSPs underspending their allowance. Opex efficiency by NSPs will contribute to outperformance against their allowed returns, though it will benefit consumers through lower opex expenditure forecasts in future regulatory determinations. This is a key feature of our incentive based regulatory framework and enhances the propensity for continual improvement by NSPs in delivering better outcomes for consumers.'* [82]

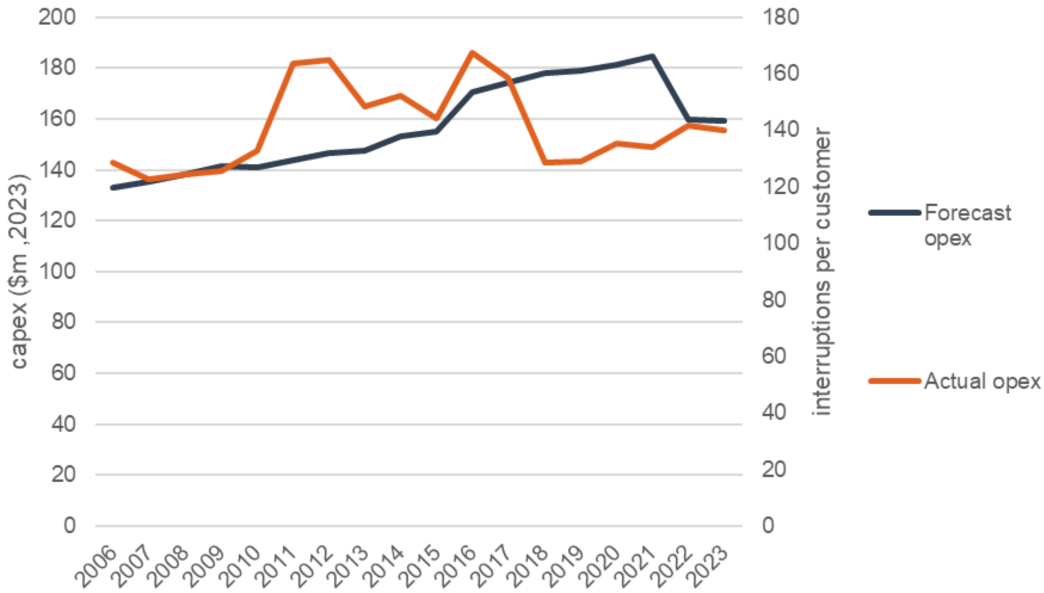
375. Figure C.7 shows a comparison of historical actual with forecast opex for United Energy. Whilst we have not been asked to consider overall opex, we observe that there has been a recent underspend of opex by United Energy consistent with the observations by the AER across NSPs.

---

81 AER, 2024 Electricity and gas network performance report

82 AER, 2024 Electricity and gas network performance report, page 29

Figure C.7: Comparison of United Energy historical actual and forecast opex



Source: AER Network performance report