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Regulatory Submission for period 2021/22 to 2025/26

POWERCOR - REVIEW OF ASPECTS OF PROPOSED EXPENDITURE

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

August 2020

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be applied to the prescribed distribution services of Powercor from 1st July 2021 to 30th June 2026. 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.

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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 EMCa prior to 31st July 2020 and any information provided after this time may not have been taken into account.

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ABBREVIATIONS

Term	Definition
ACRs	Auto Circuit Reclosers
ACS	Asset Class Strategies
ACSC	Australian Cyber Security Centre
AER	Australian Energy Regulator
AESCSF	Australian Electricity Sector Cyber Security Framework
AFAP	As Far As Practicable
AHI	Asset Health Index
AMI	Advanced Metering Infrastructure
AMI NST	Advanced Metering Infrastructure Neutral Screen Testing
AMS	Asset Management Strategies
augex	Augmentation capital expenditure
B/C	Benefit/cost Ratio
BC	Benefit Cost
BMP	Bushfire Management Plan
BST	Base Step Trend
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
CCC	Customer Consultative Committee
CIC	Capital Investment Committee
CIE	Centre of International Economics
CP	CitiPower
DAPR	Distribution Annual Planning Report
DBYD	Dial Before You Dig
DERMS	Distributed Energy Resource Management System
DNSP	Distribution Network Service Provider
DVMS	Dynamic Voltage Management System
EBSS	Efficiency Benefit Sharing Scheme
EDO	Expulsion Drop Out
EFCAP	Energy Futures Customer Advisory Panel
ELCA	Electrical Line Construction Area
EMT	Executive Management Team

ENA	Electricity Networks Association
ERP	Enterprise Resource Planning
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
GFN	Ground Fault Neutralisers
GIS	Geospatial Information System
GPS	Global Positioning System
GRP	Gross Regional Product
HBRA	Hazardous Bushfire Risk Areas
IaaS	Infrastructure as a Service
ICT	Information and Communications Technology
IGF	Investment Governance Framework
ISO	International Organization for Standardization
IVR	Interactive Voice Response
LBRA	Low Bushfire Risk Areas
LDC	Load Duration Curves
LIDAR	Light Detection and Ranging
LSAA	Local Service Area Agents
MGL	Multi-Greek Letter
MIL	Maturity Indicator Level
NER	National Electricity Rules
NNS	Non-network support
NPC	Net Present Cost
OLTC	On-load Tap Changer
opex	Operating expenditure
OT	Operational Technology
PAL	Powercor
PoE	Probability of Exceedance
PoF	Probability of Failure
PPCF	Portfolio and Project Controls Framework
PVC	Poly Vinyl Chloride
RBAM	Risk Based Asset Management
RCM	Reliability Centred Maintenance
RCP	Regulatory Control Period
REFCL	Rapid Earth Fault Current Limiter
repex	Replacement (capital) expenditure

RIN	Regulatory Information Notice
RMCC	Risk Management and Compliance Committee
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SAPN	South Australia Power Networks
SME	Subject Matter Experts
SWER	Single Wire Earth Return
TFB	Total Fire Ban
UCS	Unified Computing System
UE	United Energy
VBRC	Victorian Bushfire Royal Commission
VCR	Value of Customer Reliability
VPN	Victoria Power Networks
WAN	Wide Area Network

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1 INTRODUCTION

1.1 Scope

1. This report provides our assessment of certain aspects of Powercor's proposed expenditure allowances, and the framework of governance, management and forecasting methods that the business has used to establish these proposed amounts. The report scope covers the following topics:

- Expenditure governance, management, and forecasting framework as applied by Powercor;
- Repex;
- Non-DER augex;
- Solar Enablement expenditure (which comprises an augex component and a proposed opex step change);
- ICT expenditure (which includes capex and a proposed opex step change);
- Property-related capex;
- Minor repairs opex, and
- A proposed opex step change for replacement of EDO fuses.

2. The purpose of this report is to provide the AER with our assessment of the aspects of expenditure set out above and the basis for our findings.

1.2 Structure of this report

3. The items within our scope are covered as follows:

- In section 2, we provide an overview of the expenditure that we have been asked to assess. This includes expenditure as proposed by Powercor (and as represented in its RIN data) and also disaggregated data providing expenditure context for specific projects and expenditure categories that are referred to throughout the report.
- In section 3, we provide our assessment of Powercor's investment governance and management frameworks and relevant aspects of its expenditure forecasting methodologies.
- In section 4, we provide our assessment of Powercor's proposed repex.
- In section 5, we provide our assessment of Powercor's proposed non-DER augex.
- In section 6, we provide our assessment of Powercor's proposed Solar Enablement program, which includes its proposed Solar Enablement augex and proposed Solar Enablement operational expenditure as an opex step change.
- Section 7 provides our assessment of Powercor's proposed ICT capex and of its proposed ICT Cloud-related opex step change. This includes the ICT component of some related work under Solar Enablement (i.e., Digital Networks – see also section 6) and the ICT component of Facilities Security Upgrades, which are covered in section 8.
- In section 8, we provide our assessment of Powercor's proposed property capex.
- In Section 9, we provide our assessment of Powercor's proposed addition of an allowance for minor repairs to Powercor's base opex and of Powercor's proposed opex step change for EDO fuse replacement.

4. Two appendices follow the main sections of the report, as follows:

- In Appendix A, we provide contextual information related to consideration of an enhanced pole replacement program for Powercor.
- In Appendix B, we provide an overview and assessment of the CBRM and risk monetisation model that Powercor has used in seeking to justify its proposed expenditure for transformer and switchgear replacements.

1.3 Presentation of expenditure amounts

5. Expenditure is presented in this report in $2021 real terms, unless stated otherwise. In some cases, we have converted to this basis from information provided by the business in other terms.[1]

6. Powercor has proposed expenditure allowances which it has real-cost escalated in aggregate. However, project and program-level information presented by Powercor (such as in the project models and business cases) has generally not had escalation applied to it, and we have presented it in non-escalated terms in this report to preserve comparability with the source project information provided. We have footnoted any graphs and tables that comprise non-escalated expenditure.

7. 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 and minor differences due to rounding. Any such discrepancies do not affect our findings.

[1] Where we have needed to convert cost information provided by the business from expenditure denominated in terms other than $2021, we have done so using a common index series that is what Powercor has applied in its RIN. In some cases, we observe that Powercor has used different indices in information that it provided to us, and this may result in small discrepancies. Any such discrepancies are not sufficient to have influenced our findings.

2 BACKGROUND INFORMATION

2.1 Introduction

8. This section is structured in accordance with our brief, with some wider information shown for context. We show, in turn, Powercor's:

- Total net capex;
- Repex;
- Augex (including solar enablement capex);
- ICT capex;
- Property-related capex; and
- Opex (focused on the step changes that we were asked to assess, and which include for ICT Cloud-related opex, for solar enablement, EDO fuse replacements and a reclassification for minor repairs.).

9. The graphs and tables that follow document the expenditures that we have been asked to assess. It includes RIN data provided by Powercor and aggregated data from its project models. We have sought to aggregate project information in ways that match the structure by which we have assessed overall expenditures. For example, we have structured:

- Repex data by RIN group, with the exception that we have combined poles expenditure and pole staking expenditure;
- Augex data by 'function types' that Powercor has defined;
- ICT expenditure by project and as categorised by Powercor as Recurrent and Non-recurrent by the AER; and
- Property expenditure by project (individual depots) and programs (facilities upgrades and compliance program).

10. We also show proposed expenditure for each of the focus projects that AER asked us to assess, in the context of Powercor's overall proposed expenditure.

11. Powercor modified some aspects of its proposed expenditure after submission to the AER by removing some proposed expenditure. We have accordingly removed these amounts from the expenditure information that we have assessed.

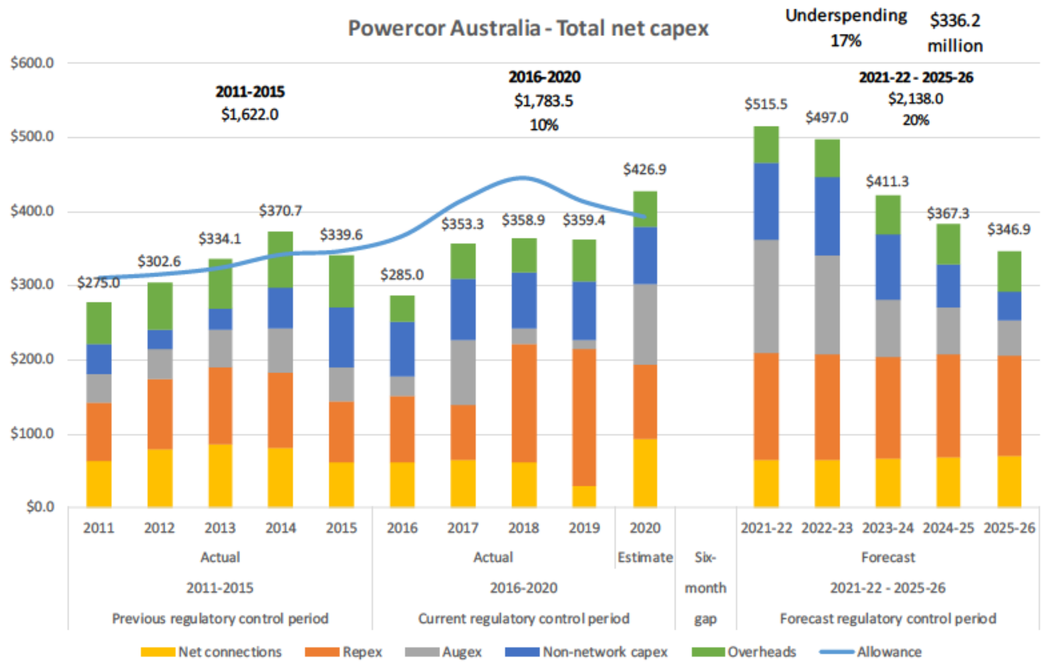
12. In this section, we provide some high-level trend information for context. More focused expenditure and trend information, relevant to our assessments, is provided in our assessment section of this report.

13. Finally, in this section, we reproduce aspects of the NER which are relevant to our assessments.

2.2 Total Net Capex

14. Table 2.1 below shows actual and estimated Powercor total net capex vs the AER allowance for the prior and current RCP's and forecast Powercor total net capex for the next RCP.

Figure 2.1: Powercor net Capex vs AER Allowance



Source: AER trend analysis 'Victoria Total Net Capex - 21 May 2020'

2.3 Category expenditure and trends

2.3.1 Repex

Proposed repex - RIN data

15. Table 2.1 shows Repex by RIN Group for the next RCP as reported in the RIN. Powercor's total forecast repex for the next RCP is $694.8m. This mirrors how repex was presented in Powercor's Regulatory Proposal (RP) in that it includes the RIN Group "Public Lighting", which should not have been included as SCS, as well as the Environmental Management program, under RIN Group "Other", which has since been withdrawn and substituted with a much lower amount.

16. Table 2.2 shows our assessment of the proposed Repex by RIN Group following these adjustments.

Table 2.1: Powercor repex for the next RCP – As reported in Powercor's RP - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	52.5	53.6	54.8	55.9	57.0	273.8
Pole Top Structures	16.5	16.8	17.1	17.4	17.6	85.4
Overhead Conductors	8.8	9.0	9.2	9.3	9.4	45.7
Underground Cables	0.6	0.6	0.7	0.7	0.7	3.3
Service Lines	9.1	9.3	9.5	9.7	9.9	47.6
Public Lighting	0.2	0.2	0.2	0.3	0.3	1.2
Transformers	11.2	10.0	10.8	10.5	8.7	51.0
Switchgear	11.5	11.8	12.0	12.3	12.5	60.0
SCADA, Network Control and Protection	4.6	4.7	4.7	4.9	4.9	23.9
Other	27.4	25.4	17.5	18.2	14.3	102.8
Total	**142.5**	**141.4**	**136.5**	**139.1**	**135.3**	**694.8**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Table 2.2: Powercor repex for the next RCP – Following adjustments for Environmental Management and Public Lighting - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	52.5	53.6	54.8	55.9	57.0	273.8
Pole Top Structures	16.5	16.8	17.1	17.4	17.6	85.4
Overhead Conductors	8.8	9.0	9.2	9.3	9.4	45.7
Underground Cables	0.6	0.6	0.7	0.7	0.7	3.3
Service Lines	9.1	9.3	9.5	9.7	9.9	47.6
Transformers	11.2	10.0	10.8	10.5	8.7	51.0
Switchgear	11.5	11.8	12.0	12.3	12.5	60.0
SCADA, Network Control and Protection	4.6	4.7	4.7	4.9	4.9	23.9
Other	16.9	12.4	8.0	8.1	8.2	53.6
Total	**131.8**	**128.2**	**126.8**	**128.7**	**128.9**	**644.4**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Repex from the project models as mapped to RIN Groups

17. The following table shows project-level repex as now proposed by CitiPower. Public Lighting and the originally proposed Environmental Management program have been superseded. Real cost escalation has not been included in the project model analysis. Values have been inflated where necessary to be in the common basis of Real 2021 dollars.

Table 2.3: Powercor repex – Following adjustments for Environmental Management and Public Lighting - $m, real 2021

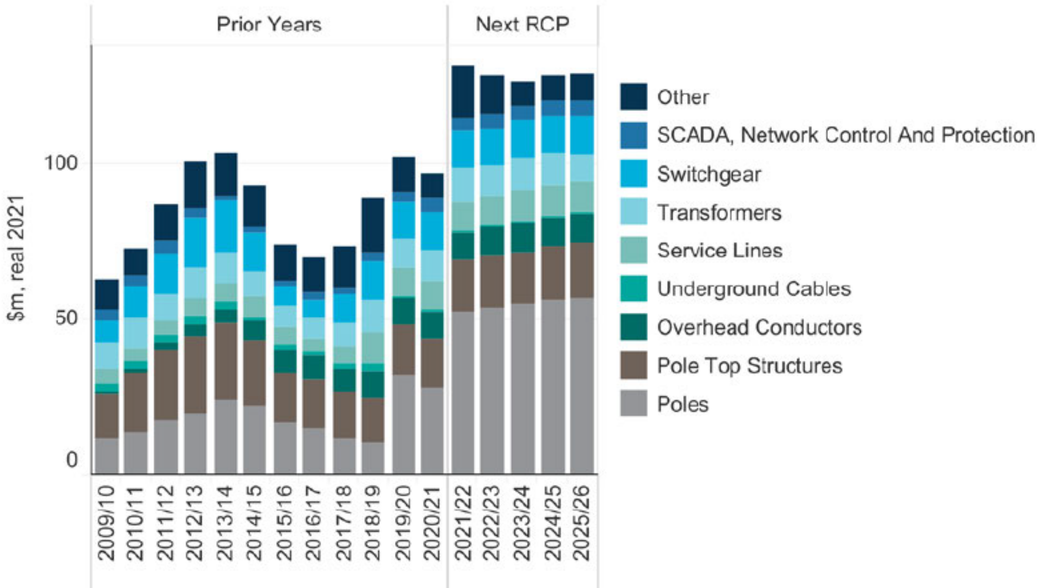
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	51.6	51.9	52.1	52.4	52.6	260.6
Pole Top Structures	16.3	16.3	16.3	16.3	16.3	81.3
Overhead Conductors	8.7	8.7	8.7	8.7	8.7	43.5
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.1
Service Lines	9.0	9.0	9.1	9.1	9.2	45.4
Transformers	11.0	9.6	10.2	9.8	8.0	48.7
Switchgear	11.3	11.4	11.4	11.5	11.5	57.1
SCADA, Network Control and Protection	4.6	4.5	4.5	4.6	4.6	22.7
Other	16.6	12.0	7.6	7.6	7.6	51.5
Total	**129.7**	**124.1**	**120.6**	**120.5**	**119.1**	**614.0**

Source: EMCa analysis of Powercor MODs 4.06, 4.09, 4.10, 4.11, 6.09. Excludes real cost escalation

Repex trend

18. Repex trends over time, by RIN Group, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. 2018/2019 FY has been populated using escalated project model data provided by AER. Forecast values for the Public Lighting RIN Group and for the Environmental Management program have been removed. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.2: Powercor repex – Following adjustments for Environmental Management and Public Lighting - $m, real 2021



Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'PAL consolidated RIN - repex - 2018-19_sent to EMCa'

Repex by program, showing AER Focus Projects

19. The following table shows the sum of the AER's designated repex 'Focus' projects and programs within each mapped RIN Group, using data from the project models without real cost escalation.

Table 2.4: Powercor repex for the next RCP – Following adjustments for Environmental Management and Public Lighting and showing AER Focus Projects and Programs - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	47.4	47.6	47.9	48.1	48.3	260.6
Focus: Wood Poles	*42.5*	*42.5*	*42.5*	*42.5*	*42.5*	*233.8*
Other	*4.9*	*5.1*	*5.4*	*5.6*	*5.9*	*26.8*
Pole Top Structures	16.3	16.3	16.3	16.3	16.3	81.3
Overhead Conductors	8.7	8.7	8.7	8.7	8.7	43.5
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.1
Service Lines	9.0	9.0	9.1	9.1	9.2	45.4
Transformers	11.0	9.6	10.2	9.8	8.0	48.7
Focus: Robinvale Transformer replacement projects	*1.6*	*0.4*	*1.9*	*1.5*	*0.0*	*5.4*
Other	*9.4*	*9.2*	*8.3*	*8.3*	*8.0*	*43.2*
Switchgear	11.3	11.4	11.4	11.5	11.5	57.1
Focus: HV ABS	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*12.3*
Other	*8.9*	*8.9*	*9.0*	*9.0*	*9.1*	*44.8*
SCADA, Network Control and Protection	4.6	4.5	4.5	4.6	4.6	22.7
Focus: Protection & Replacement	*4.6*	*4.5*	*4.5*	*4.6*	*4.6*	*22.7*
Other	16.6	12.0	7.6	7.6	7.6	51.5
Focus: VBRC	*13.3*	*8.8*	*4.6*	*4.6*	*4.6*	*35.8*
Other	3.3	3.2	3.1	3.1	3.1	15.7
Total	**129.7**	**124.1**	**120.6**	**120.5**	**119.1**	**614.0**

Source: EMCa analysis of Powercor MODs 4.06,4.09, 4.10, 4.11, 6.09. Excludes real cost escalation

2.3.2 Augex

Proposed Augex - RIN data

20. Table 2.5 below shows Powercor's proposed augex for the next RCP as reported in the RIN and RP by Project Type. Powercor's total forecast augex is $475.2m.

Table 2.5: Powercor augex for the next RCP – as reported in RP - $m, real 2021

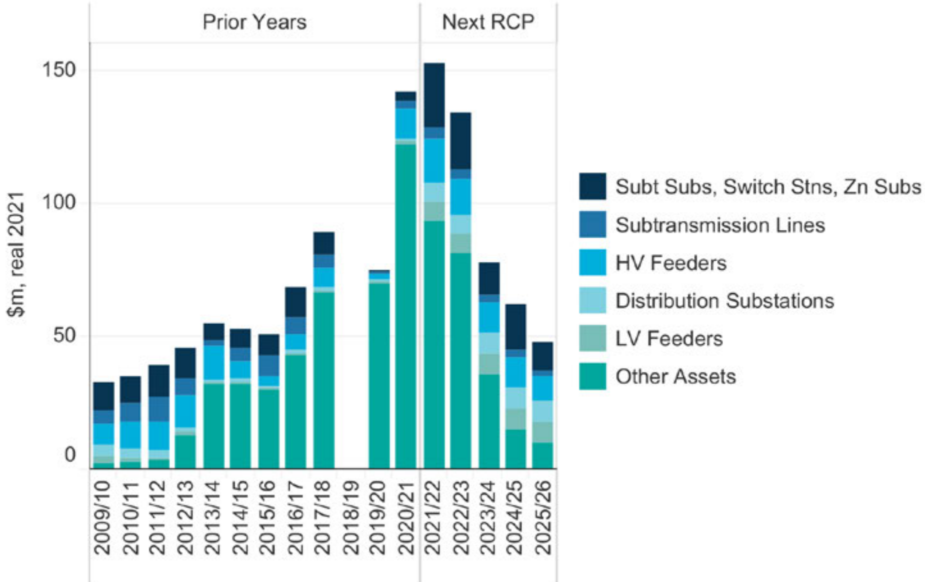
Project Type	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	24.2	22.0	12.7	17.0	10.7	86.7
Subtransmission Lines	4.2	3.3	2.7	3.0	2.2	15.4
HV Feeders	16.9	13.2	10.9	11.9	8.8	61.6
Distribution Substations	7.2	7.4	7.9	7.6	7.8	37.9
LV Feeders	7.2	7.4	7.9	7.6	7.8	37.9
Other Assets	93.1	81.1	35.9	15.3	10.2	235.7
Total	**152.9**	**134.4**	**78.0**	**62.3**	**47.7**	**475.2**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Augex trend

21. Augex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.3: Powercor augex - $m, real 2021



Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

Augex by function type, showing AER focus projects and additional business cases

22. Table 2.6 below shows Powercor's augex project expenditure for the next RCP, organised by the Function Types provided in the Consolidated Capex Model (10.05). This table also shows forecast augex for each of the AER focus projects that we assessed. 'Other' augex is included for reconciliation purposes. Real cost escalation has been excluded.

Table 2.6: Powercor augex for the next RCP by Function Type & AER Focus Projects - $m, real 2021

Function Type / Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Augmentation of Zone Substations	23.8	21.1	12.1	15.8	9.8	82.6
AER Focus projects						
Bacchus Marsh SA	*0.5*	*1.4*	*3.4*	*2.4*		*7.7*
Tarneit SA		*0.1*	*3.8*	*8.4*	*4.7*	*16.9*
Upgrading Regional Supply	*5.1*	*3.9*				*9.1*
Other	18.2	15.7	4.9	5.1	5.1	48.9
Augmentation of HV Feeders & Subtransmission	20.7	15.8	12.9	13.8	10.1	73.3
AER Focus projects						
Tarneit SA			*0.9*	*1.8*	*0.9*	*3.6*
Other	20.7	15.8	12.0	12.0	9.2	69.6
LV Augmentation	14.2	14.3	14.9	14.1	14.3	71.8
AER Focus projects						
Solar Enablement	*12.2*	*12.2*	*12.7*	*11.8*	*11.9*	*60.7*
Other	2.0	2.1	2.2	2.3	2.4	11.0
REFCL GFNs	77.0	63.3	26.7	5.8		172.7
AER Focus projects						
REFCL Ongoing Compliance	*3.6*	*24.4*	*26.7*	*5.8*		*60.5*
Other	73.4	38.9				112.3
Zone Substation Automation	15.0	15.8	8.0	9.2	10.2	58.2
Total	**150.8**	**130.4**	**74.5**	**58.7**	**44.4**	**458.7**

Source: EMCa analysis of Powercor MODs 6.01, 6.04, 6.09, 10.05. Remaining expenditure in each group is designated 'other' and is included for reconciliation purposes.

2.3.3 ICT

Proposed ICT capex - RIN data

23. Proposed ICT capex by RIN Category for the next RCP is shown in the table below, including real cost escalation. Total forecast ICT capex is $165.8m.

Table 2.7: Powercor ICT capex by RIN Category - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Corporate Services	7.8	6.3	5.4	9.1	3.7	32.3
Customer Engagement	3.9	1.8	4.3	1.9	0.6	12.5
Cyber Security	3.9	4.0	4.4	4.3	3.4	20.0
Field Work & Construction	2.7	5.5	7.2	6.7	0.7	22.9
Market Compliance	9.2	3.5	3.8	1.0	3.1	20.6
Network Assets and Network Operations	11.9	10.0	8.4	6.9	6.0	43.2
Service Management and Ops	2.7	2.8	2.8	2.9	2.9	14.1
Total	**42.1**	**34.0**	**36.4**	**32.8**	**20.5**	**165.8**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

ICT projects categorised as Recurrent / Non-recurrent

24. In Table 2.7 below, ICT capex for the next RCP is categorised from Powercor's project models as Recurrent or Non-Recurrent expenditure, with AER focus projects highlighted. This table excludes real cost escalation.

Table 2.8: Powercor ICT capex for the next RCP by project showing AER focus projects - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**26.9**	**24.2**	**20.4**	**23.0**	**17.0**	**111.5**
Focus						
Infrastructure with Cloud migration	6.5	5.3	4.4	5.8	3.2	25.2
Network Management	5.3	4.9	1.4	4.0	4.4	19.9
Other						
BI/BW	0.1	1.6	0.5	0.1	0.1	2.5
Customer Enablement	0.3	0.8	1.9	0.3	0.3	3.7
Cyber security	2.7	2.8	3.0	2.9	2.3	13.5
Device replacement	2.7	2.7	2.7	2.7	2.7	13.6
Enterprise Management Systems - Non-SAP	3.3	2.0	1.4	3.4	0.3	10.4
Facilities' security	1.2	0.9	0.7	2.9	0.3	6.0
General compliance	0.9	0.9	0.9	0.9	0.9	4.6
Market Systems	1.0	0.9	2.7		1.9	6.5
SAP S/4HANA	0.4	0.7			0.4	1.6
Telephony	2.3	0.7	0.7		0.2	4.0
Non-recurrent	**14.7**	**8.9**	**14.6**	**8.1**	**2.2**	**48.5**
5 Minute Settlements	7.2	1.6	0.0	0.0	0.1	8.9
Customer Enablement	1.1	0.3	1.6	1.4		4.4
Cyber security	1.1	1.2	1.3	1.2	1.0	5.7
Digital network	2.8	3.2	3.1	0.9	1.2	11.1
Intelligent engineering		0.9	3.1	0.5		4.4
SAP S/4HANA		1.8	5.4	4.1		11.3
Solar enablement DVMS	2.6					2.6
Total	**41.6**	**33.1**	**34.9**	**31.1**	**19.2**	**160.0**

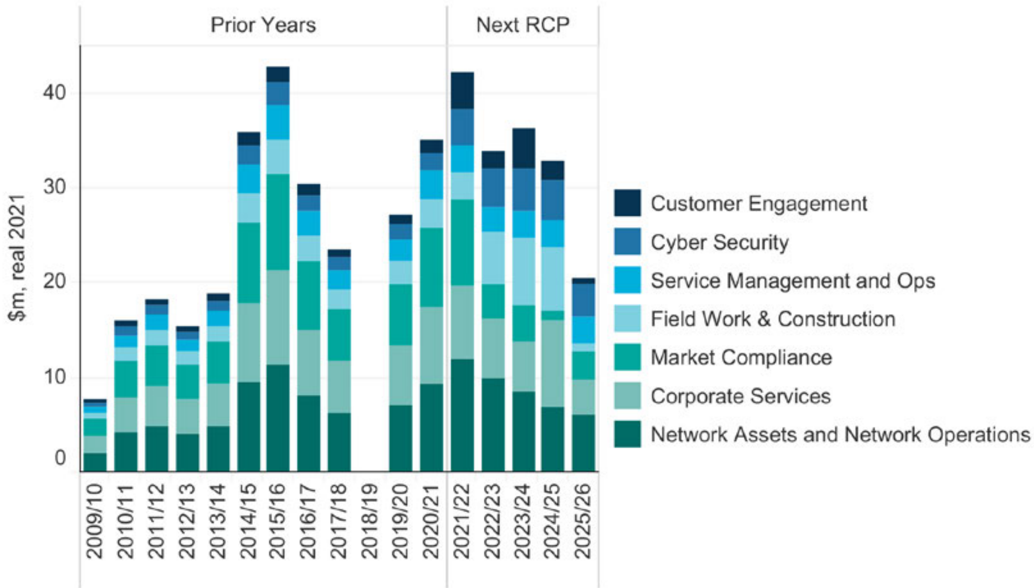
Source: EMCa analysis of Powercor MOD 7.01. Excludes real cost escalation

ICT capex trend

25. ICT Capex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

26. ICT Capex is split between Powercor and CitiPower based on a fixed percentage (%) apportionment. As such, the trends for both companies follow the same shape albeit at different scales.

Figure 2.4: Powercor ICT capex trend by RIN Category - $m, real 2021

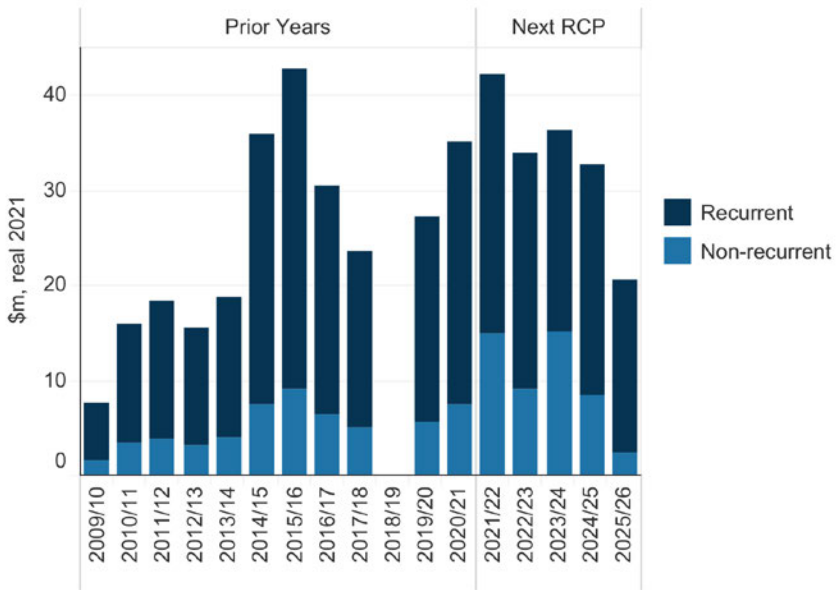


Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

ICT Capex trends by Recurrent/Non-Recurrent expenditure classification

27. The figure below shows Powercor's ICT capex trend for prior years and the next RCP, categorised by Recurrent and Non-recurrent expenditure.

Figure 2.5: Powercor ICT capex trend by Recurrent/Non-Recurrent - $m, real 2021



Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'. Data for financial year 2018/19 was not provided. (Powercor also provided historical data in Workbook 2. That data is in calendar years. While Powercor claims that the Workbook 2 data reflects AER's new definitions, we observe that the ratio of recurrent to non-recurrent expenditure in Workbook 2 is identical to that presented under the old definitions, per Workbook 8, and is also identical for each historical year)

2.3.4 Property

Proposed property capex - RIN data

28. Property expenditure is not broken down in the RIN, existing only as a line item. The table below shows Powercor's proposed property capex of $115.5m for the next RCP as presented in the RIN, including real cost escalation.

Table 2.9: Powercor property capex for the next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Buildings and property expenditure	30.7	37.7	27.9	13.8	5.4	115.5
Total	**30.7**	**37.7**	**27.9**	**13.8**	**5.4**	**115.5**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Property projects

29. Property expenditure from the project models by project description is shown below, including locations for depots.

Table 2.10: Powercor proposed property projects - $m, real 2021

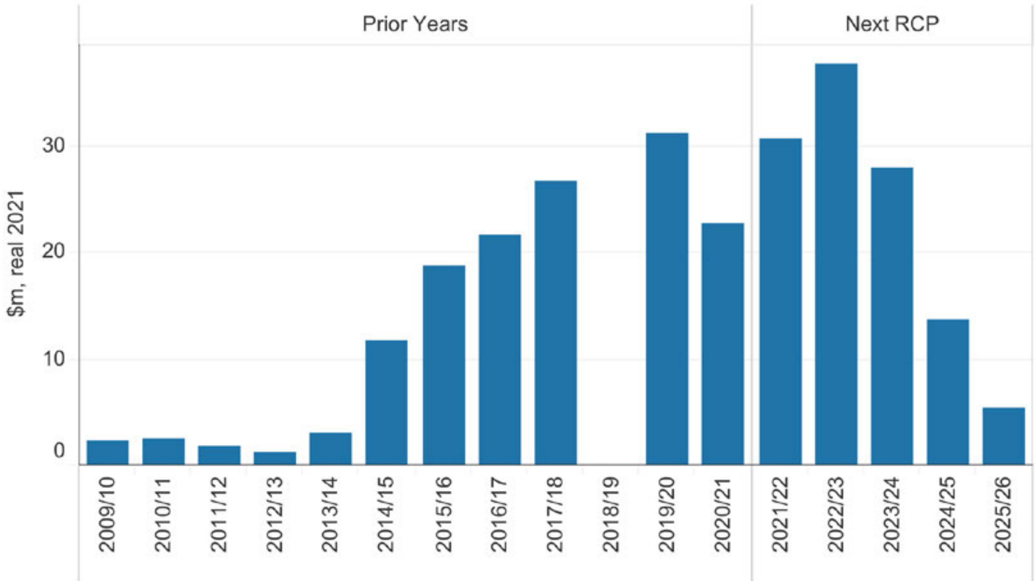
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Building compliance	1.4	1.4	0.9	0.5	0.5	4.5
Facilities	8.6	6.5	5.5	4.8	4.8	30.2
Depots	20.6	29.4	21.1	8.2		79.2
Ballarat	*7.9*	*8.0*				*16.0*
Bendigo		*11.1*				*11.1*
Brooklyn	*12.7*	*8.6*				*21.3*
Echuca			*5.7*	*8.2*		*13.8*
Warrnambool		*1.6*	*15.4*			*17.0*
Total	**30.6**	**37.3**	**27.4**	**13.4**	**5.3**	**114.0**

Source: EMCa analysis of Powercor MOD 8.01. Excludes real cost escalation

Property capex trend

30. In the figure below, Powercor's Property capex trend over time has been generated for prior years and the next RCP from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.6: Powercor property capex trend - $m, real 2021



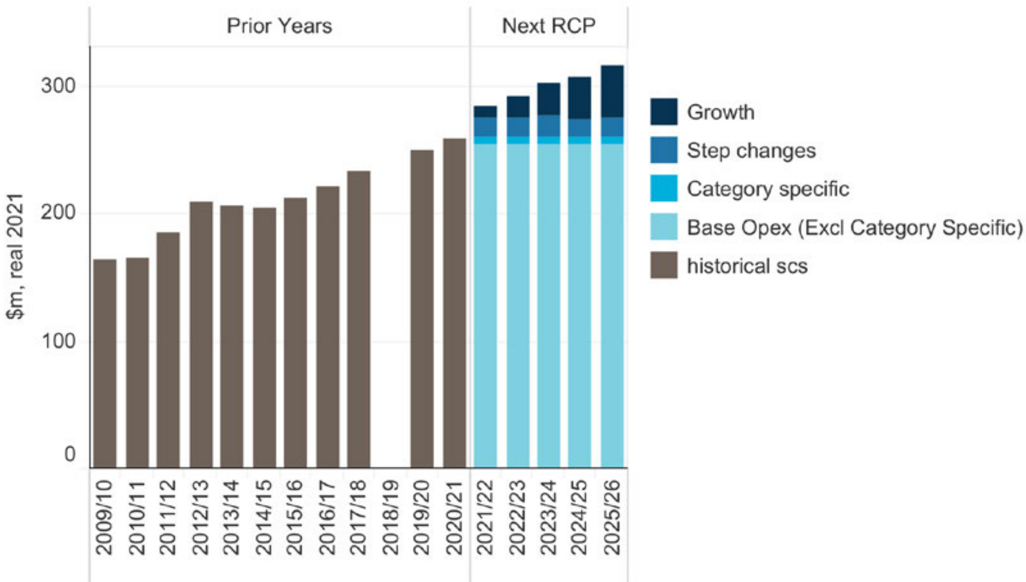
Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

2.3.5 Opex

Opex Trend and overview of next RCP

31. The opex trend over time has been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.7: Powercor opex trend - $m, real 2021



Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'. Data for financial year 2018/19 was not provided.

Step changes and 'Category-specific' opex over the next RCP

32. Proposed 'Step changes' of $76.5m and 'Category-specific' opex of $33.5m for the next RCP are further categorised as shown in the figure below, including real cost escalation.

Table 2.11: Powercor's proposed 'Step Changes' and 'Category Specific' opex for the next RCP - $m, real 2021

Group & Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step changes	**15.1**	**15.5**	**16.8**	**14.2**	**14.8**	**76.5**
5 minute settlement	0.6	0.8	1.0	1.2	1.5	4.9
EPA regulations change	3.2	3.3	3.1	0.0	0.1	9.6
ESV levy	0.7	0.8	0.8	0.8	0.9	4.0
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
Increasing insurance premiums	1.0	1.0	1.0	1.0	1.0	5.0
IT cloud solutions	0.9	0.9	1.2	1.5	1.5	5.9
REFCL on-going operating expenditure	1.8	2.2	2.8	3.2	3.3	13.3
Replacing EDO fuses with fault tamers	2.2	2.2	2.2	2.3	2.3	11.2
Security of critical infrastructure	3.1	2.8	2.8	2.9	2.9	14.5
Solar enablement	1.3	1.3	1.5	1.0	1.0	6.2
Category specific	**6.7**	**6.7**	**6.7**	**6.7**	**6.7**	**33.5**
Communications network	1.5	1.5	1.5	1.5	1.5	7.4
Emergency recoverable works	0.3	0.3	0.3	0.3	0.3	1.3
Replacement expenditure on faults and minor repairs	3.8	3.8	3.8	3.8	3.8	18.8
Wasted truck visits	1.2	1.2	1.2	1.2	1.2	6.1
Total	**21.8**	**22.2**	**23.5**	**20.9**	**21.5**	**110.0**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'. Note that this excludes the HBRA-related opex which Powercor originally proposed, but which we understand has been withdrawn

Step changes & Category-specific projects in scope for EMCa's review

33. The AER has asked EMCa to provide advice on certain aspects of Powercor's proposed opex as shown in the table below, including real cost escalation.

Table 2.12: AER Focus sections of proposed opex - $m, real 2021

Group & Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step changes	**4.4**	**4.4**	**5.0**	**4.7**	**4.8**	**23.3**
IT cloud solutions	0.9	0.9	1.2	1.5	1.5	5.9
Replacing EDO fuses with fault tamers	2.2	2.2	2.2	2.3	2.3	11.2
Solar enablement	1.3	1.3	1.5	1.0	1.0	6.2
Category specific	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**18.8**
Replacement expenditure on faults and minor repairs	3.8	3.8	3.8	3.8	3.8	18.8
Total	**8.1**	**8.1**	**8.8**	**8.5**	**8.5**	**42.0**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

34. Our assessment of ICT cloud opex is in the ICT section (section 7), and our assessment of solar enablement opex is in the Solar Enablement section (section 6). Proposed expenditure for minor repairs and EDO fuse replacements are assessed in section 9.2 and section 9.3 respectively.

2.4 NER Capex Objectives and Criteria

35. 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. 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 DNSP's 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.

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

- Drawing on the wording of the first and second capex 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 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 capex 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 capex objective (emphasis added), encompassing the need for the DNSP to show that it has properly considered demand management and non-network options;
- We tend towards a strict interpretation of compliance (under the second capex objective), with the onus on the DNSP to evidence specific compliance requirements rather than to infer them; and
- We note the word '*maintain*' in capex objectives 3 and 4 and, accordingly, we have sought evidence that the DNSP 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.

37. The NER's capex criteria and capex objectives are reproduced below.

NER capital expenditure criteria

(c) 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 and cost inputs required to achieve the capital expenditure objectives.

Source: NER 6.5.7(c) Forecast capital expenditure, v111

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 achieve 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; and

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

Source: NER 6.5.7(a) Forecast capital expenditure, v111

3 REVIEW OF INVESTMENT GOVERNANCE AND MANAGEMENT FRAMEWORK

In this section, we provide an overview of the expenditure governance and management framework applied by Powercor. We subsequently assess the extent to which expenditure forecasts developed in accordance with this framework, and that are within our scope of review, are likely to be prudent and efficient.

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

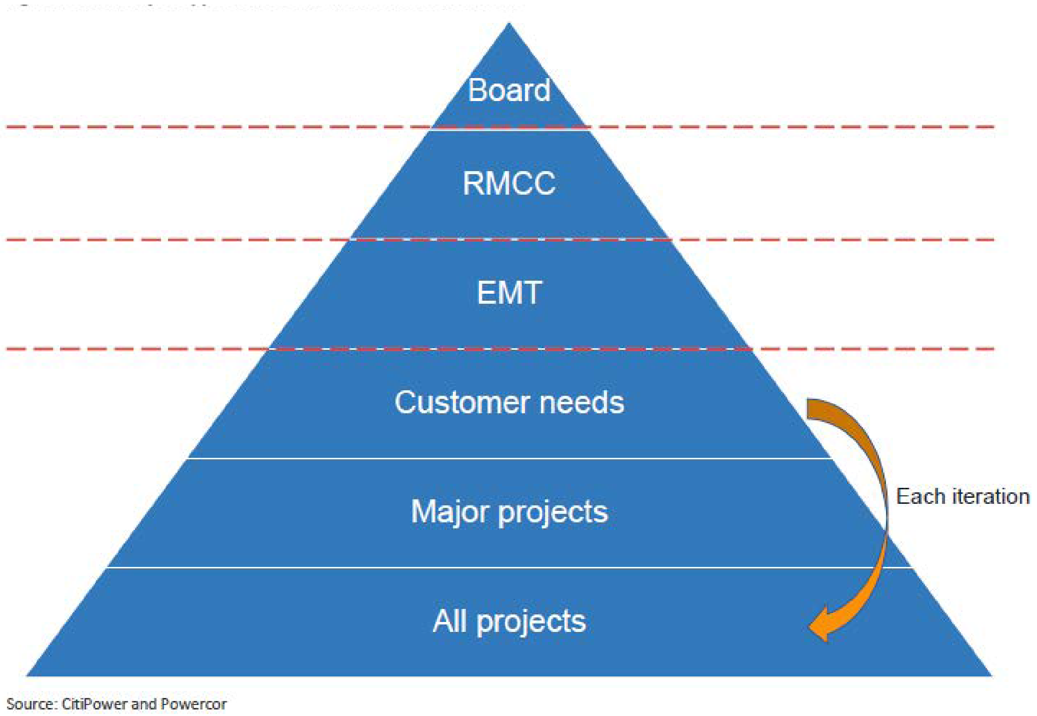
3.1 Powercor's framework

3.1.1 Investment governance and management framework

Overview of the framework

38. The investment governance framework that is applied across the Victoria Power Networks (VPN) for capex is reproduced in the following figure.

Figure 3.1: Hierarchy of approach to overall investment decision



Source: Response to information request IR017a – EMCa questions – governance and repex

39. Powercor explains each of the elements of the VPN framework as follows:[2]

- '***All projects***: *all investments that are likely to be made over the regulatory period were prepared as an initial iteration of expenditure. We removed all projects that were*

[2] Response to information request IR017a – EMCa questions – governance and repex

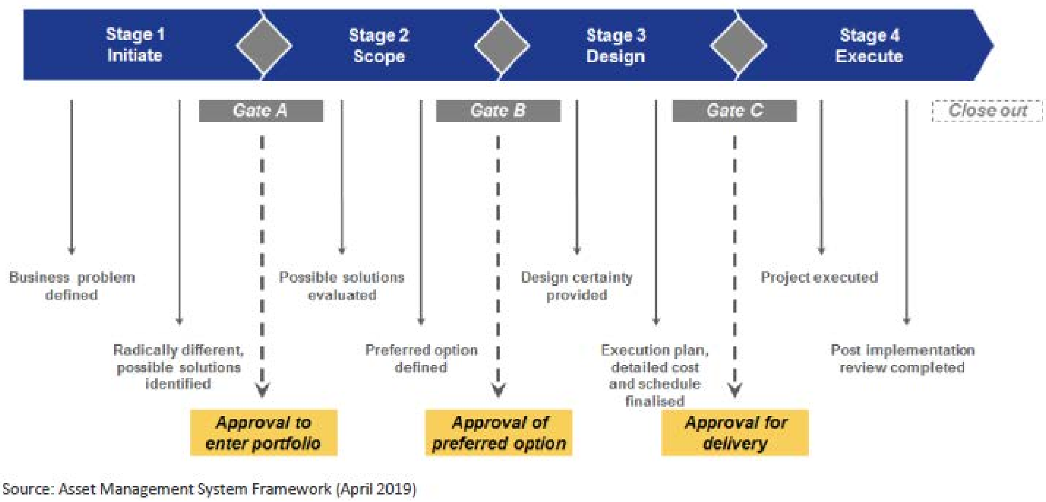
considered to be productivity enhancing, or where the driver was reliability improvements, as these projects will be self-funded by VPN during the period. Within each iteration, the list of all projects was revisited based on new or updated information;

- ***Major projects**: all major projects were assessed to understand their drivers and benefits to all customers. Those projects that had a compliance driver, or where the benefits of the project outweighed the cost to consumers, were prioritised in the iterations. Within each iteration, the major projects were revisited based on new or updated information that may have shifted the timing, or revised parameters;*
- ***Customer needs**: these were overlaid against the overall forecasts. Throughout the stakeholder engagement for the regulatory reset, affordability remained a primary concern for our customers. For other projects, our forecasts were refined based on stakeholder feedback or support for a particular investment. Within each iteration, the expenditure and projects were reviewed based on updated stakeholder feedback;*
- ***Executive Management Team (**EMT**)**: each iteration was submitted to the EMT for review. The EMT acts as a control of the regulatory risks associated with the regulatory reset for VPN, and considered the overall package of investment for the period to 2026. In particular, the EMT reviewed each expenditure iteration taking into account whether it would meet the capital expenditure objectives set out in clause 6.5.7 of the National Electricity Rules (NER), as well as the capital expenditure criteria and factors;*
- ***Risk Management and Compliance Committee (**RMCC**)**: is a Board Committee that oversees the risk profile of VPN and ensures that appropriate policies and procedures are adopted for the timely and accurate identification, reporting and management of significant risks to VPN. It also assists the Board to oversee compliance with obligations determined by statute, legislation, regulation, contract or agreement. The RMCC reviewed the controls in relation to risks arising from changes to the regulations, as well as the regulatory reset; and*
- ***Board**: the VPN Board has ultimate responsibility for VPN's capital investment forecasts for the 2021-2026 regulatory period. The Board ensures that the forecasts find a balance between meeting VPN and shareholder's needs as well as those of our customers, while managing the various risks over the medium term. The draft and final regulatory proposal forecasts were reviewed by the Board, and they approved the material assumptions underpinning the forecasts.'*

Portfolio and project gating framework

40. VPN also has a Portfolio and Project Controls Framework (PPCF). The PPCF includes four stages and three approval gates as shown in the figure below.

Figure 3.2: Portfolio and Project Controls Framework (PPCF)



Source: Asset Management framework

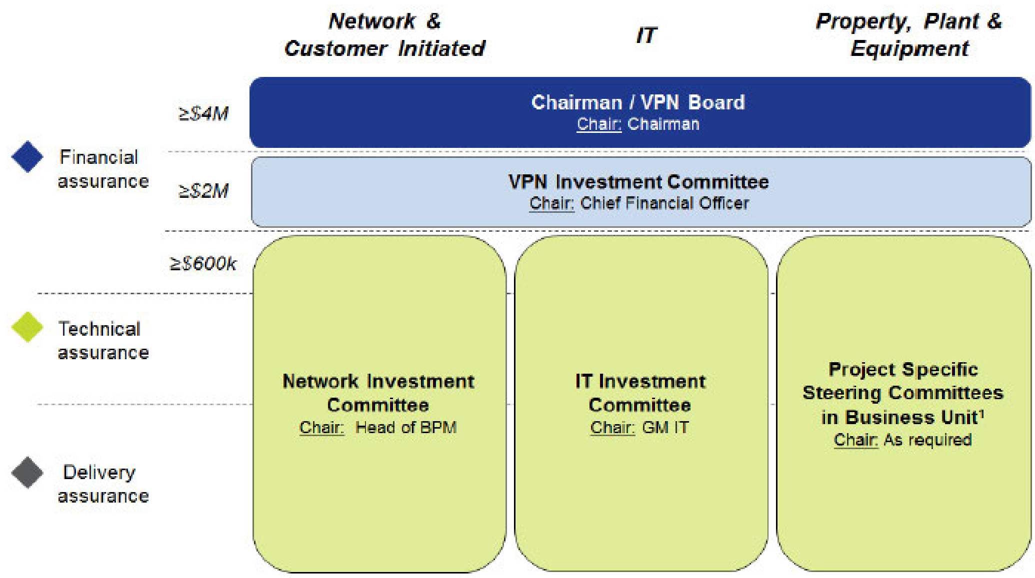
41. We understand from discussions with Powercor that a large proportion of the projects and programs for the Regulatory Proposal forecasts are at the stage of Gate A only.

42. VPN describes its capital investment policy as requiring the following governance and controls for capital investment decisions:

- projects must comply with the VPN Portfolio and Projects Controls Framework (PPCF);
- projects within the scope of the PPCF and at the request of management shall be subject to a financial peer review - and a technical review; and
- a post-implementation review must be performed within a reasonable time after the completion of the project.

43. The review and approval of expenditure proposals are based on the level of expenditure, project type and complexity. In the figure below, we show the committee structure that VPN has in place for providing financial, technical and delivery assurance for projects.

Figure 3.3: VPN committees for providing financial, technical and delivery assurance for projects



Source: PPCF
Note 1: These are ad hoc Project Committees that will have assigned chairs depending on project type and requirements.

Source: Response to information request IR017a EMCa question – governance and repex

3.1.2 Portfolio optimisation

Overview

44. In response to our request for details of the portfolio planning and management process undertaken to determine the programs/projects that comprise its whole-of-business expenditure portfolio, Powercor states that:[3]

- *'rigorous checks were made to the forecasts, including reviews by subject matter experts (SME), senior managers and the General Manager of the respective business unit, as well as other quality assurance steps to ensure that the amounts are free from error;*
- *rigorous checks were made to the various models used in preparing the forecasts;*
- *all major projects were assessed to understand their drivers and benefits to all customers. Risk-monetisation modelling was undertaken to ensure that:*

[3] Response to information request IR017a

  - *we only invest when the cost of replacing existing infrastructure is lower than the total value of the underlying risks;*
  - *capital works for augmentation were only forecast where the cost of mitigation a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand-side solution is feasible;*
  - *the highest risk mitigation option was selected for information and communication technology (ICT) projects, where the ICT risks and business risks were assessed against the expected costs; and*
- *the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure.'*

45. Powercor describes a number of oversight steering committees including the Capital Investment Committee (CIC) that review the capital expenditure to ensure it is targeted to deliver optimum outcomes for shareholders, customers, the community and employees.

Top-down review methods

46. Powercor states that:[4]

> *'.. in the absence of asset management intervention, network risk levels are forecast to increase over the next regulatory period. These risks include demand related, asset performance and bushfire risks. The interventions outlined in our regulatory proposal are driven by our asset management programs (including regulatory obligations) and articulated in specific projects addressing these risks. We believe the governance over the preparation of the expenditure has provided a significant level of review.'*

Review of Regulatory proposal forecast

Development of the expenditure forecast

47. Powercor states[5] that its Regulatory Proposal is based on its 'Steady State' planning scenario[6] and is aligned with its current asset management and planning strategies and its current risk management profile.

48. Powercor has established a steering committee ("SteerCo") which consists of all Executive Management team members. The SteerCo is responsible for overseeing projects identified in the businesses' strategic program of works, as determined annually and includes the Regulatory Proposal.

49. Powercor describes that the expenditure forecasts provided in its Regulatory Proposal have been subjected to:
- internally conducted 'deep dives' and peer review by SMEs by expenditure category including deep dives included SMEs, general managers, Energy Futures Customer Advisory Panel (EFCAP) and Customer Consultative Committee (CCC);
- public comment and review of its draft proposal;
- deep dives with external stakeholders including customer groups, the AER, the Victorian Government and local councils and community groups; and
- category level expenditure deep dives on expenditure iterations between the draft and final Regulatory Proposal.

50. For ICT, a different approach was used including subjecting the proposed program to external review and advice on how best to prepare and present the expenditure forecasts.

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4 Response to information request IR017a

5 Response to information request IR035

6 The premise of the Steady State scenario assumes that electricity is managed and supplied in much the same way as it is today. There is a strong driver to reduce costs whilst maintaining network performance and ensuring security of supply

Review of iterations of expenditure

51. Powercor advises that the development of the first expenditure iteration was prepared in June 2018, with a total of nine iterations of the capital program prior to submission of the regulatory proposal.[7] Over the iterations Powercor describe that the gross capex varied from $2,845m to $2,290m.[8] All expenditure iterations were presented to the SteerCo.

52. Powercor describes the role of the SteerCo as having:[9]

> *'provided 'top down' level guidance on expenditure at the category level. It also provided strategic direction on a number of 'marquee projects' such as solar enablement and proactive pole replacement.'*

3.1.3 Risk management framework

Overview

53. VPN has established an Enterprise Risk Management framework which sets out the governance framework for risk. The risk framework includes a 5x5 risk matrix and a risk appetite statement approved by the Board.

Risk monetisation method

54. Powercor has developed risk monetisation models that seek to quantify the risk of an asset failure on the network. The risk models indicate earliest opportunity to invest in addressing the risk.

55. Having introduced the models in 2019, many of the models indicate that Powercor has already found opportunities to defer investment and is operating at a point beyond the earliest time to invest.

56. For repex, Powercor describes its approach as:[10]

> *'Specifically, our approach to monetising risk when assessing investment decisions is to determine the annual asset risk cost (as shown in figure 4.12). This approach is taken for all identified failure modes for an asset, and the sum of the annual asset risk cost for all failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.'*

57. For repex, the risk monetisation models are currently applied only to zone substations and switchgear, primarily driven by risk cost of unserved energy.

58. The approach for repex seeks to establish:

- A probability of asset failure;
- Consequence of failure event; and
- Likelihood of the consequence occurring.

59. This is captured in the figure below.

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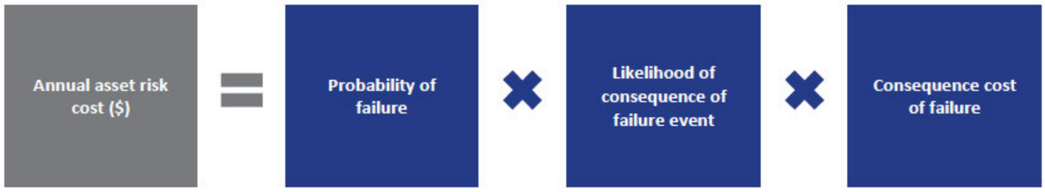
7 Response to information request IR035

8 By comparison, the total capex included in the Regulatory Proposal is $2,140m. Powercor, Regulatory Proposal page 10

9 Response to information request IR035

10 Powercor Regulatory Proposal page 45

Figure 3.4: Calculation of annual asset-risk cost



Source: Powercor Regulatory proposal Figure 4.12

60. Powercor's risk cost models sum the risk costs for network reliability, safety, financial and environmental risks.

61. Scenarios are based on central, lower, and upper sensitivity settings. RCM sensitivities are set for 5 scenarios at one of lower, central, or upper ranges. For PoF, Capex and opex, VCR and environmental costs, the range is +/-10%. For demand the range is +/-5%.

62. The outputs are risk cost vs annualised cost comparisons for each scenario. The optimal asset replacement investment timing is identified by comparing the annual monetised risk value of the existing asset and the annualised investment cost for each scenario.

63. In our assessment of proposed expenditure allowances, we have tested the sensitivity of the models to a different sensitivity range to identify projects and expenditure that can be reasonably deferred.

3.1.4 Asset management framework

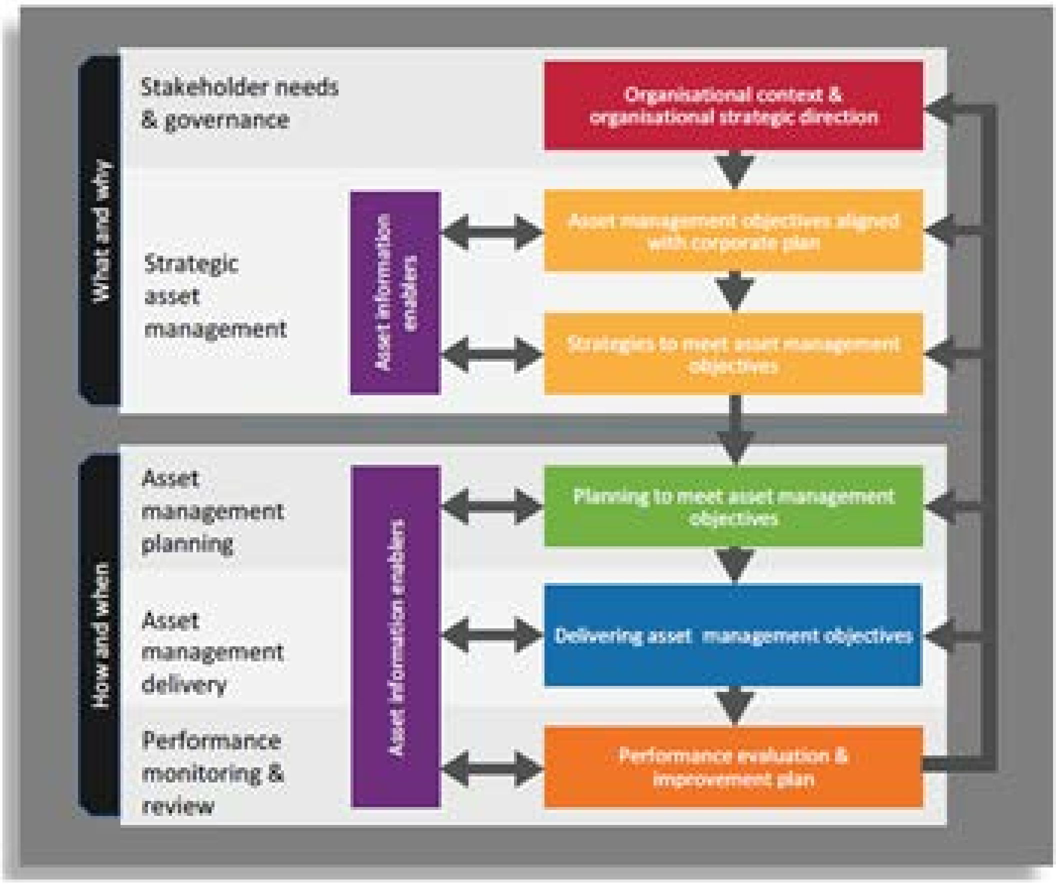
64. Powercor describes the VPN asset management approach as being aligned with the principles of the International Organization for Standardization (ISO) 55000 for asset management standards. The asset management system includes:[11]

- *'an asset management policy which sets out VPN's asset management principles and is endorsed by senior management and approved by the Chief Executive Officer (CEO);*
- *a Strategic Asset Management Plan (*SAMP*) which sets high level asset management strategies and objectives which are demonstrably linked to overall organisational objectives;*
- *management strategies which are used to develop the system and improve underlying processes;*
- *implementation processes and activities which deliver the plans; and*
- *performance measurement and improvement.'*

65. The asset management system is structured according to the following diagram.

11 Response to information request IR017a

Figure 3.5: Scope of VPN Asset Management System



Source: PAL ATT021 Strategic asset management, Figure 22

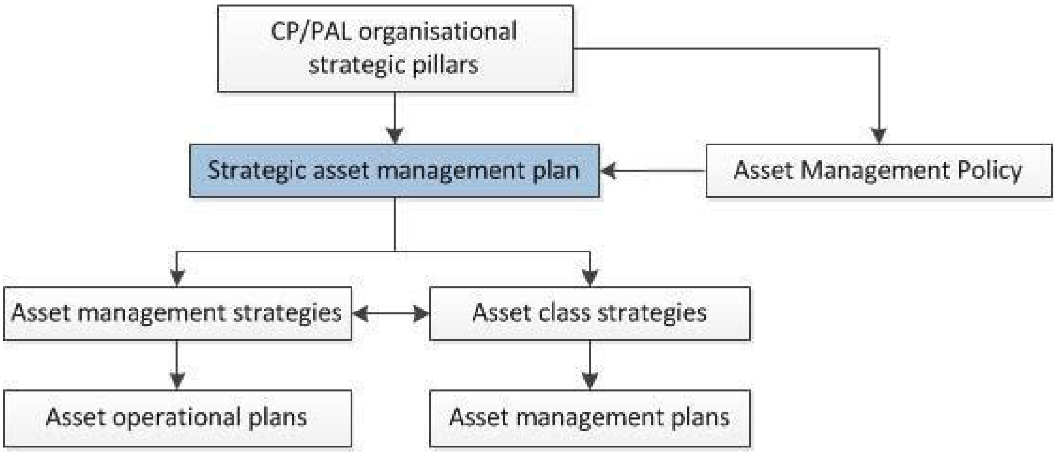
Asset management strategies and asset class strategies and plans

66. As detailed in its SAMP, VPN are developing a suite of Asset Management Strategies (AMS) and Asset Class Strategies (ACS). VPN describe these as:

- AMS address key AM activities that apply across all asset classes; and
- ACS focus on AM activities specific to the asset class.

67. The relationship between these elements is described in the figure below.

Figure 3.6: Strategy and planning hierarchy



Source: PAL ATT021 Strategic asset management, Figure 23

68. The SAMP includes a description of the Asset Management Committee to provide governance and oversight of the asset management system, with a structure of the committee and sub-committees to align with the asset management strategy accountabilities.

Changes to asset management practice

69. Changes to the asset management practices that are likely to have an impact to the forecast are described in RIN016.

3.1.5 Expenditure forecasting methods and assumptions

Overview

70. Powercor has described its modelling approach for capital expenditure as being the combination of its individual capital expenditure models as inputs to its consolidated capex model.

Expenditure justification

71. The regulatory proposal includes a number of business cases, expenditure models and other supporting information. The business cases and, in some cases, risk models account for the proportions of expenditure shown in the table below, as advised by each of the businesses we were asked to review.

Table 3.1: Proportion of expenditure included in business case documentation

Category	Powercor	CitiPower	United Energy
Repex	47%	68%	51%
Augex	74%	71%	55%
ICT	100%	100%	100%

Source: Onsite presentations to AER/EMCa by Powercor, CitiPower and United Energy

72. In addition, expenditure models provide a list of all line items that comprise the expenditure forecast for each expenditure category.

73. In response to our request for justification for expenditure that is not included in the business cases provided, we were directed to information provided with the regulatory proposal submission including the expenditure models.

Cost estimation

74. Powercor describes the cost estimation approach for network capex as being largely based upon its revealed actual costs. In response to our request for a copy of its cost estimation methodology, or similar explanation of the cost estimation and cost forecasting systems, methods and procedures, benchmarks, project cost estimation performance and approach for determining unit rates applied to the forecast capex, Powercor states that:[12]

> *'Robust cost estimates have been prepared for our regulatory proposal, which where applicable have been sourced from:*
>
> – *average historical unit costs, which may have been derived from historical revenues and volumes;*
> – *market based outcomes from competitive tender processes;*
> – *estimated data obtained from contractors or vendors; and*

[12] Response to information request IR017a

– *actual historical costs for similar projects.*

For example, for replacement projects the unit rates for high-volume works are based on average historical unit rates over the period 2014/15 to 2017/18. For larger works, project costs are based on the observed, actual costs of like-projects.'

Deliverability

75. In response to our request for an explanation of the delivery strategy and plan, including evidence of an assessment of the ability to deliver the proposed step increase in forecast expenditure, Powercor states that:[13]

'Our labour force is structured to provide flexibility in managing labour resources. This allows us to deliver our total capital program, including the forecast increase in replacement investment. For example, our labour contracts include the following types:

– Internal labour—these are permanent employees who provide the base level of labour required to provide a base level of labour services. To operate sustainably over the long term we must ensure we have secure access to a sufficient quantity of labour with the skills and knowledge required to deliver the minimum level of network and corporate services;

– Local Service Area Agents (LSAA)—these are third party owned and operated franchises that provide network services in specific network areas. LSAA's service different locations across our network and are generally assigned in the lower density network areas. LSAA's are selected through a five yearly market testing process;

– Resource partners—these are third-party businesses, for example Lend Lease and Electrix, that provide additional labour services on an as needs basis. We utilise our resource partners to manage increased workloads that may arise for specific work programs. Resource partners are identified through a three yearly market testing process; and

– Contractors—we utilise contractors for skill-specific work including electrical work, fault response, metering works, civil works (i.e., digging works), traffic management, design work and vegetation management. We have different contractual arrangements with our contractors, ranging from longer term contracts with third party businesses to project-specific arrangements with individual registered electrical contractors.

The mix between internal and external labour resources will be determined by, amongst other things workload volumes, timing and locations; skills and competencies requirements; resource availability; peak period workloads; and labour rates for internal versus external resources.

LSAA's, resource partners and contractors provide a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable Powercor to minimise the costs of engaging external resources to assist in delivering the services that customers require.

CitiPower and Powercor has a strong history of successfully delivering major capital investment programs, including our Rapid Earth Fault Current Limiter (REFCL) program and the roll-out of smart meters.'

[13] Response to information request IR019a

3.2 Assessment of Powercor's framework

3.2.1 Risk management

Risk framework is generally consistent with industry practice

76. The risk framework at the enterprise level is generally consistent with industry practice, along with the establishment of risk appetite statements. However, we did see evidence that this framework was applied differently across Powercor and CitiPower in relation to its poles repex program. We explore this further in our assessment of the poles repex.

It is misleading to treat all AFAP projects as safety regulatory obligations, without sufficient review

77. Powercor refers to its electricity safety management scheme (ESMS) as the means by which it demonstrates that risks arising from its electricity networks are minimised As Far As Practicable (AFAP). Powercor also advises that its application of disproportionality factors included in its risk monetisation models is consistent with its ESMS.

78. We understand from the onsite discussions that Powercor hold workshops to identify projects to satisfy their AFAP obligations and that these projects are subsequently discussed with ESV. Powercor stated that once its proposed projects are included in the Bushfire Management Plan (BMP) it submits to ESV, Powercor considers that completion of the activity is a regulatory obligation.

79. To our knowledge, ESV does not undertake economic analysis to allow it to approve strategies developed by Powercor as the basis of establishing new regulatory obligations. Whilst each DNSP is required to develop and submit a bushfire management plan consistent with its regulatory obligations, to ensure that the risk is AFAP, our understanding is that the economic and risk decisions remain with the DNSP consistent with its commercial and wider regulatory obligations including to the NER.

80. From the information provided to us, we consider it is misleading to assert that all components of the plan are regulatory obligations once included in the BMP and must continue without review. We saw evidence that 'safety/compliance' related projects have been included into Powercor's forecast; however, we were not provided with sufficient justification to determine the basis of their inclusion and/or how Powercor determines that the projects are required on the basis of its AFAP obligations.

Application of risk assessments to asset replacement decisions is not clearly evident for balance of expenditure

81. With the exception of those relatively confined categories where risk monetisation models are applied and were provided, the application of risk management is not clearly evident to the balance of Powercor's forecast expenditure. Rather, Powercor appears to have largely prepared its forecast on the basis of continuing existing asset management practices.

3.2.2 Risk monetisation

Reasonableness of applied method for repex

82. We consider that the approach adopted by Powercor is generally consistent with the AER practice guide.

Reasonableness of applied assumptions

83. The key drivers of risk cost as applied by Powercor are the calculation of unserved energy. We observe that the other risk costs, including safety risk, are much lower.

84. We note that Powercor uses a reasonable value for the value of a statistical life and a disproportionality factor of three (3) which we consider is reasonable for the analysis.

85. The reliability of the CBRM output depends on:

- accuracy of asset information (age/condition/history); and
- the selection of the constants used in determining the PoF curves.

86. The accuracy of Risk cost model output depends on:

- quality of input data; and
- integrity of the models – RCM model is new (2019) and relatively complex.

87. We discuss each of the input assumptions relied upon in the risk model in the sub-sections that follow.

88. We have not reviewed the demand forecast applied to the Powercor system demand or the process of calibrating demand forecast for each zone substation. We would expect the demand at the zone substation level to take account of local demand growth including spot loads in the zone substation load area.

Calculation of the probability of failure appears reasonable

89. The CBRM methodology implemented in 2008 provides the probability of failure and the likelihood and consequence cost of failure. These are inputs to the Risk Cost model.

90. Asset Health Index (AHI) is determined by applying asset condition modifiers to an initial AHI based on engineering knowledge of the asset (mainly age). A reliability modifier is used if an asset type has a known alternative PoF. Reliability modifiers take into account data on items such as oil tests, OLTC age and condition, etc.

91. The modified (current) AHI is projected to derive future health indices which, through the application of a formula, produces the PoF projection used in the RCM.

92. The PoF is determined in the CBRM model by applying the AHI to a formula derived PoF curve (provided by EA Technology and tested against Powercor/CitiPower experience). Constants are applied to calibrate the curve.

93. There are some inconsistencies between the project documentation and the CBRM AHI values that appear to have been applied in the risk cost models.

Value of VCR is weighted to outage duration

94. The value that Powercor has used for VCR is based on the AEMO 2014 report, escalated to current terms. This value is then weighted (adjusted) for outage duration for each customer class to derive a composite value of VCR that is used in the calculation of the cost of unserved energy. This has the effect of significantly reducing the value of VCR and unserved energy cost component.

95. We understand that Powercor intends to update the use of its value of VCR to the values recently published by the AER. Whilst this would reflect more recent studies, the impact to the risk cost modelling is likely to be low given the weighting approach applied by Powercor.

Use of a probability weighted demand using a 70:30 ratio has not been sufficiently justified

96. The risk cost model uses a probability weighted blend of the 10% Probability of Exceedance (PoE) demand forecast and the 50% PoE demand forecast. The weighting is 30% of the 10% PoE demand forecast to 70% of the 50% PoE demand forecast.

97. We asked for an explanation of this approach during the onsite discussions with Powercor. In summary, Powercor advised that the approach was:

- consistent with the approach taken by AEMO in calculating unserved energy;
- consistent with Powercor's current practice; and
- consistent with current Victorian industry practice.

98. We consider the key issue here is the application of a planning methodology to estimate the forecast expected value of unserved energy. Whilst we did not receive a written direct

response on this topic, we understand that Powercor considers that using the 50% PoE does not represent a realistic expectation of demand.

99. We consider that the expected value of unserved energy is not a function of the peak demand alone. It should take account of the Load Duration Curve, since the amount of energy unserved (if any) as a result of an equipment outage depends on the load during the time of the outage, and this also is influenced by any mitigation measures. We have observed different methods for taking account of these factors in DNSPs and TNSPs.

100. Powercor has asserted that the 70:30 method is the method used by all Victorian DNSPs. We are not able to verify this, however we have not encountered a 70:30 weighting being applied in planning methods in other DNSPs across the NEM or in Western Australia. Powercor has not demonstrated that its 70:30 assumption is valid for DNSP planning purposes, nor how it is derived.

101. We consider that resolving an appropriate and suitably common methodology for planning in distribution networks across Australia is of considerable importance. This goes beyond our brief of assessing the proposed expenditure using the information provided by the three Victorian DNSPs that we have been asked to assess. However, where we have found this aspect of each business' forecasting methodology to be relevant in our assessments of proposed repex and augex, we sought information from the business on any sensitivity analysis undertaken. Where provided, we have reported on this in our assessment.

Limited verification of modelling outcomes (including sensitivity analysis)

102. The Risk Cost model is a new and complex Excel model and Powercor/CitiPower confirmed that it has not been audited. However, we note that Powercor has engaged the assistance of experts in the development of its CBRM method and risk cost model.[14]

103. We do not see visibility of the overall prioritisation of projects, and therefore cannot see projects that have been rejected by Powercor as a way to validate those that have been include into the forecast. Absent this information, there is potential for the Risk Cost model to have only been applied to those projects that have already been selected for replacement in the forecast period.

104. Based on our review of the risk modelling, a number of interventions were identified to be completed in prior years and which have not been undertaken by Powercor. For instance, we asked Powercor for an explanation of the rationale for not commencing the replacement of transformer assets in the current RCP based on its own assessment that the optimal time to replace was in prior years to account for the fact that the corresponding investment had not been undertaken. Powercor states that:[15]

> *'In the current regulatory period, we have been transitioning to more sophisticated risk quantification and monetisation to manage any impacts associated with declining condition of major network assets. This commenced with the introduction of load indices in our investment decisions for major zone substation plant (rather than just health indices), and has evolved to the development and application of the risk monetisation model used in our regulatory proposal (which has also been applied to identify the efficient timing for in-flight projects).*
>
> *The application of our risk monetisation modelling has identified that some interventions are already efficient. We have regard to this in the development of a balanced works program, and actively manage risk in the intervening period (e.g. through amended works practices) until works can be designed, scheduled and completed (including completion of RIT-Ds where relevant).'*

105. We consider how effectively that Powercor has been managing the risk presented by its zone substation assets in our assessment of expenditure, including review of other indicators of asset condition.

[14] Response to information request IR032/IR035, Q19

[15] Response to information request IR017a EMCa questions – governance and repex

3.2.3 Asset Management

Asset planning and investment prioritisation framework not provided

106. In its Asset Management System framework document, VPN describe that it has:[16]

> *'implemented a new value framework comprising a set of measures that will form the basis for quantitatively prioritising investments. The value framework is being used to configure the Copperleaf C55 asset planning and investment tool to facilitate the quantitative prioritisation of investments going forward. The value framework will be used for the first time informing our 2020 budget and 5 year financial plan.'*

107. During our onsite review meetings with Powercor, we understood that the implementation of a prioritisation framework was ongoing and was not relied upon for development of the forecast expenditure. We were not provided with details of the framework or how it had been applied to the capex portfolio by VPN. Based on the description provided by VPN, the framework and tool is likely to provide a useful means to undertake scenarios at the portfolio level, and undertake sensitivity analysis to assist justify investments based on benefit to customers or VPN.

Ensuring the robustness of the provided models was a focus of our assessment

108. VPN has advised that its capital expenditure forecasts were planned and prepared using asset management and planning strategies, and:[17]

> *'In particular, for each relevant asset category, the planning and incurring of capital expenditure in accordance with the replacement asset management strategies and network capacity planning strategies.'*

109. In response to our request to provide details of the portfolio planning and management process across the portfolio, VPN stated:

> *'In preparing the capital expenditure forecasts, we note that:*

- *rigorous checks were made to the forecasts, including reviews by subject matter experts (SME), senior managers and the General Manager of the respective business unit, as well as other quality assurance steps to ensure that the amounts are free from error;*
- *rigorous checks were made to the various models used in preparing the forecasts;*
- *all major projects were assessed to understand their drivers and benefits to all customers. Risk-monetisation modelling was undertaken to ensure that:*
  - *we only invest when the cost of replacing existing infrastructure is lower than the total value of the underlying risks;*
  - *capital works for augmentation were only forecast where the cost of mitigation a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand-side solution is feasible;*
  - *the highest risk mitigation option was selected for information and communication technology (ICT) projects, where the ICT risks and business risks were assessed against the expected costs; and*
- *the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure.'*

110. We have reviewed each of the models and other supporting information provided to justify the forecast capex and present our assessment in the subsequent sections of this report. We looked for alignment between the portfolio and provided strategy documents and the

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16 Response to information request IR017a EMCa questions – governance and repex, Asset Management System Framework

17 Response to information request IR017a EMCa questions – governance and repex

robustness of the modelling and risk assessment relied upon in preparing the capex forecast.

Asset class strategies are too high level to assist with expenditure justification

111. The asset strategy documents provided are high-level and, whilst important to demonstrate the alignment of the strategies and objectives for each asset class to the SAMP, they fall short of detailing the strategies and plans (including changes) at an asset class level.

112. Powercor's plans do not include discussion of the responses to the challenges and objectives in terms of intervention options considered, risk assessments and/or application of models for technical and economic analysis. Where this information is provided, separate to the asset class strategies, we have taken this into account in our assessment.

Asset management strategies have not been considered in our review

113. On advice from VPN, asset management and operational plans are still being developed. Examples were not provided and therefore have not been considered in our review.

3.2.4 Top-down assessment and portfolio prioritisation

Measures of network performance are improving

114. During the onsite discussion Powercor stated that the frequency of extreme weather events was increasing, the associated level of network risk was also increasing, and that both of these are indicators of an increasing level of repex requirement.

115. At a global level, this trend is not evident in the information provided by Powercor, namely:

- We observe an improving trend of key service performance measures including SAIDI, SAIFI and public safety events. Similarly, the number of fire start events is also decreasing;
- Based on declarations by Powercor in RIN016, with the exception of the proposed changes to pole management, there are no material changes proposed to its asset management approach; and
- Powercor's expenditure associated with network faults has remained relatively stable irrespective of total replacement investment.[18]

116. We consider that these observations are not consistent with claims that the level of network risk is increasing, or that the repex requirements are increasing. We review the claims for increases to individual asset groups in our expenditure assessment.

Bottom-up methodologies appear to be based primarily on a reactive management approach

117. We observe evidence that the increases to the forecast expenditure are associated with new projects added to the current level of 'base' repex, which is based on projecting forward the historical level of defects.

118. For example:

- The environmental management program was added to the forecast to retrospectively apply noise abatement and bunding solutions to existing substation sites. Powercor described the driver of this work as responding to new legislation and associated obligations that were to be introduced by the EPA. Our understanding of the legislation is that the obligations on Powercor are consistent with those that currently exist and that are reflected in current design and maintenance practices;
- Programs are introduced in response to AFAP obligations that appear separate to (and potentially duplicate) programs that are developed as part of managing the specific asset class, such as conductor replacement and pole top structure replacement;

[18] Response to information requests IR032 and IR035

- There are increases to expenditure, particularly repex, in the last two years of the current RCP that are associated with the introduction of new projects and programs. With the exception of the changes to Powercor's pole management practices, the introduction of these programs is not sufficiently explained; and
- Powercor has proposed a significant program of claimed security and compliance upgrades at all of its depots in the next RCP, despite a separate current and proposed future program that involves redeveloping or rebuilding 10 of its 13 depots.

119. We did not see evidence of prioritisation of the portfolio to address the highest areas of risk, or optimisation of the proposed projects and programs. The examples indicate to us that there is further opportunity to prioritise existing projects and programs to target the highest areas of risk.

Projects are at an early stage of development

120. We understand that the projects and programs proposed in the forecast are at Gate A of the investment framework. Projects and programs typically pass Gate B about a year before commencement.

121. Therefore, the portfolio that is actually delivered is likely to be different to the portfolio that is being presented in the proposal. Whilst this is the inherent nature of a forecast, in our assessment of expenditure we sought to understand the changes made by Powercor through its process of management review and approval, the sensitivity analysis undertaken to consider investment decisions and alternatives, and consideration of option value in the risk analysis undertaken.

Full impact of cost efficiencies not evident in forecast

122. Powercor advises of efficiencies to its capex program delivered in the current RCP of $334m capex through its World class program.[19] There were similar opex efficiencies claimed.

123. We requested details of the breakdown of the efficiencies delivered by this program to understand the level of deferred work from sustained efficiency savings and to ascertain whether such efficiencies are reflected in Powercor's forecast expenditure.

124. In its response, Powercor stated that:[20]

> *'It is not possible to provide the detailed breakdown of these efficiencies by expenditure class.'*

125. It did however clarify the nature of the efficiencies gained:[21]

> *'As described in CP APP02 and PAL APP02 - What we have delivered, most of the World Class initiatives had an impact on network capital expenditure;*
>
> *In terms of technology innovations automation of field works, design and connections all enhanced network expenditure efficiency. Further network expenditure savings were realised through revised contracting arrangements for material procurement, traffic management and metering and servicing. Lean and efficient service delivery model enabled consolidation of key functions across the businesses into single points of responsibility e.g. procurement. Changes to our service delivery model also allowed removal of layers of management and synergies/downsizing to be achieved through joint provision of corporate services. Lastly efficient investment decisions relied on exploitation of advanced metering infrastructure technology and the introduction of risk monetisation and calibration of our condition based risk modelling; and*

19 Powercor - Appendix 02 - What we have delivered - 31 January 2020

20 Powercor's response to information request IR032 and IR035

21 Powercor's response to information request IR032 and IR035

These savings are now embedded in our businesses, whether it be historical unit rates, historical material costs, reduced employee numbers or our current asset management practices.'

126. In our assessment, we therefore looked for evidence that these efficiency savings had been reflected in the unit costs applied by Powercor in the development of its forecast expenditure.

127. Powercor states[22] that its forecast of high-volume, low-cost asset interventions is largely consistent with its historical investment based on an average of observed historical replacement volumes. We requested that Powercor confirm how it determined the sample period (as number of years) to include in its forecast method when considering linear trends or averages. Powercor states that:[23]

'Our high-volume, low-cost asset interventions are typically forecast based on a four-year average of historical volumes and unit rates. A four-year averaging period provides a reasonable balance between using the most current data available and the risk that a shorter period (i.e. a single year) may over or under-state future volumes. A four-year averaging period is also consistent with the approach used by the AER in its repex model.'

128. We note that the above information does not apply to the derivation of the pole intervention forecasts. For all volume based replacement programs, including poles, Powercor states that the unit rates:[24]

'…are based on average historical unit rates over the period 2014/15 to 2017/18.'

129. We observe that this period aligns with the period that Powercor undertook its World Class program. Using this period without adjustment is not likely to take account of the full benefits arising from the World Class program and is likely to overstate the unit rates for each of the programs.

130. Based on the information provided by Powercor, we are not convinced that the full capital efficiencies that it is currently achieving from its World Class program are reflected in the costs relied upon for development of its forecast expenditure.

3.2.5 Justification of expenditure

Justification documentation that was provided is not robust

131. The originally provided justification documentation did not constitute an adequate level of supporting evidence to justify the proposed expenditure. We therefore requested additional information from Powercor to justify the proposed expenditure (i.e., business cases or similar) for the total forecast expenditure in each asset group including details of the scope, key drivers, asset condition and risk information relied upon in developing the forecast, the options considered and the financial analysis undertaken and any relevant models. We also asked for a copy of any modelling that had been used in determining the proposed expenditure

132. In its response, Powercor directed us to the existing business case documents and models, the expenditure models, relevant asset class strategies, RIN016 and responses to previous information requests.

133. We also discussed our requests during our onsite meeting, where Powercor directed us to the same information. We asked further questions of Powercor and where new information was provided, we have referred to this in our assessment.

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22 Powercor Regulatory Proposal page 34

23 Response to information request IR032 and IR035 EMCa questions following onsite

24 Response to information request IR017a

134. Whilst we were typically able to determine the volume of replacements and associated forecast expenditure for the next RCP by applying the derived unit rates, in many cases we were unable to ascertain: (i) the rationale for inclusion of the program into the forecast; or (ii) the basis for the replacement volumes from the documentation that Powercor supplied.

Project and program justification documentation left areas of expenditure largely unexplained

135. The information provided in the business case documents was specific to a number of projects and programs. Similarly, the responses to information requests drew on specific models and explanations, which left areas of the proposed forecast expenditure largely unexplained. We used the information provided to derive historical replacement volumes and trends and sought to ascertain the basis for inclusion of programs into the forecast from other information provided (such as asset strategy documents).

136. We observed a reliance on the expenditure models which included lists of projects and programs that appeared to reflect an assumption that the underlying level of replacement volumes would continue and be projected forward based on a simple averaging approach.

137. As noted above, we did not see consideration of improving service outcomes to ascertain whether the existing program reflected a prudent level of expenditure, or that the proposed introduction of additional proactive programs would not displace the underlying level of replacement. In most cases, we observed this was a flat profile, indicating a constant replacement rate.

Forecast replacement volumes are not supported by evidence of observed performance

138. Powercor's forecast replacement volumes are based on its revealed historical replacement volumes. Based on a reactive 'find and fix' replacement approach, we consider that reliance on historical trends is not sufficient justification for the forecast. This may tend to overstate the required level of expenditure by effectively assuming the same level of work will be repeated. This approach indicates that the planned work is a function of factors other than the observed performance of the assets.

Absence of evidentiary support from Powercor

139. There is an absence of evidence to justify the volume and cost assumptions that Powercor has included in its proposed forecast, and whether or how these assumptions reflect an optimised risk outcome. In our assessment, we therefore looked for evidence of justification of the proposed expenditure, consistent with the normal requirements of a business case-like document, from the information that we requested.

140. Based on our experience, we consider that a typical DNSP should have this information readily available to support its claims. This is consistent with our experience of having undertaken numerous expenditure reviews for the AER, supported by the AER's capital expenditure assessment guideline and was reflected in our information requests to Powercor.

3.3 Summary of findings

The regulatory proposal governance processes of the business do not always align with their stated investment governance frameworks

141. Powercor has described the Investment Governance Framework (IGF), including the risk assessment and management review and approval process, that was applied to the development of its expenditure forecast. However, we consider that Powercor has deviated from this governance process in preparing its regulatory proposal.

142. We sought to understand the magnitude and impact of these deviations and their adherence (or otherwise) to the requirements of the NER and expenditure assessment guidelines, consistent with our scope of work.

We have focused our review on the application of Powercor's governance and management framework in our assessment of expenditure

143. The elements of the governance and management framework described to us by Powercor are generally consistent with industry practice. We have been largely guided by discussions with Powercor and the description provided of its review and engagement processes, conducted as part of the development of its Regulatory Proposal and expenditure forecast. We have focused our assessment on Powercor's application of each of the elements of this framework in developing and reviewing its expenditure forecast for the next RCP.

144. As discussed in sections 4 to 8 for capex, and section 9 for opex, we have concerns with the practical application of Powercor's governance and management elements and its forecasting processes to actual projects and programs, based on the evidence provided from our assessment of the aspects of capex and opex that are within our scope.

Forecast is likely to be overstated due to the limited application of portfolio-level assessment and optimisation

145. We observe that the approach taken to the development and review of the portfolio varies across the different expenditure categories. We have not been provided with compelling evidence to confirm that Powercor has effectively established a link between its proposed program and intended benefit to consumers including as measured by network performance outcomes and network risk.

146. At a portfolio level, we observe that Powercor intends to deliver a significant underspend of the AER's capex allowance for the current RCP, due to a combination of initiatives including changes to management of risk, its forecasting practices and efficiency improvement programs. We sought evidence of how these changes have been applied in the development of its forecast expenditure for the next RCP.

Powercor's application of risk and supplied risk-cost models are very sensitive to its consequence assumptions

147. In our assessment of the proposed expenditure, we sought evidence of the justification of the proposed expenditure including how the Risk Framework and risk cost models to its capex forecast had been applied. We also looked for evidence of how Powercor's forecasting methodologies have applied reasonable assumptions, that those assumptions were supported with evidence, and that Powercor had accounted for option value and alternative solutions.

148. We have outlined the specific aspects of Powercor's expenditure forecasting methodologies for each of the expenditure categories we have reviewed,[25] along with our assessment of these methodologies as a part of our assessment of each expenditure category.

Powercor has declared significant efficiencies in the current period, but do not appear to have accounted for these in their forecasts

149. We have not seen evidence that the cost efficiencies that have been declared by Powercor in the current period have been incorporated into its forecast expenditure. This is consistent with the observation that Powercor considerably underspent their capex allowances in the current period. Accordingly, we consider that there is potential for further cost efficiency to be accounted for in their proposed capex allowances.

Our assessment of governance and management relates to the aspects of Powercor's forecast included in our scope of review

150. Our assessment of Powercor's expenditure relates only to certain aspects of Powercor's expenditure. In sections 4 to 9 below, we consider Powercor's application of its expenditure forecasting methodologies to the relevant capex and opex categories.

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[25] repex, augmentation (non-DER and DER driven), ICT, and property

4 REVIEW OF PROPOSED REPEX

In this section, we present our assessment of forecast repex that Powercor has proposed for each RIN group in the next RCP. Our review is focused on the major drivers of expenditure. Overall, we consider that Powercor's proposed repex is not a reasonable forecast of its requirements.

We consider that its proposed expenditure allowance for wood pole replacements is considerably overstated and that elements of its proposed expenditure on service lines, pole top structures, switchgear and SCADA are also overstated (though to a lesser degree). There is also an element of duplication in Powercor's proposed 'other' expenditure.

We consider that Powercor's proposed repex for transformers, overhead conductor and underground cable replacements is reasonable.

We consider that Powercor's forecast is upwardly biased through not having properly taken account of unit cost efficiencies that it has demonstrably realised in the current RCP.

4.1 Introduction

151. We reviewed the information provided by Powercor to support its proposed repex forecast, including a sample of projects and programs. Our focus was to ascertain the extent to which the issues identified in the preceding sections are evident at the activity level, and to validate that the forecast expenditure reflects the NER criteria.

152. We sought to establish the strategic basis for, and the reasonableness of, Powercor's proposed repex for each of the identified categories of expenditure. Forecast expenditure in the next RCP is reflective of a step increase from the historical expenditure that Powercor has incurred and is expected to incur in the remainder of the current RCP.

153. Powercor has provided its bottom-up forecast and how this forecast has been apportioned to each of the RIN groups. We have referred to this in our assessment.

154. The AER has identified a number of 'Focus' projects to us. Accordingly, we have included these in our assessment of Powercor's proposed repex forecast, within the relevant category of expenditure, as shown in Table 4.2.

155. We first summarise and compare Powercor's proposed expenditure for the next RCP with its historical actual and estimated expenditure in the prior and current RCP's. We subsequently provide our review of Powercor's forecast for each repex RIN group.

4.2 Summary of Powercor's proposed repex

4.2.1 Overview

156. Powercor's repex forecast originally proposed in its regulatory submission is $694.8m for the next RCP. As described in Section 2, Powercor subsequently withdrew almost all of originally proposed Environmental Management expenditures and it had included Public Lighting, which we have removed.

157. Table 4.1 shows our assessment of the proposed Repex by RIN Group following these adjustments.

Table 4.1: Powercor repex for the next RCP – Following adjustments for Environmental Management and Public Lighting - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	52.5	53.6	54.8	55.9	57.0	273.8
Pole Top Structures	16.5	16.8	17.1	17.4	17.6	85.4
Overhead Conductors	8.8	9.0	9.2	9.3	9.4	45.7
Underground Cables	0.6	0.6	0.7	0.7	0.7	3.3
Service Lines	9.1	9.3	9.5	9.7	9.9	47.6
Transformers	11.2	10.0	10.8	10.5	8.7	51.0
Switchgear	11.5	11.8	12.0	12.3	12.5	60.0
SCADA, Network Control and Protection	4.6	4.7	4.7	4.9	4.9	23.9
Other	16.9	12.4	8.0	8.1	8.2	53.6
Total	**131.8**	**128.2**	**126.8**	**128.7**	**128.9**	**644.4**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

4.2.2 Repex from the project models as mapped to RIN Groups

158. The following table shows project-level repex of $614m for the next RCP. We also show the AER focus projects and relevant amounts. Public Lighting and the Environmental Management program have been removed, consistent with the table above.

159. Real cost escalation is not included in Powercor's project model analysis. Values have been inflated where necessary to be in the common basis of Real 2021 dollars. While noting that real cost escalation would need to be reapplied (to the extent that it is considered valid), the costs in the following table reflect the amounts that we have assessed.

Table 4.2: Powercor repex for the next RCP – Following adjustments for Environmental Management and Public Lighting, showing AER Focus Projects and Programs - $m, real 2021

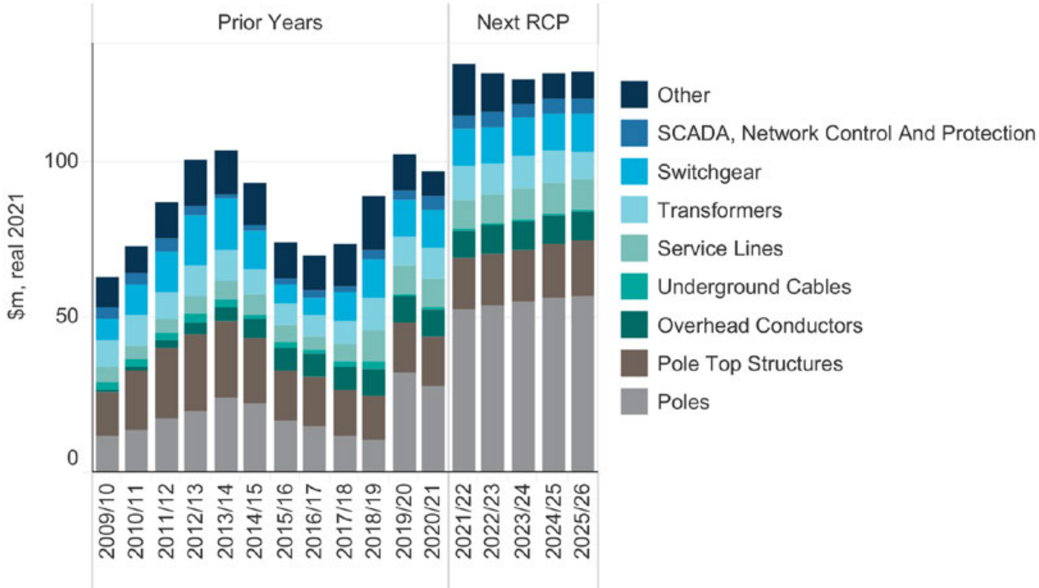
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	47.4	47.6	47.9	48.1	48.3	260.6
AER Focus: Wood Poles	*42.5*	*42.5*	*42.5*	*42.5*	*42.5*	*233.8*
Other	*4.9*	*5.1*	*5.4*	*5.6*	*5.9*	*26.8*
Pole Top Structures	16.3	16.3	16.3	16.3	16.3	81.3
Overhead Conductors	8.7	8.7	8.7	8.7	8.7	43.5
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.1
Service Lines	9.0	9.0	9.1	9.1	9.2	45.4
Transformers	11.0	9.6	10.2	9.8	8.0	48.7
AER Focus: Robinvale Transformer replacement projects	*1.6*	*0.4*	*1.9*	*1.5*	*0.0*	*5.4*
Other	*9.4*	*9.2*	*8.3*	*8.3*	*8.0*	*43.2*
Switchgear	11.3	11.4	11.4	11.5	11.5	57.1
AER Focus: HV ABS	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*12.3*
Other	*8.9*	*8.9*	*9.0*	*9.0*	*9.1*	*44.8*
SCADA, Network Control and Protection	4.6	4.5	4.5	4.6	4.6	22.7
AER Focus: Protection & Replacement	*4.6*	*4.5*	*4.5*	*4.6*	*4.6*	*22.7*
Other	16.6	12.0	7.6	7.6	7.6	51.5
Focus: VBRC	*13.3*	*8.8*	*4.6*	*4.6*	*4.6*	*35.8*
Other	3.3	3.2	3.1	3.1	3.1	15.7
Total	**129.7**	**124.1**	**120.6**	**120.5**	**119.1**	**614.0**

Source: EMCa analysis of Powercor MODs 4.06,4.09, 4.10, 4.11, 6.09. Excludes real cost escalation

4.2.3 Repex trend

160. Repex trends over time, by RIN Group, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. 2018/2019 FY RIN data has not been provided by Powercor. The capex for 2018/19 FY has been generated using escalated project model data provided by the AER. All expenditure has been inflated to Real 2021 dollars and, for the purposes of allowing comparison to the historical RIN, also includes Powercor's proposed real cost escalation.

Figure 4.1: Powercor repex – Following adjustments - $m, real 2021



Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'PAL consolidated RIN - repex - 2018-19_sent to EMCa'

4.2.4 Observations from Repex trend

161. The figure above shows that Powercor's repex forecast for the next RCP shows a significant increase across most expenditure groups, compared to actual and estimated expenditure in prior years. The forecast increase is driven primarily by higher expenditure in the 'poles' and 'switchgear' RIN asset groups.

4.3 Assessment of Powercor's repex activity forecasting methods

4.3.1 Overview

162. Powercor has applied a combination of forecasting methods to develop its bottom-up repex forecast, as discussed below and which comprise:

- Defect-driven programs - focused on high-volume, low-cost asset interventions including pole-top structures and conductors;
- Other project and program-based expenditure - including wood poles, where CBRM techniques have been applied (such as for substation-based assets) and other project specific expenditure; and
- Network faults.

4.3.2 Defect driven programs

163. As discussed in section 3, the high-volume, low-cost asset interventions (excluding wood poles) are forecast based on a four-year average of historical volumes and unit rates. Powercor stated that:[26]

[26] Powercor's response to information request IR032 and IR035 - EMCa questions following onsite

'as the majority of our forecasts are based on historical volumes and/or historical unit rates, it is not expected that service outcomes driven by these forecasts will fundamentally change (i.e., they will be maintained).'

164. Given that a large part of the forecast repex is based on this method, we asked what sensitivity analysis Powercor has undertaken to determine the level of confidence in its forecast given the significant increases in proposed expenditure. Powercor states that:[27]

'…with the exception of our pole replacement forecasts (which are justified separately, and have been the subject of a rigorous review by ESV), our replacement expenditure forecast is consistent with the AER's repex model outcomes. Similarly, our unmodelled expenditure component aligns with that forecast using the AER's previous methodology, noting that as previously communicated, we have withdrawn the forecast step up in our environmental compliance investment.'

165. In our assessment of the forecast expenditure, we reviewed the proposed defect-driven programs and projects in combination. We also reviewed whether Powercor had sufficiently justified its proposed expenditure, including any changes from the level of expenditure that it had been incurring to deliver current service outcomes against the requirements of the NER.

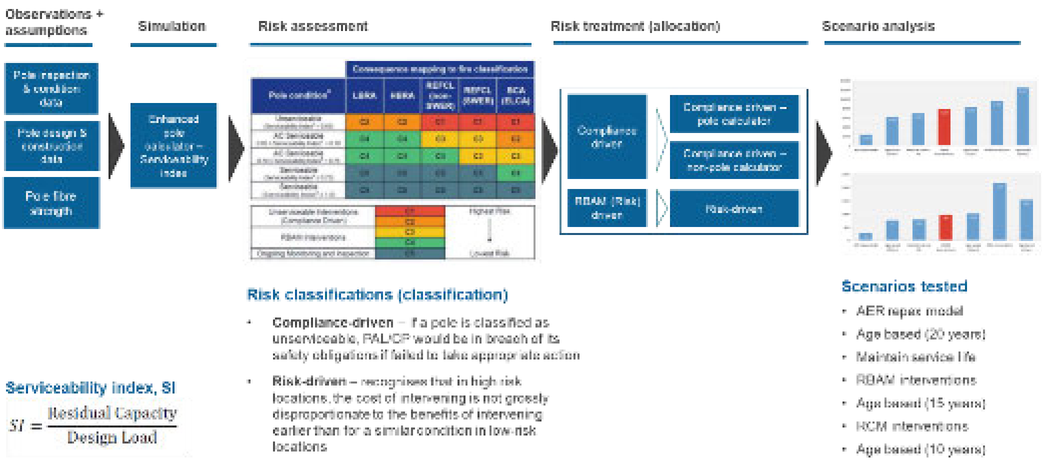
166. For some asset groups, including for service lines, Powercor provided more granular defect and replacement data to support inclusion of its proposed service line replacement programs. We comment on these in our assessment of the associated expenditure.

4.3.3 Other projects and programs

Wood pole replacement program

167. We summarise the forecasting method applied for the development of the wood poles forecast expenditure (excluding network faults) for Powercor in the figure below.

Figure 4.2: Overview of forecasting method for wood pole expenditure – Powercor and CitiPower



Source: EMCa from information and explanations provided in Powercor documents

168. We include discussion of each of the elements of this forecasting method as part of our assessment of the proposed expenditure in the subsequent sections.

Substation transformer and switchgear replacement

169. VPN applies the CBRM methodology to certain plant-based asset classes, namely transformers and circuit breakers, as well as protection and control equipment. In addition,

[27] Powercor's response to information request IR032 and IR035 - EMCa questions following onsite

risk monetisation methodologies are applied for selected transformer and switchgear replacements.

170. We have reviewed the process through which Powercor developed its repex forecasts, including the application of its CBRM and risk monetisation models and the business cases that it supplied. We provide a review of its CBRM method and risk monetisation models proposed by Powercor in Appendix B.

171. In our assessment of the proposed expenditure, we have applied tests to the various models and challenged output forecasts.

172. Whilst Powercor includes data for all transformers, circuit breakers and switchgear in its CBRM model, it does not subject all its substation assets to risk monetisation assessment.

Protection replacement projects

173. Powercor has applied the CBRM methodology to protection relays in a similar way as it has for substation transformer and switchgear to identify candidate projects for replacement.

Other targeted project and program expenditure

174. A number of additional projects and programs are included in the forecast repex that were forecast using other methods. The level of detail provided in support of these projects is limited to a single line description in the provided expenditure models, with the associated year on year costs hard-coded into these models.

175. We looked for evidence of justification for the proposed expenditure from the information provided. We expected the level of justification to be consistent with the normal requirements of a business case-like document, to support the development of a prudent, efficient and reasonable program of forecast expenditure.

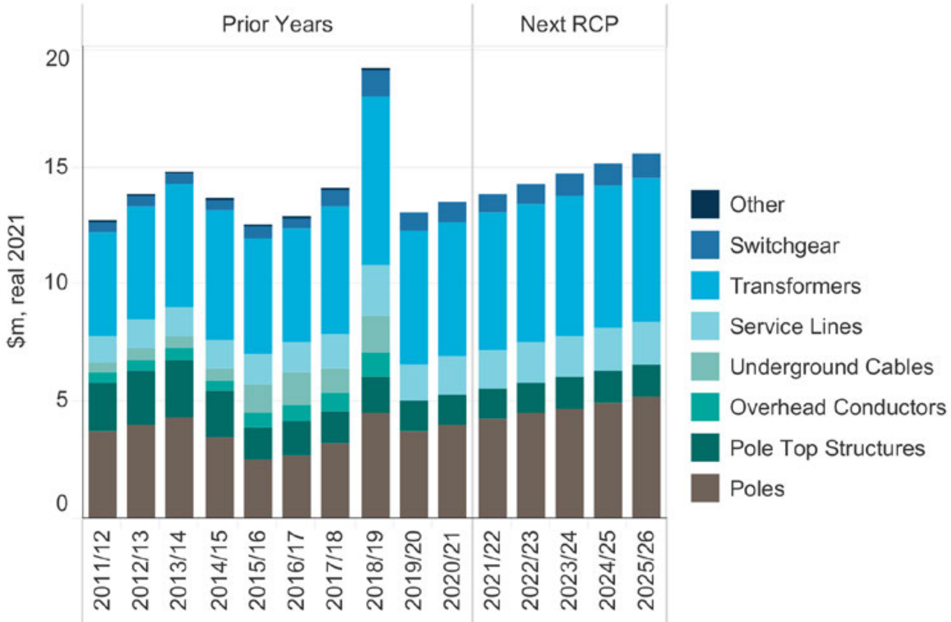
176. However, in the majority of cases, business cases were not provided for these projects. The supporting detail provided in other documentation was, in general, not sufficient to justify the proposed volume and cost assumptions that Powercor has included in its repex forecast.

4.3.4 Network faults

177. Powercor has included an allocation of $73.5m for network faults in its forecast repex,[28] across multiple RIN groups. The composition by RIN group is shown in the figure below.

[28] Excludes Public Lighting

Figure 4.3: Powercor's forecast network fault related repex by asset group - $m, real 2021



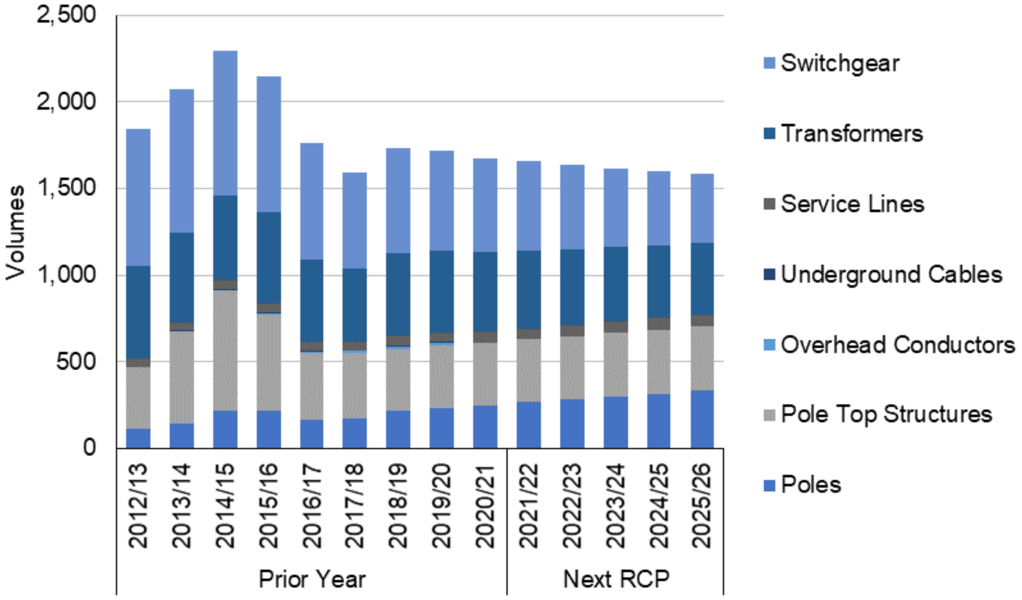
Source: EMCa analysis of Powercor MOD 4.11. Excludes real cost escalation.

178. The expenditure for the period up to and including 2018/19 is based on actual historical expenditure. The increase in 2018/19 is driven by increases to poles and pole-top transformer replacement. However, the increase is not evident in the trend of replacement volumes over the same period. This suggests to us an underlying data issue. We assume that the expenditure increase is associated with the bushfires that occurred over that period in the south-west of the state, and which we would associate with a similar increase in volumes.

179. For the remainder of the current RCP, from 2019/20, Powercor has forecast expenditure based on an expected replacement rate and unit cost. The forecast replacement level for each RIN asset group is developed by taking the average increase/decrease over the period 2011/12 to 2017/18 in units and adding this in each year commencing 2018/19 on a linear trend. That is, for 2019/20, the replacement volume is the sum of the replacement volume in 2017/18 and twice the average increase/decrease.

180. We show the changes in replacement volume that correspond to the forecast expenditure in the figure below.

Figure 4.4: Replacement volume trend for network faults repex by RIN group

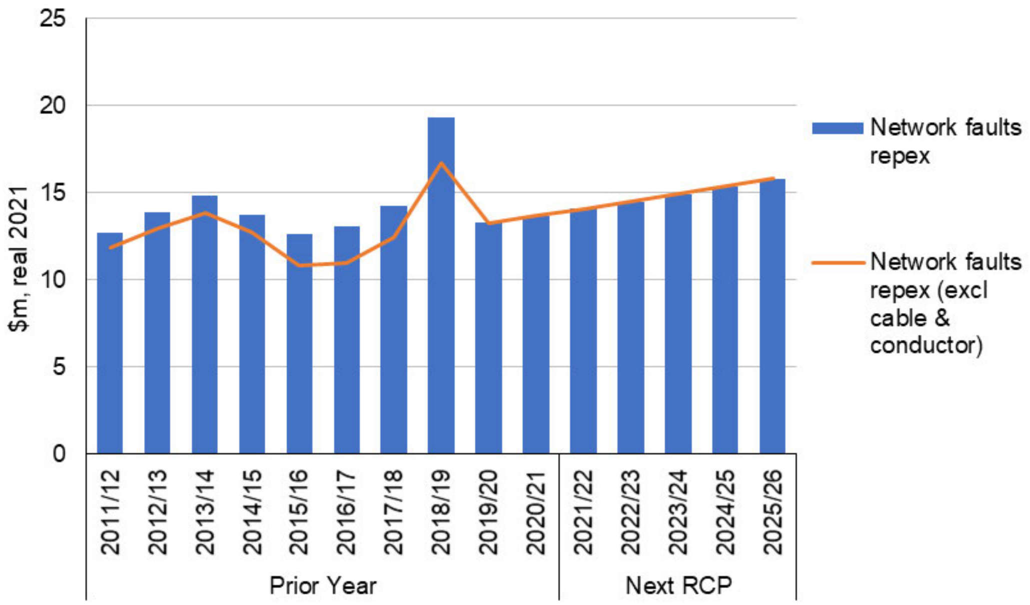


Source: EMCa analysis of Powercor MOD 4.11. Groups with zero replacement volumes have been removed.

181. From the chart, the total replacement volumes are declining, but the proportions between RIN groups are changing. Specifically, the replacement volume for poles is forecast to increase whilst the replacement volume for switchgear is forecast to decrease.

182. A further change to the forecast expenditure is that the expenditure and corresponding historical replacement volumes for overhead conductor and underground cable have been removed from the forecast. This is shown in the figure below, whereby the replacement expenditure indicated by the line is projected forward from 2017/18.

Figure 4.5: Comparison of Powercor's forecast network fault related repex with and without UG cable and OH conductor repex - $m, real 2021



Source: EMCa analysis of Powercor MOD 4.11

183. The unit rate for network faults repex is derived in the same way as for other volumetric repex, being the average over the historical period 2014/15 to 2017/18.

184. In response to our request to explain the basis for the network fault expenditure, Powercor states that:[29]

> *'For network faults, a longer-term trend was used. A longer period was considered reasonable given the persistence of the trend and our confidence in the robustness of the underlying data.'*

185. We requested that Powercor confirm if any adjustments had been made to the network faults forecast in light of the proposed increase in planned replacement programs and improving network reliability. Powercor provided evidence to demonstrate that there was little correlation between network fault expenditure and the level of total repex, on the basis that network faults are random and are primarily driven by severe weather events.[30]

186. We agree that network faults can be random and are typically driven by weather events. This also means that the composition of assets that are likely to require fault-driven replacement may change from year to year.

187. Powercor has not explained the rationale for its increasing fault driven expenditure forecast, given the relatively flat historical trend. In the absence of better information, the level of expenditure associated with network faults is more likely to remain similar to historical levels, rather than an increasing trend as proposed.

188. In our assessment of expenditure by RIN group, we have noted where Powercor has included a forecast for network faults based on the forecasting method described earlier. Accordingly, we have not included any further assessment of the network faults expenditure.

4.4 Assessment of Powercor's proposed repex by RIN group

4.4.1 Poles

Powercor's forecast

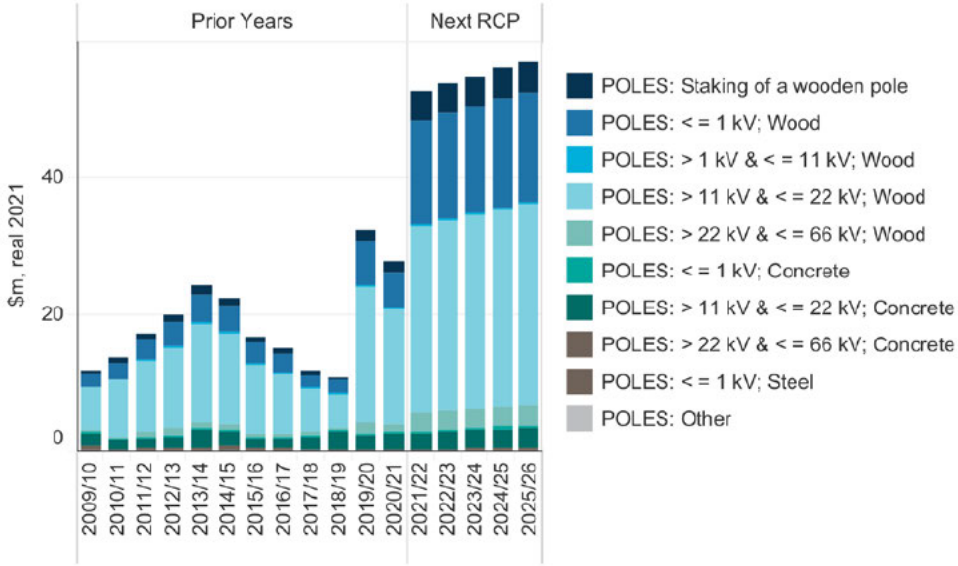
189. Powercor has proposed $273.8m[31] for the Poles asset group (including pole staking) in its repex forecast for the next RCP. The expenditure profile for the Poles asset group comparing the next RCP with previous years is shown in the figure below.

29 Powercor's response to information request IR035 - EMCa questions following onsite

30 Powercor's response to information request IR035 - EMCa questions following onsite, page 10-11

31 Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.6: Poles repex by asset category - $m, real 2021



Source: Powercor Reset RIN

190. The figure above shows a step increase in expenditure for the next RCP, with the largest increase associated with LV pole replacement. The major components of expenditure and program by construction type are shown in the tables below (which reconcile to Powercor's program when real cost escalation is excluded.)

Table 4.3: Components of Powercor's proposed pole repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Pole Replacement	43.1	43.1	43.1	43.1	43.1	215.7
Pole Life Extension - Staking	4.3	4.3	4.3	4.3	4.3	21.4
Network faults	4.2	4.5	4.7	5.0	5.2	23.6
Total	**51.6**	**51.9**	**52.1**	**52.4**	**52.6**	**260.6**

Source: Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

Table 4.4: Powercor's proposed pole repex by construction type - $m, real 2021

Construction type	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Wood poles	48.6	48.7	48.8	48.9	49.0	244.1
Concrete poles	2.9	3.0	3.1	3.3	3.4	15.6
Other	0.2	0.2	0.2	0.2	0.2	0.9
Total	**51.6**	**51.9**	**52.1**	**52.4**	**52.6**	**260.6**

Source: Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

191. Powercor has provided the following documentation with its submission to support its expenditure:

- a business case for its wood pole replacement program[32] totalling $233.8m ($2019); and
- models comprising its lines replacement expenditure (MOD4.06) and network faults related expenditure (MOD 4.11) which include poles repex.

[32] Powercor BUS 4.0 2 and CitiPower BUS 4.02 Wood Pole replacement program

Our assessment

There is a reasonable basis for increased interventions above historical practices

192. In determining a prudent and efficient level of expenditure, it is important to understand how the risk of the pole population is measured and managed over this time period and whether the service to customers is being maintained in accordance with the requirements of the NER.

193. In assessing the increase in expenditure proposed by Powercor, we first reviewed the rationale for the changes to asset management practices that the increase relies upon.

194. In the review undertaken by ESV,[33] it found that:

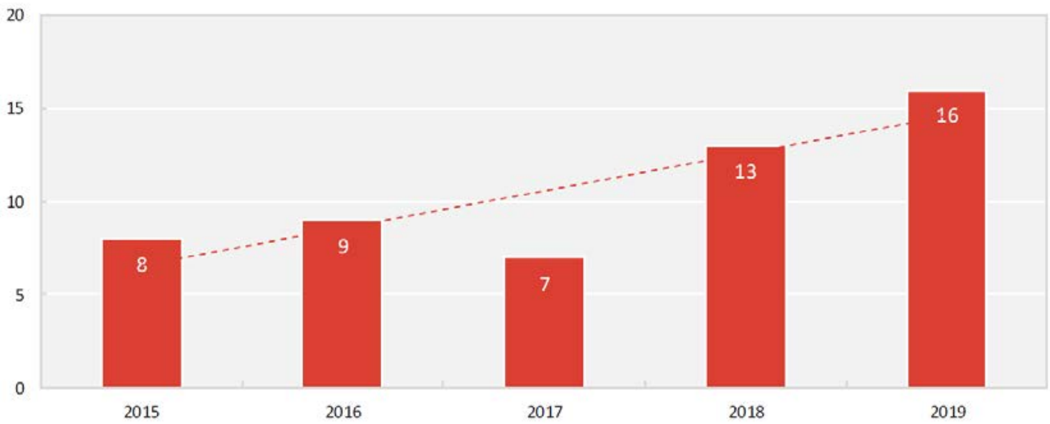
- the number of wood pole failures was increasing. Further, the wood pole failures were occurring in poles that Powercor had identified as being serviceable;
- Powercor had reduced the number of wood pole replacements and reinforcements at the same time as failures were increasing; and
- Powercor's practices were not aligned with industry practice for wood pole management.

195. Powercor's own RCM study completed in October 2019, found that:[34]

- the historical trend in pole failures shows a deterioration in performance; and
- the number of poles classified as 'unserviceable' has declined, despite increasing trends in pole failures.

196. We have reproduced Powercor's historical wood pole failure rate in the figure below. It shows a clearly increasing trend.

Figure 4.7: Historical wood pole failure performance for Powercor



Source: Powercor BUS 4.02 Figure 5

197. In response to the concerns raised by ESV, and from its own RCM study, Powercor acknowledged the need to make changes to its historical wood pole management practices. In 2019, Powercor applied a number of changes to better target poles at elevated risk of failure, including:[35]

- increasing the frequency of inspections and testing from 30 months to 12 months for all poles classified as 'added-control serviceable';

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33 Powercor ATT245: ESV, Powercor, Sustainable wood pole safety management approach, Detailed technical report, December 2019

34 Powercor BUS 4.02 page 12, which refers to Powercor ATT093: ARMS reliability, *Final report, 2019 RCM study report*, October 2019

35 Powercor BUS 4.02 page 10

- Increasing the pole residual strength safety factor from 1.25 to 1.40 for all poles; and
- Introducing a new assessment criterion to trigger replacement based on visually identified defects.

198. The impact of these changes is clearly evident in the increase to replacement and reinforcement volumes, and associated expenditure that is estimated to be incurred in the last two years of the current RCP, as shown in Figure 4.7 above.

199. For the next RCP, Powercor proposes adoption of its enhanced pole calculator. Compared with its existing pole calculator, the major changes are to:[36]

- more explicitly consider '*fibre strength loss over time, based on species and diameter loss*;' and
- Assessment of the tip load (acting on each pole) in accordance with AS7000 Overhead line design, using limit state design methods.

200. The proposed changes to the wood pole management practice have been developed with assistance of technical experts and reviewed by ESV. We understand that ESV is supportive of the proposed changes as a means of increasing the wood pole treatment volume.[37]

201. We also understand that, whilst Powercor has advised ESV of changes to its asset management practices, ESV does not approve the practices or undertake any economic assessment of approaches applied by Powercor.

202. We consider that the changes proposed by Powercor to its asset management practices for wood poles represent an improvement from its historical practice and are based on methods that, in general, are more likely to result in a reasonable assessment of treatment volumes.

Powercor has proposed a step increase in pole treatment volume that is primarily driven by the introduction of its 'enhanced pole calculator'

203. Powercor has developed its enhanced pole calculator in response to concerns raised by ESV as noted above. The enhanced pole calculator is intended to be used as a basis for predicting wood pole condition and deriving a forecast of the total volumes of wood pole interventions.

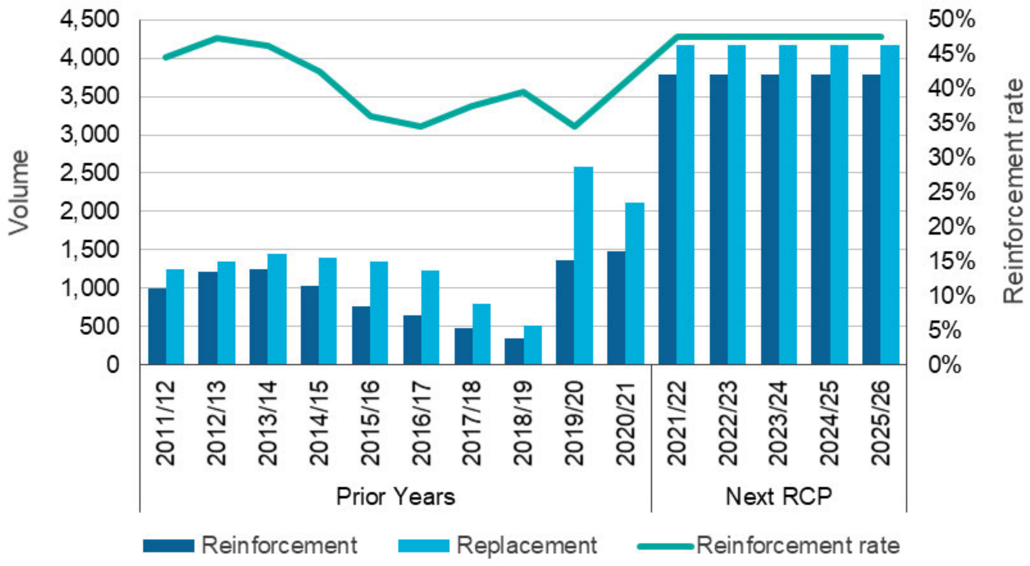
204. According to the forecasting method described in section 4.3.3, Powercor determines its replacement and reinforcement volumes through a combination of methods, including assignment to its compliance-driven interventions directly from the enhanced pole calculator. We discuss our assessment of these methods in subsequent sections.

205. The resulting profile of Powercor's forecast replacement and reinforcement volumes over time and the corresponding rate of reinforcement is shown in the figure below.

[36] Powercor BUS 4.02 page 18

[37] Powercor ATT245: ESV, Powercor, Sustainable wood pole safety management approach, Detailed technical report, December 2019

Figure 4.8: Pole intervention volumes over previous, current and next RCP (excluding network faults)



Source: EMCa analysis of Powercor MOD 4.06

206. From the above figure, we observe the following:

- from 2014/15 to 2018/19 - a decline in pole replacement and reinforcement volumes;
- from 2019/20 to 20/21 - increased replacement and reinforcement volumes as a result of the changes to wood pole condition assessment adopted during 2019 (as discussed above);
- from 2021/22 - a significant step increase to replacement and reinforcement volumes proposed and maintained during the RCP, corresponding to the assumed outcomes from application of its enhanced pole calculator; and
- the reinforcement rate is expected to increase to 47% throughout the next RCP.[38]

207. Powercor has advised that it will not start using the enhanced pole calculator in the field until the start of the next RCP.

208. The enhanced pole calculator determines the serviceability index for each pole based on assessment of a range of inputs including good wood test, age, fibre strength degradation rates, pole diameter and tip load. From this SI, Powercor ranks the poles by risk classification. The number and location of pole treatments are based on achieving the highest risk reduction. Powercor has not described how it determines the required level of risk reduction, nor has it provided information related to any economic analysis that it has undertaken to determine an economic level of risk reduction.

209. We review each of the components of Powercor's forecasting approach in subsequent sections of this report.

Risk-based asset management approach does not include an economic test

210. Powercor has developed a risk framework to map the pole condition for each wood pole (identified using its SI as determined from its enhanced pole calculator) against the bushfire classification of the pole location in increasing order of consequence as shown in the figure below.

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38 Wood pole reinforcement provides a lower cost option to mitigate against pole failure where a pole is suitable to be reinforced

Figure 4.9: Overview of risk based classifications for poles

Increasing consequence of failure

Increasing probability of failure

Pole condition	LBRA	HBRA	REFCL (non-SWER)	REFCL (SWER)	BCA (ELCA)
Unserviceable: Serviceability index < 0.65	C2	C2	C1	C1	C1
Added-control serviceable: 0.65 ≤ serviceability index < 0.70	C4	C4	C3	C3	C2
Added-control serviceable: 0.70 ≤ serviceability index < 0.75	C4	C4	C4	C3	C3
Serviceable: 0.75 ≤ serviceability index < 1.0	C5	C5	C5	C5	C4
Serviceable: Serviceability index ≥ 1.0	C5	C5	C5	C5	C5

Source: Powercor BUS 4.02 Figure 8

211. The consequence mapping reflects the following bushfire fire classifications:

- Bushfire Construction Areas (BCA)—Powercor's highest bushfire consequence regions, and is used by Powercor in place of Electrical Line Construction Area (ELCA);
- areas protected by a Rapid Earth Fault Current Limiter (REFCL) with Single Wire Earth Return (SWER) lines;
- areas protected by a REFCL with non-SWER lines;
- Hazardous Bushfire Risk Areas (HBRA); and
- Low Bushfire Risk Areas (LBRA).

212. Powercor further assigns each pole into one of five risk categories, denoted by the terms C1 to C5[39] and which overlay the above framework. The risk categories are further grouped into:

- Compliance-driven interventions (comprising the interventions that are denoted by the risk categories of C1 and C2); and
- Risk-driven interventions (comprising the interventions that are denoted by the risk categories of C3 and C4).

213. Powercor claims that its risk-based asset management approach is consistent with the AER's risk monetisation framework[40] as it has adopted serviceability criteria as a proxy for probability of failure and consequence mapping based on bushfire risk areas. Whilst Powercor has sought to describe a relationship between serviceability index (as a proxy for the probability of failure) and consequence (using bushfire consequence area), the framework in its current form does not provide a basis for economic analysis to determine an efficient level of expenditure on a risk monetisation basis.

The prioritisation of wood pole treatment is based on highest bushfire consequence – however, the determination of a reasonable level of risk is not evident

214. Powercor has simulated the estimated condition of its pole population based on previous inspection and test data and the assumptions included in its enhanced pole calculator. This is not based on 'real' in-the-field assessments (hence, 'simulated'). The outputs of the enhanced pole calculator are shown against the assessment framework in the figure below,

[39] C5 representing ongoing monitoring and inspection

[40] Powercor BUS 4.02 page 3

showing the forecast volumes of poles in each condition classification as at the end of the next RCP.

Table 4.5: Simulated pole calculator serviceability against bushfire consequence showing volumes of poles

Pole condition classification	LBRA	HBRA	REFCL (non-SWER)	REFCL (SWER)	BCA (ELCA)
Unserviceable: Serviceability index < 0.65	1,742	1,060	9,220	1,489	1,696
Added control – serviceable: 0.65 ≤ serviceability index < 0.70	1,163	831	19,438	4,349	776
Added control – serviceable: 0.70 ≤ serviceability index < 0.75	6,225	3,722	21,704	4,639	456
Serviceable: 0.75 ≤ serviceability index < 1.0	42,847	31,033	42,054	10,170	2,082
Serviceable: Serviceability index ≥ 1.0	40,311	42,376	55,011	15,021	1,487

Source: Powercor MOD 4.02 Table 4

215. Drawing from the information presented in the above figure, Powercor has nominated the pole treatment volumes for the next RCP as shown in the following table for the risk categories of C1, C2 and C3.

Table 4.6: Proposed pole intervention volume in next RCP

Pole condition classification	C1	C2	C3	C4	Total
Unserviceable poles	12,405	2,802	-	-	15,207
Added control serviceable 0.65 <= SI <0.70	-	776	23,787	-	24,563
Added control serviceable 0.70 <= SI <0.75	-	-	-	-	-
Total	**12,405**	**3,578**	**23,787**	**-**	**39,770**

Source: EMCa analysis of Powercor BUS 4.02 and MOD 4.03

216. We observe that the forecast includes 100% of C1 and C2 classifications included in its risk framework and 82% of C3 classifications, each of which are associated with REFCL and BCA areas. Although the total volume of interventions is determined by this method, we note that the actual allocation of pole interventions between pole replacement and reinforcement is not.

217. Powercor has not provided a sensitivity analysis around the input assumptions, nor the proposed treatment volumes that result in a different risk level to support the proposed treatment volumes.

Expenditure forecast reflects the bottom-up development of the component parts of the program after accounting for historical reinforcement practices

218. Powercor's wood pole program can be presented according to each of its proposed risk and compliance components as shown in the table below.

Table 4.7: Proposed pole intervention volume in next RCP

Forecasting component	Replacement	Reinforcement	Total
Compliance driven interventions: pole calculator	11,413	4,570	15,983
Compliance driven interventions: non-pole calculator	5,877	2,354	8,231
Risk-driven interventions	3,588	11,968	15,556
Total	**20,878**	**18,892**	**39,770**

Source: Powercor BUS 4.02 Table 7

219. Powercor states that it is undertaking a compliance driven replacement volume of 15,983 poles[41] as shown in the table above and which corresponds to the total estimated unserviceable poles in the risk classifications of C1 and C2 of its risk framework.

220. The '*compliance driven interventions: non-pole calculator*' total intervention of 8,231 poles is calculated as follows:

- Calculate the forecast number of poles transitioning through 'condition states'[42] by:
  - upscaling the forecast number of poles that are transitioning through 'managed states',[43] designated as AC serviceable in the risk framework (63,303 poles);
  - by the percentage of poles transitioning through managed states based on observations (69%);
  - To determine the total number of poles that are transitioning through condition states (91,485 poles); then
- Apply the percentage of poles that are 'managed' due to Powercor's wood pole policy based on observations (9%) to the total number of poles transitioning through condition states (91,485 poles) to derive the forecast volume of 8,231 poles.

221. The balance of the forecast number of poles in risk category C3 is assigned to the 'risk-driven intervention' component.

222. The replacement and reinforcement volumes within each of these forecasting components are the result of application of a decision matrix[44] reflecting a historical average compliance replacement rate of 60% and a RBAM replacement rate of 31%.[45] The reinforcement rates therefore vary between each of the forecasting components. As we would expect, the reinforcement rate is much higher for the risk-driven interventions component, associated with lower risk pole replacement.

223. We consider that this method seeks to ensure that wood poles are reinforced where possible before being considered for replacement.

224. In the information provided by Powercor in its response to an information request,[46] there is a small variation against the volumes allocated between replacement and reinforcement. The variation is small and is not likely to have a material impact on the expenditure forecast.

41 PAL BUS 4.02 Table 7

42 A condition state is the pole condition at a point in time. Based on its own observations, Powercor has determined the number of poles that transition through each pole condition 'state'. For example, Serviceable to Added control serviceable which is a managed state, or Serviceable directly to Unserviceable which is an unmanaged state. As described in Powercor's response to information request IR – MOD new – pole replacement forecast model.

43 Powercor defined 'managed states' as all states of a pole condition that exclude unserviceable

44 As detailed in IR010 MOD new pole replacement forecast model, and which includes pole for replacement where a pole is already reinforced cannot be reinforced again

45 Which infers a reinforcement rate of 69%

46 PAL IR010 MOD new pole replacement model

Fault related expenditure does not appear to have been considered in the pole management strategy

225. In its regulatory proposal, and separate to the Wood Pole Management business case, Powercor has included $23.6m for network faults allocated to the poles asset group (of which $10.3m is allocated to wood poles), as shown in the table below. The derivation of this figure is based on historical trend and developed separate to the outputs of its enhanced pole calculator and forecast pole condition.

Table 4.8: Forecast network fault expenditure (excluding real cost escalation) - $m, real 2021

Network faults	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Wood poles	1.8	1.9	2.1	2.2	2.3	10.3
Concrete poles	2.4	2.5	2.7	2.8	2.9	13.3
Total	**4.2**	**4.5**	**4.7**	**5.0**	**5.2**	**23.6**

Source: EMCa analysis of Powercor MOD 4.11

226. Powercor is silent on any impact to fault related expenditure of the proposed step increase in pole replacement and reinforcement.

227. In response to our request for information on the derivation of its proposed forecast expenditure for network faults, across all assets, Powercor states that:[47]

> *'Our network faults forecast has not been adjusted to account for our planned replacement program. This is because network faults can be random, and are primarily driven by severe weather events. The severity of these events limit the correlation to asset condition, which is a key driver of much of our planned replacement programs. The lack of correlation is observed in figure 5 and figure 6, which show that network faults have remained relatively stable irrespective of total replacement investment.'*

228. We would expect that in considering the strategies for management of its wood pole assets, Powercor would have regard to the drivers of the network fault-related expenditure for poles and what (if any) impact that the proposed increase in pole replacement and reinforcement volumes may have. We have not seen evidence of this being considered by Powercor. The network faults related expenditure, including replacement of 825 wood poles over the next RCP due to network faults, is not included in the Wood pole management business case.

Many of the assumptions relied upon in the enhanced pole calculator have not been validated

229. The enhanced pole calculator relies on a number of input assumptions which have not been verified:

- For the fibre strength, we understand that Powercor has applied the results of the ENA research. We have not been provided with evidence to understand how Powercor has, or plans to, assure itself that these assumptions are reasonable;
- For the tip load calculation, we understand that Powercor has not yet established tools to determine the load present at different parts of the network, which is subject to many variables including pole design, conductor, and pole-top hardware. In place of appropriate tools, Powercor has made an assumption of the tip load relative to the wood pole design rating. We understand that Powercor has assigned a percentage of design ratings by consequence area, namely: 100% tip load to BCA consequence areas; 90% to REFCL consequence areas; and 80% for the remaining areas. We further understand that this in part due to the design assumptions Powercor believes were applied at time of construction; and

47 Powercor's response to information request IR035 - EMCa questions following onsite

- Pole condition is being assessed under the current pole inspection method, including the assessment of diameter loss.

230. Whilst we have not been provided a copy of the enhanced pole calculator, based on our experience, the calculation of pole condition is likely to be very sensitive to these inputs. We asked Powercor to describe how it had validated these parameters against observed performance or experience given the enhanced pole calculator has not yet been put into practice. Powercor advised that it plans to undertake a testing program commencing in August 2020 to validate and calibrate these parameters, and which will be complete by January 2021.[48] We requested details of the test method that it plans to apply. This information was not available at the time of writing this report. We understand that Powercor did not have any plans for destructive testing of poles.

231. Based on our experience, wood pole lines were originally designed with safety factors to ensure that the pole design was in excess of the load acting on the pole. To assume that the tip load acting on the pole is equal to the design rating of the pole without adequate verification is likely to overstate the risk of pole failure. If this were the case, we would expect to see evidence provided by Powercor to support this assertion such as an increasing number of 'assisted' pole failures associated with poles that have failed due to forces above their design rating, such as due to extreme weather events.

232. Powercor does not describe how it has arrived at these parameters, particularly as they tend to reflect maximum values of a range, when compared with a selection of alternative parameters that are likely to result in a range of possible intervention volumes.

Options analysis is limited

233. Powercor presents three options in its business case, namely:

- maintain the status quo (with a safety factor of 1.4);
- safety factor of 1.4 and maintain average age; and
- implement proposed enhancements to the pole calculator and serviceability index calculation.

234. What we didn't see is an analysis of the intervention volumes in terms of failure rates and risk outcomes, including by varying the proposed treatment volumes or input assumptions.

235. We had understood from discussions with Powercor that there was a focus on Class three strength poles. The Business case states that 59% of Class three poles currently exceed the average life expectancy of 50 years. Further, Powercor provided a relationship between failed Class three poles with age, which shows an exponentially increasing trend.

236. However, the business case does not describe how Powercor has addressed what appear to be an increasing failure rate and corresponding risk of lower durability poles (Class three strength poles) in its proposed intervention volumes.

237. We would have expected to see analysis of a range of intervention volumes and associated expenditure compared with the benefits of reducing levels of risk, including by considering durability class and consequence areas.

Powercor's top-down review of its forecast is limited

238. As noted earlier, Powercor's reliability performance is good and improving. Fire start events are also declining.

239. There is evidence that wood failure rates are increasing, and that this failure rate may be exponentially increasing for some poles. Collectively, this information supports changes to Powercor's historical asset management practice and historical expenditure level.

240. The wood pole management business case[49] includes comparison of forecasts based on:

- AER repex model;

48 Powercor's response to information request IR010

49 Powercor BUS 4.02 section 5.2

- Maintain service life approach;
- Condition-based approach; and
- Age based approach.

241. Powercor states that:[50]

> *'Given the limitations of each of these measures, any comparisons should be used with caution. Notwithstanding this, our forecast intervention volumes based on proposed enhancements to our pole calculator and serviceability index are reasonably consistent with the maintain service life and age-based replacement estimates, and are lower than the alternative forecast using our 2019 RCM study.'*

242. We agree with Powercor that direct comparison with these scenarios should be undertaken with caution. We did not see sufficient information that seeks to moderate the expenditure, including with the top-down review methods described by Powercor in its business case, with an estimate of the forecast outcomes in terms of network risk - or to explain the relationship with what appears to be improving network performance measures.

243. Unit cost estimates are unlikely to reflect the full benefit of delivered cost efficiencies. Unit rates are calculated for each asset category based upon revealed actual costs, using the sum of the historical expenditure (converted to $2021) divided by the sum of the historical volumes for the 4-year period from 2014/15 to 2017/18. This seeks to remove year on year variations.

244. Powercor advises that the 2018/19 data is not available and will be updated as part of its RRP.

245. The unit costs are of the order we would expect to see and using revealed costs is a reasonable indicator of the efficient cost, assuming that any changes to the procurement practices and standards are a reasonable reflection of the future cost.

246. We asked Powercor to explain how they determined the review period, and whether the costs have included the efficiencies that were delivered in earlier years. Powercor stated that:[51]

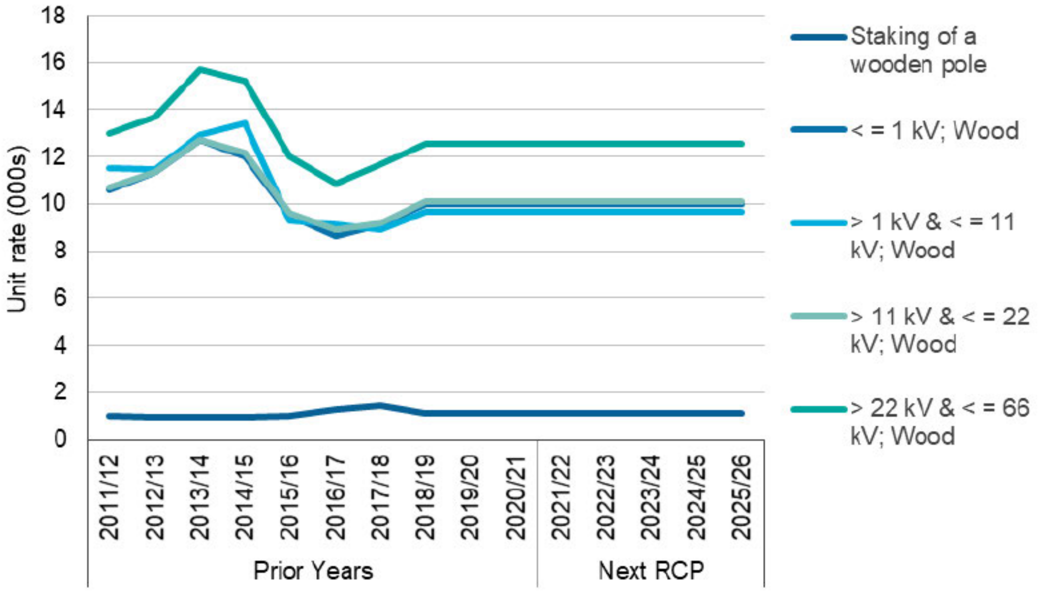
> *'A four-year averaging period provides a reasonable balance between using the most current data available and the risk that a shorter period (i.e., a single year) may over or under-state future volumes. A four-year averaging period is also consistent with the approach used by the AER in its repex model.'*

247. We see evidence of reductions to the unit costs associated with pole replacement and reinforcement that generally align with the period in which Powercor delivered its 'World Class program'. However, the unit rates assumed for the forecast expenditure are higher than these values as shown in the figure below.

[50] Powercor BUS 4.02 page 25

[51] Powercor's response to information request IR035 EMCa follow up to onsite review meetings, page 7-8

Figure 4.10: Derivation unit rates over time ($000s, real $2021 excluding real cost escalation)



Source: EMCa analysis of Powercor MOD 4.06

248. The selection of an averaging period to include the three most recent years (2015/16 to 2017/18) would result in a lower unit cost than the four-year average figures that Powercor has applied as shown in the table below (and noting that the majority of replaced poles by volume are <= 1kV).

Table 4.9: Impact of changing averaging period for unit costs - $, real 2021

Unit rate	5 years 13/14-17/18	4 years 14/15-17/18	3 years 15/16-17/18	1 year 17/18
Staking of a wooden pole	1,087	1,130	1,216	1,455
< = 1 kV; Wood	10,625	9,990	9,105	9,100
> 1 kV & < = 11 kV; Wood	10,408	9,693	9,068	8,917
> 11 kV & < = 22 kV; Wood	10,705	10,094	9,240	9,161
> 22 kV & < = 66 kV; Wood	13,286	12,577	11,545	11,711

Source: EMCa analysis of Powercor MOD 4.06

249. Variations in the most recent year are not explained by Powercor.

Summary of our assessment

250. Based on the information available to us at the time of preparing this report, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure forecast for poles is prudent and efficient.

251. We have identified a number of issues associated with the assumptions applied by Powercor in preparing its expenditure forecast for wood poles, specifically - and poles, more generally. These issues individually and collectively cast a level of doubt on whether Powercor will require the level of repex that it proposes for its poles asset group to meet the requirements of the NER.

252. We consider that Powercor has established a reasonable basis for increasing the volume of wood pole treatments above its long-term historical levels. However, based on the information provided by Powercor we do not consider that the forecast expenditure is representative of a prudent and efficient level, for the following reasons:

- The expenditure forecast is based on a bottom-up assessment of the outputs of a new ‘enhanced pole calculator’ where the underlying assumptions are conservative and un-tested;
- Powercor has not provided analysis of a range of input parameters or sensitivity analysis to the selected input parameters and we note that some inputs are already at the maximum of the feasible range;
- Whilst the proposed volume of pole interventions is prioritised according to highest bushfire consequence and poorest pole condition (SI < 0.70), the selection of the level of risk reduction is not justified;
- Similarly, Powercor has not provided economic analysis to support the selection of a prudent and efficient level of expenditure; and
- The unit cost estimates applied to the forecast expenditure do not appear to reflect the sustained benefit of recently delivered cost efficiencies, including savings to materials and procurement activities, which are evident in the delivered unit costs within the current RCP. We would expect these efficiencies to continue and perhaps increase with further increases in volumes.

253. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

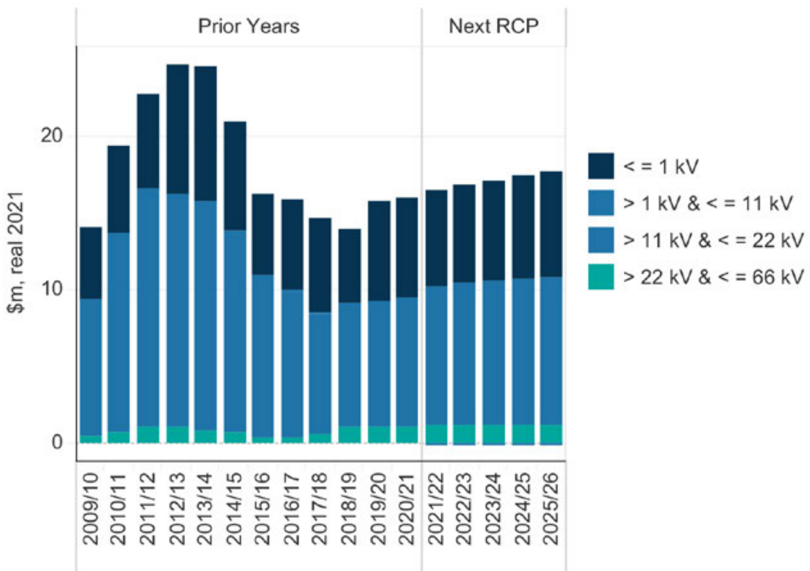
254. Accordingly, we consider that Powercor has not justified the extent of the proposed increase to its forecast expenditure for the Poles group.

4.4.2 Pole top structures

Powercor’s forecast

255. Powercor has proposed $85.4m[52] for the Pole-top structure group in its repex forecast for the next RCP. The expenditure profile for the Pole-top structure group comparing the next RCP compared with previous years is shown in the figure below.

Figure 4.11: Pole top structure repex by asset category - $m, real 2021



Source: Powercor Reset RIN

[52] Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

256. The figure above shows a small increase for the next RCP from historical trend. The major components of expenditure are shown in the table below (and which reconcile to Powercor's program when real cost escalation is excluded).

Table 4.10: Components of Powercor's proposed pole-top structure repex for next RCP - $m, real 2021

Pole top structures	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Crossarm Replacement	**14.9**	**14.9**	**14.9**	**14.9**	**14.9**	**74.5**
Base replacement program	*15.6*	*15.6*	*15.6*	*15.6*	*15.6*	*77.8*
Adjustment for pole volumes	*-0.7*	*-0.7*	*-0.7*	*-0.7*	*-0.7*	*-3.3*
Network Faults	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**6.8**
Total	**16.3**	**16.3**	**16.3**	**16.3**	**16.3**	**81.3**

Source: EMCa analysis of Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

257. Powercor has provided models comprising its lines replacement expenditure (MOD 4.06) and network faults related expenditure (MOD 4.11), which include pole-top structure repex. Powercor has not provided a business case or other justification document for the proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from other supporting information.[53]

Our assessment

Increase from current RCP not explained

258. According to Powercor,[54] the expenditure associated with pole-top structures is increasing from $76.3m to $81.3m in the next RCP. Powercor describe[55] the main driver of replacement is the asset condition based on inspection regime and/or asset failure. Powercor has not explained the basis of its proposed increase.

Forecasting approach overstates the replacement volumes based on a historical 'find and fix' reactive management approach

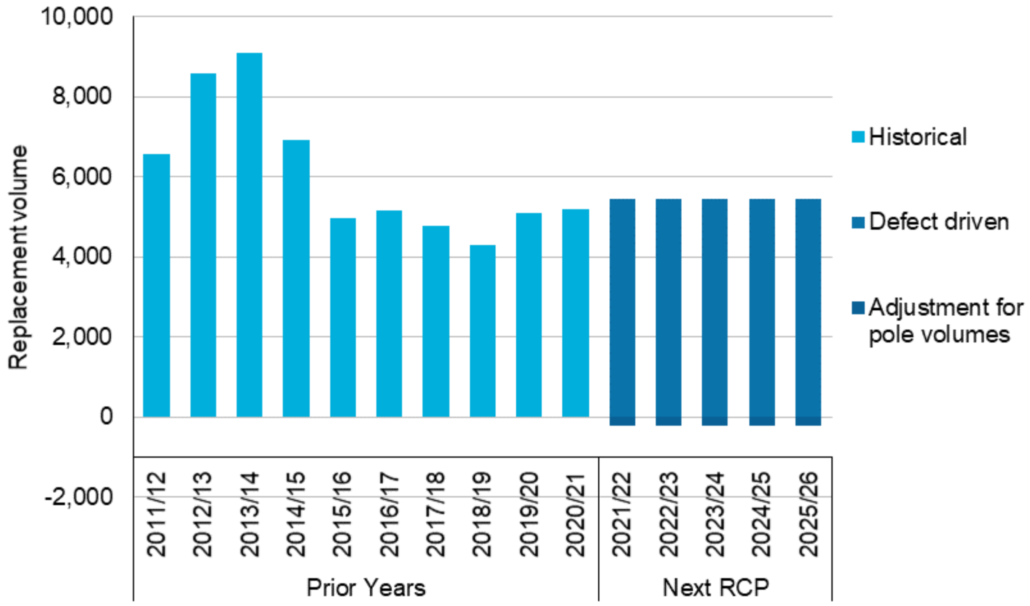
259. Powercor describes the basis of its forecast for pole-top structures as continuing its current 'find and fix' asset management approach. However, adoption of an averaging of historical defects over the period 2014/15 to 17/18, as Powercor has done, effectively "locks in" the elevated replacement volumes that are evident in prior years and continue into 2014/15 as shown in the figure below.

53 Including the Regulatory proposal, RIN016 and asset strategy documents

54 Powercor Regulatory Proposal Table 4.4

55 Powercor RIN016

Figure 4.12: Forecast pole-top replacement volumes (base replacement program)



Source: EMCa analysis of Powercor MOD 4.06

260. We have shown the adjustment to the replacement volumes as a result of the proposed increased pole replacement in the chart above, included as a negative volume by Powercor. This is a small percentage of the forecast replacement volumes.

261. We understand that the elevated replacement volume evident in the period 2011/12 to 2014/15 was in response to elevated asset failures, and the program has since been completed.

262. Making adjustments to move the averaging period to reflect more recent data results in a reduction to the defect-driven replacement volumes. For example, assuming that the level of replacement approximated the 2017/18 levels would reduce the forecast defect driven replacement volume by 466 units per annum (including the proposed negative adjustment). We estimate that the cost of the additional cross-arm replacement is approximately $1.5m per annum.[56] If the forecast replacement volume is based on 2017/18, a further reduction of expenditure is evident.

Proposed reduction included to account for increase in proposed pole replacement program is likely to be insufficient

263. Powercor states that the [57]

> *'…pole-top structures and service line forecasts have been reduced to account for the expected overlap due to our increased pole replacement volumes.'*

264. Based on our review of the provided models, the adjustment is included as a negative replacement volume of 215 units p.a. as shown in the figure above. This results in a corresponding reduction to the base replacement forecast for this group. The derivation of the 215 units is not provided.

265. We estimate that the proposed adjustment amount accounts for approximately 10% of replaced poles included in the incremental pole replacement proposed for the next RCP.[58] Due to the proposed pole replacement program, there would also be a reduction in the

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56 Based on the proposed unit cost and which may differ if a different averaging period is applied.

57 Powercor Regulatory Proposal, footnote to Table 4.4

58 Based on the most recent estimated pole replacement volume. Using the historical average wood pole replacement volume from 2014/15 to 2017/18 results in reducing this percentage by a few percent

number of cross-arm replacements required, as crossarms are typically replaced when a pole is replaced.

266. From our analysis, the proposed pole replacement program will replace, on average, an additional 2,982 wood poles per annum[59] (including crossarms) compared to the period 2014/15 to 2017/18. This will likely result in a larger reduction to the planned crossarm replacement program than Powercor has proposed.

Summary of our assessment

267. A replacement volume that more closely reflects the current asset management practice, should be based on recent data. Powercor submits that it has done this, however the inclusion of early years in the averaging means that this is not the basis of their forecast replacement volumes.

268. There is likely to be a higher reduction to the pole-top structure replacement program for cross-arms than has been proposed (i.e., there should be an adjustment to account for the cross-arms replaced when a pole is replaced). There is a direct relationship between the pole replacement program and the cross-arm replacement program, such that increases in pole replacements (including cross-arms) should be reflected in a proportional reduction in cross-arm replacements.

269. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

270. Accordingly, we consider that Powercor has not justified the extent of the proposed increase to its forecast expenditure for the Pole top structure group.

4.4.3 Overhead conductors

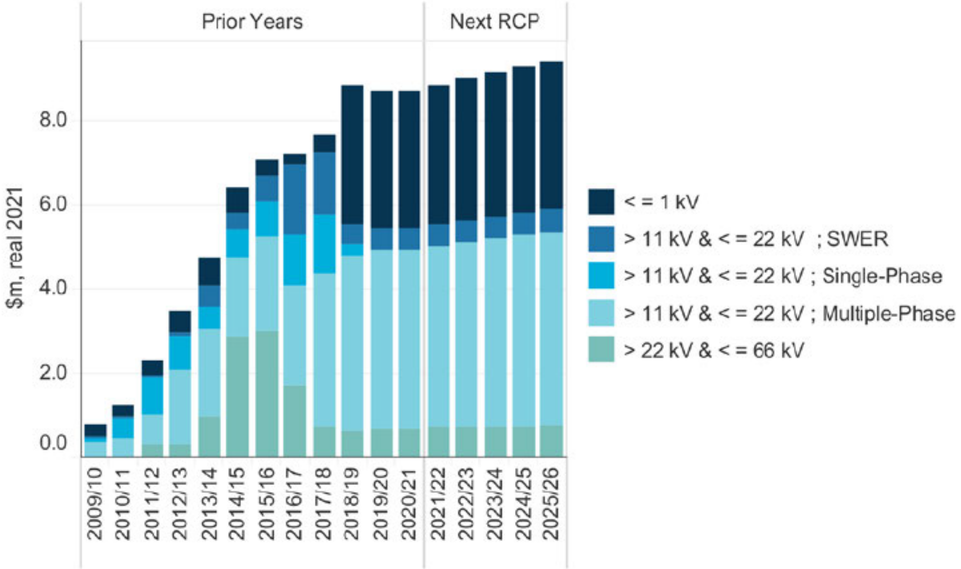
Powercor's forecast

271. Powercor has proposed $45.7m[60] for the Overhead conductor group in its repex forecast for the next RCP. The expenditure profile for the Overhead conductor group comparing the next RCP with prior years is shown in the figure below.

59 Based on average wood pole replacement in the next RCP, compared with the average for the period 2014/15 to 2017/18

60 Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.13: Overhead conductor repex by asset category - $m, real 2021



Source: Powercor Reset RIN

272. From the chart[61] above, we observe a steady increase year-on-year for overhead conductors, with a change in the expenditure composition for the next RCP comprising a focus on replacement of LV and 22kV conductors. On review of the composition of the forecast, Powercor has included a single program based on its historical defects as shown in the table below (and which reconciles to Powercor's program when real cost escalation is excluded). As noted earlier, the network fault repex for overhead conductors has been removed for the next RCP and from the Reset RIN. Therefore, this expenditure is not included in the above figure or the table below.

Table 4.11: Components of Powercor's proposed Overhead conductor repex for next RCP - $m, real 2021

Overhead conductor	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Defect driven	8.7	8.7	8.7	8.7	8.7	43.5
Network Faults	-	-	-	-	-	-
Total	**8.7**	**8.7**	**8.7**	**8.7**	**8.7**	**43.5**

Source: EMCa analysis of Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

273. Powercor has provided a line replacement model (MOD4.06), of which overhead conductor replacement is a component, to support its proposed expenditure.

Our assessment

274. The expenditure associated with overhead conductors is increasing from $41.2m to $43.5m.[62] The main driver of replacement is described as the asset condition based on inspection regime and/or asset failure.

275. Our review of the provided expenditure model shows a forecast volume of 100km p.a. for overhead conductor replacement. This represents a lower replacement volume than the historical average. Powercor has assigned this forecast replacement volume to each of the RIN asset categories on a pro-rata basis using installed volumes from those reported in the RIN.

276. We show the historical and forecast replacement volume in the figure below.

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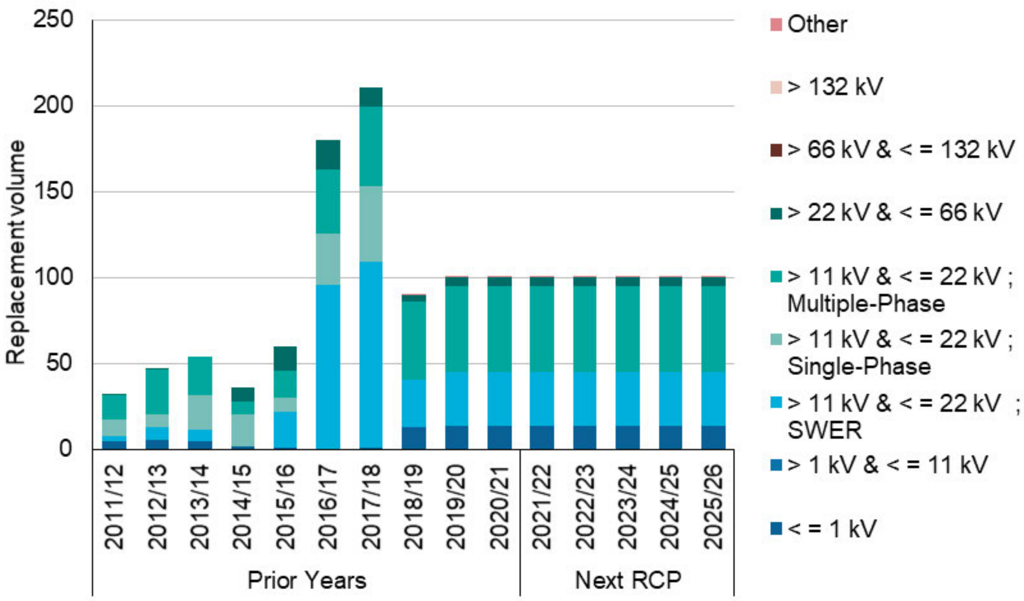
61 We observed a difference in the historical data between the project models and the RIN supplied by Powercor which relates to the early years

62 Powercor Regulatory Proposal Table 4.4

Figure 4.14: Historical replacement volume of overhead conductor



Source: EMCa analysis of Powercor MOD4.06 and 4.11

277. Powercor states that the forecast is reflective of engineering judgement of prudent and sustainable volumes, including application of LIDAR and other age and condition-based factors.[63]

Summary of our assessment

278. On the basis that Powercor has determined that this volume is necessary to meet its safety obligations, we consider that the forecast replacement volumes for the Overhead conductor group are reasonable.

279. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

4.4.4 Underground cable

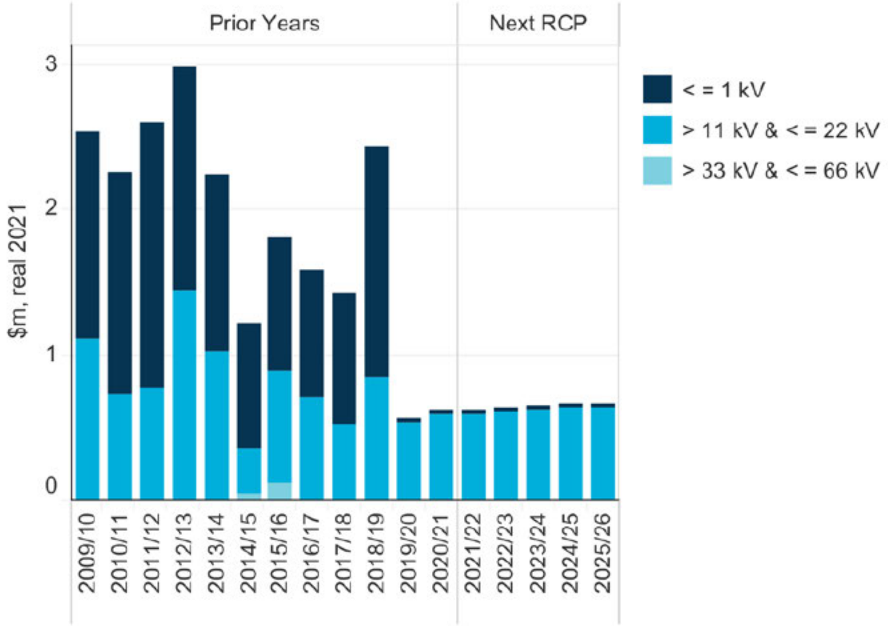
Powercor's forecast

280. Powercor has proposed $3.3m[64] for the Underground cable group in its repex forecast for the next RCP. The expenditure profile for the Underground cable group comparing the next RCP with previous years is shown in the figure below.

[63] As descr bed in Powercor's response to IR006 and IR017

[64] Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.15: Underground cable repex by asset category - $m, real 2021



Source: Powercor Reset RIN

281. The figure above shows a large decrease in forecast expenditure for the next RCP when compared with historical levels. The major components of expenditure by program are shown in the table below (and which reconcile to Powercor's program when real cost escalation is excluded). As noted earlier, the network fault repex for underground cables has been removed for the next RCP and from the Reset RIN. Therefore, this expenditure is not included in the above figure or the table below.

Table 4.12: Components of Powercor's proposed underground cable repex for next RCP- $m, real 2021

Underground cable	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Volumetric programs						
Network Faults	-	-	-	-	-	-
Projects						
HV UG Cable Replacement	0.6	0.6	0.6	0.6	0.6	3.0
LV UG Cables Planned Replacement	0.0	0.0	0.0	0.0	0.0	0.1
Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**3.1**

Source: EMCa analysis of Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

282. Powercor has provided a line replacement model (MOD4.06), of which underground cable is a component, to support its proposed expenditure.

Our assessment

283. Powercor has not provided an explanation for why it has reduced its underground cable expenditure below a level indicated by its historical trend.

284. In its documentation, Powercor states that:[65]

> *'We have a very small targeted replacement program for underground cables. Underground cables are managed through defects and fix on failure approach. Additionally, we replace damaged sections in piecemeal fashion. Regular scheduled*

65 Powercor RIN016

tests for oil filled and XLPE cables include insulation and sheath resistance tests and oil DGA tests. Engineering assessment is applied to prioritise cable defects.'

285. The forecast expenditure for its two components of LV cable replacement and HV cable replacement are proposed to be held at 2020/21 levels, which is a small increase for HV underground cable replacement from 2019/20. We have not been provided with any prior expenditure at these component levels and are therefore reliant on review of trend from the RIN. We note that the forecast expenditure also excludes the network faults related expenditure.

Summary of our assessment

286. On the basis that Powercor has determined that this volume is necessary to meet its safety obligations, we consider that the forecast expenditure for the Underground cable group is reasonable.

287. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

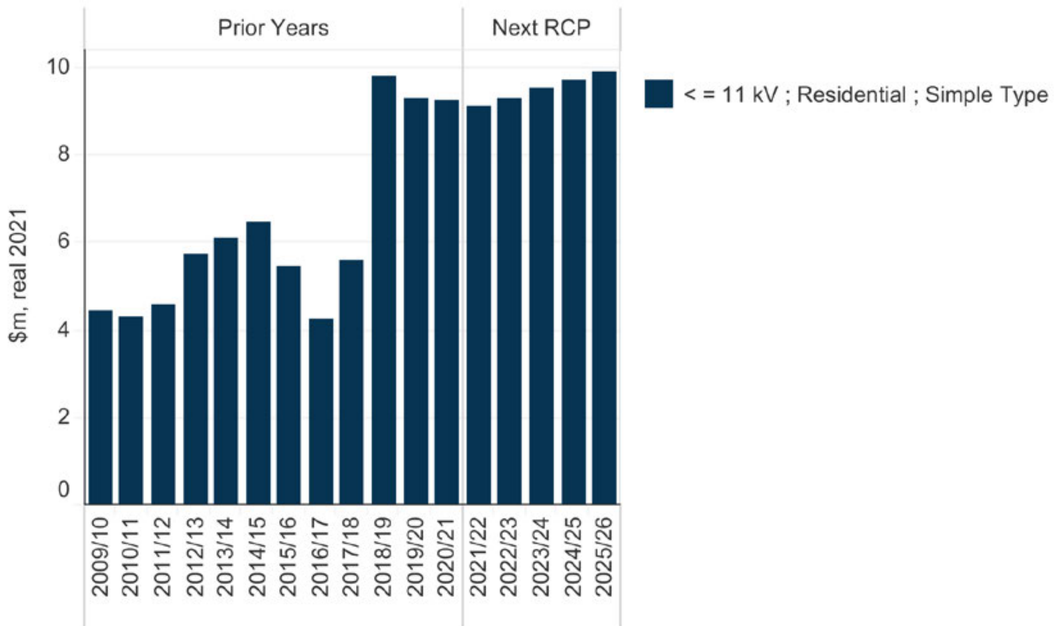
288. However, on balance, due to the low level of expenditure, the forecast is likely to be reasonable.

4.4.5 Service lines

Powercor's forecast

289. Powercor has proposed $47.6m[66] for the Service lines group in its repex forecast for the next RCP. The expenditure profile for the Service lines group comparing the next RCP compared with previous years is shown in the figure below.

Figure 4.16: Service lines repex by asset category - $m, real 2021



Source: Powercor Reset RIN

290. The figure above indicates that the recent increase in service level replacement is being maintained, with further small increases throughout the next RCP. The major components

66 Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

of expenditure and program by construction type are shown in the tables below (and which reconcile to Powercor's program when real cost escalation is excluded).

Table 4.13: Components of Powercor's proposed Service lines repex for next RCP - $m, real 2021

Service lines	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Obsolete & Defective Overhead Services	**7.3**	**7.3**	**7.3**	**7.3**	**7.3**	**36.7**
Defect driven	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*20.3*
PVC Grey Program	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*10.4*
AMI NST	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*5.7*
Veranda Access	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.9*
Adjustment for pole volumes	*-0.1*	*-0.1*	*-0.1*	*-0.1*	*-0.1*	*-0.7*
Network Faults	**1.6**	**1.7**	**1.7**	**1.8**	**1.8**	**8.6**
Total	**9.0**	**9.0**	**9.1**	**9.1**	**9.2**	**45.4**

Source: EMCa analysis of Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

291. Powercor has provided a line replacement model (MOD4.06), of which service line replacement is a component, to support its proposed expenditure.

Our assessment

Recent increases to expenditure are driven by the introduction of new replacement programs

292. The main driver of replacement is the asset condition based on inspection regime and/or asset failure. Powercor's forecast for service lines is comprised of a number of components as shown in the table above.

293. The components of the services replacement program include three proactive replacement programs:[67]

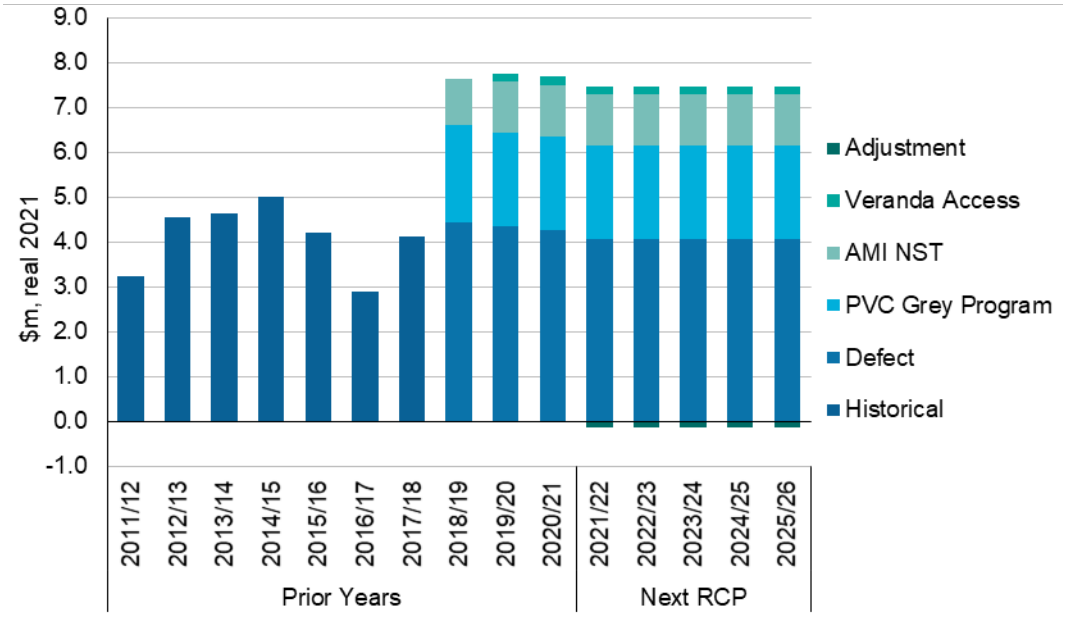
- PVC grey[68]– refers to the twisted polyvinyl chloride (PVC) grey service cable replacement program, which addresses a failure mode whereby the insulation at the connection point can be pierced and cause any attached metalwork on the premise to become energised;
- AMI NST – Advanced Metering Infrastructure Neutral Screen testing program that '*proactively detects hazardous neutral services by applying an algorithm to smart meter data that identifies particular voltage and current signatures (that are consistent with potentially faulty service connections);*' and
- Veranda access – this program is not described in Powercor's Regulatory proposal. We infer from the expenditure model provided that this program relates to replacement of services where access using standard work procedures is not possible and a non-standard replacement task is required, such as for difficult access.

294. We show the breakdown of the service line repex by program in the figure below. The estimated and forecast defect-driven expenditure is of a similar level to that which Powercor has been incurring. We also show the adjustment to the replacement volumes as a result of the proposed increase in pole replacements, included as a negative volume by Powercor. This is a small percentage of the forecast replacement volumes.

[67] Powercor Regulatory Proposal, page 35-36

[68] The metal hook connection used on a twisted PVC grey service cable is commonly referred to as a 'dog-bone'. Powercor uses the term 'dog bone' interchangeable in reference to its PVC grey service cable replacement'

Figure 4.17: Historical and proposed replacement expenditure by services program (excl network faults) - $m, real 2021



Source: EMCa analysis of Powercor MOD4.06

Introduction of programs does not appear to be supported by performance

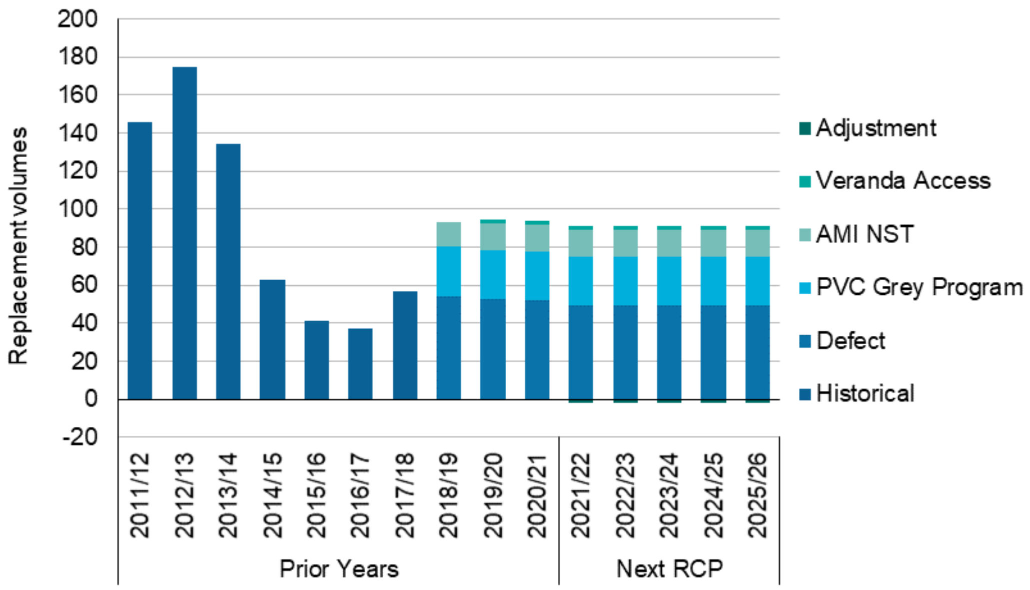
295. We looked for evidence to support the increase in volumes associated with the proposed program in the last two years of the current period and to support the program being continued into the next RCP at a similar level. The trend suggested to us that these were newly introduced programs although Powercor's Regulatory Proposal describes these programs as continuing.

296. As shown in the figure below, Powercor has undertaken a higher level of historical replacement volumes. We understand this was to target known condition issues at that time and which included the '*replacement of over 4,000 high-risk services through to 2018*'[69] following inspection of all twisted PVC grey services in its network.

297. As seen in the figure above, the total replacement volumes have reduced to an average of 50 units p.a. from 2014/15.

[69] Powercor Regulatory Proposal, page 36

Figure 4.18: Historical and forecast service lines replacement volumes



Source: EMCa analysis of Powercor MOD4.06

298. We looked for evidence to support the increase to these programs in response to a decline in asset condition, or observable decline in performance indicators. Based on our review of the historical public safety incidents and fire start performance provided by Powercor,[70] we observe a declining trend in safety impact fire starts and asset failures and a level trend of reportable incidents involving the public (including asset failures) which does not support the need for a step increase in replacement volumes.

299. Powercor has referred to addressing 'lower priority' defects for its PVC grey program and continuing replacement of AMI NST consistent with historical replacements. We are not able to reconcile these statements with what we observe as a step increase in replacement volume in 2018/19, and which is maintained throughout the next RCP over and above the underlying defect driven program.

300. The introduction of these programs appears to be primarily driven by its consumer engagement:[71]

> *'The options presented for these* [replacement of twisted PVC and NST] *programs included a status-quo option (i.e. consistent with our existing asset management approach), and incremental replacements to proactively reduce safety risk. Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact of selecting multiple safety programs throughout the entire forum;*
>
> *Our customers were overwhelming supportive of using smart meters to detect faults for repair. Further, our customers wanted us to initiate these programs immediately, rather than wait until the 2021–2026 regulatory period; and*
>
> *Based on our customer feedback, we have brought forward the timing of these projects into the current regulatory period.'*

Assumptions applied by Powercor in the supplied model for its included programs are based on limited data

301. Powercor has included some more recent defect and replacement data for each of the asset populations and used this data as the basis of forecasting additional replacement volumes as follows:

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70 Response to information request IR035 – EMCa questions following onsite

71 Powercor Regulatory Proposal, page 35

- For the 'PVC grey' replacement program,[72] the replacement volume is simply the implied failure rate by Powercor of 1.23%,[73] being the '*P28 fault notifications found as result of testing*' multiplied by the population of PVC grey services, 94,228.[74] On further review of the model, the replacement volumes are extrapolated from elevated levels of replacement that occurred in 2018, which were the order of four to five times the replacement levels that occurred prior to and following this period. In the absence of better information, we don't consider that a single data point is sufficient evidence to justify replacement at these levels;
- For the 'AMI NST' replacement program, the replacement rates are based on a 12-month period of replacement that commenced in 2018. As above, absent other information this does not provide sufficient evidence to indicate an underlying issue. We understand that smart meters are used to identify faults, by applying an algorithm to smart meter data. This would suggest that a population of service lines would be identified, and a program developed to address rather than the observed level of faults in each month of a 12-month sample period being repeated in each year of the nine years of data provided; and
- For the 'veranda access' replacement program, an extra two service lines p.a. are included based on an assessment of the estimated portion that '*cannot be accessed via SWP*'[75] that require replacement, and replacement assumptions per year.

302. Use of more recent replacement data is positive, however insufficient without other corroborating evidence that the incurred replacement levels are directed at addressing an elevated level of safety risk, systemic issues, or defects. Also, that this replacement volume should be undertaken in addition to the underlying level of defect driven replacements that are forecast based on other methods.

303. The veranda access program is not included in the descriptions provided of the included services programs in the Regulatory Proposal and did not feature in Powercor's description of its consumer engagement.

No assessment of risk or cost benefit evident from Powercor's analysis

304. Absent a clear performance driver, there may be reason to introduce these programs where the net economic benefits of doing so are positive. Accordingly, we looked for evidence of a risk assessment and accompanying cost benefit analysis.

305. Whilst Powercor recognises the need for a cost benefit analysis where it may be prudent to further reduce safety risks, it has not provided this as part of its justification. In its response to an information request, Powercor states that:[76]

> *'We have not undertaken cost-benefit analysis for this expenditure given the forecast methods outlined above,* [based on observed experience] *the underlying asset populations, and the current and ongoing nature of the replacement works* [which commenced in 2018/19]*.'*

306. We did not find a risk assessment to support the introduction of the proposed new practice replacement programs.

High unit rates are reflected in the forecast expenditure

307. Consistent with Powercor's forecasting method, the unit rates reflect the average over the period 2014/15 to 2017/18. As discussed in section 3, when we review the unit rates achieved by Powercor for its service line replacement, particularly in more recent years, we

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72 Also referred to as the 'Dogbone' program by Powecor

73 The same failure rate is assumed across Powercor and CitiPower's network

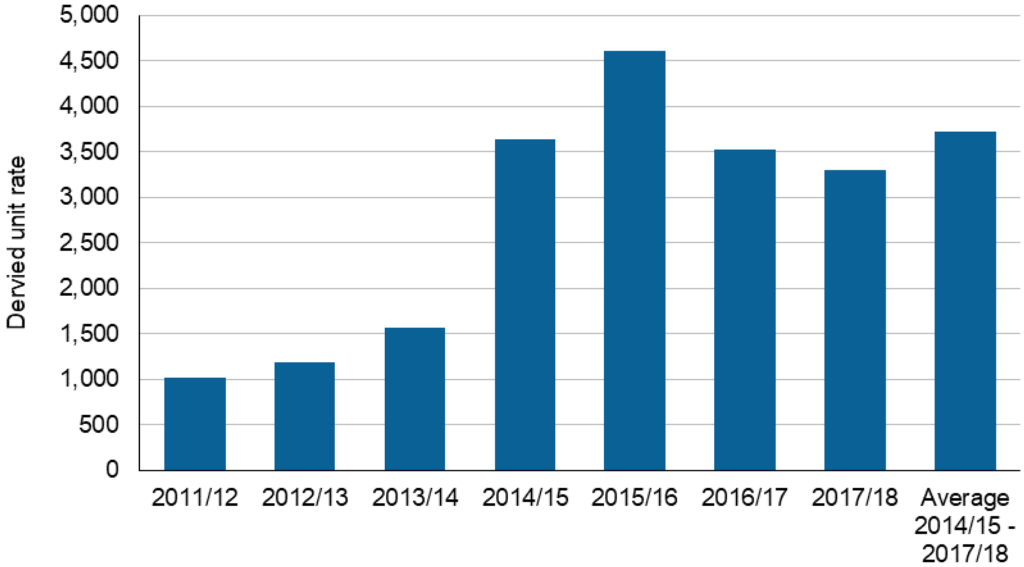
74 A further step converts the number of replacements to km pa by dividing by the average service length of 22m, for presentation in the RIN

75 The term SWP was not defined by Powercor in its expenditure model. We assume that SWP refers to Safe Work Practices

76 Response to information request IR016

see evidence that it has achieved lower rates than it has proposed. Powercor has not explained the driver for the increase as a result of its more recent replacement activity.

Figure 4.19: Derived historical unit rate for residential simple type service line replacements - $, real 2021



Source: EMCa analysis of Powercor MOD4.06

Summary of our assessment

308. Whilst programs of the type proposed by Powercor are common across the industry, and likely to require focus within Powercor's network, Powercor has not adequately demonstrated that the defect driven program, if prioritised based on highest risk service lines, will be insufficient to meet its safety obligations.

309. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

310. We have been provided additional information in IR053 relating to the rationale for the service lines repex, however this information does not materially alter our findings. Accordingly, we consider that Powercor has not justified the extent of the proposed increase to its forecast expenditure for the Service lines repex group.

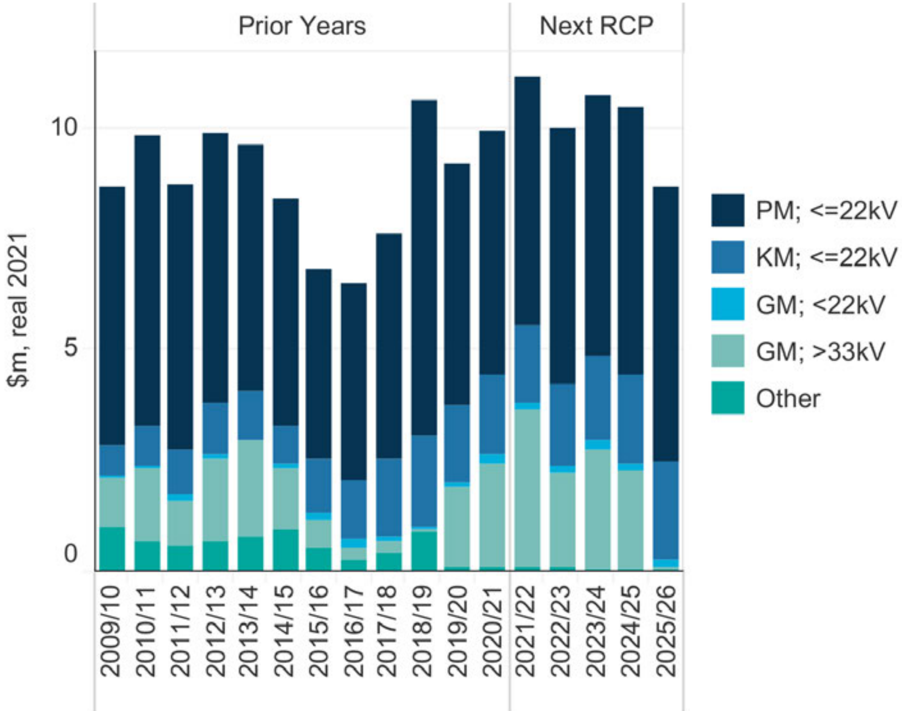
4.4.6 Transformers

Powercor's forecast

311. Powercor has proposed $51.0m[77] for the Transformer group in its repex forecast for the next RCP. The expenditure profile for the Transformer group comparing the next RCP with previous years is shown in the figure below.

[77] Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.20: Transformer repex by asset category - $m, real 2021



Source: Powercor Reset RIN. PM refers to pole-mounted, KM refers to kiosk-mounted, GM refers to ground-mounted

312. The figure above shows the largest increases for the next RCP are associated with the replacement of substation-related transformers. The major components of expenditure and program are shown in the tables below (and which reconcile to Powercor's program when real cost escalation is excluded). The largest component is network faults which is based on the forecasting method discussed earlier in the report and has not been reproduced in each assessment section.

Table 4.14: Components of Powercor's proposed Transformer repex for next RCP - $m, real 2021

Transformers	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Volumetric programs						
Network Faults	5.8	5.9	6.0	6.1	6.1	29.9
Projects						
Transformer Replacement	3.5	2.1	2.6	2.1	0.0	10.2
RVL T2	*0.0*	*0.4*	*1.9*	*1.5*	-	*3.9*
WBL T3	*1.9*	*1.5*	-	-	-	*3.5*
RVL T1	*1.5*	-	-	-	-	*1.5*
IWD Regulator	-	*0.1*	*0.6*	*0.5*	-	*1.3*
Multiple Transformer 1	-	-	-	-	*0.0*	*0.0*
Pole Type Substation Transformer Replacement	0.7	0.7	0.7	0.7	0.7	3.6
Kiosk Substation Replacement (Condition)	0.5	0.5	0.5	0.5	0.6	2.7
Station Service Transformers Replacement	0.2	0.2	0.2	0.2	0.2	0.9
Kiosk Substation Replacement (Rust)	0.1	0.1	0.1	0.1	0.2	0.6
Ground Type Substation Transformer Replacement	0.1	0.1	0.1	0.1	0.1	0.5
Indoor Substation Transformer Replacement	0.1	0.1	0.1	0.1	0.1	0.3
Total	**11.0**	**9.6**	**10.2**	**9.8**	**8.0**	**48.6**

Source: EMCa analysis of Powercor MOD 4.09 and MOD 4.11. Excludes real labour cost escalation

313. Powercor has provided the following documentation with its submission to support its expenditure:

- expenditure model comprising its transformer replacement expenditure (MOD4.09) and network faults related expenditure (MOD 4.11), which include transformer repex;
- a business case for its transformer risk and investment evaluation,[78] provided in support of the planned transformer replacement program totalling $10.2m; and
- risk monetisation models for four transformer replacements.[79]

Our assessment

Increased expenditure is driven by inclusion of zone substation transformer replacement

314. Powercor proposes to replace four zone substation transformers during the next RCP at a total cost of $10.2m.[80]

315. Powercor currently has 147 substation transformers with an average age of 38.4 years with 6 transformer assets current greater than the estimated service life.[81] The four zone substation transformers it proposes to replace in the next RCP are:

78 Powercor BUS 4.03 - Transformer risk and investment evaluation

79 WBL transformer no. 3 (MOD4.05), IWD regulator (MOD4.12), RVL transformer no. 1 (MOD4.13), and RVL transformer no. 2 (MOD4.14)

80 There is a further line item and sum of less than $0.1m included for multiple transformers, and which we infer is for preparatory work for future transformer replacement projects.

81 Powercor Asset Class Strategy – zone substation transformers, August 2019

- Robinvale (RVL) transformers 1 and 2 at a total cost of $5.4m;
- Warrnambool (WBL) transformer 3 at a cost of $3.5m; and
- Inglewood (IWD) regulator at a cost of $1.3m.

316. For each of the above projects, Powercor has provided details within the supplied business case document, including the CBRM outputs and risk monetisation models that it has relied upon.

The process used to select projects for application of Powercor's risk monetisation method appears reasonable

317. In 2018, at the commencement of its process for establishing a risk prioritised replacement expenditure forecast, Powercor calibrated its CBRM model to identify an initial list of 18 transformers as potential replacement candidates. These transformers were selected on the basis of having an asset Health Index (HI) greater than 5.5. We consider that this was a reasonable starting point particularly because in its CBRM model Powercor considers aspects such as test results, location and duty when establishing its HI for transformers.

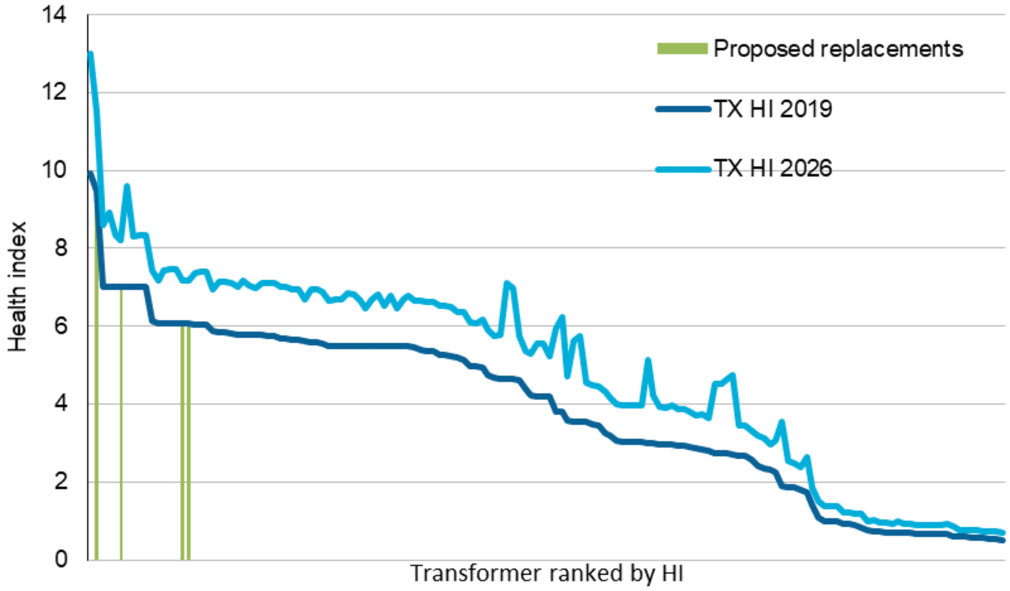
318. From its initial list, Powercor removed transformers to be decommissioned and those planned to have repair/refurbishment work. It also removed transformers for further analysis on the basis that they have experienced low loading or are identified as posing low consequence resulting from failure. In its response to our questions, Powercor supplied an explanation demonstrating how it made decisions regarding the replacement or refurbishment of major substation plant on a case-by-case basis.

319. By taking into account transformer history, availability of spares and hidden failure modes, Powercor reduced its list of candidates further. It applied its risk monetisation analysis to the four transformers (three zone substation transformers and one regulating transformer).

320. We consider that the process described by Powercor for determining the transformers that it submitted to risk monetisation assessment is reasonable because it provides for the application of engineering skill and knowledge to rationalise the initial long list of replacement candidates. The profile of HI for transformers, before and after the proposed replacement expenditure, provides further support to the claim that Powercor is applying appropriate engineering judgement rather than replacing transformers that reach a specific age and/or condition.

321. We gained a perspective of the effect of the selection by sorting the transformer population by HI. The results are shown below.

Figure 4.21: Comparison of HI at 2019 and 2026 by transformer for Powercor



Source: EMCa's analysis of Powercor's response to information request IR035 - Q15 - CBRM HI and POF summary (corrected) - received 15 June 2020

322. In the above chart, we compare the 2019 HI for each substation transformer in Powercor's network against the projected value for 2026 HI for each transformer if no replacements are made. The vertical columns indicate Powercor's proposed transformer replacements. This supports the conclusion that Powercor is targeting, but not replacing all, transformers with the highest HI.

323. The explanation provided by Powercor including its consideration of asset condition and other data indicates to us that Powercor is likely to take account of prudent replacement or refurbishment decisions. However, we were not provided details to demonstrate this in its models. Similarly, we were not provided with details of candidate projects where a lower cost refurbishment and/or condition monitoring option was selected as evidence of how this has been applied to the forecast expenditure.

324. In fact, we do not see evidence of expenditure allocated to these lower cost interventions for Powercor's transformer asset fleet within this category of expenditure. As discussed in our assessment of its 'other' repex group, we did see evidence of transformer refurbishment included there. However, it is unclear to us how these decisions are made and why the expenditure is classified in separate RIN groups.

325. Whilst Powercor has provided us with the HI for each transformer, we have no visibility of the interventions planned for each transformer or how the options have been assessed to determine that the proposed program reflects a prudent level of expenditure.

Assumed failure rates for substation transformers is low

326. We observed that Powercor had assumed a low failure rate for its substation transformers. We asked Powercor to provide the historical failure mode data for its substation transformers that was considered when establishing its CBRM inputs to the risk monetisation process.

327. Powercor confirmed that it had not experienced any major transformer failures during this five-year period:

> *'We have not experienced a major failure in the last five years. However, it was not considered appropriate to use a failure rate of zero for major failures, as many failure modes for transformers, including core, winding and bushing failures, have the potential to result in internal arcing and explosion or fire; and*

Rather, our experience suggests that a failure rate of 0.1 (or one asset in 10 years) would be a reasonable approximation for our total power transformer population. This equates to a failure rate of 0.0004 per transformer.'

328. Powercor advises that its assumed failure rate is significantly lower than other industry values, particularly given its aged asset population.[82] For example, the Transformer Reliability Survey, CIGRE Working Group A2.37, December 2015 (TB64) gives failure rate values of 0.004 to 0.012 for major failures.

329. Projecting a zero major failure rate for transformers with the age profile and condition assessments of Powercor's transformer fleet would not be appropriate. We remain concerned that the failure rate assumed by Powercor is low. However, Powercor considers that the value proposed has been supported by reputable comparative values.

Risk monetisation models applied are not sensitive to failure rate assumptions

330. When reviewing the individual project risk monetisation models, we tested the sensitivity of the optimum replacement date to changes in the commencing PoF value and the rate of change in the PoF curve as the basis to project future deterioration-based failure.

331. We found that, for the projects included in the forecast expenditure, changes to the PoF values did not have a significant deferral effect. For example, for RVL no 1 transformer replacement, the commencing PoF value needed to be reduced from 11.2% to 3.6% and the rate of change in PoF would need to be reduced by 50%, thereby flattening the curve, to move the required date out beyond the end of the next RCP.

Proposed substation transformer replacement projects are reasonable

332. We reviewed each of the models for the proposed projects. The proposed replacement projects are:

- RVL transformer no 1, manufactured in 1950 and has an asset HI of 6.06 in 2019. The transformer is now 70 years old. The HI is forecast to increase to 7.0 by 2026;
- RVL transformer no 2, also manufactured in 1950 and has the same condition as RVL no1 with a HI of 6.06 in 2019. The HI is forecast to increase to 7.0 by 2026;
- WBL zone substation transformer no 1, manufactured in 1948 and has an HI of 9.48 in 2019. The transformer is now 72 years old. The HI is forecast to increase to 11.5 by 2026; and
- IWD zone substation transformer no 1, manufactured in 1941 and has an asset HI of 7.0 in 2019. The transformer is now 79 years old. The HI is forecast to increase to 8.2 by 2026.

333. For all four replacement projects, the transformer is operating beyond its expected life of 60 years. At this age, the risk of failure increases, as reflected in the CBRM model output. The transformers have an HI at the higher end of the range of HIs for Powercor's transformer fleet and it is reasonable to consider them for replacement.

334. By applying the PoF to the input assumptions in its risk cost analysis model, Powercor projected the cost of consequence of failure for significant, major, and catastrophic event categories. To do this, it applied its input values and assumptions for the cost of expected average unserved energy, safety consequence, temporary generators and associated costs, cost of replacement transformers, environmental consequence and fire brigade attendance. To these values, the model applied an assumed likelihood of consequence and derived an output cost of consequence.

335. The main component of the derived risk cost is associated with Network Performance, principally the cost of unserved energy for a significant coincident outage event. The input assumptions for this component are therefore determining the point at which the risk cost exceeds the annualised cost of the project.

[82] Response to information request IR035 - EMCa questions following onsite – Public, response to question 18

336. At the current age and projected HI of the selected transformers, we understand that the risk of a significant coincidental failure has a relatively high probability and, if the event occurred, would lead to high unserved energy costs. The application of a duration weighted VCR value to the cost of unserved energy is reasonable and its use would not have overstated the coincidental outage risk costs.[83]

337. Powercor conclude that, under its central Base Case scenario, each of the transformers modelled should already have been replaced.

338. We undertook additional sensitivity testing to establish the point at which the optimum replacement date for the project moved beyond the end of the next RCP (i.e., the point at which some or all of the associated forecast repex would move into the following regulatory period).

339. We found that, for most input assumptions tested, the results aligned with the outcomes of Powercor's central, lower, and upper scenarios and that moving the optimal replacement date required significant and unreasonable changes to the input assumptions.

340. Based on our own sensitivity analysis of the proposed projects, the asset age and predicted condition by the end of the next RCP, we consider that the proposed replacement projects are reasonable.

The cost estimates for substation transformer replacement projects are not adequately supported

341. The proposed replacement of RVL no 1 and no 2 transformers were planned for the current RCP and did not occur. Upon review of information provided by Powercor, the cost estimates have increased by $0.5m each, relative to the amounts included in the current RCP. We consider this a large increase, given the proposed project costs of $1.5m and $3.9m[84], and so we asked Powercor for an explanation. We were advised that the costs were based on updated costs incurred for similar projects, consistent with the approach for developing cost estimates for other parts of its forecast.

342. Applying historical costs of similar projects is reasonable at the first approval gate as the accuracy of the cost estimates are likely to be improved as the project is developed, risks are quantified and scoping assumptions are refined. Powercor did not provide a breakdown of the proposed cost estimate for these projects. Whilst the risk cost model includes testing of the proposed expenditure across its scenarios of +-10%, for those projects included, the proposed change in cost estimate is well outside of this tolerance and casts doubt on the choice of representative historical projects as the basis of the provided cost estimates.

Remaining distribution transformer replacement appears reasonable

343. Based on our review of the composition of the forecast, the distribution-based transformer replacement appears consistent with the historical trend. We were not provided with a copy of the asset class strategy or operational plans that include distribution transformers to confirm any specific strategies being targeted by Powercor in the next RCP.

344. In the absence of better information, Powercor appear to be basing its justification on historical trend and, by reference, to the AER's repex model at the asset group level. Based on our review of the historical trend and the level of proposed expenditure, the approach is likely to result in a reasonable estimate of requirements.

Summary of our assessment

345. We found evidence of the issues identified in section 3 and in section 4.3 that indicate that the cost estimates relied upon in development of the forecast may be higher than would be reflective of an efficient level.

346. We tested the robustness of Powercor's risk monetisation models provided in support of its substation transformers. We found that these models supported the inclusion of the

[83] For example, for RVL transformer No. 1 Powercor applied a value of $16,785/MWh

[84] This was originally $3.4 as shown in Powercor Appendix 02, Table 7.

proposed projects. For the remainder of the project expenditure, excluding network faults, we were not provided with sufficient detail to assess this in great detail. Based on our assessment of the expenditure and historical rend, the replacement levels are likely to be reasonable.

347. We remain concerned that the information provided by Powercor does not present a complete understanding of how it manages the transformer asset class, including provision for condition monitoring and asset life extension strategies which it states that it currently undertakes. We make further comment on this in our review of the 'Other' repex asset group.

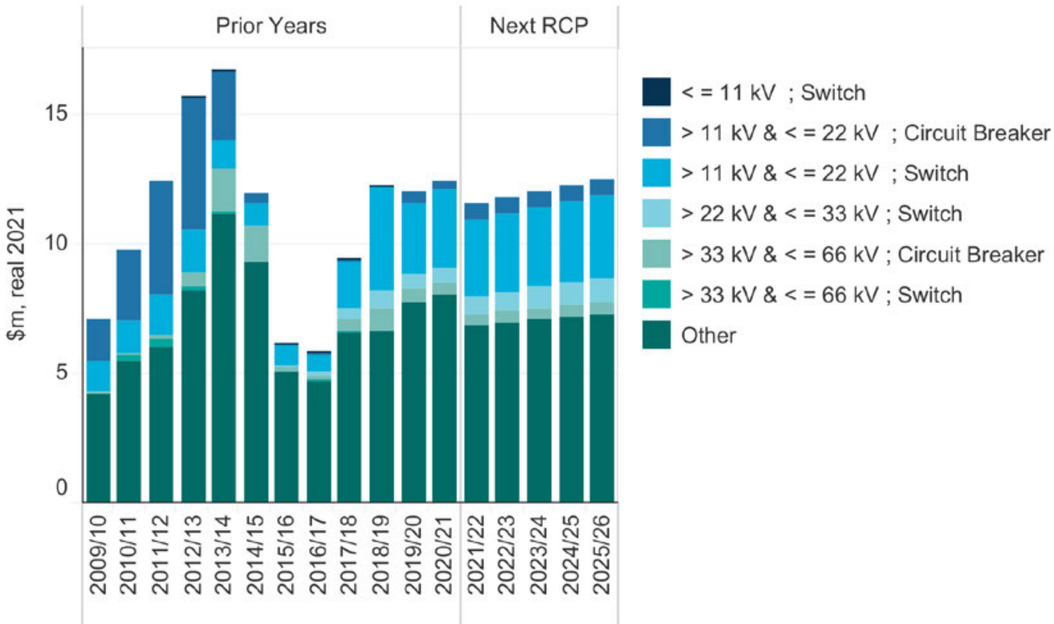
348. On balance, we consider that Powercor is likely to incur a level of expenditure similar to the level of expenditure it has proposed.

4.4.7 Switchgear

Powercor's forecast

349. Powercor has proposed $60.0m[85] for the Switchgear group in its repex forecast for the next RCP. The expenditure profile for the Switchgear group comparing the next RCP with previous years is shown in the figure below.

Figure 4.22: Switchgear repex by asset category - $m, real 2021



Source: Powercor Reset RIN

350. The figure above shows the largest proportion of the forecast is for the 'Other' asset category, which is described by Powercor as being for HV fuse and surge diverters. The largest increase for the next RCP above the historical trend is for 22kV switches.

351. The major components of expenditure by program are shown in the tables below (and which reconcile to Powercor's program when real cost escalation is excluded).

85 Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Table 4.15: Components of Powercor's proposed Switchgear repex for next RCP - $m, real 2021

Switchgear	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Volumetric programs						
HV fuses & surge diverters	5.9	5.9	5.9	5.9	5.9	29.7
Network Faults	0.8	0.8	0.9	0.9	1.0	4.5
Projects						
Outdoor HV ABS Replacement (CRO tagged interrupters)	1.4	1.4	1.4	1.4	1.4	6.9
Outdoor HV ABS Replacement (Non-Geveas)	0.9	0.9	0.9	0.9	0.9	4.6
22kV Circuit Breaker Replacement	0.5	0.5	0.5	0.5	0.5	2.4
66kV Circuit Breaker Replacement	0.4	0.4	0.4	0.4	0.4	2.2
22kV Isolator Replacement (3 Phase Groups)	0.3	0.3	0.3	0.3	0.3	1.7
22kV Insulator Replacement (3 Phase Groups)	0.3	0.3	0.3	0.3	0.3	1.5
22kV Disconnect Switch Replacement	0.2	0.2	0.2	0.2	0.2	1.0
HV ABS Replacement (Indoor substations)	0.2	0.2	0.2	0.2	0.2	0.9
Low Gas RMU Replacement	0.2	0.2	0.2	0.2	0.2	0.8
22kV Capacitor Bank Step Switch replacement	0.1	0.1	0.1	0.1	0.1	0.4
66kV HPVA Disconnect Switch Refurbishment	0.1	0.1	0.1	0.1	0.1	0.3
Low Gas Switches (OH) Replacement	0.1	0.1	0.1	0.1	0.1	0.3
Total	**11.3**	**11.4**	**11.4**	**11.5**	**11.5**	**57.1**

Source: EMCa analysis of MOD 4.06, MOD 4.09 and MOD 4.11. Excludes real cost escalation

352. Powercor has provided the following documentation with its submission to support its expenditure:

- models comprising its Plant and stations replacement expenditure (MOD4.09), volumetric program (MOD4.06) and network faults related expenditure (MOD 4.11) which includes switchgear related repex; and
- a business case for its HV ABS replacement program[86] totalling $6.6m ($2019) and expenditure model (MOD4.02).

Our assessment

Overview of stated drivers

353. Powercor describe the drivers of its switchgear group as:[87]

86 Powercor BUS 4.04 HV ABS replacement program

87 Powercor RIN response RIN016

'Asset condition based on inspection regime, operational experience and/or asset failure for distribution or overhead line switchgear. It is noted that some portion within such asset categories are proactively replaced due to safety concerns. Asset condition and risk profile based on inspection and testing regime, operational experience such as fault history, health indices, value of lost load, emergency cost, etc. and/or asset failure for zone substation switchgear.'

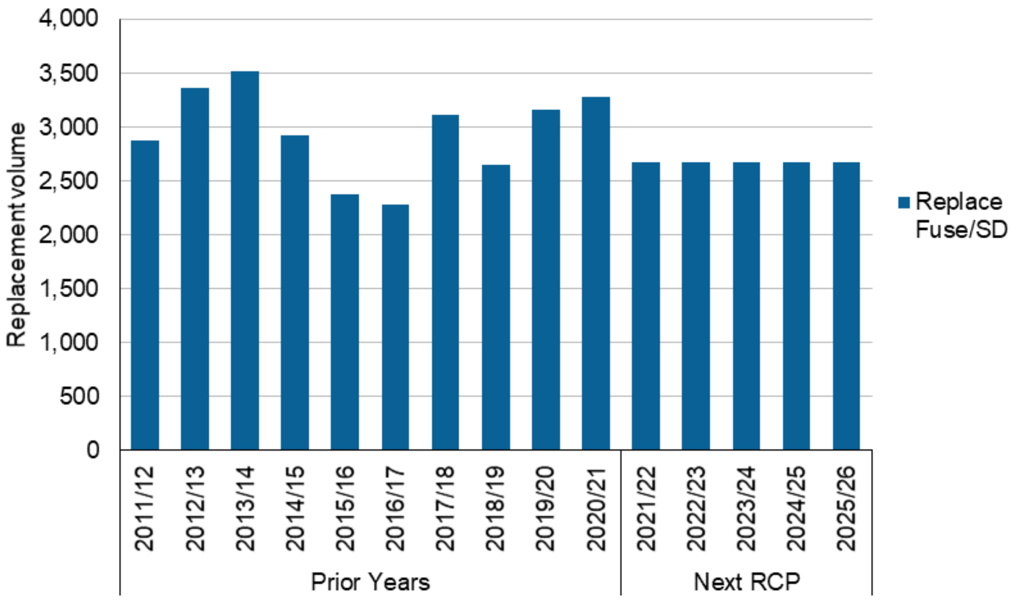
354. Powercor measures and maintains health indices for this particular asset group, especially for higher voltage equipment, from which it forms a risk profile and compares it with the cost of replacement to justify investment.

HV fuses and surge diverters is the largest component of expenditure

355. Powercor has included $29.7m in its forecast switchgear repex for defect driven replacement of HV fuses and surge diverters, which is consistent with the historical trend. The forecast follows the method described in section 4.3 for high volume, low cost asset interventions.

356. We provide the proposed asset replacement volumes in the figure below, which shows a level consistent with the historical average.

Figure 4.23: Historical and forecast replacement of HV fuses and surge diverters



Source: EMCa analysis of Powercor MOD4.06

357. Powercor has not provided any detail on the composition of this forecast, other than its expenditure model (PAL MOD 4.06) which merely presents the proposed volume and expenditure (based on its historical unit rate). Beyond extrapolating the historical average, it is therefore not clear to us how Powercor determined this was the optimum expenditure for the next RCP (such as by considering condition and risk). We also cannot readily discern from the information provided whether the proposed expenditure includes existing EDO fuse replacement, for which Powercor has separately sought additional expenditure in the next RCP.

358. We reviewed the unit cost with the intent to understand the nature of the proposed work, and whether EDO replacement and/or installation of Fault-tamer type fuses may be included in this program. The historical unit cost used for determining the forecast expenditure is $2,219 ($2021). However, the blending of multiple activities does not allow for a reasonable comparator. We note, however, that based on Powercor's records the unit rate has been much lower, which may indicate a change to the nature or proportion of activities that are undertaken. Powercor has not explained this.

359. Based on observed performance, we consider that it is appropriate to maintain similar levels of replacement to those that Powercor has historically undertaken. However, as discussed in our review of Powercor's forecasting methods in section 3 and in section 4.3, we remain concerned that the methods applied by Powercor in developing its forecast may not reflect a prudent and efficient approach.

360. We separately consider our assessment of the proposed EDO fuse replacement expenditure in a later section of this report.

Proposed increase to HV Air-break switchgear is not adequately supported

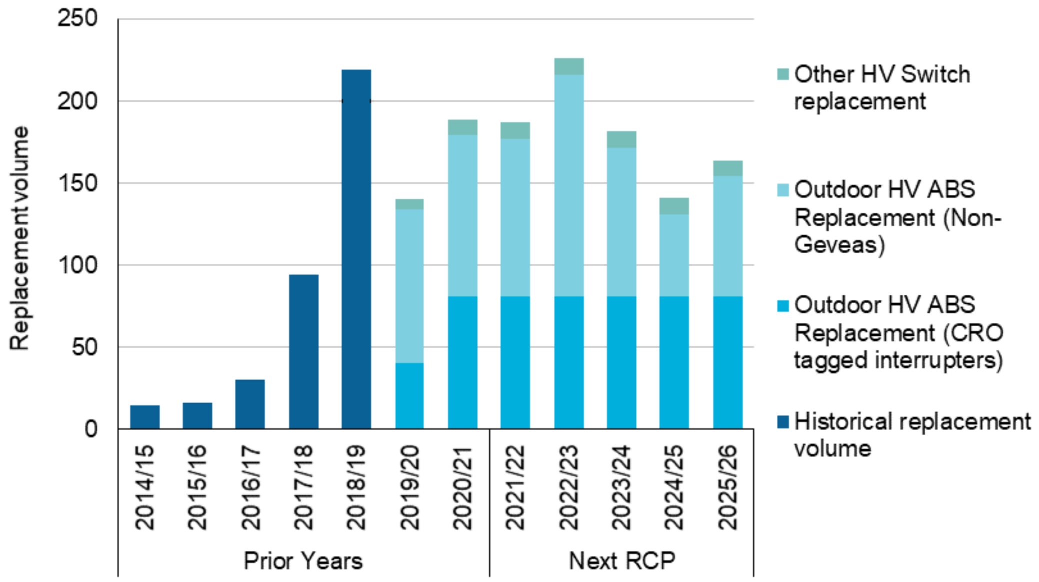
361. Powercor has included $11.5m for the replacement of outdoor high-voltage air-break switch replacement projects and a further $3.2m for other HV switch replacement projects.[88]

362. The outdoor high-voltage air-break switch replacement projects include replacement of the CRO tagged interrupters (for which the provided business case relates) and non-Gevea branded switchgear replacement projects (for which no business case has been provided).

363. Powercor describes the key drivers as being condition and risk of the CRO tagged interrupters resulting in a material negative impact on supply reliability (as measured by customer minutes lost) and safety risk.[89] For the non-Gevea branded air-break switches, Powercor advised that they have a higher failure rate than gas insulated or Gevea branded air-break switches and are generally unrepairable. Powercor has not provided options analysis that would normally be associated with a business case or similar document, or an economic analysis. In its response to our request for information, Powercor states that '[t]*here is a high likelihood that most of these switches are reaching the end of their useful lives*.'[90]

364. The proposed replacement volumes compared with the historical replacement volumes are shown in the figure below.

Figure 4.24: Comparison of historical and forecast replacement volumes



Source: EMCa analysis of Powercor MOD4.09

365. From the chart above, we observe that the proposed replacement of ABS represents a step increase on the historical replacement volumes. In Powercor's Reset RIN response, it has not identified any changes to its asset management strategy in relation to this asset group.

88 This comprises five projects: (i) low gas switch (OH) replacement; (ii) low gas RMU replacement; (iii) HV ABS (indoor) replacement; (iv) 22kV disconnect switch replacement; and (v) 66kV disconnect switch refurbishment

89 Powercor BUS 4.04 HV ABS replacement program

90 Powercor's response to information request IR017a – EMCa questions governance and repex

366. According to the asset class strategy,[91] Powercor's distribution switchgear assets are managed by defect identification from switchgear operation or from visual inspection. Powercor states that there are '*currently no preventative maintenance plans in place to determine asset condition*."[92]

367. The asset class strategy refers to a '*significant increase in reported asset defects and failures associated with switches*' and relates this directly to air-break switches and insufficient historical maintenance levels. It appears that the data relied upon in reaching this conclusion in the asset class strategy is for the period 2013 to 2017. There was a significant increase in failures in 2016, after which Powercor changed its maintenance program:[93]

> *'In 2016, the distribution air break switch maintenance program was reviewed and strengthened, resulting in an improvement in capture of switch defects. This increased maintenance effort is responsible for the reduction in failures observed in 2017 relative to 2016.'*

368. This asset class strategy also refers to *'…2,000 air break switches across the CP/PAL network flagged as inoperable due to their unknown condition status*' which leads to the articulation of a key safety challenge, including:[94]

> *'A scheduled replacement of these assets is required but is complicated by the lack of information required to prioritise these assets across the entire asset base. Failure reporting should be improved for more accurate performance monitoring.'*

369. It is not evident to us whether improvements to failure reporting have now been made, and whether any updated information has been relied upon in the development of the expenditure forecast.

370. We sought to understand the rationale for inclusion of the two ABS replacement programs in the repex forecast, the relationship between them, and whether they were addressing the same identified risk. Powercor states that:[95]

> *'…the replacement program for non-Gevea branded air-break switches is different to our CRO-tagged program, and unrelated. CRO-tagged switch volumes are not counted in the non-Gevea population.'*

371. However, we were not provided with sufficient justification for the non-Gevea program. In the absence of a clear trend of defects, assessment of risk, options analysis and economic assessment, we are unable to conclude that Powercor proposes a prudent level of expenditure.

372. The replacement of the CRO-tagged interrupters is supported by a business case and assessment models. The program of switch replacement is intended to be delivered over a 12-year cycle.

373. The economic analysis provided supports Powercor's assertion that it is more economic to replace with new than to repair the proposed switches. The benefits derived are primarily related to reductions to customer minutes lost (reliability) and safety risk.

374. The inclusion of the ABS replacement program for CRO-tagged interrupters appears reasonable.

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[91] Asset Class Strategy Distribution Switchgear, page 7

[92] Asset Class Strategy Distribution Switchgear

[93] Asset Class Strategy Distribution Switchgear, page 16

[94] Asset Class Strategy Distribution Switchgear, page 19

[95] Powercor's response to information request IR017a – EMCa questions governance and repex

Proposed volumes of the remaining substation switchgear replacement is likely to be reasonable

375. Based on our review of the composition of the forecast, the substation related plant replacement is small. Further, the asset class strategy for switchgear states that a HI value of 7 is considered to indicate that the switchgear is at end of life and triggers a review of the asset treatment plan. Powercor states that:[96]

> *'The current distribution of HI across zone substation circuit breakers is included in Figure 6. Currently none of CP/PAL's zone substation circuit breakers have a HI greater than 7.'*

376. Other substation related switchgear assets are managed through condition monitoring with intervention works driven by defect identification. This is consistent with the small volume of replacement activity that comprises the balance of work in this category to target the highest priority assets.

377. We have included our assessment of Powercor's application of its CBRM methodology in Appendix A. We have not found any systemic issues from the method undertaken by Powercor. Due to the low expenditure, we have not had to draw from this for our assessment of the proposed switchgear expenditure.

378. The proposed replacement volumes for the remainder of the substation switchgear components are likely to be reasonable.

Summary of our assessment

379. For the bulk of the proposed replacements, Powercor has described a reasonable method that has led it to determine a prudent level of replacement. In regard to the proposed HV air-break switchgear replacements, Powercor has not sufficiently demonstrated that the forecast for non-Gevea ABS reflects a prudent level of replacement.

380. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

381. Accordingly, we consider that Powercor has not justified the full extent of the proposed increase to its forecast expenditure for the Switchgear group.

4.4.8 SCADA, network control and protection

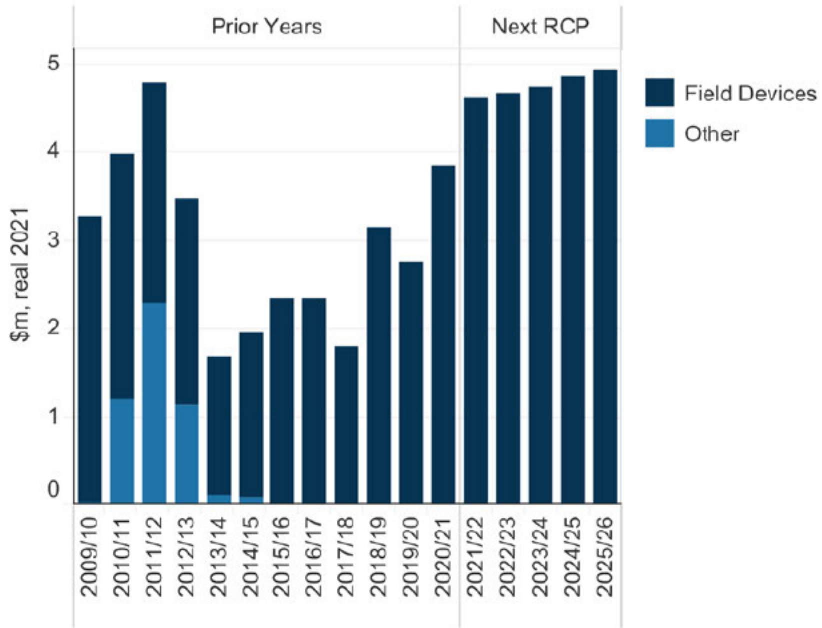
Powercor's forecast

382. Powercor has proposed $23.9m[97] for the SCADA, network control and protection group in its repex forecast for the next RCP. The expenditure profile for the SCADA, network control and protection group comparing the next RCP compared with previous years is shown in the figure below.

96 Asset Class Strategy: Zone Substation Switchgear, page 9

97 Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.25: SCADA, network control & protection systems repex by asset category - $m, real 2021



Source: Powercor Reset RIN

383. The figure above shows a step increase to the forecast expenditure associated with field device replacement for the next RCP. This includes the replacement of protection relays, RTUs and control systems equipment that is primarily located at substations. The major components of expenditure and program by construction type are shown in the tables below (and which reconcile to Powercor's program when real cost escalation is excluded.)

Table 4.16: Project groupings of Powercor's proposed SCADA, network control and protection repex for next RCP - $m, real 2021

SCADA, network control & protection systems	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Protection relay & RTU replacement	4.1	3.9	3.8	3.3	3.6	18.8
New voltage control scheme	0.2	0.4	0.5	0.6	0.3	2.1
TX parallel control replacement	0.0	0.0	0.0	0.4	0.4	0.8
Battery & charger requirements	0.1	0.1	0.1	0.1	0.1	0.5
Secondary defect design and installation	0.1	0.1	0.1	0.1	0.1	0.5
Total	**4.6**	**4.5**	**4.5**	**4.6**	**4.6**	**22.7**

Source: EMCa assignment to project groupings based on project titles included in Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

384. Powercor has provided a protection replacement expenditure model (MOD4.10) to support its proposed expenditure.

Our assessment

Powercor has relied on its CBRM model outputs for the proposed expenditure

385. We requested summary justification documents (i.e., business cases or similar) for the total forecast expenditure in this group including details of the scope, key drivers, the asset condition and risk information relied upon in developing the forecast, the options considered and the financial analysis undertaken and any relevant models. We also asked Powercor to provide a copy of any modelling that was used in determining the proposed expenditure.

386. Powercor referred to the expenditure model (MOD 4.10) which contains a list of projects and expenditure by year and its Reset RIN response (RIN016), both of which were provided within its regulatory proposal. We were also provided with a copy of its protection and control asset class strategy.[98]

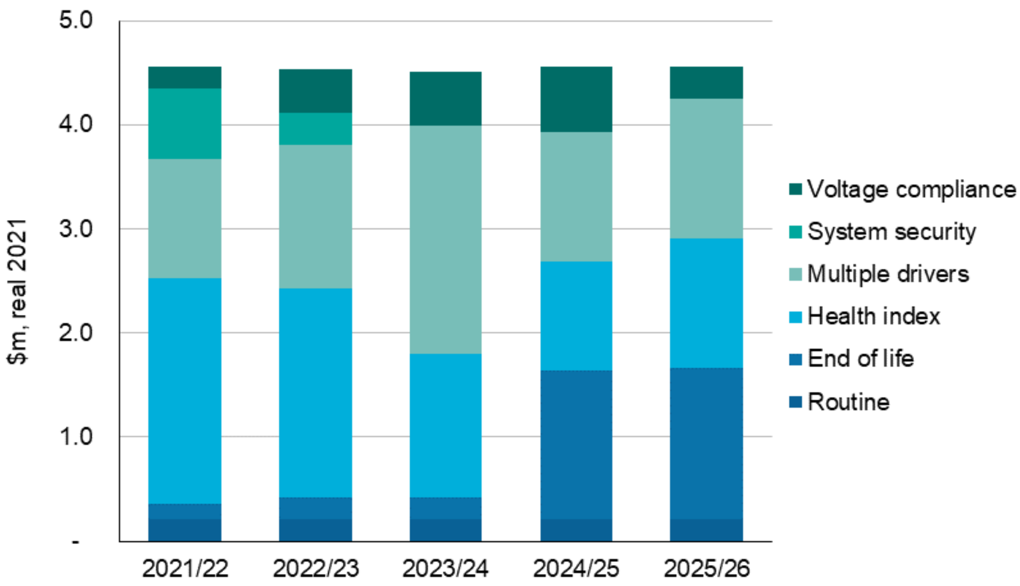
387. Collectively these documents do not provide justification for the proposed forecast expenditure, including how the replacement projects were selected or that the level of expenditure is reflective of a prudent and efficient level.

388. In response to further questions to clarify its forecasting method, Powercor provided a copy of its CBRM model on which it relied to develop the forecast expenditure and which nominated an expenditure driver for each project.[99]

389. Powercor has applied a CBRM methodology to drive a large proportion of its planned replacement expenditure requirements. Approximately 80% of the expenditure forecast is driven by end of life or condition-based replacement - or a combination of the two drivers.

390. The expenditure profile for this group of repex is shown in the chart below by the expenditure driver nominated by Powercor.

Figure 4.26: Protection and control related repex by driver - $m, real 2021



Source: EMCa review of Powercor's response to IR035 Q14 PAL MOD4.10 – drivers. Excludes real cost escalation

An increase to the level of condition-based replacement appears reasonable

391. As Powercor has identified asset condition as the dominant driver, we reviewed the CBRM model relied upon to generate the forecast replacement expenditure. The model has been developed by EA Technology and includes a methodology similar to that applied for its major substation plant.

392. Powercor has not provided a description of the provided CBRM model.

393. We have ascertained the key features of this model (from our own enquiry) as:

- It assigns a health index to each relay based on its age;
- It modifies the HI based on its 'generic reliability rating' which is a value of 1 to 4, with 1 being the poorest reliability. A value is assigned to each relay in another dataset input by Powercor. The calculation of this rating has not been provided;

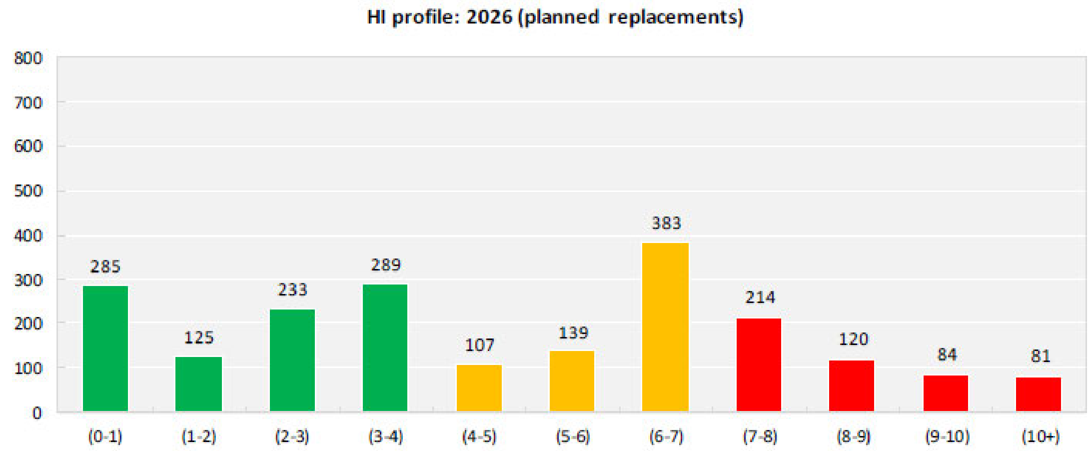
98 Received in response to information request IR017

99 Received in response to information request IR035 Q14

- This results in an adjusted HI, with a corresponding assessment of years to reach end of life; and
- A forecast HI is developed based on application of aging reduction factors to an asset degradation curve.

394. We have reproduced Powercor's plots of HI values of its fleet of protection relays as at the year 2026, with the planned replacement projects included.

Figure 4.27: Summary of HI for protection assets as at year 2026



Source: Response to information request IR035 – CBRM HI and POF summary

395. Powercor did describe the components of its program in its response to our request,[100] and that aligned with the identified drivers of expenditure in Figure 4.26. This includes consideration of: (i) asset condition and risk; (ii) asset obsolescence; (iii) system security compliance; and (iv) penetration of embedded generation. Powercor has used the CBRM model to inform the development of the proposed program, in particular: [101]

> *'…assets with a health index greater than 6.0 were assessed, with any subsequent replacement decisions having regard to the consequences of failure associated with these assets.'*

396. We have not been provided with an explanation of the model, or how the outputs of the model have been used to determine the projects it has included in the forecast expenditure for the next RCP. Our enquiry into the model was also not able to identify this relationship.

397. We note that the model produces a probability of failure and what appears to be an assessment of network performance consequence from failure of the protection assets. It is not evident from the model or from the information provided how Powercor has used this information, if at all, in producing the expenditure forecast.

398. Based on the produced HI results alone it would suggest that there is a growing population of relays that require replacement. However, upon review of the asset class strategy, there is no suggestion of an increased level of replacement compared with historical practice.

399. Notwithstanding that Powercor has not explained the relationship between its CBRM and its proposed expenditure, we accept the need for an increase of its SCADA, network control and protection program. However, the level of increase and the timing of replacement projects has not been demonstrated with the information provided.

[100] Response to information request IR035 Q14 supplementary response

[101] Response to information request IR035 Q14 supplementary response

Elements of its program appears to be based on information external to its CBRM model

400. We have not been provided with information to support projects that have been included by Powercor for drivers other than for condition and risk and for which we understand that Powercor has relied on its CBRM model.

401. On reviewing the categories of system security and voltage compliance, these drivers appear to us as being more typically associated with augmentation capex, namely:

- System security projects comprised of projects with the title '*66kV line protection dupl*', which we interpret as installing duplicated protection schemes;[102] and
- Voltage compliance projects comprised of a '*New voltage control scheme*' for '[m]*anaging risks of voltage compliance where there are increasing levels of medium scale embedded generation.*'

402. Whilst we found items listed in the CBRM model for replacement of under-voltage and over-voltage supervisory schemes, there was not a strong correlation between relays with a high HI and the nominated projects. We discounted any relationship with the model on the basis that Powercor referred to the schemes as new, and for the purpose of voltage compliance as a result of increasing levels of embedded generation.

403. We looked for evidence to support these projects as repex or as augex in the documentation provided by Powercor, including as a part of the proposed solar enablement business case. We did not find a basis for the inclusion of these projects for the next RCP, totalling $3.0m.

Summary of our assessment

404. Powercor has not demonstrated the relationship between its CBRM tool and its forecast expenditure, in order to determine how it arrived at a prudent level of replacement for this group. Further, we were not able to find a basis to support the inclusion of some projects into the forecast.

405. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

406. We consider that Powercor has not justified the extent of the proposed increase to its forecast expenditure for SCADA, network control and protection repex.

4.4.9 Other repex

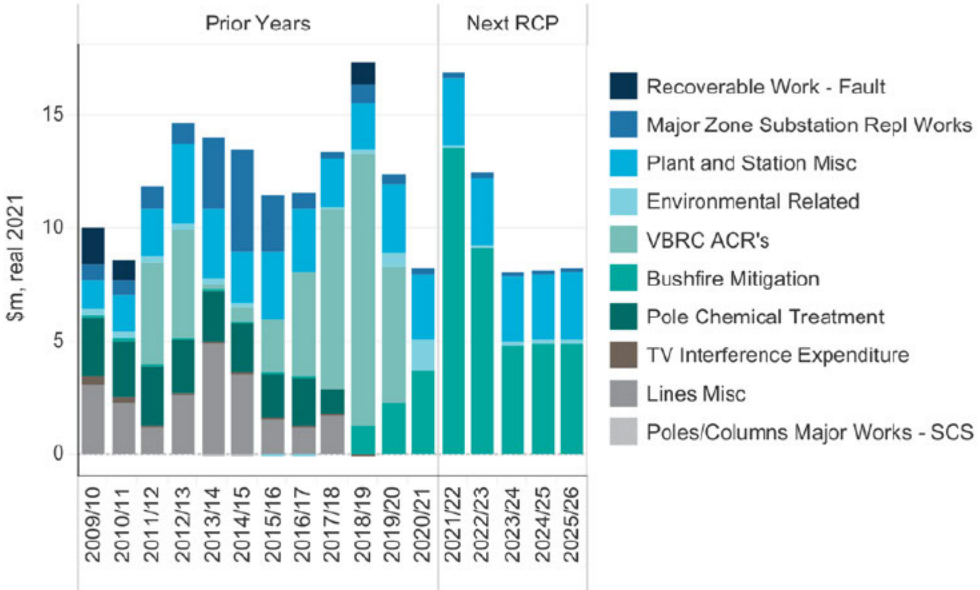
Powercor's forecast

407. Powercor has proposed $53.6m[103] for the Other group in its repex forecast for the next RCP. The expenditure profile for the Other repex group comparing the next RCP compared with previous years is shown in the figure below.

[102] As compared with the planned replacement of line protection schemes which were labelled as '*66kV Line Prot repl*' and were associated with condition based replacement drivers

[103] Powercor Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows and includes the environmental management adjustment.

Figure 4.28: Other repex by asset category - $m, real 2021



Source: Powercor Reset RIN

408. The figure above shows that Powercor has included a component of VBRC/Bushfire Mitigation related expenditure in its 'Other' group, and which has a similar level of expenditure when comparing the historical and forecast periods. The composition and extent of expenditure for the remaining asset categories is reducing for the next RCP.

409. The major components of expenditure are shown in the tables below (and which reconcile to Powercor's program when real cost escalation is excluded.)

Table 4.17: Components of Powercor's proposed Other repex for next RCP - $m, real 2021

Other repex	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Bushfire Mitigation	13.3	8.8	4.6	4.6	4.6	35.7
Mitigating REFCL reliability impacts	*8.7*	*4.2*	-	-	-	*12.9*
Cross arm and insulator replacement	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*	*6.2*
Replace LV fused overhead line connector boxes (FOLCBs) in ELCAs	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*5.0*
Replace LV fuse switch disconnectors (FSDs) in ELCAs	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*3.7*
Replace wood crossarms in ELCA's	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*3.1*
Early fault detection	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*2.7*
Technology developments and research partnerships (annual program)	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.1*
Zone Substation Plant Replacement	2.4	2.2	2.1	2.1	2.1	10.8
Bird Cover Replacement	0.8	0.8	0.8	0.8	0.8	4.0
OH/UG Line Replacement	0.0	0.0	0.0	0.0	0.0	0.1
Environmental Related	0.2	0.2	0.2	0.2	0.2	0.8
Total	**16.6**	**12.0**	**7.6**	**7.6**	**7.6**	**51.5**

Source: EMCa analysis of Powercor MOD 4.06 and MOD 4.11. Excludes real cost escalation

410. Powercor has provided the following documentation with its submission to support its expenditure:

- a business case for its Mitigating REFCL reliability impacts[104] totalling $12.9m;
- models comprising the bushfire safety related capex (MOD6.09);[105]
- models detailing the costs (MOD4.03) and benefits (MOD4.04) associated with the installation of Smart ACRs; and
- models comprising plant and stations expenditure (MOD4.09) of which some projects are allocated to the 'other' repex group.

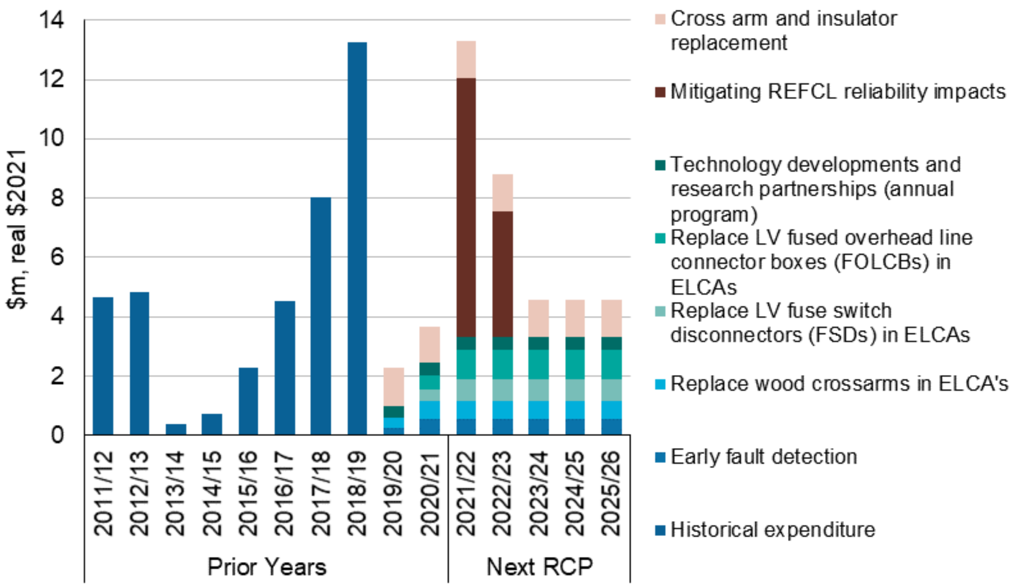
411. As discussed in section 2, we have removed the proposed environmental program from the forecast repex for this group and do not include the supporting information provided by Powercor as a part of our assessment.

Our assessment

Composition of the proposed bushfire mitigation program potentially duplicates other included programs

412. Powercor has included a bushfire mitigation program at a total cost of $35.7m with the components as detailed in the table above. This is also referred to by Powercor as its VBRC[106] program. The historical and forecast expenditure associated with this program is shown in the figure below.

Figure 4.29: Historical and forecast bushfire mitigation expenditure - $m, real 2021



Source: EMCa analysis of Powercor MOD 6.09

413. The historical expenditure was primarily associated with the installation of Auto Circuit Reclosers (ACRs) across its network, as required by ESV. The composition of the projects for the next RCP are new and include a range of initiatives such as new technology, research and development, and asset replacement.

104 Powercor BUS 4.05 Mitigating REFCL reliability impacts

105 This includes expenditure allocation to repex for bushfire mitigation and for other augex related projects, including installation of REFCLs

106 Victorian Bushfire Royal Commission

Individual bushfire safety programs proposed by the business do not necessarily or automatically become externally-imposed obligations for the purpose of assessment under the NER

414. In its RP, Powercor referred to the strong stakeholder feedback it received to include bushfire safety programs:[107]

> *'Our customers hold strong views that safety is a given, and is too important to be 'traded-off'. Throughout our engagement process, they emphasised that safety should always be our top priority and must be maintained or improved where possible.*
>
> *In particular, bushfire mitigation projects were strongly supported in our deliberative engagement forums. Our customers typical response was that we should be bringing these projects forward. This included using new technology, undergrounding of assets and increased pole inspections.'*

415. Powercor describes that its approach is to:

> *'..continue to effectively reduce the risk of bushfires from our network is set out in our BMP, which is approved by ESV. Projects included in our BMP are compliance obligations under the Electricity Safety Act 1998.'*

416. We reviewed Powercor's current BMP and identified a list of programs[108] that aligns with the components of the Bushfire safety programs included in this group. We also observe that in many cases, Powercor acknowledges that the bushfire safety programs included in the BMP are also provided as part of its regulatory submission for 2021-26, subject to the outcome of the revenue determination and subject to its ongoing review in subsequent BMPs that it is required to provide.

417. We understand that the reference to compliance obligations, is compliance with Clause 113B of the Electricity Safety Act,[109] which states:

> *'113B Compliance with bushfire mitigation plan*
>
> *(2) A major electricity company must comply with an accepted bushfire mitigation plan that applies to the company's supply network.'*

418. Under the Electricity Safety Act, we understand that ESV accepts rather than approves the BMP submitted by Powercor, based on a reasonable assessment. In providing acceptance of the programs nominated by Powercor, ESV holds Powercor accountable by means of monitoring compliance with the commitments made in the BMP. In providing its acceptance for the most recent BMP, ESV explains that:[110]

> *'This means that ESV is satisfied the submitted management plan meets the acceptance criteria adopted for the 2019/20 year, and is deemed to satisfy the requirements of Section 113A of the Electricity Safety Act 1998 incorporating amendments as at 29 June 2015, and the prescribed particulars in regulation 7 of the Electricity Safety (Bushfire Mitigation) Regulations 2013 incorporating amendments as at 1 May 2016.'*

419. We acknowledge ESV's support for inclusion of bushfire safety-related programs such as those proposed by Powercor. However, as noted in section 3.2, we consider that Powercor including reference to the proposed programs in the current BMP does not necessarily or automatically give rise to the level of an external obligation on Powercor for each individual

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107 Powercor Regulatory Proposal, page 38

108 Included as part of section 6.12 of Bushfire Mitigation Plan, revision 6, 9 December 2019

109 Electricity safety Act 1998, as at 1 January 2020. Viewed at https://content.legislation.vic.gov.au/sites/default/files/a157127e-2962-3334-9090-ec3c826dc213_98-25aa077%20authorised.pdf on 2 July 2020

110 Powercor Attachment 205 - ESV - acceptance of BMP - 31 January 2020

project or program referenced there, the purposes of assessment against the NER as part of the five-year revenue determination.

420. We therefore sought evidence to justify the inclusion of the proposed projects and to demonstrate that the net benefits of doing so are positive. Accordingly, we looked for evidence of a risk assessment and accompanying cost benefit analysis.

No assessment of risk or cost benefit is evident for its bushfire safety related expenditure

421. With the exception of the Mitigating REFCL reliability impacts, for which a business case and supporting models have been provided, Powercor has not provided a risk assessment, economic analysis or justification for the proposed projects.

422. Powercor appears to recognise the need to consider an economic test for the nature of these projects, as part of meeting its broader safety obligations. In the context of related bushfire safety programs, Powercor refers to an assessment of affordability by not proposing to extend the program to retire the SWER network in the next RCP.

> *'We have, however, had regard to affordability by not proposing to extend our program to retire our SWER network into the 2021–2026 regulatory period. Since 2014, the Victorian Government's powerline replacement fund (PRF) has funded the retirement of almost 300 kilometres of existing SWER lines in the designated highest consequence bushfire areas. The PRF is expected to conclude in 2020. If directed by ESV to continue these works, we will seek regulatory funding through the pass-through mechanisms set out in the Rules.'*[111]

No evidence of prioritisation of bushfire safety driven asset replacement across existing asset replacement programs

423. For the asset replacement programs included, we did not see evidence to demonstrate that the existing asset replacement programs could not be prioritised to deliver the intended benefits associated with this program, rather than introduce a new program. Absent demonstration that such a review had been undertaken, and together with an economic test of the benefits, we remain concerned that this is potentially duplicating asset replacement work and incurring a higher level of expenditure than is representative of an efficient level.

Mitigating REFCL reliability impacts appears reasonable

424. Powercor has included a program to correct the decline in reliability experienced by customers connected to networks where Powercor is required to install a REFCL device, consistent with the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (Amended Bushfire Mitigation Regulations) which were implemented in Victoria on 1 May 2016.

425. The program consists of replacing traditional ACRs, that are not compatible with the REFCL technology as they cannot respond as quickly to detect and isolate supply, with smart ACRs. Currently, in the event of phase to ground faults occurring downstream of ACRs and fuses, the network will be isolated by the REFCL at the circuit breaker rather than being isolated along the feeder by the ACR or fuse. Consequently, more customers are being taken off supply than would be necessary to safely isolate the faulted section.

426. Powercor has modelled the benefits arising from its Value of Unserved Energy calculation due to incompatibility of REFCLs and traditional protection device and based on historical fault data. While Powercor had not undertaken a cost benefit analysis from this information, we produced such analysis from Powercor's information and were then also able to test for sensitivity of the resulting net benefit. From this, we are satisfied that the project is benefit positive.

427. The costs have been determined by Powercor for installing smart ACRs based on the costing approach used in its REFCL contingent project applications. However, this project

111 Powercor Regulatory Proposal, page 38

relies on development of the smart technology, which Powercor states is not yet available:[112]

> *'We are confident smart ACR technology will be developed during 2020, enabling us to trial the technology on our network in 2021 and then commence a smart ACR roll out program from 2021/22.'*

428. On balance, we consider that Powercor has demonstrated that this project is reasonable.

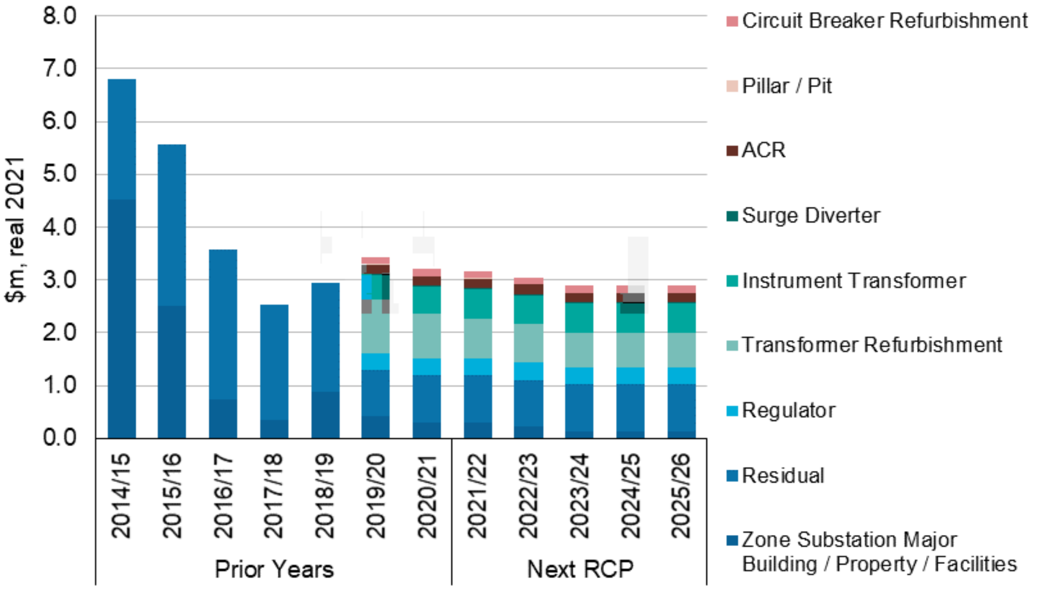
Balance of works including in the 'Other' repex group may duplicate other parts of the repex forecast

429. The expenditure for the balance of projects after removal of the bushfire related repex, appear consistent with historical trend. We were not provided with any supporting documentation to provide the rationale for these projects.

430. In the absence of better information, Powercor appears to be basing its justification on the remaining parts of the transformer replacement program using historical trend and by reference to its total unmodelled expenditure.

431. The forecast averages $3.0m per annum. We reviewed the included components of expenditure for the balance of this RIN group, as shown in the figure below.

Figure 4.30: Historical and forecast expenditure for 'Other' repex group (excluding bushfire mitigation) - $m, real 2021



Source: EMCa analysis of Powercor MOD4.09. Excluding real cost escalation

432. As shown, Powercor has included expenditure shown for Transformer refurbishment, Instrument transformer and regulator replacement. On further assessment of Powercor's expenditure models, we observe that:

- transformer refurbishment largely relates to, amongst other things, 66kV transformer bushing replacement. This also includes transformer monitoring; and
- instrument transformer largely relates to replacement of porcelain bushings for CVTs.

433. This expenditure is all associated with the transformer RIN group. With the exception of regulator replacement, the refurbishment activities relate to life extension activities associated with zone substation plant, and as such, are often associated with lower cost

112 Powercor BUS 4.05 - Mitigating REFCL reliability impacts, page 10

replacement activities that allow deferment of larger expenditure associated with transformer replacement. When considered alongside the proposed transformer replacement, the combination of activities are in line with the nature of transformer-related work that we would expect to see being incurred.

434. There is also expenditure shown as ACR, Circuit breaker refurbishment and Surge arrestors. On further enquiry of Powercor's expenditure models, we observe that:

- ACR ($0.9m) refers to replacement of three phase 22kV ACRs;
- Circuit breaker refurbishment ($0.6m) refers to 22kV Circuit Breaker Bushing Replacement / CB Refurb; and
- Surge diverter ($0.1m) refers to surge arrestor replacement and which is included in Powercor's description of the Switchgear 'Other' asset category including HV fuses and surge arrestors.

435. We question why Powercor has elected to classify a large part of this expenditure as part of its 'Other' group, which has the effect of being considered separate to the AER's repex model.

436. The bulk of this expenditure relates to the management of transformer and switchgear groups. In the absence of clear justification of this expenditure separate from those groups, a component is likely to be duplicated either in the objective of this expenditure or in the target level of replacements.

437. The remaining elements include building / property / facilities works of $1.0m and 'residual' of $4.4m which is principally associated with unplanned plant replacements, plus a small allocation to 'Operator / Maintainer Safety' (Access Platforms).

Summary of our assessment

438. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

439. We found evidence that, based on the limited information provided, components of the forecast are more reasonably allocated to other groups of repex and may, at least in part, duplicate other parts of the forecast repex.

440. We consider that Powercor has not justified the extent of the proposed forecast expenditure for the 'Other repex group.

4.5 Findings and implications for Powercor's repex forecast

4.5.1 Summary of findings

The originally provided justification documentation did not constitute an adequate level of supporting evidence to justify the proposed expenditure

441. In our assessment of the proposed expenditure, we sought to understand the basis for inclusion of the project and programs into the forecast and the rationale for the proposed replacement volumes. From the information provided, we looked for evidence of justification of the proposed expenditure (consistent with the normal requirements of a business case-like document) to support the development of a prudent, efficient and reasonable program of forecast expenditure.

442. Based on our experience, we consider that a typical DNSP should have this information readily available to support its claims. This is consistent with our experience of having undertaken numerous expenditure reviews for the AER, supported by the AER's capital

expenditure assessment guideline and was reflected in our information requests to each business.

443. In many cases, there is an absence of evidence to justify the volume and cost assumptions that Powercor has included in its proposed forecast.

Some proposed projects and programs may duplicate work already in 'base' repex, and do not appear to have been considered within the prioritisation and optimisation processes of the governance and management framework

444. Powercor has described application of an iterative top-down challenge process to their capex forecasts (as described in section 3). We understand that projects were excluded from the proposal as a part of the Executive review process. However, we also see evidence that projects and programs are included in the forecast without evidence of prioritisation or portfolio optimisation, given the existence of similar programs of an ongoing nature referred to as the 'base' level of repex.

445. Specifically, we are concerned that the application of an optimisation (or prioritisation) process was limited, to the point that it was unlikely to meaningfully consider the extent of projects that might reasonably be deferred in the proposed forecast.

446. We observed evidence of a bias in the forecast to include additional projects to the forecast capex, above what is considered a 'base' level of capex, but which still appeared to fall within a reasonable level as determined by the AER's repex model as determined by Powercor.

Forecast likely overstated due to lack of portfolio-level assessment of link between proposed program and intended network performance outcomes, including risk mitigation

447. In the absence of reasonable top-down checks including with reference to improving network performance indicators, we consider that the forecast is likely to overstate the level of expenditure required. We did not see a systematic application of risk and/or economic analysis or assessment at the portfolio level for determining an efficient level of expenditure for the associated improvement in risk.

Full impact of delivered cost efficiencies is not evident in the forecast expenditure

448. In terms of cost efficiency, we are not convinced that the cost efficiencies identified by Powercor - which have been realised during the current RCP - are adequately reflected in the unit costs relied upon by Powercor in preparing its forecast expenditure. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

4.5.2 Implications to forecast expenditure

449. Based on the information available to us at the time of preparing this report, we consider that Powercor has not sufficiently demonstrated that its proposed repex forecast is prudent and efficient. We provide a summary of our assessment by RIN group below.

450. On the basis that Powercor has determined that the proposed replacement volume for its **Overhead Conductor** and **Underground Cable** groups is necessary to meet its safety obligations, we consider the forecast replacement volumes are reasonable. Whilst the issues we have identified in section 3 are likely to be evident for this expenditure, we consider that, on balance, the forecast capex is also likely to be reasonable.

451. For the **Transformer group**, we remain concerned that the information provided by Powercor does not present a complete understanding of how it manages the transformer asset class, including provision for condition monitoring and asset life extension strategies, and which it states it currently undertakes. However, having consideration to other factors relating to its transformer fleet, we consider that Powercor is likely to incur a level of expenditure similar to the level of expenditure that it has proposed.

452. For many of the remaining groups, we consider that Powercor has not established a reasonable basis for the extent of the proposed increases in expenditure. We found:

- **Poles**: We consider that Powercor has established a reasonable basis for increasing the volume of wood pole treatments above its long-term historical levels. However, based on the information provided by Powercor, we do not consider that the forecast expenditure is representative of a prudent and efficient level;
- **Service lines:** Powercor has not adequately demonstrated that the existing defect driven program, if prioritised based on highest risk service lines, will be insufficient to meet its safety obligations;
- **Pole top structures**: there is likely to be a higher reduction to the pole top structure replacement program than has been proposed so as to account for the increased level of cross-arms being replaced as part of the pole replacement program;
- **Switchgear**: the bulk of the proposed replacements are the result of application of a reasonable method that has led it to determine a prudent level of replacement. Regarding the proposed HV air-break switchgear replacements, Powercor has not sufficiently demonstrated that the forecast for non-Gevea ABS reflects a prudent level of replacement;
- **SCADA, network control and protection**: Powercor has not demonstrated the relationship between its CBRM tool and its forecast expenditure for the SCADA, network control and protection group, to determine how it has arrived at a prudent level of replacement for this group. Further, we were not able to find a basis to support the inclusion of some projects into the forecast; and
- We found evidence that, based on the limited information provided, components of the forecast repex included in the '**Other**' repex group may be allocated to other groups of repex and may, at least in part, duplicate other parts of the forecast repex.

5 REVIEW OF PROPOSED NON-DER AUGEX

In this section, we present our assessment of Powercor's forecast non-DER augex expenditure for the next RCP, including its Rapid Earth Fault Current Limiter (REFCL) compliance-driven capex, but excluding solar enablement expenditure.

We used sensitivity analysis to examine the robustness of the proposed options and the timing of activity to variances in the demand forecast. The results suggest that Powercor's proposed expenditure may be over-estimated.

For the Focus Projects, as designated by the AER, our analysis suggests that the Bacchus Marsh and Tarneit supply area projects are likely to satisfy the NER capex criteria, whereas we consider that the Regional Supply project does not.

Powercor has provided business cases for approximately 70% of its proposed non-DER augex, supported by cost-benefit models. This has proved useful in examining the justification for project expenditure.

However, Powercor has presented little supporting information to justify the quantum of its remaining forecast expenditure. Rather, it has relied on its planning process and cost estimation methodology as evidence of prudent and efficient capex. We consider this to be insufficient evidence to justify the proposed expenditure.

5.1 Introduction

453. We reviewed the information provided by Powercor to support its proposed augex (non-solar enablement) forecast, including its business cases and relevant supporting information. Our focus is to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

454. The AER has identified a number of 'Focus' projects which we have included explicitly in our assessment of the proposed augex forecast, within the relevant category of expenditure, as denoted below and in Table 5.2:

- Bacchus Marsh supply area;
- Tarneit supply area;
- Upgrading regional supply; and
- REFCL ongoing compliance.

455. Powercor's solar enablement project is also an augex project and an AER focus project. Accordingly, we refer to it for completeness in our listing of proposed augex in this section. However, our assessment of solar enablement expenditure is presented in section 6.

5.2 Summary of Powercor's proposed augex

5.2.1 Overview

456. Powercor has proposed $475.2m for augex for the next RCP, at an average annual expenditure of $95.0m. In the table below, we show Powercor's proposed augex by RIN Category, including real cost escalation.

Table 5.1: Powercor's proposed Augex for the next RCP - $m, real 2021

Project Type	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	24.2	22.0	12.7	17.0	10.7	86.7
Subtransmission Lines	4.2	3.3	2.7	3.0	2.2	15.4
HV Feeders	16.9	13.2	10.9	11.9	8.8	61.6
Distribution Substations	7.2	7.4	7.9	7.6	7.8	37.9
LV Feeders	7.2	7.4	7.9	7.6	7.8	37.9
Other Assets	93.1	81.1	35.9	15.3	10.2	235.7
Total	**152.9**	**134.4**	**78.0**	**62.3**	**47.7**	**475.2**

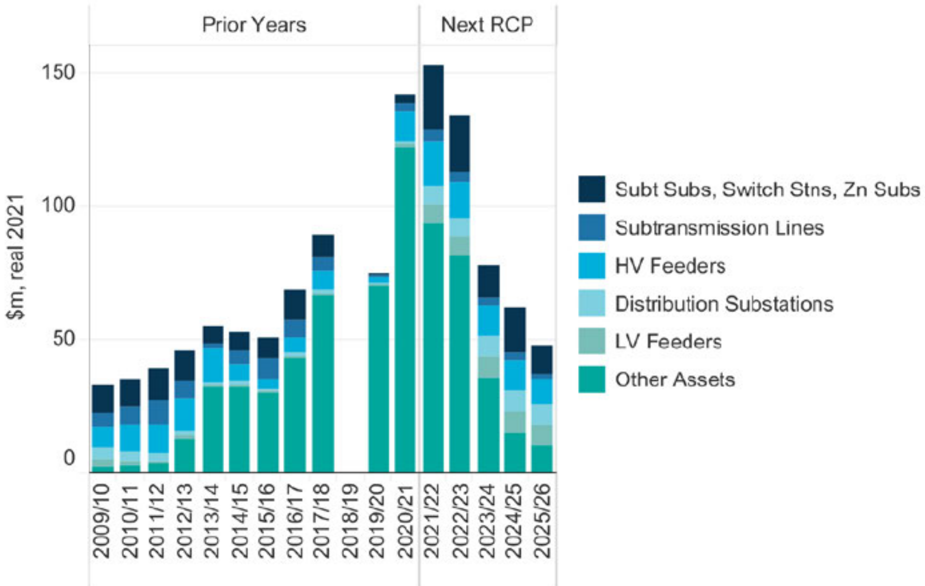
Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

5.2.2 Augex capex trend

457. Augex capex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes Powercor's proposed real cost escalation.

458. Augmentation historical expenditure reflects actual expenditure on each of the Powercor and CitiPower networks. Total overheads are split between Powercor and CitiPower network expenditure on a fixed percentage basis. As such, the trends for both companies follow the same shape albeit at different scales.

Figure 5.1: Powercor's Augex capex expenditure by asset category ($m, 2021)



Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

5.2.3 Observations from the augex trend

459. The augex forecast by Powercor for the next RCP continues the relatively high level of 2020/21 expenditure into the first two years of the next RCP. The uplift in capex is driven by REFCL compliance-related work (including a proposed new substation at Torquay) and the solar enablement program (which extends across every year of the next RCP).

5.2.4 Augex capex categorised by function

460. The table below shows grouping of projects by functional type and also illustrates the AER focus projects referred to above. Our assessment is structured according to these functional types, starting with 'Augmentation of zone substations' in section 5.4.

Table 5.2: CitiPower augex for the next RCP by Function Type and showing AER Focus projects and additional business cases reviewed - $m, real 2021[113]

Function Type / Focus & BC	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Augmentation of Zone Substations	23.8	21.1	12.1	15.8	9.8	82.6
AER Focus projects						
Bacchus Marsh SA	*0.5*	*1.4*	*3.4*	*2.4*		*7.7*
Tarneit SA		*0.1*	*3.8*	*8.4*	*4.7*	*16.9*
Upgrading Regional Supply	*5.1*	*3.9*				*9.1*
Additional Business Cases						
Bushfire Mitigation - REFCL BAU	*0.2*	*0.3*	*0.4*	*0.4*	*0.4*	*1.8*
Surf Coast Upgrades	*10.5*	*9.8*				*20.3*
Other	7.5	5.5	4.5	4.6	4.7	26.8
Augmentation of HV Feeders & Subtransmission	20.7	15.8	12.9	13.8	10.1	73.3
AER Focus projects						
Tarneit SA			*0.9*	*1.8*	*0.9*	*3.6*
Additional Business Cases						
Surf Coast Upgrades	*2.5*	*2.5*				*5.0*
Other	18.2	13.3	12.0	12.0	9.2	64.7
LV Augmentation	14.2	14.3	14.9	14.1	14.3	71.8
AER Focus projects						
Solar Enablement	*12.2*	*12.2*	*12.7*	*11.8*	*11.9*	*60.7*
Other	2.0	2.1	2.2	2.3	2.4	11.0
REFCL GFNs	77.0	63.3	26.7	5.8		172.7
AER Focus projects						
REFCL Ongoing Compliance	*3.6*	*24.4*	*26.7*	*5.8*		*60.5*
Additional Business Cases						
Bushfire Mitigation - Surf Coast REFCL	*23.8*	*23.8*				*47.5*
Bushfire Mitigation - CRO Zone Substation	*14.5*	*14.5*				*29.0*
Additional BC: Bushfire Mitigation T1,2,3	*35.1*	*0.6*				*35.7*
Zone Substation Automation	15.0	15.8	8.0	9.2	10.2	58.2
Additional Business Cases						
3G	*8.1*	*8.1*				*16.2*
Spectrum Changeover	*1.0*	*1.2*	*1.2*	*2.4*	*2.4*	*8.4*
Other	5.9	6.5	6.7	6.7	7.8	33.7
Total	**150.8**	**130.4**	**74.5**	**58.7**	**44.4**	**458.7**

Source: EMCa analysis of PAL MODs 6.01, 6.04, 6.09, 10.05. Excludes real cost escalation

113 Solar Enablement is reviewed in section 6

5.3 Powercor's augex forecasting methods

5.3.1 Augex activity forecasting process

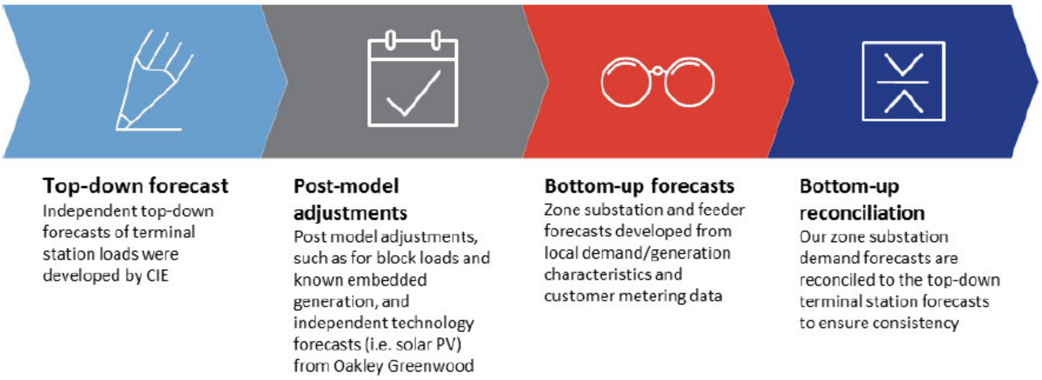
461. Powercor's augex investment includes both demand-driven and non-demand driven projects.

Demand-driven augmentation

462. Based on forecast demand, Powercor determines where the capacity of its network is expected to be exceeded and identifies the appropriate intervention. Typical interventions include reconfiguring the network, addition of infrastructure and/or implementing non-network solutions.

463. The figure below summarises Powercor's demand forecasting approach.

Figure 5.2: Powercor's demand forecasting approach



Source: Powercor Regulatory Proposal

464. Powercor applies a probabilistic approach to planning demand-driven investment decisions in which it estimates the probability of an outage occurring within the peak period and determines the energy at risk of not being supplied. The energy at risk of not being supplied is monetised by assigning the Value of Customer Reliability (VCR), determined by AEMO. Powercor states that '[o]*ur augmentation forecast only includes capital works where the cost of mitigating a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand side solution is not feasible.'*[114]

Non-demand driven augmentation[115]

465. Powercor has forecast expenditure to address non-demand driven issues on the network. These include responding to compliance obligations (such as the installation and operation of REFCL infrastructure), and to the impact of future fault currents, voltage levels and voltage quality.

Non-network solutions[116]

466. Powercor considers non-network solutions to avoid or defer the need to invest in network augmentation when it is efficient. It seeks non-network solutions through its DAPR, public forums, RIT-D process for major augmentation works and through its demand side engagement register.

114 Powercor Regulatory Proposal, p91

115 Powercor, Regulatory Proposal, p90

116 Powercor, Regulatory Proposal, p92

Cost forecasts[117]

467. Powercor states that it forecast costs for capex projects *'… based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations'* and '*rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting.'*

468. Powercor adjusts costs for forecast growth in real input prices over time, such as labour, materials, and contracted services.

5.3.2 Assessment of Powercor's augex forecasting methods

Powercor's top-down/bottom-up demand forecast reconciliation approach is consistent with industry practice

469. At a high level, Powercor's demand forecasting methodology (as shown in Figure 5.2) is consistent with industry practice. It includes a reconciliation between its top-down forecast at the terminal station level, prepared for it by the Centre of International Economics (CIE) and Powercor's own bottom-up forecasts at a zone substation level. Victoria also holds an advantage over other states in having data from its smart meter population, which helps to substantiate its bottom-up forecasts.

470. Powercor advises that it used the 'latest available' data to prepare its forecast, which is from the 2017/18 year. This data is approximately two years old. Powercor states that, when more recent data is available, it will update the forecasts in its revised regulatory proposal. For now, we acknowledge that the demand forecasts are based on presently available information.

471. As with all forecasts, the key aspects are the underlying assumptions and the factors that are taken into account (or not) to manage prospective changes in consumer behaviour, including potential changes to price signals (such as via changes to tariffs and tariff structures), government policy (such as the Victorian government's Solar Homes program) and technology innovation and adoption. We note, for example, that the top-down forecast includes input assumptions regarding solar PV penetration.

472. It is not within our scope to review Powercor's demand forecasting methodology in detail, nor to propose alternative forecasts at the zone substation and feeder levels (which are the focus of our assessment) for growth-driven capex and opex. Instead, we have applied sensitivity analyses to the demand forecast assumed by Powercor to test the robustness of the selected option and the timing of the proposed work, as we discuss below.

Energy at risk is hard-coded into the model

473. Powercor has calculated the energy at risk outside of the probabilistic planning model that was provided with its regulatory proposal. We reviewed Powercor's supporting documentation to understand the calculation method. The energy at risk is estimated by *'scaling a normalised annual load duration curve to the forecast load in MVA and determining the difference (being energy at risk) between the N-1 rating and the forecast load.'*[118] Powercor takes the average of the Load Duration Curves (LDC) of the last five years for the substation in question and has presented examples. We consider that this approach is reasonable.

The value of expected unserved energy is hard-coded in the model, but can be varied by weighting of the forecast peak demand PoE

474. Our understanding is that Powercor's expected unserved energy is based on unplanned transformer outages. The assumed probability of a transformer outage in a year is the number of transformers multiplied by the probability of failure of 1% per annum per

117 Powercor Regulatory Proposal, p92

118 Powercor ATT001, p26

transformer, multiplied by 2.6 months mean outage time and divided by 12 months.[119] The PoF rate and restoration times are similar to those used in the industry except where mobile transformers or substations are available (which Powercor does not have).

475. Powercor further explains that *'[t]he unserved energy is initially that which cannot be transferred to alternate supplies following the significant or major failure. This reduces once the generators start to come on line taking account of the number of generators which may be brought on line each day until sufficient generation support has been installed to meet the demand unserved following the initial incident.'*[120] This applies when peak demand is less than the substations N-1 firm capacity, above which load transfer is not taken into account in calculating the unserved energy. We consider that this approach is reasonable.

476. Powercor's probabilistic planning model uses a probability weighted blend of the 10% PoE peak demand forecast and the 50% PoE[121] peak demand forecast. This is used to vary the expected value of unserved energy by scaling the expected unserved energy at 10% PoE and at 50% PoE. Powercor's weighting is 30% of the 10% PoE peak demand forecast to 70% of the 50% PoE peak demand forecast. Our assessment of this approach is discussed in section 3.

477. Rather than debate the origins and merits or otherwise of this fundamental planning input, our sensitivity analyses have included testing the robustness of the proposed options and the timing of the options (i.e., within the next RCP or not) to identify prospective negative variances in the demand forecast.

Value of VCR is weighted to outage duration

478. The value that Powercor has used for value of customer reliability (VCR) is based on the AEMO 2014 report, escalated to current terms. This value is then weighted (adjusted) for each customer class to derive a composite value of VCR that is used in the calculation of the cost of unserved energy. This is a reasonable approach.

479. We understand that Powercor intends to update the use of its value of VCR to the values recently published by the AER. Whilst this would reflect more recent studies, the impact to the risk cost modelling is likely to be low given the weighting approach applied by Powercor.

Powercor's probabilistic planning models limit sensitivity analyses

480. Powercor has provided the AER with probabilistic planning models in support of the majority of its proposed augex. The models include some facility for sensitivity analyses – for example, it is easy to change the weighting of the probability of exceedance (PoE) between the 50% PoE and the 10% PoE, the discount rate, the demand management cost/MW, and the VCR.

481. However, the model includes a disconnect between the assumed timing of network capex for the various solutions and the energy at risk. This is because the timing and quantum of the expected unserved energy (MWh) is hard coded into the energy at risk calculation.

482. We have focused on the sensitivity of the planned work to negative variances of key inputs to Powercor's probabilistic planning to take into account demand and energy forecasting uncertainty because:

- Negative variances may defer expenditure whereas positive variances are likely to bring capex forward, but still be within the next RCP;
- There are known technologies (such as battery storage) and other potential changes (such as tariff restructuring) that may significantly impact augex project timings by reducing peak demands and associated energy at risk at the feeder and substation level, but the impact is uncertain even over the next 5-6 years, and

119 Powercor, ATT001, p26

120 Powercor, CP BUS 4.03 – Transformer evaluation methodology, page 8

121 50th percentile demand forecast or 50 per cent probability of exceedance (PoE). It is the "most-likely" level of demand. Actual demand in any given year has a 50 per cent probability of being higher than the 50th percentile demand forecast

- It allows us to consider the likely 'option value' or, in other words, the value of deferring large capital investment decisions in network assets for as long as practicable to help enhance the prospects that the assets will be sufficiently utilised in the future.

Powercor's cost forecasting methodology possible shortcomings

483. Powercor's approach of using a combination of relevant historical costs and/or updates from suppliers or vendors when competitive prices are not available is a reasonable approach to unit cost forecasting. However, there are two possible exceptions, both concerning historical costs:

- where Powercor's cost estimate is based on its historical internal costs without reference to industry benchmarks, it is possible that Powercor's costs are not reflective of efficient levels; and
- where Powercor's unit cost estimate is averaged over several years of historical costs, some of these historical costs may not be reflective of current practices and market conditions, especially where recent efficiencies have been realised.

484. In our project-level assessments, we identify our concerns with this aspect of Powercor's expenditure forecast.

5.4 Augmentation of zone substations

5.4.1 Introduction

485. Powercor has proposed $82.6m capex in the next RCP associated with augmentation of zone substations. The AER asked us to focus our assessment on three projects: (1) Bacchus Marsh supply area [$7.7m]; (2) Tarneit supply area [$20.5m];[122] and (3) Upgrading regional supply [$9.1m]. We have also considered information provided by Powercor on the remaining projects, with the exception of the new Torquay substation which is proposed as part of the Surf Coast supply area business case. The latter is discussed in our review of the REFCL-driven projects in section 5.7.

5.4.2 Bacchus Marsh supply area

Overview of project

486. The Bacchus Marsh supply area is supplied by Powercor's Bacchus Marsh zone substation (BMH) and is part of the western growth corridor. Powercor's maximum demand forecast foresees an average annual compound growth rate of 6.9% in the Bacchus Marsh supply area through to 2028, driven primarily by forecast population increases.

487. BMH consists of two 10/13.5 MVA 66/22 kV transformers supplying two 22 kV outdoor buses with four distribution feeders. The transformers were installed in the 1960s. Both are *'showing signs of deteriorating condition.'* Peak demand above the station's N-1 cyclic rating[123] (or N-1 capacity) and is forecast to exceed the N cyclic rating[124] (or N capacity) in 2025.

488. To provide sufficient supply capacity, Powercor proposes to install a third transformer, 66kV and 22kV circuit breakers and a new control room at BMH at a capital cost of $7.7m (which is Option 2, as discussed below).

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122 This is the total project cost including the $3.6m allocated to feeder augmentation

123 The substation supply capacity with all transformers in service. Cyclic ratings account for (i) thermal inertia of the plant, and (ii) load curves appropriate to the season

124 The substation supply capacity with all plant available and usually including the cyclic rating of the transformers

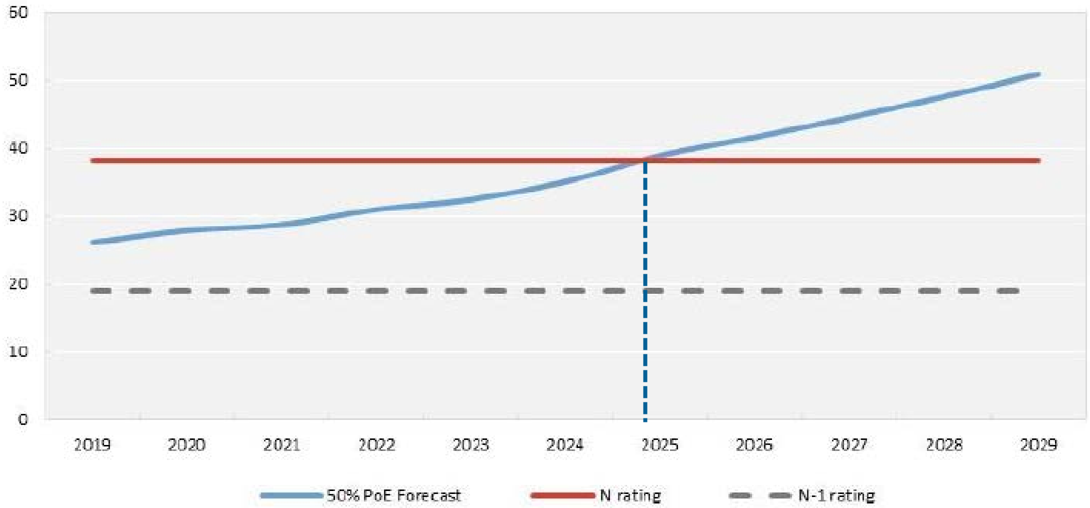
Assessment

Strong load growth forecast indicates intervention is probably required within the next ten years

489. Powercor's 50% PoE forecast is shown in the figure below. After load transfer to contiguous zone substations is accounted for, a capacity shortfall of about 20MVA is forecast for 2026, equating to about 6,700 customers. Furthermore, as Powercor points out:[125]

- The probability of a BMH transformer failing is relatively high and is likely to increase at an increasing rate over time because of the advanced age of the two transformers (each is over 50 years) and because of 'deteriorating' condition; and
- The consequence of a transformer circuit fault (or line fault) is higher at BMH substation than for 'normally'-configured substations. At BMH, a transformer or 22 kV feeder bus fault will result in the 66 kV line circuit breakers tripping, causing loss of supply to all customers until a switching operator can isolate the fault.

Figure 5.3: BMH zone substation maximum demand forecast: 50% PoE (MW)



Source: Powercor, BUS 6.04, Figure 2

490. Whilst Powercor has not provided any details supporting its condition assessment of the transformers, we consider the probability of failure is likely to be increasing at an increasing rate because of the age and (reported) condition of the transformers.

491. On this basis, there is a good case for Powercor to take some form of action to address the forecast capacity shortfall within the next 10 years.

Powercor's MBH VCR for the economic analysis is reasonable

492. Powercor has applied a weighted average $37,524k BMH VCR which is driven primarily by the 51% residential component and 36% commercial component of 2019 customer data. We consider this approach to determining an appropriate value of VCR to be reasonable.

Powercor's selected Option 2 is likely to be the prudent approach

493. Powercor considered five options, as shown in the table below. The net economic benefit is measured against the Option 0 counterfactual.

125 Powercor, BUS 6.04 – BMH supply area, page 9

Table 5.3: Summary of Powercor's options analysis -$m, real 2019

Option	PV Cost	PV Benefit	Net Benefit
0. Do nothing / maintain the status quo	-	-	-
1. Install a third transformer (10/13 MVA), 66kV and 22kV circuit breakers and a new control room	-3.1	296.2	293.1
2. Install a third transformer (25/33 MVA), 66kV and 22kV circuit breakers and a new control room	-3.4	300.8	297.3
3. Install a third transformer (25/33 MVA), 66kV circuit breaker, 22kV indoor switchroom and a new control room	-4.1	300.8	296.7
4. Non-network solution to defer preferred network option	-3.4	300.5	297.1

Source: PAL MOD 6.07

494. A common element of Options 1, 2 and 3 is the addition of a 22kV and a 66kV bus section circuit breaker. Given the projected growth in the area and good industry practice, we consider that the reconfiguration is a prudent investment when undertaken in conjunction with other major planned work, as proposed.

495. The difference between Option 1 and Option 2 is the size of the proposed third transformer, with the larger transformer in Option 2 and associated works costing an estimated $0.7m more than a 10/13MVA transformer (per Option 1). Powercor argues that with the projected ongoing strong demand growth, the 10% higher cost for the larger capacity transformer is a prudent investment. Its economic analysis predicts a slightly higher NPV for Option 2 over Option 1 based on a 20 year study period. This is due to the increasing expected unserved energy in Option 1 compared to Option 2 (with the compound annual peak demand growth held constant at 6.9%).

496. In our experience, it is unusual for relatively high demand growth rates to persist for such extended periods. Powercor supports its growth forecast, in part, by providing a diagram from the Victorian Planning Authority: the Bacchus Marsh urban growth framework.[126] There is insufficiently compelling information presented by Powercor for us to form a view about the likely load growth rate.

497. As an alternative to revisiting the demand forecast, we undertook a sensitivity study using Powercor's model with 100% weighting to 50%PoE peak demand forecast (i.e., rather than 70:30 weighting to 50%PoE/10%PoE, giving a lower expected energy unserved) as a proxy for a lower demand growth rate. It shows that the NPVs of Options 1 and 2 are virtually identical over 20 year and 10 year study periods. It would take a much lower compound average growth rate to tip the economic balance materially in favour of Option 1. We therefore consider that Option 2 is likely to be a better choice than Option 1. This is consistent with Powercor's own sensitivity analysis.[127]

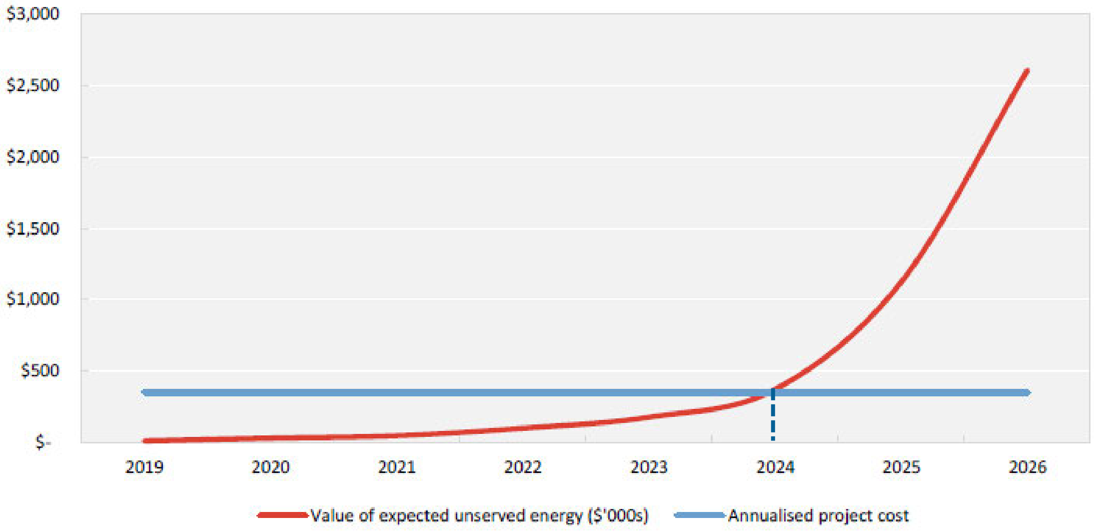
498. Option 2 calls for the substation upgrade to be completed by 2024, which is the economically optimum timing according to Powercor's probabilistic risk-cost modelling, as shown in the figure below.[128] It has modelled diminishing load transfer capacity over time, which we consider to be a reasonable approach. As a sensitivity study, with 100% weighting to 50%PoE, the model shows that reinforcement is still required before the summer of 2025. It would take a significantly lower demand growth rate to defer the economic timing to the next RCP.

126 PAL BUS 6.04, Appendix A

127 PAL BUS 6.04, p13

128 The point at which the annual value of unexpected unserved energy exceeds the levelised (or annualised) cost of the solution to 'avoid' the risk cost is the economically optimum timing'.

Figure 5.4: Powercor's assessment of the energy not served vs the annualised Option 2 project cost - $k, 2021



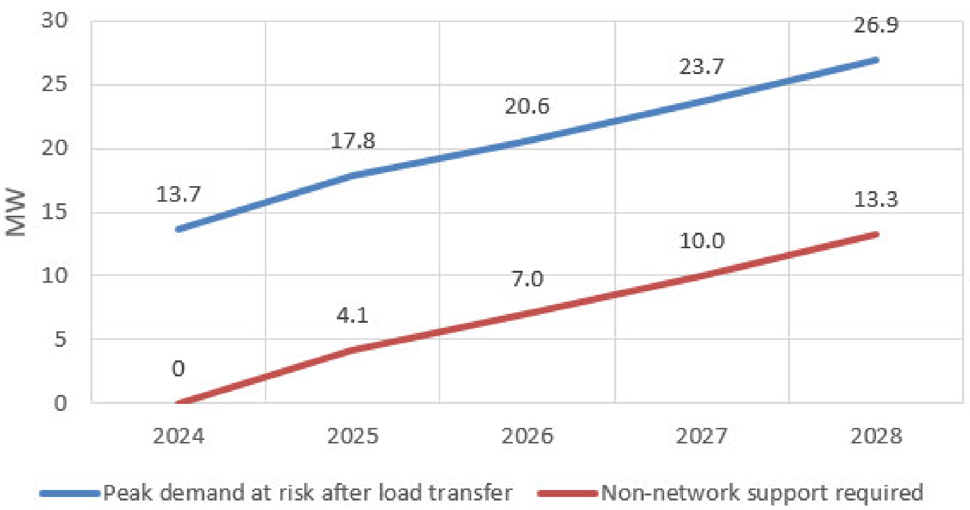
Source: PAL BUS 6.04, Figure 6

499. Option 3 differs from Option 2 due to the installation of a 22kV indoor switchroom to minimise the health and safety hazards and construction work required to realign sections of the existing outdoor switchyard. The NPV for Option 3 is lower than for Option 2. Powercor selected Option 2 primarily because it had the lowest NPV although the differences are not great. In our view, the safety risks associated with Option 2 compared to Option 3 are manageable with operational controls during the construction phase and, combined with the economic result, makes Option 2 superior to Option 3.

500. Option 4 – purchasing 4.1MW of Non-network Support (NNS), enables a one-year deferment of the substation capacity upgrade, based on Powercor's model, assumed growth rate, and assumed cost of demand side solutions ($87,000/MW). Even with NNS, the investment in substation capacity is still required within the next RCP. With 100% weighting to 50%PoE (as a sensitivity study), the Option 4 NPV is virtually identical to the Option 2 NPV.

501. The figure below shows Powercor's estimated magnitude of NNS required to maintain the expected energy at risk grows to 7.0MW ($0.6m opex) in 2026 - we refer to this as 'Option 4a'.

Figure 5.5: Powercor's estimate of network support requirements (MW)



Source: EMCa representation of information in PAL BUS 6.04, Table 6

502. With 70:30 weighting to 50%PoE/10%PoE peak demand forecast, the Option 4a NPV is similar to Option 2's. With 100% weighting to 50%PoE peak demand forecast, Option 4a NPV is again similar to Option 2's.

503. Given the practical challenges in securing 7MW of non-network support in the catchment area, Option 4a may be difficult to enact in practice for possibly little net economic gain. Nonetheless, the RIT-D process requires DNSP's to test the economic viability of non-network solutions with the market. This will be tested prior to a final decision.

504. As a further option to defer large network capex, we considered the likely net benefit of increasing the distribution transfer capacity to contiguous substations. However, based on the information in the business case and discussions at our meeting with Powercor, we are satisfied that increasing the distribution transfer capacity to Melton and to Ballarat North substations is unlikely to be a cost effective alternative to the options considered.

505. On this basis we consider that Option 2 is likely to be the prudent selection.

Cost estimates seem reasonable

506. Powercor has provided a single line diagram for the work at BMH substation and based on its estimating methodology and our experience, the cost estimate seems reasonable.

Summary

507. We consider that Powercor has presented a compelling case for taking some form of action at Bacchus Marsh substation within the next decade, mainly due to the significant forecast demand growth and commensurate supply capacity shortfall. The relatively old T1 and T2 transformers and the reduced security due to the lack of bus section breakers are also contributing drivers for action.

508. Due primarily to the strong forecast peak demand growth, using non-network support may not be practicable or economically compelling in this case to defer the planned investment by more than one year.

509. The results of our sensitivity analyses also suggest that the economically optimum timing for project completion is most likely within the next RCP.

5.4.3 Tarneit supply area

Overview of project

510. The Tarneit supply area includes some of the western suburbs of Melbourne and is supplied by Werribee (WBE) and Truganina (TNA) substations. Powercor advises that the area has experienced high demand growth and *'large greenfields developments and significant residential, commercial and industrial load growth is forecast to continue.'*

511. WBE substation consists of two 20/33 MVA and one 25/33MVA 66/22 kV transformers, with 12 x 22kV feeders. TNA substation comprises two 25/33MVA 66/22kV transformers, with a third 25/33MVA transformer to be installed in 2021. It has the capability of supplying 12 x 22kV feeders, predominantly to commercial and HV industrial customers.

512. To provide sufficient supply capacity into the Tarneit supply area, Powercor proposes to build a new Tarneit (TRT) zone substation by 2025 at a capital cost of $20.5m[129] – which is Option 1 in the table below. The net economic benefits are measured against the Option 0 (do nothing) counterfactual.

129 This is the total project cost including the $3.6m allocated to feeder augmentation

Table 5.4: Summary of Powercor's options analysis - $m, real 2019

Option	PV Cost	PV Benefit	Net Benefit
0. Do nothing / maintain the status quo	0	0	0
1. Establish TRT zone substation in 2025	-8.4	752.4	744.0
2. Establish new feeder to offload WBE, and build TNT zone substation in 2026	-8.6	751.0	742.4
3. Non-network solution to defer preferred network option	-9.0	751.3	742.3

Source: PAL BUS 6.03, Table 2 and PAL MOD 6.06

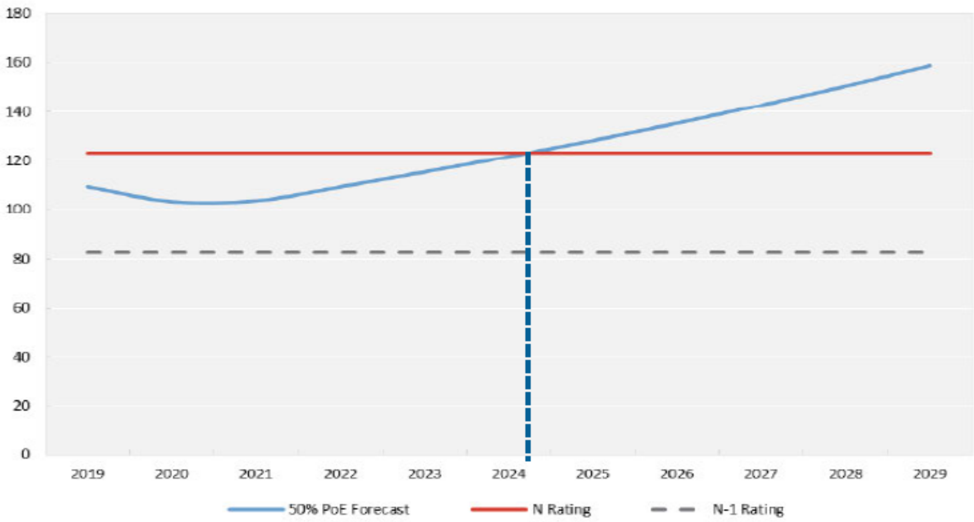
Assessment

The strong load growth forecast indicates action is probably required within the next ten years

513. Powercor's 50%PoE peak demand forecast for WBE and TNA zone substations are shown in the figures below. The peak demand is shown to be well above the N-1 ratings of both substations and is forecast to exceed the N capacity at WBE by the summer of 2025. After load transfer to contiguous substations is accounted for, a capacity shortfall of about 16MVA is forecast for 2026, equating to about 5,600 customers, if a transformer is unavailable during peak periods.

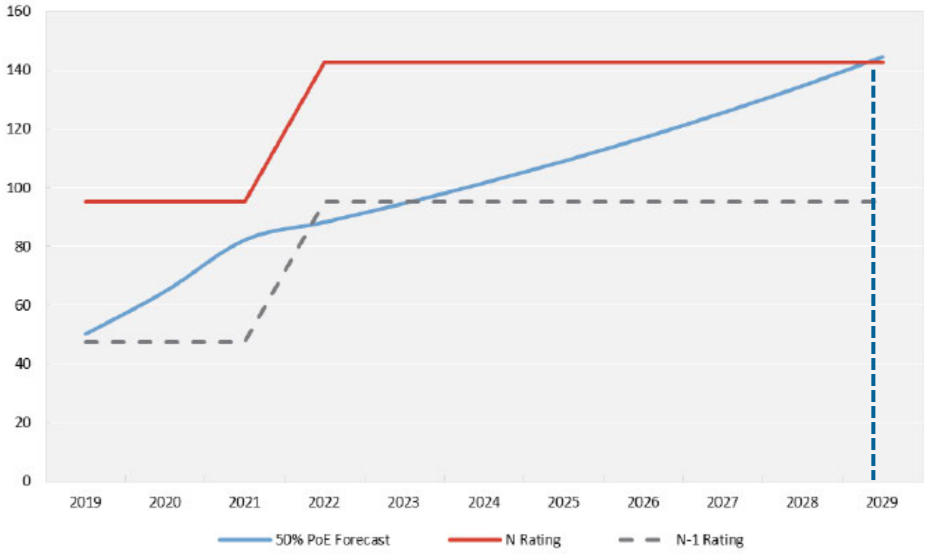
514. On this basis there is a reasonable case for a prudent operator to take some form of action within the next 10 years to address the forecast capacity shortfall.

Figure 5.6: WBE zone substation maximum demand: 50 PoE (MVA)



Source: Powercor, BUS 6.03, Figure 2, p6

Figure 5.7: TNA zone substation maximum demand forecast 50PoE (MVA)



Source: PAL BUS 6.03, Figure 3, p7

Powercor's VCR for WBE and TNA for the economic analysis seems reasonable.

515. Powercor has applied a weighted average VCR of:

- $37,983k for WBE which is driven primarily by the 49% residential component and 44% commercial component of 2019 customer data; and
- $44,478 for TNA which is driven primarily by the 81% commercial and 18% residential components.

516. We consider this approach to be reasonable.

The assumed peak demand forecast determines the prudent option

517. As shown in *Figure* 5.8, the summer peak demand forecast at TNA is very strong at 7.3% p.a. for the duration of the next RCP, from an assumed 2021 peak demand of 82.2MW, which in turn is 17.5MW higher than the assumed 2020 peak because of load transfer from Laverton zone substation.[130]

518. Powercor's demand forecast is based on expected residential and commercial load growth in a number of suburbs in the Tarneit supply area, and it refers to a 2016-2041 *Population and household forecast* by the City of Wyndham for the Tarneit locality to support its forecast.[131] This study predicts approximately 40% growth in the number of dwellings in the locality between 2021 and 2026, which is about the same as the TNA forecast peak demand over the same period. Powercor provided additional information in a PowerPoint presentation.[132] The load peak demand forecast for WBE is 5.5% p.a. over the next RCP, which is also relatively strong and sustained peak demand growth.

519. In our experience, dwelling forecasts undertaken by city councils tend to be optimistic. Therefore, we asked Powercor how it integrated the Wyndham City Council and other planning department information in its forecast. We were advised that the forecast is developed independently to these forecasts, referring us to its forecasting methodology in PAL APP03, which we note does make provision for 'local area knowledge' in developing the bottom-up forecast.[133]

520. In lieu of undertaking our own bottom-up analysis of the WBE and TNA peak demand forecasts, we undertook sensitivity analyses for selected options, as discussed below.

130 PAL BUS 6.02, p6 and PAL MOD 6.06

131 PAL BUS 6.02, Appendix A; the report was published in 2018

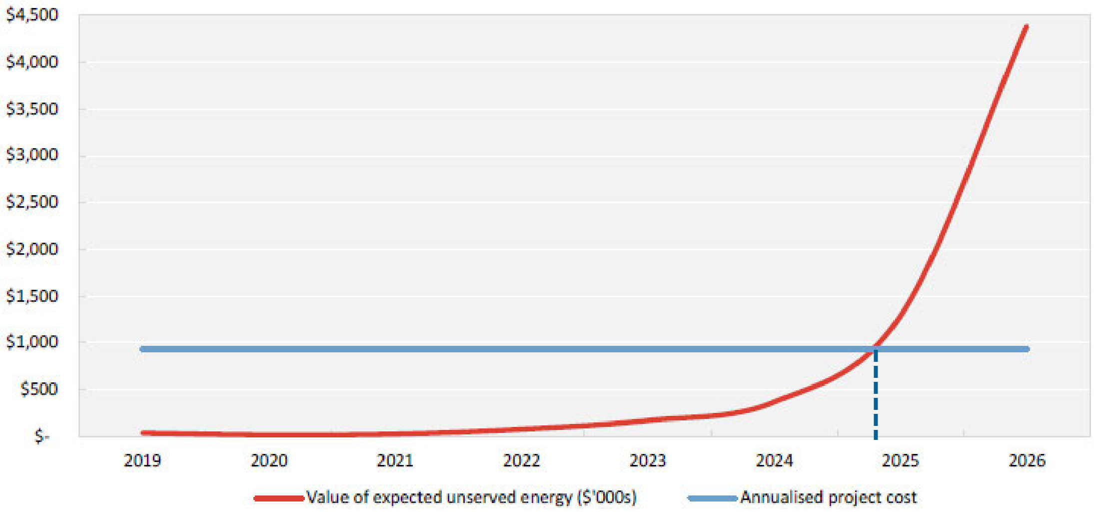
132 PAL EMCa May 2020_final, slide 42

133 PAL APP03, p9

521. Option 0 is based on no investment in the next RCP to alleviate the risk of interruptions to supply from a failure in a transformer circuit at TNA or WBE. However, if forecast demand growth occurs, peak demand will exceed the N capacity of WBE in 2024. From this point onward, customer supply will need to be interrupted even without asset failure. This is not consistent with good industry planning practice and, as discussed below, one of the other options is likely to be economically preferable to Option 0, even with significantly lower demand growth.

522. Option 1 is based on establishing a new Tarneit (TRT) substation by 2025 with two 66kV circuits, two transformers, six 22kV feeders, and a 12 MVAr capacitor bank. The figure below shows the economic timing output from Powercor's modelling.

Figure 5.8: Powercor's assessment of the energy not served vs the annualised Option 1 project cost - $k, 2021



Source: PAL BUS 6.03, Figure 9

523. We studied the sensitivity to reduced load growth of Option 1 by weighting the forecast peak demand at both TNA and WBE to 100% 50PoE (i.e., rather than 70% 50PoE and 30% 10Poe) in Powercor's model. The result is a one-year deferral of the completion of the new substation (i.e., prior to summer 2026). A further reduction in the annual demand growth rate at TNA and at WBE by 40% (i.e., from 5.5% pa at WBE to 3.3% and from 7.3% p.a. at TNA to 4.4%) is required to defer the completion of the substation by two years. There is no material difference between the NPV for Options 1 and Option 2 under this scenario.

524. The advantage of Option 1 is that when the substation is constructed, the risk of extensive loss of supply at WBE and TNA is reduced to zero (or near zero) for at least 5 years by transferring supply to the new TRT substation.

525. Option 2 is based on first off-loading WBE substation (which as shown in *Figure* 5.8, is the more heavily loaded substation) by building a new feeder at TNA. Establishment of TRT substation is deferred by one year to 2025.

526. We studied the sensitivity of Option 2 to reduced load growth using the same scenarios as for Option 1, using Powercor's model, as described above. The results are the same as for Option 1.

527. There is no material advantage of Option 2 over Option 1 because the energy at risk across the two substations is the same. As Powercor states, *'the new feeder does not address the underlying capacity constraints in the supply area, rather, it shifts load between substations.'*[134]

528. On the basis of this analysis, regardless of whether the load growth forecast is significantly lower than forecast, Option 1 is a lower risk approach.

[134] PAL BUS 6.03, p13

529. Option 3 is based on deferring the new TRT substation by contracting for 18.8MW NNS in 2026.

530. We studied the sensitivity of Option 3 to reduced load growth using the same scenarios as for Option 1, using Powercor's model, as described above. The results are the same for Option 1. The amount of NNS required towards the end of the next RCP is likely to be well over 10MW, which may be challenging to achieve.[135] Ultimately, the RIT-D test for this project will test the market's capacity to economically displace the proposed network solution with a NNS.

Summary of assessment

531. Our analysis suggests that establishing a new TRT substation within the next RCP (Option 1) is likely to be the prudent option. Based on Powercor's model, a 40% reduction in year on year peak demand growth would be required to economically defer the completion of the substation into the next RCP (which would in turn reduce capex in the next RCP by $6.9m).

5.4.4 Upgrading regional supply

Overview of project

532. Powercor's proposed regional supply upgrade allowance is comprised of four sub-projects which involve upgrading the current single-phase feeders to Tyrendarra, Strathdownie, Cape Bridgewater, and Gorae West to three phase supply, at a cost of $9.1m.[136]

533. Powercor has sought to justify these upgrades based on its assessment of a 'market benefit'. Powercor notes that typical market benefits considered in RIT-D evaluations focus on the value of unserved energy. However, for this project, Powercor has proposed broadening the definition of benefits to include consideration of additional Gross Regional Product (GRP).[137]

534. Powercor sought support from a range of interest groups, and which included holding a 'community leader's forum' in Warrnambool in April 2019. Powercor has included quotes of support in its business case and has provided a range of community and interest-group support documents in its regulatory submission. This includes a support letter from United Dairyfarmers of Victoria,[138] a letter from the Sustainability Manager at Fonterra, a letter from Rabobank, a report prepared for Dairy Australia and the Victorian Government on the economic impact of the dairy industry in regional Victoria, and words of support from the Member of Parliament for Western Victoria Region.[139] The main thrust of the stakeholder submissions is that upgrading power supply to this area would support the regional communities, attract investment including the opportunity to develop new dairy farms, and allow existing dairy farms and businesses in the region to expand.[140]

535. Powercor provided an economic model supporting its calculations of the Gross Regional Product-based benefit calculations for each of the four feeders. Powercor claims that the project has an NPV of $112m.

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135 Noting that over the next 5-10 years alternative technologies may enable applicable solutions

136 $2021 excluding real cost escalation

137 Powercor BUS 6.09 – Upgrading regional supply, page 7

138 Including a report entitled New energy options for the Victorian dairy industry, Negotiation and United Dairyfarmers of Victoria, January 2017 (Powercor Attachment 107)

139 A full list of the supporting documents is in Powercor's BUS 6.09, page 3

140 Powercor BUS 6.09 – Upgrading regional supply, page 4

Our assessment

Increased economic output is not an economic benefit[141]

536. Powercor's claimed benefits are based on an assessment of the incremental regional output that would result if one new farm is developed from each of the four feeder upgrades. Powercor bases this on an average dairy farm output valued at $1.2m per year (in 2017/18) together with a regional multiplier of 1.87 to produce a regional economic output value of $2.3m ($2019) per year per new farm. Powercor models this over 20 years, producing a PV of this benefit stream of $30m per farm. Compared with the investment costs ranging from $1.4m (Gorae West) to $3.2m (Tyrendarra), this would imply a benefit:cost ratio of between 9.4 to 1, and 21 to 1.

537. We consider that it is not valid to treat gross regional output as an economic benefit for the purpose of cost benefit analysis. Defining the benefit as gross output does not account for the cost of inputs to the assumed four new dairy farms including the capital cost of the land, costs of the dairy herds, the labour and materials involved in operating the dairy farms and associated processing over the 20-year period, including the costs of power consumed. The analysis that Powercor has presented attributes the gross regional economic benefit of the additional output to the provision of one input, namely, its provision of an upgraded distribution supply.

538. We consider that Powercor has misapplied what it claims to be a market benefit and, as a result, has grossly overstated the economic case for these upgrades.

Unclear need from existing dairying operations

539. In the report on New Energy Options for the Victorian Dairy Industry,[142] the authors describe a process of seeking to understand the extent to which the existing SWER lines is causing a problem for dairy farmers in the region. The authors undertook site visits to dairy operators in and around Tyrendarra and found that '*dairy operators were not competing with each other or other major power users to secure adequate power as a result of residual power issues associated with SWER lines.*'[143]

540. Subsequently the authors '*worked closely with UDV and some of its prominent members to invite dairy farmers across Victoria (serviced either by Powercor or AusNet) to report instances of SWER lines constraining clusters of dairy operators. We did not receive a single report.*' However, the authors did find that '*all dairy operators being serviced by SWER lines in or around Tyrendarra are constrained to some extent, even though they are not competing with other operations for power along their respective SWER lines*.[144]

541. The findings from this report do not identify the extent to which existing dairy operations are being impaired or limited. We observe that Powercor chose to consider the benefit of developing four new farms as its claimed justification.

Inadequate consideration of non-network alternatives

542. Powercor presents some limited assessment of non-network alternatives, covering diesel and batteries. For its analysis of the alternative cost from a 25kVA diesel generator, the majority of costs arise from assumed running costs. It is unclear how Powercor has modelled this, and whether it has sought to solve an issue of milking-time peak demands or to provide 'base' power for irrigation. Both are claimed as being facilitated by the regional supply upgrades, but the usage profiles (and therefore the non-network alternatives) would be completely different.

543. Powercor refers to a 'battery plus generators' option but dismisses this based on statements in the New Energy Options report. In that report, the authors state that '*…battery storage was not cost effective*' and that '*…renewables alone (are) not well-suited to providing a*

141 Powercor BUS 6.09 – Upgrading regional supply, Tables 5, 6, and 7

142 Powercor ATT 107

143 Ibid, page 8

144 Ibid, page 8

solution to the core problem' (of the *dairy daily load curve*).[145] This report was written in 2017 and considerable advances in technology, reductions in cost and more widespread application of such solutions has occurred since that time. However, in its response to an information request,[146] Powercor provides information which, while high level and open to challenge in some respects,[147] provides a reasonable indication that consumer solar / battery solutions are unlikely to be viable, at least in meeting dairy peak demands, given the amount of power consumed in what are often hours of darkness or limited insolation.

Powercor's consideration of capital contributions is inconsistent with its claimed economic benefits

544. In response to an information request, Powercor has calculated that if it were to seek a financial contribution from a beneficiary, *'…the customer would need to contribution (sic) of over $3 million as an upfront contribution. This is unrealistic*.'[148] Powercor further states that if contributions of even half this amount were sought (such as under a 'pioneer scheme'), '*this project would not go ahead… as reflected in reality whereby these offers have not been accepted'*.

545. While contributions of this level are substantial amounts of money, it is difficult to reconcile Powercor's statement that the intended beneficiaries would not be willing to pay, with its own assessment that there is a PV economic benefit of $30m value from a single new farm. Powercor has stated clearly that it cannot recover the costs from the claimed beneficiaries, which (in its analysis) would be four new, significant, commercial agricultural enterprises. It is for Powercor as the proponent to justify why the cost of the proposed regional supply upgrades should therefore be 'socialised' and recovered through higher regulated tariffs from Victorian customers generally. It has not done so.

Powercor's claimed analysis involving Value of Customer Reliability is not valid

546. In its business case, Powercor makes reference to an assessment based on the Value of Customer Reliability. We sought information on this in case it might assist with assessing the justification for the proposed investment.

547. In its response, Powercor provided a calculation in which it valued the entire amount of energy required by a dairy farm (approximately 250MWh/year at an 'agricultural VCR' of $51,600/MWh and arrives at a value to this single farm of $12.9m per year, or a 20-year PV of $200m.[149]

548. We consider that using a VCR in this manner would represent a gross misapplication of the VCR concept, which reflects the value of short-term reliability-related interruptions of existing supplies to existing customers (such as occur due to network outages). A VCR value is not intended to reflect the value that a potential customer might place on obtaining new electricity supply and, especially, does not reflect the value applicable to the entire year's supply requirement. While Powercor does not represent the VCR-based value as its justification, it nevertheless states in its business cases that it has considered the '*broader economic benefits*' because they are *'likely to exceed average VCR values*'. However, even if the VCR-based estimate was valid, its analysis shows the opposite.

145 Ibid, page 17

146 Powercor response to IR035, question 49(iv)

147 For example, Powercor makes the assumption that a farm's entire daily load would need to be able to be supplied from a bank of batteries alone

148 Powercor response to IR035, question 49(v)

149 Powercor response to IR035, question 49(i)

Powercor's proposed criteria do not appear to be grounded in the National Electricity Objective - which its proposed regional supply upgrades fail to meet

549. In its business case, Powercor has recognised that '*economic benefits is (sic) a market benefit class that may not have been considered before in the context of distribution determinations…*'. Powercor has proposed five criteria, which we summarise as follows:[150]

1. Supporting regional communities;
2. Having demonstrated stakeholder support;
3. Investment not exceeding 1% of revenue;
4. Supporting customers with a strong reliance on electricity and which Powercor further defines as recognising that '…*average VCRs applied in the electricity industry do not reflect the value of electricity to all customers;' and*
5. Considering economic benefits '…*only when those benefits are received by a large proportion of customers rather than specific interested parties'*.

550. While the specific proposed investment is for regional supply upgrades, it is unclear why Powercor has sought to define a general set of criteria that includes the need for such investments to support regional communities.

551. In regard to inclusion of VCR in the criteria, we have already stated that we consider that VCR is not relevant in considering an upgrade to provide new supplies to new customers.

552. Powercor's proposal, which is predicated on enabling four new dairy farms to be developed, does not seem to satisfy the last of its criteria (i.e., that the benefits are *'…received by a large proportion of customers…*')

553. In summary, some criteria appear to be defined to suit the proposed investment, rather than related to the NEO; on the other hand, there are some other criteria that Powercor's proposed upgrades do not appear to meet.

Summary of assessment

554. Our assessment suggests that Powercor's proposed regional supply upgrades are not justified. Moreover, we consider that Powercor has not proposed a methodology or criteria that are usable in seeking to justify distribution network upgrades by reference to market benefits.

5.4.5 Other zone substation work

Overview

555. The remainder of the forecast expenditure in the Augmentation of zone substation category comprises 32 other projects. As discussed below, there are five main expenditure groupings.

Assessment

New Torquay zone substation

556. The largest project in the remainder of the zone substation augmentation category is the proposed new Torquay zone substation (TQY) at a total cost of $20.3m.[151] The project drivers are:

- to help satisfy Powercor's REFCL obligations under the Amended Bushfire Mitigation Regulations; and
- to address forecast overloading of Waurn Ponds (WPD) substation in 2025/26.

150 Powercor BUS 6.09 – Upgrading regional supply, pages 10 and 11

151 Includes WPD ZSS - 66 CB kV works for TQY lines ($3.3m); does not include the $5.0m for the six feeder and sub-transmission line works associated with establishing the substation

557. These drivers, including the proposed timing of the substation, are discussed in more detail in section 5.7 (REFCL compliance) because the primary driver is the REFCL compliance obligation.

Land acquisition

558. In addition to the land acquisition costs for the proposed new Tarneit zone substation, Powercor proposes seven land purchase projects at a total cost of $4.5m for seven new substation sites that, it appears, will not be developed in the next RCP. No information is provided to support this forecast cost other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

Capacitor banks

559. Powercor proposes six capacitor bank projects at a total cost of $5.6m, which mainly involve new 12MVAr capacitors with VAR control facilities. No information is provided to support this forecast cost other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

Transformers

560. Powercor proposes spending $5.0m on three transformer rebuild projects or new transformers and $1.0m on transformer cooling fans in the next RCP. No information is provided to support this forecast cost other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

Circuit breakers

561. Powercor proposes spending $2.4m on circuit breakers or circuit breaker isolators at two zone substations (GLE and SA). No information is provided to support this forecast cost other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

Remainder

562. The remainder of the proposed expenditure in the next RCP comprises four miscellaneous projects for which no information is provided in support of the cost forecast other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

5.5 Augmentation of HV Feeders & subtransmission

563. Powercor has identified 197 projects in this category.

564. Powercor has provided a business case that covers seven of the largest HV feeder upgrade projects, which we discuss below.

565. In addition to $5.0m capex to establish five feeders and 66kV line work associated with the establishment of the proposed new Torquay substation (discussed in section 5.7) and $3.6m allocated to HV feeders associated with the establishment of the new Tarneit substation (discussed in section 5.4.3), Powercor proposes capex of $64.6m on 183 other projects ranging in value from $5.0m to $42k.

5.5.1 HV feeder upgrade projects

Overview

566. Powercor has provided its *assessment of key feeder projects,*[152] which are forecast to be completed in the next RCP, comprising the seven projects listed in the table below. In the table, we have incorporated the expenditure shown in Powercor's Project List,[153] rather than from its business case as the forecast capex from the sources differ.[154] The major difference is for GL013 (the feeder extension to Batesford), which is estimated to cost $3.7m ($2021) in the business case.

Table 5.5: 'Key Feeder Projects' - $m, real 2021

Feeder	Proposed commissioning year	Cost
TNA012 and TNA031 new feeders	2022/23	5.0
GL013 feeder extension to Batesford	2022/23	2.8
FNS032 feeder extension into Lara	2024/25	2.4
Re-direct WBE012 and WBE032 feeders into Point Cook	2021/22	1.6
MLN031 new feeder to offload MLN011, MLN013 and MLN024	2025/26	1.6
MLN034 new feeder to offload MLN012 and MLN022	2022/23	1.5
BAS033 new feeder to Sebastopol	2023/24	1.1
Total		**16.0**

Source: Augex Project List

Assessment

Powercor's solutions 'tool kit' for thermal or PQ issues are consistent with industry practices

567. The type of distribution feeder constraints typically experienced by Powercor on its network is excessive conductor thermal loading (>100% of the thermal limit) and, occasionally, voltage-related power quality Code breaches.

568. Thermal constraints are addressed by either: (i) replacing the conductor/cable with a higher-rated conductor; (ii) transferring load from the constrained feeder to an upgraded adjacent HV feeder; or (iii) contracting for non-network solutions. The 'solutions tool kit' that Powercor draws from includes: (i) installing voltage regulation devices; (ii) installing reactive power control devices (like line capacitors or reactors); or (iii) reducing the impedance of the network by replacing small sections of conductor.

569. These solutions are consistent with the approaches taken within the industry to address distribution feeder thermal and power quality (typically voltage) issues related to high supply demand.[155]

152 PAL BUS 6.05, p3

153 Augex Projects List – correct reference required

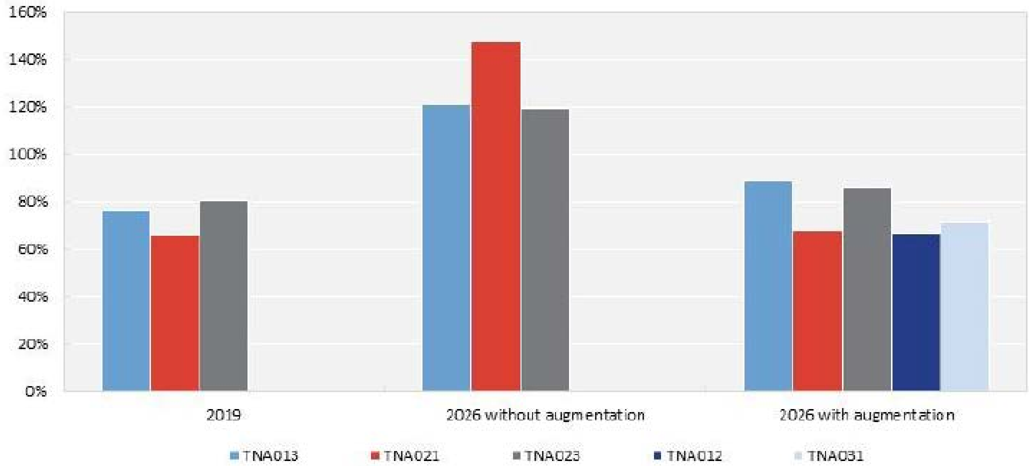
154 PLA BUS 6.05, Table 1.1 totals $17.9m

155 Statcoms have also been used in some states to provide voltage regulation, which is not mentioned in any of the solutions proposed in the large projects that are the subject of BUS 6.05

The seven projects each address feeder utilisation issues

570. The new Truganina (TNA) feeder project illustrates Powercor's approach to justifying the augmentations for all seven projects. The figure below shows the current, predicted (not treated) and treated feeder utilisations. As is the case in the other six projects, two network augmentation options are considered, with the lowest cost option selected. In this case the comparison is between: (i) uprating five feeders ($5.9m, $2019); and (ii) new TNA012 and TNA013 feeders ($4.8m, $2019).[156] The MW required for a one-year deferral using NNS is also mentioned in most cases. Power quality issues do not feature in any of the project need analyses.

Figure 5.9: Forecast TNA feeder utilisations (selected feeders)



Source: PAL BUS 6.05, Figure 3.6, p14

The impact of small delays to some planned HV feeder works is unlikely to be high

571. The demand forecast is only likely to affect projects earmarked for replacement in the last one or two years of the next RCP. Only one of the seven projects are scheduled for completion in 2025/26 (with capex of $0.7m) and two projects in 2024/25 (with combined capex of $2.0m).

572. Powercor has not provided an economic model to support its analysis. We expect that sensitivity analyses (varying the demand forecast) would show that there is a reasonable likelihood of being able to defer some of the planned work into the next RCP. This is because in some cases, the time and quantum of load excursions above 100% utilisation is likely to be small or zero at substations with minor 'breaches' of the 100% level with even a small negative variance in the demand forecast.

5.5.2 Remainder

Overview

573. The remaining expenditure in this functional category covers a total of 183 projects with a combined capex forecast of $48.7m.

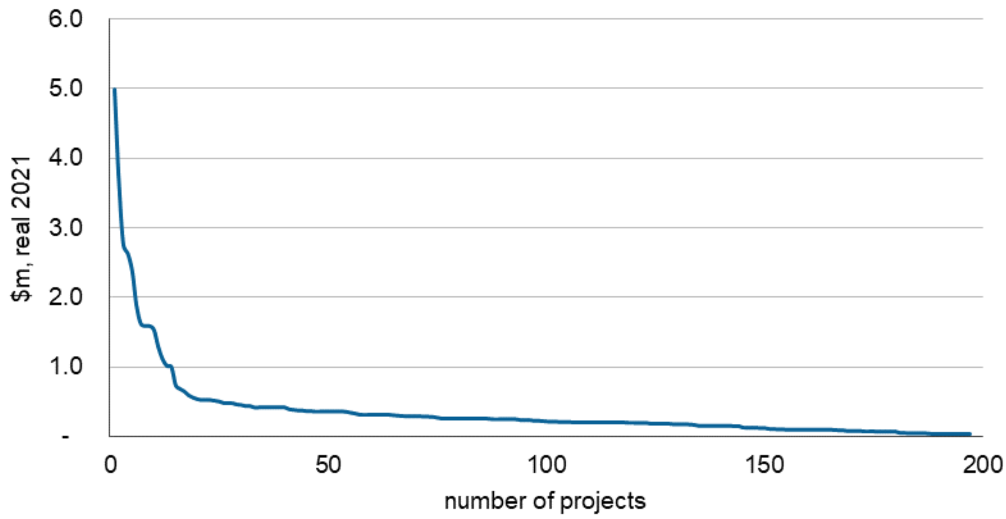
Assessment

574. The figure below illustrates the expenditure of all 197 projects in this functional category,[157] from the highest project capex of $5.0m through to the lowest of $42k. Many of the planned projects are relatively small. For instance, 103 projects have forecast expenditure of less than $0.25m and 172 projects have forecast expenditure of less than $0.50m.

156 Powercor BUS 6.05 – HV feeder program justification, Table 3.12

157 That is, including the six TQY feeder projects, the TNT feeder project, and the seven other feeder projects discussed in PAL BUS 6.05

Figure 5.10: Expenditure profile of the remaining projects in the Network development – augment distribution function - $m, real 2021



Source: EMCa analysis of Augex Projects List

575. Powercor has forecast $10.0m capex in 2024/25 and $8.4m capex in 2025/26 for the 183 'remainder' projects. It is likely that, over time, a number of the projects designated to have expenditure in these years will be 'rolled-out' because of lower than expected load growth while other projects will be 'rolled-in' due to higher than forecast load growth.

576. We note that there is limited risk from only a few hours of potential thermal overload of overhead conductors (which dominate the feeder projects). We expect that sensitivity analyses to the peak demand forecast would show that there is a reasonable likelihood of being able to defer some of the planned work into the next RCP. We therefore conclude that Powercor is unlikely to require all of the 'remainder' forecast expenditure of $48.7m in the next RCP.

5.6 LV augmentation

5.6.1 Solar enablement

577. Powercor has proposed $60.7m of solar enablement expenditure in the next RCP. Our assessment of this is provided separately, in section 6.

5.6.2 Quality of Supply

Overview of program

578. Powercor proposes spending $11.0m over the course of the next RCP, an increase of approximately 50% from the current RCP. The quality of supply program involves the following activities:[158]

- *re-balancing phases to prevent single phase overloads;*
- *upgrading conductors to prevent voltage drop or allow additional load to be connected;*
- *replacing transformers that are overloaded (proactively rather than replacing under faults); and*
- *changing conductors or transformers to address harmonics, flicker or other power quality problems.*

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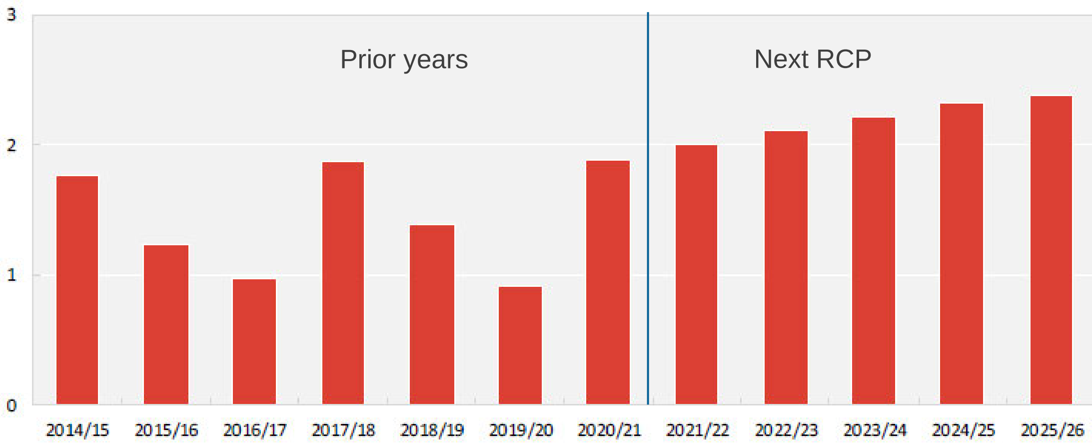
158 PAL RP, p80

Assessment

579. The expenditure profile for Powercor's power quality program is shown in the figure below.

Figure 5.11: Powercor's power quality program expenditure profile - $m, real 2021



Source: Powercor RP, Figure 6.6, p81, with EMCa annotations

Justification for the forecast is not compelling

580. Powercor has based its forecast on the extrapolation of 2020/21 forecast capex into the next RCP. The proposed approach is explained as follows:

> *…this investment trends upwards over the 2021–2026 regulatory period in line with load growth expectations for existing and new customers.*[159]

581. Powercor has not provided a basis for its 2020/21 forecast, although we note that it is equivalent to the 2017/18 expenditure.

582. Whilst we consider it likely that there will be an increasing trend in power quality issues as solar penetration and peak demand increases, Powercor has not provided compelling information to explain why it does not expect similar variations from year to year over the next RCP as it has in the current RCP, nor has it adequately justified the step change in total expenditure from the current RCP.

Overlap with solar enablement initiatives is likely to be small

583. Powercor states that *'[t]he drivers for these works are fundamentally different, and coupled with the low volumes relative to the total population, the chances of these programs overlapping is minimal.'* Taking into account the four activities that Powercor assigns to this expenditure classification and the solar enablement program activities, we consider that the extent of overlap is likely to be minimal.

5.7 REFCL compliance

5.7.1 Overview of programs

584. Powercor has included in its capex forecast for the next RCP four REFCL compliance-related programs totalling $198.1m:

- Ongoing program [$60.5m];
- Surf Coast supply area [$72.9m];
- Tranche one, two, and three sites [$35.7m]; and

159 PAL RP, p81

- Corio zone substation [$29.0m].

585. We consider each of these programs after first reviewing Powercor's compliance obligation and its capacitive charging forecasting methodology.

5.7.2 REFCL Compliance obligation

Overview

586. Powercor advises that the Victorian Government introduced regulations in 2016 which amended the Electricity Safety (Bushfire Mitigation) Regulations 2013 to specify the timeframes for Powercor to achieve compliance at its 22 zone substations. To address the requirements, Powercor structured its REFCL program into three separate tranches based on installation of Ground Fault Neutralisers (GFN)[160] at each of the designated zone substations.[161]

Assessment

587. We consider Powercor has an obligation to achieve mandated requirements at the Tranche 1, 2 and 3 substations in accordance with the regulations.

5.7.3 Forecasting methodology

Overview

588. Powercor has developed network capacitance forecasts by '*applying a growth rate based on the previous five year's average annual growth in network capacitance. One off programs of work, such as the undergrounding of overhead networks as part of the VBRC Powerline Replacement Program, are removed from the growth rate calculations. Any forecast works for these one-off programs are factored into the network capacitance forecasts to reflect the forecast year of completion.'*[162]

Assessment

589. Powercor has provided an explanation of its approach to determining the required REFCL characteristics in response to the network capacitive charging forecast.[163]

590. This approach to the forecasting of capacitive charging current was presented to the Victorian REFCL Technical Working Group on 9 September 2019. Membership of the REFCL Technical Working Group includes Energy Safe Victoria (ESV), which did not suggest any changes. We consider the methodology represents a reasonable approach for estimating network capacitance.

591. GFNs are installed on power transformers in zone substations, therefore the number of GFNs that can be installed at a substation is limited by the number of transformers at the substation.

5.7.4 REFCL Compliance - Tranche one, two and three sites

Overview of project

592. Powercor submitted contingent project applications to the AER as follows: Tranche 1 – March 2017; Tranche 2 – March 2018; and Tranche 3 – August 2019. Powercor advises that lessons learned were incorporated into subsequent applications, including:

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160 A GFN measures the shift in neutral voltage in response to an earth fault and injects additional compensation current to reduce the faulted phase voltage to near zero. This allows the GFN to reduce earth fault current levels at a fault site to near zero (PAL BUS 6.08, p5)

161 PAL BUS 6.08, p5

162 PAL BUS 6.08, p8

163 PAL ATT122

- Scope and cost estimates based on latest completed works; and
- Balancing methodology, cable and current transformer replacements and the use of earth grids were improved.

593. Powercor states that the *'unspent capital expenditure approved by the AER through its contingent project decisions is included in our regulatory proposal for the 2021–2026 regulatory period.'*[164] This 'unspent amount' is $35.5m, all directed to its Tranche 3 sites.[165]

Assessment

The AER approved $77.3m ($real, 2015) capex for Tranche 1 and $110.5m ($real, 2015) capex for Tranche 2

594. Powercor's Tranche 1 REFCL contingent program application sought to recover $87.1m capex ($real, 2015) and $5.2m ($real, 2015) opex. The AER's Final Decision (August 2017) approved $77.3m ($real, 2015) capex to complete the project in the current RCP. It approved the opex amount.

595. Powercor's Tranche 2 REFCL contingent program application sought to recover $127.1m capex and $5.8m opex ($real, 2015). The AER's Final Decision (April 2018) approved $110.5m capex and $4.8m opex ($real, 2015) - as reasonably required.

596. We note that Powercor has made a provision of $0.25m in its forecast for 'REFCL compliance: Tranche 1 and 2. No explanation is given for this capex, but it is relatively minor.[166]

The AER approved $116.2m (real, 2015) capex for Tranche 3

597. Powercor's Tranche 3 REFCL contingent project application for $164.5m ($real, 2015) included work at Ararat, Corio, Hamilton, Koroit, Merbein, Stawell, and Terang substations. The AER's Final decision was to approve capex of $116.2 million ($real, 2015). The work at Corio zone substation ($27.3m, real 2015) was excluded from this decision due to an expectation of changes to Powercor's legislated regulatory obligations. The AER further reduced the proposed capex by $20.9m (real 2015) because it did not consider that certain cost components were set by Powercor at a prudent and efficient level.[167]

598. Powercor advises that it has installed REFCLs at nine zone substations, that it must install REFCLs at a further 13 zone substations by 2023, and that:

> *'[t]he cost of installing REFCLs at these remaining sites has mostly been approved in our three contingent project applications.'*

599. Powercor further advises that:[168]

- It has submitted a separate business case (Surf Coast supply) which addresses the Waurn Ponds Tranche 3 substation obligation - refer to section 5.7.6 of our assessment); and
- It has included the CRO REFCL capex in its proposal - we discuss this in section 5.7.7.

600. Powercor does not explain what it has completed or what is yet to be completed in its regulatory proposal. However, we note from its Bushfire Mitigation Plan that it plans to complete five Tranche 3 REFCL projects in 2021/22 and a further two in 2022/23.[169]

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164 PAL RP, p83

165 PAL, RP, Table 6.9, p83

166 Augex Projects List

167 AER, Final Decision Tranche 3, Jan 2020; Labour for surge arrestors replacement, HV regulators modification, and design and procurement; the need for a spare GFN; plant hire cost; SCADA protection and control and communications cost; and works associated with Terang zone substation.

168 PAL RP, p83

169 PAL ATT094, Table 1, p22

The remaining Tranche 3 cost for the next RCP is likely to be reasonable

601. As Powercor states that it has included the unspent capital expenditure approved by the AER for the remaining work, it is reasonable to assume that the $35.7m proposed in the next RCP represents expenditure up to the cap of $116.2m ($real 2015) for the approved Tranche 3 work. For the same reason, the opex is likely to be at a reasonable level.

5.7.5 Ongoing compliance program

Overview of program

602. Powercor proposes capex of $60.5m on works at five Tranche 1 and four Tranche 2 substations without which its forecast system capacitance increases would render the substations non-compliant with the REFCL 'required capacity' requirements during the next RCP.[170]

Assessment

Powercor's claimed obligation to maintain ongoing compliance seems reasonable

603. In our view, the Amended Bushfire Mitigation Regulations oblige Powercor to ensure that each polyphase electric line originating from the selected Tranche 1 and Tranche 2 zone substations have the 'required capacity' to ensure proper functioning of the REFCLs on an ongoing basis.

Powercor draws from suitable solution options to address excessive capacitive charging

604. Depending on the characteristics of the supply system and the substation at which excessive capacitance is forecast, Powercor uses one or more of the following options:[171]

- Feeder reconfiguration;
- Adding a new GFN;
- 22kV isolating transformers;
- Mini zone substations; and
- New zone substation.

605. Powercor also describes the four-step process (plus a caveat) that it applied to determine the best option or combination of options for each substation. We consider these steps to be reasonable.[172]

606. On the basis of the descriptions of the options and option selection steps, we consider its forecasting process to be reasonable.

Powercor's selected options in each case appear sound

607. We asked Powercor the following questions regarding its selected options:[173]

- Why it was not feasible to transfer supply from CMN[174] to MRO[175] to achieve a 10A reduction at CMN?
  - Powercor's response was that, based on tests at MRO in 2019, this approach would result in MRO's network exceeding the limits of the GFN;

170 PAL BUS 6.08, p7

171 PAL BUS 6.08, pp9-10

172 PAL BUS 6.08 pp11-12

173 Powercor response to IR029

174 Castlemaine zone substation

175 Maryborough zone substation

- Why it assumed that a third transformer at EHK[176] would be required even in the absence of REFCL requirements in apparent contradiction with the Distribution Annual Planning Report (DAPR)?
  - Powercor explained that the need for the 3rd transformer to offset expected unserved energy was required towards the end of the next RCP (i.e., beyond the 2024 horizon of the DAPR);
- Why the capacitive charging limit at WIN[177] appeared low?
  - Powercor's response was that the result was based on testing at WIN, with a contributing factor being significant remote cable networks. It noted that two large underground cable sections had already been isolated via isolation transformers to reduce capacitive charging; and
- Why a 25/33MVA transformer is recommended at WIN rather than a smaller unit?
  - Powercor advised this was an error and that the recommended transformer is a 10/13MVA transformer, reducing the proposed cost by $300k.

608. Powercor's explanations of: (i) the advantages and limitations of each of its solutions options: (ii) its rationale for the selection of the option or combination of options in each of the nine substations: and (iii) its responses to our questions collectively satisfies us that the prudent option has been selected in each case.

The optimal timing of work is very dependent on network development assumptions

609. Powercor provides the capacitive charging current forecasts for relevant busbars (18 in total) across the nine substations showing the annual trajectory and the respective GFN threshold limits. The latter is the trigger for Powercor determining the timing of the planned mitigating activities. To avoid a breach of the regulations, Powercor plans to complete the work in the year prior to the forecast exceedance of the GFN threshold.

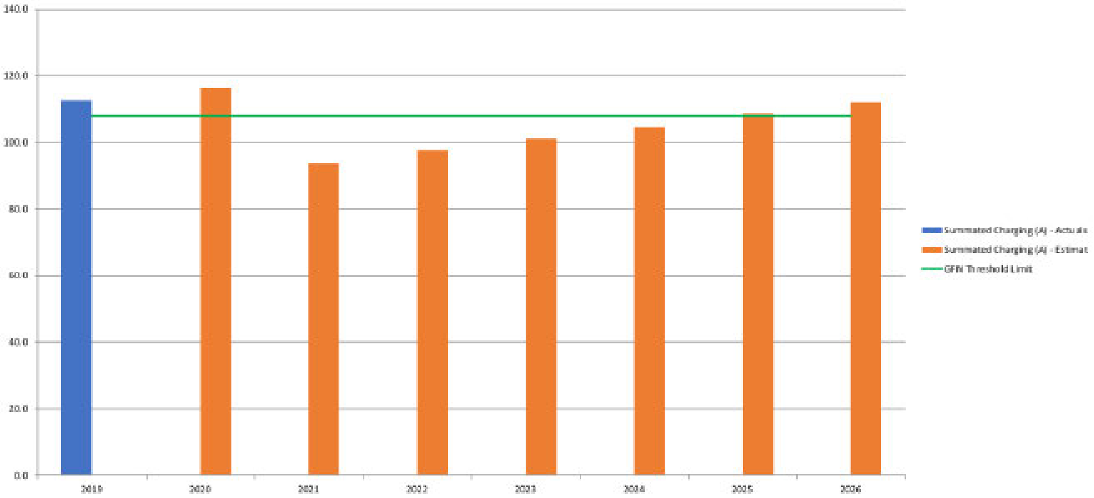
610. The figure below shows the sort of graphical information Powercor has provided for each relevant busbar. As the timing is dependent on assumed network development (including underground cables which produce approximately 40 times the charging of overhead conductors), the capacitive charging current forecasts are very dependent on demand forecasts.

611. In four of the nine compliance cases, there is likely to be an opportunity to defer the planned work if there is a small to moderate reduction in demand growth and associated network development for BETS, BGO, CMN and WIN substations. This is due to the relatively small forecast excursion above the limit in the latter years of the next RCP. The collective expenditure that may be deferred is $15.3m from these four substations or 25% of the total. Nonetheless, we consider that given the compliance obligations, a prudent operator should plan for all nine limits being reached in the next RCP.

[176] Eaglehawk zone substation

[177] Winchelsea zone substation

Figure 5.12: BETS No 4 bus capacitive charging current per year (Amps)



Source: PAL BUS 6.08, Figure 6.8

High labour costs may lead to overestimation of capital costs

612. Powercor advises that '*[o]ur approach to scoping and costing the selected option is consistent with our contingent project application for tranche three of the REFCL installation program…takes account of the lessons learnt …actual costs incurred…and the best available cost information in relation to equipment and materials*.'[178]

613. Powercor made similar statements in regard to its cost estimation methodology for its Tranche 3 works. Regardless, the AER determined the cost to be overstated by 15%.

614. As Powercor makes no reference to having taken into account the feedback from the AER regarding its model, or in its response to our question regarding unit costs,[179] we assume that its cost estimating methodology is likely to lead to overstated cost estimates.

615. Drawing from the AER's Final Decision, the proposed $60.5m capital expenditure is likely to be overstated. For the same reason, the opex is likely to be overstated.

5.7.6 REFCL Compliance and demand growth: Surf Coast supply area

Overview of project

616. Powercor is required to install REFCLs and undertake other work by 1 May 2023 to satisfy Powercor's REFCL compliance obligations at Waurn Ponds substation (WPD), which is a Tranche 3 substation. Powercor proposes installing three GFNs at WPD with six isolating substations and establish Torquay zone substation (TQY) with two GFNs and three isolating substations at a total cost of $73.5m capex and $3.0m opex.[180]

617. WPD comprises one 13.5 MVA 66/22kV and two 33 MVA 66/22kV transformers supplying the 22kV buses.

Assessment

Powercor considered a reasonable set of options

618. The table below shows the options considered by Powercor in managing the REFCL obligations at WPD. We consider this to be a reasonable set of options.[181]

178 PAL BUS 6.08, p12

179 Powercor's response to IR029, question 7

180 Powercor, BUS 6.01 – Surf Coast supply area, Table 1; includes $25.3m for establishing the zone substation; the total differs from the $72.9m in Table 6.8 of the Regulatory Proposal

181 Powercor also discusses other options it considered but discounted

Table 5.6: Surf coast supply - Summary of options considered – $m, real 2021

Option	PV costs	Net economic benefit
1 Install nine Ground Fault Neutralisers (GFNs) at WPD zone substation	57.3	35.9
2. Install five GFNs at WPD with ten isolating substations	46.1	47.0
3. Install three GFNs at WPD, establish Torquay (TQY) and Charlemont (CMT) zone substations each with three GFNs	52.1	41.0
4. Install three GFNs at WPD with six isolating substations, and establish TQY zone substation with two GFNs and three isolating substations	37.7	55.0

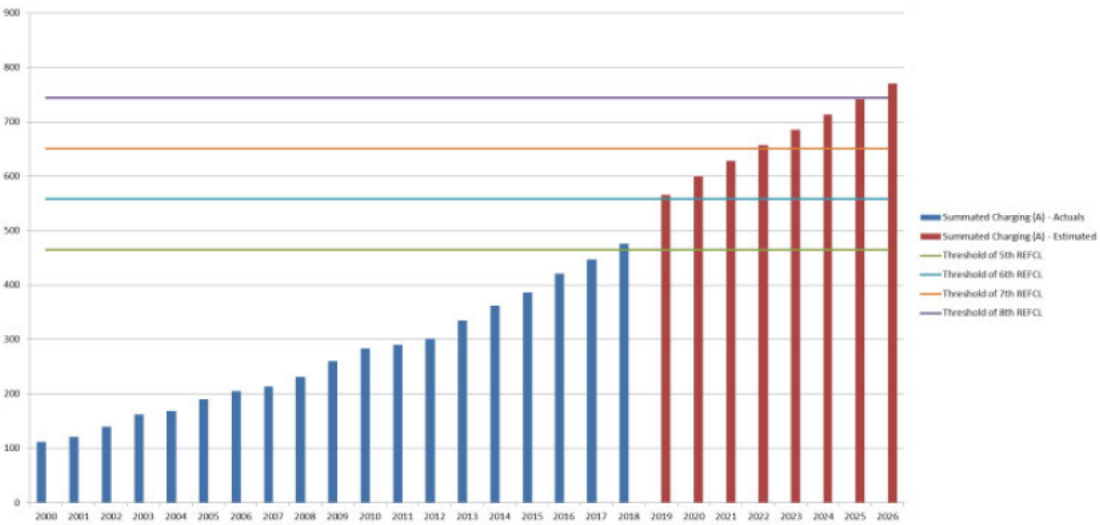
Source: PAL BUS 6.01

WPD can accommodate three GFN, but this is unlikely to be sufficient to manage the forecast capacitive charging current

619. Powercor's calculations indicate:[182]

- A limit of 93 amps of capacitive charging current is a suitable distribution network limit for each GFN operation at WPD, based on results from WIN; and
- Network capacitance at WPD is expected to be 685 amps in 2023, increasing to 770 amps by 2026 due to the large amount of underground cable growth driven in turn by the Armstrong Creek development area – the forecast is shown in the figure below.

Figure 5.13: WPD network charging current forecast (A)



Source: PAL BUS 6.01, Figure 2

620. Based on our assessment of Powercor's forecasting methodology we are satisfied that it is prudent to plan for the capacitive charging currents indicated in the figure above, even though they may be somewhat overstated (such as if the peak demand forecast does not increase at the forecast 3% over the next six years).

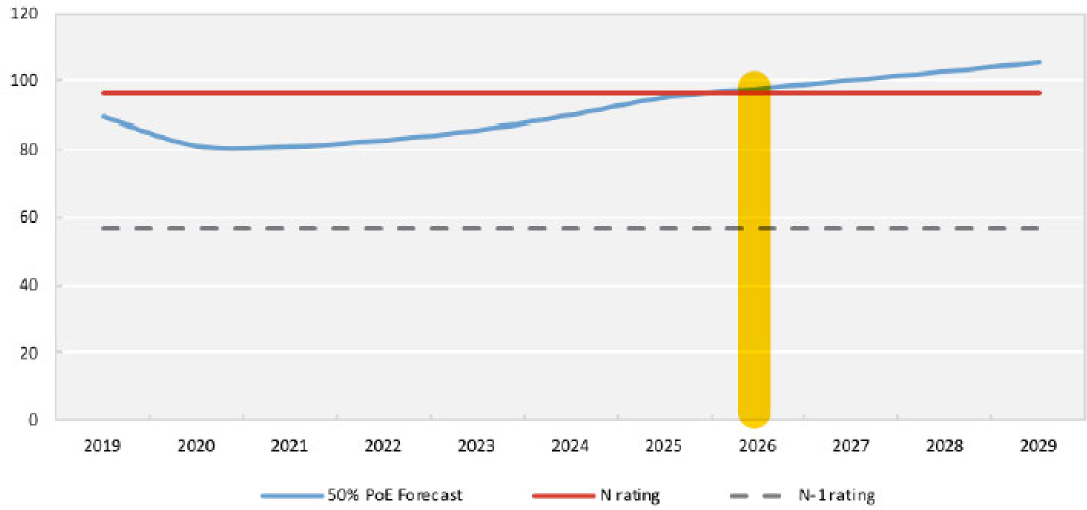
A new zone substation in the area is likely to be required within the next ten years

621. Powercor's forecast demand for WPD is shown in the figure below, along with the N-1 and N ratings of the substation. Powercor considers the average annual compound growth rate of 3% to be a conservative estimate. Its forecast is for the N capacity to be exceeded in 2026 and it argues that this thermal overload is best addressed by a new substation,

[182] Powercor BUS 6.01 – Surf Coast supply area, pages 8-9

consistent with Option 3 or Option 4. In the absence of REFCL considerations at WPD, we consider that it is reasonable to assume that a new zone substation is required to offload WPD by 2030 at the latest and more likely in the period 2026-2028.

Figure 5.14: WPD maximum demand forecast 50%PoE (MVA)



Source: PAL BUS 6.01, p10 (modified by EMCa)

The selected option is likely to be prudent

622. With regard to Option 1, Powercor sates that it is '*doubtful whether this option can be regarded as credible.'* In our view Option 1 is not credible because of the proposed configuration of WPD. Option 1 also has the lowest NPV.

623. Option 2 has the second highest NPV, but as Powercor points out, there are practical difficulties with the brownfields work to accommodate five GFNs at WPD and ten isolating substations.

624. Option 3 has the second lowest NPV and provides no practical advantages compared to Option 4.

625. Option 4 has the highest NPV and is Powercor's preferred option. It requires: (i) establishing six isolating substations, which Powercor identifies as a practical challenge; and (ii) ESV exemptions, which Powercor advised verbally have been granted by ESV for several other cases (i.e., from Tranche one or Tranche two).

626. Given the obligation to install sufficient REFCLs at WPD by May 2023, we consider that the approach is reasonable.

Possible over-estimation of cost

627. For the same reasons discussed above for on-going REFCL compliance, we remain concerned that the cost estimate for the Surf Coast area may be overstated.

5.7.7 REFCL Compliance: Corio zone substation

Overview of project

628. Powercor advises that it will not proceed with this project on the basis of advice from the Minister for Energy and the relevant Council:

> *On 28 May 2020, an Order in Council was published in the Gazette which provided an exemption from installing REFCLs at CRO and GL on condition that a new complying zone substation is established.*[183]

[183] Pages 36-36 of attachment PAL IR029 GG2020G021 public.pdf

629. It further advises that it will provide a new business case, scope, and cost model to the AER which sets out its proposed new REFCL zone substation at Bannockburn.[184]

Assessment

630. Given the advice above, Corio substation is likely to be replaced by an alternative, which is likely to require consideration in Powercor's Revised Regulatory Proposal.

5.8 Zone substation automation

631. Powercor proposes $58.1m capex in the next RCP in this category, comprising eight projects.

5.8.1 Network communications: Telstra 3G retirement

Overview of project

632. Powercor's business case advises that *Telstra's 3G communications network will be retired over the 2021–2026 regulatory period to make way for 5G technology.*[185] Powercor presently uses the 3G network for communications with 2,798 devices in its own network for operational purposes. To operate on 4G or 5G networks, it will need to upgrade the devices or components with them at an estimated cost of $16.1m.

Assessment

633. Powercor quotes advice from Telstra dated 9 October 2019 that it would shut down its 3G network in 2024. This affects the 3G devices that Powercor uses for operations. We have ascertained that Powercor's advice on the intent and timing of the 3G shut down is consistent with the latest information on Telstra's web site. On this basis, we consider that it is prudent for Powercor to depart Telstra's 3G network by 2024.

634. Powercor considered three options to address the implications of the 3G shut down: (1) do nothing; (2) upgrade 3G control boxes and access points; and (3) develop a communications network using AMI. We consider that a prudent operator would select Option 2 given that, according to Powercor's assessment, the NPV is the least negative, with a lower capital cost than Option 3.

635. Powercor has provided a detailed breakdown of the cost estimate and its approach and we consider that the expenditure forecast appears to be reasonable.

5.8.2 Network communications: spectrum changeover

Overview of project

636. Powercor proposed capex of $8.4m for its spectrum changeover project. Powercor advises in its business case that *'[to] make way for new technologies that require an increase in bandwidth (such as 5G cellular),* ACMA *will be re-allocating frequencies over the 2021–2026 regulatory period.'*[186] Powercor further advises that it will lose some of its frequency licences, which will in turn mean that it cannot: (i) comply with regulations; (ii) protect assets; (iii) maintain reliability; and (iv) maintain safety.

184 Powercor response to IR029, question 5

185 PAL BUS 6.06, p4

186 PAL BUS 6.07, p4; ACMA is the Australian Communications and Media Authority

Assessment

A prudent operator would plan for the spectrum changeover within the next RCP

637. Powercor is an apparatus licence holder operating in the 800MHz band and in the 1.5GHz band. Based on the information provided and ACMA's Five-year spectrum outlook 2019-23:[187]

- Powercor's is likely to lose access to the 820-825 MHz, 857-865 MHz, and 865-870 MHz bands by 30 June 2024;[188] and
- Powercor's may lose access to the 1.5 GHz band before the end of the next RCP: *This is extremely likely to occur within the next 7 years and impact fixed links that are licensed to Powercor for operation in the band… the fastest this would occur is approximately 3 years from now*.[189] Thus the fastest time would be 2023 and the longest timing would be mid-2026.

638. Powercor has based its work program and expenditure on losing access to the 800 MHz band by 30 June 2024 and to the 1.5 GHz frequency band by 30 June 2025. This appears to be prudent based on the advice it has received from the ACMA in writing.

Powercor has considered a reasonable range of options

639. Powercor has considered four options, including 'doing nothing', which is not a viable option. Of the other three options it has selected Option 2 (replace radio components to operate at new frequency) which has a capital cost of $8.4m. This is the lowest cost of the options considered and has the highest NPV.

640. Powercor has provided a detailed breakdown of the cost estimate for Option 2. We consider that its approach and expenditure forecast appear to be reasonable.[190]

5.8.3 Digital Network: network devices

641. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.4.2.

5.8.4 Remaining projects

Overview of remaining augex

642. In addition to the 3G shutdown and the spectrum changeover projects, Powercor has identified the following projects and proposed augex in the next RCP:

- Digital Network devices [$4.7m];
- Communication Devices – 5 minute settlement [$12.9m];
- Communication device annual program [$13.4m];
- Communications monitoring [$0.3m];
- Distribution transformer oil monitoring [$1.7m]; and
- Fibre upgrades [$0.7m].

Assessment

643. The proposed Digital Network devices and 5-minute Settlement device expenditure is discussed in ICT sections 7.4.2 and 7.6.1, respectively.

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187 Table 10, p54 (published September 2019)

188 PAL ATT116 - Letter from ACMA to Powercor, 16 August 2017 which is consistent with ACMA's Five-year spectrum outlook 2019-23

189 PAL ATT119 – Email from ACMA 23 May 2019 which is consistent with ACMA's Five year spectrum outlook 2019-23

190 PAL BUS 6.07, pp10-12, Appendix A, Appendix C

644. Powercor has not provided compelling supporting information to justify the balance of $16.1m of capex across the next RCP. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

5.9 Findings and implications for Powercor's non-DER augex forecast

Powercor's probabilistic planning and economic modelling

645. We consider Powercor's probabilistic planning model to be reasonable with one exception: determining the value of unserved energy on a weighting of 70% of the demand forecast based on the 50% PoE forecast and 30% at the 10% PoE forecast. We have sought to account for this issue by undertaking our own sensitivity analyses using Powercor's models (where they are available) to test the robustness of the selected options and the timing of the proposed work to negative variances in peak demand. From this analysis we consider that Powercor's proposed demand-driven expenditure is higher than it is likely to incur.

AER Focus Projects

646. Specific to our review of the AER focus projects, we consider that the proposed capex for the Bacchus Marsh and Tarneit supply areas is likely to be reasonable.

647. In the case of Powercor's proposed Regional supply project, we consider that the economic analysis is fundamentally flawed. This project is not justified.

Zone substation augmentation

648. For the remainder of the zone substation work proposed by Powercor, no information to support the expenditure has been provided other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

HV feeders and sub-transmission

649. Powercor proposes 197 feeder projects in the next RCP. It provided a business case in support of seven of its largest feeder augmentation projects. The projects were not supported by economic analyses. Powercor did not present the results of any sensitivity analyses to demonstrate the robustness of its proposed expenditure timing. This was also the case for the remaining projects. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

LV augmentation

650. The only project in this category is Powercor's ongoing Quality of Supply program. Powercor has not sufficiently demonstrated that its proposed 50% increase in capex in the next RCP compared to the current RCP is prudent and efficient.

REFCL compliance

651. We consider that Powercor's approach to forecasting its REFCL requirements and its approach to options selection is reasonable. However, we consider that its cost estimating methodology is likely to lead to overstated cost estimates.

Zone substation automation

We consider that Powercor has provided sufficient evidence to demonstrate that its proposed expenditure for the Telstra 3G retirement project and the Spectrum changeover project are likely to be prudent and efficient.

No information has been provided by Powercor to support the remainder of the proposed zone substation automation work other than its Planning Policy. Accordingly, we consider that Powercor has not sufficiently demonstrated that its proposed remaining expenditure is prudent and efficient.

6 REVIEW OF PROPOSED SOLAR ENABLEMENT EXPENDITURE

In this section, we review Powercor's proposed expenditure for solar enablement which includes expenditure for over 1,000 LV augmentations and a proposed opex step change for an enhanced compliance program and for LV transformer tapping.

We consider that Powercor has demonstrated that it has a reasonable solar enablement strategy involving a combination of compliance measures, transformer tapping and utilising a DVMS that Powercor proposes to install, before undertaking LV augmentations as warranted on a case-by-case basis. However, we consider that Powercor has not proposed a reasonable forecast of efficient expenditure or justified the requirements for this program.

The large majority of Powercor's proposed expenditure is capex for LV augmentations. Planned to commence at the beginning of the next regulatory period, this would be a massive increase on the level of augmentations that Powercor currently undertakes. In seeking to justify these augmentations, we consider that Powercor has considerably over-stated the economic benefits, under-stated the inherent uncertainties and has not applied a valid method for determining the timing of its proposed expenditure, including what is viable within the next RCP. We consider that the volume of proposed LV augmentations is not justified within the next RCP and that the majority of claimed benefits could be achieved from a much smaller program.

We also consider that Powercor's assumed unit cost for transformer tapping is unreasonably high, as is its proposed compliance program opex step change.

6.1 Introduction

652. Powercor is proposing a major program to better facilitate increased consumer rooftop solar. Most of these program elements are new. Powercor's proposed program is aimed at addressing voltage rise issues caused at the LV level by a combination of reduced net premises demand and increased net premises solar exports into the network at certain times of the day. The main expenditure that Powercor proposes is for capex to augment the network. However, Powercor also proposes to increase opex on several measures that can mitigate the need for, or extent, of such network augmentation.

6.2 Powercor's proposed Solar Enablement program

6.2.1 Powercor's proposed augex

653. Powercor proposes incurring $60.7m[191] over the next period for a network augmentation program to enable increased PV to be deployed. This would involve upgrading the network at 1,014 LV locations, and includes a combination of discrete LV augmentation, new transformers and some LV augmentation in conjunction with new transformers.

654. As part of its Solar Enablement program and associated Business Case, Powercor has also proposed ICT expenditure of $2.5m (un-escalated) for a Dynamic Voltage Management

191 Excluding real cost escalation

System (DVMS), that will allow remote adjustment of voltages at zone substations. Powercor has included this DVMS expenditure in its ICT forecast. Accordingly, we include this expenditure in section 7 as part of our review of ICT capex, but provide our review and advice on this proposed expenditure component here.

Table 6.1: Solar Enablement project – Augex component - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	12.2	12.2	12.7	11.8	11.9	60.7
Total	**12.2**	**12.2**	**12.7**	**11.8**	**11.9**	**60.7**

Source: EMCa analysis of Powercor MOD 6.01 (excludes real cost escalation)

6.2.2 Powercor's proposed operational initiatives and associated opex step changes

655. Powercor proposes an opex step change of $6.2m. The majority of this proposed expenditure is to allow for an increased program of manually tapping distribution transformers to help maintain LV distribution voltages within Code[192] limits and to institute a compliance program.

Table 6.2: Solar Enablement Opex Step Change - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	1.3	1.3	1.5	1.0	1.0	6.2
Total	**1.3**	**1.3**	**1.5**	**1.0**	**1.0**	**6.2**

Source: EMCa analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020' (includes real cost escalation)

Powercor's transformer tapping program

656. Powercor proposes a program where distribution LV transformer tap settings are manually adjusted to reduce the voltage profile 'downstream' of the transformer when excessive voltages are identified. Powercor's modelling of the impact of this initiative is limited by needing to ensure that the LV voltage on the particular section of the network stays within the minimum voltage threshold (as defined in the Code). In other words, in responding to high voltages which may occur at some times of the day/week, Powercor has also sought to ensure that it does not cause undervoltage compliance issues. Powercor has determined that some transformers are able to be tapped multiple times and this has been allowed for in its model. Powercor has based the cost of tapping on the average cost per site tapped in 2018.[193]

Powercor's proposed monitoring and compliance program

657. PV inverter system installers are required to ensure that inverters are set to comply with the requirements of AS4777 and Powercor's Model Standing Offer which provides for reducing the impact of solar export. It is possible to reset the inverter settings of at least some customers' legacy solar inverters to reduce voltage rises.

658. Powercor has assumed in its modelling that all new inverter systems are correctly set. Nonetheless, it considers that a monitoring and compliance program is required because '*[b]ased on our own experiences with non-compliance and that of other distributors that have already mandated new inverter settings, without any intervention we expect non-compliance with new inverter settings to be material.*'[194] Powercor has forecast the

[192] Victorian Electricity Distribution Code, Version 9A, clause 4.2.2 (Table 2, Standard nominal voltage variations)

[193] Powercor BUS 6.02 – Solar enablement, page 36

[194] Powercor BUS 6.02 – Solar enablement, page 38

monitoring and compliance cost based on the cost to implement remote monitoring and a 5% rate of non-compliance.

6.2.3 Supporting material that Powercor provided

659. In its submission, Powercor provided information, evidence, and contextual information relevant to its proposed solar program. We briefly summarise the main content of these documents below:

Material provided with Powercor's regulatory submission

1. *Powercor's business case (PAL BUS 6.02) and associated model (PAL MOD 6.02)*

In its business case Powercor describes its assessment of need, the options it has considered, its proposed program and the results in terms of customer impact and the investment amount. This includes a description of Powercor's stakeholder engagement process, how this has shaped Powercor's proposed program and mechanisms for managing constraints.

Powercor's model is a cost benefit model in which it seeks to demonstrate that the PV of benefits of its proposed program exceeds the PV of capital plus operational costs proposed over the next RCP.

2. *'Options Paper' (PAL ATT229)*

In this paper, published in April 2019, Powercor/CitiPower/United Energy describe background factors driving their consideration of the need for and form of a solar enablement program. The paper includes seven options for dealing with the issues, including 'unmitigated tripping', tariff reform and introducing quasi export tariffs as well as describing the option of a solar enablement program.

3. *Report from Jacobs on market benefits (ATT055)*

This document reports on Jacob's assessment of the market value of solar enablement, and which provides the main value assumption ($/MWh not constrained') in Powercor's cost benefit assessment.

4. *Profiling uptake of solar PV (Oakley Greenwood) (ATT 004), March 2019*

Powercor has utilised these forecasts in its modelling for cost benefit assessment purposes. (see also explanation as part of its response to IR044)

5. *Other Supporting material provided with Regulatory Submission*

Powercor provide a range of attachments (ATT054, ATT123, ATT168, ATT169, ATT170, ATT171, ATT172, ATT173). The remainder of such documents are essentially contextual, and include (for example) a Deloitte publication on global renewable energy trends, a media release by the Victorian premier, a letter of support from Geelong Sustainability Group Inc, and the Victorian government's renewable energy action plan.

660. Subsequent to its submission, Powercor provided further information and claims regarding its proposed program. We summarise these below:

Information and claims subsequent to Powercor's regulatory submission

Powercor provide additional information in its presentation to EMCa, with 14 PowerPoint pages devoted to the solar enablement program. Powercor also provided responses to three Information Requests as follows:

1. *IR019: This responds to an AER IR, and covers the topics of modelling of voltage rises, Volt-Var settings, Customer PV tripping, system average voltage levels, and whether Powercor had taken account of the future impact of batteries and electric vehicles.*
2. *IR027: This too responds to an AER IR. Powercor provided sample information on customers' solar voltage enquiries, the basis for the assumed 5kVA export limit, explained why the alternative of a Faraday Exchanger had not been included, explained how it had taken transformer tapping into account in assessing the need for augmentation, explained that it had not undertaken sensitivity analyses and described steps being taken to mitigate inverter settings non-compliance.*
3. *IR044: Powercor provided a range of information under this heading, including:*
    a. *Derivation of its average tapping cost (of $1,914);[195]*
    b. *A response on compliance drivers, in which Powercor describes its obligations under the Electricity Distribution Code and Electricity Distribution Licence, and describes and illustrates the impact of solar PV on voltages, and provides evidence on customers' solar voltage enquiries;*
    c. *A comparison between Powercor's and SAPN's solar programs, which purports to show that Powercor's program costs are $72m less than SAPN's; and*
    d. *A response which, amongst other topics:*
        i. *States that analysis of voltage fluctuations requires that analysis to examine short time intervals, noting that it is masked in day/night and longer-term averages and that voltage fluctuations affect both solar and non-solar customers;*
        ii. *Provides a response on consideration of lowering voltages across the network as a means of reducing the impact of solar;*
        iii. *States that while it has not considered the interaction between the solar enablement program and transformers to be replaced under its repex, this impact is minimal;*
        iv. *Contends that it has considered uncertainty by applying conservative benefit assumptions, that there is minimal risk of asset stranding because the augmentations will become net benefit positive well before the 30 year horizon of the analysis;*
        v. *Contends that in considering the analysis time horizon, the AER must adopt that same period for depreciation purposes; and*
        vi. *Clarifies its calculation of PV uptake forecasts and rates, and which includes lowering the uptake percentage from 34% shown in its business case, to 29% of customers (due to using a higher denominator).*

6.2.4 Main elements of Powercor's justification for its proposed program

Distributed solar penetration and implications for LV distribution networks

661. Increased distributed generation such as from rooftop solar has the effect of raising the voltage at the LV level. Customer solar system inverters which are compliant with AS4777 are set to trip when voltage exceeds set thresholds, in order to avoid over-voltage supply in the LV system to which its connected, and which can affect surrounding customers.

662. For similar reasons, distribution transformers with voltages set to minimise the risk of over-voltage, may result in under-voltage at times when there is no solar output in a particular LV network. All distributors are subject to voltage tolerance compliance obligations.

663. However in its Business Case, Powercor states that while it considers that '…*any approach to enabling solar should contribute towards rather than detract from our Code obligations*,' its primary intended outcome is not targeted at Code compliance.[196]

664. Powercor's proposed solar enablement program is intended to reduce the extent to which non-compliant voltage occurs and therefore the extent to which exported solar from customers' systems is tripped.

Powercor's current state and forecasts

665. Powercor has already undertaken some measures to assist increasing solar penetration by mandating limits on solar PV export to a maximum of 5kW and mandating inverter settings that are compliant with AS4777.

666. Powercor currently has 18% solar penetration[197] and overall the network is not currently experiencing significant constraints to solar export quantities. Based on Powercor's modelling, it still expects that by 2021/22 only a relatively small number of customers' inverters on 1.3% of its LV transformers, may experience tripping under certain circumstances sufficient to warrant consideration of LV augmentation. Nonetheless, Powercor is continuing to experience the impact of growth in solar PV and states that it expects solar penetration to increase to 34% by 2025.[198] With the increased solar penetration, Powercor expects the number of constraints to its network solar PV 'hosting capacity' to lead to an escalating number of PV inverters tripping.

Powercor's analytical approach to determining future incidence of export limitation issues[199]

667. Using capability derived from its smart grid / smart metering program, Powercor has assembled information on voltage profiles at the customer level over the day at 15-minute intervals, and determined the extent to which solar is currently constrained on each of its transformers. It has then used its solar forecasts and power flow modelling to model forecast voltage rises on each of its distribution transformers. Based on the time-of-day and season profiles, the model allows it to forecast the solar export MWh that will be constrained off because of excessive voltage rise, causing the customers' inverters to trip (no output) or for output to be reduced.[200]

668. Powercor states that it has sought to find the least cost way to address a constraint by *'…applying smart settings to customers' inverters, implementing a Dynamic Voltage Management System to lower network voltages at high solar export times, 'tapping' down*

195 From Powercor's response to IR044 – Solar Enablement (including table 1 on page 2, and its associated spreadsheet), this figure is assumed to be in nominal $2018

196 Powercor BUS 6.02 – Solar enablement, page 14

197 Powercor BUS 6.02, page 8. Measured as a percentage of total customer numbers

198 Ibid, page 8. Powercor attributes this forecast to advice from Oakley Greenwood

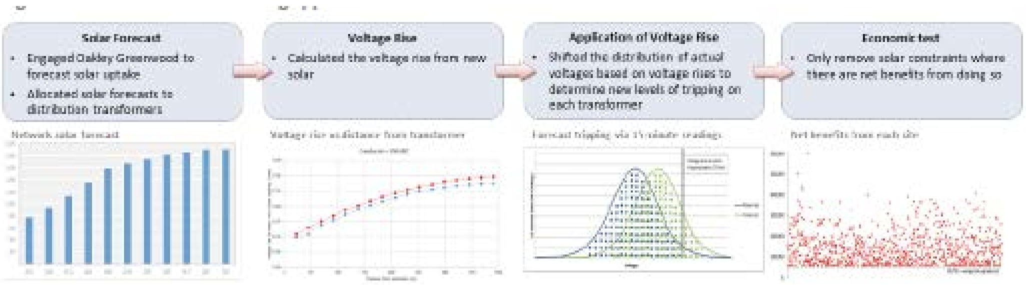
199 Ibid, page 5

200 Newer inverters have the capacity to progressively reduce output at increasing voltage thresholds but eventually a limit is reached at which the output is reduced to zero

distribution transformer (transformer) voltages and undertaking efficient network investment.'[201]

669. Figure 6.1 illustrates the process that Powercor has followed:

Figure 6.1: Powercor's modelling approach to forecasting required capex for solar enablement LV upgrades



Source: Powercor BUS 6.02 Solar enablement – Jan2020, Figure 3, p.6

670. Powercor has proposed LV network capex for the sum of LV upgrades (largely transformers) that individually pass its economic test (i.e., with a positive NPV).

Powercor's economic model

671. Powercor provided us with material from the model from which it determined the economic justification of its proposed LV transformer upgrades. We summarise the workings of this model as follows:

- For each transformer, for each year from 2021/22 to 2033/34 and for each season within those years (summer/winter/shoulder), Powercor has forecast the number of solar customers and the amounts of energy (MWh) for which exports might be curtailed from inverters tripping due to overvoltage;
- Powercor ascribes a value of $46.71 per MWh as its estimate of the economic value of the lost opportunity to export these volumes. This value is as advised to Powercor from a study undertaken by Jacobs based on modelling, and comprises Jacob's assessment of the '*reduction in total generation costs (fuel and operating and maintenance costs) and the value of carbon abatement.*'[202]
- Powercor applies a cost estimate of $56,793 (in $2019) per LV augmentation. This is derived from a weighted average of costs from the 37 such projects that it undertook over 2016 to 2018, and which included a mix of LV augmentation-only projects, transformer upgrade-only projects, and projects involving combinations of these solutions.
- From this, Powercor calculates the NPV of undertaking each potential LV upgrade over a 30-year period, using a discount rate of 2.75%. It identifies a total of 1,026 LV networks that it proposes to upgrade, being all such networks for which Powercor determines a positive NPV from this modelling.

672. Powercor bases its proposed solar enablement upgrade capex on undertaking these 1,026 LV upgrades within the next RCP.

6.3 EMCa assessment

6.3.1 Topics considered in our review

673. In our review, we have focused largely on Powercor's claimed economic benefits. Of the substantial amount of material that Powercor has provided, we have accepted the following

201 Powercor BUS 6.02 – Solar enablement, page 5

202 PAL ATT054 – Jacobs – Market benefits for solar enablement (15 August 2019)

either as reasonable for the purpose of advising on this component of Powercor's expenditure allowance, or we have considered it to be not directly relevant to the assessment:

- **Stakeholder engagement:** We acknowledge Powercor's stakeholder engagement process and the feedback that Powercor obtained through this process. Our observation is that Powercor appears to have considered the options that it presented for consultation as mutually exclusive, leading it to the view that its solar enablement program is the required solution. Over the 30-year period of Powercor's analysis, we consider it likely that some of the other options that it canvassed may also be adopted and may act to mitigate the need for the proposed program.
- **PV uptake assumptions:** We have not investigated these beyond the scope of supporting document that Powercor provided.[203] This appears to be a reasonable and independent source for the value that Powercor has adopted.
- **Market benefit value:** We have not investigated this beyond the scope of the supporting document that Powercor provided.[204] This appears to be a reasonable and well-founded source for the value that Powercor has adopted. In other information that Powercor has provided, it appears to contradict the advice that it was provided for this value. For example, Powercor compares the economic benefit value to a feed-in tariff calculated by ESC and claims from this that '*the value of DER that we have used is very conservative*.' While we have not analysed evidence other than what Powercor has provided, and have therefore not analysed the alternative values referred to, we do not see any indication in Powercor's consultant's report that would position its recommended value as a conservative estimate.
- **Modelling of voltage impacts of solar:** We have not investigated this beyond the supporting description that Powercor provides.[205] We consider that the description of load flow modelling in association with the forecast solar uptake rate and Powercor's AMI data on its network at the individual customer level, is likely to have provided a reasonable basis for such estimation.

674. We have noted Powercor's descriptions of its obligation under the Electricity Distribution Code, that *'….customers' voltages should not fall outside the range 216-253V for more than 1% of time as measured over one week*.'[206] Also, under its Distribution Licence, Powercor has an obligation to offer to connect solar[207] and therefore must manage resulting voltage excursions within the parameters of the Code.

675. In the remainder of our review of proposed augex, we have considered the following topics:

   1. Uncertainty inherent in the 30-year economic model that Powercor has used to support its augmentation program;
   2. The relationship that Powercor has claimed, between the 30-year economic assessment horizon and the economic life used for depreciating LV network assets (including transformers);
   3. Factors that could lead to the proposed augmentation program being overstated; and
   4. Powercor's assessment of the appropriate timing of each proposed augmentation, including its justification for this taking place within the current RCP.

676. In our assessment of Powercor's proposed opex step change, we consider Powercor's estimated volume of required tapping and its assumed unit cost for this.

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[203] PAL ATT 004: Report by Oakley Greenwood

[204] PAL ATT055: Report by Jacobs

[205] For example, in section B.1.3 of its business case (PAL BUS 6.02)

[206] Response to Powercor IR044, page 1. This in turn references section 4.1 of version 11 of the Code

[207] Ibid, page 2

6.3.2 Guiding principles for our review

677. As the use of distribution networks changes, for example through increased distributed generation from consumer-level solar uptake, it is reasonable to expect the networks to adapt to assist with accommodating these changes. In assessing the reasonableness of the proposed program, we have been guided by two principles:

- **Proportionality:** We observe that Powercor is typically seeking to be able to accommodate between around 50 and 100 PV customers on each LV network. At Powercor's proposed LV augmentation cost averaging around $57,000 for each such upgrade, this represents a network upgrade investment of around $600 to $1,200 per customer. This is not an insubstantial amount compared with customers' own PV installation costs. This demonstrates the need to ensure that lower-cost solutions are exhausted, and that each augmentation is individually justified, before proceeding; and
- **Timeliness:** LV upgrades are relatively granular and can be undertaken relatively quickly, when they are required. This makes it possible to undertake augmentations when they are required as measured by information at the time. There is no reason to undertake such investments before they are needed, based on anticipation alone.

678. We consider that principles such as these will guide towards the most appropriate actions being taken at the appropriate time to help accommodate distributed solar and to enable customers to achieve the benefits of their own investments.

6.3.3 Review of Powercor's justification for proposed augex

Analysis period

Powercor has not adequately considered the uncertainty inherent in seeking to justify capex based on a 30-year analysis of assumed PV export benefits

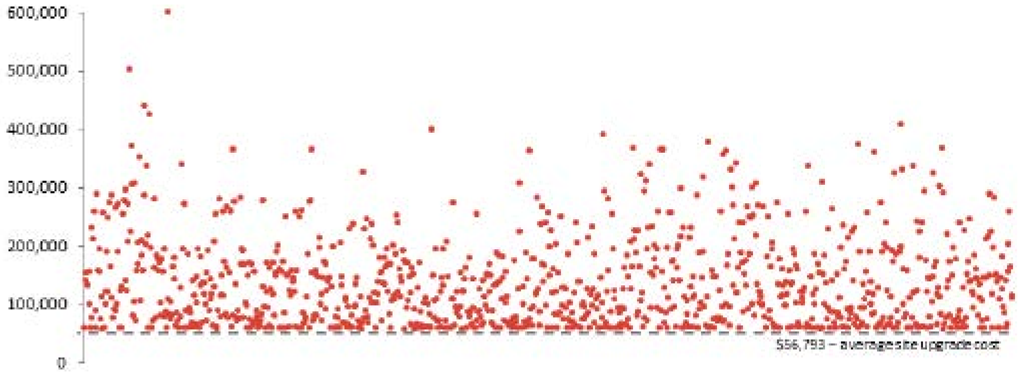
679. Whilst we consider that modelling of both tripped export volumes and individual upgrade economics at the level of granularity that Powercor has undertaken is a useful approach, we have significant concerns with aspects of this modelling and therefore with the conclusions that Powercor has drawn from it.

680. Our primary concern is with Powercor seeking to justify the proposed expenditure based on modelling over a period of 30 years and with its assumption that the benefits will be as Powercor has currently estimated over this period.[208] With a low real discount rate of 2.75%, the model outcomes are highly sensitive to the assumed benefits well into the future, and specifically to their continuation at the level that Powercor has assumed out to 2051/52.

681. It is evident from Powercor's representation of the NPVs of the 1,026 individual LV network augmentations that comprise the augex component of its program, that a large number of these augmentations have a only a marginally positive NPV under Powercor's analysis, as can be seen in Figure 6.2 below

[208] Powercor models these benefits specifically for 13 years to 2033/34, but then assumes that those benefits continue at the modelled 2033/34 level, until 2051/52.

Figure 6.2: Powercor's representation of the NPV of its proposed 1,026 LV augmentations - $2020

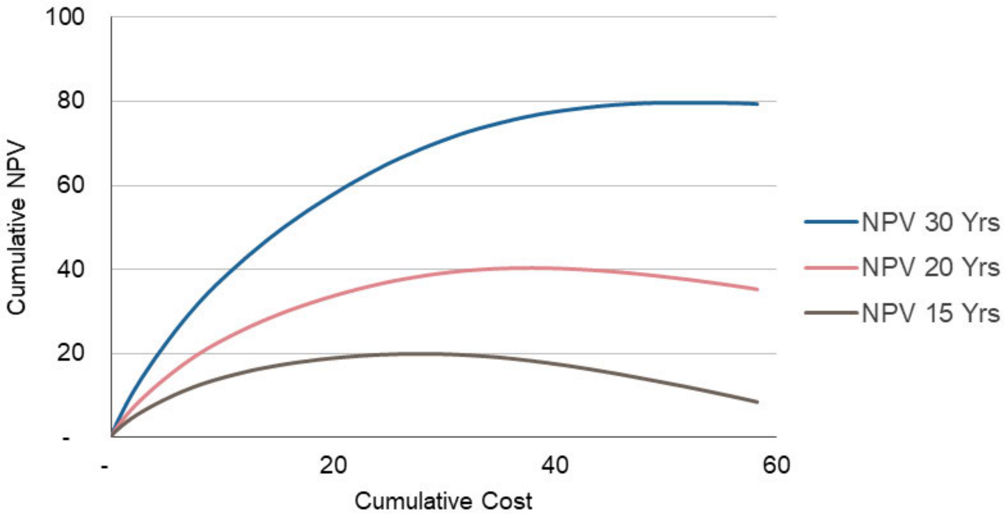


Source: Powercor BUS 6.02, Figure 11. (The Y axis is the PV of benefits for each proposed upgrade)

682. In Figure 6.3 below, the top line shows the cumulative NPV of each of the 1,026 LV augmentations that Powercor has proposed, ordered with the highest NPV augmentations first, based on Powercor's analysis. There a clearly decreasing marginal benefit. Our analysis indicates that 90% of the aggregate NPV of the program would be achieved from a program of only half the size of that proposed.

683. We then tested for the sensitivity of Powercor's result to the time period considered. The lower two lines in Figure 6.3 show the implication of adopting 20-year and 15-year horizons, respectively, for the analysis. With analysis over only 15 years, on the plausible assumption that forecasting beyond that time is too uncertain, only around half of the proposed augmentations would have a positive NPV. The remainder of the augmentations would have a negative NPV and so will reduce from the NPV of the aggregate program if all upgrades were undertaken.

Figure 6.3: Cumulative NPV of the proposed 1,026 LV augmentations, over different analysis horizons - $millions



Source: EMCa analysis from Powercor MOD 6.02

684. We consider it inevitable, given the transformation of the energy sector that PV is itself part of, that assumed benefits out to 30 years will be very different from even the best possible estimates made now. We observe that Powercor adopts a 20-year horizon in the economic analysis that it has put forward to justify its augex for general load growth, and which would typically be seen as more amenable to forecasting. We consider that seeking to justify a solar enablement augex investment based on a 30-year analysis is, at best ambitious, given uncertainties such as:

- The challenges of forecasting the PV uptake rate and the market benefit value over such a 30-year timeframe;
- The strong possibility of technology providing new solutions to managing voltage at some stage over the 30-year timeframe, at a lower cost;
- The likelihood of significant further changes affecting demand patterns and demand and voltage fluctuation rates at the LV level, including batteries and EV uptake, at some stage over the 30-year timeframe;
- More refined and more dynamic definitions of the operating envelope for solar exports and how these can be cost-effectively managed; and
- The reasonable likelihood of implementing other measures such as those Powercor canvassed with customers, including changes to tariff structures and possible further compliance requirements, within the timeframe.

685. It is challenging to build such unknowns into a forecast. However, we consider that it is essential to recognise the uncertainties in interpreting and seeking to act on the results of numerical analysis involving such a long period and to recognise the marginal viability of a significant proportion of the upgrades that Powercor has proposed.

We refute Powercor's claim that use of a shorter NPV analysis period would imply a position that use of solar would decrease

686. Powercor has provided further information in its IR responses, relevant to the question of the NPV time-period and uncertainty. We address these points here.

687. Powercor states that '…*If the AER seeks to reduce the NPV due to the uncertainty of DER in the future under our modelling approach, the AER would need to conclude that the use of solar will decrease in the future, not only that solar exports will decrease.*'[209] We refute this statement – it is not axiomatic that adopting an NPV analysis period shorter than Powercor has proposed implies a view that the use of solar will decrease. We have described above why it would be reasonable to adopt a shorter analysis period than Powercor has adopted. None of these reasons rely on an assumption of decreased solar.

We do not accept Powercor's argument that the NPV analysis period must equal the depreciation life of the relevant asset

688. In any situation that involves decision making under uncertainty, there is an option value to deferment. This implicitly recognises that a decision made today (including a decision not to augment) is not necessarily the decision that will be indicated at every point in future, but that the decision will be better informed and, therefore, if it can be reasonably delayed, a better-justified decision is likely with lower chance of regret. While a decision to augment now may not be justified, there may be a time when a decision to augment is clearly indicated at some time in the future. Equally, there may be a time when, for whatever reason, it becomes clear that a decision to augment is unlikely ever to be justified, because alternative and preferred options have arisen with time, or the need has changed.

689. Powercor asserts that '….*if the AER considers network assets to enable solar only offer benefits over a shorter period, in accordance with the Rules it must depreciate these assets over a shorter life*.'[210] Powercor has then extended this argument to suggest that the shortened depreciation period would lead to higher network prices resulting from its SE program.[211]

690. In its response, Powercor reproduces Clause 6.5.5 of the NER in part as follows:

> *(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements; and*

209 Response to Powercor IR044, 3 July 2020, response to question 7

210 Ibid, page 11

211 Ibid, page 12

(a) (1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.

691. We consider that Powercor has misrepresented this clause, the purpose of which is to define a basis for establishing depreciation schedules. It does not prescribe how economic analysis to justify an investment should be undertaken.

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

693. Regulatory depreciation schedules relate to the economic life of an asset, irrespective of the time horizon or any aspects of the decision made in deciding whether (for example) to augment or replace an existing asset. We consider it both incorrect and something of an ambit claim for Powercor to suggest that by using a shorter timeframe in cost benefit analysis to justify augmentation, it would be necessary to apply shorter regulatory depreciation lives for the relevant assets and that this would therefore result in higher prices to consumers.

Assumptions and Sensitivity analysis

We refute Powercor's claim that sensitivity analysis is unnecessary

694. In response to an IR, Powercor states that it has '…*not undertaken formal sensitivity analysis…*'. Powercor then explains that its model is '…*insensitive to augmentation cost – if the augmentation cost increases/decreases then the number of transformers than(sic) meet the economic test conversely decreases / increases*.'[212]

695. This seems to be a direct statement that the resulting number of justified upgrades is in fact sensitive to the augmentation cost, which is as we expect and as we find in the model, while noting the higher cost per upgrade. In fact, we find that the program is highly sensitive to this cost. By inspection of Powercor's scatter graph in Figure 6.2, it can be seen that raising the cost by 10% would render the large number of marginally-positive NPV augmentations negative. Inspection of Figure 6.3 similarly shows the significant number of transformer upgrades (as measured along the X axis) that would not meet a 10% lower NPV threshold, such as would result from a higher unit cost per LV upgrade.

696. Particularly, with a forecast over 30 years, all assumptions and all aspects of Powercor's forecast have varying degrees of uncertainty. We consider that some factors have significant uncertainty and that the results are sensitive to the assumptions made for those factors. Powercor's case is weakened by the lack of such sensitivity analysis, and by its claims that this is unnecessary.

Powercor has not justified its claim that its assumptions are conservative

697. Powercor claims to have been '*very conservative in valuing the benefits of* (its) *solar enablement program'*.[213] In presenting this claim:

- Powercor states that it considers that the value of DER that it has used is conservative; yet this value is as recommended by Powercor's advisor – Jacobs. Jacobs' report does not position this as a 'conservative' value and it appears disingenuous for Powercor to

212 Powercor's repose to IR027, question 5, page 3

213 Powercor presentation to AER and EMCa, 1st June 2020 (page 63). The points that Powercor makes on that presentation page are a precis of points made in its response to Powercor IR044 – Solar Enablement, question 7

suggest that its advisor has not provided it with a reasonable estimate, especially given that Powercor has used it as such;

- Powercor states that '…*varying the value of DER in our model would only serve to expand the program.*'[214] Powercor seems to have taken the position that it would not undertake a symmetrical sensitivity analysis;
- Powercor has assumed 100% compliance with new converter settings. This appears to us a reasonable assumption to make; it should not be for Powercor to assume responsibility for undertaking augmentation investment, which brings costs to all consumers, in order to redress non-compliance by another party; and
- Powercor states that it '*has not valued additional customer benefits from solar including retail and wholesale arbitrage opportunities, wholesale market support, transmission and distribution congestion management*.'[215] These are general claimed benefits of solar and their link to Powercor's proposed augmentations is tenuous. Powercor's case is based on addressing voltage issues and the occasional limit that this can place on solar exports in a small proportion of its LV networks at some point in the future. To take factors such as these into account, Powercor would need to be able to demonstrate a counterfactual 'lost opportunity' and the extent to which it is remedied by its proposed program.

698. Against these points, we consider that there are other aspects of its modelling that could be considered to overstate the case. Examples could include enhanced operational solutions, the possibility that increased solar does depress wholesale prices at the times that it provides export (just as it has significantly reduced the shape of middle-of-the-day demand profiles), future technology solutions, and the inherent uncertainties in forecasts (such as PV uptake, for example).

699. In summary, we consider that there are various alternative assumptions, some positive and some negative, that could be applied and for which analysis results could be stress tested.

We refute Powercor's claim that there is not a material risk of 'stranded' investment

700. If the LV augex investments are made as proposed by Powercor, many of these have only a marginal net benefit on a 30-year analysis basis with Powercor's assumptions. For reasons that we have stated above, we consider that there is a material risk that the assumed 30-year benefits could be less than Powercor has assumed. With so many of the augmentations being economically marginal, it would take only a small decrease in a 'benefit' assumption or a foreshortening of the benefits stream, for all of those with only a marginally positive NPV to return a negative NPV, resulting in a 'regret' outcome where the augmentation was not justified.

701. Powercor has claimed that '…*the augmentations we have proposed will become net benefit positive well before the time shown in the model and before 30 years*', also that it has '…*already implicitly factored in uncertainty*' through '*conservative modelling*'.[216]

702. As we have shown in Figure 6.3, when we adopt a shorter analysis period, a large number of the proposed augmentations have a negative NPV. We also do not accept the proposition that uncertainty is accounted for by Powercor adopting conservative assumptions. Even if conservative assumptions have been adopted, there is a range of techniques available for modelling such analysis under uncertainty, with sensitivity analysis and scenario analysis being two of the more basic techniques that can be applied.

703. If solar enablement augmentations are 'justified' on the basis of assumptions forecast over 30-years, without proper consideration of the uncertainties of what will arise over this period, then we consider that there is a material risk of those augmentation investments turning out to have not been required.

214 Response to Powercor IR044 – Solar Enablement, page 9

215 Powercor presentation to AER and EMCa, 1st June 2020 (page 63)

216 Ibid

Time profile and justification within the next RCP

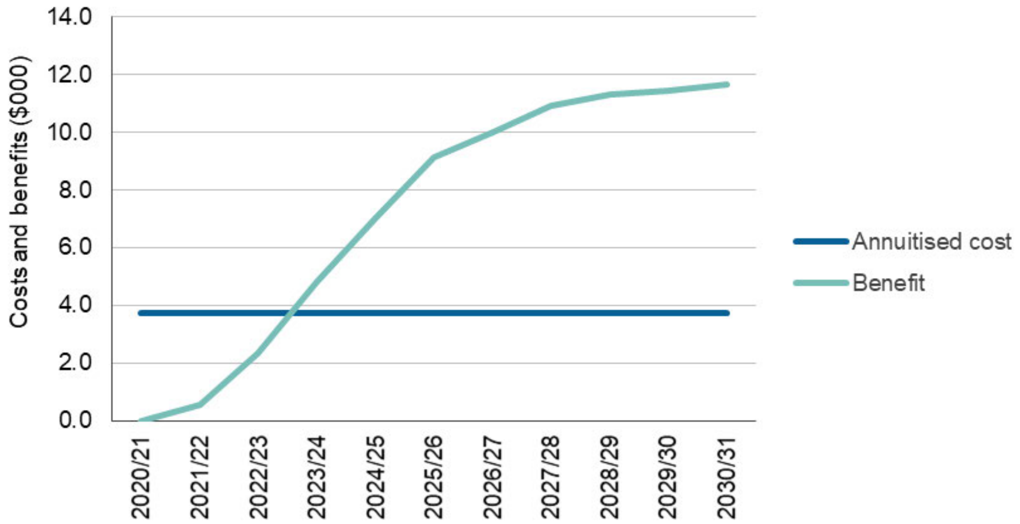
Powercor has misapplied analysis to forecast the time profile of its expenditure

704. For its solar enablement analysis, Powercor has sought to determine a time-profile for its proposed augmentation expenditure based on the year (for each of the 1,026 proposed LV augmentations) when its CBA model first produces a positive NPV. This is erroneous, and also inconsistent with the method that Powercor has applied in seeking to determine the appropriate timing for other augex. The approach that Powercor has applied for its proposed solar enablement augmentations has the effect of bringing forward augmentations when they are still uneconomic, but which in Powercor's analysis have a positive NPV only because their forecast of distant future positive net benefits is offsetting the still negative net benefits within the RCP.

705. We consider the correct approach is to identify when the annual benefits exceed the annual cost, in this case (in the absence of incremental opex) being represented by the annuitised cost of the upgrade being considered. There is no benefit in undertaking such augmentations before this time. Examples of where Powercor has applied this approach are illustrated in Figure 5.5 and Figure 5.9 and for other augex projects in that section.

706. In Figure 6.4, we show an example of this methodology applied to a specific LV transformer from Powercor's solar enablement analysis. In this case, it indicates that an upgrade would be warranted in 2022/23, based on Powercor's benefit assumptions including its forecast PV uptake rate for customers connected to that transformer.

Figure 6.4: Annuitised cost and modelled benefits for one of Powercor's proposed LV upgrades[217]



Source: EMCa analysis from PAL MOD 6.02. The upgrade cost in this example is annuitized over 20 years.

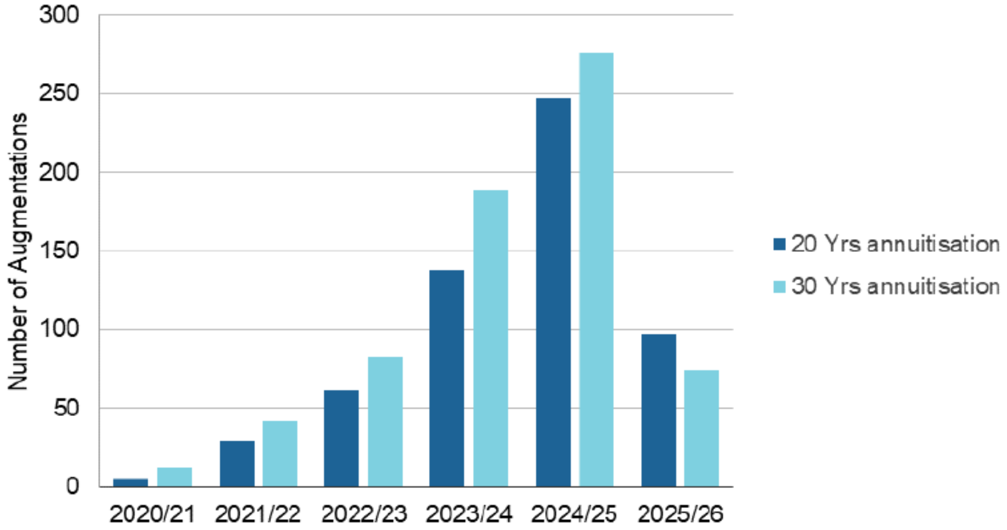
707. When we apply this method to all 1,026 of Powercor's proposed augmentations, we find a profile of augmentations as shown in Figure 6.5. We have undertaken this analysis with augmentation costs annuitised over 30 years, as per Powercor's assumptions, and an alternative forecast in which the cost is annuitised over 20 years.

708. Only a small number of augmentations are indicated for the early years, which is as we would expect given Powercor's relatively low current PV penetration and its evidence of a relatively small number of PQ issues. If the uptake rate and other benefit assumptions are as Powercor has forecast, our analysis suggests an increasing trend of augmentations at least to 2024/25. However, our analysis also shows that under Powercor's cost and benefit assumptions, only 662 of its proposed 1,026 augmentations would be viable. Further, if a

[217] The modelled transformer in this example has Powercor's designated ID 19883068-014

20-year annuitisation period is adopted (consistent with Powercor's non-DER augex justification approach), then only 572 augmentations would be viable within the next RCP.

Figure 6.5: Augmentation profile indicated by identifying year when benefits exceed costs



Source: EMCa analysis from PAL MOD 6.02

Table 6.3: Implied annual expenditure profile based on indicated timing for each transformer - $m, 2020

	2021/22	2022/23	2023/24	2024/25	2025/26	TOTAL
20 Yrs annuitisation	1.6	3.5	7.8	14.0	5.5	32.5
30 Yrs annuitisation	2.4	4.7	10.7	15.7	4.2	37.6

Source: EMCa analysis from PAL MOD 6.02

709. We note that the analysis above considers the proposed augmentations solely from the point of view of timing both within the next RCP and beyond. It does not supplant our consideration also of assumptions and uncertainties as described in the preceding subsections.

710. When compared with Powercor's proposed expenditure from Table 6.1, this analysis suggests that, from a timing perspective alone, between around one-half and two-thirds of the proposed augmentations would be justified within the next RCP. Moreover, unlike the relatively flat expenditure profile that Powercor has proposed, the expenditure would be heavily weighted towards the middle to later years of the RCP. This is advantageous from a decision-making perspective, as it means the expenditure can be incurred where and when real-time evidence indicates that it is needed and not in anticipation of a need that may or may not arise for a particular LV network.

6.3.4 Findings and implications on proposed augex

A smaller program of LV augmentations is likely to be required within Powercor's package of solar enablement measures

711. In the context of significant uncertainty, we observe that even from Powercor's modelling over 90% of the estimated benefits would be achieved from a program that involves only addressing the top 50% of LV augmentations, if ranked in order of descending NPV. This rapid fall-off in incremental benefit with increasing scale of the proposed project can be seen in Figure 6.3. It is also evident in the large number of projects with an NPV close to the X axis as shown in Powercor's own diagram in Figure 6.2.

712. We are struck by the scale of Powercor's proposed program, with 1,026 LV upgrades proposed from 2021/22 to 2025/26, relative to only 37 similar upgrades that it undertook in the three years 2016 to 2018.[218] While we understand that the need 'accelerates' with increasing PV penetration on a given LV network, this is nevertheless a massive increase.

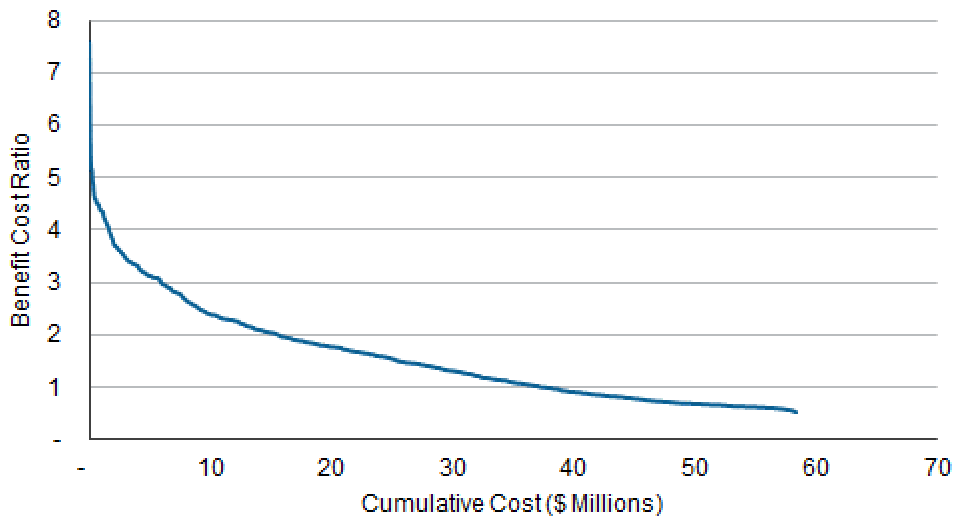
713. We also observe the current relatively low PV penetration rate of 18% on the Powercor network, compared to, for example, a rate of around 30% in Queensland. Victoria also has a lower solar insolation rate than Queensland. Powercor's forecast of (now) a 29% penetration by 2025/26 would seem to provide the opportunity for Powercor to compare what it proposes with what Queensland DNSPs have already done.

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

A program of around 250 to 450 upgrades over the next period would represent a significant increase over Powercor's current activity and still provide significant solar enablement benefit

715. As an indication, we have re-expressed the Powercor cost benefit analysis in terms of Benefit/Cost ratio (B/C ratio) with a 20-year horizon. A B/C ratio of one reflects the threshold for a positive NPV. Given the uncertainties, even with a 20-year analysis, we consider that a prudent allowance would be to assume a threshold B/C ratio around 1.5 to 2.0 and allow expenditure sufficient for projects that appear to exceed this threshold.

Figure 6.6: Ranked Benefit/Cost ratio of 1,026 LV upgrades (20-year analysis)



Source: EMCa analysis from PAL MOD 6.02

716. This would imply reasonable justification for a program involving around 25% to 45% of the augex that Powercor has proposed. This would represent around 250 to 450 LV augmentations over the period, which is a considerable increase over the 37 such upgrades that Powercor undertook from 2016 to 2018.

218 PAL MOD 6.02, tab 'Aug cost'

6.3.5 Review of Powercor's justification for enhanced operational initiatives and proposed opex step

Indications of current PQ issues

Customer feedback does not indicate a systemic PQ issue with Powercor's LV network

717. Whilst Powercor reports that 75% of customers support network investment and 'modernising' the grid with new technologies, it also reports that:[219]

> *'our residential customers are generally satisfied with our existing reliability and power quality levels…'*

718. Despite Powercor reporting an increase in voltage-related enquiries over the last four financial years, Powercor's information suggest that about 800 complaints were made in 2018/19, from its total of over 800,000 customers. We note that this was over a period when its PQ expenditure was also decreasing. While there may be localised pockets with voltage-related issues, there does not appear to be widespread customer dissatisfaction with power quality.

Tapping program

Powercor's strategy of exploiting the benefits of tapping before applying network solutions is appropriate

719. Manually tapping distribution transformers is a recognised technique for responding to changes in voltages in the LV network over time. It is already a technique Powercor applies to deal with PQ issues. It is a relatively coarse, manual adjustment and it does not provide a dynamic response to voltage changes over the course of a day (i.e., with varying net load demand from customers and with varying levels of distributed generation). However, it is a relatively inexpensive means of improving the hosting capacity of an LV feeder or section of feeder. We therefore endorse Powercor's proposed strategy of employing manual tapping of distribution transformers.

Powercor's estimated volume of tapping is likely to be reasonable

720. Powercor's modelling of the opportunity for voltage profile adjustment using tap changing results in a forecast of 2,292 manual tap changes in the next RCP. The proposed number of tap changes is highest in 2023/24 (562) and lowest in 2024/25 (387).[220]

721. This profile is counterintuitive given that we would expect voltage rise issues to increase over time, at an increasing rate, with increasing PV penetration levels. However, we understand that Powercor's model is based on identifying localised constraints and this may explain why the year in which the model predicts the highest number of extra tap changes being required is followed by the year in which the lowest number is required.

722. We assume that this program represents the total number of tap changes that can be proactively made to increase hosting capacity in the next RCP. This means that it supplants the number of tap changes currently made under its complaints-driven power quality program discussed in section 6.3.5.[221]

723. Given that we consider Powercor's modelling of voltage rises and constraints to be a reasonable approach, we consider that it is likely that the number of tap changes that can be applied in the next RCP to increase PV hosting capacity is likely to be a reasonable estimate.

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[219] Powercor Regulatory Proposal, p71

[220] PAL MOD 6.02 – Enabling solar

[221] We asked Powercor to provide the annual number of tap changes it has made in response to voltage issues in the current RCP under its PQ program but it advised that it does not capture this information separately (Powercor response to IR044)

Powercor's unit cost for tapping appears to be relatively high

724. Powercor has based its unit cost on information from CitiPower (2018). It is appropriate for Powercor to apply recent revealed costs if the revealed costs are demonstrably efficient. However, at $1,995 per unit, Powercor's unit cost is significantly higher than United Energy's $1,563/unit[222] and AusNet Services' $865/unit.[223] We are not aware of any reasons to explain the significantly higher unit cost at CitiPower/Powercor.

725. In our view, Powercor's unit cost is unjustifiably high. From the AusNet comparison, we consider that expenditure commensurate with a unit cost under $1,000 per unit would represent an efficient level.

Monitoring and compliance program

Powercor's monitoring and compliance program as proposed is not a justified step change

726. Powercor has a right to require a consumer to only connect inverters that are compliant with its MSO and AS4777. If it appears that an inverter is not compliant, Powercor is within its rights to require the customer to rectify the non-compliance. Powercor proposes to spend $340k over the next RCP to establish and maintain a monitoring program, plus a further $890k over the next RCP to address instances of non-compliance.[224]

727. We are satisfied that if a non-compliance is detected, correction of the settings is likely to be a relatively cost-effective means of helping to limit the effects of PV export voltage rise. We are <u>not</u> convinced that Powercor:

- has explored cost effective options for proactively ensuring installers apply the correct inverter settings;
- has explored cost effective options for identifying and addressing non-compliances; and
- requires a separate program to its business-as-usual Power Quality program (reactive rectification of PQ issues in response to customer complaints).

Links to Powercor's proposed ICT initiatives

Powercor's proposed DVMS is a prudent initiative

728. Powercor has included the introduction of a Dynamic Voltage Management System as an ICT initiative at an estimated capital cost of $2.5m. It provides the capability to '*remotely and dynamically adjust voltages at the zone substations, meaning we can lower voltages at peak solar times and then increase them again later.*'[225]

729. We support this initiative and consider that the cost estimate is likely to be reasonable, for the following reasons:

- A DVMS has recently been implemented within United Energy's network and, according to United Energy, has worked effectively to increase solar hosting capacity;[226] and
- Powercor has based its cost estimate on the United Energy revealed costs.[227]

We have considered the link to the Digital Network initiative in our ICT assessment

730. Powercor has noted linkages and dependencies between its Digital Network initiative[228] and its Solar Enablement program. Specifically:

222 UE MOD 6.02

223 AusNet Services response to IR049

224 PAL

225 PAL BUS 6.02, pages 21-22

226 UE BUS 6.02, page 21

227 PAL BUS 6.02, Appendix C, page 40

228 The business case for Digital Networks is included in UE's Information and Communication Technology (ICT) category

- in its modelling of constraints to PV export, Powercor assumes that solar connections will be balanced across phases; and
- Powercor also proposes in its Digital Networks business case '*building the foundations*' to dynamically control customers' PV system inverters, which requires what it calls a Distributed Energy Resource Management System (DERMS).[229]

731. We have considered these linkages in our assessment of Powercor's ICT expenditure forecast.

6.4 Implications to Powercor's proposed solar enablement augex and associated opex step change

732. Based on the information available to us at the time of preparing this report, we consider that Powercor has not sufficiently demonstrated that its proposed expenditure forecast for its solar enablement program is prudent and efficient.

733. We have identified a number of issues associated with the capital and operating expenditure proposed by Powercor in preparing the expenditure proposed to economically reduce the constraints on solar export in the next RCP.

734. We consider that:

- Powercor has not adequately considered the uncertainty inherent in its assumed benefit stream from mitigating solar export constraints over time, leading it to: (i) overstate the reasonably expected benefit; and therefore to (ii) overstate the reasonably justified extent of network augmentations;
- Powercor has appropriately identified introduction of a DVMS as a cost-effective means of increasing solar hosting capacity and we are satisfied that this cost is likely to be a reasonable estimate;
- Powercor has appropriately identified transformer tapping as a relatively inexpensive initiative to mitigate over-voltages prior to network augmentation – however, we are not satisfied that the unit cost of proposed tap changes has been adequately justified; and
- Powercor has appropriately identified rectifying non-compliant inverter settings as a sensible precursor to investing in transformer tapping or network augmentation – however, we are not satisfied that the proposed opex step change to reactively address non-compliant inverters at Powercor's expense is the most cost-effective approach.

229 PAL BUS 6.02 Solar enablement, page 18

7 REVIEW OF PROPOSED ICT EXPENDITURE

In this section, we present our assessment of forecast ICT capex for the next RCP and of Powercor's proposed opex step change for the migration of ICT infrastructure to the cloud.

Our assessment of the projects that the AER asked us to focus on leads us to conclude that, in each case, the proposed expenditure is likely to be overstated compared with the level of expenditure that a prudent and efficient operator would incur.

For non-recurrent expenditure projects, we found issues with the claimed benefits based on what we consider to be overstated assumptions, particularly given the uncertainty of the duration over which the benefits will be realised. We undertook sensitivity analyses with what we consider to be more reasonable assumptions. Based on that analysis, we conclude that there are several cases in which the proposed expenditure is unlikely to satisfy the capex criteria.

For recurrent expenditure (end-of-life driven replacement/upgrade projects), we find some cases in which Powercor has provided insufficient justification for the proposed level of expenditure.

We consider that the proposed opex step change to account for the increase in hosting charges resulting from the transition of ICT infrastructure to the cloud is reasonable.

7.1 Introduction

735. We reviewed the information provided by Powercor to support its proposed ICT forecast, including the business cases. Our focus is to ascertain the extent to which the issues identified in our assessment of Powercor's expenditure governance, management and ICT forecasting methodologies are evident at the project/activity level and to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

736. The AER identified two 'Focus' projects to us. We have included these projects in our assessment of the proposed ICT forecast, within the relevant category of expenditure as denoted below and in Table 7.2:[230]

- ICT infrastructure cloud migration ($25.2m capex and $5.9m opex step change);
- Network Management Systems ($19.9m).

737. Following discussion with AER, we also paid particular attention to the following additional projects:

- Customer enablement program ($8.1m capex);
- SAP S/4 HANA ($12.9m capex);
- Digital Network ($11.1m); and
- Intelligent Engineering ($4.4m).

[230] The expenditure amounts shown are the allocation to Powercor – the business cases consider total costs

738. Victoria Power Networks has a common ICT governance, management and forecasting approach that is applied to ICT programs and expenditures for Powercor and CitiPower. All of the Powercor ICT business cases are presented as joint CitiPower/Powercor business cases, with allocation of the total cost of the initiative to each entity in percentages that vary between projects. In some cases, the business case provided in support of the project includes the total expenditure applicable to CitiPower, Powercor and United Energy – again with apportionment of the total cost between the three entities. In the assessment of individual projects that follows (commencing in section 7.4), we identify which DNSPs share the total costs and the method of apportionment.

7.2 Summary of Powercor's proposed ICT expenditure

7.2.1 Overview

739. Powercor has proposed $165.8m for ICT capex for the next RCP, at an average annual expenditure of $33.2m. In the table below, we show ICT capex by RIN Category including real cost escalation.

Table 7.1: Powercor's ICT expenditure by RIN category- $m, real 2021

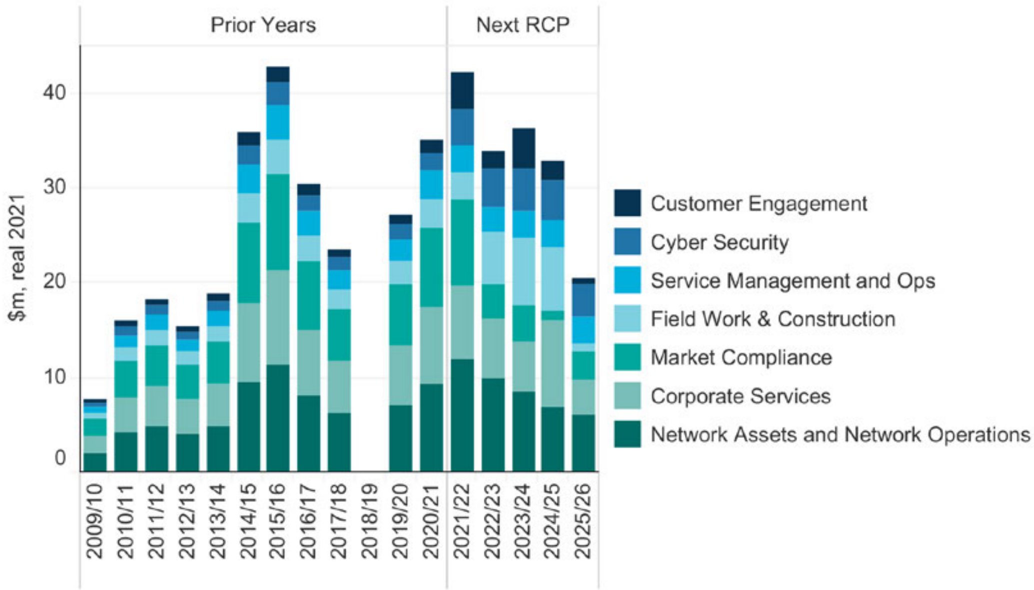
Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Corporate Services	7.8	6.3	5.4	9.1	3.7	32.3
Customer Engagement	3.9	1.8	4.3	1.9	0.6	12.5
Cyber Security	3.9	4.0	4.4	4.3	3.4	20.0
Field Work & Construction	2.7	5.5	7.2	6.7	0.7	22.9
Market Compliance	9.2	3.5	3.8	1.0	3.1	20.6
Network Assets and Network Operations	11.9	10.0	8.4	6.9	6.0	43.2
Service Management and Ops	2.7	2.8	2.8	2.9	2.9	14.1
Total	**42.1**	**34.0**	**36.4**	**32.8**	**20.5**	**165.8**

Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

7.2.2 ICT capex trend

740. ICT Capex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes Powercor's proposed real cost escalation.

Figure 7.1: Powercor's historical and forecast ICT capital expenditure - $m, real 2021



Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

7.2.3 Observations from ICT capex trend

741. The proposed ICT capex for the next RCP is an increase from the historical trend, with increases in several of the RIN categories.

7.2.4 ICT projects categorised as Recurrent / Non-recurrent

742. The table below shows the project-level expenditure according to the recurrent and non-recurrent expenditure classifications. This table excludes real cost escalation.

Table 7.2: Powercor's project-level expenditure allocated to Recurrent and Non-recurrent classifications - $m, real 2021

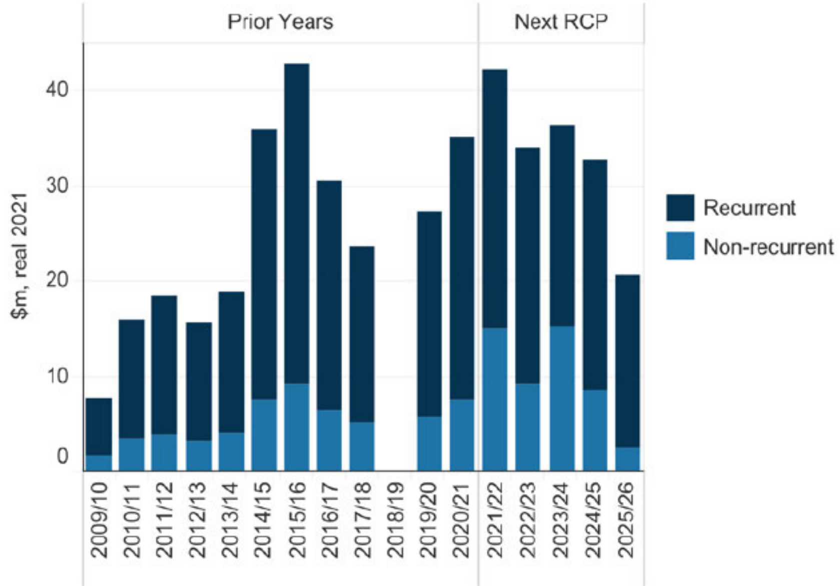
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**26.9**	**24.2**	**20.4**	**23.0**	**17.0**	**111.5**
Focus						
Infrastructure with Cloud migration	6.5	5.3	4.4	5.8	3.2	25.2
Network Management	5.3	4.9	1.4	4.0	4.4	19.9
Other						
BI/BW	0.1	1.6	0.5	0.1	0.1	2.5
Customer Enablement	0.3	0.8	1.9	0.3	0.3	3.7
Cyber security	2.7	2.8	3.0	2.9	2.3	13.5
Device replacement	2.7	2.7	2.7	2.7	2.7	13.6
Enterprise Management Systems - Non-SAP	3.3	2.0	1.4	3.4	0.3	10.4
Facilities' security	1.2	0.9	0.7	2.9	0.3	6.0
General compliance	0.9	0.9	0.9	0.9	0.9	4.6
Market Systems	1.0	0.9	2.7		1.9	6.5
SAP S/4HANA	0.4	0.7			0.4	1.6
Telephony	2.3	0.7	0.7		0.2	4.0
Non-recurrent	**14.7**	**8.9**	**14.6**	**8.1**	**2.2**	**48.5**
5 Minute Settlements	7.2	1.6	0.0	0.0	0.1	8.9
Customer Enablement	1.1	0.3	1.6	1.4		4.4
Cyber security	1.1	1.2	1.3	1.2	1.0	5.7
Digital network	2.8	3.2	3.1	0.9	1.2	11.1
Intelligent engineering		0.9	3.1	0.5		4.4
SAP S/4HANA		1.8	5.4	4.1		11.3
Solar enablement DVMS	2.6					2.6
Total	**41.6**	**33.1**	**34.9**	**31.1**	**19.2**	**160.0**

Source: EMCa analysis of Powercor MOD 7.01. Excludes real cost escalation

7.2.5 ICT Capex trend by Recurrent/Non-Recurrent expenditure classification

743. The trend of ICT capex by recurrent / non-recurrent expenditure classification is shown in the following chart. It shows that non-recurrent expenditure is a major contributor to the proposed uplift in ICT capex in the first four years of the next RCP. The reduced level of expenditure in 2025/26 results from the conclusion of most of the non-recurrent projects and tailing-off of recurrent expenditure in large projects such as Enterprise Management Systems and Facilities Security.

Figure 7.2: Expenditure by Recurrent/Non-Recurrent - $m, real 2021



Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'Powercor - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020' (Powercor also provided historical data in Workbook 2. That data is in calendar years. While Powercor claims that the Workbook 2 data reflects AER's new definitions, we observe that the ratio of recurrent to non-recurrent expenditure in Workbook 2 is identical to that presented under the old definitions, per Workbook 8, and is also identical for each historical year)

7.2.6 Proposed ICT opex step change

744. Powercor has proposed an opex step change associated with its cloud migration project. The corresponding expenditure is shown in the table below and includes real cost escalation.

Table 7.3: Powercor ICT – Related Opex step change - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
IT Cloud Solutions	0.9	0.9	1.2	1.5	1.5	5.9
Total	**0.9**	**0.9**	**1.2**	**1.5**	**1.5**	**5.9**

Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

7.3 Assessment of Powercor's ICT forecasting methods

745. Powercor and CitiPower's ICT forecasting methodologies are consistent. In this section we refer to Powercor only.

7.3.1 Overview of Powercor's ICT forecasting methodology

746. Powercor describes its forecasting approach for ICT capex to '*only invest in ICT when there is a clear benefit to customers.*'[231] We summarise the approach described in its Regulatory Proposal as having:

- Assessed whether the existing ICT capabilities and services are no longer providing value to customers;
- Examined '*synergy opportunities*' to align ICT systems with United Energy;
- Considered whether existing systems can withstand maturing and emerging cyber-security threats;

[231] Powercor, Regulatory Proposal 2021-2026, p101

- Forecast the efficient level of investment needed to retain the effectiveness and security of existing capabilities;
- Considered whether new technologies can address '*key business requirements*'; and
- Tested '*new projects with customers and other stakeholders to ensure we prioritised our investments in areas customers most value*'.

747. Powercor also describes that it has subjected the portfolio forecast to a top-down challenge:[232]

> *'We engaged PwC Australia (PwC) to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers'.*

748. To inform the selection of ICT investments, Powercor advised that it:[233]

- Applied a deterministic risk-based framework to '*help quantify whether a project risk outweighs its expected cost*', considering ICT risk and business risk using its risk monetisation approach; and
- Determined expenditure at a granular level, applying unit costs based on past projects of a similar scale and complexity, using external labour rates and known vendor costs, and seeking external validation.

749. Powercor's project delivery framework is described as comprising the common industry approach of initiation, scoping, design and execution phases with approval gates as milestones.[234]

Cost estimation methodology

750. Powercor describes its cost estimation methodology as follows:[235]

> *'cost estimates are developed by our internal project delivery leads who are SMEs for the group of systems. SMEs develop costs taking account of experience with historical projects of a similar nature, size, scale, scope and complexity.'*

751. The table below summarises the input parameters applied by Powercor in developing its cost estimates.

Table 7.4: Input parameters for ICT capital expenditure

Component of cost	Description
Labour rate	Blended IT labour rates developed by PWC. Cross-checked against internal aggregate labour rate. Labour resource is outsourced through our IT supplier panel and our IT resource partners selected through competitive tendering processes
Labour hours	Hour incurred for like projects of similar nature, size, scale, scope and complexity
Contracts	Vendor charges for like projects of similar size and complexity, or specific quotes where available
Materials	Current unit rates or supplier quotes

Source: Powercor response to IR023, question 16

232 Powercor, Regulatory Proposal 2021-2026, p102

233 Powercor, Regulatory Proposal 2021-2026, p102

234 Powercor, ATT007, p3

235 Powercor response to IR023, question 16

7.3.2 Assessment of Powercor's ICT forecasting methodology

752. Powercor's overall forecasting methodology, including its cost-estimation methodology, is reasonable. However, we observed issues with the application of the methodology to individual projects in some cases, particularly the assumptions underpinning the:

- claimed benefits; and
- its risk analyses.[236]

753. We also note apparent inconsistencies in product refresh strategies which lead in some cases to a seemingly high frequency of upgrades that are not adequately explained.

754. We discuss each of these concerns below and in our observations regarding the proposed expenditure in individual projects (starting with the Digital Networks project in section 7.4.2).

Benefits-modelling can be biased towards over-estimation of benefit streams

755. Powercor has obviously devoted considerable effort in modelling the costs and benefits associated with its benefits-driven ICT projects, such as Digital Networks, Customer Enablement, and Intelligent Engineering.

756. However, in our view, Powercor's modelling assumptions appear to be biased towards over-estimation of benefits. For example:

- Several critical input assumptions are hard coded and not adequately explained – such as the assumed number of Energy Easy portal users over the duration of the next RCP that will access the portal on average 4 times per year - the assumed benefit stream from reducing time spent by customers accessing the portal is very sensitive to these assumptions;
- In one case we consider the benefit estimation approach is fundamentally flawed; and
- In some cases, the duration of the benefits stream is too long and/or the required payback period is too long given the uncertainty of the durability of the benefits stream identified. In our view, a prudent operator would require faster payback of its investment than Powercor allows.

Risk monetisation methodology considers appropriate risks, but is of limited value for comparative analysis

757. Powercor applies its IT risk monetisation approach to quantify risk across four ICT risk categories and five business risk categories.[237] Again, Powercor has obviously devoted considerable effort to this modelling. However, whilst we typically see Powercor's assumptions leading to sharp discrimination between the 'do-nothing' counterfactual and the other options, there are relatively minor differences between the other options in its risk modelling. This renders Powercor's assessment of risk as an unhelpful tool for comparative analysis in many business cases.

Our top-down cross-checks of expenditure forecasts reveal apparent over-estimation in some cases

758. Powercor's cost estimation methodology is based on a '*bottom-up forecast approach taking account of their experience providing projects of similar nature, size, scale and complexity*.[238] Powercor refers to specific vendor quotes (when available) and labour rates that have been determined by PwC. This is consistent with industry practice with one exception – where there is a declining cost trend, this does not appear to be reflected in the forecast. An example is the cost of data storage. Based on our experience, most storage technologies have exhibited strong unit price declines over the last 5 years and may reasonably be expected to continue to do so. In these cases, we consider that Powercor

236 Such as non-compliance, business productivity impacts through system failure

237 Powercor Regulatory Proposal, page 104

238 Powercor response to IR023, question 7

should provide more detail about its cost assumptions, referring to the historical price trend(s) and explaining, more explicitly, the basis of its cost estimate for forecasting purposes.

7.4 Assessment of selected non-recurrent capex business cases

7.4.1 Overview of proposed non-recurrent capex

759. Powercor proposes spending $48.5m over the next RCP on non-recurrent ICT capex, comprising seven projects as shown in the table below.

Table 7.5: Powercor's proposed non-recurrent projects for the next RCP - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
5 Minute Settlements	7.2	1.6	0.0	0.0	0.1	8.9
Customer Enablement	1.1	0.3	1.6	1.4		4.4
Cyber security	1.1	1.2	1.3	1.2	1.0	5.7
Digital network	2.8	3.2	3.1	0.9	1.2	11.1
Intelligent engineering		0.9	3.1	0.5		4.4
SAP S/4HANA		1.8	5.4	4.1		11.3
Solar enablement DVMS	2.6					2.6
Total	**14.7**	**8.9**	**14.6**	**8.1**	**2.2**	**48.5**

Source: EMCa analysis of Powercor MOD 7.01. Excludes real cost escalation

760. We provide our assessment of four of the seven projects in the following sections, noting that the 5-Minute Settlements expenditure is discussed in section 7.6.1 and the proposed expenditure for solar enablement is discussed in section 6, including Powercor's proposed solar enablement augex and related proposal for an opex step change.

7.4.2 Digital Network

Overview of the proposed project

761. The Digital Network project is common to CitiPower and Powercor. The capital costs are allocated equally to CitiPower and Powercor. Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Stated need/project driver

762. VPN advises that this program is part of its response to changing customer requirements, which require it to develop greater visibility of its low voltage network, including to facilitate increasing penetration of solar PV and electric vehicles.

763. From the project, VPN proposes implementing '*more sophisticated analytical, monitoring and management capabilities in order to run the network more dynamically in real time.*' [239] This includes extending its coverage of Advanced Metering Infrastructure (AMI) network devices to large customers and unmetered supply in a targeted rollout, so that it can '*further*

239 PAL BUS 7.08, p4

improve safety, defer capital expenditure, enable better demand management, provide supply compliance and reduce customer complaints.'[240]

Options considered by VPN

764. VPN has considered three options:

- Option 0 - Baseline – '*continue utilising AMI data through existing technology and receive base level of benefits*';
- Option 1 - Digital network technology – '*invest in new technology that provides greater network monitoring and control capabilities*'; and
- Option 2 - Technology plus targeted rollout of network devices – '*in addition to rolling out Option 1 technology, increase the current coverage of network devices to improve LV visibility.'*.

765. The preferred Option 2 for this project requires a forecast $22.2m capex in the next RCP. VPN proposes to absorb the associated operating expenditure, '*given the importance of the project.*'[241]

766. The preferred option was selected due to the higher NPV ($141m for Option 2 vs $104m for Option 1, excluding operating expenditure) and a strong IRR (30.6% vs $28.7%, excluding operating expenditure) derived from application of its modelling.

Composition of the proposed expenditure

767. There are eleven components to the capex required for the Digital Network project, with the forecast amounts to be incurred in the next RCP as shown in the table below. Most of these components require capex for systems refresh in the subsequent regulatory control periods and significant operating expenditure.

Table 7.6: Overview of digital network technological capabilities and capex for the next RCP - $m, real 2021[242]

Area	Capability	Capex (2021-2026)
Data	Real-time data platform	2.1
	IoT platform for Network Sensors	5.1
	IoT platform for customer sensors	1.2
	LV model extension	3.2
Analytics	Real-time grid analytics platform	2.1
	Real-time LV power flow analysis	1.1
Monitoring	Real-time grid monitoring and control	2.2
	LV management capability	1.0
	Dynamic forecasting capability	1.1
	DER – monitoring capability	1.1
Automation	DER automation	1.1
Total		**21.3**

Source: PAL BUS 7.08 Digital Network, Table 4, p15. Excludes real cost escalation.

240 PAL BUS 7.08, p16

241 PAL BUS 7.08, p6, CP BUS 7.08, p6

242 Costs are total costs for CitiPower and Powercor.

Our assessment

There are interdependencies with the Solar Enablement project

768. The Solar Enablement and Digital Network projects are complementary but address different needs. VPN's Digital Network program as proposed will:[243]

- Assist with balancing solar PV systems across phases;
- Enable real-time visibility of voltage rises on the network; and
- Provide full LV network visibility, including the conductor type on every location of our network, '*ensuring we only undertake works where it is efficient to do so (as modelled).'*

769. We have considered these aspects of VPN's proposed Digital Networks project in our assessment of VPN's Solar enablement project, while being cognisant of our findings as presented in this section.

Most of the benefits may be able to be realised without real-time data and processing capabilities

770. VPN has identified four sources of tangible benefits:[244]

- Optimising load control – optimising existing customer load control and enabling new load control programs such as air conditioners and pool pumps;
- Promoting electric vehicle uptake - monitor and optimise electric vehicle charging;
- Enhancing cost reflective pricing - use existing and future AMI interval data to construct more effective time-of-use tariffs or demand management; and
- Detecting electricity theft - identify bypass connections and unregistered DER.

771. The table below summarises VPN's estimate of the NPVs of the benefit streams provided by its Digital network project. The NPV analysis is undertaken over a 20 year period.

Table 7.7: VPN's estimate of NPVs for benefit streams - Digital Network project - $m, real 2021[245]

Benefit category	Sub-category	PV Benefit Option 1	PV Benefit Option 2
Customer load monitoring and optimisation	MVA incremental reduction	59.2	61.7
	Unconstrained DER exports	19.9	19.9
EV charging optimisation	Reduced augex	46.1	46.1
	Capacity savings for public EV charging infrastructure	0.0	27.6
	Capacity savings for commercial EV sites	0.0	6.1
Cost reflective pricing	Summer Saver program	10.6	14.3
Reduction in non-technical losses	Theft reduction	3.6	6.7
	Value of un-recorded UMS	0.0	2.8
Total		**139.4**	**185.2**

Source: PAL MOD 7.13

243 PAL BUS 7.08, pp22-23

244 PAL BUS 7.08, p5

245 Benefits are total benefits for CitiPower and Powercor

772. VPN describes its benefits streams as all being dependent on the availability of a real-time data platform and, depending on the benefit, a real-time grid analytics platform and real-time monitoring and control.[246] Our understanding is that real-time data cannot be achieved from the exiting AMI devices without significant additional investment to the level being proposed by VPN. AMI devices currently provide ‘near’ real time data. Also, VPN does not have devices in the LV networks that are remotely controllable, to provide the claimed ‘real-time control’ capability. We therefore assume that for the next RCP, only load control of customer appliances is likely to be possible. Therefore, what would be delivered with VPN’s proposed program will not be access to real-time data or real-time control functionality. Furthermore, as discussed below, we do not consider that real-time control is required to extract the majority of the proposed benefits.

773. Regardless of whether real-time data is available cost-effectively, it is our view that VPN has not made a sufficiently strong case for real-time data or real-time control in support of its proposed enhanced capabilities, or for its proposed forecast capex as shown in Table 7.6. Our reasoning is as follows:

- **Customer load monitoring and optimisation** – VPN describes the benefit as being derived from: (i) optimising existing hot water load control; (ii) enabling new load control programs on an opt-in basis to reduce the peak or shift loads to periods of low demand; which will (iii) reduce the need for network augmentation. Whilst the proposed new analytical capability as a part of VPN’s Digital networks proposal may assist with ‘optimising existing hot water load control,’ our understanding of Powercor’s analysis is that the benefit derives from adding more load control customers. VPN states that the technical capabilities (and therefore the cost) from all eleven components of its Digital Network initiative denoted in Table 7.6 are required to enable the benefit stream. Whilst we consider that there is likely to be merit in improving energy management at residential and commercial premises:
  - we do not consider that real-time data is required to extract this benefit and therefore we do not consider that the costs proposed by VPN are fully justified; and
  - some of the benefits may be able to be achieved through a combination of price signals (such as through tariff reform) and 3rd party providers rather than solely through actions by VPN;
- **EV charging optimisation -** VPN describes the benefit as being derived from: (i) monitoring EV charging to understand the impact on the distribution network, and from this information; (ii) designing tariffs to encourage charging at non-peak periods; which will (iii) enable deferment of network augmentation. We do not consider that EV tariff design requires real-time data. We consider that the benefits can be achieved without the proposed level of expenditure;
- **Cost-reflective pricing** – VPN describes the benefit as being derived from: (i) extracting more insights about load and customer behaviour and better identifying network constraints; which will in turn (ii) enable it to develop more effective tariffs and voluntary demand management programs (and extend their coverage); which will in turn (iii) enable deferment of network augmentation. We note that United Energy has successfully applied its Summer Saver program without real-time data and we see no reason why Powercor cannot also do so. In short, we do not consider that tariff design requires real-time data; and
- **Reduction in non-technical losses** – the Option 1 level of benefit is said by VPN to be achieved by utilising Digital Network technology with its AMI data to allow it to more precisely monitor network usage and to detect electricity theft and other unallocated network losses. The extra benefits from Option 2 are to be derived from installing more network devices to large customers and unmetered supplies. VPN has not provided any evidence to support its estimate of benefits and, without such evidence, we consider the benefit claim to be optimistic given that existing AMI data should provide sufficient information for economically minimising electricity theft from the majority of

[246] PAL BUS 7.08, Table 6, p20

premises. In short, we do not see a strong case from reduction in non-technical losses to support the proposed new capabilities,[247] or the extra monitoring devices.

Our sensitivity analysis suggests net benefits are marginal

774. The table below shows the NPV over the 20 year study period in the VPN cost-benefit model for the three options considered by VPN.

Table 7.8: VPN options analysis: NPV - $m, real 2021[248]

Option	PV[249] Cost	PV Benefit	NPV
0. Baseline – 'continue utilising AMI data through existing technology and receive base level of benefits	0	0	0
1. Introduction of Digital Network (and Baseline for relevant Initiatives)	-80.4	139.4	59.0
2. Increased Coverage of AMI Devices	-114.5	185.2	70.7

Source: PAL MOD 7.13

775. VPN's model shows positive cash flows occurring from 2026 for its preferred Option 2. However, its analysis does not include opex (presumably because it proposes to absorb the costs). As seen from the table above, opex is a significant component of the total cost. When Powercor's calculation of opex is taken into account, the cumulative benefits do not exceed cumulative costs until 2030 which, even then, is due primarily to the assumed strong benefits stream from 2031 onwards. In our view, there is significant uncertainty in the benefits streams continuing as forecast beyond 5-10 years.

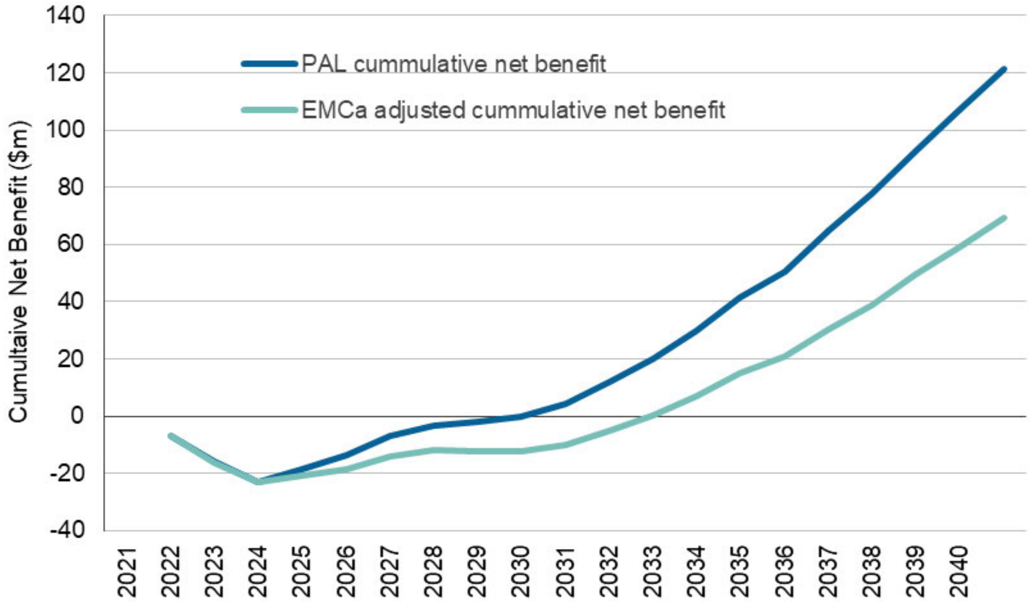
776. In the absence of a sensitivity analysis from VPN, we used its model to examine the impacts of lower benefits and higher costs. The figure below shows that with a modest 10% reduction in benefits and a 10% increase in costs, positive cash flows will not occur until 2033. This relies heavily on high benefits in the back-end of the 20-year study period. Alternatively, reducing the study period to a more reasonable 10 years due to the uncertainty of the benefits streams and asset stranding risks means that a positive NPV is unlikely to be achieved.

247 Real-time data platform, IoT platform for network sensors, IoT platform extension for customer sensors per Table 6 in PAL BUS 7.08

248 PV Costs include capex and opex for both CitiPower and Powercor. NPV Study period is 20 years.

249 PV Cost include capex and opex for both CitiPower and Powercor. The NPV analysis is for 20 years

Figure 7.3: VPN Option 2: Cumulative net benefit



Source: EMCa analysis of PAL MOD 7.13

Progressively extending visibility of the LV network may be prudent in the future

777. There is sufficient evidence that the future use of the LV electricity network is changing. It is increasingly likely that consumers will '*buy, trade, sell, and store electricity and participate in new service markets*.'[250] VPN quotes the AEMC as follows:

> *'The electricity system (especially at the distribution level) is increasingly likely to have multi-directional flows and become a platform to support different services, such as access to various markets, that future electricity system users may demand. The future electricity system and the regulatory framework need to be able to support these and potentially many other varieties of use.'*

778. Whilst extending the visibility of the LV network may be warranted in the future, VPN has not provided compelling evidence that such visibility is required in the next RCP in its business case.

Summary of our assessment

779. Our analysis suggests that the project as presented does not represent a prudent investment for Powercor. VPN has identified benefit sources from its proposed Digital Network project, but it has not justified the capex and opex as being required to achieve the majority of the identified benefits.

780. The majority of the expenditure for Options 1 and 2 is directed to establishing platforms to manage real time data and the extra analytical power to derive insights from the massively increased volume of data that this would bring. However, we consider that the majority of the benefits cited by Powercor, at least in the next RCP, can be derived without real time data.

781. Furthermore, the project NPV as claimed by VPN is strongly dependent on benefit streams continuing for 10-20 years. We consider that there is considerable uncertainty in these benefit streams beyond 5-10 years. Importantly, electric cars, smart devices and solar PV arrays are already internet connected, providing the opportunity for third parties to provide energy management services.

[250] PAL BUS 7.08, p13

782. Our position is not altered by VPN's commitment to absorb the operating expenditure. Based on our assessment, we consider that the absorption of opex by VPN is not an efficient long-term outcome for customers.

7.4.3 Customer enablement

783. The Customer Enablement project is common to CitiPower/Powercor. Powercor and CitiPower have allocated capital costs 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers).[251] Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Overview of VPN's proposed project

Stated need/ project driver

784. Approximately 130,000 of VPN's approximately 1.2 million residential, commercial, and business customers are registered users of VPN's portals and other tools used to access their data and information online. However:[252]

- its HV customers and embedded generators are not able to access the tools; and
- to access each application, customers need separate usernames and passwords, and need to learn to use each tool differently.

785. VPN's recent research indicates that of the 5,000 customers it surveyed, more than 80% '*supported investment in easier access to data and sharing of more data that can help them make informed energy choices.*'[253]

Options considered by VPN

786. VPN has considered three options:[254]

- Option 0 – Do nothing;
- Option 1 - One-stop-shop portal and enhanced customer experience - *unify the tools on a compatible Salesforce platform, extend the tools to HV customers and embedded generators, improve: online capabilities, outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports*; and
- Option 2 - One-stop-shop with enhanced customer experience and near real-time data — *option 1 plus providing customers access to 15-minute interval usage data on a new phone application, as well as 4-hour data updates on the myEnergy portal*'.

787. VPN recommends Option 2 at a cost of $11.6m capex. It will provide a '*one-stop-shop with enhanced customer experience and near real-time data*'[255] to achieve the following:

- improved and consolidated customer-facing access tools;
- provide more effective SMS notifications during outages;
- introduce SMS notifications on the efficiency of customers' rooftop solar output and exports;
- extend tools to HV customers and embedded generators; and
- give customers access to more frequent data to better inform their energy choices.

251 PAL BUS 7.02, p19

252 PAL BUS 7.02, p4

253 PAL BUS 7.02, p4

254 PAL BUS 7.02, Table 1, p5

255 PAL BUS 7.02, p19

788. Although it is the highest-cost option, VPN has selected it on the basis that '*it offers the highest customer benefits that outweigh the efficient cost of delivering them*,'[256] and has a higher NPV.

789. The cost attributable to Powercor is $8.1m with the balance of $3.5 allocated to CitiPower.[257]

Claimed tangible benefits

790. The table below shows the sources and quantum of benefits claimed by VPN from improving customer information and access to the information. The only material difference between Options 1 and 2 is that, for Option 2, customers are '*expected to save even more time and effort with access to near real-time data on a mobile application, by not having to access and log into the online portal to get the updates.*'[258]

Table 7.9: VPN's estimate of customer and operational benefits - $m, real 2021[259]

Source	Description of benefit	Saving p.a.	Benefit ($m p.a.)
Customer time saved	Reduced time spent on calls to enquiries line	61,013 min	0.02
	Reduced time spent on accessing data	7,775,232 min	2.08
	Reduced time spent on website and accessing various portals	6,443,808 min	1.73
	Embedded generators' reduced time on application forms	44,280 min	0.03
	Reduced time on investigating incorrect SMS notifications	500,000 min	0.13
	Time saved from preventing fault calls	124,234 min	0.03
Operational benefits	Reduced calls to contact centre staff	5 FTE	0.44
	Reduced staff required to process manual generator requests	0 FTE	0.00
	Estimated total average annual savings[260]	**Option 1** **Option 2**	**1.12** **1.85**

Source: EMCa analysis of PAL MOD 7.21

Claimed NPV of costs and benefits for 2021-2031 period

791. The table below summarises VPN's cost-benefit analysis.

256 PAL BUS 7.02, p19

257 PAL BUS 7.02, Table 12

258 PAL BUS 7.02, p18

259 The Costs are total costs for CitiPower and Powercor. The profile of benefits varies over time and differs between Options 1 and 2 - the estimated total average annual savings are averages of the benefits over the 10-year study period

260 The profile of benefits varies over time and differ between Options 1 and 2 - the estimated total average annual savings are averages of the benefits over the 10 years study period

Table 7.10: Summary of VPN's cost-benefit analysis - $m, real 2021

Option	PV Cost	PV Benefit	NPV
0. Do nothing	0	0	0
1. One-stop-shop portal and enhanced customer experience - unify the tools on a compatible Salesforce platform, extend the tools to HV customers and embedded generators, improve: online capabilities, outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports	-12.7	16.1	3.3
2. One-stop-shop with enhanced customer experience and near real-time data — option 1 plus providing customers access to 15-minute interval usage data on a new phone application, as well as 4-hour data updates on the myEnergy portal'	-15.4	26.3	10.9

Source: PAL MOD 7.21

Our assessment

Most of the benefits are derived from only three sources

792. Based on its interpretation of customer survey results, VPN proposes spending $11.6m in the next RCP and a further $5.8m over the following five years to provide eight customer service enhancements. VPN estimates the customer enablement project will reap a net economic benefit of $10.9m over 10 years. However, the claimed benefits are derived in the main from three initiatives. For all three initiatives, we have fundamental concerns about the claimed benefits as discussed below.

Alternatives to VPN's proposed mobile app may erode assumed benefits

793. VPN proposes $2.0m incremental capex in the next RCP for providing near real-time data[261] on a mobile phone app on the assumption that:[262]

- customers are likely to be '*more engaged and incentivised to monitor their usage data'* on a mobile phone application; and
- retailers and third parties (with customers' permission) can easily link and integrate the application into their applications and products, reducing their costs of developing the application and reducing long-term costs to consumers.

794. It is not clear to us why VPN should be developing mobile phone apps when solar/battery energy systems manufacturers and suppliers already provide mobile apps. These mobile apps allow customers to monitor their energy use in near real time. With the right price signals from tariff changes (mooted as part of the Digital network business case), customers may demand more information for their own analysis. Alternatively, they may choose to contract with their retailer or a third party for that real-time information or for those parties to optimise their energy production and use for maximum customer benefit.

795. Consequently, in our view, the benefits claimed by Powercor in its business case may already be captured by 'competitors' or may be eroded quite quickly by competitors who have more to gain in offering their customers this type of service.

796. It is our view that speculative investment by VPN for customer-focused 'added services', that would be underwritten by customers through the RP process, is not consistent with the expenditure criteria in the NER.

261 VPN proposes that myEnergy data will be refreshed every 4 hours and AMI data will be refreshed every 15 minutes

262 PAL BUS 7.02, p18

Benefits calculations are biased by unreasonable assumptions

797. VPN's approach to estimating most of its benefits is to determine how many customers are likely to be impacted (positively) by its improved portal and other offerings, by deriving:

- time savings for VPN customers – using $0.268 as the value of a saved customer minute; and
- operational benefits to VPN from reduced call centre activity as a result of reduced customer calls.

798. VPN also uses several key parameters sourced from its historical records, such as the number of calls to the call-centre, the average duration of a call and number of embedded generator connections per year. However, these numbers are hard-coded in its cost-benefit model. The underlying data is not provided so we cannot easily verify it.

799. Of much greater concern to us is Powercor's assumption regarding the number of customers that will register to use its 'easy access' tools.[263] Its two largest benefit streams are derived from reduced customer time to access its portals. Powercor forecasts that, when combined with CitiPower, it will have an average of 1,295,872 customers over the next RCP and assumes that an average of 50% of these customers (647,936) will be registered portal users during the whole of the next RCP:

- to calculate the benefit of 'Reduced time spent on accessing data', VPN further assumes that all 647,936 registered users will access the portal four times per year and each will spend an average of 3 minutes logging-in/accessing the portal;
- to calculate the benefit of 'Reduced time on website and accessing portals', VPN assumes that 100% of the assumed registered users (i.e., 647,936) will avoid 4 minutes of wasted time per year; and
- it assumes that there is no overlap in these two benefit streams.

800. We consider these assumptions are unreasonable for the following reasons:

- the current number of registered users is 135,800[264] and it has taken four years to achieve this number.[265] We consider it unreasonable to assume that the average number of registered users will increase five-fold to an average of 647,936 over the next RCP;[266] and
- we consider it very unlikely that the claimed benefits from the two benefit streams discussed above are mutually independent – that is, we expect that the benefits derived from providing the mobile app (to reduce time spent on accessing data) will reduce the benefit from 'Reduced time on website and accessing portals' to be achieved by 'website artificial intelligence' and by removing multiple log-ins and navigation.

Using more reasonable user registration numbers renders the project uneconomic

801. The figure below shows that the NPV is very sensitive to the assumed number of users as this is the key parameter in deriving the two largest benefits streams. Without accounting for our concerns about the other factors that may impact the claimed net economic benefit, reducing the assumed registered users by 30% means the project does not achieve breakeven until the end of the 10-year study period. Factoring in lower benefits from the other sources would extend the payback period even further.

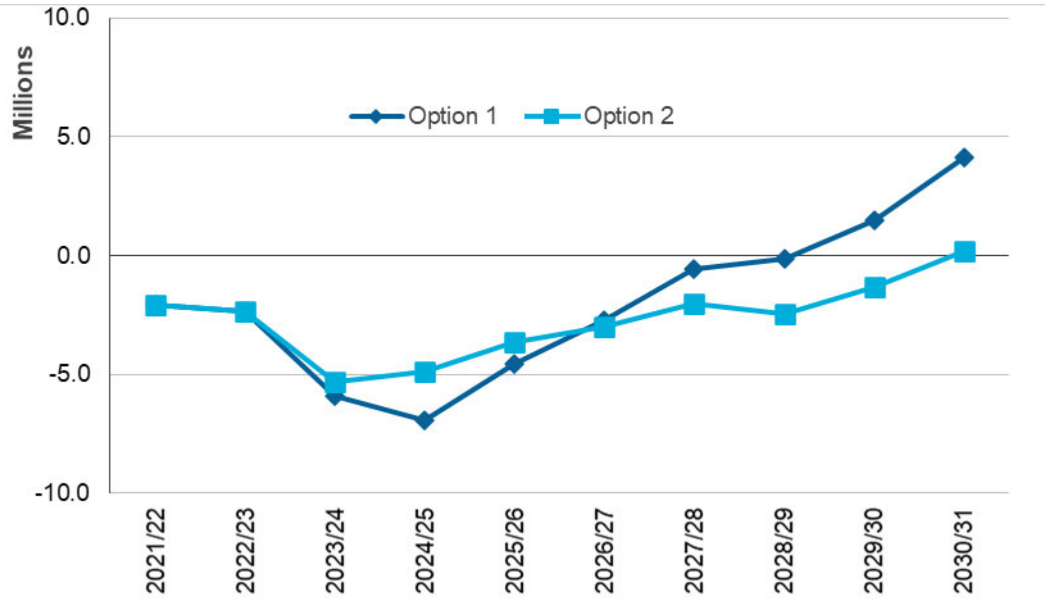
263 Which we understand from the business case PAL BUS 7.02 to include the myEnergy, mySupply, and eConnect portals

264 For myEnergy, mySupply and eConnect portals

265 Powercor BUS 7.02, p6

266 VPN hold this number constant at 647,936 throughout its 10 year study period

Figure 7.4: Cumulative net benefit - $m, real 2021



Source: EMCa analysis using PAL MOD 7.21 Note: NPV are totals for CitiPower and Powercor

Summary of our assessment

802. We have considered VPN's cost benefit analysis and consider that neither of Option 1 nor 2, as presented, are likely to be NPV positive when more reasonable assumptions are applied to the benefit streams.

803. VPN has not demonstrated a compelling case for seeking to provide as part of its preferred Option 2 a mobile app service for energy management and to recover the costs of this initiative from shared users as a regulated charge (particularly given the competitive threats to the assumed benefit stream). We consider this to be a speculative investment.

804. In responding to customer feedback, we see possible merit in delivering a subset of the proposed Option 1 features, including creating a unified access point (such as introducing contact centre AI), and improving the effectiveness of SMS notifications. We consider that these features are likely to address the core complaints from customers (as reported in Powercor's business case) at a significantly reduced cost. Powercor would still however need to demonstrate that there is a positive net economic benefit.

7.4.4 Intelligent engineering

805. The Intelligent Engineering project is common to CitiPower and Powercor. Capital costs are allocated on an equal share to Powercor and CitiPower. Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN.

Overview of the proposed project

806. VPN proposes to spend an estimated $8.9m in the next RCP to enhance its 'intelligent engineering capability' and to introduce a Dial Before You Dig (DBYD) mobile application to collectively *'reduce safety risks, reduce the cost of asset damage, deliver operational savings internally and to third parties, and ensure better asset information exchange with the Government and its stakeholders'*.[267] This is referred to as Option 2 by VPN.

Options considered by VPN

807. VPN has identified three options, as shown in the table below.

[267] PAL BUS 7.07, p3

Table 7.11: VPN options summary for Intelligent Engineering project - $m, real 2021

Option	PV capex	PV benefit	NPV
0 - Do Nothing - do not make any changes or improvements to GIS and asset data management	0	0	0
1 - Base intelligent engineering capability	10.6	19.3	8.7
2 - Base intelligent engineering capability plus DBYD mobile application	11.8	33.0	21.2

Source: PAL BUS 7.07

Our Assessment

The project drivers present a reasonable case for action

808. VPN advised that its Geospatial Information System (GIS) asset records are not aligned with the physical earth, or with Global Positioning System (GPS). It also notes that this mismatch can result in:[268]

- *'higher risk of safety incidents for our employees and third parties working around our underground assets (less accuracy in Dial Before You Dig data)*
- *higher cost of managing the network if assets are damaged accidently due to wrong coordinates*
- *inefficient management of works around and on our underground assets, by our employees and third parties, resulting in higher cost to our customers and those of third parties.'*

809. VPN further advised that:[269]

- as the Victorian Government aligns its assets to GDA2020[270] and improves its cadastre, the growing disparity between its asset records (held in the GIS) and the Government's will result in increasing safety risks and inefficiency; and
- its GIS has important links to several internal systems and to external data sources.

810. VPN also advised that the GIS limitations described above means it cannot provide accurate location information of underground assets. VPN therefore does not allow digging within 30 meters of the indicated location of its assets in its GIS (using the DBYD service), creating construction delays. Furthermore, the format of the DBYD advice can be difficult to interpret on a mobile device, leading to inconvenience and costs to parties working around its assets.[271]

811. VPN identified issues with its Map Insights platform[272] which relies on VPN's GIS data with overlays from the Victorian government cadastre and other external sources. VPN advised that '*Due to lack of accuracy between our GIS and other external mapping sources, we are unable to extend our platform to a wider range of stakeholders at present.'*[273]

812. On the basis of widening of data discrepancies between VPN's GIS asset records and external data systems we consider that there is a case for action. Moreover, the issues appear to be of such significance that there is a case for undertaking some of this work in the current RCP rather than waiting until the next RCP. However, in response to our

268 PAL BUS 7.07, p8

269 PAL BUS 7.07, p8

270 Australia's Geospatial Reference System

271 PAL BUS 7.07, p7

272 A mapping platform that allows our staff and third party contractors to visualise the detail and location of VPN's assets and the topology in relation to the asset's real-world location (PAL BUS 7.07, p7)

273 PAL BUS 7.07, p7

information request, Powercor advised that there is no work underway on this project in the current RCP.[274]

Our sensitivity analysis suggests the net benefits are likely to be achievable

813. VPN has proposed four initiatives to: (i) reduce safety risk and the costs of asset damage; (ii) improve operational efficiency (for VPN and third parties); and (iii) improve asset information exchange with stakeholders. The initiatives comprise:

1. introducing a master data management system;
2. conflating its GIS records to the physical earth;
3. enhancing Map Insights platform; and
4. improving DBYD accuracy and access to information.

814. The benefits are inter-related, with VPN identifying lower customer costs [$3.0m pa] from:

- the time saved from fewer delayed projects [$180k pa];[275] and
- the time saved from having a mobile DBYD app [$2.8m p.a.]:

815. The operational benefits total $4.9m p.a. and are all related to VPN savings.[276]

816. VPN assumes these benefits will persist for the ten-year study period. In our opinion, the benefit quantification approach is reasonable, but the assumptions underpinning the savings are not substantiated.

817. Given the somewhat speculative nature of the benefit assumptions underpinning VPN's NPV results, we consider it prudent to undertake a sensitivity analysis. VPN did not provide sensitivity analysis results, nor the facility to do so directly in its model.

818. Nonetheless, we have used VPN's model to undertake our own sensitivity analysis, the results of which are shown in the figure below. The NPV is positive for Option 2 even with a 50% reduction in claimed benefits (and Option 1 is marginally NPV negative) over the 10 year study period.

819. On this basis: (i) a positive net benefit for the project with a reasonable IRR is likely to be achievable, noting that a positive net cash flow is achieved in 2026/27 for most scenarios; and (ii) Option 2 (which captures the value of the mobile DBYD app) is preferable to Option 1 for all scenarios considered.

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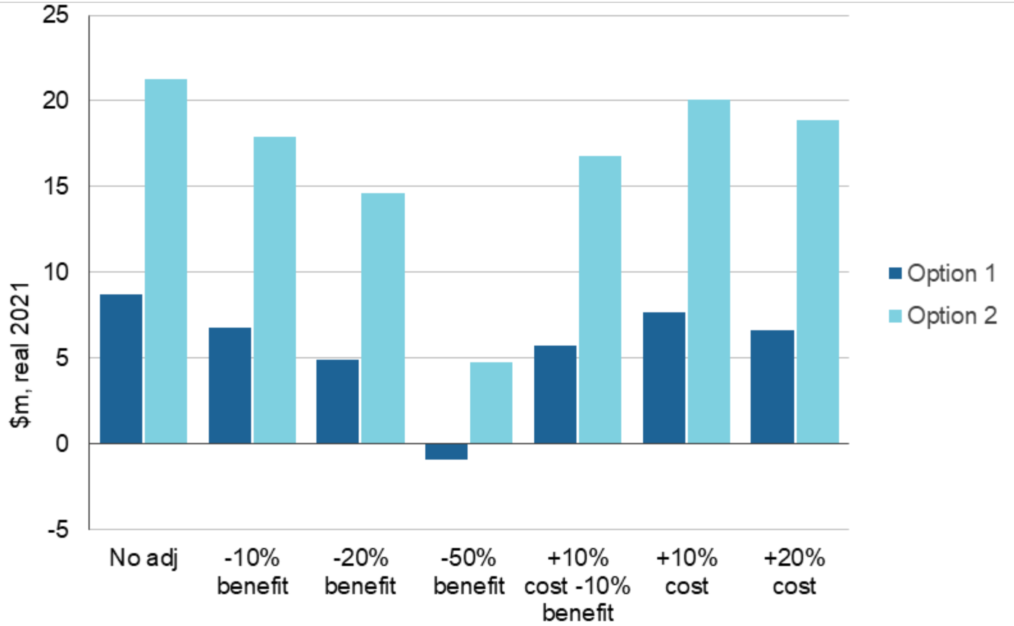
274 Powercor response to IR023, Table 4, p4

275 PAL MOD 7.11

276 PAL MOD 7.11

Figure 7.5: Sensitivity analysis of VPN NPV to project cost and benefits - $m, real 2021



Source: EMCa analysis of PAL MOD 7.11

VPN's proposed Option 2 is likely to maximise net benefits

820. As a further check on the prudency of Option 2, we asked Powercor to provide the separable portions of cost to help us identify whether there was merit in VPN proceeding with only the highest value aspects of its project, namely the DBYD mobile app and fewer on-site inspections.

821. Powercor's response[277] states that the program cost estimate was based on '*a program of works that is interdependent and optimally phased…'* and that if the program was not treated as an integrated package '*separate delivery of the initiatives would result in an approximate 30% increase in costs for independent project management and delivery.'*

822. Whilst the quantum of the extra project management and delivery costs seems high, we accept that the four program initiatives, as designed, work together to produce the customer and operational savings.

823. VPN also states that there are cost synergies with United Energy's equivalent project[278] and that those cost savings are already built into the VPN estimate, including via a phased implementation approach and alignment of initiatives.

VPN's cost estimating methodology is reasonable

824. We also asked Powercor to explain the basis for the unit costs and quantity of units used to build up the costs in its model. Powercor's response[279] explains the basis for its bottom-up estimates as a combination of: (i) blended IT labour rates developed by PWC, crossed checked with internal rates; (ii) labour hours incurred for similar/relevant projects; (iii) Vendor charges for like similar/relevant projects or quotes where available; and (iv) current unit rates or supplier quotes for material. We consider this methodology to be reasonable.

Summary of our assessment

825. Whilst we have concerns that the benefits claimed by VPN for its project may be overstated, we recognise that the current limitations with its GIS records are likely to have an increasing and cascading impact on safety risk and operational efficiency. We consider the four

277 Powercor's response to IR023, p8

278 Separately costed and discussed in UE BUS 7.07 at $5.4m

279 Powercor's response to IR023, p9

proposed initiatives have merit as a program of work. Even with claimed benefits reduced to 40% of VPN's claims, the NPV is positive.

826. Our analysis suggests that the project capex for VPN's Option 2 of $8.9m is likely to be prudent and reflective of an efficient level.

7.4.5 SAP Upgrade

827. The SAP upgrade project is common to Powercor, CitiPower and United Energy. Capital costs are allocated 25% to Powercor, 25% to CitiPower and 50% to United Energy. The project includes recurrent and non-recurrent expenditure for VPN/UE. Unless otherwise stated, our assessment is of costs and benefits attributable to the total costs to VPN/UE.

Overview of the proposed project

828. SAP Enterprise Resource Planning (ERP) software is used to run VPN's and UE's payroll, HR, finance, and network organisational asset management systems. The two 'instances' of the SAP ECC6 version will reach end-of-life support in 2025 based on the vendor's advice. The next available version is SAP S/4HANA.

829. The scope of the project covers the lifecycle upgrade of SAP. The recommended approach is to incur $51.5m capex on upgrading to SAP S/4HANA as a single integrated instance across VPN/UE (i.e., Option 3).

Options considered by VPN/UE

830. VPN/UE have identified five options for providing a '*stable, compliant and fit-for-purpose*'[280] ERP, as shown in the table below.

Table 7.12: VPN/UE's options summary - $m, real 2021[281]

Option	Description	Capex	Opex	Totex	NPV	Risk
0	Maintain two (VPN and UE) unsupported SAP ECC6 instances (do nothing)	0.0	0.0	0.0	0.0	414.8
1	Engage third party support for two SAP ECC6 instances	8.3	6.5	14.9	13.6	408.6
2	Upgrade to S/4HANA as two separate instances	60.0	0.0	60.0	55.1	29.2
3	Upgrade to S/4HANA as a single instance across VPN/UE	51.5	0.0	51.5	47.3	29.2
4	Replace two SAP ECC6 instances with a single instance of a new, non-SAP ERP solution	69.8	0.0	69.8	64.2	101.6

Source: EMCa version of Table 1 in PAL BUS 7.01, p4 with costs from PAL MOD 7.02;

Summary of VPN/UE's options analysis

831. The figure below presents a summary of VPN/UE's options analysis. The three dimensions that it considered are:[282]

- Leverage existing '*platforms before investing in new technology to minimise - Before implementing a new system, we first look whether leveraging existing platforms would minimise cost;*"
- Enterprise fit – '*investigate solutions with an enterprise-wide lens*'; and

280 PAL BUS 7.01, p4

281 Options 1-4 include costs for maintaining currency of SAP ECC6 in addition to the SAP S/4HANA upgrade. Costs are total costs for CitiPower, Powercor and United Energy

282 PAL BUS 7.01, p18

- Current and future needs – '*Solutions must be sustainable, scalable, and secure.'*

832. Whilst no description is provided in the Business Case, we assume that the traditional traffic light colours denote the degree of alignment of the option with the dimensions. The analysis is qualitative.

Figure 7.6: Summary of VPN/UE's initial SAP options analysis

Source: EMCa modification to PAL BUS 7.01, Table 5

VPN/UE preferred option

833. VPN/UE has chosen Option 3 because:[283]

- It avoids the significant risks and operational expenditure of options 0 and 4;
- Continues with direct SAP vendor support without disruption;
- It is the most affordable way to achieve and maintain a stable, compliant and fit-for-purpose ERP;
- It supports integration of the three businesses, allows new capabilities to be built, and simplifies future ERP maintenance and support needs; and
- It allows new capabilities to be built and simplifies future ERP maintenance and support needs.

Our assessment

The assessment criteria applied by VPN/UE are reasonable

834. VPN/UE has used a combination of quantitative and qualitative analysis to select the preferred Option 3. The qualitative assessment summarised in Figure 7.5 is supported by information in the business case and the dimensions considered provide a reasonable perspective on organisational fit.

835. VPN/UE have also applied a risk monetisation framework, to help distinguish between options and, to some extent, confirm the timing of the proposed project. It considers both IT impacts[284] and Business impacts.[285] Whilst we may not agree with all the assumptions at a level of detail, VPN/UE has put significant effort into the risk analysis and has included a sensitivity analysis. We consider that the risk dimensions and approach are both reasonable.

Options 0, 1 and 4 are inferior to Options 2 and 3

836. Option 0, do nothing, will not incur zero costs, as Powercor's business case indicates, and it is not consistent with good industry practice to operate the ERP of a large and complex business without support. Therefore, in its CBA, Powercor should not define the costs of options 1 to 3 relative to a zero base counterfactual.

837. Option 1 - engaging 3rd party support for the two SAP ECC6 instances - is a strategy that has been deployed by some large businesses, including United Energy (from 2017), as a

[283] PAL BUS 7.01, p28

[284] Outage, suitability, and system sustainability – as descr bed in Table 15, p31, PAL BUS 7.01

[285] Reliability, compliance risk, customer experience risk, safety risk, bushfire risk, and financial risk – as described in Table 15, pp 15-16, PAL BUS 7.01

means of reducing opex, deferring upgrade costs and reducing dependency on the OEM vendor. Powercor provides a comparison of the different reliability/stability performance between CitiPower/ Powercor and United Energy over the period 2017-2020. During this time, United Energy had over 15 times the volume of incidents.[286]

838. United Energy decided to return to an SAP-supported model in late 2018, however: '*…rectification of the contractual damage came at a far greater cost than any short term savings that had been realised.'*[287] VPN has used the SAP support model for its ERP. We concur that the risk of adopting Option 1 is unacceptably high, outweighing potential benefits.

839. We are also satisfied that deferring replacement of SAP ECCC6 beyond 2025 is unlikely to be prudent as:[288]

- There will be a decrease in the provision of system fixes and support packs through to 2025 from SAP;
- CitiPower/Powercor's ECC6 version of SAP will be 19 years old by the end of the next RCP and United Energy's version will be 17 years old at this time;
- Product divergence risk with a third party support service is high;
- Consequences of system failure are high and would be likely to offset any deferral benefits; and
- Compliance risk is transferred to the three DNSPs (from SAP).

840. Option 4, replacing ECC6 with a new non-SAP, Tier 1 enterprise software system as an alternative to SAP, would require *'… a full business transformation and rebuild solution interfaces…'*[289] We agree that the risks and cost involved in transitioning to an alternative product are unlikely to outweigh any potential benefits.

Upgrading to S4/HANA is likely to be the prudent approach

841. Based on our experience and the provided options analysis, upgrading from SAP ECC6 to SAP/4HANA within the next 5-7 years appears to be the prudent choice. To assist an assessment of the recommended option, we first considered the delivery risks associated with each option.

842. VPN/UE's assessment of delivery (or project) risks posed by Options 2 and 3 in the business case is superficial – it states only that there may be '*Unplanned system and process integration impacts*.'[290] Furthermore, whilst we are supportive of the risk assessment criteria and approach in its risk model (e.g., PAL MOD 7.03), it states in the model that: '*We assume an upgrade to S4 HANA (2 instances) will carry similar levels of risk as this option'*[291] where 'this option' is the single instance proposed in Option 3.

843. Based on our experience, unless VPN and UE create a unified set of business processes ahead of the project, unifying the platform will lead to significantly higher project risks due to sequencing, testing, data migration and integration. Without this, Option 3 represents a significantly more complex and higher risk project than Option 2 because:

- There is considerable effort, and therefore cost involved in merging the database and merging the business processes of multiple organisations (VPN and UE);
- The change management in merging to organisational business processes would be very large and have a high risk of disrupting both businesses – we estimate that VPN/UE's estimate of the risk cost of Option 3 of $29.2m may be higher than Option 2

[286] PAL BUS 7.01, Table 8, p21

[287] PAL BUS 7.01, p20

[288] PAL BUS 7.01, pp10-13

[289] PAL BUS 7.01, p25

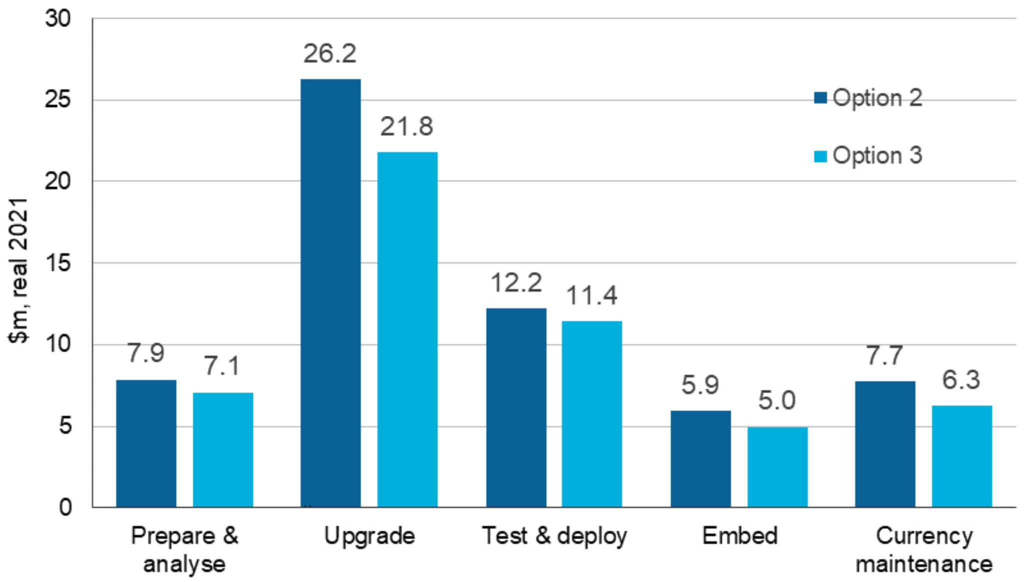
[290] PAL BUS 7.01, Table 11, p24

[291] PAL MOD 7.03,

as a result of the change management complexity, integration complexity and merged data migration.

844. With this in mind, we looked closely at the costs allowed for Options 2 and 3 for preparation versus the costs involved for establishing and maintaining two instances of SAP (Option 2) versus one instance (Option 3). The figure below shows the comparative cost estimates for various aspects of the work.

Figure 7.7: Comparison of VPN Option 2 and Option 3 cost assumptions - $m, real 2021



Source: EMCa analysis of PAL MOD 7.02

845. It is possible that VPN/UE has allowed for extra time/resources in its 'Prepare & analyse' cost estimate, given that the 'Prepare & analyse' cost for Option 3 is, at $7.1m, significant and comprises 35,000 hours of labour and $5.7m of materials and contracts.[292]

846. Overall, the $8.5m capex difference in favour of Option 3 compared to Option 2 is considerable. We consider that Option 3 remains preferable to Option 2. Furthermore, a single instance will require considerably lower opex running and support costs over time.

847. Based on: (i) the number of SAP modules; and (ii) the organisational business process complexity and migration from a legacy SAP platform to a modern SAP platform, an SAP implementation cost of $51.5m for a single instance as proposed for Option 3 is reasonable. Building two SAP instances will increase testing and integration costs. Given its complexity, we also consider the Option 2 cost of $60m to be reasonable.

Maintaining the currency of the two SAP instances during the transition period is prudent, however the cost seems unreasonably high

848. The business case allows for refreshes of the existing SAP ERP in 2021/22 and in 2022/23 at a total cost of $4.8m (9% of the project cost) across the two instances ($2.4m for VPN and $2.4m for United Energy). We consider that this could be reduced by 50% (or $2.4m) by refreshing the SAP ECC6 versions in 2022/23 or 2021/22, but not both. A further refresh of the single instance costing $1.4m in 2025/26 (i.e., immediately after the planned deployment) also seems excessive given the commissioning of the new instance will still likely be in its hypercare phase.

Summary of our assessment

849. VPN and UE have selected a reasonable range of options for dealing with the vendor advice that its current two instances of SAP ECC6 ERP software will not be supported from 2025.

292 PAL MOD 7.02

There is sufficient information provided in the business case, when combined with our experience, to conclude that upgrading to SAP S/4HANA within the next RCP (Option 3) is likely to be the prudent approach.

850. Our analysis suggests that refreshing the existing ERP in 2021/22 and 2022/23 is unlikely to be prudent – we consider that only one refresh (in 2022/23) prior to the 2024/25 go-live of the proposed upgraded ERP needs to be included in the proposed expenditure allowance and that this would represent an efficient cost estimate.

7.4.6 Cyber security

851. Powercor's business case provides the supporting information for the proposed expenditure for its cyber security improvement project for both CitiPower and Powercor. The project includes recurrent and non-recurrent expenditure for VPN. Cost is allocated 30% to CitiPower and 70% to Powercor. We have assessed both components in this section and unless stated otherwise, we refer to the combined expenditure for VPN.

Overview of the proposed project

852. VPN proposes $19.4m recurrent capex to maintain current levels of cybersecurity and non-recurrent capex of $8.2m to enhance its cyber security posture, for total capex in the next RCP of $27.5m. Its justification for the 'enhancement' capex is based on the consequences of a cyber security breach, which is potentially significant as explained below:[293]

- There have been cyber security breaches in the electricity sector (worldwide);
- The Australian Cyber Security Centre (ACSC) ranks the energy sector in the top four industries most at risk of a cyber-security threat;
- The Security of Critical Infrastructure Act 2018 (Cth) was developed in recognition of the evolving national security risks to infrastructure including electricity assets;
- Its self-assessment against the Australian Electricity Sector Cyber Security Framework (AESCSF) developed by industry and AEMO;
- Its regulatory obligations under the Australian Privacy Act 1988 which, among other things, requires VPN to take reasonable steps to protect personal information it holds; and
- It is ranked as one of VPN's top 10 risks on its risk register.

853. VPN considered four options in its cyber security business case, as summarised in the table below. VPN selected Option 2 with total capex of $27.5m, comprising $19.4m of non-recurrent expenditure and $8.2m of recurrent expenditure.[294]

Table 7.13: VPN's Cybersecurity options summary - $m, real 2021

Option	Cost	Risk
0 Do Nothing - do not invest in maintaining cyber security capabilities	0.0	183.1
1 Maintain Currency – maintain existing cyber security capabilities as is	19.4	58.6
2 Optimise Effectiveness – build on Option 1 by optimising the effectiveness of existing cyber security capabilities by increasing coverage	27.5	29.3
3 Expand Analytics Capability – build on Option 2 by expanding cyber security monitoring and behavioural analytics capabilities	39.4	15.5

Source: PAL BUS 7.04, Table 2, p14

293 Powercor RP, p95 and PAL BUS 7.04, pp6-9

294 PAL BUS 7.04, Table 8

Our assessment

Cybersecurity obligations do not yet apply to DNSPs

854. The AESCSF provides a consistent means for businesses to assess and improve cyber security maturity, but its use is currently voluntary. Whilst we understand that the intention is for mandatory maturity levels to be introduced into regulations, this has not yet been done.

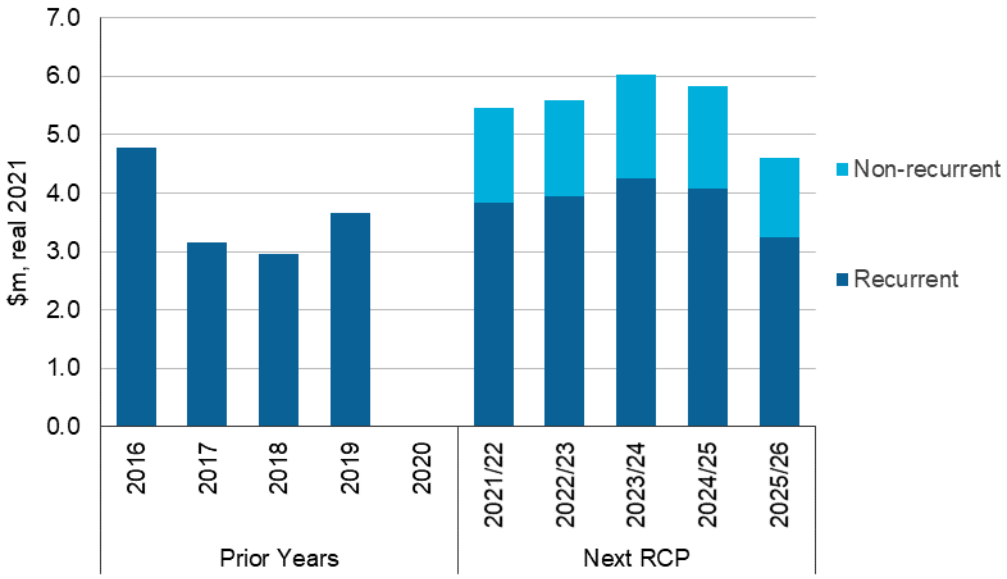
855. Nonetheless, given the escalating risk of cyber threats, which is evident from recent cyber-attacks in Australia,[295] a prudent distribution network operator should align its cyber security posture to align with the recommended MIL2/SP-2 level.[296]

VPN proposes a 6% increase in its recurrent cybersecurity capex

856. The figure below compares the historical cyber security recurrent capex with the forecast recurrent and non-recurrent cyber security capex for the next RCP. The 2020 amount has not been provided.

857. Based on the previous four years, Powercor proposes a 6% higher average annual recurrent capex in the next RCP or about $1m in total. VPN does not explain the basis for this uplift. Nonetheless, based on the level of detail provided in its cost model, we consider the recurrent capex estimate to be reasonable.

Figure 7.8: VPN's historical and proposed cybersecurity capex - $m, real 2021[297]



Source: EMCa analysis of Powercor's response to IR023 (Table 3) and PAL MOD 7.05

Options 0, 1, and 3 are not prudent approaches

858. Based on the information provided in the business case and our understanding of the cyber security landscape in Australia, Option 0 (Do nothing) and Option 1 (Maintain the current level of cyber security) would not align with the recommendations of government, AEMO's recommended position for DNSPs (discussed below) nor with VPN's cyber security risk exposure. In our view, a prudent operator would not pursue these options.

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295 E.g. refer to https://www.theguardian.com/australia-news/2020/jun/19/

296 Recent updates to the AESCSF framework (version 2019-8) incorporated Security Profiles (SP) in which distr bution electricity service providers are categorised as moderately critical per the Critical Assessment Tool and as such should achieve SP-2 level of security which is equivalent to the MIL2 standard

297 VPN provided actual for 2016 – 2019 based on calendar years (PAL IR0023) while 2021/22 – 2025/26 are based on financial years. We converted 2016 – 2019 into real $2021.

859. Option 3 provides enhanced ‘security monitoring and behavioural analytics’ in addition to the full scope of Option 2 (discussed below) to *‘uplift [VPN’s] ability to proactively detect and respond to cyber threats in particular to address the evolving nature of the tools, tactics, and procedures that cyber-attackers employ and the increasingly complex environment that our cyber security team monitors.’*[298] VPN concludes that Option 3 does not provide sufficient additional security benefits given the additional investment of $11.9m over 5 years.

860. In our view of the Options considered by VPN, we agree that Option 2 is preferable to Options 0, 1 and 3.

VPN’s outcome measured against the AESCSF maturity levels is reasonable

861. VPN’s business case is silent on what Maturity Indicator Level (MIL) it expects to achieve from the proposed Option 2 investment. We therefore asked Powercor to explain:

- What the proposed capex achieves in terms of the MIL and in terms of the 23 NIST[299] categories that underpin the five NIST functions per the AESCSF; and
- Where the proposed work program positions Powercor against the MIL/SPs following completion of the proposed capex program.

862. In summary, Powercor’s response is that: (i) it sought to ensure that it has ‘balanced coverage’ defined by the NIST functions and AESCSF domains; and (ii) it did not use the MIL/SP target as its primary driver and that it forecasts *a ‘MIL of around 2-2.3 at the end of the 2021-2026 regulatory control period.’* [300]

863. Based on the information provided and from our experience,[301] we consider that VPN’s approach to defining and costing Option 2 is reasonable in the context of the AESCSF framework (version 2019-8) suggested target of MIL2/SP-2. Restricting its cyber security measures to achieve exactly MIL2/SP-2 rather than slightly over 2 is likely to be sub-optimal.

Cybersecurity benefits from the rest of its ICT program are taken into account

864. It was not initially clear to us from its business case how VPN accounted for the cyber security benefits that derive from the rest of the ICT program (e.g., replacements and upgrades) to avoid double counting. In response to our information request, VPN advised that: [302]

> *’The main benefit of ensuring IT asset currency across our IT portfolio is that we have hardware and software that is ‘in support’ and can continue to receive security patches for known vulnerabilities within these assets.’.*

865. We are satisfied with this explanation and consider that the incremental expenditure proposed is unlikely to double count costs.

VPN’s cost estimate is reasonable

866. Based on our assessment of VPN’s cost estimation methodology, we are satisfied that the cost estimate for the proposed recurrent and non-recurrent expenditure is likely to be representative of an efficient level.

Summary of our assessment

867. VPN proposes $19.4m of recurrent capex and $8.2m of non-recurrent opex to be shared in the ratio 30:70 CitiPower/Powercor. Our assessment suggests that VPN’s recurrent and

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298 PAL BUS 7.04, p19

299 National Institute of Standards and Technology

300 Powercor response to IR023, question 15

301 Including from providing advice to Australian businesses in Australia and overseas, and from reviewing utilities’ cyber security expenditure and expenditure forecasts

302 Powercor response to IR023, question 17

non-recurrent capex for the next RCP is commensurate with what a prudent and efficient operator would incur because:

- It is prudent to target a higher level of resilience against cyber-attack;
- Its cost estimation practices are reasonable;
- Its recurrent capex is commensurate with the historical trend; and
- The proposed non-recurrent capex is likely to achieve MIL 2 to 2.3, which is consistent with the proposed maturity level target level for DNSPs as identified by AEMO.

868. However, as far as we are aware, there is currently no regulatory obligation to achieve MIL 2 (or higher).

7.5 Assessment of selected recurrent capex business cases

7.5.1 Overview of proposed recurrent capex

869. Powercor proposes spending $111.5m over the next RCP on recurrent ICT capex, as shown in the table below.

Table 7.14: Powercor's proposed recurrent ICT projects

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Infrastructure with Cloud migration	6.5	5.3	4.4	5.8	3.2	25.2
Network Management	5.3	4.9	1.4	4.0	4.4	19.9
BI/BW	0.1	1.6	0.5	0.1	0.1	2.5
Customer Enablement	0.3	0.8	1.9	0.3	0.3	3.7
Cyber security	2.7	2.8	3.0	2.9	2.3	13.5
Device replacement	2.7	2.7	2.7	2.7	2.7	13.6
Enterprise Management Systems - Non-SAP	3.3	2.0	1.4	3.4	0.3	10.4
Facilities' security	1.2	0.9	0.7	2.9	0.3	6.0
General compliance	0.9	0.9	0.9	0.9	0.9	4.6
Market Systems	1.0	0.9	2.7		1.9	6.5
SAP S/4HANA	0.4	0.7			0.4	1.6
Telephony	2.3	0.7	0.7		0.2	4.0
Total	**26.9**	**24.2**	**20.4**	**23.0**	**17.0**	**111.5**

Source: EMCa Analysis of 'Powercor - RIN001 - Workbook 1 - Reg Determination - 31 January 2020',

870. Recurrent expenditure is incurred in 12 projects, including Facilities Security (which is discussed in section 8.3) and SAP S/4HANA and Cybersecurity, which are discussed in section 7.4. We provide our assessment of ICT infrastructure and cloud migration and Network Management System in the following sections.

7.5.2 ICT Infrastructure cloud migration

871. The ICT Infrastructure cloud migration project is common to Powercor and CitiPower. The businesses have allocated capital costs allocated 70% to Powercor and 30% to CitiPower,

and operating costs 72% to Powercor and 28% to CitiPower.[303] Unless otherwise stated, our assessment is of costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Overview of the proposed project

872. The majority of VPN's ICT infrastructure is located on-premise, with some applications transitioned to cloud-hosting during the current RCP. The cloud is becoming the de facto platform for many application vendors. For the next RCP, VPN reviewed its infrastructure refresh/upgrade requirements to maintain its health, capacity and suitability and assessed the costs and benefits from migrating some or all of the on-premise infrastructure to cloud hosting. VPN recommends Option 2 – balanced (or hybrid) cloud migration, because it has the lowest NPV cost and it provides the (unquantified) benefits of cloud hosting, such as easy scalability and adaptability of its ICT infrastructure to changing requirements.

Options considered by VPN

873. The table below summarises VPN's risk-cost assessment of the four options.

Table 7.15: VPN's summary of options - $m, real 2021

Option	Description	Capex	Incremental opex	PV expenditure	Risk
0 - Do nothing	No refresh/growth of existing on-premise infrastructure; no migration to cloud	0.0	0.0	0.0	328.4
1 - On-premise infrastructure refresh	Do not migrate existing on premise infrastructure to cloud hosting	50.4	0.0	46.5	7.5
2 - Balanced cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 5% of non-core applications p.a. to cloud hosting to cloud hosting; refresh remaining on-premise infrastructure	36.0	7.7	40.5	7.5
3 - Aggressive cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 10% pa of non-core applications to cloud hosting; refresh remaining on-premise infrastructure.	35.5	11.1	43.2	7.5

Source: PAL BUS 7.10, Table 6. Note: The NPV analysis is undertaken over 5 years

Our assessment

VPN's selected strategy to move progressively to the cloud is sound

874. Option 0 is not a viable option. It is not based on good industry practices and serves only as a counterfactual for assessment of Options 1-3.

875. Option 1 – on-premise infrastructure refresh - is not recommended by VPN because there is an opportunity to migrate its core applications to cloud hosting which, as discussed below, should bring the benefits of scalability, adaptability, reliability and, over time, reduced costs.

303 No explanation for this difference between capex and opex is provided although the opex allocation is consistent with (i) advice provided in Powercor's response to IR016, question 5 which states: '*We apportioned the forecast operating costs based on relative customer number forecasts for the two networks over 2021-2026. This results in an allocation of 28% for CitiPower and 72% for Powercor*', and (ii) the customer number calculation in the Assumptions sheet of PAL MOD 9.01 – Step changes – Jan2020. The capex apportionment in Table 12 of PAL BUS 7.10 is 70:30

876. VPN's Options 2 and 3 involve progression to cloud IT hosting during the next RCP while retaining some applications on-premise. We refer to this as a 'hybrid cloud' approach. VPN identifies the benefits of adopting a hybrid cloud approach as including:[304]

- *'Improved agility and adaptability to business needs;*
- *Reduced risk of applications changing beyond the hosting platforms' ability to support;*
- *Provision of agile and scalable hosting platforms as needs change;*
- *Allow incremental non-capital intensive capacity growth; and*
- *Provide greater ability to manage peak demands aligned to business needs.'*

877. The identified benefits are consistent with our experience and the trend we observe within the industry. We therefore consider VPN's strategy of moving progressively to the cloud, as proposed in Options 2 and 3 to be superior to Option 1.

878. VPN's preferred 'balanced' strategy (Option 2):[305]

- Migrates 100% of core applications and 25% of non-critical applications to cloud hosting by the end of the next RCP;
- Connects on-premise data centres to external cloud offerings;
- Includes a cloud-first shift to IaaS platform; and
- Requires a slightly lower capex and incremental opex than Option 3.

879. VPN consultant's advice regarding Option 2 is that it *'…reflected the best value and most achievable option for an alternate IT Hosting strategy during the next regulatory reset period*.'[306] The same consultant's advice is that Option 3 is riskier than Option 2, primarily because of its relative lack of maturity in cloud adoption: [307]

> *'Adopting this scenario carries some additional risk, as it requires CitiPower, Powercor & United Energy to continue developing a high level of internal maturity in cloud adoption and understanding of its application compatibility with cloud based platforms.'*

880. We are not in a position to comment on VPN's relative maturity regarding cloud adoption. In accepting its consultant's advice in adopting Option 2, we assume that VPN acknowledges its relative lack of maturity compared with cloud adoption. However, we note that its risk analysis (shown in Table 7.15) does not distinguish between the risk cost of Options 2 and Options 3.

881. A further reason for selecting Option 2 is the superior risk-cost trade-off offered compared to Option 3, also as shown in Table 7.15. There does not appear to be duplication of costs across the inter-related SAP, BI/BW and ICT Infrastructure cloud migration projects.

882. The figure below illustrates the current and future states of the planned cloud migration and refresh of remaining on-premise infrastructure following implementation of VPN's preferred option.

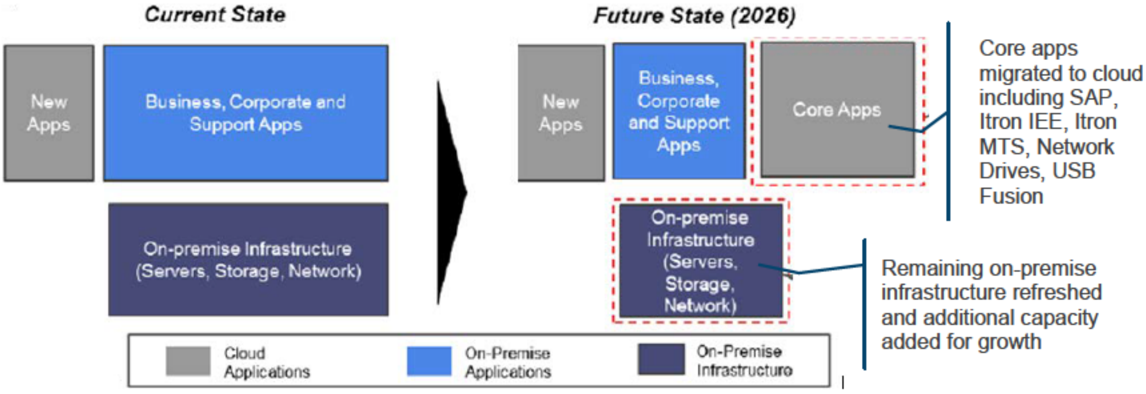
[304] PAL ATT 046, p21

[305] PAL ATT 046, p5

[306] PAL ATT 046, p29

[307] PAL ATT 046, p21

Figure 7.9: Current and Future state following implementation of VPN's preferred option 2



Source: EMCa modified version of Powercor's Figure 4, PAL BUS 7.10

883. As shown in the diagram above, VPN is planning to migrate its on-premise SAP version to the cloud in the next RCP. Based on our initial review, the SAP business case and this Cloud infrastructure business case appear to double count at least some capex. We had similar concerns with respect to the BI/BW[308] business case costs. We sought clarification from VPN.[309] We summarise its response as follows:

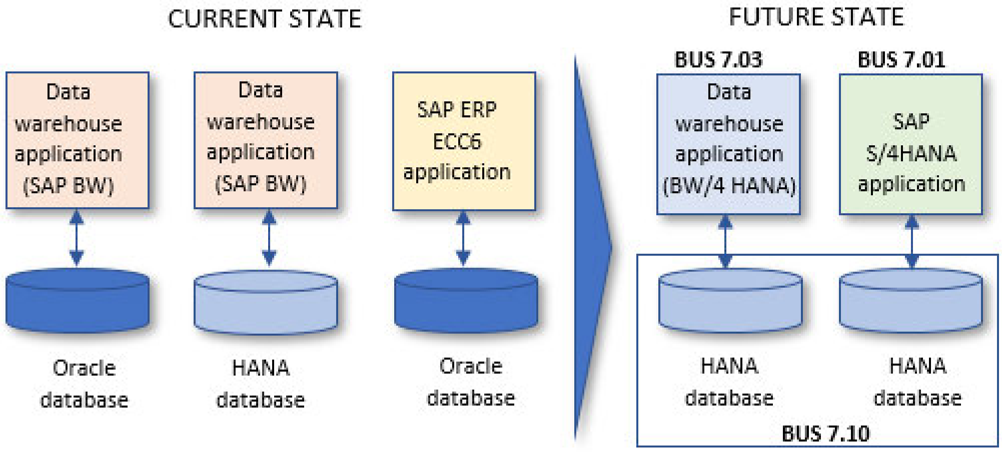
- The Cloud infrastructure business case:
  - covers only IT infrastructure;
  - includes all capex allowance for all residual infrastructure needs to support its IT portfolio (applications and platforms);
  - recognises the reductions in on-premise infrastructure refresh/upgrade costs from moving infrastructure to cloud hosting (i.e., IaaS);
  - includes incremental opex increases for cloud hosting charges for the 'new' cloud-hosted infrastructure; and
  - includes reductions to the opex that would otherwise have been incurred on maintaining on-premise infrastructure moving to IaaS.
- The SAP Business case (PAL BUS 7.01):
  - covers the SAP ERP IT application only;
  - includes capex to upgrade from SAP ECC6 to SAP S/4HANA; and
  - does not include incremental opex.
- The BI/BW business case (PAL BUS 7.03):
  - covers IT application for business reporting only;
  - includes capex for consolidating the applications to SAP S/4HANA; and
  - does not include incremental opex.

884. This is illustrated in the figure below. We have reviewed the SAP and BI/BW cost models and we are satisfied that the costs across the three business cases are not likely to be duplicated to a material extent. However, if the Cloud project slipped even slightly VPN/UE will not have the data ready for the SAP/Hana project.

308 Business Intelligence/Business Warehouse

309 Response to IR048

Figure 7.10: Demarcation between Cloud infrastructure, SAP and BI/BW business cases



Source: EMCa modification of Figure 1, Powercor response to IR048
Note: BUS 7.03 (BI/BW business case); BUS 7.01 (SAP business case); BUS 7.10 (Cloud infrastructure business case)

The proposed Option 1 capex for refreshing and growing the on-premise infrastructure is not adequately justified

885. The average annual VPN capex for recurrent infrastructure from 2016-2019 was $8.2m.[310] Given that VPN has already begun transitioning infrastructure to the cloud, we consider the average of $7.0m over the last three years (2017-2019) is likely to be more representative of the BAU recurrent infrastructure capex. VPN has not provided sufficient information in its business case to justify the significantly higher forecast annual average capex of $10.1m throughout the next RCP. Furthermore, although there are multiple references to additional capacity to support 'growth' in the business case, there is no explanation of the growth drivers or growth components that have been incorporated into the forecast.[311]

886. We therefore consider that a reasonable estimate for the Option 1 capex would be approximately $35m for the next RCP. This would in turn reduce the Option 2 capex by $15m (i.e., to $21m) based on the Option 2 capex reduction shown in Table 7.13.

VPN's methodology for estimating the cost of the residual on-premise infrastructure included in Option 2 is reasonable

887. To determine the reduction in infrastructure costs afforded by shifting some infrastructure to the cloud, VPN has first identified the assumed proportions of infrastructure material cost that are currently used by each of the seven core applications and non-critical applications that VPN propose transitioning to the cloud. The negative percentages (indicating reductions) are summarised in the table below.

310 Powercor response to IR023, Table 3, p3

311 We note that the costs to accommodate additional storage associated with the 5 minute settlement rule change are not included in the PAL BUS 7.10 (note to Table 4, p12)

Table 7.16: VPN's assumed material-related capex reductions from migration to IaaS over the next RCP[312]

Application	Server	Storage	Database (Exadata)	Backup	Network	Database (HANA)	Option 2 materials saving ($m, 2021)
Itron IEE	-1%	-2%	-20%	-11%	-1%	0%	-1.0
Itron MTS	-1%	-1%	-10%	-6%	-1%	0%	-0.5
SAP ERP	-1%	-5%	-5%	-5%	-1%	0%	-0.4
SAP BW	-2%	-5%	-10%	-8%	-1%	-100%	-5.9
SharePoint	-3%	0%	0%	0%	-1%	0%	-0.3
Oracle USB	-1%	-1%	-10%	-6%	-1%	0%	-0.8
Non-critical apps	-5%	-10%	-10%	-10%	-1%	0%	0.0
Network drives	-1%	-15%	0%	-8%	-1%	0%	-0.8
Total	**-15%**	**-39%**	**-65%**	**-52%**	**-8%**	**-100%**	**-9.7**

Source: PAL MOD 7.15, Option 2

888. The reduction to capex afforded by Option 2 (compared to Option 1) is derived by applying these negative percentages to the materials component of cost, resulting in a reduction of $9.7m. Of this $9.7m reduction, the model assumes a further 20% reduction for labour savings ($1.9m) and a 35% reduction for contracts savings ($3.4m), for a total savings of $15.0m.

889. VPN did not provide compelling justification in its model or in its business case for the assumptions used in Table 7.14. These values are fundamental to determining the reasonableness of the opex-capex trade-off that transitioning to IaaS represents. In response to our request for the basis for the assumptions, VPN advised that: [313]

- *'Our estimated capex reduction for migrating these non-core eligible applications is based on the current share of infrastructure for each application'; and*
- *Our infrastructure capacity is also heavily utilised by a number of OT applications which are not considered eligible for cloud migration and therefore will remain on premise.'*

890. We have reviewed the proposed percentages in the table above in light of our experience, the response to the information request, and the information in Table 15 in the business case. We consider them to be reasonable estimates.

Opex step change appears to be reasonable in conjunction with reduced on-premises infrastructure capex

891. VPN advises that the forecast opex for migrating applications to cloud hosting was based on vendor advice sourced by external advisors.[314] The costing spreadsheet shows the annual cost (i.e., cloud hosting fee) for each of the 42 infrastructure components that will be cloud hosted. It is appropriate for VPN to source vendor estimates as the basis for its forecast. Based on our review of the itemised costs, they appear to be reasonable estimates. The proposed opex step change itself appears to be reasonable, but only if taken in conjunction with reduced on-premises infrastructure capex.

312 The percentage reduction is from the assumed capex without any cloud transition. The Option 2 saving for non-critical apps is zero for Option 2 – this may be an error in PAL's model

313 Powercor response to IR023 question 19

314 Powercor BUS 7.10, p13

The proposed opex reduction in the next RCP to account for fewer on-premise infrastructure is reasonable

892. VPN estimates the reduction in opex from migration to cloud hosting as 5% of the capex reduction. VPN did not provide justification for this amount in its business case or model. In response to our request for more information Powercor advised that '*achieving material operating expenditure savings will only occur in future regulatory periods.'*[315] Based on our experience, we consider that VPN's estimate for the next RCP is reasonable.

Summary of our assessment

893. Our assessment suggests that:

- VPN's proposed strategy of migrating applications and the supporting infrastructure to the cloud is consistent with industry trends and should bring the benefits of scalability, adaptability, reliability and, over time, reduced costs.
- VPN's selected Option 2 'balanced cloud migration' appears to be an appropriate choice and is informed by external advice.
- VPN's estimates for capex and opex savings and opex increases for its preferred option are based on reasonable methodologies.
- VPN's proposed capex for refreshing and growing its remaining on-premise infrastructure has not been adequately justified. Its forecast for the next RCP is approximately $15m higher than its most recent three years of capex would indicate. On this basis, the reduction in capex for the preferred Option 2 would also be $15m lower than proposed. The revised Option 2 capex would then be $21m.
- On the basis of reduced on-premises infrastructure capex as above, VPN's proposed opex step change to cover cloud hosting fees of $7.7m is reasonable.

7.5.3 Network Management Systems

894. The Network Management Systems project is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our assessment is of the total costs and benefits attributable to VPN.

Project overview

895. VPN proposes to invest $28.4m in the next RCP on maintaining the currency of its network management systems which comprise: six core network management systems; two geospatial systems; and two reporting and data processing systems. The main driver of the proposed expenditure is to '*avoid the risk of unsupported or end-of-life systems that may compromise VPN's ability to effectively monitor and manage our electricity network.'*[316]

896. VPN considered three options, described in the table below, and selected Option 1.

[315] Powercor response to IR023 question 19

[316] PAL BUS 7.05, p3

Table 7.17: Options summary – VPN Network management systems - $m, real 2021

Option	Capex	PV Cost	Risk
0 - Do nothing - do not upgrade, maintain current software versions in relation to our network management systems.	0.0	n/a	50.9
1 - Refresh current suite of network management systems - Perform prudent technical upgrades to maintain core currency and regulatory compliance, whilst targeting alignment and simplicity	28.4	26.3	13.5
2 - Replace the network management systems with alternative solutions	47.3	43.1	13.6

Source: PAL BUS 7.05

Our assessment

Option 0 is not consistent with good industry practice

897. VPN's network management systems include 'mission critical' systems running the network. It is not consistent with good industry practice to build up significant 'technology debt'[317] for core systems/applications. The most significant risk arises from systems not being supported by the vendors[318] or alternative third-party suppliers. VPN has estimated monetised risk from IT risks and business risks (reliability, compliance, safety, and bushfire risks). Business risk is estimated to comprise 80% of the total Option 0 risk of $50.9m, arising primarily from the risk of non-compliance. Whilst we have some issues with the input assumptions underpinning the monetised risk,[319] we consider that the reasonable conclusion is that the IT and business risk of Option 0 is significantly higher than for Options 1 and 2.

Option 2 does not add value commensurate with the cost

898. Option 2 as described by VPN involves replacing the network management systems with alternative solutions which provide similar functionality. VPN states that *'[t]his option would involve significant organisational and technology change'*… and '*…would introduce an increased risk of interruptions to network operations/performance'* and '*impact on supply reliability, safety and customer service.'*[320]

899. VPN has provided a breakdown of its assumed labour, materials, and contract cost components. Not surprisingly, the major source of difference between Option 1 and Option 2 is the systems (materials) cost where the Option 1 cost of refreshes and upgrades are a fraction of the Option 2 cost of installing new systems.

900. It is clear from the information provided by VPN[321] and from our own experience, that the benefits of Option 2 are unlikely to outweigh the cost in any reasonable assessment.

901. We note that VPN also considered a variation of Option 2 in which a subset of systems would be replaced with alternatives. Like VPN, we consider this sub-option to be inferior to Option 1 because of integration-related issues.

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317 Technology debt is built up by skipping multiple refreshes and, particularly, version upgrades which progressively builds risk of bugs causing malfunctions/errors and business disruption, non-compliance breaches, loss of productivity, and damages

318 That is, beyond published end-of-support dates

319 E.g. annual occurrence of a reliability event, non-compliance, and safety event is assumed, starting in the 1st year of the next RCP – we consider this overstates the likelihood of occurrence; the non-compliance consequence cost is assumed to be $4.75m per event – insufficient evidence is provided to support this

320 PAL BUS 7.05, p16

321 Including the description of the disadvantages of Option 2 in Table 9 of PAL BUS 7.05

VPN does not discuss the option of cloud migration in the business case

902. VPN's business case makes no reference to the option of migrating some or all of its core Operational Technology (OT) systems to cloud-based hosting to take advantage of the benefits of hosting that it promotes strongly in its ICT Infrastructure Cloud Migration business case (PAL BUS 7.10). In response to our question, VPN advises that its OT applications are '*not considered eligible for cloud migration due to the requirement to host these applications in a highly secure environment physically close to the electrical network being managed. These systems must be able to operate independently of external events…'*[322]

903. It is not clear from the response how cloud migration fits into the OT vendors' plans for the future; however, we infer from VPN's response that there will continue to be vendor support for the on-premise versions for at least the duration of the next RCP.

Option 1 appears to include too many upgrades

904. The figure below shows VPN's network management systems roadmap which identifies multiple upgrades for several OT systems in the next RCP. This includes annual upgrades for the AWS product and biannual upgrades for the Sensor IQ product. Whilst we acknowledge that building up significant technology debt is not commensurate with good industry practice, the frequency of system upgrades (not refreshes) appears to be excessive.

905. We discussed our concern with VPN at our meetings with them and via a follow-up information request. VPN's position is summarised as:[323]

- The roadmap timing profile is aligned with vendor product support schedules;
- The forecast cost per refresh is based on previous refresh costs incurred in the current RCP and projected infrastructure hardware replacement cycles (every five years);
- VPN does not necessarily adopt the most recent vendor release version immediately, '*rather we wait allowing other parties to test the new product first, so we have assurance that there are no significant defects and/or any defects identified have been rectified';*
- Of the forecast $26.9m for the current RCP, it expects to spend $26m; and
- It '*also considered a number of general factors (e.g., project concurrency, resource availability…).'*

906. In relation to VPN's reference to delaying the adopting of vendor releases, we note from our review of VPN's Market Systems business case, discussed in section 7.6, that VPN states that its selected option '…*extends asset life beyond formal vendor recommended upgrade timelines within acceptable risk levels and delays upgrades and associated costs until necessary*[324]*'.* We consider that approach, which is based on considering recommended vendor upgrade timelines, risks and costs provides a more compelling basis for ensuring a prudent level of expenditure than has been provided by VPN in relation to Network management systems.

907. VPN's proposed capex for the next RCP is $2.4m (9%) higher than the expected Network management systems expenditure in the current RCP. We remain concerned about the prudency and efficiency of the proposed upgrade cycle because the value of each upgrade may not be realisable, and as shown in the roadmap, the resourcing load appears to be unnecessarily high.

322 Powercor response to IR0023, question 19(b)

323 PAL BUS 7.05, pp11, 15; Powercor response to IR0023, question 12

324 PAL BUS 7.06, page 4

Figure 7.11: VPN network management systems roadmap

System	Product	2021/22	2022/23	2023/24	2024/25	2025/26
Network Management Core						
SCADA/DMS	PowerOn Advantage	Complete DMS/OMS migration	Maintenance Release		Upgrade	Upgrade
OMS	PowerOn Restore	Retired				
Supply Quality	Sensor IQ	Upgrade		Upgrade		Upgrade
Switching	EDNAr	System Refresh	System Refresh		System Refresh	System Refresh
Protection Systems	Schneider Electric ION		Upgrade		Upgrade	
Network Geospatial						
GIS	GE Smallworld CORE		Upgrade	S4HANA Integration	Upgrade	
Network Visualisation	Map Insights	System Refresh			System Refresh	
Network Reporting and Analytics						
Network Data Processing	AWS Data Analytics, tooling, platform	Upgrade	Upgrade	Upgrade	Upgrade	Upgrade

Source: PAL BUS 7.05

Summary of our assessment

908. We remain unconvinced of the prudency and efficiency of VPN's proposed frequency of upgrades/refreshes, particularly: (i) annual Network data processing ($5.4m); and (ii) four EDNAr refreshes in five years ($2.5m). Our analysis suggests that an amount that is 10-15% less than proposed is more likely to represent an efficient level of expenditure.

7.6 Observations on remainder of proposed capex

7.6.1 5 Minute Settlement (non-recurrent)

909. Powercor's business case provides the supporting information for its proposed incremental opex, non-recurrent ICT capex, and augex for communications devices to meet the 5-minute settlement compliance obligations for both CitiPower and Powercor.[325] We have made observations regarding all three components in this section and unless stated otherwise, we refer to the combined expenditure for VPN.

Overview of the proposed project

910. Any Victorian smart meter installed after December 2018 must have the capability to record five-minute interval energy data by 31 December 2022. VPN advises that its ICT systems do not currently comply with the relevant changes to the Rules. It proposes $17.8m ICT capex, $6.9m incremental opex and $14.1m network communications capex to address this compliance gap.[326]

Our observations

Obligations must be met by 31 December 2022

911. VPN has a firm obligation to be able to retrieve, process and deliver data from Type 5 AMI Meters to the market by 31 December 2022. The proposed expenditure relates to this obligation.

325 AEMC, Rule determination, National Electricity Amendment (Five Minute Settlement) Rule 2017,

326 Powercor BUS 7.09 – 5 minute settlement, Table 1

IT systems upgrade costs are based on relatively old information

912. To manage the expected increased volume of data that VPN is responsible for under the five minute settlement rule change, VPN has identified that it will need to:[327]

- Upgrade its IT systems;
- Install additional communication devices;
- Increase its wide area network (WAN) and data processing capacity; and
- Manage an increase in the volume of manual validations of meter data exceptions.

913. VPN advises that its proposed IT systems upgrade is to support retrieval of five minute interval meter data from smart meters, together with the subsequent validation, storage, and distribution of five minute data to market participants including retailers, AEMO and customers.

914. Powercor's labour time estimates are based on historical costs, referring to its metering contestability project in 2017 and its IT systems upgrade project to accommodate AMI meters in the AMI roll-out.

915. Whilst using historical costs is typically a reasonable starting point for cost estimation, the recency of the information is fundamental to achieving a reasonable estimate. Given the quantum of capex involved ($17.8m) and the time that has elapsed from its reference projects, we would have expected more compelling information to be provided to demonstrate that the materials costs and labour volumes are based on reasonable assumptions. The labour rates are based on information provided by PwC (per PAL MOD 12.02), which should provide a reasonable source for the labour rates.

916. We would expect that benchmarking of unit costs and the capex and opex per customer for VPN and the other three Victorian DNSPs would provide a useful starting point for establishing the efficiency or otherwise of the proposed costs.

WAN and data processing capacity costs appear reasonable

917. VPN has provided a breakdown of the volume and unit costs assumed in its forecast. VPN leverages off recent unit costs and they appear to be reasonable.

Communication network costs

918. VPN has estimated the capex for new communications devices by having: (i) identified the four types of devices required; (ii) estimated the increased volume of each device from forecast growth in meter reads plus the expected geographical gaps in its existing comms network capability; and then (iii) applied unit rates derived from recent costs.[328]

919. This approach seems reasonable. VPN has provided its cost model with a detailed breakdown of components of the unit cost and the volumes of devices.[329] The cost model differentiates between the communications devices required for 5-minute settlement obligations and for its other related projects including the 3G-shutdown (refer to section 5 in our assessment of Augex) and for its annual repex program. Therefore, there appears to be no overlap/duplication of costs. The communications network costs therefore seem to be reasonable estimates.

Opex step change

920. VPN further advises that it will incur incremental operating expenditure during the next RCP for: (i) increased WAN capacity to transport increased volume of meter data between IT systems; and (ii) to manage the increase in manual validations of meter data exceptions.

[327] PAL BUS 7.09, p9

[328] PAL BUS 7.09, p18

[329] PAL MOD 6.03 (there is no CP model)

921. VPN has estimated the opex increase based on the growth in forecast meter data volumes times the unit rate of WAN capacity and nodes. This approach seems to be reasonable. A step change is evident in its forecast from 2021/22 onwards.[330]

Summary of our observations

922. With the exception of the lack of compelling information to support the cost estimate for IT systems upgrades costs, our observations suggest that VPN's approach and cost estimates are reasonable.

7.6.2 Market Systems (recurrent)

923. The Market Systems project is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

924. VPN proposes to invest $9.3m in the next RCP on maintaining the currency of its market systems (which provide storage and validation of meter reading data and manage market-compliant communications and customer requests). VPN considered three options, as described in the table below, and selected Option 1.

Table 7.18: Options summary – Market systems - $m, real 2021

Option	Capex	Risk
0 - Do nothing - do not upgrade to maintain current software versions in relation to Market Systems. Additional operating expenditure is charged by vendors.	0.0	36.4
1 - Prudent technical upgrades - remain within vendor support by adopting every second software version release upgrade	9.3	2.2
2 - Vendor released technical upgrades - perform system upgrades as released by vendors, maintaining pace with newest available versions as they are released	11.4	2.2

Source: PAL BUS 7.06, Table 1

Observations

925. We consider that adopting Option 0 would not be consistent with the actions of a prudent operator. Option 2 results in upgrades approximately every two years and '*…the full value of each upgrade may not be realised and the resourcing load is high.*'[331]

926. Unlike Option 2, Option 1 extends asset life beyond the vendors' recommended upgrade timelines at what VPN considers to be acceptable risk levels, delaying upgrades and associated costs until necessary – which VPN refers to as an 'N-1' strategy. VPN also advises that '*our vendors will continue to support the previous version (N-1), however they will not support prior versions (N-2 or earlier).*'[332]

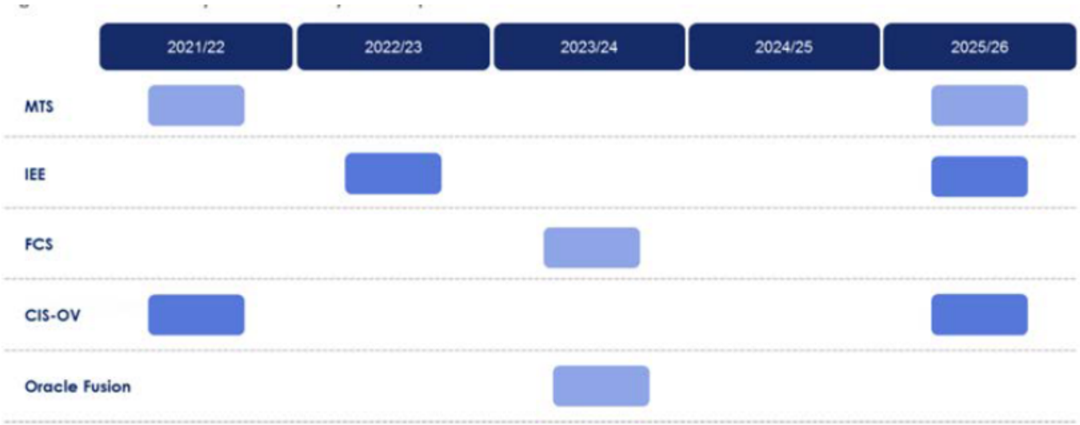
927. As shown in the figure below, the proposed upgrades appear well balanced between the five systems and the 3-5 year refresh cycles for the systems do not appear to be excessive.

330 PAL BUS 7.09, Table 10

331 PAL BUS 7.06, page 17

332 PAL BUS 7.06, pages4, 10

Figure 7.12: VPN's Market Systems currency roadmap



Source: PAL BUS 7.06, p20

928. VPN's average annual market systems capex in the current RCP (2016-2019) was $1.9m, which is the same as its forecast annual average capex for the next RCP.[333]

7.6.3 Business Intelligence and Warehousing (recurrent)

929. The Business Intelligence/Business Warehousing (BI/BW) project is common to Powercor, CitiPower and United Energy. Capital costs are allocated 42% ($2.5m) to Powercor, 18% ($1.1m) to CitiPower and 40% ($2.3m) to United Energy. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN and United Energy.

Project overview

930. VPN/UE proposes to invest $5.9m in the next RCP to consolidate all data warehouses to have a shared data warehouse used by all three businesses. VPN/UE considered three options, as described in the table below, and selected Option 2.

Table 7.19: VPN/UE's options summary – BI/BW - $m, real 2021

Option	Capex
0 - Do nothing - Leave the existing data warehouse and reporting solutions as they are currently without any upgrade.	0.0
1 - Retain the current respective data landscapes at CitiPower, Powercor and United Energy. Undertake periodic upgrades of Data Warehouses and Reporting applications.	6.8
2 - Consolidate all existing data warehouses to have a shared data warehouse used by all businesses and increase the scope of self-service reporting capability to support needs of all our businesses.	5.9
3 - Consolidate the Data Warehouse Platforms to have a single data warehouse for each business: one for CitiPower, Powercor and one for United Energy.	8.3

Source: PAL BUS 7.03, Table 1, p4

Our observations

931. Options 0 is not consistent with good industry practice.

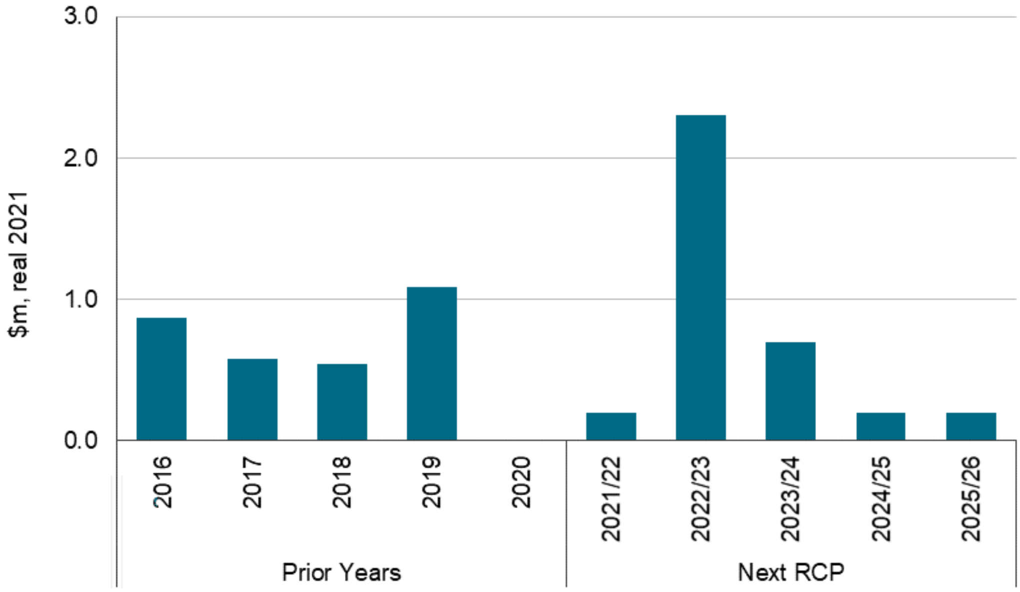
932. Currently the VPN and United Energy business intelligence functions are supported by separate presentation layers and are underpinned by multiple data warehouses. VPN/UE propose consolidating the data warehouses, which is the cheapest option and appears to be the prudent and efficient choice. Consolidating on an integrated common Data Lake

333 Powercor response to IR023

platform as a foundation to a consolidated Enterprise Data Warehouse & Analytics platform is the recommended approach and appears to be the prudent approach. VPN identifies a business risk due to having a single core data warehouse system and concludes that the benefits outweigh the risks.

933. As a crosscheck, we asked VPN to provide the BI/BW capex for the current RCP, which is shown in the figure below for VPN only along with the annual forecast capex for the next RCP, noting that the expected 2020 amount was not provided. The average annual historical capex of $0.77m (2016-2019) for VPN is 6% higher than the forecast capex of $0.72m pa for VPN for the next RCP.

Figure 7.13: VPN's historical and forecast BI/BW capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.03

7.6.4 Device replacement (recurrent)

934. The Device replacement project is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

935. VPN proposes to invest $19.4m in the next RCP on maintaining the currency of its end-user devices.[334] VPN considered three options, as described in the table below, and selected Option 1. VPN states that *'[i]f we do not replace devices at end of useful life we will experience significant cost increases in the delivery field services, as well as deteriorations in network reliability and safety risks.'*[335]

[334] Computers, laptops, mobile phones and tablets, videoconferencing units, projectors and display screens

[335] PAL BUS 7.12, p3

Table 7.20: Options summary – Device replacement - $m, real 2021

Option	Capex
0 - Do nothing - do not replace devices	20.0
1 - Replace devices at end of useful life	19.4
2 - Replace the devices in bulk at the beginning of the period	26.7

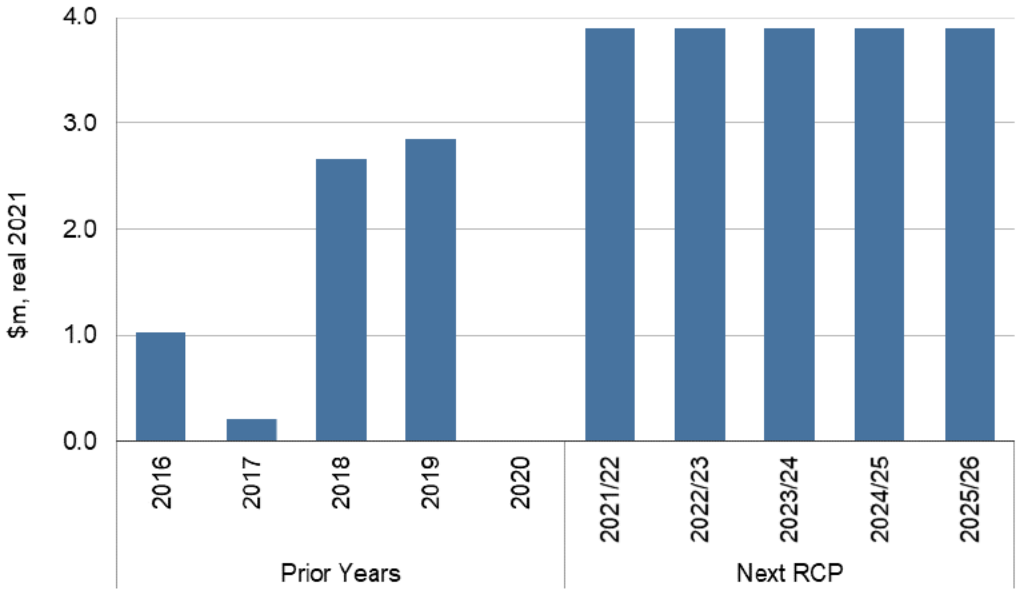
Source: PAL BUS 7.12, Table 1

Our observations

936. Options 0 and 2 are not consistent with good industry practice, with Option 2 unlikely to add sufficient sustained net benefits compared to Option 1.

937. With respect to Option 1, we asked VPN to provide the device replacement capex for the current RCP, which is shown in the figure below along with the annual forecast capex for the next RCP, noting that the expected 2020 amount was not provided. The average is $1.7m or roughly 50% of the forecast capex of $3.9m p.a. for the next RCP. VPN does not explain this difference in its business case, but in its response to our information request (IR023) it explains that the cost increase is due to reverting to a purchase rather than lease approach.

Figure 7.14: VPN's historical and forecast Device replacement capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.12

938. VPN advised that its useful device life is '*…based on our experiences with devices over the past decade, vendor recommendations and current replacement practices.*'[336] We would expect VPN's opex forecast for the next RCP to be reduced by an amount commensurate with its reduced lease charges.

7.6.5 Enterprise management systems (recurrent)

939. The Enterprise management systems business case is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

336 PAL BUS 7.12, p7

Project overview

940. VPN proposes to invest $14.8m in the next RCP to maintain the currency of its Enterprise Management Systems (EMS) because:[337]

- Applications are reaching end-of-life or end-of-vendor support;
- Integration of EMS applications with the proposed upgraded SAP system (referred to in section 7.4.4) is required; and
- Of changes in technology, customer requirements and cyber security threats.

941. VPN considered three options, as shown in the table below, and selected Option 1.

Table 7.21: VPN's options summary – Enterprise management systems - $m, real 2021

Option	Capex
0 - Do nothing – do not perform any work, leave systems in current state, and manage resulting impacts and consequences	0.0
1 - Maintain – perform required updates or upgrades to maintain a stable and efficient IT ecosystem, while retaining an adequate level of vendor support	14.8
2 - Transform – identify opportunities for transformation with the aim of unlocking larger benefits that could be passed on to customers (additional functionalities and efficiencies).	19.0

Source: PAL BUS 7.11, EMS, Table 1

Our observations

942. Option 0 is not consistent with good industry practice. Option 2 is unlikely to add sufficient sustained net benefits compared to Option 1.

943. VPN states that its objective is to *'…ensure that all the applications in the scope of this business case are kept current (*N-1*), efficient, secure, and within an adequate vendor support window over the 2021–2026 regulatory period.*[338] We observe that what VPN refers to as a 'N-1' strategy is likely to lead to more efficient costs than an N-0 or an N-2 strategy.[339]

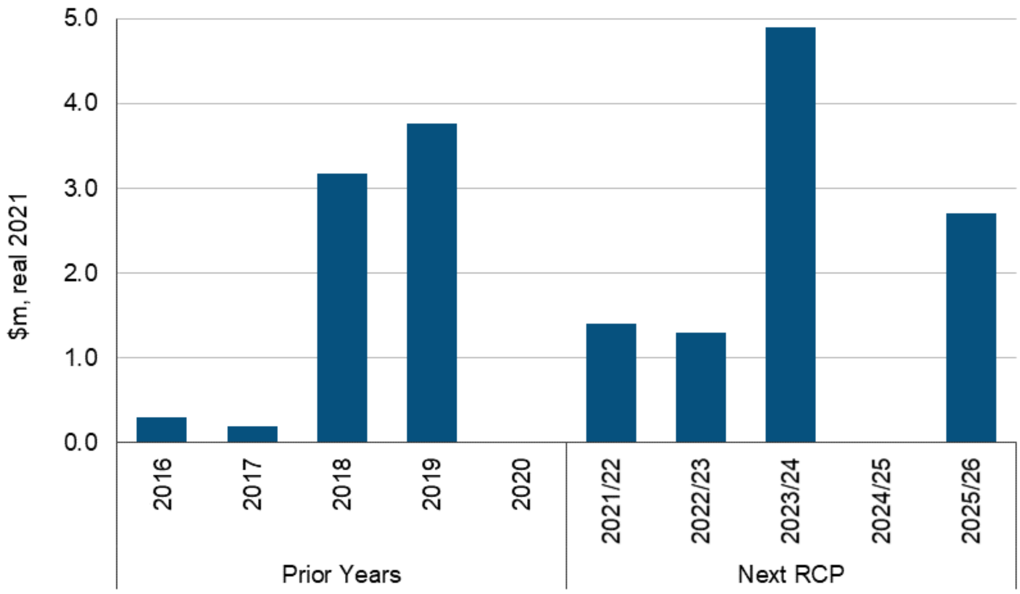
944. We asked Powercor to provide the EMS capex for the current RCP, which is shown in the figure below together with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The forecast capex of $3.0m p.a. for the next RCP is 26% higher than the $2.3m annual average capex over the period 2016-2019.

337 Powercor BUS 7.11 – EMS, page 4

338 Powercor BUS 7.11 – EMS page 10

339 'N-1': applications are maintained within one release of the latest available version; 'N-2' maintaining applications within two releases of the latest available version

Figure 7.15: VPN's historical and forecast Enterprise Management Systems capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.12[340]

Note: Annual expenditure is based on format of data provided by VPN

945. VPN does not explicitly explain the reason for the 26% higher forecast expenditure for the next RCP. It does, however, identify the status of the 12 enterprise systems and its plans for each in Table 7 of the business case. This provides us with some confidence in VPN's analysis.

946. However, we observe that VPN proposes approximately $1.3m capex in 2022/23 on upgrading the Oracle database, which is planned to be replaced by the HANA database in 2023/24 as part of the SAP S/4HANA and ICT Infrastructure Cloud Migration projects discussed in sections 7.4.4 and 7.5.2, respectively. Given that VPN also proposes upgrading to version 12c in 2021/22, we consider that upgrading the oracle database in the year prior to its replacement is unlikely to be prudent.

7.6.6 Facilities security (recurrent)

947. Powercor's forecast $6.0m ICT component of VPN's $8.5m Facilities security project is discussed in our review of property capex included in section 8.3.

7.6.7 General compliance (recurrent)

948. The General compliance project is common to Powercor and CitiPower. Capital costs are allocated 50% to Powercor and 50% to CitiPower. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

949. Powercor proposes spending $4.6m as part of VPN's $9.2m 'General IT compliance' projects to meet anticipated obligations as they are periodically amended. VPN advises that *'[w]e anticipate that during 2021–2026 there will be a similar trend in amendments to regulatory obligations we have seen over the current regulatory period.'*[341] VPN considered two options – Do nothing and its preferred approach.

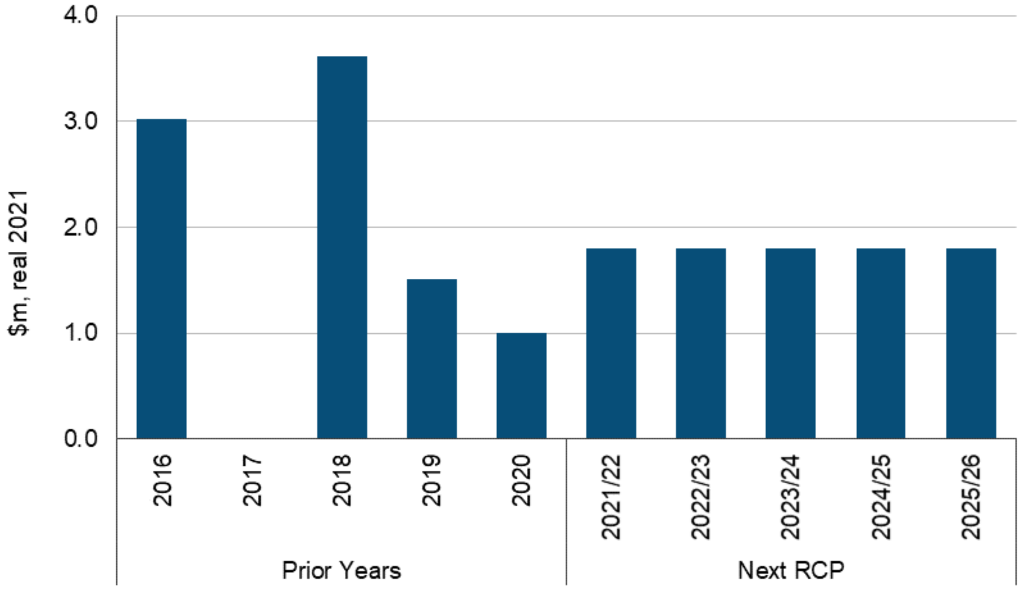
340 Data is from Powercor sources which comprised historical data in calendar years and forecast data in financial years. This also applies for the subsequent similar graphs

341 PAL BUS 7.14, p4

Our observations

950. We asked VPN to provide the General IT compliance capex for the current RCP, which is shown in the figure below along with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The historical average annual capex over 2016-2019 is $2.0m, which is slightly higher than the proposed annual average of $1.8m p.a. for the next RCP.

Figure 7.16: VPN's historical and forecast General IT compliance capex - $m, real 2021[342]



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.14

7.6.8 Telephony (recurrent)

951. The Telephony business case is common to Powercor, CitiPower, and United Energy. Capital costs are allocated 40% to Powercor, 17% to CitiPower and 44% to United Energy based on: (i) their respective customer share; and (ii) United Energy bearing the full cost of integrating its contact centre with VPN's. Unless otherwise stated, our observations relate to the total costs and benefits that are attributable to VPN/UE.

Project overview

952. VPN/UE proposes spending $10.1m on Telephony to maintain system currency, to integrate United Energy's contact centre, and to enhance customer experience (which it refers to as Option 2). VPN/UE considered two other options in addition to the preferred option:

- Option 0: Do nothing—do not upgrade the existing telephony platforms ($0.0m); and
- Option 1: Maintain the currency of current systems and integrate United Energy's contact centre ($8.5m).

Our observations

953. Option 0 (do nothing) is not consistent with good industry practice as it will build up significant technology debt and could reasonably be expected to progressively lead to degraded performance and higher maintenance costs.

954. Option 1 involves investing in: (i) the latest available version of the Unified Computing System (UCS) platform offered by Cisco in 2021/22; (ii) the latest available version of the BT telephony platform in 2023/24; and (iii) upgrading telephony capacity for the integration of

342 Data from 2016 to 2020 are based on calendar year while 2921/22 to 2025/26 are based on financial year. All data provided by VPN.

the United Energy general enquires/connections line. The latter step is claimed to be more efficient than maintaining separate call centres: [*t]hese savings have been accounted for in the operating expenditure cost estimate of the efficient integration of the contact centres…*'[343] The quantum of savings is not identified in the business case or the supporting model.[344]

955. VPN/UE does not consider (and therefore does not cost) the option of maintaining separate systems between VPN and United Energy in its business case. It is reasonable to assume that there are cost savings from integrating the contact centres, but this option should have been presented for completeness.

956. For an extra $1.5m over 5 years, VPN/UE's Option 2 will increase its telephony capabilities to improve the customer experience by incorporating: (i) omni-channel capabilities; and (ii) faster customer identification through an interactive voice response (IVR) interface. VPN/UE claim that this feature will:[345]

- save customers a minimum of 1 minute each per annum and that this is sufficient to '…*ensure the investment is worthwhile*'; and
- provide a credible response to customer feedback: '*Around 80% of our customers across the three networks were interested in easier access to their data and information and enhances [sic] customer experiences.* [346]

957. VPN/UE value a residential customer minute at about $0.18, and collectively the three DNSPs are forecast to have about 2.0m customers in the next RCP. However, VPN/UE's economic model does not include its estimate of how many customers will actually benefit from the new service. Therefore, it does not provide an NPV inclusive of benefits and infrastructure refresh costs.

958. The cost estimates for the major components of Option 1 are based on relatively recent upgrades and integration projects involving the three DNSPs, which is a reasonable approach.

959. Referring to the figure below, the average annual expenditure in the current RCP for VPN only is $0.9m p.a., whereas for the proposed Option 2, this will increase to an annual average of $1.1m or an extra $1.0m p.a. over the next RCP (incurred mostly in 2021 and for VPN's share of the additional Option 2 features).

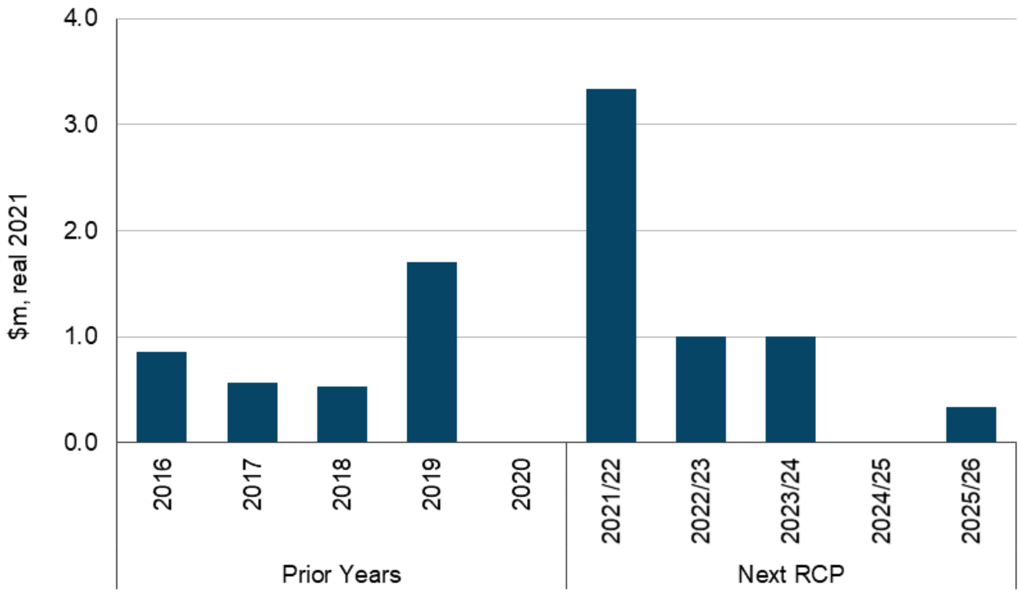
[343] PAL BUS 7.13, page 11

[344] No opex – either savings or expense – is identified in the model PAL MOD 7.19

[345] PAL BUS 7.13, page 14

[346] PAL BUS 7.13, page 13

Figure 7.17: VPN historical and forecast Telephony capex - $m, real 2021[347]



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.14

7.7 Summary of findings and implications for Powercor's ICT capex forecast

960. We consider that Powercor's proposed capex on its ICT programs for the next RCP is above that required by a prudent and efficient operator.

Selected options are typically appropriate

961. With two exceptions (Digital Network and Customer Enablement) we consider that the preferred options identified and presented in the business cases are appropriate. In our opinion, the selected options for the Digital Network and Customer Enablement business cases are not supportable as a whole. However, components of the options may be economically justified with a reduced scope. In some other cases, for completeness, we consider that another credible option should have been included in the analyses although we do not have reason to believe that these would have been preferable to the selected option.

Some claimed benefits in non-recurrent projects are over-stated

962. For several projects with non-recurrent expenditure, Powercor provided supporting models which identify benefit streams to help justify the expenditure. Our assessment is that the benefits suffer from one if not more of the following issues:

- benefits are overstated – underlying assumptions do not pass the 'reasonableness test';
- benefits are not adequately supported by evidence; and
- benefits are assumed to be immune to erosion over time - in our view there is significant uncertainty in the longevity of some of the claimed benefit streams relied upon to generate a positive NPV for the project.

963. For every business case for which a model was presented, we undertook sensitivity studies to test the robustness of the proposed quantum and timing of the proposed expenditure to determine reasonable prospective negative variances. In some cases, such as Intelligent Engineering, we found that despite overstated benefits, the project is likely to be undertaken

347 Data from 2016 to 2020 are based on calendar year while 2921/22 to 2025/26 are based on financial year. All data provided by VPN

by a prudent operator. However, in other cases, we determined that the extent of expenditure is unjustified.

Approaches to recurrent expenditure timing varies between business cases

964. We consider that the strategy of maintaining ‘technology debt’ at prudent levels by balancing vendor refresh/upgrade recommendations with a combination of skipping some upgrades and extending maintenance support is consistent with good industry practice. However, in several instances, we identified planned upgrades and refreshes that are likely unnecessary and which we consider reflect unjustified capex. They will also put at risk the organisation’s capacity to efficiently absorb the change management workload which, in turn, will threaten the value of the upgrade.

Change management risk to project delivery may be under-recognised

965. In our opinion, business cases which promote integrating VPN and United Energy systems, consolidating on one platform and/or incorporating cloud hosting options are likely to provide long term net benefits (i.e., beyond the next RCP). However, there is significant change management risk in such projects, which may affect the delivery of the entire work program as proposed.

The ICT infrastructure cloud migration opex step change is reasonable

966. We consider that the proposed opex step change for VPN to account for the increase in hosting charges resulting from the transition of ICT infrastructure to the cloud is reasonable. The opex-capex trade-off is reasonable only with our proposed reduction to the proposed $36.0m capex for the refresh/upgrade of the remaining on-premise infrastructure.

8 REVIEW OF PROPOSED BUILDINGS AND PROPERTY CAPEX

In this section, we present our review of Powercor's proposed buildings and properties capex, which comprises three streams: (i) facilities security upgrades; (ii) depot developments (both new builds and redevelopments); and (iii) a proposed proactive building compliance program to rectify identified defects.

Except for a component of facilities security upgrades allocated to depots (which is likely duplicated), we consider that the proposed security upgrade expenditure is reasonable.

We consider that three of the five proposed depot developments (Ballarat, Bendigo and Warrnambool) are reasonable and have been adequately justified. We consider that an allowance for upgrade work is also justified for the two other proposed depot developments (Brooklynn and Echuca), though on the information provided to us, Powercor has not sufficiently justified the full scope and cost that it has proposed for these sites.

We consider that Powercor has not provided sufficient information to justify its proposed pro-active building defect rectification program.

8.1 Introduction

967. In this section we discuss and review Powercor's proposed expenditures for Building and Property for the next RCP. The proposed program of work comprises depot upgrades, facilities security upgrades and building compliance upgrades.

968. Powercor's business cases for some of its proposed work have been prepared in conjunction with CitiPower. Accordingly, we have reviewed the joint program expenditure, but provide our findings in this section specific to the Powercor expenditure component.

8.2 Overview of buildings and property expenditure

969. As shown in Table 8.1 below, Powercor proposes to spend a total of $115.5m (including real labour cost escalation) on buildings and property in the next RCP (2021 – 2026). This equates to an average of $23.1m per year, which appears to be broadly similar to expenditure in the current period.[348]

Table 8.1: RIN category - Buildings and property capex - $m, real 2021

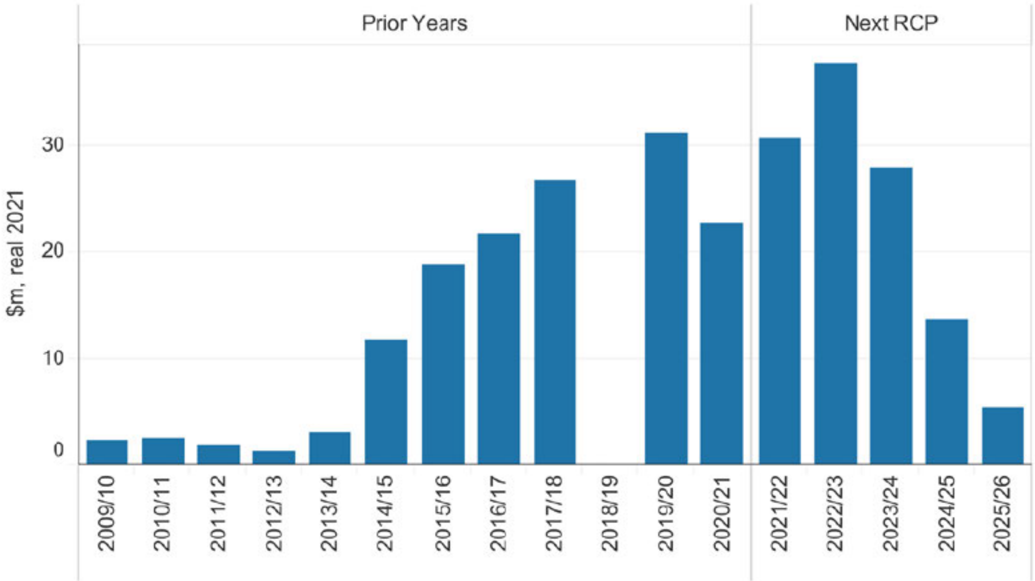
Asset Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total next RCP
Buildings and Property	30.7	37.7	27.9	13.8	5.4	115.5
Total	**30.7**	**37.7**	**27.9**	**13.8**	**5.4**	**115.5**

Sources: Powercor RIN001

348 Because of missing data for 2018/19, and current period comprising 5.5 years, we do not have the information for an exact comparison

970. The graph below shows Powercor's expenditure trend from prior years (2009/10 – 2020/21) compared to the next RCP (2021/22 – 2025/26). It shows a significant increase in expenditures from 2014/15. The proposed amount is forecast to peak in 2022/23 before decreasing in the following years.

Figure 8.1: Buildings and property capex trend graph - $m, real 2021



Source: Powercor RIN001 & RIN008. Powercor provided calendar year data of $28.9m for 2018 and $33.3m for 2019 (in $2021). It did not provide financial year data for the 2018/19 year hence we have left this blank in the graph, however an indicative amount could be reasonably interpolated.

971. Powercor's disaggregation of its proposed amount excludes real cost escalation and amounts to $114m.[349] As shown in Table 8.2 below, $79.2m (69.5%) of total expenditure is proposed for Powercor's depot upgrades and replacements, while $30.2m (26.5%) and $4.5m (4.0%) is proposed for its facilities and building compliance programs, respectively.

Table 8.2: Powercor Building and Property capex, excluding real cost escalation - $m, real 2021

Asset category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Facilities	8.6	6.5	5.5	4.8	4.8	30.2
Building compliance	1.4	1.4	0.9	0.5	0.5	4.5
Depot	20.6	29.4	21.1	8.2	0.0	79.2
Total Cost	**30.6**	**37.3**	**27.4**	**13.4**	**5.3**	**114.0**

Sources: EMCa analysis from PAL MOD 8.01

8.3 Review of proposed facilities security upgrades

8.3.1 Basis for Powercor's proposal

972. Powercor submitted its Business Case (PAL BUS 8.07) and options analysis models (PAL MOD 8.03) to support its proposed expenditures. The Business Case and the model are for both Powercor and CitiPower with the details of the split as shown in Table 8.3 below.

349 Powercor Regulatory Proposal, Table 8.1, page 106

973. According to Powercor, the proposed expenditure is to increase the security of its critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access.

Table 8.3: Facilities capex for Powercor and CitiPower - $m, real 2021

Company	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Powercor	8.6	6.5	5.5	4.8	4.8	**30.2**
CitiPower	3.0	2.1	1.6	1.4	1.4	**9.4**
Total	**11.6**	**8.6**	**7.1**	**6.2**	**6.2**	**39.6**

Source: EMCa analysis from PAL MOD 8.03, excludes real cost escalation

974. Powercor/CitiPower engaged an independent security review from Bellrock Group to assess the security of their critical assets using a risk-based approach. Based on that review, Powercor has developed a program to install new fencing, enhance monitoring measures such as anti-theft alarms and lighting, and to establish a security control room to proactively manage security alerts. According to Powercor, these measures will help ensure the safety of their staff, the community and their assets.

975. In its business case, Powercor/CitiPower states *'The Review noted that Powercor/CitiPower are managing some risks well, with good controls in place, and [are] recognised as having a strong commitment from the Executive and Board to improve its security program and underlying culture. However, it also identified that there are some gaps and a lower level of maturity when assessed against the industry and some high security risks across [our network]. This places CitiPower and Powercor at a higher level of risk, potential increased costs, lower operational effectiveness and increased reputation risk, compared to its peers.'*

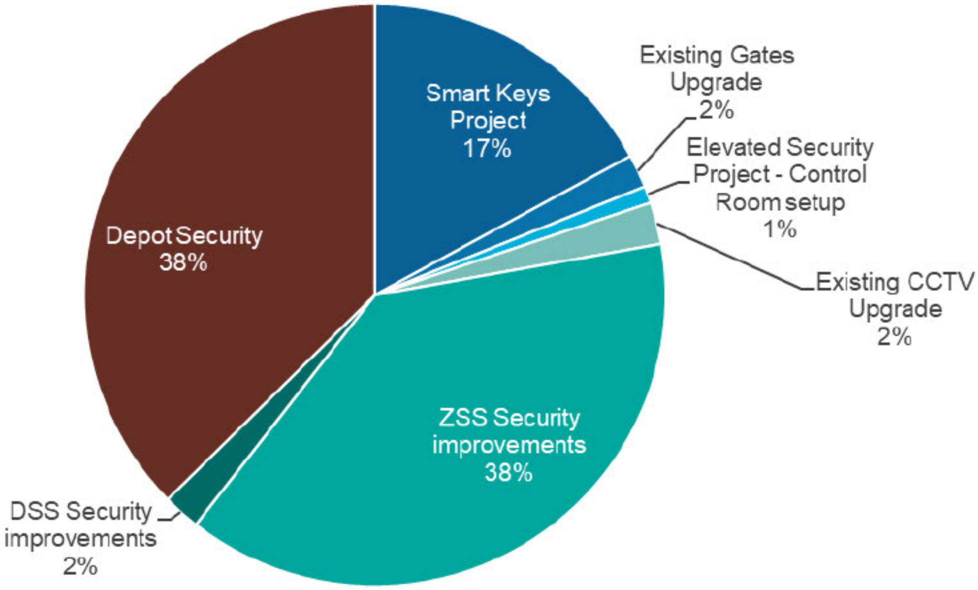
976. Details of the facilities projects proposed by Powercor and CitiPower are shown in the table and chart below.

Table 8.4: Powercor/CitiPower proposed Facilities projects - $m, real 2021

Proposed projects	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Smart Keys Project	4.3	2.5	0.0	0.0	0.0	6.8
Existing Gates Upgrade	0.7	0.0	0.0	0.0	0.0	0.7
Elevated Security Project - Control Room setup	0.4	0.0	0.0	0.0	0.0	0.4
Existing CCTV Upgrade	0.0	0.0	0.9	0.0	0.0	0.9
ZSS Security improvements	3.0	3.0	3.0	3.0	3.0	15.2
DSS Security improvements	0.2	0.2	0.2	0.2	0.2	0.8
Depot Security	3.0	3.0	3.0	3.0	3.0	14.8
Total	**11.6**	**8.6**	**7.1**	**6.2**	**6.2**	**39.6**

Source: EMCa analysis from PAL MOD 8.03, excludes real cost escalation

Figure 8.2: Powercor/CitiPower proposed Facilities projects - percentage breakdown



Source: EMCa analysis from PAL MOD 8.03

977. Powercor/CitiPower assessed three broad options for its proposed facilities program of work, which are:

- Option 0 - do nothing to invest in our facilities' security;
- Option 1 - address highest risk sites; or
- Option 2 - address all sites.

978. Costing of these options is shown in Table 8.5, with Option 1 being Powercor's preferred approach.

Table 8.5: Powercor/CitiPower options analysis costings - $m, real 2021

Company	Option 0	Option 1	Option 2
Powercor	0	30.2	54.6
CitiPower	0	9.4	52.4
Total	**0**	**39.6**	**107.0**

Source: EMCa analysis from PAL MOD 8.03, excludes real cost escalation

979. Option 1 is Powercor's preferred option for the following reasons:

- **Safe & dependable:** Option 1 supports the continued safe, reliable, and secure delivery of electricity;
- **Flexible:** Option 1 includes reasonable provisions to address increasing physical security threats according to industry best practice security standards; and
- **Affordable:** Option 1 reflects a balanced investment in physical security, targeting high risk sites.

8.3.2 Our assessment

Key assumptions in its CBA are not evidenced and some assumed benefits appear overstated

980. We reviewed Powercor's supporting documentation including its Cost Benefit Analysis model. Powercor's CBA sought to quantify a range of benefits as follows:

- Reduced risks of death or serious injury from unauthorised entry to zone substations and at distribution substations and from unserved energy arising from security breaches;
- Reduced risks of death or serious injury and reduced direct costs, from copper theft; and
- Reduced risks of death or serious injury, staff safety, damage by vandals and theft, from depots.

981. Powercor/CitiPower did not provide evidence to support the assumptions in its CBA. For example, it did not provide evidence of increasing risks of the type described above, or of the average incidence of such events. Whilst we acknowledge the nature of the risk-costs described, we consider that some input assumptions are questionable. For example, Powercor/CitiPower's assumptions regarding the likelihood of a death or serious injury are applied to several possible circumstances and then at each such facility.

982. For example, Powercor/CitiPower describes the risk of a death or serious injury from copper theft as a '*one in 100 year event'*. However, its calculation then multiplies that by 44, being the '*average annual number of unauthorised entry incidents*', such that its calculated risk becomes 44% in any one year.[350]

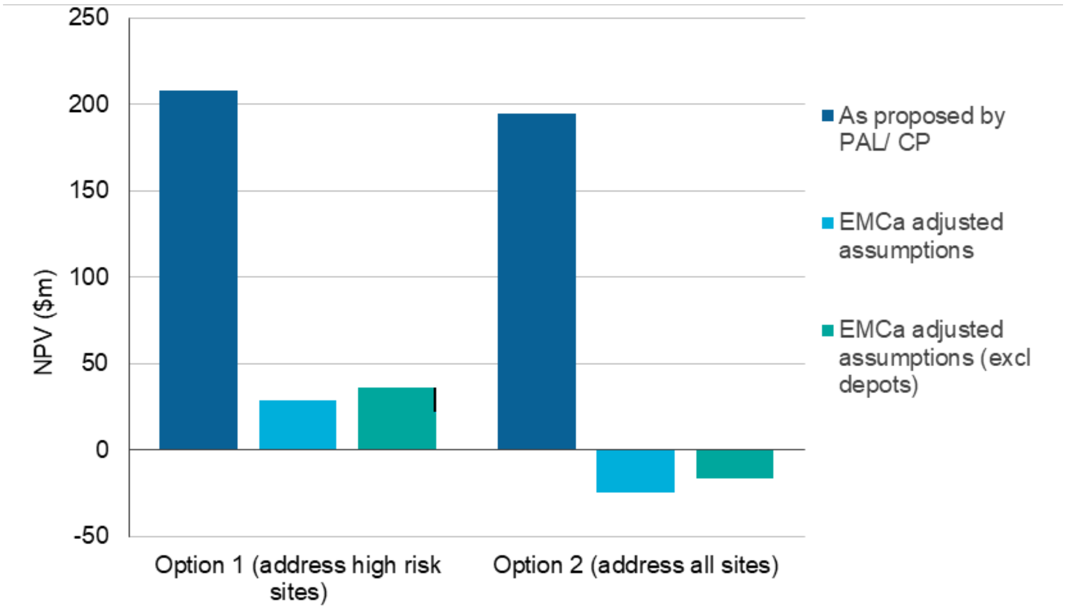
983. Taking all of the sources of risk in aggregate, we calculated that Powercor/CitiPower's assumptions imply that deaths or serious injuries are currently occurring across Victoria Power Networks at a rate of 1.6 per year. We would not expect this to be the case and Powercor did not provide evidence of such extreme current risk.

Our analysis indicates that the proposed Facilities Security program has a positive NPV and that upgrading only the 'key risk' distribution substation sites is the preferred option

984. As presented by Powercor/CitiPower, the proposed Facilities Security upgrades have a positive NPV of over $200m. However, our stress testing of the economic analysis suggests a much lower NPV, in the order of $30m, though still positive as shown in Figure 8.3 below. Our testing of the CBA also supports Powercor's proposed Option 1 as the preferred option – that is, upgrading key risk sites only. Taken in conjunction with the more moderate benefit assumptions described above, Option 2 (all sites) would have a negative NPV.

350 PAL MOD IR039 response, tab 'Option 0'

Figure 8.3: NPV analysis - $millions



Source: EMCa graph derived from PAL MOD IR39 – Q5

985. We sought information from Powercor as to how it had classified 'key risk' sites and also whether a subset of the proposed remediation measures had been considered. We are satisfied that Powercor has described a reasonable attribute-related assessment process by which it determined the key risk zone substation and distribution substation sites. However, Powercor did not similarly classify its depots based on risk and its CBA indicates that this program covers all 13 of the Powercor/CitiPower depots.[351] We come back to this in the subsection below.

986. We are also satisfied with Powercor's response that the remediation measures which comprise its program have been designed to operate as a package and to align with industry standard practices - and that there are not clear and obvious subsets of the proposed program that could achieve similar objectives.[352]

The 'depots' component of the facilities upgrade does not have a positive NPV and appears to duplicate costs that would be included with depot developments/re-developments

987. Of its 13 depots, we understand that Powercor is upgrading five in the current RCP and proposes to upgrade a further 5 in the next RCP. It seems both unlikely and imprudent that Powercor would undertake these depot upgrades without including adequate physical security in those works. Yet, in its Facilities upgrades CBA, Powercor/CitiPower has attributed benefits of reduced risks arising from its proposed upgrades to all 13 depots.

988. In assessing the Powercor/CitiPower CBA, we have assessed the sensitivity to removing all benefits attributed to depots. For consistency, we also removed all identifiable depot-related costs. As can be seen from Figure 8.3, the NPV of the program is higher when we exclude depot-related costs and benefits in the CBA model. This indicates that the depot component of the proposed facilities upgrades has a negative NPV.[353]

989. We also remain concerned that there is duplication between the depot-related cost component (which amounts to around $14m of the proposed Facilities security upgrade program) and Powercor's proposed expenditure on complete depot upgrades and new

351 Powercor advises that it has 13 depots, and CitiPower has one depot

352 Powercor response to IR039 PAL – question 5

353 We reach this conclusion with the model assumptions modified as referred to above. However, we have also tested with Powercor/CitiPower's assumptions unchanged; in this case, we find that the depots component effectively has a zero NPV

builds at up to 10 of its 13 depot sites.[354] Powercor describes this work as involving installing '*Gates technology, fencing, intruder detection, new CCTV and lighting*'.[355]

990. The depot upgrades that Powercor has proposed include complete new builds at some sites and major redevelopments at others. It does not seem logical to us that Powercor would plan such depot upgrades on a basis that does not meet industry standards or ENA security guidelines and which would not, for example, incorporate current standard security fencing, security lighting and similar into the work scope.

991. On the basis that the current five depot upgrades could reasonably be expected to comply with the industry standards that Powercor refers to, and if all five proposed depot upgrades were to be undertaken in the next RCP, then we would expect that the proposed $14m depot component of facilities upgrades could be proportionately reduced as this would leave only three Powercor depots otherwise proposed to be upgraded or rebuilt.

8.4 Review of proposed depot upgrades and rebuilds

8.4.1 Overview of Powercor's proposal and justification

Proposed sites and costs

992. Powercor proposes to spend $79.2m[356] for upgrading and building depots on new sites for the next Regulatory period (2021/22 – 2025/26).

Table 8.6: Powercor's proposed expenditure on depot upgrades and rebuilds - $m, real 2021

Depot Location	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Ballarat	7.9	8.0				16.0
Bendigo		11.1				11.1
Brooklyn	12.7	8.6				21.3
Echuca			5.7	8.2		13.8
Warrnambool		1.6	15.4			17.0
Grand Total	**20.6**	**29.4**	**21.1**	**8.2**		**79.2**

Source: EMCa analysis of Powercor MOD 8.01.

993. The works and associated drivers presented by Powercor in its Regulatory Proposal[357] are summarised below:

- ***Ballarat:*** *'we will redevelop and optimise our depot in Ballarat. The Ballarat depot has severely aged office facilities, which limits the number of resources it can house. There are poorly laid out material storage areas, limiting the type and volume of materials that can be stored on site and leads to poor traffic flow, necessitating the leasing of further storage space.'*
- ***Bendigo****: 'we will upgrade and expand our depot in Bendigo. Works are required to accommodate employee growth and consolidation of our contact centre into a single location. We will also update the facilities that have not been upgraded in 15 years. We will improve the current site layout to rectify poorly configured and inefficient material storage areas.'*

354 PAL model tab 'Option 1 Property costs', lines labelled Depot security

355 PAL BUS 8.07 Facilities Security, page 8

356 Excludes real cost escalation

357 Powercor – regulatory proposal – 31 January 2020 p. 106 – 107

- ***Brooklyn:* '*we will develop a depot at a site in Brooklyn and reallocate some resources from our Ardeer depot. The Ardeer depot was initially established as a gas and fuel site and was not constructed to service an electricity distribution business. As a result it suffers from poor layout, including an oversupply of office space but insufficient space for material and fleet storage. Building a depot at Brooklyn provides an efficient way of meeting capacity requirements for the rapid network growth in the western region.'*
- ***Echuca:* '*we will construct a new depot in Echuca following the purchase of land in 2019. This site no longer meets the operational and diversity needs for employees and equipment resulting from growth in the region. There is insufficient space resulting in congested traffic flows leading to safety risks and logistical inefficiencies with materials being moved between sites on a daily basis.'*
- ***Warrnambool:* '*we will purchase a replacement site and construct a new depot in Warrnambool. The existing depot layout is not fit for purpose with sub-optimal traffic flow and ineffective material storage, which can impact the safety of employees working onsite. The close proximity to the sea and resulting salt corrosion is doubling the deterioration of materials, fleet and buildings at the current site. In addition, we will improve facilities to meet increasing workplace diversity.'*

Powercor's business cases and other documentation

994. Powercor provided business cases for each of the five proposed depot redevelopments. Each business case includes some background information on the depot, a statement of 'identified need', a description of the treatment options considered including their costs, a brief summary of advantages and disadvantages and a recommendation.

995. In response to an information request (IR03), Powercor also provided budget estimates from a project and construction management firm for each of the depots.[358]

Cost benefit analysis (CBA)

996. In response to an information request (IR003), Powercor submitted CBA models in which it analysed the present value cost (PV cost) of each option for all depots. For most sites, Powercor considered four options:
    - Option 0: Do nothing;
    - Option 1: Redevelop existing site;
    - Option 2: Develop 'Greenfields site'; and
    - Option 3: Purchase 'brownfields' site.

997. For 'Brooklyn', Powercor's Option 1 is to develop the proposed new depot at Brooklyn, while its Option 3 is to redevelop the current site at Ardeer.

998. For Warrnambool and Echuca, Powercor also added an '*Option 4: Minimum Spend*.' This was an option requested by the AER to represent a minimum-scope project to address safety compliance issues.

999. Powercor presented its analysis in terms of the Net Present Cost (NPC) of each option. All options include risk cost, such as we describe below. Options other than '*Option 0: Do Nothing*' also include the capital cost of the proposed development. By comparing these to determine the option with the lowest NPC, Powercor is effectively treating the reduced risk costs of the upgrade options relative to the 'do nothing' counterfactual as benefits.

1000. Powercor uses assumptions in the models to derive PV cost, for factors such as the following, to the extent each is relevant to the particular depot and upgrade option:
    - Cost of inadequate storage;
    - Costs of outdated facilities;

[358] PAL ATT IR003 – documents for each of Ballarat, Bendigo, Brooklyn, Echuca and Warrnambool. By B2B Project and Construction Management. (These are variously dated in late April and early May, 2020)

- Cost of inadequate depot capacity;
- Costs of not addressing safety risks;
- Costs of suboptimal depot location;
- Loss of efficiency as a result of disruption;
- Loss of efficiency as a result of temporary facility;
- Loss of efficiency in transitioning to new depot; and
- Impact of coastal corrosion.

8.4.2 Assumptions in Powercor's cost benefit analysis

Key assumptions in its CBA are not evidenced, and some assumed benefits appear overstated

1001. We reviewed Powercor CBA models including the assumptions used. We sought further information on the basis for the 'benefit' assumptions, which effectively derive from the difference between the assumed costs if nothing is done and lower assumed costs if upgraded. However, Powercor did not provide evidence or other sources for the assumptions that it has made.

1002. We observe that the CBA is very sensitive to the relative cost assumptions between doing nothing and the proposed upgrade. We observe for example that:

- **Productivity assumption:** The Powercor analysis makes assumptions regarding productivity improvements arising from factors such as 'inadequate storage' and 'substandard facilities'. These are additive in Powercor's model, such that increases in productivity are assumed to occur for each factor and it could be that there is an element of duplication. For example, in the Bendigo CBA, Powercor assumes productivity improvements for 66 personnel arising from three different factors of 1.0%, 1.5% and 5%, respectively. This implies an aggregate productivity improvement of 7.5%.
- The assumed percentage improvements are not supported by evidence. For example, results could have come directly from the five similar upgrades and rebuilds that Powercor is undertaking in the current period. There is also an argument that 'benefits realisation' would imply a 7.5% reduction in staffing could be achieved in this instance.
- Using Powercor's assumptions, we calculate that the upgrades imply a $17.5m opex productivity benefit, taken over all of the depots in the next RCP. This should manifest as a benefits realisation through the ability to reduce staff numbers. However, Powercor does not show evidence of having considered this, and which could be a considered a top-down 'sense-check' on the assumptions.
- **Safety risk assumption:** Similarly, by way of a cross-check, we calculated the risk of a depot-related fatality using Powercor's risk assumptions. We find that those assumptions imply a probability of a depot-related fatality occurring of over 20% for Powercor during the next RCP. We consider it to be extremely unlikely that Powercor would be currently operating depots with safety risk levels this high. We consider it more likely that either the risk is not as high as Powercor's assumptions in its CBA or that the risk could be reduced considerably through mitigation measures with a lesser scope than building a new depot or rebuilding an existing depot.
- **Customer service assumption:** We observe that Powercor has accounted for reduced customer Unserved Energy costs arising both from 'inadequate depot capacity' as well as from 'inadequate storage'. Further, the percentage improvements are not supported by evidence, which we consider could have been obtained from benefits realisation assessment from previous rebuilds undertaken by Powercor. The additive treatment of these two factors raises the possibility of duplication.

1003. We tested the sensitivity of Powercor's resulting analysis, by modifying assumptions in the model. Primarily, we removed what could be considered 'duplicated' factors as above and, for safety risks, we introduced a 'Probability of Consequence' factor of 10%, on the basis that not each 'major safety incident' would necessarily result in a fatality. We also reduced other probabilities that had been entered without supporting evidence. The purpose of doing so is to stress test the net benefits of the proposed upgrades and rebuilds, and to assess whether Powercor's choice can be considered sufficiently robust.

8.4.3 Cost estimation

Powercor's cost estimates for the works are suitably evidenced

1004. We have compared Powercor's cost estimates with the budget costs for each depot prepared by B2B Project and Construction Management. We observe disaggregated budgets that appear to be specific to the requirements for each depot. The amounts tally with the amounts that Powercor has proposed (when contingencies are excluded).

1005. We also consider it relevant that Powercor is currently working through redevelopments of five depots in the current period and it therefore seems reasonable to expect that Powercor understands the cost of such works.

1006. On this basis, we consider that Powercor's cost estimates for each site provide a reasonable basis for the determination of allowances.

8.4.4 Redevelopment of current depot in Ballarat

Basis for Powercor's proposal[359]

1007. Powercor states in its business case that the current Ballarat depot is no longer effective because:

- *'the larger office building that houses the network construction group has not been upgraded in over 15 years and has a poor layout which limits the number of resources that can be housed in the building. There is also a lack of suitable meeting room spaces;*
- *there is insufficient storage space to cater for growth in the volume of spare equipment held, in particular, the current bunded area for the storage of transformers is insufficient to cater for growth in the volume of transformers;*
- *due to the lack of space, there are major difficulties in loading and unloading of materials; and*
- *there is insufficient space for the servicing team to undertake servicing works and store materials.'*

1008. To support the proposed expenditure, Powercor undertook four options analyses including a 'Do Nothing' option in response to our Request for Information (IR003).

1009. We reviewed and assessed the model and made some adjustments which we believe are reasonable.

Our assessment

The CBA supports Powercor's business case to redevelop the current Ballarat depot

1010. In its Business Case and CBA model, Powercor presents four options with input assumptions as discussed above. As shown in Table 8.7, the PV results with Powercor assumptions show that redeveloping the Ballarat depot has a lower PV cost compared with the do nothing counterfactual and also a lower PV cost than development at new greenfield or brownfields sites. Our sensitivity assessment supports Powercor's assessment.

[359] Summarised from PAL BUS 8.06

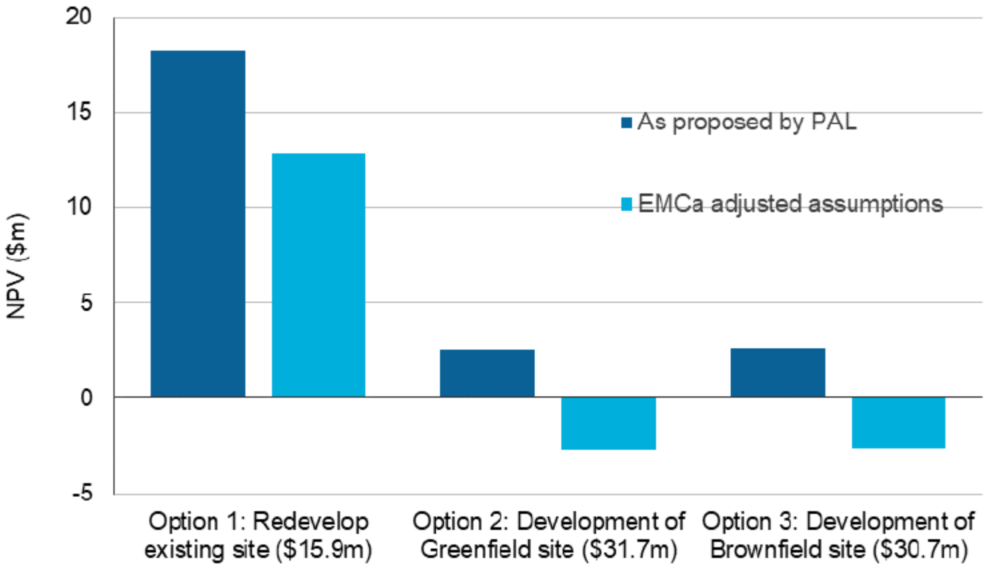
Table 8.7: Option analysis for depot at Ballarat - $m, real 2021

Description of option - Ballarat	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0	34.8	4	29.5	2
Option 1: Redevelop existing site	15.9	**16.5**	**1**	**16.7**	**1**
Option 2: Development of Greenfield site	31.7	32.2	3	32.2	4
Option 3: Development of Brownfield site	30.7	32.1	2	32.1	3

Source: EMCa table derived from PAL MOD IR003(a) – Ballarat depot

1011. As can be seen in Figure 8.4, our NPV analysis indicates that redeveloping the Ballarat site (Option 1) has a strong positive NPV. We consider that the proposed expenditure by Powercor for redevelopment of the Ballarat depot is reasonable.

Figure 8.4: NPV analysis for Ballarat depot - $millions



Source: EMCa table derived from PAL MOD IR003(a) – Ballarat depot

8.4.5 Redevelopment of current depot at Bendigo[360]

Basis for Powercor's proposal

1012. Powercor explains the reasons for the proposed expenditures to redevelop/upgrade the existing depot at Bendigo as follows:

- The current material storage areas are poorly laid out resulting in inefficiencies when loading materials to undertake project or rectification works;
- A car park is located in the middle of the depot so that workers must cross depot grounds where vehicles are operating in order to access the office buildings, which creates potential safety issues;
- Strong population growth in Bendigo has increased the operational requirements of the depot. Between 2016 and 2026, the number of residential dwellings is forecast to grow by 31%. If Powercor does not upgrade the Bendigo depot, it will not be able to keep pace with forecast growth in workloads and materials storage requirements leading to detrimental response times and network reliability performance; and

360 Summarised from PAL BUS 8.05

- The front office facilities have not been upgraded in over 15 years and require significant modifications in order to modernise the facility and maximise the available space.

Our assessment

The CBA supports Powercor's business case to redevelop the existing Bendigo site

1013. In its Business Case and CBA model, Powercor presents four options with input assumptions as discussed above. The PV results with Powercor assumptions show that developing the new depot at Bendigo has a considerably lower PV cost compared with the do nothing counterfactual. While our sensitivity assessment indicates a lower PV cost for the do nothing counterfactual than Powercor calculates, it nevertheless supports Powercor's assessment that redeveloping the Bendigo site has a lower PV cost compared with 'do nothing' and is the preferred development option.

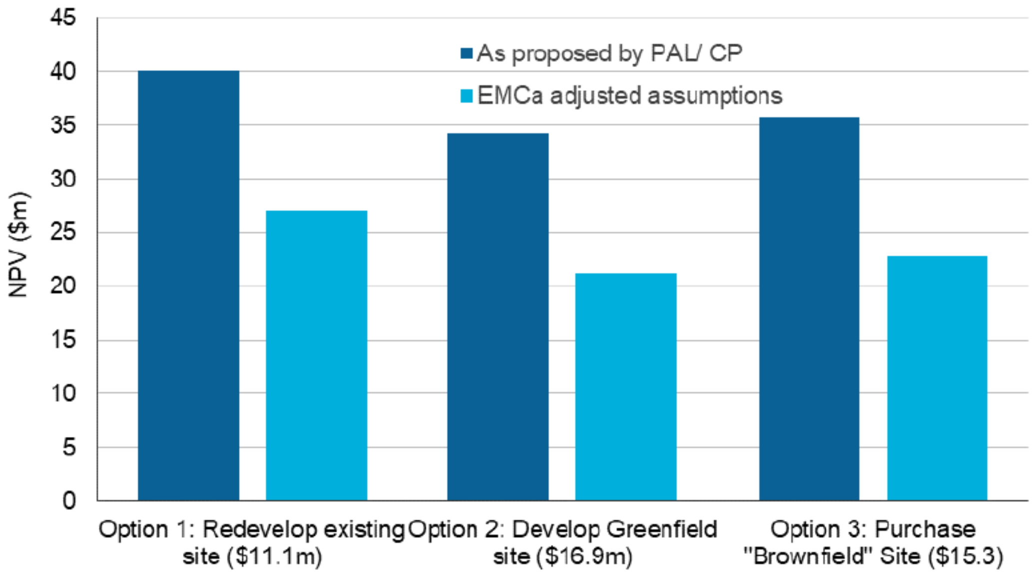
Table 8.8: Option analysis for proposed depot at Bendigo - $m, real 2021

Description of option	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	60.9	4	45.9	4
Option 1: Redevelop existing site	11.1	**20.9**	**1**	**18.9**	**1**
Option 2: Develop Greenfield site	16.9	26.7	3	24.7	3
Option 3: Purchase "Brownfield" Site	15.3	25.1	2	23.2	2

Source: EMCa table derived from PAL MOD IR003(b) – Bendigo depot

1014. This result is presented in Figure 8.5, which shows the NPV of each of the development options relative to the 'do nothing' counterfactual. Both under Powercor's assumptions and with our more conservative sensitivity assumptions, the proposed project shows a positive NPV, with Powercor's proposed redevelopment of the existing site having the highest NPV. Powercor's proposal also has the lowest capital cost of the development options considered.

Figure 8.5: NPV analysis for depot at Bendigo - $millions



Source: EMCa graph derived from PAL MOD IR003(b) – Bendigo depot

1015. We consider that the proposed expenditure by Powercor for redevelopment of the Bendigo depot is reasonable.

8.4.6 Development of new depot on a site at Brooklyn

Basis for Powercor's proposal[361]

1016. Powercor states that the proposed development of the depot at Brooklyn will allow for the relocation of resources from the Ardeer depot which currently houses approximately 200 operational resources. This depot has an inefficient layout with an oversupply of office space and insufficient space for effective material and fleet storage. The limited onsite storage space means that materials are scattered throughout the site making loading materials prior to commencing works cumbersome and time consuming. This site was initially established as a gas and fuel site and was not constructed as a purpose-built-facility for servicing an electricity distribution business. There is also a lack of secure fencing, creating safety concerns.

1017. Further, the Ardeer depot services the Western growth corridor which, according to Powercor, is experiencing strong growth. For example, the number of customer connection assessments has nearly doubled from 504 in 2014 to 938 in 2017. Between 2016 and 2026, the number of residential dwellings is forecast to grow by 38%. Zone substations including at Torquay and Tarneit are also being built in the upcoming period, which will add to operational requirements. Accordingly, the volume of work managed from this depot is expected to increase significantly.

1018. Powercor forecasts continued strong growth in the western corridor of Victoria over the 2021-2026 regulatory period and believes it will not otherwise be able to efficiently manage the volume of works required - with consequential adverse impacts on operational performance, including deteriorations in connection times, emergency response times and network reliability - if it does not invest.

1019. Powercor states that the location of the new Brooklyn depot also provides an ideal location for the storage of materials required to service the network. Currently, bulky materials such as cable and distribution transformers that are required to service the growing Western Corridor area are stored at a number of sites and various zone substations due to a lack of available space. This presents significant logistics and security issues.

Our assessment

The CBA does not appear to support a business case to develop a new depot at Brooklyn with the scope and cost that Powercor has proposed

1020. In its Business Case and CBA model, Powercor presents four options with input assumptions as discussed above. The PV result of the options with Powercor assumptions shows that developing the new depot at Brooklyn has a considerably lower PV cost compared with the do nothing counterfactual. However, our assessment shows how sensitive this result is to the assumptions that Powercor has chosen. The sensitivity assumptions that we have applied would lead to 'doing nothing' being preferable to developing the new depot at the scope and cost that Powercor has proposed.

1021. Of the development options (i.e., Options 1 to 4), our sensitivity analysis does support development of the new depot at Brooklyn as the preferred development.

[361] Summarised from PAL BUS 8.04

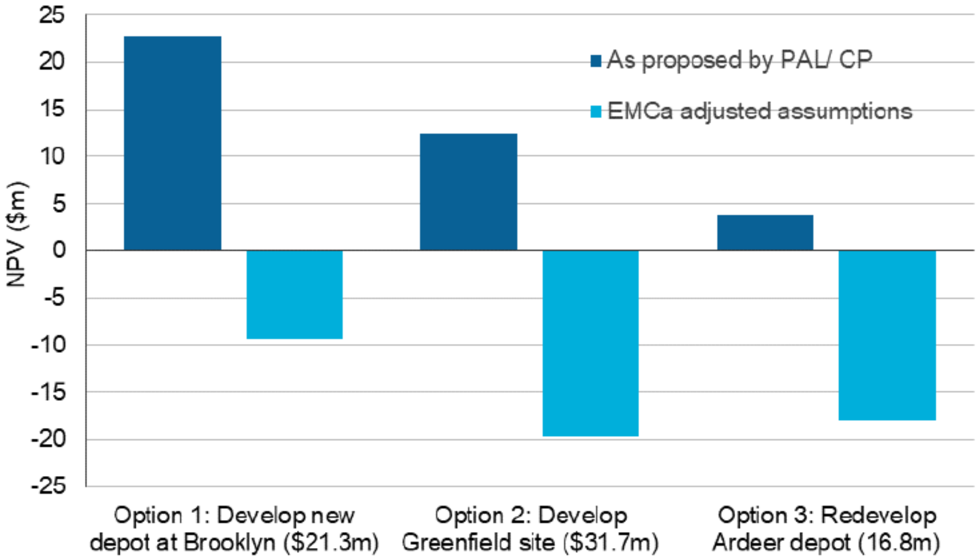
Table 8.9: Option analysis for proposed depot at Brooklyn - $m, real 2021

Description of option	Undiscounted capex[362]	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0	45.4	4	**13.3**	**1**
Option 1: Develop new depot at Brooklyn	21.3	**22.6**	**1**	22.6	2
Option 2: Develop Greenfield site	31.7	32.9	2	32.9	4
Option 3: Redevelop Ardeer depot	16.8	41.6	3	31.4	3

Source: PAL MOD IR003(c) – Brooklyn depot

1022. The result in Figure 8.6 below shows the NPV of each of the development options relative to the 'do nothing' counterfactual, both under Powercor's assumptions and with our more conservative sensitivity assumptions. It shows that, using de-rated benefit assumptions as described above, all options would have a negative NPV, although the Brooklyn development (Option 1) is the least negative. Based on the information that Powercor has provided, our assessment therefore indicates concerns with the option that Powercor has proposed to address the issues at this site.

Figure 8.6: NPV analysis for proposed depot at Brooklyn - $millions



Source: PAL MOD IR003(c) – Brooklyn depot

1023. The material that Powercor provided does indicate the need for some form of action to address the deficiencies that it has identified with the current depot in Ardeer. We sought further information from Powercor on possible less comprehensive options that could be considered. Powercor replied that redeveloping the Ardeer site is essentially infeasible, and would cost around $16.8m, but would not address the shortcomings inherent in the Ardeer site's location. Powercor did not provide the AER with analysis for a 'minimum spend' option.

362 Excludes real cost escalation

8.4.7 Development of new depot on a "Greenfield" site at Echuca

Basis for Powercor's proposal[363]

1024. Powercor states in its business case that the current Echuca depot houses operational employees on a land size of 5500sqm/1.4 acres. Capital improvements were completed at the depot throughout 2013. The opportunity to expand the current site is severely limited due to the existing HV (66kv) line that adjoins the depot. As a result, Powercor has purchased land for a replacement site in 2019, valued at $1.2m.

1025. Further Powercor states that strong population growth in Echuca has increased the operational requirements of the depot. Between 2013 and 2026 the number of residential dwellings is forecast to grow by 17%. The closest depots from which Powercor could get additional resources or stores are located at least an hour away in Shepparton and Cobram. Powercor states that these depots are already highly utilised and would have limited capacity to service the Echuca area.

1026. Powercor explains that the current Echuca depot site is of insufficient size to cater for operational requirements as evidenced by the need to currently lease an additional 500sqm for the storage of network equipment. This lease was established in 2015 at a cost of $0.01m per annum. Further, a zone substation and associated HV cables located next to the depot restricts Powercor's ability to expand further on the site. As a result of space constraints, there are existing logistical inefficiencies with materials (predominantly poles) being moved between sites on a daily basis. The limited onsite storage space means that materials are scattered throughout the site making loading materials, prior to commencing works, cumbersome and time-consuming.

1027. In its business case, Powercor also states that a health, safety and environment review of the Echuca depot found that the confined depot layout presented a number of risks, namely:

- a shared area for private car parking and heavy fleet vehicles, meaning pedestrian activity is occurring in close proximity to the operation of heavy vehicles and cranes;
- vehicles exiting the depot having to perform a turn onto the busy Midland Highway;
- large store trailer having to reverse into the store area representing a risk to staff operating within the store area; and
- drivers having to manoeuvre large vehicles within tight confines due to the lack of adequate traffic flow throughout the site.

Our assessment

The CBA does not appear to support a business case to develop a new depot at Echuca at the scope and cost that Powercor has proposed

1028. Powercor presents five options including a 'Do Nothing' option. The results of the options analysis with Powercor assumptions and our scenario-adjusted assumptions are shown in Table 8.10 below.

1029. The PV results with Powercor assumptions suggest that developing a new depot at Echuca has a lower PV cost compared with the do nothing counterfactual and a lower PV cost than the other development options. However, Powercor's PV cost for its proposed option is within 15% of the PV cost of all other options (including 'do nothing'), except for Option 1: Redevelop the existing site, which is the least preferred.

1030. Our assessment shows that, with the sensitivity adjustments that we describe in section 8.4.2, the 'Do nothing' option has a lower PV cost than the greenfield site development that Powercor has proposed and a lower PV than each of the other options.

363 Summarised from PAL BUS 8.02

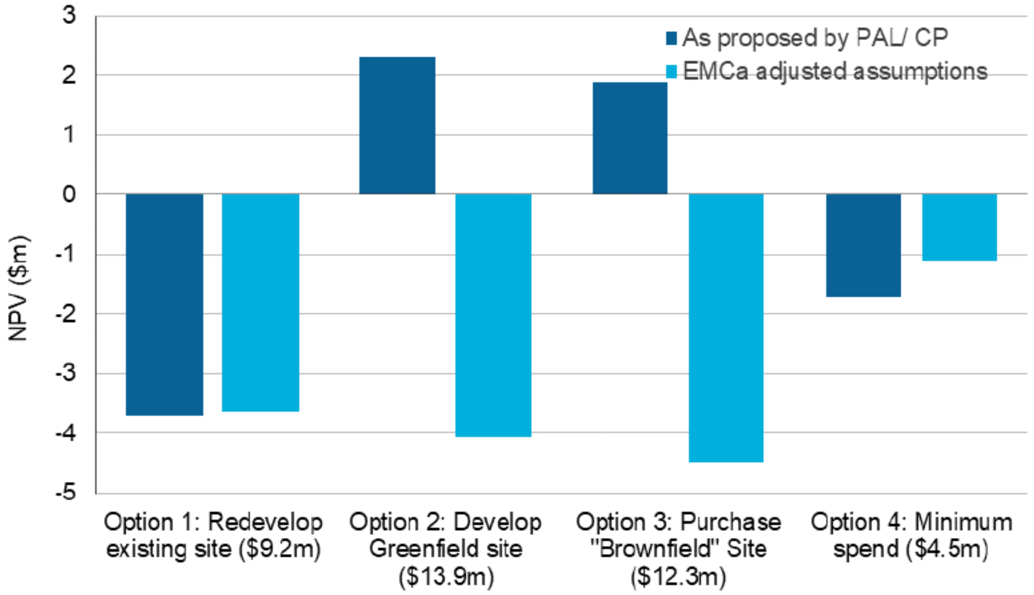
Table 8.10: Option analysis for development of new depot at Echuca - $m, real 2021

Description of option	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	19.0	3	**11.3**	**1**
Option 1: Redevelop existing site	9.2	22.7	5	14.9	3
Option 2: Develop Greenfield site	13.9	**16.7**	**1**	15.3	4
Option 3: Purchase "Brownfield" Site	12.3	17.1	2	15.8	5
Option 4: Minimum spend	4.5	20.7	4	12.4	2

Source: EMCa table derived from PAL MOD IR003(d) – Echuca depot

1031. In Figure 8.7 below, we show the NPV of each of the upgrade options relative to the 'Do nothing' counterfactual. With more conservative assumptions, each of the development options shows a negative NPV. A 'minimum spend' option shows the least negative NPV.

Figure 8.7: NPV analysis for Development of new depot at Echuca - $millions



Source: EMCa graph derived from PAL MOD IR003(d) – Echuca depot

Deferral or minimum spend appear to be the preferred options

1032. The proposed Echuca depot development would be completed in the later years of the next RCP. We infer from this that Powercor has recognised this development as lower priority. From Powercor's analysis, it is difficult to support the proposed development occurring in the next RCP.

1033. We consider that some form of 'minimum spend' would appear to obviate the need for the proposed depot development, or to provide the opportunity to defer it until the need is stronger.

8.4.8 Development of a new depot on a "Greenfield" site at Warrnambool

Basis for Powercor's proposal[364]

1034. The current Warrnambool depot houses 60 operational employees on a land size of approximately 20,000sqm.

364 Summarised from PAL BUS 8.03

1035. As Powercor states in its business case, the proximity of the current depot to the sea poses issues relating to accelerated deterioration of materials, fleet and buildings due to salt corrosion. Warrnambool is located in the highest salt corrosion exposure area in Victoria. Therefore, Powercor believes that a more suitable location should be identified that is further inland and thus not impacted by these conditions to the same degree.

1036. Powercor has undertaken analysis on the impacts of salt corrosion on asset failures and which demonstrates a doubling of asset failures in high corrosion areas compared with low corrosion areas. Powercor provided some evidence of site photos capturing the salt corrosion of network assets.[365]

1037. Powercor further states that the current depot layout is not 'fit for purpose' with poor traffic flow and ineffective materials storage. The limited onsite storage space means that materials are scattered throughout the site making loading materials prior to commencing works cumbersome and time consuming. These issues were unable to be addressed via the prior upgrade due to the limited land size and location of existing buildings. Issues will be compounded in future due to strong population growth in the region, which will increase the operational requirements of the depot. Between 2016 and 2026, the number of residential dwellings is forecast to grow by 25%.

1038. The car park is easily accessible to the public and is located in the front of the property without proper security fencing. Powercor believes that this creates security and safety concerns from potential break-ins.

Our assessment

The CBA supports Powercor's business case to develop a new site to replace the current Warrnambool depot

1039. In its Business Case and CBA model, Powercor presents four options with input assumptions as discussed above. The PV results with Powercor assumptions show that developing a new depot at Bendigo has a lower PV cost compared with the do nothing counterfactual and also a lower PV cost than either redeveloping the existing site or 'minimum spend'.

1040. Powercor presents five options including 'Do Nothing' option. The results of the options analysis with Powercor assumptions and our adjusted assumptions are shown in Table 8.11 below.

Table 8.11: Options analysis for development of a new depot in greenfield site at Warrnambool - $m, real 2021

Description of option - Warrnambool	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	25.4	3	20.8	2
Option 1: Redevelop existing site	12.7	29.9	4	25.9	5
Option 2: Develop Greenfield site	17.0	**21.4**	**1**	**20.7**	**1**
Option 3: Purchase "Brownfield" Site	14.3	21.9	2	21.0	3
Option 4: Minimum spend	2.5	30.2	5	25.4	4

Source: EMCa table derived from PAL MOD IR003(e) – Warrnambool depot

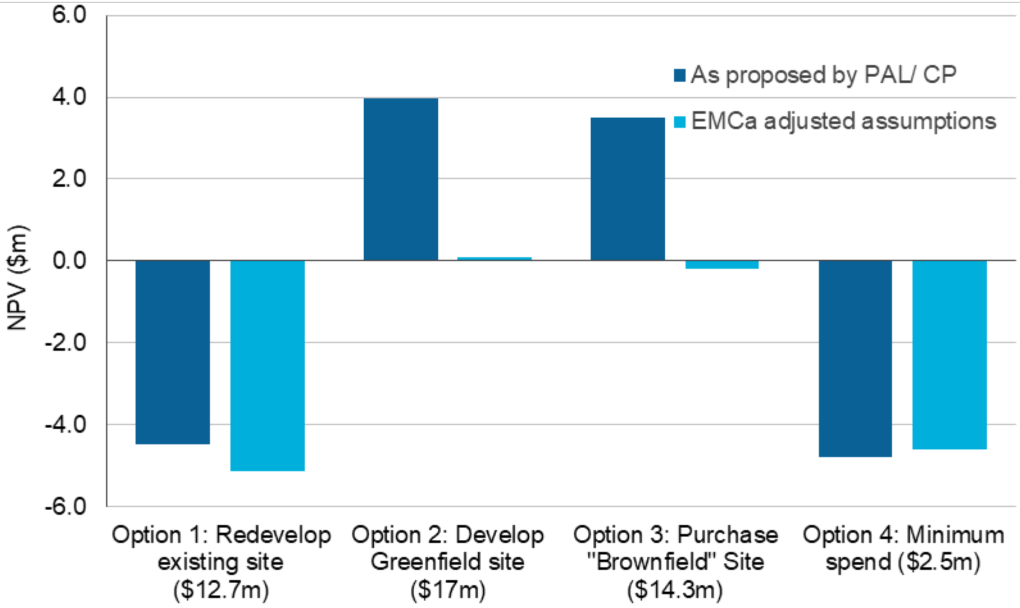
1041. Our sensitivity assessment supports Powercor's assessment that developing a site at a new location is preferable to redeveloping the existing site or the 'minimum spend' option. However, our assessment indicates that the economics are more finely balanced than Powercor's assessment.

1042. This result is illustrated in Figure 8.8, which shows the NPV of each of the development options relative to the 'do nothing' counterfactual. Under Powercor's assumptions the

365 Appendix B

proposed project shows a clearly positive NPV, with Powercor's proposed redevelopment of the existing site having the highest NPV. With our more conservative sensitivity assumptions the project is marginally positive but could still reasonably be accepted as meeting an NPV hurdle.

Figure 8.8: NPV analysis for a new depot in greenfield site at Warrnambool - $millions



Source: EMCa graph derived from PAL MOD IR003(e) – Warrnambool depot

For Warrnambool, a brownfields development would deliver essentially the same net benefits, but with a lower capex

1043. Both with Powercor's assumptions and with our sensitivity analysis assumptions, there is no meaningful difference in the NPV cost of developing a greenfield site or the lower capital cost purchase and development of a brownfields site. On Powercor's costing, the brownfields option would require $2.7m less capex than the greenfield option. We have further reviewed Powercor's assessment of the advantages and disadvantages of a brownfield development.[366] These also appear to be finely balanced and some of the mooted disadvantages could be considered hypothetical prior to identifying specific potential sites.

1044. In response to an IR,[367] Powercor stated that it had researched possible properties for brownfields development and concluded that the majority would not be suitable. While Powercor concluded then that finding a suitable brownfields site is highly unlikely, it nevertheless retained this as an option.

1045. On current information, therefore, we consider that a brownfields development would represent a reasonable assumption for expenditure allowances purposes - only when Powercor reaches the point where it must select a site, will the available options be known.

[366] PAL BUS 8.03, page 8

[367] Powercor response to PAL IR 039

8.5 Review of proposed building compliance-related expenditure

8.5.1 Basis for Powercor's proposal

1046. Powercor proposes expenditure of $4.5m[368] for Building Compliance for the next regulatory period. Its preferred option is to undertake a full audit and to undertake a proactive defect rectification program.

1047. Powercor commissioned a site audit for what appears to be one zone substation site. Powercor shows a cost estimate of around $37,000 for compliance rectification for this site[369] and has extrapolated from this, with adjustments, to determine a budget of just under $2m (in $2019 terms) for the zone substation element of the work.

1048. Powercor has estimated the remainder of its forecast from an assumed cost of $5,000 applied to each of 477 distribution substations.

1049. Powercor has presented, but dismissed, an alternative of what amounts to a reactive approach, undertaking corrective measures 'as they arise' with an estimated cost of $3.2m. It is unclear what process Powercor would follow to identify such issues.

8.5.2 Our assessment

Need not clearly established

1050. Powercor's need to undertake such work is somewhat undermined by its proposal to commence this work only in 2021/22. Powercor refers to the potential for financial penalties for non-compliance; however, it also refers to the issues as dating from their time of construction by SECV or by local councils (which would have been at least 25 years ago). Powercor does not provide evidence of either recorded safety incidents or any past compliance penalties, nor does it indicate that it is currently undertaking, or has recently undertaken, such defect rectification work. This raises the question as to why Powercor considers that they warrant rectification commencing in 2021/22, whether they will be otherwise subject to compliance penalties, or the extent of the safety risk. Whilst the nature of the defects identified in the audit may warrant rectification at some point, Powercor has not demonstrated this to be the case.

Cost estimate not sufficiently established

1051. There appears to be no audit or other evidence to support the cost estimate for the majority of the proposed work for Powercor's distribution substations. Further, we question the validity of extrapolating costs from a single site audit of one zone substation to 84 others.[370]

8.5.3 Summary and implications

1052. We consider that Powercor has not sufficiently justified its proposed building compliance expenditure for proactive defect rectification in the next RCP.

[368] Excludes real cost escalation.

[369] PAL BUS 8.01, page 11. This figure is in $2019. We note that the breakdown table shown on page 12 of this document shows a 'total budget estimate' of $167,700 for the audit site, however the component items in this table do not add to this figure, but rather, support the $37,000 figure that Powercor has used

[370] Refer to PAL BUS 8.01, page 11

8.6 Findings and implications

8.6.1 Findings summary

Facilities security upgrades

Except for the depot component, we consider that the proposed expenditure for facilities security upgrades is reasonable

1053. We consider that Powercor's proposal to upgrade security at its 'high risk' substations, is justified. However, we consider that there is an element of duplication in the proposed security upgrades for depots, given Powercor's program of rebuilding most of those depots. Further, on review of the cost benefit assumptions, we consider that Powercor has not demonstrated a positive business case.

Depot redevelopments

Three of the proposed depot developments are reasonable

1054. We consider that Powercor has made a reasonable case for the following:

- Redevelop the current depot at Ballarat;
- Redevelop the existing depot at Bendigo; and
- Develop a depot at a new site, to replace the Warrnambool depot. However, from the information that Powercor provided, we consider that development of a brownfields site would appear to provide essentially the same benefits, at a lower cost.

Powercor has not reasonably justified inclusion of allowances for two proposed new depot developments

1055. On the information provided by Powercor, and on our review of the assumptions made, the following do not appear to have a positive business case:

- Developing a new depot on Powercor's site at Brooklyn, to replace Powercor's Ardeer depot; and
- Developing a new depot on a greenfield site at Echuca.

1056. For these two depots, an option should be considered to do nothing and/or provide for a minimum spend option for priority rectification work. This will allow for deferral of the more significant investment proposed by Powercor until there is a positive business case.

Building compliance program

Powercor has not reasonably justified inclusion of the proposed proactive building compliance program

1057. Powercor has not demonstrated the need for this program in the next RCP, or that, if proactive building compliance rectification is required, that it has made a reasonable forecast of the cost.

8.6.2 Implications of findings

1058. Powercor's proposed expenditure is $115.5m including real cost escalation. Powercor has provided project and program-level costs of $114m, which excludes real cost escalation.

1059. The implications of our findings above are as follows:[371]

[371] The figures here are at the project / program level, and exclude real cost escalation

- The $14m depot component of Powercor-related facilities security upgrades amounts to around $1m per depot. If such work was required only at the three depots that are not being newly built or rebuilt in the current and next RCP, then an amount of around $8m to $10m less than this would appear to suffice (depending on the number of depot redevelopments that proceed, as below);
- If the new depots at Brooklyn and Echuca are not required in the next period, that would reduce the required expenditure by $35.1m. An allowance for priority safety and other compliance-related works may be required in its place. Where Powercor has estimated costs for such work, it was in the order of $2.5m to $4.5m per depot.
- For the replacement of the Warrnambool depot, there would be a reduction of $2.7m in the depot developments allowance by selecting a brownfields option as the basis for the proposed allowance.
- If the proposed proactive building compliance rectification program was not undertaken, then this would reduce Powercor’s required expenditure by $4.5m. An allowance for reactive or prioritised compliance rectification may be required in its place.

9 REVIEW OF PROPOSED OPEX STEP CHANGES

In this section we consider the opex step increases that Powercor has proposed for reclassifying as 'minor repairs opex' certain repair costs that it has previously classified as repex, and to expense EDO fuse replacements.

We consider that Powercor has not presented a reasonable case for the proposed amounts to be included in its opex allowance. We base this finding both on our consideration of the case that Powercor has presented for reclassification, as well as information that it has provided as the basis for determination of the proposed amounts, which we consider to lack sufficient justification.

9.1 Introduction

1060. In its Regulatory Proposal, Powercor has proposed step changes to its opex that it describes as delivering new customer benefits and which are incremental to its 2019 base year costs: (i) solar enablement; (ii) IT cloud migration; and (iii) EDO fuse replacement; along with (iv) a base year adjustment for minor repairs opex.

1061. In this section, we consider Powercor's proposal to reclassify and add components to its opex allowance, for 'minor repairs' and for EDO fuse replacements. We have separately assessed the proposed opex step change for solar enablement in section 6 and for IT cloud migration in section 7.

9.2 Minor repairs opex addition to base year opex

9.2.1 Powercor's proposal

1062. Starting from the next RCP, Powercor proposes to reclassify what it refers to as 'minor repairs' as opex and has proposed an opex step increase as part of its Base Step Trend (BST) based opex forecast, as shown in Table 9.1 below.[372] Powercor currently capitalises this expenditure as repex.

Table 9.1: Powercor's proposed opex step increase for reclassification of minor repairs opex - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Minor Repairs	3.8	3.8	3.8	3.8	3.8	18.8
Total	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**18.8**

Source: EMCa analysis from Powercor RIN001

1063. Powercor's justification for its proposal is as follows:[373]

> *"Typically, minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired);*

[372] Powercor applies this as a base year adjustment, rather than a step change. However, it has also presented it as an annual and equal amount – which mathematically is the same in any case. For convenience, we will use the general term 'step change' to describe the proposed amount in line with the BST terminology

[373] Powercor Regulatory Proposal, page 124

Treating minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period; and

We propose to adjust our base year operating expenditure for the total cost of minor repairs in 2019 and remove any forecast minor repairs from our capital replacement expenditure forecast. These changes are net present value (NPV) neutral, which means customers are no worse-off in the long term."

1064. Powercor also provided a workbook in which it had recast historical repex which it considers would have fit into the new 'minor repairs' classification[374] as opex, and its Cost Allocation Methodology.[375]

9.2.2 Our assessment of Powercor's proposed expenditure re-classification

Approach to our assessment

1065. In undertaking our assessment, we have considered the following three factors:

- In order to accept a reclassification such as Powercor has proposed, we consider that it is necessary to first have a clear definition of the relevant expenditure types, and that is capable of auditable application. Without a clear definition, it would be possible for a regulated business to propose expenditure as opex for regulatory proposal purposes, but to apply regulatory accounting classifications in such a way that some or all of the proposed opex is nevertheless capitalised. This would allow the business to retain the opex underspend and, under efficiency carry-over scheme mechanisms such as the EBSS, to enjoy further benefits in the following regulatory period, while capitalising the relevant expenditure for inclusion in the RAB and subsequent recovery through returns and depreciation.
- Secondly, we sought to understand the nature of the work that Powercor is proposing to classify.
- Thirdly, if we were to propose accepting the reclassification as an opex step change, it is necessary to gain confidence in the basis for the proposed amount.

Defining minor repairs

We established clear definitions from information provided by SAPN when it sought a similar reclassification – and which AER accepted in its decision

1066. In its 2020-2025 Regulatory Proposal, SAPN proposed a similar reclassification, although the SAPN case was specific to what it deemed as 'minor repairs' to cables and conductors. In its decision, the AER accepted this reclassification though with an adjustment to the amount.

1067. SAPN explained its distinction between minor repairs to be treated as opex and 'refurbishment' (repex), and which we summarised in our report to the AER as follows:

"Minor repair work is work that would typically be discarded when a subsequent refurbishment is undertaken, whereas a refurbished section of conductor or cable would be retained in the event of subsequent further refurbishment of the cable or conductor;

Minor repair work could therefore not be considered to be extending the life of the asset, but its purpose is rather either addressing a failure or addressing a defect that is likely to lead to failure;

[374] PAL RIN003 – Workbook 3 – Recast category analysis

[375] PAL ATT027 – Cost Allocation Methodology – Jan2020 - Public

Refurbishment is of a scale such that it is treated internally as a 'project', and is therefore subject to project protocols in regard to decision-making, resourcing and management of the work; and

Refurbishment of cables would typically involve replacing a whole section of cable; similarly, conductor refurbishment typically involves replacing a whole section of conductor. Minor repair works on the other hand tend to involve cutting and re-joining and/or patching a new and much shorter length of cable or conductor, and/or application of a joint or sleeve."[376]

1068. From this, we identified three factors as summarising SAPN's definition of minor repairs opex, namely that it would involve:

i. *small segments of cable or conductor (with the majority resulting from failures or localised defects);*

ii. *a large number of repair projects (several thousand per year) with a small unit cost per repair; and*

iii. *repaired lengths would be abandoned if the cable or conductor was subsequently replaced*.[377]

1069. On the basis of this definition, and of expenditure information that SAPN provided consistent with that definition, we proposed that the AER accept the reclassification (although, based on other information that SAPN provided, we advised not accepting the proposed amount).

Powercor's definition of minor repairs leaves room for interpretation

1070. The only relevant clause that we observe in Powercor's Cost Allocation Method is a statement that the following is not capitalised:

"minor repairs resulting from asset failure and identified defects that could result in an imminent asset failure (if not repaired)"[378]

1071. As a definition of minor repairs, this has an element of circularity. However, the statement that such repairs result from *asset failures* and from *identified defects that could lead to imminent asset failure*, does provide some refinement to the definition.

1072. If a 'repair' resulting from an *asset* failure was that the asset was replaced, then this would be replacement capital expenditure, not opex. If the repair resulted from a *component* failure that may (if not repaired) lead to failure of the asset (and assuming that the asset was repaired and not replaced), then this could potentially form the basis for an auditable definition of an opex minor repair. However, this is not how Powercor has defined what it proposes as minor repairs in its Cost Allocation Methodology.

1073. The part of Powercor's definition that relates to defects could also be open to wide interpretation as to whether a failure was imminent, and therefore whether or not to classify it as minor repair opex or to capitalise it as repex.

1074. We consider that Powercor has not provided a clear, auditable definition of a minor repair that is consistent with regulatory accounting practices regarding the distinction between opex and capex.

Identifying expenditure that Powercor proposes classifying as minor repairs

Powercor's supporting expenditure information

1075. Powercor has based its proposed step change amount on what it presents as a review of its 2019 minor repairs expenditure, as shown in Figure 9.1.

376 EMCa review of aspects of SAPN's 2020-25 RP (September 2019) page 58

377 Ibid, page 62

378 ATT 027 Cost Allocation Methodology, page 11

Figure 9.1: 2019 minor repairs opex, as presented by Powercor at onsite meeting

Powercor Asset type	Type of works	2019 estimate, $000 2019
Underground	Cable termination/joint minor works	$114
Underground	SWER Iso earth minor works	$330
Major plant	Zone substation switchyard lighting	$148
Major plant	Transformer oil regeneration	$29
Overhead	Overhead conductor minor works	$1,134
Underground	Underground cable minor works	$1,847
	Total expenditure	**$3,602**

Source: PAL EMCa presentation May 2020, page 32. Note that this information is in $2019, and this is the basis for the proposed annual amount of $3.8m when escalated to $2021 real terms

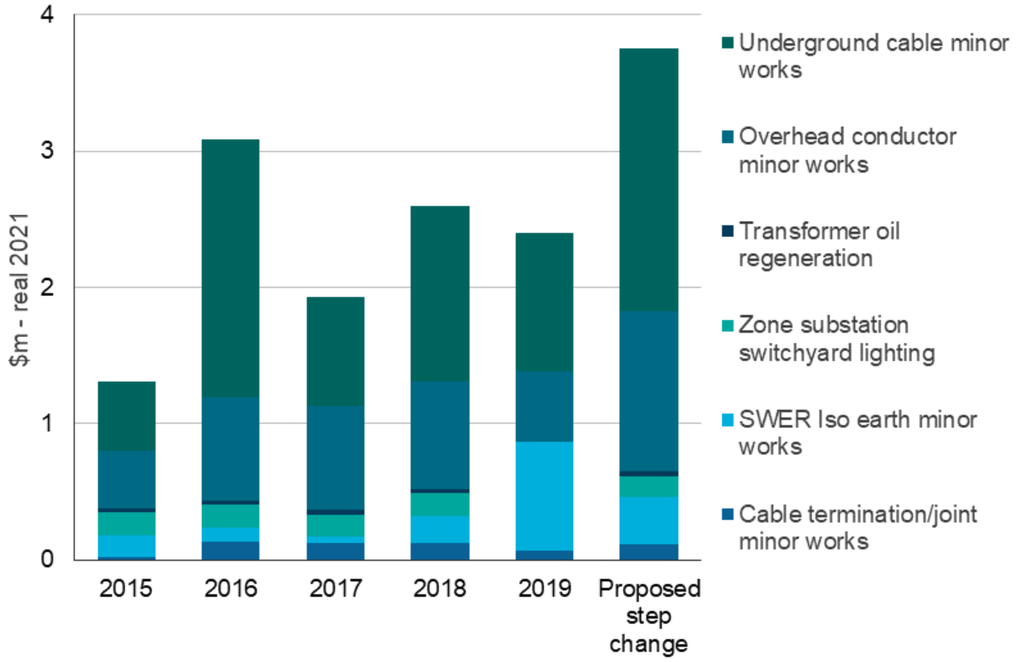
1076. We sought further information on these works, including Powercor's historical analysis to estimate minor repairs opex that it had previously classified as repex and which we understood to underly its 'recast RIN'. (see paragraph 990). We sought information on Powercor's method and calculations by which it had recast historical repex to minor repairs opex and the volumes and associated unit repair costs for that work.

1077. We also sought information on the nature of the work activities or tasks undertaken, together with Powercor's justification of the treatment of expenditure on those tasks as 'minor repairs opex' by reference to the definition in its Cost Allocation Methodology.

Powercor's proposed expenditure was not supported by the historical information that it provided

1078. Powercor provided the historical information shown below, with 2019 expenditure adding to $2.4m (in $2021 terms). This does not match with the $3.8m that it has proposed.

Figure 9.2: Historical expenditure described by Powercor, recast as maintenance opex, and compared with proposed step change - $m, real 2021



Source: EMCa analysis from response to IR PAL035, question 29

1079. We also reviewed the historical amounts provided in Powercor's response, which range from $1.3m in 2015 to $2.6m in 2018. We observe that the variance is strongly driven by what Powercor classified as underground cable minor works and which were $0.5m in 2015, but $1.3m in 2018.

1080. We also observed that there were several line items for which Powercor had registered the exact same amount (in nominal terms) for each of several years. This indicates to us that Powercor did not derive these amounts by inspecting its work volumes and expenditures in each year. Rather, it would appear that Powercor determined an estimated amount (perhaps in one year) and then extrapolated that amount to prior years.

Powercor did not show evidence of having considered specific repairs that it proposes to reclassify, on the particulars or the nature of that category of repair

1081. As part of our IR PAL035, we sought explanation for the specific types of repair categories that Powercor proposed treating as minor repairs. In its response, Powercor listed nine types of repair. These differ from the 6 types of repair presented in the information shown in Figure 9.2, and which Powercor presented at the onsite meeting with us as shown in Figure 9.1. However, apart from one different word in one of these cases, its response was to repeat the following phrase nine times:

> *"Treating these costs as operating expenditure better reflects the nature of the work—the costs are minor in nature and only include works on part of a network asset (as opposed to the replacement of the whole asset), they are incurred to maintain the age of the asset rather than extend its life, and the work does not result in the creation of a new 50-year asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period. This is reflected in our updated cost allocation methodology."*[379]

1082. This response does not indicate any consideration of the different types of repairs listed. The logic in this paragraph is essentially circular. It also refers to Powercor's Cost Allocation Methodology which, as we have described above, also contains only a high-level definition that is limited by its own circularity.

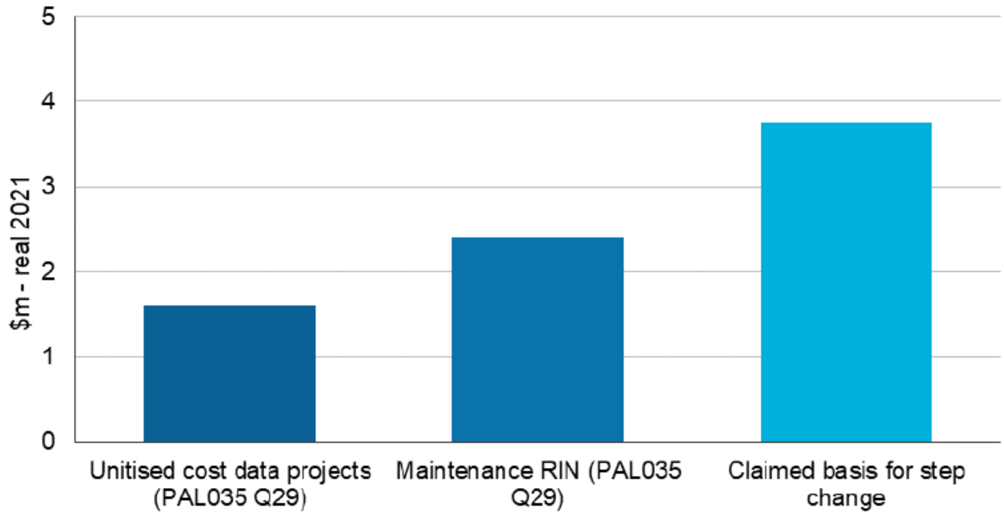
Powercor's proposed step change amount was not supported by its disaggregation of its claimed relevant costs

1083. We reviewed the composition of the works that Powercor proposes to classify as minor repairs, based on its response to our IR where we sought information on the categorised volumes of - and expenditures on - such works. From this, we sought to understand the unitised costs so as to understand Powercor's proposed classification as 'minor' works.

1084. We first compared the aggregate expenditure for which Powercor provided unitised cost information. As shown in Figure 9.3, the information that Powercor provided (which totalled $1.6m in 2019, in $2021 terms) did not match with either its recast RIN information or the claimed 2019 expenditure basis for its proposed step change.

[379] Powercor response to IR PAL035, Question 27

Figure 9.3: Powercor claimed basis for step change compared with its 2019 reported minor repairs maintenance and its reported 2019 unitised cost information - $m, real 2021



Source: EMCa analysis from response to IR PAL035, question 29

The repair volume and cost information does not tend to support classification of the proposed amount as 'minor repairs'

1085. From the limited data provided, we determined the unit costs per 'project'. From this, we sought to understand the size and volumes of these works.

1086. In Table 9.2, we show the results of this analysis. Using an indicative filter of 'repairs with unit costs greater than $10,000', we found that Powercor's information included 15 such repairs with average unit costs of over $34,000 each, with the largest single repair costing $58,000. By comparison, when we analysed SAPN's data for the expenditure that it proposed as minor repairs opex under its definition, we found that each minor repair cost on average around $4,000.[380]

Table 9.2: Analysis of works proposed by Powercor as 'minor repairs', categorised by unit cost

	Repairs over $10,000	Repairs under $10,000
Number of repairs	15	1,188
Total cost ($000)	514	1,085
Average unit cost ($)	**34,282**	**913**

Source: EMCa analysis from response to IR PAL035, question 29

1087. Whilst we consider that a qualitative definition is most appropriate for minor repairs, the individual repair cost information that Powercor provided does not appear to support classification of the proposed amount as comprising 'minor' repairs. We also note Powercor's claim that its proposed amount of $3.8m per year (in $2021 terms) results from its analysis of such repair costs in 2019. However, it was not able to provide the individual repair volume and cost information that forms the basis of this claimed amount. Rather, it was able to account for only around $1.6m in this way. Powercor was also unable to account for its historical recast of minor repairs on the basis of volume and unit cost information, from which it is reasonable to infer that this is not how Powercor undertook its expenditure 'recast'.

380 EMCa analysis of SAPN CA RIN data provided from AER, 28 June 2019.

9.2.3 Findings and implications

1088. We consider that Powercor has not adequately defined a policy that would allow a portion of its repairs to be classified as opex. We also consider that Powercor has not provided sufficient justification for the amount that it proposes, either in aggregate, or within a reasonable definition of what constitutes a 'minor' repair.

1089. We do not see merit in allowing the proposed amount as an opex step change or (as Powercor has proposed) adding it to Powercor's base year opex in developing its BST forecast.

9.3 Assessment of EDO fuse opex step change

9.3.1 Powercor's proposal

1090. Starting from the next RCP, Powercor has proposed an opex step increase as part of its Base Step Trend (BST) based opex forecast, for the proactive replacement of EDO fuses as shown in Table 9.3.[381]

Table 9.3: Powercor proposed opex step increase for replacement of EDO fuses opex - $m, real 2021

Category	2021-22	2022-23	2023-24	2024-25	2025-26	Total
EDO fuse replacement	2.2	2.2	2.2	2.3	2.3	11.2
Total	**2.2**	**2.2**	**2.2**	**2.3**	**2.3**	**11.2**

Source: EMCa analysis from Powercor RIN001. Includes real cost escalation.

1091. Powercor proposes justification of its EDO fuse replacement program as follows:[382]

> *'Fuse replacements are part of our maintenance and repair operating expenditure. Our proposed replacement program would result in a material increase in our operating expenditure not captured in our 2019 base year. Our latest BMP, accepted by ESV, establishes the use of fault tamers in-lieu of EDO fuses.'*

9.3.2 Our assessment of proposed expenditure

1092. For the EDO fuse replacement, Powercor has provided a business case supporting its preferred option of proactive replacement of all EDO fuses with fault tamers in high-consequence Electrical Line Construction Areas (ELCA) and substituting fault-tamers for EDO fuses in High Bushfire Risk Areas (HBRA). Powercor has considered three options to reduce bushfire risk, using risk monetisation modelling to arrive at its preferred option based on its assessment of the highest net benefit to customers and which will result in the largest reduction in bushfire risk across its network.

Approach to our assessment

1093. In undertaking our assessment, we have considered the following factors:

- Firstly, we sought to understand the nature of the work that Powercor is proposing to classify as opex, relative to activities included in its repex forecast for the reasons as outlined in our assessment of proposed 'minor repairs' opex; and
- Secondly, if we were to propose accepting the classification as an opex step change, it is necessary to gain confidence that Powercor has established the basis for, and

381 Powercor applies this as a base year adjustment, rather than a step change. However, it has also presented it as an annual and equal amount – which mathematically is the same in any case. For convenience, we will use the general term 'step change' to describe the proposed amount in line with the BST terminology

382 Powercor Regulatory Proposal, page 124

adequately justified the extent of, the proposed amount as being reflective of an efficient cost.

Classification of expenditure

Powercor's classification of expenditure leaves room for interpretation

1094. The only relevant clause that we observe in Powercor's Cost Allocation Method is a statement that the following are not capitalised: [383]

> *'assets that don't provide future economic benefit for longer than 12 months.'*

1095. When we asked Powercor as to why EDO fuse replacements had been classified as an opex step change as opposed to a capex item, it stated:[384]

> *'Fuse replacements form part of our network maintenance and repair and are treated as operating expenditure in our accounts. This approach reflects the type of work involved in fuse replacements and its purpose in network management: majority of the cost of a fuse replacement is the cost of labour to perform the replacement, while the purpose of the fuse is to protect our network assets from damage which is in line with our asset maintenance practices.'*

1096. This explanation places a high level of importance on the proportion of the total cost made up by the cost of labour. We accept that the changing of a fuse following operation for a fault, as a part of its normal function, may be considered maintenance-based activity and treated as opex. However, the proposed project involves pro-actively changing the fuse asset, including fuse carrier assembly. The categorisation does not appear consistent with statements in the Cost Allocation Method.

Powercor's asset management systems describe replacement drivers associated with replacement capital

1097. Powercor has developed an Asset Class Strategy under its asset management system which includes high voltage fuse assets described as including Expulsion Drop Out (EDO) fuses.[385] EDO fuses make up over 85% of the total fuse population, with 144,688 EDO fuses installed in Powercor's network.

1098. Powercor's Asset Class Strategy includes strategies to 'Manage and operate the network safely' and which includes the following statement: [386]

> *'The management of pole top structures including HV fuses and surge arresters has focussed on the progressive elimination of aging, obsolete or poor-performing assets that have had a disproportionate share of faults/incidents.'*

1099. Powercor states that a proportion of the fuse holders / mounts are considered obsolete and they are described by Powercor as either no longer available, or no longer meeting compliance and certification requirements. For HV fuses, the specific concern relates to 'performance issues.'

Powercor's proposed replacement capex includes fuse replacement

1100. As described in our assessment of the switchgear category of repex, Powercor forecasts to incur an average of \$6.0m per annum replacing HV fuses and surge diverters. To better understand the activities involved, we reviewed the unit rates associated with this activity. We found the unit rates, when accounting for a blend of activities, closely approximated the unit rates used by Powercor in its models for the proposed step change.

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383 Powercor ATT 027 Cost Allocation Methodology, page 11

384 Powercor's response to information request IR008

385 Powercor, Asset Class Strategy pole top structures, HV fuses and surge arrestors provided as part of IR006

386 Powercor, Asset Class Strategy pole top structures, HV fuses and surge arrestors provided as part of IR006, p20

1101. The average unit rate over the 3-year period 2015/16 to 2017/18[387] is $1,930, whereas the assumed Fault Tamer cost in the model is $1,876 and EDO replacement cost is $1,564. The higher unit cost is most likely explained by the inclusion of a proportion of surge diverters for the switchgear category, which will incur a higher replacement cost when compared with EDO fuses.

1102. Powercor has not explained the composition of its existing fuse replacement program, or to confirm that EDO replacement is not included in this replacement program.

1103. As noted in our assessment of minor repairs, without a clear understanding of the composition of the expenditure, it remains possible that expenditure proposed as opex for regulatory proposal purposes may be nevertheless capitalised.

Similar bushfire safety programs are all capitalised

1104. In the RP and in its BMP,[388] Powercor describes its proposal as a practical replacement program rather than responding to an external driver, as follows:

> *'Powercor's proposal is to proactively replace all EDO fuses with fault tamers in Electric Line Construction Areas (ELCAs), and progressively replace EDO fuses with fault tamers in Hazardous Bushfire Risk Areas (HBRAs) other than ELCAs, as part of the regular inspection and maintenance program.'*

1105. The proposed replacement program is included in section 6.12 of the Bushire mitigation plan[389] as a part of the nominated bushfire asset replacement and technology implementation programs for highest fire risk areas.

1106. With the exception of the proposed opex step change for EDO replacement, the programs nominated in section 6.12 are all related to capital expenditure and most are included in the 'other' repex category.[390]

EDO fuse replacement programs are typically capitalised

1107. We reviewed the practices across the industry to understand how other DNSPs classify this type of expenditure. We found the accepted practice is to capitalise EDO fuse replacement.

1108. We note that in the regulatory proposals for other Vic DNSPs for the 2021-26 period, both Ausnet and United Energy have included proposals for EDO replacement programs as repex.

Justification of proposed expenditure

Claims of an external driver are not supported

1109. Powercor includes changes to network requirements as an external driver for changes in the asset population of HV fuses in its Asset Class strategy:[391]

> *'Changes in regulatory requirements and the ESV compliance regime will result in the need for CP/PAL to replace some pole top assets. In particular, the requirement to install REFCL devices will necessitate the replacement of more than 30% of the distribution surge arresters. Similarly, in HBRA areas particularly, EDO fuses need to be progressively replaced by fault tamer fuses to reduce the risk of fires. Several types of fuse holders are considered obsolete.'*

387 This differs from Powercor's assumed unit rate of $2,219 which is based on the 4-year period 2014/15 to 2017/18

388 Powercor, Bushfire Mitigation Plan 2019-2024, page 34

389 Powercor ATT094 - Bushfire mitigation plan

390 Item 6.12.2 SWER replacement program targeting ELCAs ha been proposed by Powercor as a contingent project to continue to replace bare wire SWER overhead in ELCAs with underground cable or covered conductor solutions

391 Powercor, Asset Class Strategy pole top structures, HV fuses and surge arrestors provided as part of IR006, Table 5

1110. We have not been provided with evidence to support this statement, specifically that there is an external driver on Powercor to change its current asset management practice.

Powercor's analysis in its risk model is flawed

1111. In the BMP, Powercor proposes that the EDO replacement program will reduce the risk of EDO fuses starting a bushfire to as low as reasonably practicable and:[392]

> *'We consider it is prudent and practical to reduce bushfire risk in cases where the net economic benefit of doing so is positive. We have identified an opportunity to reduce the risk of EDO fuses causing bushfires with a positive net economic benefit, by replacing a large number of EDO fuses with fault tamers.'*

1112. The benefits are captured in the risk monetisation model. In response to a request to explain why it considers the assumptions are reasonable, Powercor provides supporting material on the derivation of these estimates, including that:[393]

> *'We consider these assumptions reasonable as the key assumptions are sourced from actual Powercor asset fire start data, and the probability and consequence of a catastrophic fire are sourced from the 2015 'Regulatory Impact Statement (RIS) Bushfire Mitigation Regulations' prepared by ACIL Allen Consulting for the Victorian Government - PAL ATT114 submitted as part of our regulatory proposal.'*

1113. On examination of the models, we found examples of assumptions that are likely to overstate the risk cost and which are not effectively moderated in the calculations, including:

- The derivation of the probability of failure of an EDO fuse that results in a fire differs between HBRA and ELCA; however, both are very sensitive to the assumed average number of EDO caused fire starts p.a. on TFB days, which is a manual input. When the same probability of failure assumptions is applied to each area, the resulting risk cost decreases by up to 50%;
- We would have expected that the methodology for probability of a failure for EDOs is the same, independent of its location. We would then expect to see moderating factors applied to account for the failure causing a fire, occurrence on a TFB day and the likelihood that an unsuppressed fire resulted in a catastrophic consequence;
- The assumption used for the average number of EDO fire starts on TFB days appears to be based on population data.[394] Absent better information, using the population data results in a higher probability of a fire start per EDO site on a Total Fire Ban (TFB) day;
- Likelihood of a catastrophic consequence of an EDO fire start appears high. Based on the 2019 safety performance report, 1.6% of ground fires were larger than 10 hectares.[395] If other reported fires are included, that are contained to the network and do not result in a ground fire, the percentage reduced to 0.7%; and
- The use of a disproportionality factor of 6 to a catastrophic consequence of $442m, overstates the potential consequence. This is because the consequence cost already includes a level of disproportionality in the estimated consequence value.

1114. As a further sense check, we reviewed the annual risk cost calculated by Powercor under the base case, or business as usual approach, which is over $34m per annum for HBRAs and over $7m per annum for ELCAs. On the basis that this reflects a small subset of the EDO fuse population, to which the proposed expenditure relates, we do not consider that this represents a credible reflection of the current and prior level of risk.

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392 Powercor BUS 9.04 EDO fuse replacement

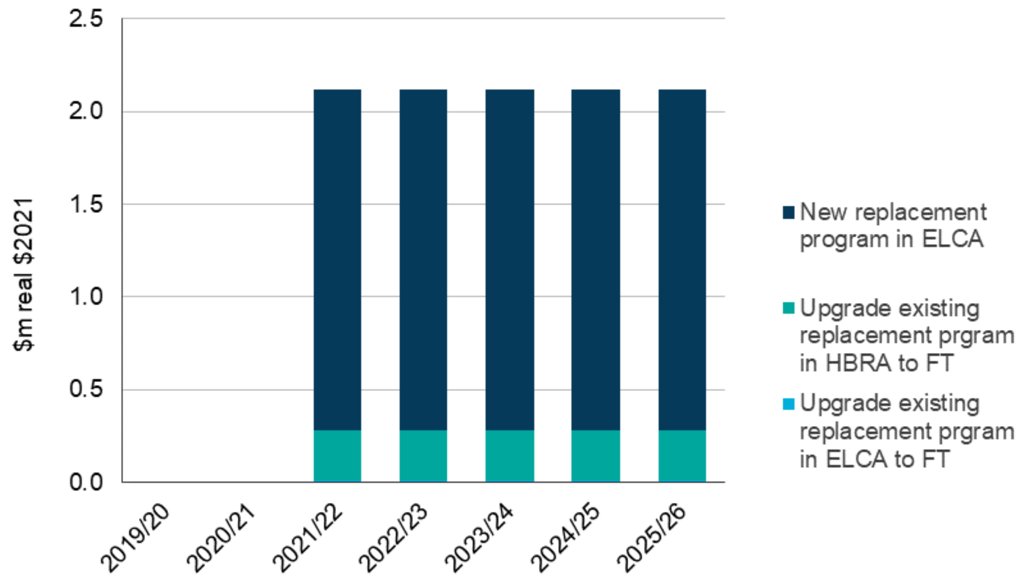
393 Response to information request IR008

394 Powercor MOD 9.06 EDO HBRA risk, referred to as PAL: EDO population data (Total of 15 EDO Site Fire Starts on TFB days in 7 years)

395 ESV, 2019 Safety performance report on Victorian electricity networks (accessed at https://esv.vic.gov.au/wp-content/uploads/2019/10/2019-Safety-Performance-Report-on-Victorian-Electricity-Networks.pdf)

1115. Powercor's proposed expenditure is shown in the figure below.

Figure 9.4: Composition of proposed expenditure for EDO fuse replacement - $m, real 2021



Source: EMCa analysis of PAL MOD 9.01 – Step changes

1116. Powercor's risk model would indicate that replacement of EDOs is needed at a much higher level and with much greater priority than Powercor has proposed, in order to mitigate the risk cost at this level. For example, the annualised cost determined by Powercor for replacement in HBRA is $0.27m p.a., against an annual risk cost of $34m p.a. We consider that this casts a level of doubt on the robustness of the provided models.

9.3.3 Findings and implications

1117. We consider that Powercor has not adequately justified that its proposed EDO fuse replacement project should be classified as opex. We found evidence that Powercor has undertaken similar activities as part of its replacement capex for EDO replacement. If an additional EDO program is undertaken as opex, it is likely that a component of the replacements will be capitalised by Powercor in the future.

1118. It is also typical for EDO replacement programs to be capitalised - as is the case in other jurisdictions and as proposed in regulatory proposals for other Victorian DNSPs.

1119. We acknowledge the potential safety benefit associated with proactive replacement of EDO fuses with Fault Tamer fuses to further reduce bushfire risk. We expect that there is likely a business case for Powercor to undertake a replacement program.

1120. We consider that Powercor has not adequately justified the extent of the proposed increase in expenditure. Our sensitivity analysis indicates a significantly lower calculation of risk cost. This casts doubt on the claimed economic case for the program expenditure that Powercor has proposed as an opex step change.

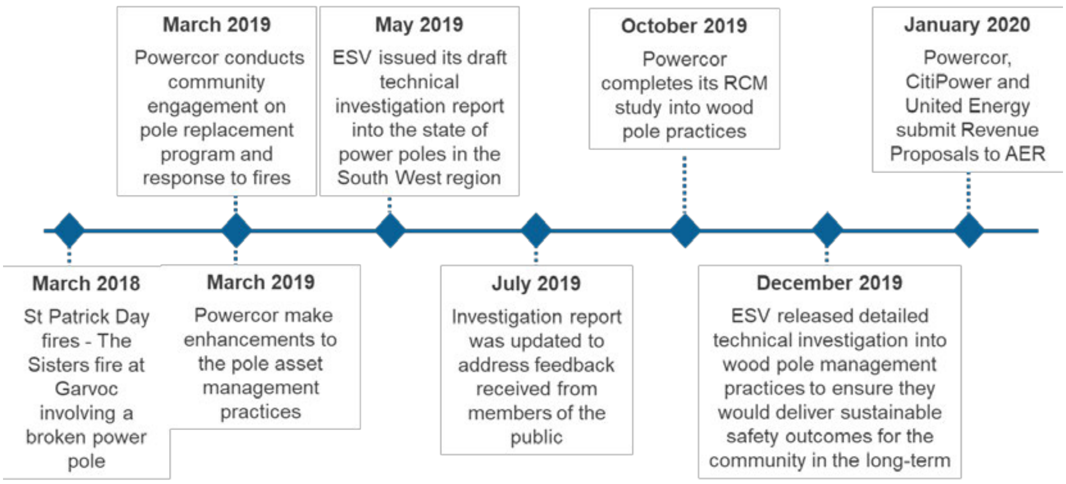
APPENDIX A – CONTEXT FOR PROPOSED INCREASE IN POLES REPEX

1121. Increases to the proposed repex relative to the current RCP are evident in the expenditure proposals for CitiPower, Powercor and United Energy. The increases to repex are primarily driven by poles repex in each case.

1122. We have been advised that for all three DNSPs, the step increase has been proposed in response to findings arising from a review undertaken by Energy Safe Victoria (ESV) into the sustainable management of wood poles in the Powercor network.[396] ESV undertook a detailed and systematic review of wood pole management practices of Powercor in response to an investigation into an asset initiated bushfire and concern regarding the current level of wood pole replacement and reinforcement activity.

1123. We have provided an overview of the key milestone dates for Powercor in the figure below. The outcome of the ESV technical report has been referenced by CitiPower and United Energy, and we comment on the applicability of the findings to those businesses, as a part of our assessment of their proposed expenditure in his report.

Figure A.1: Overview of key review milestones



Source: EMCa

1124. We show the increases to pole repex when comparing the historical expenditure with the next RCP and explore how each DNSP has responded to the findings of ESV's technical report in relevant assessment sections of our report.

396 PAL ATT245: ESV, Powercor, Sustainable wood pole safety management approach, Detailed technical report, December 2019

APPENDIX B – OVERVIEW OF RISK MONETISATION APPROACH

In this Appendix B we provide our understanding of the risk monetisation models applied by Powercor / CitiPower to support the proposed expenditure for the next RCP.

We have limited the content of this Appendix B to an explanation of the models. Our assessment of the models forms a part of our assessment of the expenditure proposed for the next RCP, where the risk monetisation models have been relied upon to justify the expenditure.

The design concept and structure of the risk monetisation model was consistent with the explanation provided by Powercor / CitiPower 's explanations and included the relevant input assumptions relied upon in its calculations. The model worked as expected when changes were made to input assumptions.

B.1 Overview

1125. Powercor and CitiPower have applied the same risk monetisation model to support elements of its proposed capex forecast.

1126. At a high-level, the structure of Powercor/CitiPower's risk monetisation forecast building approach is set out in the figure below. The risk cost values are derived from calculated values of probability and consequence of failure.

Figure B.1: Calculation of annual risk cost

Source: Powercor RP Figure 4.12; CitiPower RP Figure 4.11

1127. The risk monetisation model applies the PoF projections to input assumptions for the consequences of failure to calculate a yearly risk cost value.

1128. The derived risk cost value is than compared to the annualised cost of the proposed remedial action (e.g., asset replacement) to determine the optimum economic point for completion of the remedial action.

B.2 Probability of failure

1129. The probability of failure is a key input assumption in the risk monetisation model.

1130. In development of a probability of failure, Powercor / CitiPower make use of:

- historical asset failure rates based on internal data; and
- CBRM methodology to inform the probabilities of failure.

1131. The CBRM model establishes a projection of the probability of failure (PoF) values for individual asset as a function of an asset's health score. The health score is informed by the normal expected life of the asset, its location and service history, its reliability performance, and observed condition and measured condition.

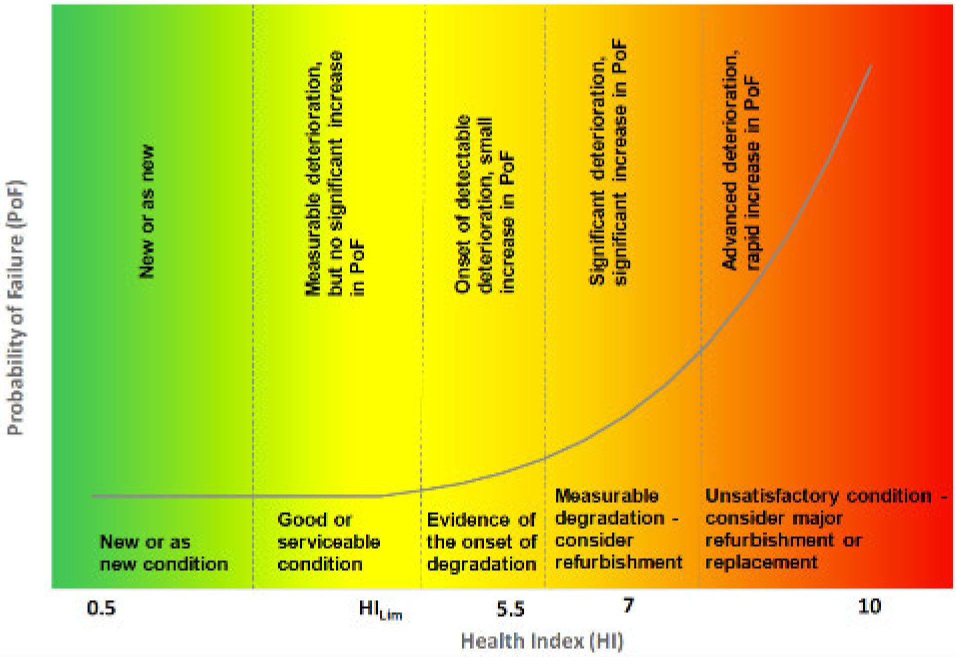
B.2.1 Summary of CBRM approach

1132. The CBRM model converts input information on individual assets into health index values and probability of failure projections. The risk monetisation model draws on the probability of failure values and for an assumed consequence of failure, calculates the point at which replacement becomes economically preferable.

1133. The Probability of Failure (PoF) of the asset is determined in the CBRM models by applying the health index (HI) of the relevant asset to a formula-derived expected life cycle curve. This establishes the PoF for the asset for each year taking into account its HI.

1134. Powercor / CitiPower use a 1 to 10 scale for its HI, 1 being as new and 10 having advanced deterioration. The HI scale is reproduced below.

Figure B.2: Relationship between health index and probability of failure



Source: Powercor BUS 4.03 Transformer risk and evaluation, Figure 2.2, p6; CitiPower BUS 4.03 Transformer risk and evaluation, Figure 2.2, p6

1135. The CBRM model used to determine the PoF values was provided by EA Technology and tested against Powercor / CitiPower experience. Powercor / CitiPower noted that its CBRM model continued to evolve and was recalibrated in 2019. Powercor / CitiPower explained that mathematical modelling techniques carried out by EA Technology concluded that use of *a cubic relationship (3rd order polynomial)* was appropriate to define the health index and probability of failure relationships. Powercor / CitiPower adopted this formula and applied it in its CBRM models.

> *'Our CBRM models were re-calibrated in 2019, having regard to Ofgem's Common Network Asset Indices Methodology (CNAIM). The probability of failure estimates used in our risk monetisation models are based on our re-calibrated 2019 CBRM model.'*

1136. Powercor / CitiPower also indicates that HI values have been revised over time. [397]

[397] CitiPower and Powercor - IR032 and IR035 - EMCa questions following onsite – Public, page 14

'Our asset data quality improvements are discussed … (e.g., the work undertaken with EA Technology has already led to the application of lower health scores for some assets).'

1137. Input assumptions for the current asset health index are important drivers of the substation asset replacement forecast. As the HI defines the asset's position on the probability of failure curve, assets towards the higher end of the HI are more sensitive to increased probability of failure for relatively small changes in the HI. Sensitivity testing CBRM model outputs to changes in HI is important.

1138. HI for each asset are determined by applying asset condition modifiers to an initial HI based on engineering knowledge of the asset (primarily age). Modifiers are applied to the initial HI take into account asset location, loading and condition and, for transformers oil test results and On-load Tap Changer (OLTC) age, features and condition. A reliability modifier is used if an asset type has a known PoF profile.

1139. The outputs from the CBRM are HI values and PoF values for current and future years for each asset. The PoF values are used in the risk monetisation models to determine the need for and optimal timing of asset replacements. The HI can be used to provide indications of future asset health for intervention and non-intervention scenarios. Powercor / CitiPower has provided this analysis at an asset fleet level.

1140. The CBRM models supplied by Powercor / CitiPower had produced only 2019 and 2025 HI and PoF projections. The risk monetisation models include a PoF projection to 2030. Also, the CBRM model produces PoF values for minor, significant and major categories when the risk monetisation model has significant, major and catastrophic categories.

1141. Powercor / CitiPower did not provide information on how the CBRM outputs are converted into the risk model inputs. However, we found that the categorisation issue appeared to have been resolved by aligning the significant and major values of the CBRM model with the significant and major values of the risk monetisation model and, duplicating the major PoF values for the catastrophic category.

1142. To gain an understanding of the reasonableness of the PoF values that Powercor / CitiPower used in the risk monetisation model we considered the appropriateness of the PoF curves relative to other information available for the assets.

B.2.2 Reliability and accuracy of asset information

1143. We asked Powercor / CitiPower to supply the results of any assessments that Powercor / CitiPower has undertaken to determine or review the reliability and accuracy of asset information and data used in its CBRM modelling. We asked that the information supplied include any improvement measures taken in response to any identified data quality issues.

1144. Powercor / CitiPower responded with the following explanation:

'We are confident in the robustness of the underlying data used in our CBRM model. The relevant asset information and data is subject to random audits, and our engineers are required to undertake site visits as part of their annual planning processes to verify data collected by field personnel. EA Technology also had regard to data quality when assisting the calibration of our CBRM model; and

In regard to improvement measures, our asset class strategy for zone substation transformers acknowledges the opportunity to further develop our data standards as part of our commitment to continuous improvement. We are now in the process of implementing a maintenance data platform and mobility solution. The mobility tool, for example, will allow for electronic capture of asset information in the field, rather than the current method of paper based forms that are subsequently translated into our existing IT systems.'

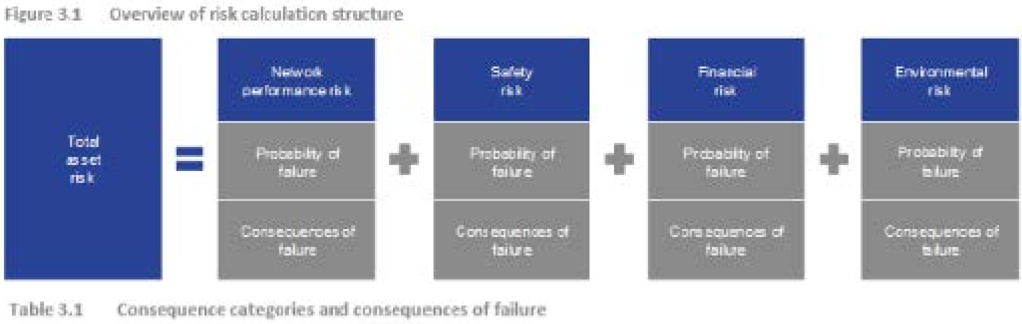
1145. It is positive that Powercor / CitiPower recognises that the acquisition and management of robust and reliable asset data is critical to its risk monetisation process. The use of random audits, together with the in-field verification process, provide some assurance that the present data quality for substation assets is reasonable for CBRM modelling.

1146. It is also positive that Powercor / CitiPower recognise the opportunities for further improvement in data quality and are planning to implement future continuous improvement initiatives.

B.3 Consequence of failure

1147. The total expected cost of consequence is equal to the likelihood of the consequence of a failure event and the consequence cost of that failure

Figure B.3: Structure of risk calculation structure



Source: Powercor onsite presentation EMCa May 2020_final, page 27; CitiPower onsite presentation EMCa May 2020_final, page 27

B.3.1 Input assumptions

1148. We review the reasonableness of the input assumptions as they relate to the determination of the expenditure forecasts in each of the assessment sections in the report. Some of the key inputs include:

- VCR is a composite of the values for industrial, commercial, residential; and agricultural loads, it is also weighted (adjusted) for outage duration and this results in reducing the VCR and therefore unserved energy cost component of the consequence cost, when compared with using a value based on the state-wide average;
- Demand forecast is based on substation level forecasts, and probability weighted using a combination of the 10% PoE and 50% PoE demand forecasts; and
- In most instances the consequence costs and likelihood of consequence factors are input values based on estimates from Powercor / CitiPower, rather than derived values.

B.3.2 Consequence categories

1149. The consequence costs are made up of four consequence categories:

- Network performance - unserved energy, and coincident outages;
- Safety - minor injuries, serious injuries, fatality;
- Financial - repair and replacement costs, generation support, Fire brigade attendance; and
- Environmental - volume of oil released, volume of SF6 released to atmosphere, fire starts, volume of waste produced, level of disturbance.

1150. The consequence values are based on estimates from Powercor / CitiPower provided in each of the models.

1151. The above costs of consequence are calculated for three categories of events, whereby the probability of failure, consequence cost and likelihood of consequence are varied:

- Significant failure - the loss of the asset for the time it takes for the repair to be carried out and the asset returned to service;
- Major failures - has two possible outcomes: either the asset failure will result in damage to the asset, or the failed asset and adjacent assets; and
- Catastrophic failures - is determined on a case-by-case basis at each zone substation.

B.4 Model outputs

B.4.1 Risk cost

1152. The risk cost is established as the product of the probability of failure (which increases with time), consequence cost and likelihood of the consequence occurring.

1153. The probability of failure is based on either historical data or outputs of a CBRM model as explained above.

B.4.2 Annualised cost

1154. The annualised cost of the proposed remedial action is determined by calculating the:

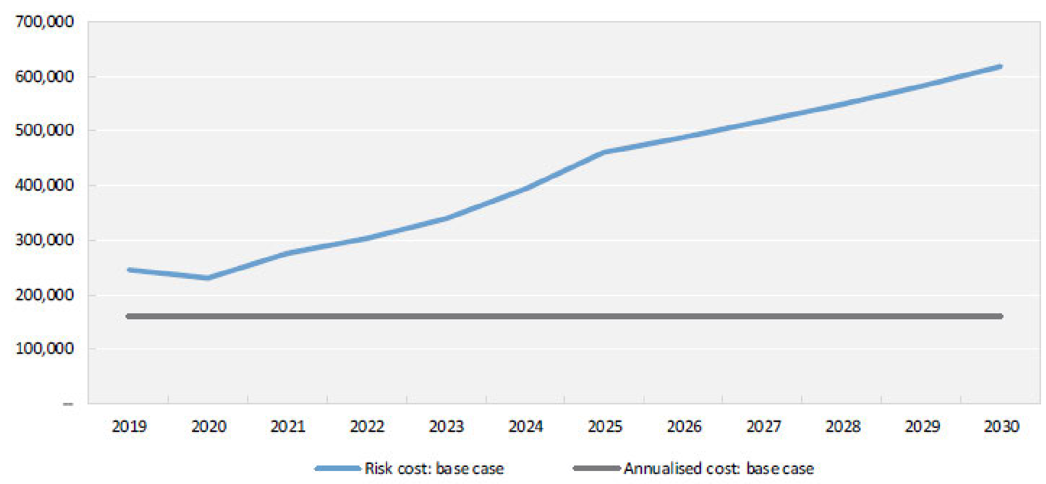
- Expenditure to complete the replacement project (based on asset unit costs) and proposed timing of the expenditure; and
- Ongoing operational costs for the asset. The replacement cost used in the calculation (based on the historical average routine maintenance and inspection costs).

B.4.3 Optimal timing of replacement

1155. The output from Powercor / CitiPower's risk monetisation models are scenarios each comparing the derived risk cost with the annualised cost of implementing the proposed replacement. Powercor / CitiPower uses high, medium and low scenarios to test the sensitivity of the modelled outputs for a selection of input assumptions.

1156. An example of the risk cost scenario (Base case) is provided below from the risk monetisation model. The optimum time of investment is the point at which the risk cost is greater than the annualised cost of the scenario. For the example given, the base case indicates that at the commencement of the study period, the risk cost is already higher than the annualised replacement cost, indicating the optimal date for replacement is prior to the study period.

Figure B.4: Example of outputs from risk monetisation model (base case) - $ real 2021



Source: Powercor BUS 4.03 Transformer risk and evaluation, Figure A.1. Shown for RVL transformer number one

B.4.4 Sensitivity analysis

1157. Powercor / CitiPower includes sensitivity testing of the input assumption values through use of five senecios: central, lower and upper sensitivity settings. The sensitivity setting range for PoF, Capex and opex, VCR and environmental costs, is +/-10%. For forecast demand the range is +/-5%.

1158. The structure of the scenarios used in the risk monetisation models Powercor / CitiPower provided to support its transformer and switchgear replacements are provided in the table below.

Table B.1: Variables used for each scenario

Scenario	Probability of failure	Capital expenditure	Forecast demand	VCR	Operating expenditure	Environment cost
Base case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
A	Lower bound	Upper bound	Lower bound	Lower bound	Upper bound	Lower bound
B	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound
C	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound
D	Upper bound	Lower bound	Upper bound	Upper bound	Lower bound	Upper bound

Source: Powercor BUS 4.03 Transformer risk and evaluation, Table 4.2

1159. We found that the inclusion of sensitivity testing was positive, the ranges applied were not sufficient to account for what we found were examples where input assumptions had been overstated.

1160. To satisfy our concerns on this issue we tested the sensitivity of the models to a broader range on input values than Powercor / CitiPower's scenarios had done. The results of this testing is discussed in the associated assessment of expenditure sections. The tests identified some issues with the sensitivity of the model to changes in important input assumptions.

B.4.5 Assurance that the CBRM and Risk monetisation models are fit for purpose

1161. Whilst we undertook a review of the structure, operation and sensitivity of CBRM and risk monetisation models, we considered that appropriate quality assurance assessments would have been completed by Powercor / CitiPower prior to finalising its replacement capex forecasts. We noted that the risk monetisation models had been revised in 2019, but found no documents indicating that audits had been undertaken.

1162. Because of the potential issues we identified when undertook sensitivity testing of the risk monetisation models, we considered that appropriate to understand if quality assurance assessments had been completed by Powercor / CitiPower prior to finalising its replacement capex forecasts. We noted that the risk monetisation models had been revised in 2019, but found no documents indicating that audits had been undertaken.

1163. In response to our questions Powercor / CitiPower supplied the following additional explanation of the external reviews/verification it had undertaken to validate the approach and outcomes of the models. Powercor / CitiPower supplied the following explanation on its response: [398]

> *'EA Technology (UK) was engaged to assist with the CBRM and risk quantification models for transformers and switchgear, recognising they bring independent, expert technical knowledge when calibrating the model. Notably, they have a strong track record with these types of assets and specialise in modelling risk for electrical utilities worldwide; and*
>
> *Inflection Point Advisory was also engaged to provide a further independent review and verification of the risk monetisation models and methodology. This included a quality assurance that the model was functioning as intended.'*

1164. In addition, Powercor / CitiPower confirmed that neither EA Technology nor Inflection Point Advisory were required to provide a report as part of their reviews; the relevant outputs were the models themselves.

1165. In the course of our review we have not identified any errors in the structures. We are satisfied that Powercor / CitiPower has taken reasonable steps to assure itself that the models are suitable to assist its capex decision making.

[398] CitiPower and Powercor - IR032 and IR035 - EMCa questions following onsite – Public, page 20