Draft decision

CitiPower electricity distribution determination

1 July 2026 – 30 June 2031

Attachment 2 – Capital expenditure

September 2025

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	30 September	68

Contents

2 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS).[1] Generally, these assets have long lives, and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, to maintain the safety, reliability, quality, and security of its network and contribute to achieving targets for reducing Australia's greenhouse gas emissions (the capex objectives).[2]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand, cost inputs, and other relevant inputs (the capex criteria).[3] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of the price, quality, safety, reliability and security of supply, and contribute to achieving targets for reducing Australia's greenhouse gas emissions, for the benefit of consumers in the long term, as required under the National Electricity Objective (NEO).[4]

The *AER's capital expenditure assessment outline* explains our and distributors' obligations regarding capex under the National Electricity Law and Rules (NEL and NER) in more detail.[5] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Where relevant we also assess capex associated with emissions reduction proposals taking into account our Guidance on amended *National Electricity Objectives*.[6]

Total capex framework

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

Once the ex-ante capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. This incentive-based framework

1 These are services that form the basic charge for use of the distribution system.

2 NER, cl. 6.5.7(a).

3 NER, cl. 6.5.7(c).

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

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

6 AER, *Guidance on amended National Electricity Objectives*, September 2023.

provides distributors with the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

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

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs.

Assessment approach

We provide guidance on our assessment approach in several documents, including the following which are of relevance to this decision:

- Expenditure Forecast Assessment Guidelines.[7]
- Regulatory Investment Test for Distribution and Transmission (RIT-D and RIT-T) Guidelines.[8]
- Asset Replacement Industry Note.[9]
- Information and Communication Technologies (ICT) Guidance Note.[10]
- Better Resets Handbook – Towards consumer centric proposals.[11]
- Guidance note on network resilience.[12]
- Interim guidance note on the Value of Emissions Reduction.[13]

Our draft decision has been based on the information before us at this time, which includes:

- the distribution network service provider's (DNSP's) regulatory proposal and accompanying documents and models
- the DNSP's responses to our information requests
- stakeholder comments in response to our Issues Paper
- technical review and advice from our consultant's reports. In January 2025, we engaged Energy Market Consulting associates (EMCa) to assist us in reviewing certain aspects of CitiPower's capex proposals; and Baringa for demand forecasting advice.

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7 AER, *Expenditure Forecast Assessment Guideline for Distribution*, August 2022. The legal requirements of the AER under the NEL and the NER in assessing capex are outlined in section 2.1.

8 AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017,* September 2017.

9 AER, *Industry practice application note for asset replacement planning,* January 2019.

10 AER, *Guidance note on non-network ICT capital expenditure assessment approach*, November 2019.

11 AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

12 AER, *Network resilience: A note on key issues*, April 2022.

13 AER, *Guidance note on emissions reduction: Interim Guidance Note*, 16 June 2025.

2.1 Draft decision

Our draft decision is to not accept CitiPower's proposed total forecast capex of $1,216.3 million ($2025–26) for the 2026–31 period. This is because we are not satisfied that it reasonably reflects the prudent and efficient costs to maintain the safety, reliability and security of the network.

Our substitute forecast is $882.2 million, which is 27.5% below CitiPower's forecast. We consider this forecast will provide for a prudent and efficient service provider in CitiPower's circumstances to meet the capex objectives.

We encourage CitiPower to respond to the issues we have raised in our draft decision and welcome further supporting information in its revised regulatory proposal.

CitiPower's proposed forecast capex and our substitute estimate is set out in Table 2.1.

Table 2.1 AER's draft decision on CitiPower's total net capex forecast for 2026–31 ($2025–26, million)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower's proposal	280.9	285.6	235.6	212.9	201.3	1,216.3
AER's draft decision	207.2	214.1	182.4	137.1	141.4	882.2
Difference ($)	**-73.8**	**-71.5**	**-53.2**	**-75.7**	**-59.9**	**-334.1**
Difference (%)	**-26.3%**	**-25.0%**	**-22.6%**	**-35.6%**	**-29.8%**	**-27.5%**

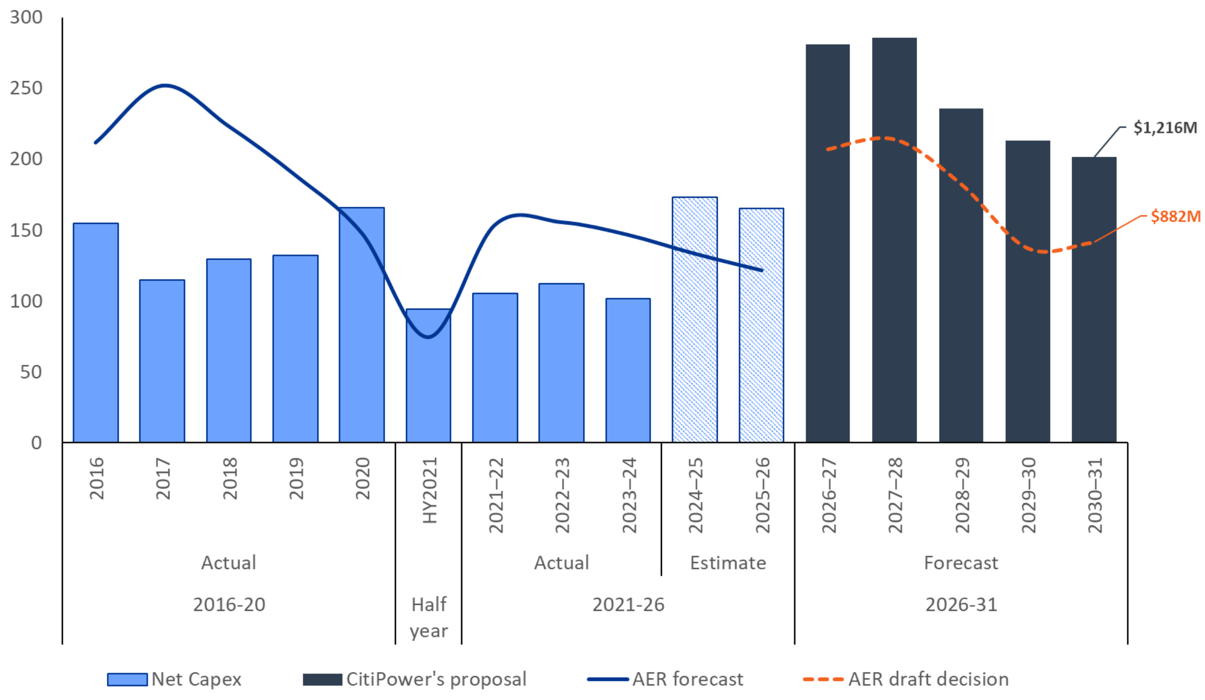
Source: CitiPower proposal, AER analysis. Numbers may not sum due to rounding.

2.2 Overview of CitiPower's proposal

CitiPower's forecast includes $1,216.3 million ($2025–26) capex over the 2026–31 period.

Figure 2.1 outlines CitiPower's historical capex trend, its proposed forecast for the 2026–31 period, and our draft decision. Consistent with our usual practice, the chart presents a time-series of CitiPower's net capex.

Figure 2.1 CitiPower's historical and forecast capex ($2025–26, million)



Source: CitiPower's regulatory proposal and AER analysis.
Note: Capex is net of disposals and capital contributions.

As can be seen in Figure 2.1, CitiPower is proposing a material step up in the forecast period relative to the current period. We also observe material underspends in actual capex in the current and previous periods. The main driver of the underspend in the current period is due to disposals, where there is a large increase in actual disposals compared to the forecast disposals in the 2021–26 period.[14] While we have seen a large increase in actual disposals in Ausgrid's 2024-29 proposal as a result of a compulsory acquisition in the Sydney CBD, this is not a type of underspend we typically see.

Figure 2.1 also shows that while our draft decision is a reduction to CitiPower's forecast, it is also a step up from CitiPower's current period actual/estimates. We note that some of this step up is because:

- For connections, there was a temporary decrease in volumes in the current period due to COVID. The forecast reflects volumes which are consistent with expected economic activity and pre-COVID levels.
- There was a significant increase in CitiPower's property forecast relative to the current period, which is mainly driven by its Burnley depot upgrades. We found the proposed expenditure for these upgrades to be prudent and efficient.

Table 2.2 provides a breakdown of CitiPower's capex proposal. In the forecast period, CitiPower proposes a step up in total capex of 84.4% relative to current period

14 Capex is assessed on a net capex basis (gross capex minus asset disposals)

actual/estimates. CitiPower proposes a step up in the forecast for almost all capex categories; the main drivers of the step up in repex, augex, connections and property.

Table 2.2 CitiPower's capex forecast by category compared with actual/estimated capex in 2021–26 ($2025–26, million)

Capex category	CitiPower's 2021–26 capex	CitiPower's 2026–31 forecast	Change from 2021–26	Contribution to increase in net capex	Proportion of total forecast capex
Replacement	206.2	351.6	70.5%	26.0%	28.9%
Innovation	N/A	4.8	N/A	N/A	0.4%
Augmentation	104.7	212.6	103.0%	19.3%	17.5%
Connections	156.3	236.7	51.4%	14.4%	19.5%
ICT	99.2	119.5	20.4%	3.6%	9.8%
Property	19.8	84.3	325.7%	11.5%	6.9%
Fleet	12.6	21.1	67.9%	1.5%	1.7%
CER integration	15.3	11.8	-22.9%	-0.6%	1.0%
Cyber security	0.0	5.6	N/A	N/A	0.5%
Non-network capex – other	6.2	7.0	13.0%	0.1%	0.6%
Capitalised overheads	136.0	162.1	19.2%	4.7%	13.3%
Total capex (less capital contributions)	**756.3**	**1,217.1**	**60.9%**		
Less Disposals	-99.1	-0.7	-99.3%		
Net capex	**657.2**	**1,216.3**	**85.1%**		

Source: CitiPower's regulatory proposal and AER analysis. CitiPower's 2021–26 actual/estimates in this table differ from its RIN data as per its response to IR011.

Notes: Numbers may not sum due to rounding. CitiPower's 2021–26 actual/estimate may include cyber security capex in other categories that is not identifiable in the Category Analysis RIN. CitiPower's regulatory proposal shows forecast capex for each category and project in $real 2025–26 un-escalated dollars. In this paper, we present all forecast capex for the 2026–31 period in $real 2025–26 escalated dollars. We re-categorised Citipower's 2026–31 forecast to align with how we assessed each category. We re-categorised $5.6 million of ICT to cyber security, $2.4 million of augex to innovation and $2.4 million of repex to innovation. CitiPower did not propose resilience capex.

2.3 Reasons for draft decision

We reviewed CitiPower's capex drivers, programs and projects to inform our view on a total capex forecast that reasonably reflects the capex criteria. We conducted top-down analysis such as examining trends and forecast costs compared with historical capex, and interrelationships between cost categories. To complement this, we conducted a bottom-up analysis of CitiPower's major programs and projects.

Our capex assessment focused primarily on the material capex categories that either represented a significant uplift in expenditure, had stakeholder interest, or are new and evolving areas such as data centre connections, CER and resilience. Capex that was relatively small and forecast using established modelling approaches and inputs in line with our expectations, meant that we did not need to undertake a more detailed analysis of the individual programs and projects. Our draft decision is reflective of this approach.

Further, in considering the scope of our review we had regard to how CitiPower has performed against the Better Resets Handbook expectations for capex.[15] Our assessment against each expectation is set out in Table 2.3. We consider that CitiPower has satisfied the capex expectations related to genuine consumer engagement on its capex proposal and has partly satisfied the remaining expectations. We have therefore undertaken a bottom-up review in most capex categories.

Table 2.3 CitiPower's performance against the capex expectations

Capex expectations	AER position
1. Top-down testing of the total capex forecast and at the category level	CitiPower has not satisfied this expectation because: • Its proposed total capex forecast is materially above (84.4%) current period actual/estimates. • It is proposing a step up in the forecast for almost all capex categories, with a material step up in the largest components of capex. • It has materially underspent in the current period while forecasting a material step up. • The repex modelling results indicate that CitiPower has higher unit rates and shorter replacement lives compared to the other 13 NEM DNSPs. As CitiPower's modelled repex is 66% of its total repex, the repex model results indicates that a closer review of CitiPower's repex forecast is required. • There is a decreasing trend in SAIFI from 2015 to 2024, suggesting that reliability of its network is generally improving over time.
2. Evidence of prudent and efficient decision-making on key projects and programs	CitiPower partly satisfied this expectation. While it provides quantitative evidence of prudent and efficient decision-making such as cost benefit analysis for some projects and programs, it has not done so for several parts of its forecast. Further, in some cases where it has provided quantitative evidence, we found overestimated costs and/or benefits such that we are not satisfied that its preferred option will result in the greatest net benefit to consumers. There is also a lack of quantitative portfolio prioritisation and optimisation given the proposed increase in capex.

15 AER, *Better Resets Handbook – Towards Consumer Centric Network*, December 2021, pp 19–23.

Capex expectations	AER position
3. Evidence of alignment with asset and risk management standards	CitiPower has partly satisfied this expectation. While there is evidence of good asset management, we found a lack of risk monetisation in certain key areas of capex which is not in line with good industry practice.
4. Genuine consumer engagement on capex proposals	Overall, CitiPower has satisfied this expectation. We acknowledge the significant engagement undertaken by CitiPower with its Customer Advisory Panel (CAP).[16] The Consumer Challenge Panel (CCP32) noted the engagement for CitiPower was part of an engagement program for the CPU businesses. The CCP submits that CitiPower used responses to the Draft Plan well and incorporated feedback into the final proposal with a significant range of 'Test and Validate' discussions and events.[17]

Overall, we found the majority of CitiPower's forecast of $1,216.3 million would be required to maintain the safety, reliability and security of electricity supply of its network.

We are satisfied that our alternative forecast of total capex of $885.0 million is reasonable and sufficient for CitiPower to maintain its network. In particular, based on the information before us, we have reviewed CitiPower's total capex forecast from a top-down and bottom-up perspective. Our top-down observations (set out in Table 2.3) informed the scope of our bottom-up review.

Given CitiPower's performance against our top-down findings, we have undertaken a bottom-up review on most capex categories.

We have accepted CitiPower's forecast where it has provided sufficient evidence to support prudency and efficiency of its forecast. This is the case for its forecast for property, fleet, cyber security and other non-network.

We have not accepted CitiPower's forecast in full (reducing it by 27.2%) because we found that it did not provide sufficient quantitative evidence to support the material step up in the forecast. For several projects and programs, we found the optimal timing for investment is beyond 2026–31. We note a pattern of underspending across the previous and current period. CitiPower has deferred some capex during this time; we have adjusted the CESS payment accordingly to address deferrals in augex and ICT. In other cases, we have made reductions to CitiPower's repex forecast such as for its substation switchgears as we consider that the more expensive option of a substation re-build is not optimal in this regulatory period. More generally, we note that the pattern of deferral of capex projects reduces our confidence in CitiPower's proposed timing of its capex investments especially as it has discretion in delivering these projects. While we appreciate that there are uncertainties

16 Customer Advisory Panel, *Customer Advisory Panel report on CitiPower's Regulatory Proposal 2026–31*, April 2025.

17 CCP32, *CCP32 Advice to the Australian Energy Regulator on the 2026–31 Regulatory Proposal for CitiPower Electricity Distribution Network*, May 2025, pp 10–11.

associated with the scheduling of projects, it is not in consumers' interests to pay for projects that are not required where the optimal timing is beyond 2026–31.

In some cases, such as for poles and distribution switchgear programs, it did not provide cost benefit analysis to demonstrate that its preferred higher than historical cost option is prudent and efficient. In other cases, such as the Brunswick modernisation program and customer driven electrification augex projects, we found the economic analysis to have overestimated costs and benefits. Its preferred investments were found to not have positive net benefit once more reasonable assumptions are applied.

We acknowledge that there is uncertainty when forecasting large capex investments. We also understand that the option of proposing a contingent project gives businesses the assurance of the inclusion of capex into the regulatory period if certain triggers are satisfied. Our draft decision is to not accept CitiPower's proposed contingent projects. This is because with some of the projects, it was unclear if they were sufficiently certain such that these should be included as part of forecast capex, rather than as a contingent project. For one contingent project, we found there was some overlap between the contingent project and repex which is not consistent with the NER. We encourage CitiPower to engage with us on its revised proposed contingent project.

Our draft decision sets out reasons for our position including information gaps and/or lack of supporting information. We invite CitiPower to address these issues in its revised proposal. We would also encourage CitiPower to engage with its customers about its revised proposal. We acknowledge the extensive customer engagement that CitiPower undertook on its capex proposal and would encourage it to continue to ensure that its customers' preferences are considered in its revised proposal.

Bottom-up review

Our bottom-up review found that CitiPower provided sufficient evidence to support the forecast for some capex categories; namely in property, fleet, cyber security and other non-network. However, for the other areas of capex, CitiPower did not demonstrate the prudency and efficiency of its forecast.

Table 2.4 sets out our draft decision for CitiPower by capex category.

Table 2.4 CitiPower's capex forecast and our draft decision by category ($2025–26, million)

Capex category	CitiPower's proposal	AER's draft decision	Difference ($)	Difference (%)
Replacement	351.6	194.1	-157.5	-44.8%
Innovation	4.8	0.9	-3.9	-81.9%
Augmentation	212.6	130.6	-81.6	-38.4%
Connections	236.7	209.7	-27.0	-11.4%
ICT	119.5	108.5	-11.0	-9.2%
Property	84.3	84.3	0.0	0.0%

Capex category	CitiPower's proposal	AER's draft decision	Difference ($)	Difference (%)
Fleet	21.1	21.1	0.0	0.0%
CER integration	11.8	9.8	-2.0	-16.9%
Cyber security	5.6	5.6	0.0	0.0%
Non-network capex – other	7.0	7.0	0.0	0.0%
Capitalised overheads	162.1	144.1	-18.0	-11.1%
Total capex (less capital contributions)	**1,217.1**	**915.6**	**-301.5**	**-24.8%**
less Disposals	-0.7	-0.7	0.0	0.0%
Modelling adjustments		-32.7		
Net capex	**1,216.3**	**882.2**	**-334.1**	**-27.5%**

Source: CitiPower's regulatory proposal and AER analysis.
Notes: Numbers may not sum due to rounding. For Citipower's proposal, we re-categorised capex to align with how we assessed each category. We re-categorised $5.6 million of ICT to cyber security, $2.4 million of augex to innovation and $2.4 million of repex to innovation.

Table 2.5 summaries our reasons for accepting parts of CitiPower's forecast by capex driver. For capex drivers that we do not accept, our reasons are set out in Appendix A.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or project/program. However, we use our findings on the different capex drivers to assess a regulated business' proposal as a whole and arrive at an alternative estimate for total capex where necessary. Our decision on total capex does not limit a regulated business' actual spending.

Table 2.5 Summary of our findings and reasons, by capex driver

Driver	AER's findings and reasons
Replacement	Our draft decision does not include CitiPower's repex forecast of $351.6 million as part of our total capex forecast. Instead, we have included a substitute estimate of $194.1 million, which is $157.5 million (44.8%) lower than CitiPower's forecast. Our bottom-up review confirmed concerns we found at the top-down level. Our reductions are mainly driven by a reduction to CitiPower's forecast volumes in several programs. Our largest reduction has been to CitiPower's forecast for its high value, low volume assets (substation switchgears and substation transformer programs) which are the main drivers of CitiPower's 70.5% repex forecast step up. We have concerns with the reasonableness of inputs and assumptions in its economic analysis. We also found that CitiPower did not

Driver	AER's findings and reasons
	explore lower cost-effective options, such as refurbishment, instead choosing more expensive options. This is further discussed at Appendix A.1.
Innovation	Our draft decision does not include CitiPower's innovation forecast of $4.8 million as part of our total capex forecast. Instead, we have included a substitute estimate of $0.9 million, which is $3.9 million (81.3%) lower than CitiPower's forecast. Our bottom-up review found several of CitiPower's proposed projects to not be innovative or expenditure that we would otherwise expect to be a business-as-usual activity. We also do not accept CitiPower's proposed CESS exclusions. CitiPower, Powercor and United Energy have each proposed similar innovation expenditure proposals. They submitted very similar information in their business cases and other supporting evidence for these projects. As such, we have assessed the innovation expenditure forecast proposed by the 3 businesses at the aggregate level and make specific business observations where relevant. This is further discussed at Appendix A.6.
Augmentation	Our draft decision does not include CitiPower's augex forecast of $212.6 million as part of our total capex forecast. Instead, we have included a substitute estimate of $130.6 million, which is $82.0 million (38.6%) lower than CitiPower's forecast. Our bottom-up review found that some of CitiPower's forecast at the project level is not prudent and efficient. While we made no changes to the demand forecast, we found issues in CitiPower's cost benefit analysis including issues with optimal timing, high costs and incorrect use of value of customer reliability (VCR). We have reduced CitiPower's $40.9 million forecast for the customer driven electrification project by $36.0 million as we found a range of issues with its proposal. This includes incorrect use of the VCR and unsubstantiated increases in forecast complaints numbers. We have reduced the proposed $60.3 million forecast for the Brunswick modernisation program by $12.7 million. We have deferred part of this program into the next regulatory control period. We found that the proposed $29.1 million forecast for the zone substation capacity upgrades is not adequately justified and have reduced by $14.6 million. The benefits were too high and it had not adequately considered non network solutions or how earlier stages of the project may have impacts on the timing of later stages. We have reduced the proposed $23.5 million forecast for the asset relocations by $18.3 million. We are not satisfied that CitiPower adequately justified its expenditure as it has not considered Yarra Trams forecast poles replacements. This is further discussed at Appendix A.3.
Connections	Our draft decision does not include CitiPower's connections forecast of $236.7 million as part of our total capex forecast. Instead, we have included a

Driver	AER's findings and reasons
	substitute estimate of $209.7 million, which is $27.0 million (11.4%) lower than CitiPower's forecast. For "business as usual" connections, we have updated the unit rate calculation for the forecast period based on an averaging period spanning the current period (i.e., 2021–24). For data centres, we have rejected CitiPower's proposal in full due to the lack of evidence of any committed data centres. This is further discussed at Appendix A.2.
ICT	Our draft decision does not include CitiPower's ICT total expenditure forecast of $136.6 million ($119.5 million capex, $17.1 million opex) as part of our total expenditure forecast. Instead, we have included a substitute estimate of $122.2 million ($108.5 million capex, $13.7 million opex), which is $14.5 million (10.6%) lower than CitiPower's forecast. CitiPower, Powercor and United Energy have each proposed the same 9 recurrent projects and 3 non-recurrent projects. They submitted very similar information in their business cases and other supporting evidence for these projects. As such, we have assessed the ICT total expenditure forecast proposed by the 3 businesses at the aggregate level and make specific business observations where relevant. Our assessment concurs with EMCa's technical assessment and findings which found the businesses did not provide sufficient evidence to demonstrate its aggregate ICT forecast is prudent and efficient. This is further discussed at Appendix A.4.
Property	Our draft decision includes CitiPower's property forecast of $84.3 million as part of our total capex forecast. We tested CitiPower's forecast at the top-down and bottom-up level and are satisfied its forecast is prudent and efficient.
Fleet	Our draft decision includes CitiPower's fleet forecast of $21.1 million as part of our total capex forecast. This forecast is 67% higher than its actual/estimated expenditure for the 2021–26 period. We note CitiPower has had low spending on fleet in the current and previous period. We also reviewed CitiPower's fleet volumes over multiple regulatory periods and consider an increase in fleet capex is in line with the expected peak stage of its replacement cycle. We are satisfied that CitiPower's forecast is reasonable and reflective of the efficient costs of a prudent operator.
CER integration	Our draft decision does not include CitiPower's forecast of $24.1 million in totex ($11.8 million capex, $12.3 million opex) for CER integration as part of our total expenditure forecast. Instead, we have included a substitute estimate of $19.2 million in totex ($9.8 million capex, $9.4 million opex), which is 20.3% lower than CitiPower's forecast. CitiPower, Powercor and United Energy adopted a common strategy for addressing CER. For CER ICT, these are also enterprise-wide investments for which expenditure is allocated between the 3 entities. Due to their commonality, we have assessed the proposed strategy and forecast programs collectively. We have considered EMCa's findings and agree that while the expenditure to introduce flexible services is prudent and efficient, the businesses have not

Driver	AER's findings and reasons
	provided sufficient information to demonstrate prudency and efficiency of its remaining 2 projects. This is further discussed at Appendix A.5.
Cyber security	Our draft decision includes CitiPower's cyber security forecast of $11.2 in totex ($5.6 million capex, $5.6 million opex) in its total expenditure forecast. CPU's cyber security total expenditure forecast is $75.6 million. Our assessment concurs with EMCa's findings that CPU has provided sufficient evidence of increased cyber threat risk and therefore that its shift from SP-1+ to SP-2 is reasonable. CPU has also provided evidence of how its proposed activities will address the gap between SP-1+ and its move to SP-2. They have also provided an options analysis to demonstrate that its preferred investments are efficient.[18]
Non-network capex – other	Our draft decision includes CitiPower's forecast of $7.0 million for other non-network (i.e., tools and equipment) as part of our total capex forecast. CitiPower demonstrated to us that its forecast is based on historical expenditure. We are satisfied that CitiPower's forecast method is reasonable and its forecast for other non-network is reflective of the efficient costs of a prudent operator.
Capitalised overheads	We have accepted CitiPower's method for calculating capitalised overheads, which is consistent with the AER's standard approach. We have made reductions to CitiPower's forecast of $162.1 million for capitalised overheads to account for reductions to the wider capex forecast as well as other modelling adjustments. We have included a substitute estimate of $144.1 million, which is $18.0 million (11.1%) lower than CitiPower's forecast.
Disposals	We have included CitiPower's disposals forecast in its total capex forecast.
Modelling adjustments	Our draft decision includes standard modelling adjustments for updated inputs to inflation and labour real cost escalation. We also included adjustments to internal and contract labour. CitiPower submitted that most of its labour is outsourced and that its forecast does not include any direct network internal labour.[19] Therefore, our draft decision capex model re-classifies any internal labour as contract labour for all direct network capex. Given we do not apply real cost escalation to contract labour, we also applied zero real cost escalation for this cost component. Adjustments for internal and contract labour reduces our alternate forecast by $27.3 million. Updates to inflation and labour real cost escalation reduces our alternate forecast by a further $5.4 million. In its capex model, CitiPower's base year for its capex inputs were in end year $2025–26, which is the beginning of its forecast regulatory period. It is unclear

[18] Energy Market Consulting associates, *Review of Proposed Expenditure on Cyber Security*, *CitiPower, Powercor and United Energy 2026-2031 Regulatory Proposals*, report for the AER, EMCa, 2025.

[19] CitiPower, *Response to information request 041*, July 2025, p 31.

Driver	AER's findings and reasons
	which methods and inputs CitiPower used to escalate its costs to end year $2025–26 given this is a forecast year. In its revised proposal, we encourage CitiPower to explain how it escalated its base year costs and apply a non-forecast base year to its capex model.
Ex-post review	We are required to provide a statement on whether the roll forward of the regulatory asset base (RAB) from the previous period contributes to the achievement of the capex incentive objective.[20] The capex incentive objective is to ensure that, where the RAB is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in value of the RAB.[21] Where, during the review period,[22] a distributor's capex exceeds its allowance (and therefore the overspending requirement is satisfied),[23] we may reduce the RAB by the amount of capex that we are satisfied does not reasonably reflect the capex criteria.[24] We have reviewed CitiPower's capex performance for the 2020 to 2023–24 regulatory years. CitiPower incurred total capex below its regulatory forecast for the ex-post review period. On this basis, the overspending requirement for an efficiency review of past capex is not satisfied.

[20] NER, cl. 6.12.2(b).

[21] NER, cl. 6.4A(a).

[22] NER, cl. S6.2.2A(a1).

[23] NER, cl. S6.2.2A(b).

[24] AER, Capital Expenditure Incentive Guideline, November 2013, p. 17; and NER, cl. S6.2.2A(f)

A Reasons for decision on key capex categories

This appendix sets out our assessment of key capex categories and programs/projects within CitiPower's total capex forecast. It also sets out the reasons for our decision. This appendix includes:

- Repex (A.1)
- Connections (A.2)
- Augex (A.3)
- ICT (A.4)
- CER integration (A.5)
- Innovation (A.6).

We note that CitiPower, Powercor and United Energy submitted information that is very similar in content to support its forecast for the same or similar list of projects for specific capex categories. Given these similarities, our assessment of ICT (at A.4) and CER integration (at A.5) is based on the aggregate total expenditure forecast presented by these 3 businesses.

A.1 Repex

We do not accept that CitiPower's repex forecast of $351.6 million would form part of a total capex forecast that reasonably reflects the prudent and efficient costs to maintain the safety, reliability and security of the network. Our draft decision includes $194.1 million in repex, which is $157.5 million (or 44.8%) lower than CitiPower's proposal.

A.1.1 CitiPower's proposal

CitiPower estimates it will overspend its repex by 33.4% in the current period which it submits '… reflects rising input costs. Noting the impacts of the pandemic and ongoing global supply chain pressures have limited the ability for contract management to mitigate these uplifts.'[25]

CitiPower's forecast is also a material step up (70.5%) relative to current period spend.[26] It is proposing increases in replacement needs for most repex asset categories.[27] It notes that the increase is due to a combination of volume increases (reflecting ongoing deterioration in the

25 CitiPower, *Regulatory proposal 2026–31, Part B: explanatory statement, Revenue and expenditure forecasts*, 31 January 2025, p 42.

26 Rather than using RIN data for this comparison, we relied on CitiPower's response to information request IR011.

27 CitiPower, *Regulatory proposal 2026–31*, p 46.

underlying asset populations) and unit rate increases.[28] Table A1.1 sets out CitiPower's forecasts for its repex programs compared to its current period spend.

Table A1.1 CitiPower's repex forecast by program compared with actual/estimated capex in 2021–26 ($2025–26, million)

Program	CitiPower's 2021–26 actual/est	CitiPower's 2026–31 forecast	Change from 2021–26 (%)	% of total repex
Poles	26.8	38.8	44.8%	11.0%
Pole top structures	38.0	39.7	5.8%	11.3%
Underground cables	40.6	67.0	64.9%	18.9%
Service lines	8.9	3.1	-65.7%	0.9%
Distribution transformers	12.3	17.9	45.1%	5.1%
Distribution switchgears	16.5	54.6	230.3%	15.5%
Substation transformers	0.0	31.0	n/a	8.8%
Substation switchgears	33.9	79.1	133.3%	22.5%
SCADA	13.6	12.8	-5.6%	3.6%
Other	16.0	7.7	-52.0%	2.9%
Total repex	**206.6**	**351.6**	**70.2%**	**100%**

Note: CitiPower's regulatory proposal, AER analysis. The 2026–31 forecast repex uses CitiPower's capex model and 2021–26 actuals/estimated repex uses its RIN data.

Source: Doesn't include the innovation program. For CitiPower's 2021–26 actual/estimated, we grouped overhead conductors to pole top structures given the immateriality of its conductor expenditure. Total repex for 2021–26 actual/estimated does not reconcile with Table 2.2 ($206.2 million) due to errors with CitiPower's RIN data.

CitiPower submits that the drivers of the step up in 2026–31 relative to the current have been in underground cables, distribution switchgear and zone substation transformers.[29] We also identified step ups in its poles, and substation switchgear programs.

To derive its forecasts, it used several forecasting methods including historical trend, condition-based risk model (CBRM), and economic analysis.

A.1.2 Reasons for our decision

We have reviewed the information CitiPower provided in support of its repex forecast. We engaged EMCa to review aspects of CitiPower's proposed repex. Where required, we have sought further information from CitiPower through information requests.

[28] CitiPower, *Regulatory proposal 2026–31*, p 46.

[29] CitiPower, *Regulatory proposal 2026–31*, p 42.

We undertook a top-down assessment which informed our bottom-up assessment of CitiPower's proposed repex. Our draft decision at a program level is set out in Table A1.2.

Table A1.2 CitiPower's repex forecast and AER draft decision by program ($2025–26, million)

Program	CitiPower's 2021–26 actual/est	CitiPower's 2026–31 forecast	AER's draft decision	% change (forecast vs draft decision)
Poles	26.8	38.8	28.5	-26.5%
Pole top structures	38.0	39.7	30.1	-24.2%
Underground cables	40.6	67.0	42.4	-36.7%
Service lines	8.9	3.1	3.1	0.0%
Distribution transformers	12.3	17.9	17.9	0.0%
Distribution switchgears	16.5	54.6	21.3	-61.0%
Substation transformers	0.0	31.0	10.0	-67.7%
Substation switchgears	33.9	79.1	20.3	-74.3%
SCADA	13.6	12.8	12.8	0.0%
Other	16.0	7.7	7.7	0.0%
Total repex	**206.6**	**351.6**	**194.1**	**-44.9%**

Source: CitiPower's regulatory proposal, AER analysis.
Note: Doesn't include the innovation program. 2026–31 forecast repex uses CitiPower's capex model and 2021–26 actuals/estimated repex uses its RIN data. For CitiPower's 2021–26 actual/estimated, we grouped overhead conductors to pole top structures given the immateriality of its conductor expenditure. Total repex for 2021–26 actual/estimated does not reconcile with Table 5.2 ($206.2 million) due to errors with CitiPower's RIN data.

A.1.2.1 Top-down assessment

Our top-down assessment revealed that CitiPower's proposed step up in repex of 70.5% in the forecast period relative to current period spend requires a closer review.[30] In particular, our top-down assessment found:

- CitiPower is proposing an increase in repex relative to the current period across almost all programs.
- CitiPower is expecting to overspend by 33.3% in the current period but its forecast for 2026–31 is materially higher.
- CitiPower's last 2 years of estimates in the current period are exponentially high compared the first 3 years of the current period (approximately 100% higher).

30 Rather than using RIN data for this comparison, we relied on CitiPower's response to information request IR011.

- CitiPower does not perform well against the AER's repex model – the repex modelling results indicate that CitiPower has higher unit rates and shorter replacement lives compared to the other 13 NEM DNSP. As CitiPower's modelled repex is 66% of its total repex, the repex model results indicates that a closer review of CitiPower's repex forecast is required.
- CitiPower's SAIFI results indicate improvement in performance overtime. We observe a decreasing trend in SAIFI from 2015 to 2024, suggesting that reliability of its network is improving over time.

A.1.2.2 Bottom-up assessment

Our bottom-up review found that the majority of CitiPower's forecast at the program level is not prudent and efficient. We make some following overall observations:

- *Our largest reductions have been in CitiPower's forecast for its high value, low volume assets (substation switchgears and substation transformer programs) which are the main drivers of CitiPower's 70.5% repex forecast step up*.

  We have concerns with the reasonableness of inputs and assumptions in its economic analysis. Once adjustments are made, we found that the optimal option in several cases is to defer beyond 2026–31. We also found that CitiPower did not explore lower cost-effective options, such as refurbishment, choosing to propose the more expensive option. This reflects CitiPower's asset management approach to its high value, low volume assets, where it proposes the more expensive and extensive solution which is prone to delivery constraints and/or high cost of delivery. As a result, we are observing a pattern of deferral, which reduces our confidence in the prudency and efficiency of its forecast. For instance, for its substation switchgear expenditure, CitiPower incurred less than $1 million in the first 3 years of the current period, where we included a capex of $40.9 million in the current period. Yet, CitiPower is proposing 8 project completions in 2026–31 with a capex of $79.1 million next period.

- *In a few cases, we did not have confidence that CitiPower's forecasting approach to volumes would result in prudent and efficient outcomes*.

  CitiPower uses its CBRM to develop forecast volumes for the bulk of its programs. We do not have confidence that this approach results in the most efficient outcome. CitiPower uses the CBRM to predict the probability of failure (PoF), probability of consequence (PoC), and a health index (ranging from zero to 10), where it intervenes when the health index exceeds a certain number (health index of 7 or above). Typically, the results of the CBRM are subsequently used in a cost benefit analysis (in term of PoF and PoC) to determine the optimal investment that would result in greatest net benefits to consumers. We found that CitiPower did not undertake the critical end step of a cost benefit analysis (the monetarisation of cost and benefit), instead assuming that its deterministic outcome from the CBRM is prudent and efficient. We also found that CitiPower applied 2 forecasting approaches (CBRM and a separate risk-based model) in forecasting repex for some assets and added both forecasts to come up with an aggregate forecast for the asset group. We consider that this forecasting approach may result in double-counting of the repex requirement.

- *CitiPower did not provide cost benefit analysis to support some of its forecast.*

As set out in our asset replacement guidance note, we expect businesses to undertake economic analysis to demonstrate prudency and efficiency of its preferred investment.[31] We consider a cost benefit analysis to be critical evidence especially where CitiPower is forecasting a material step up in forecast volumes and/or unit rates. This is because the option that results in the greatest net benefit may change with material forecasted changes in volumes and/or unit rates. This is the case for CitiPower's forecast for its poles program, some of its forecast for its distribution switchgear program and underground HV program.

We discuss each of our findings on CitiPower's forecast for each of its repex programs below.

Substation switchgears

CitiPower proposes $79.1 million for the completion of 8 switchboard replacements in 2026–31. Its forecast is 133.3% higher than current period spend. Its proposed program involves 5 new substations (AR, RD, NC and VM), switchboard retirement of R and completion of 3 'in-flight' switch board replacements (CW, LQ and B). Table A1.3 sets out CitiPower's proposal and our draft decision position on each of the proposed replacements. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $20.3 million which is 74.3% lower than CitiPower's forecast.

Table A1.3 CitiPower's forecast for its substation switchgear program and the AER's draft decision ($2025–26, million)

Substation	CitiPower's forecast	Expected completion date	AER's draft decision
In-flight replacement projects			
Little Queen (LQ)	13.4	2027–28	6.7
Collingwood (B)	18.5	2028–29	9.3
Collingwood (CW)	2.3	2026–27	2.3
Forecast retirement projects			
R	2.7	2026–27	0.0
Forecast substation re-build projects			
AR	9.7	2027–28	0.5
RD	8.5	2028–29	0.5
NC	8.5	2029–30	0.5
VM	16.1	2030–31	0.5
Total	**79.1**		**20.3**

Source: CitiPower, *ASSET CLASS OVERVIEW: ZONE SUBSTATION SWITCHGEAR*, January 2025.

31 AER, *Industry practice application note for asset replacement planning,* January 2019.

We came to our draft decision having regard to the following findings:

- For its in-flight projects (CW, LQ and B), we found CitiPower's forecast for CW to be reasonable but not for LQ and B:
  - For LQ and B, capex was included for these projects in the previous review. CitiPower submits that, for LQ, there were temporary delays that results in rebuilding aspects of the LQ substation. For B, CitiPower submits that following supply chain and other cost increases, the revised cost to deliver the B switchboard replacement increased significantly. Due to these higher costs, CitiPower proposes to instead replace the 11kV switchboard at CW.[32]
  - Based on the information before us, we are satisfied that the forecast for CW is prudent and efficient. While CW was not included in total capex from the previous review, we consider it reasonable to be undertaken due to network conversion needs and the more efficient replacement of B.
  - However, we are not yet satisfied that its forecasts associated with LQ and B are prudent and efficient. CitiPower's estimate for the last 2 years of the current period (2024–25 and 2025–26) is higher than is justified given the information provided. This indicates some of these in-flight projects may have a total cost well above $20 million. CitiPower does not provide supporting information to explain this material cost increase. Our alternative estimate assumes 50% of LQ and B repex requirements resides in the current period based on an average replacement cost of $15.0 million per project. We invite CitiPower to provide further information in its revised proposal to support capex associated with LQ and B including its latest project schedule and detailed estimates for all in-flight projects in the current period (including CW).

- For its retirement project, R, we consider that it would be prudent for R to be deferred beyond 2026–31. EMCa found that:[33]

  > … a further risk is added to the analysis as 'other'. However, CitiPower does not explain the source of this risk, nor has it provided additional supporting information to assist with understanding the condition and/or safety risk at the site… If this risk value was removed, and a change to the VCR applied, we consider that the project timing is likely to be deferred, beyond the end of the next RCP.

  We also note that CitiPower has also proposed a contingent project for the rebuild of the R substation if the demand exceeds CitiPower's forecast. Our draft decision on CitiPower's contingent project is in Appendix B.

- For its forecast substation re-build projects (AR, RD, NC and VM), most of the expenditure could be deferred either to later in 2026–31 or beyond 2026–31 based on EMCa's review of CitiPower's economic analysis.

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32 CitiPower, *ASSET CLASS OVERVIEW: ZONE SUBSTATION SWITCHGEAR*, January 2025, p 15.

33 EMCa, *Review of certain aspects of proposed expenditure on repex, augex and vegetation management*, CitiPower 2026-2031 Regulatory Proposal, p 53.

- For its 4 forecast substation re-build projects (AR, RD, NC and VM), we found that adjustment for more reasonable input assumptions is likely to lead to deferral of the projects. CitiPower proposes to rebuild these substations to mitigate the risk of switchboard failure at these substations. EMCa found:[34]
  - Lack of evidence of the optimal timing of the replacements. Further, timing of projects appears to be subject to the completion of other projects. For instance, the timing of the VM project appears contingent on completion of LQ which is already delayed;
  - Modelling errors where the timing of benefits are not the same as the costs, and differences in cost escalation; and
  - CitiPower applies 2023 VCR values and once 2024 VCR values are applied, there is a deferral of these projects.

We also note that CitiPower did not sufficiently quantify other lower cost options to manage risks in the short to medium term especially when faced with the likelihood of further delivery constraints next period. Our alternative forecast is based on the cheaper option of retrofitting existing oil circuit breakers with vacuum circuit breakers. This is consistent with good industry practices when DNSPs are faced with the challenges of managing a large volume of aged switchboards within one or two regulatory periods. We consider that vacuum circuit breakers are highly effective in mitigating the consequences of failure. This is because it removes the catastrophic risk of oil fire from switchboard failures, which in turn allows electrical workers to safely access the site and repair the fault in a shorter timeframe (i.e. greatly mitigate safety and reliability risks from major failure events). Our alternative forecast of $0.5 million per site is reflective of similar solutions from other DNSPs in past proposals and AER decisions.

Underground cables

CitiPower proposes $67.0 million for its underground cables program. This is a 65% step up from its current period actual/estimates. Table A1.4 sets out CitiPower's forecast at the project level, and our draft decision position. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $42.4 million which is 36.7% lower than CitiPower's forecast and is in line to CitiPower's historical spend.

Table A1.4 CitiPower's repex forecast by program and AER draft decision ($2025–26, million)

Intervention type	Program	Forecasting approach	CitiPower's forecast	AER's draft decision
Fault/corrective	LV cable	Historical average	4.9	4.9
	HV cable	CBRM	28.1	15.0
	Pits and Pillars	States CBRM but unclear	14.4	11.5
Risk-based	HV cable	CBRM and Risk-based	8.6	0.0

34 EMCa, *Review of certain aspects of proposed expenditure on repex, augex and vegetation management*, CitiPower 2026-2031 Regulatory Proposal, pp 52–53.

Intervention type	Program	Forecasting approach	CitiPower's forecast	AER's draft decision
	HV cabus boxes	Risk-based	11.0	11.0
Total repex			**67.0**	**42.4**

Source: CitiPower, *ASSET CLASS OVERVIEW: UNDERGROUND CABLES,* January 2025.

We came to our draft decision having regard to the following findings:

- We found CitiPower's forecast for its LV cable program to be reasonable. Failures and defects appear stable in recent years and CitiPower forecast is in line with its recent actual spend.
- We found CitiPower's forecast for its HV cabus program to be reasonable. This is a safety related program where above ground pitch-filled metallic box termination poses a public risk (that is, failure from moisture ingress resulting in failures which scatter molten pitch and metal debris in a 50-metre radius). Given there has been previous near miss incidents associated with this type of asset, we consider it reasonable for CitiPower to implement its proposed 10-year prioritised program to address this safety concern.
- We found CitiPower's forecast for its pits and pillars program to be overestimated. Failures and defects are trending downwards and CitiPower is proposing an uplift of its historical spend.[35] It is also unclear what forecasting approach it applied as its business case notes that there is no age record for this type of asset. Our alternative estimate is based on its current period spend of $11.5 million.
- We found CitiPower's forecast for its HV cable program (classified as fault/corrective and risk-based type of intervention) to be overestimated. While there is a step-up in defects in 2021, failures were trending downwards since 2020 and defects did not increase further in 2023. For the risk-based program, the key inputs and calculations of CitiPower's submitted cost benefit analysis model is hardcoded and cannot be objectively verified. Further, CitiPower applies 2 forecasting approaches (the CBRM and a risk-based model) to derive 2 separate forecasts, which are aggregated and included as the total forecast. We are concerned that the application of 2 forecasts may double-count the repex required to address the risk to be mitigated. CitiPower has not provided evidence to demonstrate that any double-count has been netted off. Our alternative forecast applies CitiPower's historical spend.

Substation transformers

CitiPower proposes $31.0 million for its substation transformers program. Table A1.5 sets out its proposal and our draft decision position. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $10.0 million, which is 67.7% lower than CitiPower's forecast.

35 CitiPower, *ASSET CLASS OVERVIEW: UNDERGROUND CABLES*, January 2025, pp 7–8.

Table A1.5 CitiPower's forecast for its substation transformer program and the AER's draft decision ($2025–26, million)

Transformer program	CitiPower's forecast	AER's draft decision
Transformer replacement • Armadale (AR) • Northcote (NC) • Victoria Market (VM)	22.9	6.3
Transformer environmental refurbishment	5.0	2.5
Minor works	3.0	1.2
Total	**31.0**	**10.0**

Source: CitiPower, *ASSET CLASS OVERVIEW: ZONE SUBSTATION TRANSFORMERS,* January 2025.

CitiPower's forecast involves the replacement of 3 transformers and the continuation of its expected current period environmental refurbishment program to manage transformer oil leaks in accordance with regulatory requirements.

Transformer replacement

We found that deferral of the proposed replacement projects was often more optimal. We came to our draft decision having regard to the EMCa findings that:

- CitiPower's framework for its risk analysis in support of its forecast for substation transformer replacement is reasonable. However, its options analysis does not consider the life extension option of refurbishment of the transformer.
- Adjustment for more reasonable input assumptions (updating the VCR value to 2024 and removing the multiple of VCR applied to unserved energy for VM) is likely to lead to deferral of some proposed replacement projects.
- Application of an aggregate hard-coded value for environmental risk, which CitiPower provides little support for.
- Misalignment of the assessment periods for benefits (50 years) and costs (20 years). Once adjustments are made, this results in reductions to the NPV, such that some nominated sites for replacement are not economic to proceed in 2026–31.
- Cost estimates for substation projects are high which was noted in our 2021-26 decision. We also found that an average like-for-like replacement cost of $7.6 million for a 30MVA 66/11kV transformer to be out of step with other DNSPs we observed so far in the NEM.

Due to these findings, our alternative forecast is based on deferral of one transformer at VM and a reduction to the unit rates of the 2 transformers at AR and NC.

Transformer environmental management program

CitiPower's proposed transformer environmental management program is intended to address identified oil leaks. It submits a model in support of the cost associated with this program. EMCa identified concerns with the forecast, including incorrect quantification of the risk cost and poor quantification of consequence costs. EMCa also observes that a more targeted smaller program in 2026–31 to address high-risk sites would be prudent.

Our alternative forecast is based on a 50% reduction to CitiPower's forecast. Our alternative forecast is based on the information before us, which includes the consideration of an existing program in the current period with no actual completion to date. We invite CitiPower to address these concerns and resubmit its economic model to support this program in its revised proposal.

Minor works

We have considered EMCa's findings and agree that CitiPower's forecast of $3.0 million to address unplanned and reactive works should more closely follow a historical average.[36] Given the unexplained step increase in the final year that is materially above other years in the forecast, our alternative estimate of $1.2 million is consistent with CitiPower's forecast for the first 4 years of the 2026–31 period (i.e. 2026–27 to 2029–30).

Distribution switchgears

CitiPower proposes $54.6 million for its distribution switchgear program. Table A1.6 sets out its forecast and our draft decision position. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $21.3 million is 61% lower than CitiPower's forecast.

Table A1.6 CitiPower's forecast for its distribution switchgear projects and the AER's draft decision ($2025–26, million)

Asset type	Forecasting approach	CitiPower's forecast	AER's draft decision
Defective Switches	CBRM	32.7	14.0
Defective fuses and surge diverters	Historical	1.3	1.3
Inoperable HV ABS program	Risk-based/cost benefit analysis	6.0	6.0
Inoperable RMU program	Risk-based/cost benefit analysis	14.6	0.0
Total		**54.6**	**21.3**

Source: CitiPower, *ASSET CLASS OVERVIEW: DISTRIBUTION SWITCHGEAR,* January 2025.

We came to our draft decision having regard to the following findings:

- We found CitiPower's forecast for its defective fuses and surge divertors and inoperable HV ABS program to be reasonable. CitiPower have provided sufficient evidence to support its forecast for its defective fuses and surge diverters program. For its inoperable HV ABS program, while we have some concerns with the assumptions associated with

36 EMCa, *Review of certain aspects of proposed expenditure on repex, augex and vegetation management*, CitiPower 2026-2031 Regulatory Proposal, pp 46–47.

its forecast, adjusting for more reasonable assumptions still results in a positive economic case.

- We found the repex forecast for CitiPower's defective switches program to be overestimated. Historical failures are stable and the slight increase in defects in recent years is driven by lower priority defects. Further, CitiPower is forecasting a material step up, where expenditure over the current period is about $14 million. It did not provide a cost benefit analysis in support of the step up. We would expect businesses, especially where there is a step up in the forecast relative to historical spend, to provide cost benefit analysis to demonstrate that its proposed unit rate/volume combination results in the greatest net benefit. Our alternative forecast is based on CitiPower's historical spend.
- We found CitiPower's repex forecast for its inoperable RMU program to be overestimated. We consider CitiPower's estimates for its unserved energy and safety risk in its cost benefit analysis to be high. Once adjusting for more reasonable assumptions, none of the replacement options proposed by CitiPower for 2026–31 results in a positive economic case. We consider there may be specific circumstances where the replacement of inoperable RMU switches may be economically justified and encourage CitiPower to investigate this in its revised proposal.

Poles

CitiPower proposes $38.8 million for its poles program. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $28.5 million, which is 26.5% lower than CitiPower's forecast. This is based on CitiPower's historical 3-year average of pole volumes.

CitiPower forecasts pole intervention volumes of 3,359 poles, with its staking ratio based on a 5-year average (FY2020 to FY2024) of 59%. CitiPower submits that in the current period it is observing an increasing proportion of wood poles requiring intervention due to deterioration, therefore its forecast is above current period spend. Its forecasting method is similar to Powercor's approach where it uses a decay model (condition-based model). The decay model predicts the sound wood thickness of each pole based on the historical annual decay rate of sound wood thickness. This is used as a key input to the wood pole serviceability and therefore the forecast number of poles that require intervention.

We consider that CitiPower has not provided sufficient evidence to support prudency and efficiency of its forecast; in particular the step up in pole volumes in 2026–31 relative to historical spend. EMCa found that CitiPower proposed a higher pole volume than the outcomes of the decay model. When asked in an information request how CitiPower tested whether its proposed volumes were prudent and efficient, CitiPower responded that it did not consider alternative pole volumes. Further, contrary to CitiPower's submission, EMCa do not observe a worsening trend in pole defects and failures, with a declining trend from 2022–23. We also observe that CitiPower's unassisted wood pole failures are around 0.55 failures per 10,000 poles since 2020, which significantly outperforms the generally accepted industry benchmark of 1 in 10,000 poles.

Pole top structures

CitiPower proposes $39.7 million for its pole top structures program. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $30.1 million, which is 24.2% lower than CitiPower's forecast. This is based on CitiPower's historical 3-year average of pole top volumes.

CitiPower bases its forecast for pole top structures on its historical defect find rate. We are not satisfied that its forecast is prudent and efficient as CitiPower has not provided sufficient evidence to support the step up in volumes. EMCa found that CitiPower did not adequately take account of the impact of related replacement programs which would lower the volume forecast. The defects and failure information provided by CitiPower indicates a declining trend in defects since 2021–22. With a declining number of defects, we would expect a reduction to the forecast crossarm replacement program. EMCa also found that CitiPower's unit rates for its crossarm replacement are materially higher than other comparable DNSPs.[37]

Distribution transformers

CitiPower proposes $17.9 million for its distribution transformer program. Our draft decision is to accept CitiPower's forecast.

Although CitiPower is proposing a forecast that is a material step-up from historical, we consider that there is a need for that level of investment. We concur with CitiPower that in the current period, its defects and failures of its distribution transformers have been increasing, mainly driven by deteriorating condition of indoor and kiosk transformers.

SCADA, service lines and other replacement program

CitiPower proposes $12.8 million for its SCADA program, $3.1 million for its service lines program and $7.7 million for its other replacement program.[38] Our draft decision is to accept CitiPower's forecast for these programs.

We consider that CitiPower provided sufficient evidence in support of these forecasts. In particular, our review of CitiPower's historical spend indicates that its forecast is reasonable.

For its SCADA forecast, we found CitiPower's targeted approach to its planned program to its 2 substation sites is prudent. We have considered EMCa's findings and concur that CitiPower's forecast is reasonable despite some issues it found with the lack of transparency in deriving risk costs. For its service lines forecast, we note that failure rates are low and defect rates are stable. This is consistent with the service line forecast being materially below historical spend.

For other replacement, CitiPower noted this category includes the innovation fund and that there was a misallocation with another category in its reset RIN.[39] Once removing the innovation fund and accounting for potential misallocations from CitiPower's forecast for this category, there does not appear to be a step up from its historical expenditure. In its revised proposal, we expect CitiPower to re-submit its reset RIN adjusting for any errors it found since submitting its proposal.

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[37] EMCa, *Review of certain aspects of proposed expenditure on repex, augex and vegetation management*, CitiPower 2026-2031 Regulatory Proposal, pp 36.

[38] Rather than using CitiPower's reset RIN forecast for the other replacement category, we relied on its capex model and CitiPower's categorisation in IR041. We also removed CitiPower's innovation program from the other replacement category.

[39] CitiPower, *Response to information request 041*, July 2025, pp 5, 29.

A.2 Connections

We do not accept that CitiPower's net connections capex forecast of $236.7 million and capital contributions (type 1) of $609.2 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $209.7 million in net connections capex and $480.9 million in capital contributions. When compared to CitiPower's proposal, this is a decrease of $27.0 million (11.4%) in net connections and $128.3 million (21.1%) in capital contributions.

A.2.1 CitiPower's proposal

CitiPower proposes $236.7 million in net connections capex. CitiPower's net connections capex forecast represents a 51.4% increase in expenditure compared to the current period actual/estimates of $156.3 million. CitiPower has explained the rebound in residential connections following the pandemic and an increase in data centre connections have significantly contributed to this uplift.[40] CitiPower has also proposed $609.2 million in capital contributions (type 1), which is a 45.3% increase from the current period of $419.4 million.

Table summarises the changes in total net connections and capital contributions from the current period to the forecast period.

Table A2.1 CitiPower's connections proposal ($2025–26, million)

CitiPower proposal	Current period	Forecast period	% change
Net Connections	156.3	236.7	51.4%
Capital Contributions	419.4	609.2	45.3%

CitiPower engaged with its consultant Macromonitor to develop its forecast modelling approach for connections capex. Macromonitor applied an econometric model that incorporates historical trends, demographic forecasts, occupant/purchase demand and expected growth in various customer types in developing its final forecasts for connection volumes and unit rates. It also provided a summary of their forecasting methodology for both residential and non-residential connections which employs:

- publicly available data
- known projects
- a detailed analysis of economic influences used in their econometric model.

Across their material business as usual (BAU) connection types, CitiPower forecasts an average increase of 29.6% from its current period volumes.[41] We excluded subdivision and embedded generation connections in calculating this increase as we found they were immaterial in net connections and skewed the volume aggregate. Macromonitor has

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40 CitiPower, *Regulatory proposal 2026–31*, p 53.

41 BAU connections consists of residential, commercial and industrial, subdivision and embedded generation connection types. CitiPower, *CP MOD 5.01 - Connections - Jan2025 – Public,* January 2025.

attributed drivers such as a reduction in interest rates and an increase in residential occupant demand to their increasing volumes.[42]

CitiPower also proposes a gross capex of $131.1 million and net capex of $19.7 million for data centres. It engaged with L.E.K to model its data centre load forecasts and has forecast an 85% capital contribution rate (to gross capex excluding overheads) for data centres. CitiPower stated its forecast only includes contracted data centres.[43] In response to our information request, CitiPower clarified its forecast is based on a top-down methodology rather than estimated costs for specific data centres.[44] The capex forecast is based on an average $/MW rate multiplied by data centre capacity in the forecast period as estimated by L.E.K.[45]

A.2.2 Reasons for our decision

For our analysis of CitiPower's connections forecast, we have divided its proposed capex into 2 separate categories: BAU connections, and large bespoke connections (such as data centres).

We engaged Baringa to assess CitiPower's connections volumes. We came to our draft decision having regard to Baringa's findings and our assessment of CitiPower's proposed connection volumes, unit rates and associated methodologies.

A.2.2.1 BAU connections

Our draft decision includes $209.7 million in BAU net connections capex and $480.9 million in capital contributions, which is $7.4 million (3.4%) and $16.9 million (3.4%) lower than CitiPower's proposal respectively.

We broadly accept CitiPower's forecast volumes for BAU connection types. Baringa found the alignment of the gross state product growth rates with historical trends ensured volumes forecasts were realistic, reflecting long-term economic dynamics.[46] Further, Macromonitor had used publicly available sources (such as the ABS) as inputs for its projections, which were able to be verified. Based on Baringa's assessment, we are satisfied that the forecast connection volumes are prudent and efficient. However, we note some of CitiPower's forecast volumes methodology could benefit from increased transparency of its intermediary calculation steps.

We do not consider CitiPower's forecast unit rates are reasonable as it used 2023–24 unit rates as the basis for its forecast. While CitiPower considered the prior years' unit rates were not a reliable indicator of forecast unit rates because of volatility during the pandemic, it did

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42 Occupant demand is the number of dwellings required to house the population, based on demographic projections and a given set of household formation behaviour assumptions. CitiPower has forecasted ~80% of its net connections derived from residential, complex connections. Therefore, an increase in residential occupant demand is significant for volumes. Macromonitor, *CP ATT 5.04 - MacroMonitor - Forecasts by region - Aug2024 – Public,* August 2024, p 1, 9; CitiPower, *Regulatory Proposal 2026–31*, p 57.

43 CitiPower, *Regulatory proposal 2026–31*, p 53.

44 CitiPower, *Response to information request 029 – Data centres and large connections,* May 2025, p 1.

45 CitiPower, *CP ATT 5.03 - LEK - Customer electricity use* – Oct 2024 – PUBLIC.

46 Baringa, *Baringa_AER_Victorian distribution demand_CitiPower_Final report_v2.0,* July 2025, p 27.

not sufficiently explain how this approach addresses the issue of volatility.[47] We consider that using a longer historical trend better reflects forecast unit rates, particularly where volatility is an issue. For this reason, our alternative forecast is based on the last 3 years of CitiPower's actual unit rates in the 2021–26 period. This results in a $7.4 million or a 3.4% decrease in net connections. We intend to update this to include the 4th year when the data is available.

We also reviewed CitiPower's capital contributions formula. In response to an information request, CitiPower clarified that the contribution rates have been calculated from samples of completed projects by connection category.[48] These samples are updated based on the global weighted average costs of capital. We consider this methodology reasonable.

We encourage CitiPower to respond to the issues we have raised in its revised regulatory proposal. We also welcome further supporting information, including actual capex from 2024–25, policy changes, and updated economic and demographic statistics which could materially impact its forecast assumptions.

A.2.2.2 Large bespoke connections

CitiPower proposes gross capex of $131.0 million (net capex of $19.0 million) for data centres and forecasts an 85.0% capital contribution rate (to gross capex excluding overheads) for data centres. Our draft decision is to not accept CitiPower's forecast. This is because we do not consider its forecast is prudent and efficient, given the basis of its forecast does not reflect the capex it requires in the 2026–31 period.

CitiPower's top-down methodology, estimated by their consultant L.E.K, is based on an average $/MW rate multiplied by data centre capacity in the forecast period, which does not identify the data centres that need to be constructed in the 2026–31 period. It also assumes that data centre capacity has a relationship with forecast capex. However, we consider CitiPower has not demonstrated this relationship. This is because the forecast capacity measure appears to include data centres that have been or will be constructed in the current period. Further, CitiPower has not provided information to support the volume of expected data centre connections with reference to actual connection inquiries in the forecast period.

It is our understanding that CitiPower will be revising its data centre forecast for our consideration in its revised proposal. We would expect CitiPower to provide forecast information supported by actual data centre connection applications, as this includes contract information for committed data centres and the status of any connection enquiries.

Guidance for revised proposal data centres forecast

We acknowledge that demand for data centres is likely to increase in the forecast period relative to the current period. However, we must be satisfied that the forecasts accurately reflect the likely demand for data centre connections in the forecast period.

To assist CitiPower with its revised proposal, we have broadly identified 3 categories of data centre connection projects with differing levels of information to support them. We have provided this guidance given that data centres are a relatively new type of connection. We do

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47 CitiPower, *Response to information request 019 – CESS and Connections*, April 2025, p 6.

48 CitiPower, *Response to information request 019 – CESS and Connections*, April 2025, p 5.

not consider this guidance to be comprehensive and expect there to be adjustments to factor in the information that is available to CitiPower.

We encourage CitiPower in its revised proposal to provide information to support the following categories.

- *Committed in-flight projects.*

  For committed 'in-flight' connections, we consider these to be data centre connections where committed works agreements (CWAs) have been signed. If CitiPower provides evidence of these CWAs for connections to be constructed in the forecast period, we will be satisfied CitiPower has demonstrated that the capex is prudent and efficient.

- *Projects that are between the connection enquiry to connection offer stage.*

  For projects that are at the enquiry to CWA stage, we would require cost build ups for projects at the feasibility and offer stages. This should be based on actual unit rates from historical projects. Where this unit rate is not available, it should be based on a comparable unit rate multiplied by the MVA. These projects should then be weighted against the probabilities of them progressing within the forecast period. These weights should be supported by evidence of how often projects at their respective stages of maturity at the time of the revised proposal are likely to progress to the CWA stage in the forecast period.

- *Future project which are anticipated but enquiries have not yet been received.*

  For projects that have not advanced to the enquiry stage, we acknowledge that it may be difficult for CitiPower to forecast based on actual enquiries. Where available, we expect CitiPower to provide evidence of the volume of interest it has received for data centre connections. For example, if a connection applicant has paid any fees, or there has been public announcements or scoping and drawing documents. We note that data centres may have significant lead time so we expect that any data centres to be constructed in the forecast period should already have evidence available.

  However, we acknowledge that there could be data centres constructed towards the latter years of the forecast period where direct evidence is not currently available. If CitiPower intends to include a forecast for data centres where limited evidence is available, then we expect CitiPower to provide independent evidence that there will be continued uptake in data centres in their network.

CitiPower will also have to demonstrate that holistically their forecast is in line with the expectations of other organisations such as AEMO. CitiPower must explain why it considers the uptake in data centres will likely occur in its network area rather than in another Victorian network. We also consider CitiPower should factor in that applicants may apply to multiple DNSPs and that some may be more speculative in nature relative to typical connection applications.

A.3 Augex

We do not accept that CitiPower's augex forecast of $212.6 million would form part of a total capex forecast that reasonably reflects the prudent and efficient costs to maintain the safety, reliability and security of the network. Our draft decision includes $130.6 million in augex, which is $82.0 million (or 38.6%) lower than CitiPower's proposal.

A.3.1 CitiPower's proposal

CitiPower has proposed $215.0 million for augex. We consider $2.4 million of proposed augex is network innovation and have assessed this as such. For our draft decision, we have assessed the remaining $212.6 million as augex and refer to this amount for the remainder of this section.

CitiPower expects to underspend its augex by 17.9% in the current period, which it submits is due to several factors including:[49]

- peak demand and consumption in the CBD and inner-city falling by 20–30% during lockdowns
- delays to the modernisation program and other deferred augmentation works
- better than expected performance from operating solutions to enable solar exports
- lower than expected costs for certain projects.

CitiPower's forecast is a material step up (103.0%) relative to its current period spend. It notes that the increase is primarily driven by an increase in its demand forecast and demand driven capex as a result.[50] CitiPower has proposed $144.6 million for demand driven and $68.0 million for non-demand driven augex. The key drivers of demand driven augex for CitiPower are increasing peak demand, population growth, and electrification of gas and transport.

A.3.2 Reasons for our decision

In coming to our decision, we reviewed the information CitiPower provided in support of its augex forecast and had regard to findings from consultants EMCa and Baringa. We engaged EMCa to review aspects of CitiPower's proposed augex and Baringa to review CitiPower's demand forecast. When assessing CitiPower's proposal for augex, we had regard to major project business cases, key assumptions, identification of need, historical comparison, options and cost benefit analysis. Where required, we have sought further information from CitiPower through information requests.

We received a submission from CCP32 indicating broad support for CitiPower's augex programs. We acknowledge this support and the customer support for several of CitiPower's augex projects. Our role is to assess these projects to determine if they are prudent and efficient and provide a positive benefit to consumers.

We undertook a top-down assessment which informed our bottom-up assessment of CitiPower's proposed augex.

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49 CitiPower, *Regulatory proposal 2026–31*, p 31.

50 CitiPower, *Regulatory proposal 2026–31*, p 31.

A.3.2.1 Top-down assessment

Our top-down assessment revealed that CitiPower's proposed step up in augex of 103.0% in the forecast period relative to current period spend required a more in-depth assessment. Our top-down assessment found:

- The quality and transparency of the economic analysis and investment options considered by CitiPower requires review.
- CitiPower's demand forecasting model requires a full review to justify the large increases in demand.
- CitiPower is proposing an increase in augex relative to the current period particularly in its demand driven augex. The key drivers of demand driven augex for CitiPower are increasing peak demand, population growth and electrification of gas and transport.
- CitiPower is expecting to underspend by 17.9% in the current period but its forecast for 2026–31 is materially higher. CitiPower's underspend in the current period is partially due to the deferral of the Brunswick modernisation program, which it has resubmitted in its forecast with updated costs. The increase in its forecast for 2026–31 is partially driven by CitiPower's large customer driven electrification program.

A.3.2.2 Bottom-up assessment

We make the following overall observations:

- *CitiPower's cost benefit analysis was not sufficient in some cases*

  We engaged EMCa to undertake a targeted review of 5 demand and non-demand augex projects ($173.4 million or 81.6%). These were the customer driven electrification ($40.9 million), Brunswick modernisation program ($60.3 million), ZSS capacity upgrades ($29.1 million), asset relocations ($23.5 million) and CBD security of supply projects ($19.7 million).

  We note the following key findings identified by EMCa:[51]

  – CitiPower has selected the highest net present value (NPV) option in each case (except for projects based on a compliance obligation) and the business cases presented both the optimal timing of the project and sensitivity analyses focussed on the NPV. The sensitivity analysis was focused on the robustness of the NPV against negative changes however, it did not include changes to the optimal timing.
  – CitiPower presented business cases and supporting cost-benefit analysis models that provided foundational material to support assessment. However, cost benefit analysis models were not transparent and contained hard-coded data. In some cases, CitiPower's responses to information requests did provide the additional detail necessary but there were still some responses with hard coded data.
  – An issue with the business cases and cost benefit analysis models is the limited information on the cost estimation for projects and that in several cases the cost estimates are too high.

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[51] EMCa, *CitiPower 2026 – 2031 Regulatory Proposal: REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT,* report to the AER, EMCa, 2025 pp 86–87.

- For the demand-driven projects EMCa were satisfied that there was a need for CitiPower to consider means of mitigating the risk of unserved energy with increasing demand. CitiPower presented a good range of options but did not consider any non-network solutions to economically defer network expansion.
- Overall concerns with CitiPower's analysis include not adequately justified timings, high costs and the incorrect use of VCR.

Our assessment concurs with EMCa's findings and we have undertaken a similar analysis for the remaining projects and found similar concerns for some projects.

- *Issues were identified with the demand forecast but these did not materially affect the augex forecast*

  Baringa assessed the methodologies and assumptions underpinning the demand forecast. We note the following Baringa findings:[52]

  - CitiPower's forecasting approach is generally well-documented, though there are inconsistencies in the treatment of block loads.
  - Baringa had some concern with the maximum demand forecast due to validation challenges with the Blunomy model and the exclusion of gas electrification impacts. Baringa also had moderate concerns with the minimum demand forecast. However, errors in the maximum and minimum demand forecasts have opposite effects on augex and customer energy resources (CER) enablement expenditure. As such, issues with maximum and minimum demand have had no material impact on the augex at a project level.
  - Customer number forecasts did raise some concern, with the stated methodology appearing inconsistent with regulatory information notices (RIN) data and likely overstating growth given historically slower customer growth. This did not have an impact on augex at the project level.

  We agree with Baringa's findings on the demand forecast. This includes that, despite the issues identified by Baringa, we do not consider it had a material impact on our conclusions on augex. We have not made any adjustments for the demand forecast and all our adjustments related to the issues identified with the cost benefit analysis above.

Our bottom-up review found that some of CitiPower's forecast at the project level is not prudent and efficient. While we made no changes to the demand forecast, we found issues in CitiPower's cost benefit analysis including issues with optimal timing, high costs and the incorrect use of VCR. Our project specific issues are discussed in more detail below. Table A3.1 sets out our alternative forecast for CitiPower's augex projects.

Table A3.1 CitiPower's augex forecast by project compared with draft decision ($2025–26, million)

Project	CitiPower's forecast	Reduction	AER's draft decision
Brunswick modernisation program	60.3	12.7	47.6

[52] Baringa, *Report to AER on CitiPower Demand Forecast*, July 2025, p 6, pp 27–36.

Project	CitiPower's forecast	Reduction	AER's draft decision
Customer driven electrification	40.9	36.0	4.8
ZSS capacity upgrades	29.1	14.6	14.5
Asset relocations	23.5	18.3	5.2
CBD security of supply	19.7	0.0	19.7
System security	14.2	0.0	14.2
HV feeder program	9.2	0.0	9.2
Operational technology	5.5	0.0	5.5
Fishermans bend modernisation	5.1	0.0	5.1
Communications	4.0	0.0	4.1
Metering	0.9	0.4	0.6
Total augex	**212.6**	**82.0**	**130.6**

Source: CitiPower proposal, AER analysis. Numbers may not sum due to rounding.

For the projects in Table A3.1 that we have accepted, we found these are prudent and efficient investments. CitiPower assessed investment options using reasonable assumptions and provided options analysis where relevant. Where projects were ongoing BAU programs we found that the costs were consistent with historical spending. For projects proposed to meet compliance obligations we found that CitiPower had proposed the least cost option to rectify the issue.

We have made adjustments to proposed metering capex to reflect our updates to communications equipment unit costs. This includes reducing unit costs and installation costs to better align with historically approved costs for a few types of communications equipment. Please see Attachment 15 – Metering Services for details.

We discuss our findings on CitiPower's forecast where we recommend an alternative forecast below.

Customer driven electrification

CitiPower proposes a $40.9 million capex program to improve its steady-state voltage compliance by investing in proactive augmentation and reactive augmentation. CitiPower prefers proactive investment that maintains existing voltage performance levels. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $4.9 million which is $36.0 million lower than CitiPower's forecast.

Our analysis of the cost benefit analysis model has shown that CitiPower has not justified the need to conduct this level of augmentation during the next regulatory period. Our alternative forecast applies historical costs from the current regulatory period to maintain voltage compliance.

In coming to our draft decision, we had regard to and agree with EMCa's findings, including:[53]

- EMCa were satisfied that CitiPower is likely to have to spend on maintaining voltage compliance above the functional limit over the next regulatory period due to forecast demand and the expected trend to electrification. However, CitiPower's modelling indicates it is likely to maintain compliance until the end of the next regulatory period. EMCa considers the impact of voltage decline is likely to be less than CitiPower has forecast.
- Based on the information provided, the jump from no voltage complaints in FY24 to 27 voltage complaints forecast for FY27 is not reasonable. In CitiPower's 2024 and 2023 annual RINs, it recorded zero complaints related to technical quality of supply. However, CitiPower has included a forecast of 27 complaints in its model for FY27. CitiPower has not provided sufficient justification for the gap between the RINs and the inputs to CitiPower's model.
- The use of VCR to value energy served to customers at less than 216 volts is not a valid application of the VCR. CitiPower values energy supplied to customers at non-compliant voltages using the VCR. Electric vehicle (EV) charging interruption is the main example given for valuing curtailment using VCR. Using the VCR to assign value to energy supplied with non-compliant voltages is inconsistent with the AER's intended application of it, even for curtailment of EV charging. The use of VCR leads to a significant overestimation of the economic cost of undervoltage supply because, while the risk of loss of supply may increase, energy supply is generally not lost when voltage falls below lower standard threshold. Customer impacts of undervoltage would be much less than VCR. There is likely delay to EV charging but this is not typically real-time critical. EMCa expect that the VCR is much higher than the economic cost of an undervoltage excursion and much higher than what people would be prepared to pay, given what we assume to be modest impacts. CitiPower's use of VCR to attribute an economic cost to undervoltage supply overestimates this cost, leading to an overestimation of the economic benefits of rectification.
- CitiPower would not risk breaching its voltage compliance obligations[54] within the next regulatory control period. EMCa consider there are other approaches that are less expensive than a large augmentation project that can be used to maintain this obligation. This includes CitiPower using AMI data to deploy a mix of focused HV, LV, proactive and reactive interventions as required. CitiPower can also use non-network approaches, including Flexible Services, to mitigate voltage decline. As such, we consider CitiPower has not demonstrated the need and justification to maintain voltage service at current levels throughout the 2026–31 period.

We have considered EMCa's findings and agree that CitiPower has not justified this level of augmentation during the next regulatory period. In particular, we consider that the use of VCR to value undervoltage is not appropriate and that the impacts would be much less. We

[53] EMCa, *CitiPower 2026 – 2031 Regulatory Proposal: REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT,* report to the AER, EMCa, 2025 pp 78–85.

[54] Victorian Essential Services Commission, Electricity distribution code of practice clause 20.4.1

also consider that the increase in voltage complaints is not reasonable and CitiPower needs to consider approaches that are less expensive to maintain its functional compliance obligations.

Based on the information provided CitiPower can maintain voltage compliance obligations with existing expenditure. We do not consider that CitiPower's proposal justifies the step up in expenditure for this project in the next regulatory period. Given the range of issues we consider that historical costs is an appropriate alternative estimate as CitiPower has not justified the need for additional expenditure beyond historical spending. However, we invite CitiPower to consider this project in its revised proposal while taking into account the concerns we have raised.

Brunswick modernisation program

CitiPower proposes $60.3 million to modernise its inner-city network's legacy design, which includes lower capacity and older assets. CitiPower proposes to manage risks by decommissioning aged substations at optimal times. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $47.6 million which is $12.7 million lower than CitiPower's forecast. Our alternative forecast removes the cost for the third transformer as we consider it is not prudent and efficient and should be deferred to the next period.

We came to our draft decision having regard to the EMCa findings that:[55]

- 2 network health-driven projects (the offloading of Brunswick to West Brunswick and Fitzroy to Collingwood substations) commenced in the current regulatory period and are proposed to continue into the 2026–31 period. EMCa reviewed the associated RIT-D and concluded that the 2 off-load projects remain as the most economic approach to address the identified drivers. Given the costs have been subject to a recent update, EMCa are also satisfied that the cost estimates were reasonable.
- Following the load transfers, Collingwood and West Brunswick are still forecast to be overloaded in the next regulatory period. CitiPower proposes further augmentation to address the cumulative effects of forecast demand growth by installing a third transformer at Collingwood at the estimated cost of $12.7 million capex. EMCa found that the proposed third transformer at Collingwood to manage forecast overloads is the prudent solution. However, EMCa consider that the estimated cost of $12.7 million capex to install the third transformer at Collingwood is inadequately justified. No evidence is provided to support this cost estimate and it did not explain why it is higher than the RIT-D, which only included $7 million ($7.9 million converted to 2026) for the third transformer.
- EMCa has concerns with the expected unserved energy calculations in the cost benefit analysis model. This includes the use of a 2019 ratio in the 10PoE forecast, energy at risk in the cost benefit analysis model not aligning with supplementary models provided, and zero transfer from Collingwood to contiguous substations is an overly conservative assumption.

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55 EMCa, *CitiPower 2026 – 2031 Regulatory Proposal: REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT,* report to the AER, EMCa, 2025 p 65-68.

Given the issues with the expected unserved energy calculations and the uncertainty with the demand forecasts so far in the future, we consider it is reasonable to delay the optimal timing for the third transformer by 1-2 years. It is also likely that some distribution transfer capacity (DTC) will be available in response to N-1 events.

ZSS capacity upgrades

CitiPower proposed $23.5 million to increase transformer capacity at several substations to meet growing demand. This will ensure reliable supply for customers in Collingwood and Bouverie St by installing a third transformer at each by the summer of FY28. Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $14.5 million which is $14.6 million less than CitiPower's forecast.

In our alternative forecast, we have delayed this project from 2026–28 to 2030–32 which defers approximately half of this expenditure into the 2031–36 regulatory control period. We recommend CitiPower include DTC and a higher cyclic rating in its revised proposal.

We came to our draft decision having regard to these EMCa findings:[56]

- While the option to install a third transformer at Collingwood and Bouverie substations is prudent to manage forecast overload, CitiPower does not appear to account for DTC in its cost benefit analysis model.
- CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates exclude any planned augmentation or operational response, such as load transfers to mitigate the impact of an outage, meaning that CitiPower has not included any DTC in its calculations. EMCa considers that this results in a conservative estimate of the optimal timing for the proposed augmentation. Accounting for DTC would have the effect of reducing the quantified benefit, reducing the NPV, and deferring the optimal timing.
- CitiPower's cost benefit analysis model did not allow for adjustments to the DTC. In response to an information request, CitiPower provided a subsequent model to support its forecast but this model also had hardcoded data which did not allow for adjustments. Hence, EMCa could not determine the optimal timing for this project.
- The cyclic rating used to determine the N-1 capacity looks low.
- EMCa also notes that the RIT-D process may identify a non-network solution that CitiPower can use to defer the requirement for the third transformer to the 2031–36 regulatory control period.

We have considered EMCa's findings and agree that CitiPower has not provided enough information to determine the exact optimal timing for this project. We consider it is reasonable to defer this project to 2030–32 and recommend CitiPower include DTC and a higher cyclic rating in its revised proposal.

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[56] EMCa, *CitiPower 2026 – 2031 Regulatory Proposal: REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT,* report to the AER, EMCa, 2025 p 69-73.

Asset relocations

CitiPower proposes $23.5 million for asset relocations within the Yarra Trams network. Yarra Trams has an ongoing pole renewal program where it expects to replace 130 poles in each year of the 2026–31 period. CitiPower submit that 'When Yarra Trams replaces one of their aging poles, we must relocate our assets to a suitable alternative location…'.[57] Our draft decision is to not accept CitiPower's forecast and to include an alternative forecast of $4.9 million which is $18.6 million lower than CitiPower's forecast.

We consider that CitiPower has not adequately justified its large increase in expenditure for this program, especially regarding its pole replacement volumes forecast. We have included the average historical expenditure from the last period in our alternative forecast and recommend CitiPower uses Yarra Trams forecast pole replacements in its revised proposal.

We came to our draft decision having regard to the EMCa findings that:[58]

- CitiPower has demonstrated the prudency of this project, as it is required to cover the costs to remove and relocate any assets on the poles that Yarra trams replaces.
- CitiPower uses an average of the actual and forecast expenditure to arrive at an average unit cost of $30,553 ($2024), leading to an annual average expenditure of $4.0 million ($2024). CitiPower details that the cost varies substantially at the individual pole relocation level because of differences in the solutions required. It stated that 'we typically scope, design and plan groups of co-located works to ensure that the most efficient solution is chosen for each set of relocations.'[59] EMCa considers this is a reasonable approach.
- In its cost benefit analysis model, CitiPower provided the 2021–2023 actual volumes of poles that were relocated by Yarra Trams and a forecast for 2024. We note the forecast for 2024 was the highest at 166 poles. It averaged the number of poles which resulted in a forecast of 130 poles in each year of the 2026–31 period. This contrasts with CitiPower's approach in the current period where it used a forecast from Yarra Trams to determine the numbers of poles to be relocated.
- It does not explain why it has not relied upon, or at least taken into account, Yarra Trams' forecast pole relocation volumes and locations. Not accounting for Yarra Trams' forecast could lead to high costs for this program.

We have considered EMCa's findings and agree that CitiPower has not adequately justified its increase in expenditure for this program. We recommend CitiPower uses Yarra Trams forecast pole replacements in its revised proposal.

A.4 ICT (CitiPower, Powercor and United Energy)

We do not accept that:

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57 CitiPower, *AUGMENTATION: YARRA TRAMS POLE RELOCATION*, January 2025, p 2.

58 EMCa, *CitiPower 2026 – 2031 Regulatory Proposal: REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT,* report to the AER, EMCa, 2025 pp 73–75.

59 CitiPower, *AUGMENTATION: YARRA TRAMS POLE RELOCATION*, January 2025, p 7.

- CitiPower's information and communication technologies (ICT) total expenditure forecast of $136.6 million ($119.5 million capex, $17.1 million opex) would form part of a total expenditure forecast that reasonably reflects the capex and opex criteria. Our draft decision includes $122.2 million ($108.5 million capex, $13.7 million opex), which is $14.5 million (10.6%) lower than CitiPower's proposal.
- Powercor's ICT total expenditure forecast of $312.7 million ($277.8 million capex, $34.9 million opex) would form part of a total expenditure forecast that reasonably reflects the capex and opex criteria. Our draft decision includes $283.9 million ($251.9 million capex, $32.0 million opex), which is $28.8 million (9.2%) lower than Powercor's proposal.
- United Energy's ICT total expenditure forecast of $324.5 million ($287.4 million capex, $37.1 million opex) would form part of a total expenditure forecast that reasonably reflects the capex and opex criteria. Our draft decision includes $275.9 million ($242.9 million capex, $33.1 million opex), which is $48.6 million (15.0%) lower than United Energy's proposal.

In this section, we set out our assessment of the ICT expenditure proposed by CitiPower, Powercor and United Energy. This excludes cyber security and CER related expenditure, which we have assessed separately.

A.4.1 CPU's proposal

CitiPower, Powercor and United Energy (CPU) have proposed the same ICT projects. They have submitted business cases and supporting information for these projects and these documents contain similar information and similar drivers for the proposed expenditure. Additionally, we note there are shared costs among CPU – for shared project costs, the allocation of costs are broadly based on customer numbers (70% split to CitiPower and Powercor, 30% to United Energy).[60] As such, we have assessed CPU's totex forecast at the aggregate level and make specific business observations where relevant.

CPU propose an aggregate of $773.8 million total expenditure for the 2026–31 period. The split of the aggregate ICT forecast by business is set out in Table A4.1.

Table A4.1 CPU's ICT forecast by business ($2025–26, million)

Business	Capex	Opex	Total
CitiPower	119.5	17.1	136.6
Powercor	277.8	34.9	312.7
United Energy	287.4	37.1	324.5
Total ICT expenditure	**684.6**	**89.2**	**773.8**

Source: CitiPower, Powercor and United Energy's regulatory proposals.

60 CitiPower's response to information request IR027, p 7. We note that while CitiPower's response was about shared project costs for property expenditure, this cost allocation methodology also applies to CPU's other categories of capex programs and projects.

Each of the CPU businesses is forecasting a step up in ICT capex, reflecting uplifts in recurrent expenditure (network and infrastructure refreshes) and non-recurrent expenditure (mainly the replacement of the enterprise resource planning (ERP) and billing systems).[61]

A.4.2 Reasons for our decision

We have reviewed the information each of the CPU businesses provided in support of its ICT forecast, including business cases and cost-benefit models. We also engaged EMCa to review aspects of CPU's ICT proposal. Where required, we have sought further information from CPU through information requests.

Our assessment of CPU's collective forecast involved undertaking a top-down assessment and bottom-up review, consistent with the expectations described in our ICT Guidance Note.[62]

CPU's aggregate total recurrent expenditure forecast (excluding CER ICT, post-2025 NEM market reforms and cyber security) is a step up of 17% compared to current period actual/estimates. Each business' forecast is higher by 16% (CitiPower), 35% (Powercor) and 3% (United Energy).[63]

Based on our assessment and EMCa's findings, we are not satisfied that CPU's aggregate ICT forecast reasonably reflects the capex and opex criteria. In coming to our draft decision, we had regard to the technical advice and expertise from EMCa in forming views on the prudency and efficiency of CPU's forecast by considering the business cases, cost-benefit analysis and options analysis. We have also had regard to stakeholder submissions, including CCP32's comments in response to our Issues Paper.[64] CCP32 notes there was solid engagement on CPU's ICT proposal and that while there is a large increase in total ICT expenditure, it considered that customers in general may see ICT expenditure as 'necessary but still hard to swallow'.[65]

We discuss our findings on CPU's forecast for each of the ICT projects below.

A.4.2.1 Recurrent projects

Customer enablement

CPU proposes $19.6 million capex for its customer enablement project in 2026–31 to maintain the currency of its online customer gateway services.[66] Our draft decision is to accept CPU's forecast.

We consider that CPU provided sufficient evidence in support of its forecast. In response to an information request, CPU submitted an options analysis to demonstrate it had considered

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61 CitiPower (and the Powercor/United Energy equivalents of), *Regulatory Proposal 2026–31*, p 59.

62 AER, *Guidance Note for non-network ICT capex assessment approach*, November 2019.

63 EMCa, *CitiPower, Powercor and United Energy ('CPU') 2026 - 2031 Regulatory Proposals: REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, report to the AER, EMCa, 2025, pp 14–15.

64 AER, *[CitiPower - Determination 2026–31: Issues Paper]*, 28 March 2025.

65 Consumer Challenge Panel, sub-panel CCP32 (CCP32), provided submissions on CitiPower, Powercor and United Energy's respective 2026–31 regulatory proposals, each dated May 2025.

66 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: CUSTOMER ENABLEMENT*, January 2025, p 3.

different investment scenarios. Our assessment concurs with EMCa's findings that CPU's current version of its Salesforce platform will need to be replaced in the 2026–31 period to maintain its online services.[67] We are also satisfied that CPU's forecast cost is reasonably derived based on the supporting evidence and EMCa's findings.

Enterprise management systems

CPU proposes $41.8 million capex for the 2026–31 period to upgrade, refresh or enhance many enterprise management systems. Our draft decision is to not accept CPU's forecast and instead include an alternative forecast of $35.5 million, which is 15% lower than CPU's forecast.

CPU submit that the key drivers for its forecast include ensuring applications are under vendor support, changes to other parts of its technology landscape, and external factors such as cyber security.[68] While we have considered EMCa's findings and agree that the principles underpinning CPU's proposed scope of work are sound and consistent with good industry practice, we consider that CPU has not sufficiently demonstrated that its forecast is efficient.[69]

In response to information requests, CPU provided historical data regarding its enterprise management systems expenditure. However, due to issues found with the historical data it could not be reliably used to assess CPU's forecast expenditure. Additionally, our assessment concur with EMCa's findings that CPU has not provided sufficient evidence to show it had applied its investment principles to the many individual applications within its enterprise management systems.[70]

End user device management

CPU proposes $42.8 million capex for the 2026–31 period to refresh its end user devices fleet and to upgrade meeting room technology as they are at the end of their useful lives. Our draft decision is to not accept CPU's forecast and instead include an alternative forecast of $36.2 million, which is 15.5% lower than CPU's forecast. This is based on CPU's historical spend.

We have considered EMCa's findings and agree that while CPU have demonstrated that its investment is prudent, it did not sufficiently justify the uplift in its forecast expenditure. In response to an information request, CPU provided its current period expenditure for end user devices. This data showed that CitiPower and Powercor's forecasts are higher than their current period spend by 31% and 44% respectively, while United Energy's forecast was 3% lower.[71] Despite providing more supporting evidence in a further information request, CPU were unable to adequately justify the uplifts in CitiPower and Powercor's forecasts for the 2026–31 period compared to their current period spend.

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67 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 15–16.

68 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: ENTERPRISE MANAGEMENT SYSTEMS*, January 2025, p 7.

69 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 16–19.

70 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 19.

71 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 20.

Facilities security

CPU proposes $12.8 million capex for the 2026–31 period for its facilities security. Our draft decision is to not accept CPU's forecast as there was insufficient evidence to demonstrate the need for this investment.

The proposed scope of works for this project include installing security fencing and building access control systems (BACS) integration to improve the physical security of premises. CPU submitted a business case and cost model to support its forecast. However, EMCa found that overall CPU's supporting information lacked details about the BACS assets and there was no analysis provided about the contribution of BACS to zone substation security.[72] Additionally, CPU did not provide historical data about its recurrent investment in BACS, which reduces our confidence in the prudency and efficiency of its forecast.

We have considered EMCa's findings and agree that CPU has not sufficiently justified the need for its proposed BACS replacement in the 2026–31 period. We acknowledge there may be a case for some level of investment and invite CPU to address the issues raised above in its revised proposal.

Infrastructure refresh

CPU proposes total expenditure of $103.0 million ($81.5 million capex, $21.6 million opex) for the 2026–31 period to refresh its IT infrastructure (both hardware and software). As part of this, CPU propose to move some of its on-premise infrastructure applications to cloud-based solutions. The drivers for this project are shorter-term asset lifecycles and longer-time drivers, such as adapting to evolving technology needs and managing market obsolescence.[73]

Our draft decision is to accept CPU's forecast for its proposed infrastructure refresh. We consider that CPU provided sufficient evidence to support its forecast. EMCa's assessment found CPU's options analysis and approach to determining the refresh timing for each infrastructure item to be reasonable.[74] Our assessment concurs with EMCa's findings that although CPU did not quantify potential sources of avoided costs or economies of scale, CPU's forecast is prudent and the costings are reasonable.[75] Additionally, CPU provided information demonstrating how base expenditure has been accounted for in its proposed opex step change amount. We are therefore satisfied that the change from on-premise infrastructure represents a prudent capex/opex trade-off.

Market compliance

CPU proposes $49.2 million capex for market compliance in the 2026–31 period. We note this expenditure is separate from CPU's proposed non-recurrent expenditure regarding compliance with AEMO NEM reforms (see A.5.2.2). Our draft decision is to not accept CPU's forecast and instead include an alternative forecast of $34.5 million, which is 30% lower than

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72 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 23.

73 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: INFRASTRUCTURE REFRESH*, January 2025, p 2.

74 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 24–26.

75 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 27.

CPU's forecast.

In its proposal, CPU state its expenditure forecast is based on 'historical outlay in this category over the past five years.'[76] In response to an information request, CPU provided historical data for this expenditure category for FY17–FY23 but it admitted this data includes market systems expenditure.[77] This inclusion distorts analysis of the expenditure CPU propose for market compliance. Additionally, EMCa found that CPU's forecast includes an uplift on its historical average expenditure which has not been sufficiently justified.[78] We have considered EMCa's findings and agree that CPU's forecast expenditure is prudent and that it's reasonable to base its forecast on historical expenditure, but we are not satisfied that CPU's forecast is efficient. Our alternative estimate is based on a reasonable forward estimate of CPU's historical costs.

Market systems

CPU proposes $40.9 million capex to maintain the currency of its market systems platforms over the 2026–31 period. Our draft decision is to accept CPU's forecast.

We consider CPU has provided sufficient evidence in support of its forecast. We have considered EMCa's findings and agree that the principles underpinning CPU's forecast are appropriate and that its cost build-up appears to apply these principles to efficiently maintain market systems currency.[79] Despite the issues identified in the market compliance section above, we consider CPU's proposed market systems expenditure is reasonable.

Network management systems

CPU proposes $117.7 million capex to maintain currency of its network management systems over the 2026–31 period. Our draft decision is to not accept CPU's forecast for network management systems and instead include an alternative estimate of $107.2 million, which is 8.9% lower than CPU's forecast. This is based on CPU's historical costs.

CPU submits:[80]

- 'our timing profile is based on prudent and timely investments aligned with roughly every second vendor product release to ensure we remain within vendor support.
- our forecast cost per refresh is based on previous refresh costs incurred in 2021-2026 as well as projected infrastructure hardware replacement cycles.'

We agree with CPU's proposed strategy for refreshing its network management systems to remain within vendor support. In response to information requests, CPU submitted data regarding its historical costs – this was presented as totex rather than separating capex and opex to allow a comparison with its forecast expenditure. Despite this, EMCa's review of this information, RIN data and other information request responses found that CitiPower and

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76 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: MARKET COMPLIANCE*, January 2025, p 8.

77 Powercor, *Response to information request 008: ICT and cyber security*, 18 March 2025, p 11.

78 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 29.

79 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 31.

80 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: NETWORK MANAGEMENT SYSTEMS*, January 2025, p 20.

Powercor's forecast expenditure were in line with historical levels.[81] We are satisfied that CitiPower and Powercor's forecasts are reasonable.

However, EMCa's findings highlighted that United Energy's forecast represents a 17% increase from its current period spend which was not adequately explained.[82] Our assessment concurs with EMCa's findings that in the absence of a robust variance analysis to explain this uplift in expenditure, United Energy's forecast is not efficient.

Telephony

CPU proposes $16.8 million capex for the 2026–31 period to re-architect and transform its contact centre and telephony solutions. Our draft decision is to not accept CPU's forecast and instead include an alternative forecast of $10.9 million, 35% lower than CPU's forecast.

We consider that CPU provided sufficient evidence to demonstrate the prudency of its telephony forecast and acknowledge the risks if the telephony platforms do not operate reliably. However, our assessment concurs with EMCa's findings that CPU chose the most expensive option (Option 3) without sufficient justification. EMCa found several issues with the cost models and benefit analysis that CPU submitted in response to an information request – additionally, CPU were unable to provide historical telephony costs to support its forecast.[83]

Our alternative forecast is based on the costs CPU proposed in maintaining the currency of telephony systems (Option 2). We have considered EMCa's findings and agree that despite the lack of historical data for comparison, the costing information gives us more confidence that the Option 2 cost is more reasonable than Option 3.[84]

A.4.2.2 Non-recurrent projects

ERP & billing systems

CPU proposes total non-recurrent expenditure of $228.0 million ($174.2 million capex, $53.8 million opex) for the 2026–31 period to replace its existing ERP systems and network billing systems with SAP products on the SAP S/4HAHA platform. The AER had accepted the CPU's proposed SAP S/4 HANA upgrade in the 2021–26 determination, as the legacy platform would no longer be supported. However, the vendor subsequently extended support until 2030 so CPU deferred its upgrades to the ERP & billing systems.

Our draft decision is to not accept CPU's forecast and instead include an alternative total expenditure forecast of $174.2 million ($174.2 million capex, $0 opex), which is 23.6% lower than CPU's forecast.

We note there are stakeholder comments about CPU's ERP & billing systems proposal. CCP32 note that the forecast of $228.0 million seems too high for only one aspect of CPU's ICT expenditure and the extent of which ICT investment and capabilities are shared across

81 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 33–34.

82 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 34.

83 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 35–37.

84 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 37–38.

the 3 CPU businesses is unclear.[85] CCP32 also noted it did not hear any discussion with consumers about whether $233.4 million of value was being generated or how efficiencies across the 3 businesses were being generated and shared with customers.[86] We had regard to these matters during our assessment of CPU's proposal and in coming to our determination.

We also had regard to EMCa's findings including that CPU sufficiently demonstrated the prudency of the investment. We agree with CPU that there is significant risk to its operations if it continues to use these legacy systems beyond vendor support. CPU submitted a detailed cost build-up and project timing to support its forecast. EMCa found that CPU's proposed costs, while preliminary, appear to have been reasonably derived. Additionally, while there are some issues with CPU's cost-benefit analysis, its preferred option is still positive and higher than the other credible options. Based on these findings, our assessment concurs with EMCa's findings that CPU's proposed capex for this project is prudent and efficient.

However, we are not satisfied that CPU's opex forecast is prudent and efficient. Firstly, we note our 2021–26 determination provided for the business to upgrade its end-of-life ERP system, including a $2.2 million ($2020–21) opex/capex trade-off IT cloud step change.[87] We note the business provided information on the reasons for this deferral.[88] Although we acknowledge the basis of this deferral and that it is at the discretion of the business to allocate resources according to priorities, we are concerned with the prudency of providing an allowance again for a program which has previously received specific forecast expenditure.

We also consider the replacement of business applications to largely be a business-as-usual activity. As such, it is not clear these costs meet our typical requirements for a step change under our opex forecasting framework. While we acknowledge this replacement has a longer than normal replacement profile, we are not satisfied existing resources assigned to the current platform would be insufficient to manage the transition. We further note this program will converge the 3 business' operations. We agree with CPU that this will lead to improved capabilities and streamlining of operational processes and overall result in greater business efficiencies. The Efficiency Benefit Sharing Scheme is intended to incentivise businesses to pursue efficiencies, so we do not provide additional forecast opex for efficiency improvement initiatives. As we state in the Expenditure Forecast Assessment Guideline explanatory statement, providing a step change to undertake an activity that will reduce a network's expenditure, would not be consistent with the opex criteria nor the revenue and pricing principles.[89]

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85 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31,* May 2025, p 20; CCP32, *Submission – United Energy electricity distribution proposal 2026–31*, May 2025, p 19.

86 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31,* May 2025, p 19; CCP32, *Submission – United Energy electricity distribution proposal 2026–31*, May 2025, p 20.

87 AER, *Final decision: CitiPower distribution determination 2021–26 – Attachment 6 – Operating expenditure*, April 2021, p 33.

88 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: ERP & BILLING SYSTEM UPGRADE*, January 2025, p 6.

89 AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement* – Final, November 2013, p 74.

We also note the business's reference to costs being associated to new capital expenditure activities. However, as we detail in the Expenditure Forecast Assessment Guideline explanatory statement, we consider the opex element would already be sufficiently accounted through the forecasting approach, including the proposed business case.[90] That is, where the new capital expenditure activities results in increased output, the trend (output growth) component in our opex forecasting approach provides for an associated opex uplift. Alternatively, where new capital expenditure activities may not increase output, then we would expect opex to decrease. This is because, if the proposal is efficient, the avoided expenditure and benefits must outweigh costs for the project to result in a positive NPV.[91]

In this context, EMCa also observed that although the business identifies efficiency benefits in its NPV modelling, it considers these to be conservative based on the business case narrative and claimed outcomes.[92] Further, although the base year expenditure is accounted for in the step change, this amount does not account for the efficiency benefits, including that no offset for the identified billing system efficiency dividend appears to have been recognised in the proposed step change.[93] EMCa overall considered that the non-recurrent portion of this program is overestimated, and that the recurrent portion is not justified as net incremental expenditure.[94]

Flexible trading arrangements

CPU proposes $17.3 million for flexible trading arrangements. Our decision is to not accept CPU's forecast and to include an alternative forecast of $4.3 million, which is 74.9% lower than CPU's forecast.

In August 2024, the AEMC released its final determination on unlocking consumer energy resources through flexible trading arrangements. All 5 Victorian DNSPs have proposed expenditure in response to this rule change. CPU advised that most of the flexible trading arrangements costs required to meet compliance will be incurred during the current period, which it will submit a cost pass-through application for during 2025.[95] CPU's proposed forecast of $17.3 million is for testing and support activities being conducted in the 2026–31 period, after FTA implementation.[96]

We agree with CPU that it is required to undertake this project, as it is compliance-driven. We have also considered EMCa's findings and agree that CPU's basis for estimating the project's costs is reasonable, however the forecast is uncertain as the rule change requirements are yet to be finalised.[97] Based on the information submitted by the 5 Victorian businesses, EMCa found that with CPU's proposal, most of the expenditure is better suited

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90 AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement* – Final, November 2013, p 74.

91 AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement* – Final, November 2013, p 74.

92 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 49.

93 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp xiii, 46–47 and 49.

94 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 14, 49–50.

95 CitiPower (and the Powercor/United Energy equivalents of), *INFORMATION AND COMMUNICATIONS TECHNOLOGY: AEMO NEM REFORMS*, January 2025, pp 2, 7.

96 CitiPower, *INFORMATION AND COMMUNICATIONS TECHNOLOGY: AEMO NEM REFORMS*, p 2.

97 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p 53.

to alternative control services.[98] Costs associated with alternative control services are related to ancillary network services and public lighting; this is in contrast to standard control services where costs are spread across the general customer base. Therefore, our alternative forecast is based on a portion of CPU's proposed expenditure which we consider should be allocated to standard control services.

We encourage the CPU businesses to provide updated cost estimates if applicable in its revised proposals.

Market interface technology enhancements

CPU proposes total expenditure of $78.5 million ($70.1 million capex, $8.4 million opex) for market interface technology enhancements (MITE). Our draft decision is to not accept CPU's forecast and to include an alternative total expenditure forecast of $64.6 million ($58.4 million capex, $6.2 million opex).

In August 2022, AEMO identified the MITE that are required as a prerequisite to the wider NEM reform implementation program. The reform has 3 core components including identity and access management, industry data exchange, and portal consolidation.[99] We agree with CPU that these enhancements represent a new regulatory obligation that it must comply with.

While we are satisfied that CPU provided sufficient evidence to demonstrate prudency, we are not satisfied that its capex forecast is efficient. EMCa's benchmark analysis of MITE costs proposed by the 5 Victorian businesses found CPU's cost estimates for CitiPower and Powercor to be reasonable, yet United Energy's estimate is much higher than the benchmark average. We have considered EMCa's findings and agree that while benchmarking results are not definitive, we consider it is a strong indicator that United Energy's costs are overestimated, particularly as United Energy did not provide an explanation or justification to support its capex forecast.[100]

Our assessment of CPU's MITE proposal also identified a likely transcription error in CitiPower's opex model. Specifically, CPU used the same cost model across all 3 business, allocating costs per business proportionally. However, CitiPower's step change model costs do not correspond to those detailed in the business's MITE NPV model and business case.[101] Instead CitiPower appears to have included one of the other business's MITE costs. We have therefore corrected this and substituted the value as detailed in CitiPower's MITE business case and NPV model.

We also acknowledge that CPU's cost estimates are based on the information available. We encourage the CPU businesses to submit updated costs in its revised proposals once the remaining regulatory guidance documents have been finalised and published.

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98 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 53–54.

99 CitiPower, *INFORMATION AND COMMUNICATIONS TECHNOLOGY: AEMO NEM REFORMS*, p 4.

100 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 51–52..

101 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025; CitiPower, *INFORMATION AND COMMUNICATIONS TECHNOLOGY: AEMO NEM REFORMS*, p 10.

A.5 CER integration (CitiPower, Powercor and United Energy)

We do not accept that:

- CitiPower's CER totex forecast of $24.1 million ($11.8 million capex, $12.3 million opex) would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $19.2 million in totex ($9.8 million capex, $9.4 million opex), which is 20.3% lower than CitiPower's proposal.
- Powercor's CER totex forecast of $56.1 million ($27.4 million capex, $28.7 million opex) would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $44.8 million in totex ($22.8 million capex, $22.0 million opex), which is 20.1% lower than Powercor's proposal
- United Energy CER totex forecast of $36.5 million ($17.6 million capex, $18.9 million opex) would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $28.1 million in totex ($14.6 million capex, $13.5 million opex), which is 23.0% lower than United Energy's proposal

In this section, we set out our assessment of the CER ICT expenditure proposed by CitiPower, Powercor and United Energy. It does not include our assessment of the LV Augmentation project that has been associated with customer electrification, which is discussed in section A.3.

A.5.1 CPU's proposal

CitiPower, Powercor and United Energy (CPU) have proposed 3 enterprise-wide projects relating to CER ICT, for which expenditure has been allocated between the 3 entities. CPU proposes totex of $116.7 million for CER-related expenditure in 2026–31 which comprises $56.7 million capex and $60 million opex.

Table A5.1 sets out CPU's proposed forecast for its ICT CER-related projects.

Table A5.1 CPU's proposed ICT CER-related expenditure ($2025–26, million)

Business	Capex	Opex	Total
CitiPower	11.8	12.3	24.1
Powercor	27.4	28.7	56.1
United Energy	17.6	18.9	36.5
Total CER-related expenditure	**56.8**	**59.9**	**116.7**

Note: Direct escalated costs ($ June 2026). Totals may not sum due to rounding.
Source: CitiPower, Powercor and United Energy's regulatory proposals.

In addition to its proposed investments for flexible services, network data visibility and non-network marketplace platform, CPU plans to implement demand management measures through two-way pricing (export tariffs). We note that CPU has engaged with its customers on its preferences in developing its CER Integration Proposal.[102]

A.5.2 Reasons for our decision

We reviewed CPU's CER integration strategy as well as its supporting NPV analysis and business cases. Our assessment was informed by both our CER strategy and DER integration expenditure guidance note.[103]

Overall, we have considered EMCa's findings and agree that while CPU's expenditure to introduce flexible services is prudent and efficient, it has not provided sufficient information to demonstrate prudency and efficiency of its Network Data Visibility and its non-network marketplace platform. Our alternative forecast therefore only includes expenditure for CPU's flexible services project.

In coming to our position, we also had regard to submissions from DEECA, CPU's CAP and Origin Energy in response to our Issues paper. All are supportive of CER investment but note the importance of affordability. DEECA submits that that "…DNSPs should invest to enable DER market development, publish LV network data, procure network support services to establish efficiencies and reduce costs, enable flexible services, support the adoption of bi-directional EV charging and avoid expenditure where capabilities already exist."[104] The CAP submits that CPU's proposal is responsive to the issues raised by customers about balancing capacity growth and affordability.[105] Origin Energy noted the challenges of the combination of growth in CER, the uncertainty with energy demand and ongoing cost of living pressures.[106]

Flexible services

CPU propose $92.0 million in total expenditure ($47.1 million capex, $44.9 million opex) for its flexible services project. This relates to deploying flexible service offerings and is intended to address increasing curtailment of exports driven by CER and potentially constrained import capacity driven by electrification over the 2026–31 period.

CPU proposes that it will allow customers the option to select between a static export of 1.5kW or a dynamic connection and receive up to 10kW of export capacity per phase based on the available network capacity. It also submits that '*flexible export products allow all customers to export excess solar, rather than reserving capacity for some and using static zero export limits for others'*.[107] In support of this project, CPU provides a costed plan for the development, deployment and ongoing operations of its proposed flexible services and an economic analysis of its proposed and alternative options for each entity.

Our assessment concurs with EMCa's findings that CPU has provided adequate justification for its proposed development and deployment of flexible services and its economic analysis

102 CitiPower, *Regulatory proposal 2026–31*, pp 15–20.

103 AER, *Consumer energy resources strategy*, April 2023; AER, *Distributed energy resources integration expenditure guidance note*, June 2022.

104 Department of Energy, Environment and Climate Action, *Issues papers – Electricity Distribution Determination 2026- 31*, June 2025, p 2.

105 Customer Advisory Panel, *CitiPower's Regulatory Proposal 2026–31*, April 2025, p 14.

106 Origin Energy, *Submission to the AusNet, CitiPower, Jemena, Powercor and United Energy regulatory proposals*, May 2025, p 1.

107 CitiPower, *Regulatory proposal 2026–31: Part A: overview – January 2025*, p 22.

supports the reasonableness of its capex and opex forecasts. This includes EMCa's findings that:[108]

- CPU submitted an options analysis and its preferred investment provides the greatest net benefit.[109]
- While EMCa identified issues with CPU's cost benefit analysis, its preferred option is still positive and preferred even after making corrections. In particular, EMCa found that the net benefits calculation did not include all costs, and while benefits extend to 2040 the model does not include costs beyond the end of the 2026–31 period. After making adjustments to address these issues, the preferred option is still positive albeit less so.
- CPU's identification of the benefits from the program is reasonable where CPU identifies reductions in the Customer Export Curtailment Value-based value of avoidance of curtailed exports and associated CO2 reductions.
- CPU's cost build-up of its forecast totex is reasonable. It describes the procurement process by which it had engaged with vendors and provided 2 quotes from vendors to evidence this.
- CPU's estimate to roll out flexible imports (after having first deployed flexible exports) is relatively modest ($1.1 million for CitiPower, $2.5 million for Powercor and $1.6 million for United Energy).

We note CPU's use of the emissions reduction benefit stream in its cost-benefit modelling. We recently published our interim emissions reduction guidance note, which provides worked examples in quantifying emissions reduction benefits.[110] CPU should have regard to this guidance going forward to ensure it is adopting a consistent approach to quantify this benefit.

Network data visibility

CPU proposes total expenditure of $9.7 million ($3.5 million capex, $6.2 million opex) for its network data visibility project. It relates to developing a customer portal that will allow users to obtain '*contextualised information regarding constraints and spare capacity*'.[111] Data would be presented in a variety of formats including geospatial views, dashboards and narratives. Users will be able to extract and download weekly updated data and provide feedback to CPU.

Our draft decision is to not include expenditure for CPU's proposed Network Data Visibility project. We acknowledge the importance of providing the market with access to low-voltage data. However, we are not satisfied that CPU provided sufficient evidence to demonstrate the prudency and efficiency for this investment. While CPU provided a business case in support of this project, it did not provide quantitative evidence to demonstrate prudency and

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108 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, pp 62–71.

109 CPU identifies 4 options; to maintain/static controls (non-intervention option), to offer flexible export services, to offer flexible services plus flexible load services (preferred), augmentation of the network to provide sufficient export and import capacity.

110 AER, *Interim guidance note on emissions reduction*, 16 June 2025.

111 CitiPower, *ELECTRIFICATION AND CER INTEGRATION: FLEXIBLE SERVICES*, January 2025, p 6.

efficiency of its forecast. In coming to our decision, we had regard to EMCa's observations that:[112]

- CPU's business case and other information does not support a need for investment – EMCa found that the volume of request does not appear overly onerous where in many cases information requested would not be available on the portal so bespoke queries would continue and it seems unlikely that the feedback capability would be viable.
- CPU already has LV data visibility for internal purposes through CPU's proposed Flexible Service initiative which we have accepted. It would be more cost effective for CPU to re-assemble this data rather than investing in a new program.
- A lower cost approach would be to make modest improvements to the existing system to address current deficiencies – CPU did not identify this as an option in its business case.

We also note that the AEMC is considering Energy Consumers Australia's "Integrated distribution system planning" rule change request, which would reform the current distribution annual planning process and require DNSPs to publish new types of network data.[113] We support this rule change proposal as a pathway to provide the market with low-voltage network data. We will have regard to the outcomes of this process in making our final decision. We consider that until there is clarity on the status of this proposal, including the potential for new data collection and reporting obligations, there is a risk that DNSPs may implement bespoke network visibility solutions that require subsequent standardisation.[114]

Non-network marketplace platform

CPU proposes total expenditure of $15.0 million ($6.1 million capex, $8.9 million opex) for its non-network marketplace platform, which involves developing a platform in FY2027 for operation over the 2026–31 period. CPU submits that it will better allow customers and the market to actively participate and be rewarded for their contribution to the management of the distribution network.[115] CPU provided an economic analysis in support of this project.

Our draft decision is to not include expenditure for CPU's proposed non-network marketplace platform. While we acknowledge that more generally there are benefits from a non-network platform, CPU did not provide sufficient evidence to support the prudency and efficiency of the investment in the 2026–31 period. We had regard to EMCa's findings in coming to this position, noting:

- A lack of evidence in demonstrating the need for the investment – CPU states that over the past 5 years, it has not received any economically viable non-network alternatives from the market to date that it has been able to implement.[116] Further, CPU's 2023 trial of the platform resulted in no bids. It concluded that while there are non-network

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112 EMCa, *REVIEW OF PROPOSED EXPENDITURE ON ICT AND CER*, p.71.

113 AEMC, *Integrated distribution system planning*, accessed 14 August 2025.

114 The AEMC is required to publish its draft determination on the IDSP rule change proposal by 19 March 2026.

115 CitiPower, *ELECTRIFICATION AND CER INTEGRATION: NON-NETWORK MARKETPLACE*, January 2025, p 2.

116 CitiPower, *ELECTRIFICATION AND CER INTEGRATION: NON-NETWORK MARKETPLACE*, January 2025, p 4.

providers keen to participate, the market is not presently mature enough to meet network constraints at a lower cost than network augmentation.

- Benefits from its cost benefit analysis arise in the medium term, long after CPU proposes to invest – This raises the more viable option of delaying the investment especially where there are significant changes to the energy transition landscape, including technology changes and other changes in the regulatory and policy environment.
- Issues with the cost benefit analysis which, once corrected for, results in the investment not being NPV positive – there is a formula flaw and the period for costs and benefits do not align (benefits calculated to 2041 and costs to 2031).

A.6 Innovation (CitiPower, Powercor and United Energy)

We do not accept that:

- CitiPower's total expenditure forecast of $8.0 million ($4.8 million capex, $3.2 million opex) for network innovation would form part of a total expenditure forecast that reasonably reflects the expenditure criteria. We have included $1.4 million ($0.9 million capex, $0.5 million opex) in our alternative estimate.
- Powercor's total expenditure forecast of $21.0 million ($12.6 million capex, $8.4 million opex) for network innovation would form part of a total expenditure forecast that reasonably reflects the expenditure criteria. We have included $4.1 million ($2.3 million capex, $1.8 million opex) in our alternative estimate.
- United Energy's total expenditure forecast of $16.3 million ($9.8 million capex, $6.5 million opex) for network innovation would form part of a total expenditure forecast that reasonably reflects the expenditure criteria. We have included $3.7 million ($2.1 million capex, $1.7 million opex) in our alternative estimate.

In this section, we set out our assessment of the innovation expenditure proposed by CitiPower, Powercor and United Energy.

A.6.1 CPU's proposal

CitiPower, Powercor and United Energy (CPU) have proposed the same suite of innovation projects across 3 focus areas, consisting of 12 projects:

- assisting the energy transition
- improving customer experiences
- developing sustainable networks.

In addition, Powercor and United Energy have proposed a further 3 projects under a fourth focus area: building network resilience.

All 3 businesses used the same business case, proposing different expenditure and scope for each project. CPU proposes an aggregate of $41.3 million totex for the 2026–31 period. The split of the aggregate innovation forecast by business is set out in Table A6.1.

Table A6.1 CPU's innovation forecast by business ($2025–26, million)

Business	Capex	Opex	Total
CitiPower	4.8	3.2	8.0
Powercor	12.6	8.4	21.0
United Energy	9.8	6.5	16.3
Total innovation expenditure	**23.2**	**18.1**	**41.3**

Source: CitiPower, Powercor and United Energy's regulatory proposals.

CPU's innovation forecast includes innovation projects for the initial 2 years of the regulatory period as they state that they do not typically forecast innovation projects beyond this timeframe.[117] Their total innovation forecast is comprised of the expenditure of the 2 years of projects, with this amount duplicated across the final 3 years of the regulatory period in a 50:50 split. CPU stated that the reduction in annual spending for the latter years acknowledges the inherent uncertainty of predicting innovation expenditure long term.[118]

CPU proposes to self-fund 10% of the total program across both capex and opex ($4.6 million).[119] They also propose to exclude innovation expenditure from Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme calculations.[120]

CPU proposes to establish an innovation committee that will develop a standardised evaluation framework against which to compare all potential investment options and perform periodic audits and post-project reviews.[121] This committee would include industry representatives, customer representatives and internal representatives.

A.6.2 Reasons for our decision

We recognise the importance of innovation investment in supporting the energy transition and protecting customers. There is a need for trials and pilots to test and explore new ideas, concepts and technology before committing to implementation of solutions and rolling these into business-as-usual activities. We also recognise CPU's customer engagement on innovation-related expenditure.

We have not accepted CPU's forecast in full. Our alternative forecast is $9.2 million. We have accepted the forecast for some projects as we found that these projects align with the criteria for ex-ante innovative projects. In particular, we have accepted forecasts for the following projects:

- supporting hard to abate industries in their electrification transition
- EV load product trial

117 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE,* 31 January 2025, p 10.

118 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 12.

119 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 12.

120 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 18.

121 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, pp 17–18.

- supporting sensitive customers with new technologies
- portable protection systems
- smart cable guard.

However, we found that the majority of projects did not satisfy the ex-ante innovation criteria; especially the criteria that the project be innovative.

CPU stated that they consider some of the AER's requirements around innovation expenditure, as set out in recent decision determinations, are not consistent with innovation in practice,[122] specifically requirements that:

- every innovation project expected to be undertaken during the regulatory period be set out in the regulatory proposal, and
- for each project, detailed cost build ups and input assumptions along with quantified benefits and efficiencies are provided.

CPU has expressed concerns that, due to the fast-changing nature of innovation, projects undertaken in the second half of the regulatory period would likely differ substantially from what is forecast in the regulatory proposal.[123] We met with CPU to discuss these concerns. CPU was able to provide us with cost build ups and input assumptions for the projects that they are proposing as part of their innovation forecast.[124] However, consistent with the reasoning of its proposal, this information only relates to the proposed trials for the first 2 years of the regulatory period.

Our alternative forecast is based on reviewing CPU's innovation forecast for the initial 2 years of 2026–31. We have not provided expenditure for the remaining years of 2026–31 as CPU did not provide information about its proposed innovation projects for those remaining years.

We acknowledge the inherent uncertainty associated with forecasting ex-ante innovation expenditure. However, we note that in previous determinations, other businesses have forecast, and we have assessed, a full suite of innovation projects for the entire period. [125][126] To address uncertainty with its ex-ante innovation proposal, businesses have also used different techniques such as an "investment safety margin" or uncertainty factor in their estimates. We appreciate CPU's efforts in providing cost build ups of its proposed projects for the first 2 years of 2026–31 and encourage it to provide supporting information for the remaining years of 2026–31.

While we acknowledge the potential benefits of ex-ante innovation expenditure, we are also conscious of the more cautious support among some consumer groups in previous processes. Some issues raised include whether innovation proposals could already be

122 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 10.

123 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 10.

124 CitiPower, *CitiPower - IR 013 – innovation allowance CBA – 20250526 – public.xlsx*, 26 May 2025.

125 AER, *Draft Decision, SA Power Networks Electricity Distribution Determination 2025 to 2030, Attachment 5 Capital Expenditure*, September 2024, pp 37–38.

126 AER, *Final Decision, Ausgrid Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, April 2024, p 37.

funded through the regulatory allowance and other regulatory mechanisms. We therefore appreciate the need for transparency about the ex-ante innovation expenditure to ensure that the proposed trials and pilots are likely to result in net benefits to consumers.

Our position is to not exclude CPU's innovation program from CESS. For more information regarding our decision, refer to attachment 6. Further, our position is that there does not appear to be a means within the limits of the NER requirements by which unspent funds could be returned to consumers.

Below we set out our assessment against our innovation program criteria and how we have derived our alternative forecast.

A.6.3 Criteria to assess CitiPower, Powercor and United Energy's Innovation Program

Consistent with our recent determinations, we use the following criteria to assess innovation programs:

- the proposed projects in the program must be "innovative"
- the justification for the proposed projects must be linked to the expenditure objectives
- the business has explained how the existing incentive schemes, allowances, government grants and regulatory sandboxing have been considered and genuinely exhausted before considering innovation expenditure
- the proposed projects must be prudent from a scale perspective for a trial/pilot phase. There is also a framework setting out the pathway from trial/pilot to BAU phase, including success factors/criteria applied to trials/pilots to assess whether it proceeds to BAU phase
- there is stakeholder support for the innovation expenditure.

The projects must be "innovative"

We consider that innovative projects should have the following characteristics:[127]

- Involve a new concept or technology/technique or activity – Where these have been already tested on another network, the business must provide justification that an innovation project is required to address implementation risk for this proven concept, technology/technique or activity.
- Not be a BAU activity – A BAU activity would have enough information available to be proposed as expenditure in a business' regulatory proposal.
- Have an unproven business case – As an untested activity, we would not necessarily expect a net positive outcome for an innovation project. In particular, a net positive outcome would indicate that a business should invest as a BAU activity, beyond a trial or pilot. However, we would expect that a business could demonstrate the potential benefits to consumers in the event the activity is successful.

127 AER, *Final Decision, Ausgrid Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, April 2024, pp 37–38.

- Be untested at scale – Deployment/volume should reflect trial/pilot phase of the testing.

We found that CPU partly satisfied this criterion. We have removed 10 projects from CitiPower and 13 from Powercor and United Energy). We found several of CPU's proposed projects to not be innovative or expenditure that we would otherwise expect to be a business-as-usual activity. One example of this is Trial New Sustainable Fleet Options project. This project involves procuring one 2-3 tonne forklift, one prime mover and one tray truck. In our view, CPU did not provide sufficient reasoning as to why this trial is required and we are of the view this would be considered a business-as-usual activity in response to an underlying need.

We have also removed the 3 projects proposed under the focus area of Building Network Resilience from our alternative forecast for Powercor and United Energy for this reason. We consider that the Stand-Alone Power Systems (SAPS) and fire-resistant technologies have already been successfully trialled by other networks.[128][129] In addition, we consider that the enhanced climate modelling project would be considered a business-as-usual activity in response to an underlying need.

The justification for the proposed project must be linked to the expenditure objectives

We consider that CPU has partially satisfied this criterion.

We consider that a business should explain how its proposed projects are linked to the expenditure objectives because these objectives are the service outcomes that are in the long-term interests of consumers. We consider that while CPU's project level benefit analysis indirectly refers to the expenditure objectives, there is no direct linkage to which of the objectives each project satisfies. For future innovation proposals, we would expect CPU to explicitly link each project to the expenditure objectives.

The proposed projects cannot be funded elsewhere

We consider that CPU has partially satisfied this criterion. We have removed one program we found to have not met this criterion; this being the Smart Connection Processes program.

We consider that our ex-ante regime and other mechanisms are available to incentivise (for instance, the Customer Service Incentive Scheme) as well as directly fund innovation solutions (for instance, the Demand Management Incentive Scheme or DMIAM). We acknowledge that our regulatory framework may not necessarily capture the benefits from trials and pilots at the localised/community level. We expect a business to provide supporting information to demonstrate that it has considered other existing funding mechanisms prior to requesting for explicit innovation funding.

CPU's proposal described the alternative sources of innovation funding that it has used in the current period, including the Demand Management Incentive Allowance Mechanism (DMIAM) as well as external funding such as through the Australian Renewable Energy

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128 AER, *Draft Decision, Essential Energy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, September 2023, p 22.

129 AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 Capital Expenditure*, September 2024, p 81.

Agency.[130] In addition, CPU stated that the DMIAM will continue to operate separately from the innovation allowance and that all innovation would remain in the DMIAM.[131] However, we consider the Smart Connection Processes program to be an example of a program that would be better funded under the Customer Service Incentive Scheme. This would ensure that the consumer doesn't pay twice for the benefits incurred by this program. Therefore, we have removed it from our alternative forecast.

The proposed projects must be prudent – deployed at a scale consistent with a trial/pilot

We consider that CPU has partly satisfied this criterion.

We consider that when testing an unproven or new activity on a business' network, it would be prudent to limit rollout/deployment to a level that is consistent with a trial/pilot phase. There is a threshold where these innovative activities could then become business-as-usual activities.

While the majority of CPU's projects satisfy this criterion, we note that some projects, such as the Business Network Tariff Information Tool project, account for benefits in both an initial trial as well as a further scaled trial. CPU has not provided sufficient detail of the unknown element that this trial will attempt to assess. Therefore, it is not clear why a scaled trial is required beyond the initial trial. We expect that networks seeking innovation funding explicitly link the trial deployment, including quantities required, to the reasoning that an innovation trial is required for the technology, as well as the pathway to BAU.

There is stakeholder support for the innovation expenditure

We consider that CPU has satisfied this criterion.

The CPU Customer Advisory Panel (CAP) demonstrated support for CPU's innovation fund as well as broad support that CPU not be required to specify potential topics at this early stage.[132] It also considered that transparency and governance arrangements to be critical and so encouraged businesses to develop these in advance of preparing its revised proposals. It stated that it would like to see more clarity about customer involvement in the committee and expressed disappointment that there is a commitment to involve just one CAP member. The Panel also questioned why the project on customer communication required innovation funding rather than being regular program expenditure.

The Victorian Greenhouse Alliances recommends the acceptance of all DNSP's proposed additional expenditure on innovation where evidence of a clear pathway to business-as-usual funding and delivery is provided.[133] It also recommends that the AER develops a new innovation allowance scheme over the next regulatory period that permits distributors to invest in innovation up to an agreed portion of capex (%) that is commensurate with other industrialised businesses. The Victorian Greenhouse Alliances would also require all

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130 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, pp 5–7.

131 CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 12.

132 CPU Customer Advisory Panel, *Report on CitiPower's Regulatory Proposal 2026–31*, April 2025, p 30.

133 Victorian Greenhouse Alliances, *Submission to the Australian Energy Regulator (AER), Local Government response to the Victorian Electricity Distribution Price Review (EDPR) 2026–31,* May 2025, p 18.

networks to establish innovation advisory committees using AusNet's innovation advisory committee governance model plus ongoing cross-network information sharing mechanisms.

We note that customer support for this program was in part based on the inclusion of the 'use-it or lose-it' mechanism within CPU's proposal.[134] As outlined above, we do not consider that there is a means within the limits of the NER requirements by which unspent funds could be returned to consumers.

[134] CitiPower, *INCENTIVES: INNOVATION ALLOWANCE*, p 13.

B Contingent projects

Contingent projects are usually significant network augmentation projects that are reasonably required to be undertaken to achieve the capital expenditure (capex) objectives. However, unlike other proposed capex projects, the need for the project within the regulatory control period and the associated costs are not sufficiently certain. Consequently, expenditure for such projects does not form a part of the total forecast capex that we approve in this determination. Such projects are linked to unique investment drivers and are triggered by defined 'trigger events'. The occurrence of the trigger event must be probable during the relevant regulatory control period.[135] The cost of the projects may ultimately be recovered from customers in the future if certain predefined conditions (trigger events) are met.

If, during the regulatory control period, CitiPower considers that the trigger event for an approved contingent project has occurred, then it may apply to us.[136] At that time, we will assess whether the trigger event has occurred, and the project meets the threshold. If satisfied of both, we would determine the efficient incremental revenue which is likely to be required in each remaining year of the regulatory control period as a result of the contingent project and amend the revenue determination accordingly.[137]

This appendix details our assessment of CitiPower's proposed LS Zone Substation, J Zone Substation and R Zone Substation contingent projects as part of its regulatory proposal for the 2026–31 regulatory control period.

B.1 AER decision

Our decision is to reject CitiPower's proposed LS Zone Substation, J Zone Substation and R Zone Substation contingent projects for the 2026–31 period. We consider CitiPower's contingent projects do not meet the requirements in the NER to be included as contingent projects.

B.2 CitiPower's proposal

CitiPower proposes $192 million for 3 contingent projects for the 2026–31 regulatory control period.[138] CitiPower submits the proposed projects are probable or plausible to occur by 2031.

The 3 proposed contingent projects are:

- LS Zone Substation ($70.0 million)
- J Zone Substation ($54.0 million)
- R Zone Substation ($68.0 million).

135 NER, cl. 6.6A.1(c)(5).

136 NER, cl. 6.6A.2(a).

137 NER, cl. 6.6A.2(e).

138 CitiPower, *MANAGING UNCERTAINTY*, January 2025, p 4.

CitiPower submits that the proposed contingent projects would be reasonably required to meet the NER capital expenditure objectives to meet or manage expected demand and to maintain the quality, reliability and security of supply.

For the LS Zone Substation CitiPower submits that the inner North is currently experiencing a period of rapid growth, with the BQ and VM Zone Substations forecast to exceed their summer and winter N-1 ratings in the 2026–31 regulatory periods.[139] It submits that this growth will likely be accelerated with the construction of the Arden Precinct. CitiPower proposes an augex project to address this and proposes the LS Zone Substation as a contingent project if the load growth from the Arden Precinct necessitates additional investment.

For the J Zone Substation CitiPower submits that the JA Zone Substation will not be compliant with its N-1 Secure rating by 2027 as a result of the projected high load growth in the Docklands area.[140] CitiPower proposes the CBD security of supply augex project to address this compliance obligation. One of the options of this project is the rebuild of the J Zone Substation. However, CitiPower proposes the J Zone Substation as a contingent project as there is uncertainty on the timing of the load growth in the area served by the J Zone Substation.

CitiPower submits that maximum demand at the R Zone Substation currently exceeds its summer and winter N-1 ratings and will remain above these rating in the 2026–31 regulatory period.[141] Its preferred option for managing this issue in the 2026–31 period is to transfer load from the R Zone Substation to adjacent substations. It has included the R Zone Substation as a contingent project as if the demand exceeds its current forecast it will need to introduce an additional measure to meet the demand.

B.3 Reasons for decision

B.3.1 Assessment approach

We reviewed each of CitiPower's proposed contingent projects against the assessment criteria in the NER.[142] We considered whether:

- the proposed contingent project is reasonably required to be undertaken to achieve any of the capex objectives[143]
- the proposed contingent project capital expenditure is not otherwise provided for in the capex proposal[144]
- the proposed contingent project capital expenditure reasonably reflects the capex criteria, taking into account the capex factors[145]

139 CitiPower, *MANAGING UNCERTAINTY,* p 28.

140 CitiPower, *MANAGING UNCERTAINTY,* p 31.

141 CitiPower, *MANAGING UNCERTAINTY,* p 33.

142 NER, cl. 6.6A.1 (a)

143 NER, cl. 6.6A.1(b)(1).

144 NER, cl. 6.6A.1(b)(2)(i).

145 NER, cl. 6.6A.1(b)(2)(ii).

- the proposed contingent project capital expenditure exceeds the defined threshold,[146] and
- the trigger events in relation to the proposed contingent project are appropriate.[147]

CitiPower's revenue proposal included a description of each contingent project, proposed trigger events, project requirement, proposed capex and demonstration of rules compliance.[148]

We reviewed each project based on CitiPower's and our own analysis. We reviewed whether each contingent project is reasonably likely to be required in the 2026–31 regulatory control period based on the materiality and plausibility of the trigger conditions. This gives us a high-level view of whether the project is reasonably required to achieve any of the capex objectives and reflect the capex criteria.

We also considered whether the proposed trigger events for each project are appropriate. This includes having regard to the need for the trigger event:

- to be reasonably specific and capable of objective verification[149]
- to be a condition or event which, if it occurs, makes the project reasonably necessary to achieve any of the capex objectives[150]
- to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole[151]
- to be described in such terms that it is all that is required for the revenue determination to be amended,[152] and
- to be a condition or event, the occurrence of which is probable during the 2029–31 regulatory control period but the inclusion of capex in relation to it (in the total forecast capex) is not appropriate because either:
    - it is not sufficiently certain that the event or condition will occur during the regulatory control period or if it may occur after that period or not at all, or
    - assuming it meets the materiality threshold, the costs associated with the event or condition are not sufficiently certain.[153]

B.3.2 Concerns with trigger events

CitiPower proposes similar trigger events for each of its contingent projects. This section details our overall concerns with CitiPower's trigger events.

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146 NER, cl. 6.6A.1(b)(2)(iii).

147 NER, cl. 6.6A.1(b)(4).

148 CitiPower, *MANAGING UNCERTAINTY,* p 4.

149 NER, cl. 6.6A.1(c)(1).

150 NER, cl. 6.6A.1(c)(2).

151 NER, cl. 6.6A.1(c)(3).

152 NER, cl. 6.6A.1(c)(4).

153 NER, cl. 6.6A.1(c)(5).

For example, the triggers CitiPower has proposed for the LS Zone Substation are:

- prepares a business case and relevant regulatory investment test for distribution documentation, including a cost-benefit analysis that demonstrates that the preferred option is rebuilding the LS Zone Substation; and
- obtains all relevant internal approvals to proceed with the project.

We had concerns that the triggers did not meet the requirements of 6.6A.1(c). In particular, that the triggers were not specific enough and were not an event that, if that event occurred would make the undertaking of the proposed contingent project necessary. Additionally, we were concerned that the triggers were not objectively verifiable as the findings of the business case were not factually objective. We considered that the triggers did not accord with the requirements of clauses 6.6A.1(c)(1), (2) and (4).

We issued an information request to CitiPower highlighting our concerns and requested that CitiPower provide updated triggers to address our concerns. In response CitiPower provided new triggers for all 3 contingent projects.[154]

CitiPower's new proposed trigger events for each contingent project have 3 common elements: the successful completion of a RIT-D, CitiPower board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER and a specific additional load.

For example, the new triggers CitiPower has proposed for the LS Zone Substation are:

- CitiPower receives a connection application or applications for 25 MW of load in the Arden precinct that will increase annualised expected unserved energy above the annualised cost of the contingent project within 3 years of a contingent project application; and
- CitiPower has completed a Regulatory Investment Test for Distribution (RIT-D) to determine the preferred credible option to connect and supply the load or loads, pursuant to the NER; and
- CitiPower commits to proceed with the preferred credible option from the RIT-D, subject to the AER amending CitiPower's 2026–31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Chief Executive Officer of CitiPower will be sent to the AER to confirm such commitment.

Broadly, we consider these triggers are more appropriate because the successful completion of a RIT-D process may demonstrate that a project is reasonably necessary to achieve the capex objectives and reasonably reflects the capex criteria. The successful completion of a RIT-D is an important step to ensure that the capex for a project is required to achieve the capex objectives and reasonably reflects the capex criteria. Completion of the RIT-D process provides evidence of a comprehensive and transparent assessment of credible options which demonstrates that the proposed network investment maximises net economic benefits.

154 CitiPower, *Response to information request 053,* August 2025.

However, we consider a determination by us that the preferred option satisfies the RIT-D will provide greater surety that the cost and scope of the proposed contingent projects will satisfy the capex objectives and capex criteria.

We also had concerns with the specific additional load trigger for the LS Zone Substation and J Zone Substation. This is discussed below with our project specific concerns.

B.3.3 Assessment of CitiPower's proposed contingent project

CitiPower submitted 3 contingent project proposals for its LS Zone Substation, J Zone Substation and R Zone Substation as part of its regulatory proposal. This section details our findings on each contingent project including our project specific concerns.

LS Zone Substation

We consider the LS Zone Substation contingent project may be reasonably required to be undertaken to achieve the capital expenditure objectives. However, we consider that the trigger event is sufficiently certain and as such does not meet the requirements to be included as a contingent project.

CitiPower provided 3 triggers in response to our information request for the LS Zone Substation, one of which was:

- CitiPower receives a connection application or applications for 25 MW of load in the Arden precinct that will increase annualised expected unserved energy above the annualised cost of the contingent project within 3 years of a contingent project application.

We note that Development Victoria has advised CitiPower that the development timeframe will see 33.5MVA of load by 2029 from the Arden precinct. Given the trigger wording states that only 25MW is needed to trigger this project we consider that the occurrence of the trigger event in the 2026–31 regulatory control period is extremely likely. We consider that this project does not meet the requirements of NER cl 6.6A.1(c)(5)(i). That is the timing of the trigger events is reasonably known such that it is sufficiently certain that they will occur in the regulatory control period.

We also consider that the costs associated with the trigger event are reasonably certain which means this project doesn't meet NER cl 6.6A.1(c)(5)(ii) either. CitiPower has included the scope of work in the associated business case for the ZSS capacity upgrades project.[155]

We recommend that CitiPower either provides additional evidence to support why the occurrence of the trigger event for this project is not sufficiently certain or include this expenditure in its capex in its revised proposal. If CitiPower includes this as a contingent project in its revised proposal we also recommend it considers determination by the AER in its RIT-D trigger.

J Zone Substation

We consider the J Zone Substation contingent project may be reasonably required to be undertaken to achieve the capital expenditure objectives. However, we consider that the

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155 CitiPower, *AUGMENTATION: BOUVERIE QUEENSLAND SUPPLY AREA*, January 2025, p 7.

event is not reasonable specific and it is also unclear if the event is reasonably uncertain. As such it does not meet the requirements to be included as a contingent project.

CitiPower provided 3 triggers in response to our information request for the J Zone Substation, one of which was:

- CitiPower receives a connection application or applications for 22 MW of load in the Richmond supply area that increases annualised expected unserved energy above the annualised cost of the contingent project within 3 years of a contingent project application.

We consider that the 22MW of load in the Richmond supply area is not reasonably specific and does not provide enough information for us to determine if this event is reasonably uncertain. We cannot determine whether this load is not sufficiently certain and should be included as a contingent project. Hence, we are not satisfied that this trigger event is appropriate having regard to the requirements of NER cl 6.6A.1(c)(5)(i). We do not have enough information to conclude whether the timing is reasonably known such that it is likely to be required in the regulatory control period.

We also consider that the cost for this project is reasonably certain which mean this project doesn't meet NER cl 6.6A.1(c)(5)(ii) either. CitiPower has included the scope of work in the associated business case for the CBD security of supply project.[156]

We recommend that CitiPower either provides additional evidence to support why the occurrence of the trigger event for this project is not sufficiently certain or include this expenditure in its capex in its revised proposal. If CitiPower includes this as a contingent project in its revised proposal, we also recommend it considers determination by the AER in its RIT-D trigger.

We note that this contingent project is related to CitiPower's CBD security of supply augmentation project. While we recommend including this project in our alternative capex forecast we note that the need for this project is related to the J Zone Substation and we may need to revisit this project in our final decision.

R Zone Substation

We consider the R Zone Substation contingent project may be reasonably required to be undertaken to achieve the capital expenditure objectives. However, we consider that part of the cost of the proposed R Zone Substation is included in CitiPower's forecast repex. As such it does not meet the requirements to be included as a contingent project.

CitiPower proposes to retire the switchboard at R Zone Substation as part of a switchboard replacement program submitted as part of its repex proposal. However, replacement of the switchboard would also be part of the R Zone Substation rebuild. This means that part of the expenditure is already accounted for in the forecast capital expenditure in the regulatory control period. NER 6.6A.1(b)(2)(i) requires that the expenditure is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure for the relevant

[156] CitiPower, *AUGMENTATION: CBD SECURITY OF SUPPLY*, January 2025, p 7.

regulatory control period. Hence this project does not satisfy the NER requirements to be a contingent project.

We recommend CitiPower provide addition information in its revised proposal to demonstrate the repex included for the R Zone Substation does not address the same need (in whole or in part) as this proposed contingent project. Alternatively, if the repex included for the R Zone Substation does address the same need we request CitiPower resubmits its contingent project application without the component that is already accounted for and we also recommend CitiPower considers determination by the AER in its RIT-D trigger.

Shortened forms

Term	Definition
AER	Australian Energy Regulator
ACS	alternative control services
augex	augmentation expenditure
BAU	business as usual
capex	capital expenditure
capcon	capital contributions
CBRM	condition-based risk model
CER	consumer energy resources
CESS	capital expenditure sharing scheme
CWAs	committed works agreements
DNSP	distribution network service providers
DTC	distribution transfer capacity
EMCa	Energy Market Consulting associates
EV	electric vehicle
ICT	information and communications technology
MITE	market interface technology enhancements
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Energy Objectives
NER	National Electricity Rules
opex	operating expenditure
RIN	regulatory information notice
RIT-D	Regulatory Investment Test for distribution network service providers
RIT-T	Regulatory Investment Test for transmission network service providers
SAIFI	system average interruption frequency index
SCS	standard control services
VCR	value of customer reliability
ZSS	zone substation