Final decision

United Energy electricity distribution determination
1 July 2026 – 30 June 2031

Attachment 2 – Capital expenditure

April 2026

AUSTRALIAN ENERGY REGULATOR

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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 emissions reduction 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 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).[4]

The AER capital expenditure assessment outline explains our and distributors' obligations 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 Energy 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. Our assessment of the ex-ante capex is consistent with the National Electricity Objective, which in addition to providing for

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, *Capital expenditure assessment outline for electricity distribution determinations*, February 2020.

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

the lowest possible costs also recognises that services should be valued appropriately and adapt to changing circumstances to maintain efficiencies in the long-term interest of consumers. This incentive-based framework 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 reset. 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:

- AER's *Expenditure Forecast Assessment Guideline*[7]
- AER's *Regulatory Investment Test for Distribution (RIT-D) – Application Guidelines*[8]
- AER's *Asset Replacement Industry Note*[9]
- AER's *Information and Communication Technologies (ICT) Guidance Note*[10]
- AER's *Guidance on amended National Energy Objectives*[11]
- AER's *An interim guidance on emissions reduction*.[12]

We also had regard to the guiding principles in the AER's *Better Resets Handbook – Towards consumer centric network proposals* which encourages networks to develop high quality, well-justified proposals that genuinely reflect consumers' preferences.[13]

Our final decision has been based on the information before us, which includes:

- the distributor's revised regulatory proposal and accompanying documents and models
- the distributor's responses to our information requests

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7 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024.

8 AER, *Regulatory Investment Test for Distribution – Application Guidelines*, November 2024.

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

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

11 AER, *Guidance on amended National Energy Objectives*, September 2023.

12 AER, *An interim guidance on emissions reduction*, June 2025.

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

- stakeholder comments in response to our draft decision and the distributor's revised proposal.

2.1 Final decision

Our final decision is to not to accept United Energy's proposed total forecast capex of $1,257.8 million ($2025–26) for the 2026–31 period because we are not satisfied that it reasonably reflects the capex criteria. We are not satisfied that it reasonably reflects the prudent and efficient costs, and a realistic expectation of demand and cost inputs required, to meet the capex objectives. Our alternative forecast is $1,161.2 million, which is 7.7% below United Energy's forecast.

We consider this forecast will provide for a prudent and efficient service provider in United Energy's circumstances to meet the capex objectives. Table 2-1 outlines our alternative estimate of forecast capex and compares this to United Energy's proposed forecast capex.

Table 2-1 AER's final decision on United Energy's total net capex forecast ($2025–26, million)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's revised proposal	239.4	243.6	256.6	261.3	256.8	1,257.8
AER's final decision	230.4	235.1	233.1	236.3	226.3	1,161.2
Difference ($)	**-9.0**	**-8.6**	**-23.5**	**-25.1**	**-30.5**	**-96.6**
Difference (%)	**-3.7%**	**-3.5%**	**-9.2%**	**-9.6%**	**-11.9%**	**-7.7%**

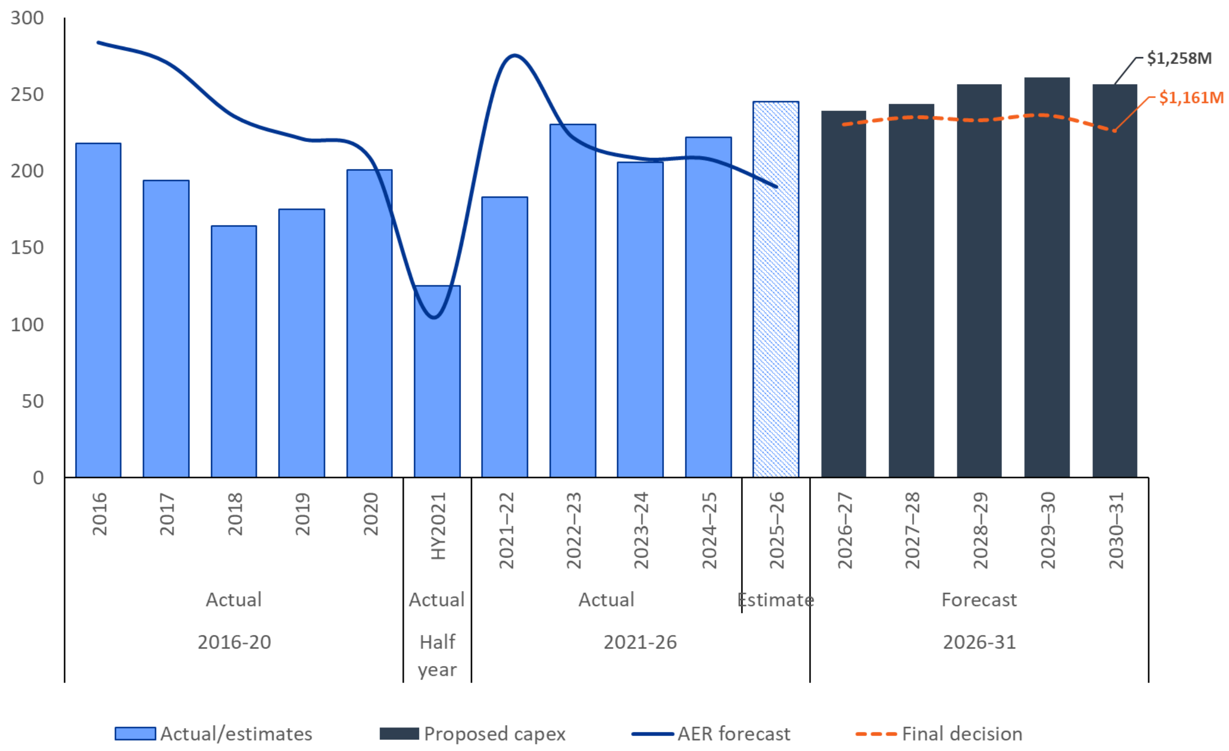
Source: United Energy's revised proposal and AER analysis.
Note: Numbers may not sum due to rounding.

2.2 United Energy's revised proposal

United Energy's revised proposal forecasts $1,257.8 million capex over the 2026–31 regulatory control period. This represents an increase of approximately 15.7% compared to actual and expected expenditure over the 2021–26 period.

Figure 2-1 outlines United Energy's historical capex trend, its revised proposed forecast for the 2026–31 regulatory control period, and our final decision. As can be seen, United Energy is forecasting a material step up from current period actual/estimates. The main drivers of the step up are augex and connections.

Figure 2-1 United Energy's historical and forecast capex ($2025-26, million)



Source: United Energy's revised proposal and AER analysis.
Note: Capex is net of disposals and capital contributions.

2.3 Reasons for final decision

We are satisfied that our alternative forecast of total capex of $1,161.2 million is reasonable and sufficient for United Energy to maintain its network.

Our final decision to reduce United Energy's forecast by 7.7% is materially different from our draft decision of a reduction of 25.3%. This reflects United Energy accepting some of the lower forecasts in our draft decision and our acceptance in this final decision of a higher forecast for some programs because of additional supporting information.

We reviewed United Energy'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 inter-relationships between cost categories. To complement this, we conducted bottom-up analysis of United Energy's specific 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 CER integration, resilience and capex for data centres. 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 final decision is reflective of this approach as set out in Table 2-2 and Table 2-3 below.

Overall, we found that the majority of United Energy's forecast of $1,257.8 million would be required to meet the capex objectives. For instance, we have accepted United Energy's forecast repex as it has sufficiently demonstrated its repex program is required to maintain reliability and safety objectives and its forecast is prudent and efficient.

However, we have not accepted United Energy's total capex forecast in full, reducing it by 7.7% because of the differences in our forecasts mostly in augex and connections. In some cases, we found that while we agree with United Energy that some level of investment is prudent in these areas, United Energy did not provide sufficient information to demonstrate that its preferred option is efficient. For augex, our reductions were driven by reductions to the customer driven electrification and Lower Mornington Peninsula programs. For these programs we found that United Energy had not justified its economic modelling, and we have included a reduced forecast. In regard to connections capex, we have reduced the forecast for United Energy's data centre connection program. We consider United Energy's forecast likely overstates volume of data centres forecast for the 2026–31 regulatory control period.

For new and emerging areas of expenditure, our assessment of proposals takes account of the limitations and challenges in forecasting these areas of expenditure. We have accepted some expenditure like United Energy's CER forecast in full acknowledging the merits in strengthening United Energy's CER capability in the immediate term given the longer-term benefits. For resilience expenditure, United Energy accepted our draft decision that includes expenditure for 3 of its 4 proposed programs. Similarly, we have also partly included the forecast for emerging expenditure such as for explicit ex-ante innovation funding because there a material gap in supporting information to demonstrate the net benefits to consumers.

We observed that our final decision total capex forecast is not materially different from its current period actual/estimates, being 6.8% higher. This is because:

- For repex, which is the largest category of capex (35.8%), we have accepted United Energy's forecast in full where that forecast is close to current period actual/estimates
- For connections, we have broadly accepted United Energy's forecast where that forecast is close to current period actual/estimates. Our forecast also reflects addition of emerging connections to United Energy's networks such as data centre and grid connected batteries.

Table 2-2 sets out our final decision for United Energy by category.

Table 2-2 AER's final decision by capex category ($2025–26, million)

Category	United Energy's revised proposal	AER's final decision	Difference ($/%)	
Replacement	453.2	452.1	-1.1	-0.2%
Augmentation	172.8	101.5	-71.3	-41.3%
Connections	387.0	386.3	-0.7	-0.2%
ICT	245.6	245.6	-	-

Category	United Energy's revised proposal	AER's final decision	Difference ($/%)	
Property	17.2	17.2	-	-
Fleet	63.5	63.5	-	-
CER integration	16.4	16.4	-	-
Non-network - other	1.0	1.0	-	-
Capitalised overheads	171.7	168.7	-3.0	-1.8%
Gross Total	**1,528.4**	**1,452.3**	**-76.1**	**-5.0%**
Less customer contributions	268.8	272.2	3.4	1.3%
Less disposals	1.8	1.8	-	-
Modelling adjustments		-17.1		
Net Total	**1,257.8**	**1,161.2**	**-96.6**	**-7.7%**

Source: United Energy's revised proposal, AER analysis.

Note: Numbers may not sum due to rounding.

Within these capex categories contains resilience, innovation and cyber security, which we assess separately:

- Resilience: Our forecast includes United Energy's proposed $11.9 million for network and community resilience, spread between augex, ICT and fleet. United Energy accepted our draft decision for resilience.
- Innovation: Our forecast includes $3.7 million for innovation, spread between repex and augex. This is $2.2 million (37.6%) lower than United Energy's revised proposal.
- Cyber security: Our forecast includes United Energy's proposed $18.1 million of cyber security, which sits within the ICT expenditure. United Energy accepted our draft decision for cyber security.

United Energy updated its proposed connections forecast to $390.4 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.[14]

Our final decision net capex of $1,161.2 million does not include forecast capex approved separately in our determination for United Energy's *unlocking CER benefits through flexible trading* cost pass through of $11.3 million. This cost pass through capex is included in United Energy's final decision Post Tax Revenue Model.[15]

Table 2-3 summarises our views on each of the capex categories and whether they are prudent and efficient and reflect the capex criteria, and the reasons for this. A number of capex categories were considered and accepted in our draft decision and are reflected in this table but should be read in conjunction with our draft decision.[16] Further detail and reasons on the remaining capex categories that we further considered in response to United Energy's revised proposal are contained in Appendix A.

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[14] United Energy, *IR#087 Connection policy upfront tax recovery - Public*, March 2026.

[15] AER, *AER Determination: United Energy – Unlocking CER benefits through flexible trading cost pass through*, April 2026.

[16] AER, *Attachment 2 – Capital Expenditure – Draft decision – United Energy electricity distribution determination 2026–31*, September 2025.

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's 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's actual spending.

Table 2-3 Summary of findings and reasons, by capex category

Issue	Findings and reasons
Replacement	We have included United Energy's proposed repex forecast of $450.3 million in the total capex forecast.[17] Its revised proposal is 13.5% lower than its initial proposal and in line with current 2021–26 period actual/estimates. United Energy accepted our draft decision forecasts for most programs except for its poles and zone substation programs. In response to our draft decision, United Energy provided further information to support its revised lower forecasts for poles and zone substation programs as well as adjusting its STPIS target to reflect the expected reliability improvements from its proposed conductor investments.[18] Our review identified some areas of improvement in the forecasting approach United Energy applies for its pole volume. We would encourage United Energy to review its revised pole decay model for future processes as it could be overestimating its pole volume, when having regard to limited life pole intervention rates.
Augmentation	Our final decision does not include United Energy's augex forecast of $161.2 million as part of our total capex forecast.[19] Instead, we have included a substitute estimate of $91.0 million, which is $70.2 million (43.6%) lower than United Energy's forecast. Our final decision on United Energy's customer driven electrification program is to approve $47.9 million, which is $39.6 million higher than our draft decision. We consider this is a reasonable amount for United Energy to balance the need to manage the issue of undervoltage and allows United Energy to do some proactive investment. For the Lower Mornington Supply program, we have maintained our draft decision to not include this program in our alternative forecast. We maintain our position that the non-network solution (provided for in opex) is the prudent and efficient option to manage this issue.

17 United Energy proposed $453.2 million for repex. We consider $2.9 million of this is innovation and have assessed it as such. We have assessed the remaining $450.3 million as repex.

18 United Energy, *Revised Proposal 2026–31 – Revenue and expenditure forecasts*, December 2025, p 36.

19 United Energy proposed $172.8 million for augex. We consider $2.9 million of this is network innovation and $8.6 million is resilience and have assessed these as such. We have assessed the remaining $161.2 million as augex and referred to this amount in A.1.

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<table>
<tr><th>Issue</th><th>Findings and reasons</th></tr>
<tr><td></td><td> We note that our bottom up augex forecast, driven by the customer driven electrification and Lower Mornington Peninsula programs, is below current period actuals/estimated spend. However, from our top down review we recognise the need for expenditure for augex is similar to the current regulatory control period. Hence, we have increased our alternative forecast to be in line with actual/estimated spending in the current period. This is further discussed at Appendix A.2. </td></tr>
<tr><td>Resilience</td><td> Our final decision includes United Energy's resilience forecast of $11.9 million as part of our total capex forecast. United Energy accepted our draft decision on this capex category. Following our final decision, the AER issue a notice to the Energy Safe Victoria and United Energy identifying the resilience projects that United Energy will be required to undertake in the 2026–31 regulatory control period:[20]
<table>
<tr><th>Resilience project</th><th>Capex</th><th>Opex</th><th>Total</th></tr>
<tr><td>Mobile generation</td><td>8.6</td><td>0.0</td><td>8.6</td></tr>
<tr><td>Situational awareness for extreme weather</td><td>3.2</td><td>0.0</td><td>3.2</td></tr>
<tr><td>Mobile emergency response vehicles</td><td>0.3</td><td>0.0</td><td>0.3</td></tr>
<tr><td>Community support officers</td><td>0.0</td><td>0.0</td><td>0.0</td></tr>
<tr><td>Total resilience project</td><td>12.2</td><td>0.0</td><td>12.2</td></tr>
</table></td></tr>
<tr><td>Connections</td><td> Our final decision does not include United Energy's connections forecast of $387.0 million as part of our total capex forecast. United Energy updated its proposed connections forecast to $390.4 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections. Instead, we have included a substitute estimate of $386.3 million, which is $4.0 million (1.0%) lower than United Energy's updated forecast. We have accepted United Energy's business as usual connections and grid connected batteries forecast. However, we have made an adjustment to its data centre forecast. We do not agree with United Energy's assumption that CitiPower, Powercor and United Energy's catchment would host 85% of forecast data centre demand. We consider this assumption is likely to overstate volume forecast of data centres. This is further discussed at Appendix A.3. </td></tr>
<tr><td>ICT</td><td> Our final decision includes United Energy's ICT expenditure forecast of $245.6 million as part of our total capex forecast. United Energy accepted our draft decision on this capex category. </td></tr>
</table>

20 Section 90G of the Electricity Safety Act requires the AER to submit a notice of the approved resilience projects to Energy Safe Victoria and applicable Victorian DNSP. Section 90H states that the applicable Victorian DNSP is required to submit a network resilience plan to Energy Safe Victoria for approval.

<table>
<tr><th>Issue</th><th>Findings and reasons</th></tr>
<tr><td>Property</td><td>Our final decision includes United Energy’s property forecast of $17.2 million as part of our total capex forecast. United Energy accepted our draft decision on this capex category.</td></tr>
<tr><td>Fleet</td><td>Our final decision includes United Energy’s fleet forecast of $63.5 million as part of our total capex forecast. United Energy accepted our draft decision on this capex category.</td></tr>
<tr><td>CER integration</td><td>CitiPower, Powercor and United Energy (‘CPU’) adopted a common strategy for addressing CER. Due to the commonality between the 3 entities, we have assessed their revised CER proposal collectively.

Our final decision accepts CPU’s CER integration forecast of $114.2 million ($54.6 million capex, $59.6 million opex) as part of our total expenditure forecast.

Our draft decision accepted CPU’s forecast for the Flexible Services program, the largest of the 3 CER programs. CPU’s revised proposal re-proposed the same forecasts for its 2 remaining CER programs: $9.7 million for network data visibility ($3.5 million capex, $6.2 million opex); and $15.0 million for non-network marketplace ($6.1 million capex, $8.9 million opex). Our final decision therefore accepts CPU’s CER forecast in full. We identified some information gaps, but on balance we see merit in strengthening the businesses’ CER capability in the immediate term given the longer-term benefits. We also appreciate this is a new and uncertain area where quantification of costs and benefits is not straightforward.

In coming to our decision, we also had regard to the Victorian Government’s submission and note its expectations in the forecast period that:[21]

• The non-network marketplace program involves consultation with third parties, so the platform is fit-for-purpose and implemented as proposed.

• The data visibility program is prioritised in the near term and necessary changes are delivered within 12 months; that basic network data remains accessible without direct changes to requesting parties; and the DNSPs have regard to potential future obligations arising from the Integrated Distribution System Plan rule change.</td></tr>
<tr><td>Non-network - other capex</td><td>Our final decision includes United Energy’s non-network other forecast of $1.0 million as part of our total capex forecast. United Energy accepted our draft decision on this capex category.</td></tr>
<tr><td>Capitalised overheads</td><td>We have included an alternative forecast of $168.7 million for United Energy’s capitalised overheads in the total forecast capex. This is to account for our substitute estimate of total direct capex.</td></tr>
</table>

21 Victorian Government, *Response to AER draft decision for the Victorian Electricity Distribution Determination 2026–31*, 28 January 2026, pp 4–5.

Issue	Findings and reasons
Innovation	CitiPower, Powercor and United Energy ('CPU') have each proposed similar innovation expenditure proposals. As such, we have assessed their revised proposals collectively. Our final decision does not include CPU's innovation expenditure forecast of $25.4 million ($15.2 million capex, $10.2 million opex) as part of our total expenditure forecast. Instead, we have included a substitute estimate of $17.2 million ($12.4 million capex, $4.9 million opex). We have accepted the forecast for 4 projects where CPU provided sufficient supporting information consistent with our ex-ante innovation criteria. However, we have not accepted its forecast for 3 projects as these projects were not innovative or it relied on overestimated benefit quantification values that we have not accepted in other parts of CPU's proposal. This is further discussed at in Attachment 2 (capital expenditure) of our final decision on CitiPower's regulatory proposal.
Customer contributions	We have included United Energy's customer contributions forecast in the total capex forecast. We have also included the tax offset for all high voltage and sub-transmission connections >=22kV, and embedded generators greater than 1.5MW. This is discussed in Attachment 16 (connections policy) of our final decision on United Energy's regulatory proposal.
Disposals	We have included United Energy's disposals forecast in the total capex forecast.
Modelling adjustments	Our final decision includes standard modelling adjustments for updated inputs to inflation and labour real cost escalation. We have not accepted United Energy's revised apportionment of internal labour and contract labour to its proposed investments. This is because these are inconsistent with its outsourcing arrangement with Zinfra.[22] Further, consistent with our decisions in previous resets, we do not accept CPU's proposal to apply real cost escalation to contract labour. We have therefore applied real escalation to internal labour only.
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.[23] 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.[24]

22 United Energy, *IR#064 Innovation and Contract Services - Confidential*, January 2026, p 4.

23 NER, cl 6.12.2(b).

24 NER, cl 6.4A(a).

Issue	Findings and reasons
	We may exclude capex from being rolled into the RAB when a distributor has overspent the amount of capex above the forecast that does not reasonably reflect the capital expenditure criteria. We have reviewed United Energy's capex performance for the 2020 to 2023–24 regulatory years. United Energy incurred total net 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. We are satisfied that including this actual capex in the RAB is likely to contribute towards achieving the capex incentive objective.

A Reasons for decision on key capex categories

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

- augmentation expenditure (A.1)
- connections (A.2).

A.1 Augmentation expenditure

Augmentation is capital expenditure required to build or upgrade the network to address system constraints driven by changes in demand and network utilisation to enable the network service provider to comply with quality, safety, reliability, security of supply and greenhouse gas emission reduction target requirements. United Energy's augmentation consists of expenditure mainly on demand driven augmentation capital expenditure, connection enablement, reliability, compliance and safety. It also includes expenditure related to resilience and the innovation allowance.

A.1.1 AER's final decision

We are not satisfied that United Energy's proposed $161.2 million ($2025–26) for augmentation capital expenditure (augex) would form part of a total capex forecast that reasonably reflects the capex criteria.[25] Our final decision includes an alternative forecast of $91.0 million which is $70.2 million or 43.6% lower than United Energy's revised proposal.

A.1.2 United Energy's revised proposal

United Energy's proposed augex of $161.2 million. Table A1.1 provides a breakdown of United Energy's revised augex. This forecast is 8.5% higher than United Energy's initial proposal. United Energy accepted our draft decision for some augex programs and revised its forecast for customer driven electrification and the Lower Mornington Peninsula programs.

Table A1.1 United Energy's revised augex proposal and AER final decision ($2025–26, million)

Program	United Energy revised proposal	AER final decision	Difference ($/%)	
Customer driven electrification	87.8	54.0	-33.8	-38.5%
Lower Mornington Peninsula supply	39.2	2.7	-36.4	-93.0%
System security	12.7	12.7	-	-

25 United Energy has proposed $172.8 million for augex. We consider $2.9 million of proposed augex is network innovation and $8.6 million is resilience and have assessed these as such. We have assessed the remaining $161.2 million as augex and refer to this amount for the remainder of this section.

Program	United Energy revised proposal	AER final decision	Difference ($/%)	
Communications	9.0	9.0	-	-
Operational technology	5.9	5.9	-	-
Metering	2.7	2.7	-	-
HV feeder program	2.8	2.8	-	-
Power quality	0.6	0.6	-	-
Subtransmission upgrades	0.5	0.5	-	-
Total augex	**161.2**	**91.0**	**-70.2**	**-43.6%**

Source: United Energy's revised proposal, AER analysis. Numbers may not sum due to rounding.
Note: United Energy has proposed $172.8 million for augex. We consider $2.9 million of proposed augex is network innovation and $8.6 million is resilience and have assessed these as such.

A.1.3 Reasons for decision

We reviewed the information United Energy provided in support of its revised augex forecast, including the business cases and cost-benefit models. Where required, we sought further information from United Energy through an information request.

Our final decision is $47.0 million higher than our draft decision. The higher augex forecast in the final decision is reflective of our finding that for the customer driven electrification program, we found the new and additional information supported a step up from our draft decision position but did not justify United Energy's full revised forecast.

We discuss our specific findings from our bottom-up assessment on United Energy's revised customer driven electrification and Lower Mornington Peninsula forecasts below. These findings were informed by EMCa's review of Powercor's customer driven electrification program.[26] CPU has used consistent methodology for all its customer driven electrification programs so EMCa's findings on Powercor's modelling are also relevant to United Energy.

We note that our bottom-up assessment produces an augex forecast that is below United Energy's current period actual/estimated spend. We have compared this to our top-down assessment of augex. In this case, from a total augex perspective we recognise that the overall program of work United Energy requires to maintain its network is similar to that in the current regulatory period. As such, United Energy may need additional expenditure on augex above what we found in our bottom-up assessment. We consider using its actual/estimated spend from the current period in our alternative forecast is more appropriate. We have achieved this by increasing our alternative forecast for the customer driven electrification and Lower Mornington Peninsula programs and this is reflected in Table A1.1. The sections below discuss our bottom-up assessment before this adjustment is made.

26 EMCa, *EMCa assessment of selected Powercor RRP augex projects FINAL*, April 2026, pp 6–22.

A.1.3.1 Customer driven electrification

We do not accept United Energy's forecast of $87.8 million for its customer driven electrification program would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $47.9 million for this program in our alternative capex forecast, which is 45.4% lower than United Energy's proposal and 475.7% higher than our draft decision.

Our draft decision was an 88.2% reduction to United Energy's forecast. We found that the use of the Value of Customer Reliability (VCR) to value undervoltage was not appropriate and that the impacts would be much less. We also found that the increase in voltage complaints was not reasonable. We considered that United Energy could maintain voltage compliance obligations with existing expenditure and included historical expenditure in our alternative forecast.

United Energy did not accept our draft decision and re-proposed its customer driven electrification program. Table A1.2 shows United Energy's revised proposal and sets out our analysis in response.

Table A1.2 United Energy revised forecast and AER sub-category analysis ($2025–26, million)

Project	United Energy's Revised proposal	AER sub-category analysis
Proactive investment	56.8	37.0
Reactive investment	31.0	10.9
Total	**87.8**	**47.9**

Note: These numbers do not align with Table A1.1 as these are before we made the adjustment to bring this program up in line with historical expenditure.

We received several submissions from stakeholders regarding United Energy's customer driven electrification program.

- CCP32 commented on CPU's engagement on this program and was satisfied that consumers support the proposed expenditure. They also commented on the application of VCR and stated this is an important topic that would benefit from a wider discussion.[27]
- CAP commented on the customer driven electrification program and supports United Energy's evidence-based view that customer driven electrification is outpacing the capability of existing LV networks and targeted proactive investment is the most efficient way to avoid larger costs later.[28]
- Nexa Advisory had concerns on the scale of augmentation expenditure uplifts proposed and stated that without strong least cost testing we risk locking in higher RAB growth rather than prioritising efficient utilisation of existing network capacity. They commented

[27] CCP32, *Submission – United Energy electricity distribution proposal 2026–31*, January 2026, pp 15–16.

[28] Customer Advisory Panel, *Submission – United Energy electricity distribution proposal 2026–31*, January 2026, p 6.

that the AER has a responsibility to promote long-term outcomes in line with the National Energy Objectives.[29]

In its revised proposal, United Energy changed its approach for its proactive program from containing forecast decrease in compliance and increase in complaints to a proactive investment valued at 10% VCR. United Energy is now justifying the proactive upgrades under economic grounds.[30]

We found that the modelling approach appears reasonable and adequate in forecasting voltage impact at the LV level. We consider United Energy's assumed value of 10% of VCR is not an unreasonable modelling assumption, though it should not be treated as a definitive value. We recognise that the value is non-zero but consider that values larger than 10% may not be indicative. Nevertheless, we accept United Energy's use of 10% to value undervoltage in this case.

However, we do have concerns with United Energy's economic modelling.

- We found that a few of these sub projects (totalling $2.1 million, $2023–24) included in the proactive program did not exhibit an increase in undervoltage within the next regulatory period. This indicates that the problem of undervoltage for these projects is not getting worse over the next regulatory period.
- We also found that several sub projects (totalling $16.4 million, $2023–24) had an optimal timing to be completed in 2024/2025 according to United Energy's modelling. Given United Energy has not addressed the issue of undervoltage in the current period by addressing the projects that are already optimal, this weakens the justification for proposing such a large program in the next regulatory period.

For its reactive program United Energy has maintained its approach but provided further supporting information to justify its complaints forecast. We found that some expenditure is justified in order for United Energy to maintain compliance but EMCa's report raised concerns with Powercor's economic modelling which also apply to United Energy.[31]

We found that United Energy has now justified its complaints forecast and has shown that complaints are trending upwards over time. However, United Energy has increased the percentage of major complaints over time which has the effect of increasing the required expenditure. We consider that United Energy has not justified the increase in major complaints relative to minor complaints.

For United Energy's reactive program, we have used the historical complaints and reactive expenditure from 2024 and 2025 to calculate a unit cost per complaint. Using United Energy's complaints forecast and this unit cost of $10,829 per complaint, over the next regulatory period, results in a reactive forecast of $10.9 million ($2025–26 escalated). We consider that this amount will allow United Energy to remain compliant with its obligations.

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29 Nexa Advisory, *Submission – Victorian electricity distribution proposals 2026–31*, January 2026, p 5.

30 United Energy, *Revised Proposal 2026–31 – Revenue and expenditure forecasts*, December 2025, pp 28–29.

31 EMCa, *EMCa assessment of selected Powercor RRP augex projects FINAL*, April 2026 pp 6–22.

For United Energy's proactive program, we found that it is not reasonable to include sub projects for which the issue of undervoltage is not getting worse over the next regulatory period. The goal of this program is to prevent further deterioration of voltage levels and avoid further undervoltage across its network.

We also found United Energy has not justified the size of the proposed proactive program. Given United Energy has included $16.4 million ($2023–24) of projects for which its modelling indicates the optimal timing is in the current regulatory period, we consider United Energy has not justified why this large program should all be completed in the next regulatory control period. The proactive program is not driven by compliance but rather because it is an efficient economic investment. Given that many of these projects are already economic according to United Energy's modelling, then we consider that it should have already been conducting this investment in the current period.

This results in a proactive program forecast of $37.0 million, which we consider is a reasonable amount for United Energy to manage the issue of undervoltage and allows some proactive investment. This is a prudent and efficient forecast based on the available data.

A.1.3.2 Lower Mornington Peninsula

We do not accept United Energy's forecast of $39.2 million for its Lower Mornington Peninsula program would form part of a total capex forecast that reasonably reflects the capex criteria. Consistent with our draft decision, we have not included this program in our alternative capex forecast.

In our draft decision we recommended United Energy continues with the current non-network solution in the 2026–31 period and reconsiders this project in the next regulatory control period. We determined that continuing or expanding the existing non network solution in FY31 is a cost-effective way to defer the new line, and the resilience benefits can be delivered through the use of mobile generation.

United Energy has not accepted our draft decision and has re-proposed its Lower Mornington Peninsula supply program. United Energy has provided further economic modelling in its revised proposal including a non-network solution as an option in its analysis.

In United Energy's updated cost benefit analysis, the NPV of the new transmission line is $14.6 million and the NPV for non-network solution is $11.0 million. The sensitivity analysis shows that these NPVs are very sensitive to changes in the energy at risk and capex costs. The NPV is only marginally higher for the transmission line but has a substantial upfront cost. In addition, this project has been deferred successfully since 2016 and there is no new reasoning as to why this is necessary to be completed in the next regulatory period when the non-network solution remains NPV positive.

Our final decision on United Energy's Lower Mornington Peninsula project is to maintain our draft decision to not include this project in our alternative forecast. We still consider that continuing with the current non network solution in the 2026–31 period is the prudent and efficient solution. Given our concerns, we do not consider that United Energy has justified the need to complete this project in the current regulatory period. We found that there is not enough evidence that this issue is getting worse and while the non-network solution remains NPV positive we maintain this is the prudent and efficient approach.

We consider that the risk of putting in a new line that may not be needed yet is much higher than continuing with the non-network solution. Given this project is scheduled towards the end of the next regulatory period and the non-network solution is already funded in opex, we consider this project should be deferred to the next period.

A.2 Connections

The cost of electricity connections is recovered from United Energy's customers and is made up of the cost of connection (gross connections), minus any capital contribution a customer makes towards the cost of the connection (the result is referred to as the net connection cost). Typically, the gross connection cost is based on the forecast volumes of new connections and expected unit costs.

We assess the amount of connection costs United Energy is proposing to recover from its customers as well as the proportion of capital contributions that is netted off the connection costs in line with United Energy's connections policy.[32]

A.2.1 AER's final decision

We are not satisfied that United Energy's proposed $387.0 million ($2025–26) for connections capital expenditure would form part of a total capex forecast that reasonably reflects the capex criteria. United Energy updated its proposed connections forecast to $390.4 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.[33] Our final decision includes an alternative forecast of $386.3 million which is $4.0 million or 1.0% lower than United Energy's updated revised proposal. Table A2.1 provides a breakdown of our decision for gross connections capex.

Table A2.1 United Energy's revised proposal and AER's final decision ($2025–26, million)

Project	United Energy's updated revised proposal	AER's final decision
Business-as-usual connections	359.2	359.2
Grid Connect Batteries	31.7	31.7
Data Centres	119.8	93.0
Capital contribution tax liability	(120.4)	(97.6)
Gross connections total	**390.4**	**386.3**

Source: AER analysis.
Note: United Energy initially proposed $123.8 million as capital contribution tax liability. It updated its capital contribution tax liability to $120.4 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.

32 The connections policy specifies the categories of persons that may be required to pay a connection charge, the services for which a charge may be made, the basis on which the charge is determined, how this is paid and the threshold below which a retail customer (not being a non-registered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation.

33 United Energy, *IR#087 Connection policy upfront tax recovery - Public*, March 2026.

The alternative forecast relates to our adjustments for United Energy's data centre connection program and the tax liability for capital contributions.

For tax liability, our final decision is to apply tax liability offset for all new load customers above 22kV and embedded generators greater than 1.5MW. United Energy provided updated tax liability values to meet this requirement as part of an information request.[34] Our capex allowance is adjusted to reflect the updated information.

The alternative forecast also relates to our adjustments for United Energy's data centre connection program. We consider United Energy's forecast likely overstates the volume of data centres forecast for the 2026–31 regulatory control period. United Energy's proposal and reasons for our decision in relation to data centres are set out below.

A.2.2 United Energy's revised proposal

United Energy's revised data centre connections forecast is $119.8 million in gross capex, or $18.0 million in net capex. United Energy also proposed $101.8 million or 85% of gross capex as capital contributions.

United Energy did not include data centre forecast in its initial proposal. United Energy proposed a data centre forecast broadly following our draft decision guidance included in CitiPower and Powercor. The guidance included 3 categories of data centre connections:

- type 1 – Committed in-flight projects which have committed work agreement signed and it is likely these data centres will be established within the early years of the forecast period
- type 2 – Projects that are between the connection enquiry to connection offer stage and these data centres will likely be established in middle of the forecast period
- type 3 – Future project which are anticipated but enquiries have not yet been received and these data centres will be established towards the end of the forecast period.

United Energy did not include any type 1 data centres.

For type 2 data centre connections, CitiPower, Powercor and United Energy (CPU) jointly engaged an independent consultant, Mandala Partners', to develop and apply a weighted probability assessment framework ('CPU probability assessment framework) for all data centre enquiries they had received. The CPU probability assessment framework includes factors such as grid connection and firm offers, construction phase, proponent track record with establishing data centres in Australia, site identification and feasibility, and utility assessment. The CPU probability assessment framework was applied to determine the probable data centre capacity (in MW) that would likely be built and energised within United Energy's catchment in the 2026–31 regulatory control period. Then, using historical cost of connecting data centres with similar scope, United Energy determined the forecast capex for data centres.

For type 3 data centre connections, CPU jointly engaged Mandala Partners' to identify future projects to anticipate any future enquiries they may receive. Mandala Partners' applied a

[34] United Energy, *IR#087 Connection policy upfront tax recovery - Public*, March 2026.

linear regression-based analysis to estimate data centre demand that may eventuate towards the end of the forecast period and is not yet in United Energy's pipeline (i.e. where enquiries are anticipated in future).

Furthermore, United Energy revised its connections policy with respect to tax liability. From 1 July 2026, all high voltage and sub transmission connections, including data centres, connected to its network will be liable for the tax payable on their capital contributions.

A.2.3 Reasons for decision

We have reviewed the information United Energy provided in support of its data centre connection revised capex forecast, including the business cases and other relevant artifacts. Where required, we have sought further information from United Energy through information requests.

We have assessed United Energy's data centre forecast by examining the forecast volumes of new data centre connections and expected unit costs including the capital contributions. Our assessment is described below.

A.2.3.1 Volumes

We consider United Energy has not sufficiently supported the forecast volume of data centres that will likely be established in the 2026–31 regulatory control period.

In principle, we consider United Energy's methodology of applying the CPU probability assessment framework to the enquires it has received is reasonable for type 2 data centres. However, we are concerned that the CPU probability assessment framework appears to result in higher demand than anticipated as per AEMO's data centre forecasts.

CPU jointly has also undertaken the top-down assessment using AEMO's data centre forecasts as a starting point and converted it to installed capacity expected within the CPU's catchment.[35] It calculated AEMO's step change scenario would represent 1,663MW of installed data centre capacity within CPU's catchment. It also assumes that approximately 85% of the data centres usage will be in CPU's catchment in the forecast period. Then, it escalated the installed data centre capacity to reflect the additional enquiries CPU received since the data for AEMO's step change scenario was collected. This escalation effectively doubles AEMO's step change scenario forecasts to 3,338MW. Based on the modified AEMO data, United Energy considered that its total bottom-up forecast demand of 3,576MW for CPU's joint catchment area was reasonable.[36]

We do not agree with the aggregated forecast of CPU's AEMO-modified escalated data centre volumes. We consider its underlying assumption that CPU's catchment would represent 85% of installed data centre is likely overstated. Even though CPU may have 85% of the data centre capacity in the current period, we do not consider this metric is reflective for the forecast period. In reaching this position, we had regard to the data centre forecasts and the maturity levels of these forecasts from other Victorian distribution businesses' regulatory proposals. Based on our assessment, we consider CPU's top-down challenge used to justify its bottom-up forecast is likely to be overstated. Subsequently, we consider

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35 United Energy, *UE RRP BUS 3.6.01 – PUBLIC – Data Centre Connections*, 1 December 2025, pp 10–12.

36 United Energy, *UE RRP BUS 3.6.01 – PUBLIC – Data Centre Connections*, 1 December 2025, pp 10–12.

that United Energy's data centre volume forecast, which is based on an allocation from the CPU forecast, is also likely to be overstated.

Further, CPU's sensitivity analysis predicted data centre demand to range from 2,570MW to 3,549MW across CPU's catchment.[37] We note that CPU's forecast demand of 3,576MW is at the higher end of the sensitivity range. Based on this, and the assumption that CPU will receive 85% of forecast data centre capacity, we consider the aggregate CPU forecast is likely to be overstated.

We also consider that the population of the data centres in United Energy's probability assessment framework may include some future data centre projects that will be completed towards the end of the forecast period. Therefore, there might be an overlap between United Energy's type 2 and type 3 forecast. Holistically, this has resulted in a forecast that is likely to overstate the volume of data centres United Energy requires.

In developing an alternative estimate, we considered whether the supporting evidence provided by United Energy was sufficiently robust. We acknowledge that United Energy's type 2 data centre volumes are built on enquires it has received to date and the maturity levels of these enquiries. We consider this is relatively robust information. However, United Energy's type 3 projections are more speculative and less robust, so we have elected to omit type 3 data centres from our alternative forecast.

We also note that the Capital Expenditure Sharing Scheme (CESS) now allows us the ability, at our discretion, to exclude any CESS penalty that arises from data centre capex. This provides an added level of protection for United Energy if there is an increase in the volume of data centres above our alternative forecast.

A.2.3.2 Unit rate and capital contribution

United Energy has applied the capital contribution formula and used a mixture of historical capital contribution rates and forecasting assumptions. This formula is applied to each data centre across a range of scenarios using relevant unit rates on a case-by-case basis to arrive at the lowest cost to consumers.

Furthermore, we note that United Energy has not expressly included overheads as part of its capital contribution formula.

As per our draft decision, we are satisfied with this approach. This approach is consistent with the current connections charge guidelines.[38]

A.2.3.3 Tax liability associated with customer contribution

In relation to tax liability associated with customer contributions, we did not agree with United Energy's proposal to recover tax payable from all high voltage and sub transmission connections. Instead, our final decision is to apply tax liability offset for all new load customers above 22kV and embedded generators greater than 1.5MW. Reasons for our decisions on this matter are set out in Attachment 16 (connection policy).

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37 Powercor, *PAL RRP BUS 3.6.01 – PUBLIC – Data Centre Connections*, 1 December 2025, p 11.

38 AER, *Connection charge guidelines for electricity customers – Under chapter 5A of the National Electricity Rules*, October 2024.

To be consistent with our position on the recovery of the upfront tax liability associated with the contributions for large connections (including data centres), we have updated our modelling to reflect our final decision threshold of new load customers above 22kV and embedded generators greater than 1.5MW. This has no impact on net capex.

B Contingent Projects – Lower Mornington Peninsula

Contingent projects are usually significant network augmentation projects that are reasonably required to be undertaken to achieve the 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.[39] The cost of the projects may ultimately be recovered from customers in the future if certain predefined conditions (trigger events) are met.

This appendix details our assessment of United Energy’s Lower Mornington Peninsula contingent project proposal as part of its revised proposal for the 2026–31 regulatory control period.

B.1.1 AER’s final decision

Our final decision is to not accept United Energy’s proposed Lower Mornington Peninsula contingent project for the 2026–31 regulatory control period. We have concluded that United Energy’s $38 million ($2025–26, unescalated) contingent project is not reasonably required to be undertaken to achieve the capex objectives over the 2026–31 period.[40]

B.1.2 United Energy’s proposal

United Energy’s initial regulatory proposal did not include any contingent projects for the 2026–31 regulatory period. United Energy stated that while it maintains this position in the revised proposal, in the event the AER does not accept the revised augmentation project to construct a new 66kV sub-transmission in the lower Mornington Peninsula, then the alternative solution determined by the AER should include the sub-transmission line as a contingent project.[41]

As detailed in Section A.1.3 we have not included the Lower Mornington Peninsula project in our alternative augex forecast. As such, we have considered the new 66kV line in the Lower Mornington Peninsula as a contingent project.

B.1.3 Assessment approach

A contingent project should reflect a project that United Energy can reasonably expect would occur in the 2026–31 period, with uncertainty related to the scope, timing and costs of the contingent project.

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

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

41 United Energy, *Revised Proposal 2026–31 – Revenue and expenditure forecasts*, December 2025, pp 65–66.

We reviewed United Energy's proposed contingent project against the assessment criteria in the NER. We considered whether:

- the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capex objectives[42]
- the proposed contingent project capex is not otherwise provided for in the capex proposal[43]
- the proposed contingent project capex reasonably reflects the capex criteria, taking into account the capex factors[44]
- the proposed contingent project capex exceeds the defined threshold[45]
- the trigger events in relation to the proposed contingent project are appropriate.[46]

As part of our assessment, we reviewed whether the proposed contingent project is reasonably likely to be required in the 2026–31 regulatory control period based on the materiality and plausibility of the trigger events. This gives us a high-level view of whether the project is reasonably required to be undertaken in the regulatory control period to achieve any of the capex objectives and reflect the capex criteria.

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

- to be reasonably specific and capable of objective verification[47]
- to be a condition or event which, if it occurs, makes the project reasonably necessary in order to achieve any of the capex objectives[48]
- 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 transmission network as a whole[49]
- to be described in such terms that it is all that is required for the revenue determination to be amended[50]
- to be a condition or event, the occurrence of which is probable during the 2024–29 period but the inclusion of capex in relation to it (in the total forecast capex) is not appropriate because either:

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42 NER, cl 6.6A.1(b)(1). Relevantly, a DNSP must include forecast capex in its revenue proposal which it considers is required in order to meet or manage expected demand for standard control services over the regulatory control period (see NER, cl 6.5.7(a)(1)).

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

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

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

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

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

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

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

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

- 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.[51]

B.1.4 Reasons for decision

United Energy's proposed forecast capex of $38 million ($2025–26, unescalated) for the contingent project exceeds the materiality threshold.

NER clause 6.6A.1(b)(2)(i) requires that the expenditure in a contingent project is not otherwise provided for in the total of the forecast capital expenditure for the relevant regulatory control period. Given that we have provided opex for a non-network solution to address the need for the Lower Mornington Peninsula supply program we do not consider that the Lower Mornington Supply Program meets the conditions to be considered a contingent project.

We also consider that the costs and timing for this project are reasonably certain (given we are providing opex to address this issue) which means this project also doesn't meet NER clause 6.6A.1(c)(5).

As this project does not meet the conditions to be considered a contingent project, we have not accepted the Lower Mornington Supply contingent project in our final decision.

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

Shortened forms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	customer energy resources
CESS	capital expenditure sharing scheme
CPU	CitiPower, Powercor and United Energy (collectively)
DNSP or distributor	distribution network service provider
ESV	Energy Safe Victoria
ICT	information and communication technology
kV	kilovolts
LV	low voltage
NEL	National Electricity Laws
NER	National Electricity Rules
NPV	net present value
opex	operating expenditure
RAB	regulated asset base
repex	replacement expenditure
SCS	standard control service
STPIS	service target performance incentive scheme
VCR	value of customer reliability