DRAFT DECISION
Evoenergy
Distribution Determination

2019 to 2024

Attachment 5
Capital expenditure

September 2018

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Evoenergy for the 2019–2024 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

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Attachment 11 – Demand management incentive scheme

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Contents

Shortened forms

Shortened form	Extended form
ADMS	advanced distribution management system
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP/CCP10	Consumer Challenge Panel (sub-panel 10)
CESS	Capital expenditure sharing scheme
DER	distributed energy resources
DSO	Distribution System Operator
EBSS	Efficiency benefit sharing scheme
FPSC	fixed price service charge
ICT	Information and Communications Technology
MEFM	Monash Electricity Forecast Model
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net present value
NSP	Network Service Provider
RAB	Regulatory asset base
repex	replacement expenditure
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme

5 Capital expenditure

Capital expenditure (capex) refers to the investment made in the network to provide standard control services. This investment generally relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory periods.

On an annual basis, the financing and depreciation costs associated with these assets are recovered (return of and on capital) as part of the building blocks that form Evoenergy's total revenue requirement.[1]

This attachment sets out our draft decision on Evoenergy's total capex forecast. Further detailed analysis is provided in the following appendices:

- Appendix A - Assessment techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Engagement and information-gathering process
- Appendix D - Repex modelling approach
- Appendix E - Demand
- Appendix F - Real material cost escalation

Our draft decision is based on our analysis of the information we have received to date. We will be informed by Evoenergy's revised proposal, submissions and further analysis in arriving at our final decision in April 2019.

5.1 Draft decision

In assessing forecast capital expenditure, we are guided by the National Electricity Objective and underpinning capex criteria and objectives set out in the NER. We must accept a distributor's capex forecast if we are satisfied that the total forecast for the regulatory control period reasonably reflects the capex criteria.

This criteria outlines that a distributor's capex forecast must reasonably reflect the efficient costs of achieving the capex objectives, the costs that a prudent operator would require to achieve the capex objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.[2]

The capex objectives relate to a distributor's ability to comply with regulatory obligations and maintain the quality, reliability and security of supply of standard control services.[3]

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1 NER, cl. 6.4.3(a).7

2 NER, cl. 6.5.7(c)(1).

3 NER, cl. 6.5.7(a).

Where a distributor is unable to demonstrate that its proposal complies with the capex criteria and objectives, the NER requires us to set out a substitute estimate of total capex that we are satisfied reasonably reflects the capex criteria, taking into account the capex factors.[4]

Evoenergy has not justified that its proposed total forecast capex of $329.8 million reasonably reflects the capex criteria. Our substitute estimate of $261.4 million is 20.7 per cent below Evoenergy's forecast. We are satisfied that out substitute estimate reasonably reflects the capex criteria, taking into account the capital expenditure factors. Table 5.1 outlines our draft decision.

Table 5.1 – Draft decision on Evoenergy's total forecast capex ($2018-19, million)

	2020	2021	2022	2023	2024	Total
Evoenergy's initial proposal	62.4	65.3	75.9	65.6	60.6	329.8
AER draft decision	50.3	49.9	47.1	60.9	53.1	261.4
Difference	-12.0	-15.4	-28.8	-4.7	-7.5	-68.4
Percentage difference (%)	-19.3%	-23.6%	-38.0%	-7.1%	-12.3%	-20.7%

Source: Evoenergy and AER draft decision capex models

Note: Numbers may not add up due to rounding.

Note: The figures above do not include equity raising costs. For our assessment of equity raising costs, see attachment 3.

Table 5.2 summarises our findings and the reasons for our draft decision by 'capex driver' (e.g. augmentation, replacement and connections). This reflects the way we have assessed Evoenergy's total capex forecast.

Our findings on the capex drivers 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. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

Our assessment highlighted that we are satisfied that some aspects of Evoenergy's proposal, such as its proposed connections expenditure, would form part of a total capex forecast that reasonably reflects the capex criteria. However, we found other capex drivers associated with Evoenergy's proposal, such as augmentation and replacement expenditure, are likely to be higher than an efficient level and therefore

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

are not likely to reasonably reflect the capex criteria[5], taking into account the capex factors and the revenue and pricing principles.[6]

We therefore formed a substitute estimate of total capex. We test this total estimate of capex against the capex criteria (see section 5.3 for a detailed discussion). We are satisfied that our estimate represents a total capex forecast that as a whole reasonably reflects the capex criteria. As set out in appendix B, we are satisfied that our overall capex forecast forms part of an overall distribution determination that will or is likely to contribute to the achievement of the National Electricity Objective to the greatest degree.

Table 5.2 – Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	Evoenergy's proposed a total capex forecast of $329.8 million ($2018-19) in its revised proposal. Evoenergy has not justified that its estimate reasonably reflects the capex criteria. We are satisfied that our substitute estimate of $261.4 million ($2018-19) reasonably reflects the capex criteria. Our substitute estimate is 20.7 per cent lower than Evoenergy's initial proposal. The reasons for this decision are summarised in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	We consider Evoenergy's key assumptions and forecasting methodology are generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment and section 5.4.2.
Augmentation capex	Evoenergy has not justified that its forecast augex of $47.2 million ($2018-19) reasonably reflects the capex criteria. We have instead included an amount of $24.8 million ($2018-19) in our substitute estimate. Our revised forecast reflects that: • Based on the information available, Evoenergy has not demonstrated that its use of deterministic planning standards for augmentation is justified. We consider this practice is overly conservative, with Evoenergy proposing augmentation measures when the risk of unserved energy remains minimal. • Evoenergy has not demonstrated how it has incorporated the forecast benefits of its Chamber Substation SCADA Program and Distribution Monitoring Program into its overall proposal.
Customer connections capex	We consider that Evoenergy's revised forecast customer connections capex of $85.7 million ($2018-19) is justified and reasonably reflects the capex criteria. This includes capital contributions of $28.3 million ($2018-19). We have included this amount in our substitute estimate of total capex. We accept that Evoenergy's connections forecast reasonably reflects the required expenditure for this driver.
Replacement capex (repex)	Evoenergy has not justified that its repex forecast of $91.6 million ($2018-19) reasonably reflects the capex criteria. We have included $83.6 million ($2018-19) in our substitute estimate of total capex. We note that Evoenergy's modelled repex lies slightly above our predictive modelling threshold, which compares distributors' asset categories on both unit costs and expected replacement lives. We also used these results to help inform our bottom-up review of a sample of Evoenergy's repex

5 NER, cl. 6.5.7(c) and (d).

6 NER, cl. 6.5.7(c) and (d).

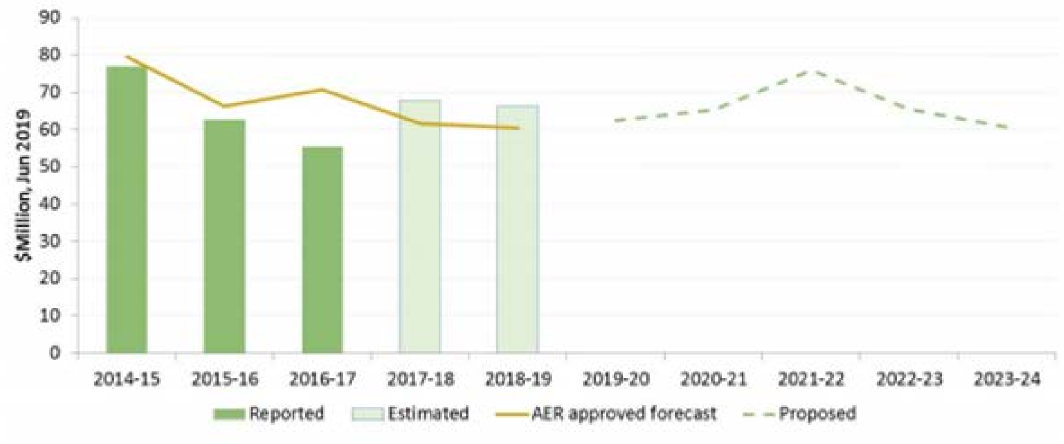
Issue	Reasons and findings
	programs and projects. While we accept that some of Evoenergy's repex forecast reasonably reflects the required expenditure for this driver, Evoenergy has not justified that its repex forecast for the underground cable asset group is prudent and efficient. We do not consider that its total repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.
Non-network capex	Evoenergy has not justified that its forecast non-network capex of $58.3 million ($2018-19) reasonably reflects the capex criteria. We have instead included an amount of $46.0 million ($2018-19) in our substitute estimate. Our revised forecast reflects that: • We have removed contingency costs from ICT program forecasts; • Based on the information available, we do not consider that Evoenergy has demonstrated that the proposed advanced distribution management system (ADMS) and information and communications technology (ICT) asset extension programs are prudent and efficient or that Evoenergy has accounted for the benefits of these programs within its overall proposal; • Evoenergy's forecast assumed a target replacement age for elevated work platforms and heavy commercial vehicles lower than industry standard benchmarks.
Capitalised overheads	Evoenergy propose capitalised overheads of $75.6 million ($2018-19). Evoenergy has not justified that its estimate reasonably reflects the capex criteria. We include in our substitute estimate of overall total capex an amount of $58.0 million ($2018-19). We consider that the reasons Evoenergy has presented do not warrant the increase in capitalised overheads. Our revised forecast reflects a decrease in support requirements for our alternative capex estimate compared with Evoenergy's proposal.
Real cost escalators	Evoenergy's proposed real material cost escalators would lead to cost increases above CPI. We consider that zero per cent real cost escalation is likely to reasonably reflect the capex criteria and is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2019–24 regulatory control period. For labour cost escalation, we have used the average growth rate in the wage price index (WPI) for the Australian Capital Territory utilities industry forecast by Deloitte Access Economics and Evoenergy's consultant, BIS Oxford Economics. See Attachment 6, Section 6.4.2.

Source: AER analysis.

5.2 Evoenergy's proposal

For the 2019-24 regulatory control period, Evoenergy proposes total forecast net capex of $329.8 million ($2018-19). Evoenergy's 2019-24 capex forecast is $1.0 million (0.3 per cent) higher than its actual capital expenditure of $328.8 million over the 2014-19 regulatory control period. Figure 5.1 outlines Evoenergy's historical capex trend vs its forecast for the 2019-24 regulatory control period.

Figure 5.1 – Evoenergy's historical vs forecast capex, including 2014-19 allowance ($2018-19)



Source: AER analysis

5.2.1 Background

The key drivers of Evoenergy's capex proposal are:

- Augmentation[7] - $53.4 million (16 per cent)
- Connections - $51.7 million (16 per cent)
- Replacement - $91.6 million (28 per cent)
- Non-network - $58.3 million (18 per cent)
- Capitalised overheads - $75.6 million (23 per cent)
- Material cost escalation - $1.6 million (0.5 per cent)[8]

This draft decision highlights the concerns we have with a number of areas of Evoenergy's proposal. We have identified those capex categories and assessments that would benefit from further information and discussions with Evoenergy and its stakeholders. We recognise Evoenergy's latest efforts to engage more thoroughly with its stakeholders, particularly in the area of ICT expenditure and encourage this level of engagement on an ongoing basis.

The reasons for our draft decision, including a summary of these capex drivers, are outlined in section 5.4. More detailed analysis of each of these drivers is outlined in appendix B.

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7 Includes reliability and quality improvements.

8 Refer to Appendix F for our assessment of Evoenergy's real material cost escalation.

5.3 Assessment approach

In determining whether Evoenergy's proposal reasonably reflects the capex criteria, we use various qualitative and quantitative assessment techniques to assess the different elements of Evoenergy's proposal.[9]

More broadly, we also take into account the revenue and pricing principles set out in the NEL.[10] In particular, we take into account whether our overall capex forecast provides Evoenergy with a reasonable opportunity to recover at least the efficient costs it incurs in:[11]

- providing direct control network services; and
- complying with its regulatory obligations and requirements.

When assessing capex forecasts, we also consider that:

- the efficiency criteria and the prudency criteria in the NER are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[12]
- past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[13]

5.3.1 Considerations in applying our assessment techniques

Appendix A outlines our assessment approach and appendix B details how we came to our position on Evoenergy's capex forecast. In summary, some of these assessment techniques focus on total capex, while other focus on high-level, standardised sub-categories of capex. Importantly, while we may consider certain programs and projects in forming a view on the total capex forecast, we do not determine which programs or projects a distributor should or should not undertake.

This is consistent with our ex-ante incentive based regulatory framework. Our approach is based on approving an overall ex-ante revenue requirement that includes an assessment of what we find to be a prudent and efficient total capex forecast.[14] Once the ex-ante allowance is established, distributors are incentivised to provide services at the lowest possible cost because their returns are determined by the actual

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9 NER, NER, cl. 6.5.7(c).

10 NEL, ss. 7A and 16(2).

11 NEL, s. 7A.

12 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8 and 9.

13 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

14 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. vii.

costs of providing services. If distributors reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.

This ex-ante incentive-based regulatory framework recognises that the distributor should have the flexibility to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake programs or projects that it did not anticipate during the distribution determination process. The distributor may also not need to complete some of the programs or projects it proposed during the forecast regulatory control period if circumstances change. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Therefore, recognising the interplay between the broader incentive framework and program and project investment considerations, when reviewing a capex forecast we use a combination of bottom-up and top-down assessment techniques. Assessment of the bottom-up build of forecasts including underlying assumptions is an informative way to establish whether the forecast capex at the program or project level is prudent and efficient. Many of the techniques we apply at this level encompass the capex factors that we are required to consider. However, we are also mindful that a narrow focus on only a bottom-up assessment may not itself provide sufficient evidence that the forecast is prudent and efficient. Bottom-up approaches tend to overstate required allowances, as they do not adequately account for interrelationships and synergies between programs, projects or areas of work.

Thus, we also review the prudency and efficiency of aggregate expenditure areas or the total capex forecast.[15] Top-down analysis provides us with assurance that the entire expenditure program is prudent and efficient, and allows us to consider a distributor's total capex forecast. We use holistic assessment approaches that include a suite of techniques such as trend analysis, predictive modelling and detailed technical reviews. Consistent with our holistic approach, we take into account the various interrelationships between the total capex forecast and other components of a distributor’s distribution determination, such as forecast opex and STPIS interactions.[16]

In the event we are not satisfied a distributor’s proposed capex forecast reasonably reflects the capex criteria, we are required to determine a substitute estimate. We do so by applying our various assessment techniques. We then use our judgement to weight the results these techniques case-by-case, in light of all the relevant information available to us.

Broadly, we give greater weight to techniques that we consider are more robust in the particular circumstances of the assessment. By relying on several techniques, we ensure we consider a wide variety of information and take a holistic approach to

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[15] For example, see AER, *Draft decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, October 2015, p. 21; AER, *Draft decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, October 2015, pp. 20–21.

[16] NEL, s. 16(1)(c).

assessing the distributor's capex forecast. Where our techniques involve the use of a consultant, their reports are considered when we form our draft decision position on total forecast capex.

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

The regulatory framework has a number of mechanisms to deal with these circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[17]

Similarly, a distributor may spend less than the capex forecast because it has operated at a more efficient level than expected. In this case, the distributor will keep on average 30 per cent of this reduction over time, with the remaining benefits shared with its customers.

5.3.2 Safety and reliability considerations

Our position in this draft decision is that our approved capex forecast will provide for a prudent and efficient service provider in Evoenergy's circumstances to maintain performance at the targets set out in the STPIS. Therefore, it is appropriate to apply the STPIS, as set out in attachment 10. The STPIS provides incentives to distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

Our analysis in appendix B outlines how our assessment techniques factor in network safety and reliability. We consider our substitute estimate will allow Evoenergy to maintain the safety, service quality and reliability of its network, consistent with its legislative obligations.

5.3.3 Interrelationships

In coming to a position on Evoenergy's capex proposal, we have taken into account the various interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[18]

For some elements, such as capitalised overheads, we will consider the proposed capital expenditure in the context of total expenditure. For other elements, such as

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[17] NER, r. 6.6.

[18] NEL, s. 16(1)(c).

capability growth, we may consider any opex-capex trade-offs to determine whether the capital expenditure will result in a net benefit to electricity customers.

Evoenergy has included within its opex forecast a step-change to procure demand management solutions in the development of Strathnairn, in order to postpone the requirement to construct a new zone substation to meet demand in the area.[19] The step change is $1.8 million over the 2019-24 regulatory control period. Evoenergy's consultant CutlerMerz found that the option of a feeder extension combined with demand management would be cheaper in net present value terms than construction of the new zone substation.[20]

5.4 Reasons for draft decision

We applied the assessment approach set out in section 5.3 and appendix A to Evoenergy. Evoenergy has not demonstrated that its total capex forecast reasonably reflects the capex criteria. We outline how we have applied our assessment techniques and how we came to our position in appendix B. We are therefore required to set out a substitute estimate, which we are satisfied that our substitute estimate reasonably reflects the capex criteria.

Table 5.3 sets out the capex amounts by driver that we included in our substitute estimate of Evoenergy's total capex forecast for the 2019-24 regulatory control period.

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[19] Evoenergy, Attachment 6 Operating expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, pp. 6–16.

[20] Evoenergy, Attachment 6.2 CutlerMerz Demand management opex step change business case - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 3.

Table 5.3 – Assessment of required capex by capex driver 2019–24 ($2019, million)

Category	2019	2020	2021	2022	2023	Total
Augmentation	5.5	6.8	2.6	5.1	4.7	**24.8**
Connections	16.2	17.1	17.5	17.7	17.2	**85.7**
Replacement	15.8	16.0	15.2	15.8	20.7	**83.6**
Non-network	8.5	6.1	8.5	16.9	6.0	**46.0**
Capitalised overheads	11.3	11.3	10.7	12.9	11.8	**58.0**
Gross capex (includes capital contributions)	57.3	57.3	54.5	68.5	60.5	**298.0**
Less capital contributions	(6.8)	(7.2)	(7.2)	(7.3)	(7.1)	**(35.6)**
Less disposals	(0.2)	(0.3)	(0.2)	(0.2)	(0.3)	**(1.1)**
Net capex (excluding capital contributions)	**50.3**	**49.9**	**47.1**	**60.9**	**53.1**	**261.4**

Source: AER analysis.

Notes: Capital contributions in this table include an overheads component.

Numbers may not add up due to rounding.

The reasons for our alternative capex forecast of $261.4 million are summarised below:

Augmentation:

- Evoenergy's proposed augex of $47.2 million ($2018-19) does not appear to be a reasonable estimate of the efficient costs required for this capex category. Evoenergy has not justified that its augex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.
- Evoenergy has not justified that its demand-driven capex reflects the prudent and efficient costs on the basis that:
  - Evoenergy relies on deterministic planning standards for demand-driven augmentation proposals. We consider this practice is overly conservative, with Evoenergy proposing augmentation measures when the risk of unserved energy remains minimal–earlier than would be efficient to do so.
  - In the case of the proposed Molonglo zone substation and feeders, Evoenergy's forecast of demand in the Molonglo Valley district is currently subject to considerable change. We consider it would be more appropriate to consider the prudency and efficiency of the proposed augmentation measure once there is greater certainty on the load that would need to be supplied.
- The proposed non-demand-driven network capex is justified and is reasonably likely to reflect prudent and efficient costs.

- With the exception of one program, the proposed secondary systems capex is justified and is reasonably likely to reflect prudent and efficient costs.
- Evoenergy has not justified that its proposed capex for chamber substation SCADA and distribution substation monitoring (reliability capex) is reasonably likely to reflect prudent and efficient costs. This is on the basis that Evoenergy has not demonstrated how the forecast benefits were incorporated into its overall proposal.

Customer connections:

- Evoenergy's proposed connections capex of $85.7 million ($2018-19, excluding overheads) is justified and is likely to reasonably reflect prudent and efficient costs. Evoenergy's connections capex forecast for 2019-24 is lower than in the regulatory period, reflecting the lower volume industry and government growth estimates.

Repex:

- Evoenergy's proposed repex of $91.6 million ($2018-19, excluding overheads) does not appear to be a reasonable estimate of the prudent and efficient costs required for this capex category. Evoenergy has not justified that its repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $83.6 million ($2018-19, excluding overheads) in our substitute estimate of total capex.
- Evoenergy's forecast for modelled repex ($55.3 million) lies $8.2 million above our 'repex model threshold' ($47.1 million). We applied this $8.2 million reduction to Evoenergy's total repex forecast of $91.6 million, to produce a repex forecast of $83.4 million. Our substitute estimate of $83.6 million is slightly higher due to other modelling adjustments.[21]
- Evoenergy's repex forecast is broadly in line with our modelled results for all asset groups except underground cables. Its forecast for unmodelled repex ($36.3 million) is not materially higher than historical trends.
- Our modelling results informed our more detailed bottom-up assessment of the underground cable asset group. Evoenergy is forecasting a significant increase in both repex and replacement volumes for underground cables. In addition, our assessment indicates that Evoenergy has altered its replacement strategy for these assets and its underlying cost-benefit analysis includes conservative assumptions.

Non-network:

- Evoenergy's proposed non-network capex of $58.3 million ($2018-19) does not appear to be a reasonable estimate of the prudent and efficient costs required for this capex category. Evoenergy has not justified that its non-network forecast would form part of a total capex forecast that reasonably reflects the capex criteria.
- In reviewing the information provided by Evoenergy, we have found that:

[21] These other modelling adjustments relate to changes in forecast materials and labour cost escalators, and adjustments for modelling errors.

    - Evoenergy has included contingency costs in forming forecast capital expenditure for ICT replacement programs.
    - Evoenergy has not demonstrated that the upgrade of its advanced distribution management system (ADMS) is prudent and efficient in the forthcoming regulatory period. Evoenergy has also not demonstrated any forecast benefits associated with this upgrade within its overall proposal.
    - Evoenergy has not demonstrated that proposed ICT asset extension programs are prudent and has not demonstrated how any forecast benefits were incorporated into its overall proposal.
    - Evoenergy's forecast assumed a target replacement age for elevated work platforms and heavy commercial vehicles lower than industry standard benchmarks.

Capitalised overheads:

- Evoenergy’s proposed capitalised overheads of $75.6 million ($2018-19) does not appear to be a reasonable estimate of the prudent and efficient costs required for this capex category. Evoenergy has not justified that its capitalised overheads forecast would form part of a total capex forecast that reasonably reflects the capex criteria.
- In using 2018-19 as the base year for forecasting the fixed price service charge, we consider that Evoenergy has over-estimated its capitalised overheads forecast.
- In particular, we do not consider that increased ICT operating expenditure should lead to an increase in capital expenditure.
- We also consider that Evoenergy’s forecast decrease in direct labour expenditure should lead to a lower support requirement and therefore counter-balance any increase in wages.
- Our revised forecast reflects a decrease in support requirements for our alternative capex estimate in 2019-24 compared with Evoenergy’s proposal.

A Assessment techniques

This appendix describes the approaches we applied in assessing whether Evoenergy's total capex forecast reasonably reflects the capex criteria. Appendix B set out in greater detail the extent to which we relied on each of these assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply when assessing opex. This is reflective of differences in the nature of the expenditure that we are assessing. We therefore use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We outline this in the Expenditure Assessment Guideline (the Guideline).[22]

Below we outline the assessment techniques we used to assess Evoenergy's capex forecast.

A.1 Trend analysis

We consider past trends in actual and forecast capex as this is one of the capex factors under the NER.[23] We also consider trends at the asset category level to inform our view on the prudency and efficiency of a distributor's capex forecast.

Trend analysis involves comparing a distributor's forecast capex and volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. We also assess whether the historical levels of expenditure are indicative of the required expenditure moving forward. In doing so, we consider the reasons the distributor provides in its initial proposal, as well as any potential changing circumstances.

In considering whether the total capex forecast reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand and comply with relevant regulatory obligations.[24] Demand and regulatory obligations (specifically, service standards) are key capex drivers. More onerous standards or growth in maximum demand will increase capex. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex the distributor requires.

Maximum demand is a key driver of augmentation or demand-driven expenditure. Augmentation (augex) often needs to occur prior to demand growth being realised. Forecast demand, rather than actual demand, is therefore most relevant when a distributor is deciding the augmentation projects it will require in the forecast regulatory control period. However, to the extent that actual demand differs from forecast demand, a distributor should reassess project needs. Growth in a distributor's network

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22 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

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

24 NER, cl. 6.5.7(a)(3).

will also drive connections-related capex. For these reasons, it is important to consider how capex trends, particularly for augex and connections, compare with trends in demand and customer numbers.

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important when considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected the distributor's capex requirements.

We analysed capex trends across a range of levels including at the total capex level and the category level, (e.g. augex, connections and repex). We also compared these with demand trends and any relevant changes in service standards.

A.2 Category analysis

Expenditure category analysis allows us to compare expenditure across distributors, and over time, for various levels of capex. The comparisons we analyse include:

- overall costs within each category of capex;
- unit costs across a range of activities;
- volumes across a range of activities; and
- expected asset lives across a range of repex asset categories.

Using standardised reporting templates, we collect data on augex, repex, connections, non-network capex, overheads and demand forecast for all distributors in the NEM. Using standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works that distributors incur and how these factors may change over time.

A.3 Predictive modelling

Background

The AER's repex model is a statistical based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy) and unit costs. We use the repex model to only assess forecast repex that can be modelled. This is typically includes high-volume, low-value asset categories and generally represents a significant component of total forecast repex. The repex model is currently only used to forecast modelled repex for electricity distributors.

The repex model forecasts the volume of assets in each category that a distributor would expect to replace over a 20-year period. The model analyses the age of assets already in commission and the time at which, on average, these assets would be expected to be replaced, based on historical replacement practices. We refer to this as the calibrated expected asset replacement life. We derive a total replacement expenditure forecast by multiplying the forecast replacement volumes for each asset category by an indicative unit cost.

We can use the repex model to advise and inform us where to target a more detailed bottom-up review and define a substitute estimate if necessary. We can also use the model to compare a distributor against other distributors in the National Electricity Market (NEM)[25]. In coming to our position, we also had regard to feedback from distributors on some of the underlying assumptions and modelling techniques.

Scenario analysis

Our repex modelling approach analyses four scenarios that consider both a distributor's historical replacement practices and the replacement practices of other distributors in the NEM. In contrast to previous determinations, the current approach considers intra-industry comparative analysis for unit costs and expected asset replacement lives, rather than analysing inter-company historical performance. The four scenarios analysed are:

1. historical unit costs and calibrated expected replacement lives
2. comparative unit costs and calibrated expected replacement lives
3. historical unit costs and comparative expected replacement lives
4. comparative unit costs and comparative expected replacement lives.

We define comparative unit costs as the minimum of a distributor's historical unit costs, its forecast unit costs and the median unit costs across the NEM. We define comparative replacement lives as the maximum of a distributor's calibrated expected replacement life and the median expected replacement life across the NEM.

The 'cost, lives and combined' scenarios rely on a comparative analysis technique that compares the performance of all distributors in the NEM. The technique analyses the two variable repex model inputs – unit costs and expected replacement lives.

The 'cost scenario' analyses the level of repex a distributor could achieve if their historical unit costs were improved to comparative unit costs. The 'lives scenario' analyses the level of repex a distributor could achieve if their calibrated expected replacement lives were improved to comparative expected replacement lives.

Previous distribution determinations where we have used on the repex model have primarily focused on the 'historical scenario'. This scenario forecasts a distributor's expected repex and replacement volumes based on their historical unit costs and asset replacement practices (which are used to derive expected replacement lives).

Our refined comparative analysis repex modelling approach builds on this previous analysis and now introduces the historical performances of other distributors in the NEM into the forecast period. The 'cost, lives and combined' scenarios rely on a

25 This includes Power and Water Corporation.

comparative analysis technique that compares the performance of all distributors in the NEM. The technique analyses the two variable repex model inputs – unit costs and replacements lives.

The 'cost scenario' analyses the level of repex a distributor could achieve if their historical unit costs were improved to comparative unit costs. The 'lives scenario' analyses the level of repex a distributor could achieve if their calibrated expected replacement lives were improved to comparative expected replacement lives.

Repex model threshold

Our 'repex model threshold' is defined taking these results and other relevant factors into consideration. For the 2019-24 determinations, our proposed approach is to set the repex model threshold equal to the highest result out of the 'cost scenario' and the 'lives scenario'.[26]

This approach considers the inherent interrelationship between the unit cost and expected replacement life of network assets. For example, a distributor may have higher unit costs than other distributors for particular assets, but these assets may in turn have longer expected replacement lives. In contrast, a distributor may have lower unit costs than other distributors for particular assets, but these assets may have shorter expected replacement lives.

Further details about our repex model are outlined in appendix D.

A.4 Assessment of bottom-up and top-down methodologies

In assessing whether Evoenergy's capex forecast is prudent and efficient, we examined the forecasting methodology and underlying assumptions used to derive their forecast. In particular, some of the evidence that we can use to justify the prudency and efficiency of a bottom-up forecast at the program or project level is:

- identifying and quantifying all reasonable options in a cost-benefit analysis, including deferral or 'do nothing' scenarios;
- cost-benefit analysis that incorporates a proper quantified risk assessment, where the most beneficial program or project is selected, or clear and justified reasoning as to why another option was chosen; and
- reasons to support the expenditure timing for the forecast regulatory control period, particularly if the expenditure may have been deferred in previous regulatory control periods.

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26 Our modelling approach means the 'historical scenario' will always be higher than the 'cost scenario' and the 'lives scenario', and the 'combined scenario' will always be lower than the 'cost scenario' and the 'lives scenario'.

Our industry practice application note[27], which relates to asset replacement planning, aims to assist network businesses with this bottom-up forecast. At the time of this draft decision, the draft industry practice application note is open for consultation. The final industry practice application note will be published in late November 2018. We therefore encourage Evoenergy to have regard to the final application note and the consultation process in its revised proposal.

In addition to a bottom-up build, a holistic and strategic consideration or assessment of the entire forecast capex portfolio would be evidence that some discipline has been applied at the top-down level. In particular, a top-down challenge would give us confidence that:

- the bottom-up builds have been subject to overall checks against business governance and risk management arrangements;
- synergies between programs or projects have been identified, which may reduce the need for, scope or cost of some programs or projects over the forecast regulatory control period;
- subjectivity from the bottom-up forecasts has been addressed; and
- the timing and prioritisation of capital programs and projects have been determined over both the short and long term, such that delivery strategy has been considered.

A.5 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report.[28] The NER requires us to have regard to the annual benchmarking report, as it is one of the capex factors.[29] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to the operating environment and network characteristics.[30]

Economic benchmarking allows us to compare the performance of a distributor against its own past performance and the performance of other distributors. It also helps to assess whether a distributor's capex forecast represents efficient costs.[31] The AEMC stated:

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27 This Application Note does not replace published guidelines. Rather, it supplements the guidelines by outlining principles and approaches that accord with good asset management and risk management practices. Good asset management and risk management practices are often aligned with international standards of practice, such as ISO 55000 for asset management and ISO 31000 for risk management.

28 AER, *Annual benchmarking report: Electricity distribution network service providers*, December 2017.

29 NER, cl. 6.5.7(e)(4).

30 AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines*, November 2013, p. 78.

31 NER, cl. 6.5.7(c).

> "Benchmarking is a critical exercise in assessing the efficiency of an NSP".[32]

Several economic benchmarks from the annual benchmarking report are relevant to our capex assessment. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment.

We consider each distributor's operating environment in so far as there are factors outside of a distributor's control that affects its ability to convert inputs into outputs.[33] Once we consider these exogenous factors, we expect distributors to operate at similar efficiency levels. One example of an exogenous factor we consider is customer density.

A.6 Other assessment factors

We considered several other factors when assessing Evoenergy's total capex forecast. These factors included:

- safety and reliability statistics (SAIDI and SAIFI);
- internal technical and engineering review;
- external consultant review;
- submissions made by various stakeholders; and
- other information provided by Evoenergy.

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[32] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 25.

[33] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

B Assessment of capex drivers

This appendix outlines our detailed analysis of the categories of Evoenergy's capex forecast for the 2019-24 regulatory control period. These categories are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that Evoenergy's proposed total capex forecast reasonably reflects the capex criteria. In this appendix, we set out further analysis in support of this view. This further analysis also explains the basis for our substitute estimate of Evoenergy's total capex forecast, which we are satisfied reasonably reflects the capex criteria, taking into account the capex factors. In coming to our views and our substitute estimate, we applied the assessment techniques outlined in appendix A.

This appendix sets out our findings and views on each capex category. The structure of this appendix is:

- Section B.1: substitute estimate
- Section B.2: forecast augex
- Section B.3: forecast customer connections capex, including capital contributions
- Section B.4: forecast repex
- Section B.5: forecast non-network capex
- Section B.6: forecast capitalised overheads.

In each of these sections, we explain why we are satisfied the amount of capex that we have included in our substitute estimate reasonably reflects the capex criteria.

B.1 Substitute estimate

Our substitute estimate of Evoenergy's total capex forecast for the 2019-24 regulatory control period is $261.4 million ($2018-19). We analysed Evoenergy's proposal and determined that we were not satisfied that it reflects the capex criteria. We then set out our substitute estimate of capex, which we are satisfied reasonably reflects the capex criteria, taking into account the capital expenditure factors. [34] We have based our substitute estimate on our assessment techniques explained in section 5.3 and appendix A. Our weighting of each of these techniques is set out under the capex drivers in appendix B.

[34] NER, cl. 6.5.7(e).

B.2 Forecast augex

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

B.2.1 Evoenergy's proposal

Evoenergy's has proposed forecast augex of $47.2 million ($2018-19, excluding overheads). The proposal includes:[35]

- $7.0 million for zone substations
- $32.4 million for distribution system augmentation
- $6.0 million for secondary systems augmentation
- $1.2 for transmission augmentation.

Evoenergy submit that major augmentation projects it expects to be undertake during the 2019-24 regulatory period include:

- construction of a zone substation in the Molonglo district for the provision of power to the new suburbs of Whitlam, Denman Prospect, Coombs, Wright and North Weston;
- a network security project, known as Second Supply to the ACT Project—Stage 2, involving the construction of a double circuit 132 kV transmission line and the installation of 11 kV capacitor banks at four zone substations. It is aimed at meeting the requirements of the *Electricity Transmission Supply Code 2016*.

B.2.2 Position

Evoenergy has not demonstrated that its capex forecast of $47.2 million ($2018-19) for augmentation is prudent and efficient and would form part of a total forecast capex allowance that reasonably reflects the capex criteria. Instead, we have included $24.8 million ($2018-19) of augmentation expenditure in our alternative capex forecast. This is a reduction of $22.4 million or 47.5 per cent. We consider that this amount is prudent and efficient, and would form part of a total forecast capex allowance that reasonably reflects the capex criteria. In coming to this view, we have assessed:

- trend analysis comparing recent actual and forecast expenditure
- the forecast peak load on Evoenergy's network
- the utilisation rates of Evoenergy's assets

[35] Evoenergy, Attachment 5 Capital expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24 January 2018, pp. 5–53.

- the project documentation accompanying Evoenergy's proposal and any further information provided by Evoenergy;
- advice from engineering/technical experts; and
- stakeholder submissions.

Table 5.4 summaries Evoenergy's proposal and our alternative amounts for augex.

Table 5.4 – AER draft decision on Evoenergy's total forecast augex ($2018, million)

	2019	2020	2021	2022	2023	Total
Initial regulatory proposal	11.1	13.8	10.9	5.7	5.8	47.2
AER draft decision	5.5	6.9	2.6	5.1	4.7	24.8
Total difference b/w the AER decision and initial proposal	(5.5)	(6.9)	(8.3)	(0.6)	(1.2)	(22.4)
Percentage difference b/w AER decision and initial proposal (%)	-49.9%	-50.2%	-75.7%	-10.6%	-18.7%	-47.5%

Source: AER analysis.

Note: Numbers may not add up due to rounding.

In this section we have also considered Evoenergy's proposed reliability capex. Evoenergy has also proposed $6.2 million ($2018-19) in reliability capex for the 2019–24 regulatory control period, at $1.2 million per year. Evoenergy has not demonstrated that its proposal is prudent and efficient and have therefore not included an allowance for reliability capex in our decision.

Our findings are:

- Evoenergy has not demonstrated that its proposed demand-driven capex is prudent and efficient on the basis that:
    - Evoenergy relies on deterministic planning standards for demand-driven augmentation proposals. We consider this practice is overly conservative, with Evoenergy proposing augmentation measures when the risk of unserved energy remains minimal–earlier than would be efficient to do so.
    - In the case of the proposed Molonglo zone substation and feeders, Evoenergy's forecast of demand in the Molonglo Valley district is currently subject to considerable change. We consider it would be more appropriate to consider the prudency and efficiency of the proposed augmentation measure once there is greater certainty on the load that would need to be supplied.
- Evoenergy proposed non-demand-driven network capex justified and is reasonably likely to reflect prudent and efficient costs.
- With the exception of one program, the proposed secondary systems capex justified and is reasonably likely to reflect prudent and efficient costs.

- Evoenergy has not demonstrated that its proposed capex for chamber substation SCADA and distribution substation monitoring (reliability capex) is prudent and efficient. This is on the basis that Evoenergy has not demonstrated how it has incorporated the forecast benefits into its overall proposal.

B.2.3 Reasons for our position

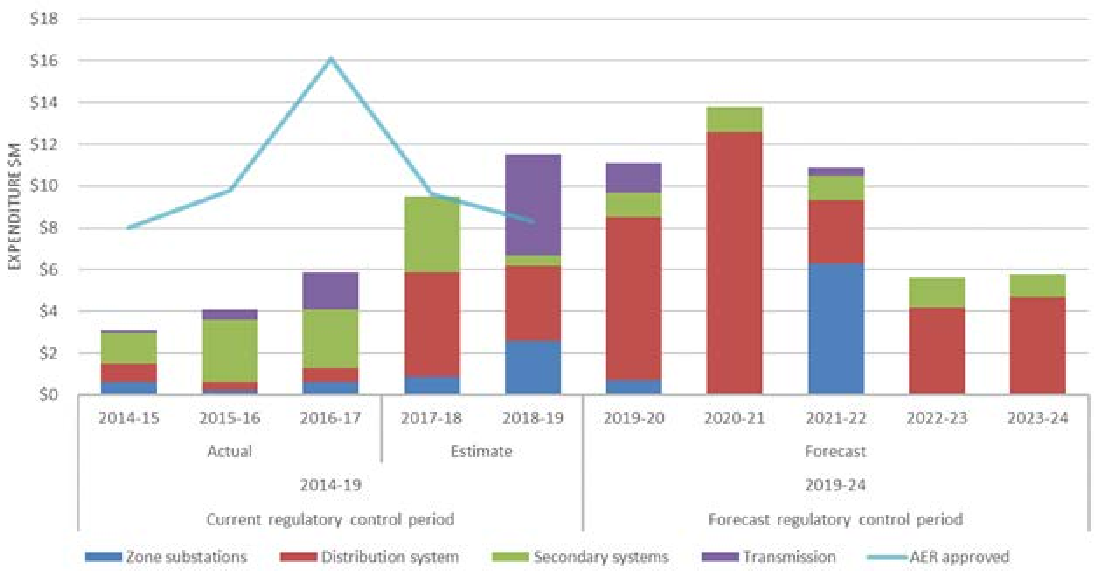
In coming to our position, we have considered the trend of historical and forecast expenditure, the accompanying demand forecast and asset utilisation. We then focused on the project documentation accompanying Evoenergy's proposal and any further information Evoenergy provided on its network and secondary systems projects.

Trend analysis

The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.[36] Our use of trend analysis is to gauge how Evoenergy's historical actual augex compares to its expected augex for the 2019-24 regulatory control period.

Figure 5.2 shows Evoenergy's actual/estimated augex since 2014-15 and its forecast augex for the 2019-24 regulatory control period, and the previously approved augex amount.

Figure 5.2 – Evoenergy historical and forecast augex ($2018-19)



Source: Evoenergy proposal Attachment 5 Capital expenditure, pages 5–52, 53.

Figure 5.2 indicates that Evoenergy has forecast an increase in augex in the 2019-24 regulatory control period. Evoenergy forecasts an average annual augex increase from

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

$6.7 million per annum in the 2014-19 regulatory control period to $9.3 million in the 2019-24 regulatory control period. The volume of forecast zone substation and distribution level augmentation are the drivers of the higher forecast expenditure. Over the 2014-19 regulatory control period, Evoenergy expects to underspend the allowance of $51.7 million by 35 per cent.

An increasing or decreasing trend in total augex by itself is not enough for us to determine whether a distributors' proposed augex is prudent and efficient. We must assess whether Evoenergy's augex proposal is justified and would form part of a total forecast capex allowance that reasonably reflects the capex criteria.

Demand forecast

Peak demand is a fundamental driver of a distributor's forecast augex. Evoenergy must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. We have considered Evoenergy's peak demand forecast relative to the Australian Energy Market Operator's (AEMO) independent forecast of ACT peak demand.

In summary, we consider Evoenergy's system peak demand forecasts to be reasonable. It forecasts peak demand growth to be negative in both the summer and winter periods between 2018 and 2024. AEMO also forecasts negative growth in summer peak demand, but in contrast, forecasts winter peak demand growth to be positive. We consider that Evoenergy's forecast of negative system peak demand growth indicates that forecast demand-driven augmentation should be minimal, addressing only localised peak demand pressures that are forecast to arise.

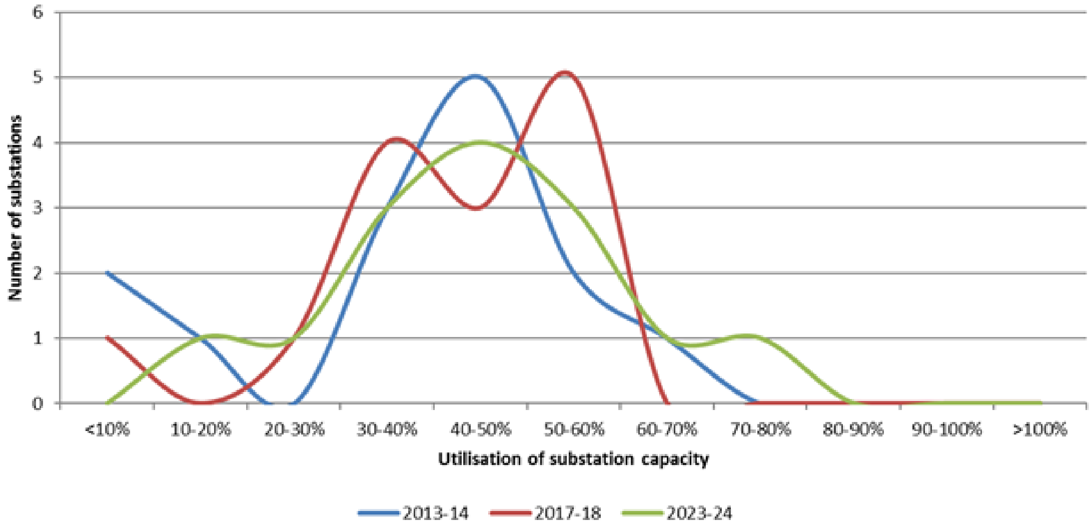
Our review of the peak demand forecasts is outlined in Appendix E.

Asset utilisation

To examine the impact of a maximum demand on the need for network augmentation, we have looked at network utilisation. Network utilisation is a measure of the installed network capacity that is, or is forecast to be, in use. Where utilisation rates decline over time (such as from a decline in maximum demand), it is expected that total augex requirements would similarly fall.

Figure 5.3 shows Evoenergy's zone substation utilisation between 2013-14 and 2017-18, and forecast utilisation in 2023-24 (at the end of the regulatory control period). Between 2013-14 and 2017-18, there has not been a significant shift in the utilisation profile, more substations are operating between 50 to 60 per cent of capacity, but fewer at 60 to 70 percent. The forecast indicates that utilisation rates of some zone substations are likely to increase, but not to levels that would necessitate augmentation.

Figure 5.3 – Evoenergy's zone substation utilisation 2013-14 and 2017-18 actual, and 2023-24 forecast



Source: AER analysis, Evoenergy's reset RIN.

Taken together with Evoenergy's forecast of declining demand growth, this suggests there is sufficient capacity in most areas of its network, such that significant investment should not be required.

Review of network augmentation projects

We have reviewed a variety of Evoenergy's network augmentation proposals, including demand, replacement and compliance-driven projects. We reviewed the project justification reports provided in support of each project to assess whether these programs are prudent and efficient.[37] Separately, we have reviewed the supporting material accompanying the proposed secondary systems and reliability capex. We have also considered the likely effects of the proposed expenditure on the entire regulatory submission (i.e. capex or opex savings, increase in productivity, etc.).

As discussed below, Evoenergy has not justified a number of demand-driven augmentation projects will be required in the 2019-24 regulatory control period.

On the other hand, the business cases supporting replacement and compliance driven projects do justify the proposed expenditure in these areas.

Demand-driven augmentation projects

We have reviewed Evoenergy's demand-driven augmentation projects, and have concluded that Evoenergy relies on pre-determined standards (called 'deterministic standards') for zone substation and high voltage line augmentation projects.

Evoenergy's application of deterministic standards

[37] NER, clauses 6.5.7(c)(1) and 6.5.7(c)(2).

We have reviewed a sample of large augmentation projects that Evoenergy proposed to undertake in the 2019-24 regulatory control period. Our review of these demand driven augmentation projects is detailed in the following sections of this report. However, from the project justification documentation provided, we note Evoenergy's statements that its Distribution Network Augmentation Standards set out a process to apply deterministic standards to augment its network:[38]

> Evoenergy's planning standards are determined on an economic basis but expressed deterministically so that peak demand can be met with an appropriate level of backup should a credible contingency event occur.

From our review of the project justification reports and modelling, we understand this statement to mean that if Evoenergy forecasts peak demand to exceed specified thresholds in an area, it must apply some measure to ensure sufficient network capacity remains in place ('expressed deterministically'). Evoenergy will then determine its preferred measure, selecting the lowest net present cost solution from a range of potential options (the 'economic basis').

Evoenergy's use of deterministic standards is also highlighted in its asset management and governance documentation:[39]

> As a starting point, deterministic criteria are used to identify parts of the network where demand may exceed supply capacity.
>
> …
>
> Evoenergy supports the deterministic methodology by using risk-based and probabilistic methods.

The specified thresholds set out in the deterministic standards that Evoenergy applies are as follows:[40]

- Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 50% PoE[41] under N-1 conditions exceeds the two-hour emergency rating.
- High voltage lines must be augmented or demand management solutions provided if the forecast 50% PoE feeder exceeds firm ratings. Whereby the firm feeder ratings vary depending on the feeder configurations.[42]

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38 Evoenergy, Project justification report - Molonglo Valley 11 kV Feeders - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 10.

39 Evoenergy, Attachment 1: Asset management and governance - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, pp. 1-18.

40 Evoenergy, Project justification report - Molonglo Valley 11 kV Feeders- Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, pp. 10-11.

41 Probability of exceedance – 50% PoE indicates a level of peak demand expected to be realised once every two years.

These statements, and the supporting analysis provided by Evoenergy, highlight the use of deterministic standards as the justification for the demand driven augmentation projects.

We recognise that Evoenergy does not apply a purely deterministic approach to network augmentation. However, Evoenergy has not demonstrated that its application of deterministic standards would result in augmentation proposals that are prudent and efficient and which would form part of a total capex allowance that reasonably reflects the capex criteria. Deterministic planning relies on a pre-determined set of triggers for initiating augmentation works. The advantage of deterministic standards is that they are easy to understand and relatively easy to apply. However, they are intrinsically less efficient as they do not consider the individual circumstance (cost, benefit and risk) of the project or program in question.

In addition, deterministic standards must also be designed to accommodate all foreseeable contingencies. This means that they must be sufficiently conservative so as to cater for a wide range of circumstances. This conservatism results in increased overall costs when compared to individual project evaluations.

A useful example is with CitiPower where, in defining deterministic standards in its Distribution Annual Planning Report, notes that a strict use of the approach may lead to inefficient outcomes:[43]

> Deterministic planning standards: this approach calls for zero interruptions to customer supply following any single outage of a network element, such as a transformer. In this scenario any failure or outage of individual network elements (known as the "N-1" condition) can be tolerated without customer impact due to sufficient resilience built into the distribution network. A strict use of this approach may lead to inefficient network investment as resilience is built into the network irrespective of the cost of the likely interruption to the network customers, or use of alternative options.

Evoenergy propose a number of projects, the purpose (benefit) of which is to ensure that there is sufficient capacity on the network to meet electricity demand on high-demand days, and in the event of an outage on parts of the network. Of the sample of projects we have reviewed (discussed below), it would appear that many would be more appropriate to undertake during the 2024-29 regulatory control period rather than the upcoming 2019-24 regulatory control period, should demand be realised as forecasted. This is because, based on Evoenergy's calculations, the value of unserved energy remains particularly low in the absence of augmentation. This would indicate that the proposed augmentation projects have a relatively low benefit.[44] Evoenergy

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[42] One feeder tie - load to 50% of thermal capacity; two or more feeder ties - load to 75% of thermal capacity. Other feeder arrangements have alternative firm ratings.

[43] CitiPower, Distribution annual planning report, December 2017, p. 22.

[44] Unserved energy refers to the electricity load that the network would not supply to customers in the event of peak demand and/or an outage on a part of the network.

recognised the low value of unserved energy, for example, with respect to its project 'Supply to Canberra CBD':[45]

> The 'Do Nothing' option would result in insufficient network capacity in the area to meet demand during a contingency event.
>
> The value of energy at risk is estimated to be approximately $1,361 over a five year period based on the probability of a contingency event at the same time as demand exceeding firm capacity.
>
> Despite, the relatively low value of energy at risk, the Do Nothing option would result in Evoenergy breaching its Distribution Network Augmentation Standards and thus its obligation to provide a reliable and secure power supply.

Our view on Evoenergy's deterministic standards is shared by CCP10:[46]

> …the planning standards that underpin the timing of the development of major new distribution assets appears to be conservative, encouraging significant expenditure before the impact of demand management, consumer demand response and more progressive network risk management approaches can take effect. This may be an outcome of the rather proscriptive approach taken under the Utilities Act – 2000 (ACT), and we encourage Evoenergy to work with the ACT government to develop a more reflective approach to network security and risk management.

We confirmed with Evoenergy whether the deterministic standards it applies are required under ACT legislation or internally imposed. Evoenergy explained that:[47][48]

> Reliability targets are set by the ACT Utilities Technical Regulator – refer ACT "Utilities (Electricity Distribution Supply Standards Code) Determination 2013". These are:
>
> - SAIDI = 91.0 minutes
> - CAIDI = 74.6 minutes
> - SAIFI = 1.2
>
> The electricity distribution network in the ACT has been designed and constructed to meet these targets by way of meshed HV and LV networks.

Evoenergy explained in order to meet these targets, its assets are loaded in accordance with its internal distribution standards to ensure:[49]

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45 Evoenergy, Project justification report – Supply to Canberra CBD - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 12.

46 CCP10, *Advice on Evoenergy Proposal*, 16 May 2018, p. 7.

47 Evoenergy, Response to information request #024, May 2018, pp. 1–2.

48 SAIFI: System average interruption frequency index; SAIDI: System average interruption duration index; CAIDI: Customer average interruption duration index

> …capacity is available in the event of planned or unplanned outages. Loading above these levels risks unserved energy and breaches of the reliability targets.

We recognise that the reliability targets may be more onerous than those set by other jurisdictions, however we are not satisfied that Evoenergy must necessarily apply its own deterministic standards in order to ensure compliance with these targets. Evoenergy has not demonstrated to us that to move away from deterministic standards would significantly increase the likelihood that the reliability targets would be breached. Further, we do not consider that the use of deterministic standards are a regulatory requirement or requirement under the NEL.

Application of probabilistic planning

We consider that the forecast for demand-driven augmentation projects should better take into account the individual circumstances of a project, through an approach referred to as 'probabilistic planning'. At its heart, probabilistic planning involves assessment of the costs and benefits of a range of options. The assessment of risk in terms of probabilities and consequences is also a key feature of probabilistic planning. In discussing its application of probabilistic planning, CitiPower state:[50]

> The quantity and value of energy at risk … is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:
>
> - the cost of providing additional network capacity to remove constraints; and
> - the cost of having some exposure to loading levels beyond the network's capability.
>
> In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

Probabilistic planning is a more intensive and therefore costly process to apply than the use of deterministic standards, as it requires more data and greater levels of analysis. As such, probabilistic planning is still predominantly utilised for larger projects in the Australian electricity sector. Nevertheless, we consider that it is important for a distributor to have regard to the economic balance between the cost of providing additional network capacity, and the cost of having some exposure to loading levels beyond the network's capability. Under a probabilistic approach, if the distributor

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49 Evoenergy, Response to information request #024, May 2018, p. 2.

50 CitiPower, Distribution annual planning report, December 2017, pp. 22–23.

concludes the value of the unserved energy is lower than the annualised cost of the augmentation measure, the distributor would choose to bear the risk that energy will be unserved. Therefore, under a probabilistic planning approach, an augmentation solution is less likely to be proposed, resulting in a more efficient use of the existing assets.

Probabilistic planning and risk assessment is consistent with good electricity industry practice.[51] International standards ISO 55001[52] and ISO 31000[53] support the use of probabilistic planning, and have been widely adopted throughout the industry. CitiPower[54], Powercor[55], AusNet Services[56], United Energy[57], Endeavour Energy[58], and SA Power Networks[59] currently are certified or moving towards certification to ISO 55001 for asset management.

Evoenergy has identified that is also certified to ISO 55001 for asset management.[60] As part of its submission documentation, Evoenergy identified that it has significantly reduced reliance on deterministic planning criteria in recent years.[61] This reduced reliance on deterministic planning is consistent with the continual improvement processes contained within ISO 55001. We commend Evoenergy for reducing reliance on deterministic standards, and recognise that Evoenergy does apply risk-based probabilistic methods. However, we note that Evoenergy's major augmentation projects are often proposed because the 'do nothing' option breaches its Distribution Network Augmentation standards, which incorporate deterministic standards.[62] They do not appear to be primarily driven by the risk based assessments that are intrinsic to ISO 55001 or ISO 31000.

In our last decision, we expressed concern with Evoenergy's (then ActewAGL) application of deterministic standards.[63] While we continue to hold these concerns, in the absence of Evoenergy adopting a pure probabilistic planning approach, we are

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51 Probabilistic planning and risk assessment is also a requirement under the Regulatory Investment Test. AER, Regulatory investment test for distribution – Application Guidelines, September 2017. Section 14, pp. 48–50.

52 ISO 55001 calls for the implementation of risk-based decision making process and also notes the effectiveness of addressing asset and financial risks together.

53 ISO 31000 is a risk management guideline and provides principles, framework and a process for managing risk.

54 CitiPower, Distribution annual planning report, December 2017, p. 60.

55 Powercor, Distribution annual planning report, December 2017, p. 71.

56 AusNet Services, Distribution annual planning report, December 2017, p. 93.

57 United Energy, Asset management plan 2016 – 2025, April 2015, p. 9.

58 Endeavour Energy, 2017 Distribution annual planning report, December 2017, p. 11.

59 SA Power Networks, SA Power Networks distribution annual planning report 2017/18 to 20201/22, December 2017, p. 43.

60 Evoenergy, Attachment 1: Asset management and governance - Regulatory proposal for the ACT electricity distribution network 2019–24 January 2018, pp. 1-1, 1-5.

61 Evoenergy, Attachment 1: Asset management and governance - Regulatory proposal for the ACT electricity distribution network 2019–24 January 2018, p. 1-18.

62 Evoenergy, Project justification report – Supply to Canberra CBD - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 12.

63 AER, Final decision ActewAGL distribution determination – Attachment 6 – Capital expenditure, April 2015, pp. 6-42–6-44.

open to considering further information, as part of Evoenergy's revised regulatory proposal that demonstrates how:

- it has evaluated its internal planning standards in the context of good industry practice, including with respect to the international standards noted above.
- it has evaluated its internal planning standards and determined what standards and processes are required to efficiently meet jurisdictional requirements.
- the findings from the evaluations above are reflected in its augmentation proposals.

Review of demand-driven Augmentation projects

We have reviewed a number of Evoenergy's proposed demand-driven augmentation projects, our views on these projects are discussed below.

Proposed projects with a low value of unserved energy

We have identified that for a number of augmentation projects, Evoenergy's forecast of the value of unserved energy would remain particularly low in the absence of any augmentation measure.

We have not considered the following projects in detail, but consider these projects would be more appropriately deferred to the 2024-29 regulatory control period, because the value of unserved energy in the 2019-24 regulatory control period is lower than the annualised cost of the proposed augmentation measure:

- Supply to Canberra City and Dickson ($2.9 million)[64]
- Supply to Kingston ($712,950)[65]
- Supply to Canberra CBD ($892,600)[66]
- Supply to Pialliago ($3.0 million)[67]
- Supply to Gungahlin Town Centre ($2.8 million)[68]
- Supply to Belconnen ($2.4 million)[69]

Consistent with our view that Evoenergy should adopt probabilistic planning and the implications in assessing a projects benefit, we do not consider that these projects reasonably reflect the costs that a prudent operator, acting efficiently, would require to achieve the capex objectives.

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[64] Evoenergy, Appendix 5.27 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 13.
[65] Evoenergy, Appendix 5.28 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 16.
[66] Evoenergy, Appendix 5.31 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 12.
[67] Evoenergy, Appendix 5.32 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 13.
[68] Evoenergy, Appendix 5.33 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 12.
[69] Evoenergy, Appendix 5.35 - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 1, 12.

We are open to considering further information from Evoenergy, as part of its revised regulatory proposal, to demonstrate how the risks of undertaking these projects at the beginning of the 2024-29 regulatory control period are such that it would be efficient and prudent to do so in the 2019-24 regulatory control period.

Molonglo Valley zone substation, ($6.2 million) and Molonglo Valley feeders ($4.5 million)

Evoenergy expects that over the next 20 years, land releases will result in new suburbs being built in the Molonglo Valley district. Evoenergy expects the development result in a total population of 55,000, with current development proceeding at approximately 1000 dwellings per annum.[70] To supply this load, Evoenergy has proposed to construct a new 132/11kV zone substation in the Molonglo Valley with future 11kV feeders from the zone substation to serve the residential areas as they develop.

We reviewed the supporting information, and noted that Evoenergy forecasted the value of unserved energy over the 2019–24 regulatory control period to be approximately $2,000 if no augmentation occurs.[71] On this basis, the proposed works are not justified, as the value of the load at risk is substantially less than the cost of the proposed works. Consistent with our views above regarding projects with a low value of unserved energy, we considered that augmentation measures would not be required.

Evoenergy explained that the reported load at risk in this instance is not a true reflection of a scenario where no augmentation occurs, rather it assumes that an extension of the Black Mountain, Streeton and Hilder feeders to supply the greenfield development would occur.[72] Evoenergy estimates the cost of these feeder extensions to be in the order of $4.055 million.

Evoenergy recently provided updated information on its Molonglo Valley demand forecast based on updated information from developers,[73] and has indicated that development of areas may occur ahead of the schedule assumed in its regulatory proposal.[74] Evoenergy also describes its load forecasts as being ‘very dynamic’, with development proceeding at a rapid pace and the size of proposed developments increasing.[75] We recognise the dynamic nature of Evoenergy’s forecast, as it provided us with further revisions to its updated forecast within a one-week period.

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70 Evoenergy, Attachment 5 Capital expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, pp. 54-55.

71 Evoenergy, Appendix 5.23 Molonglo zone substation project justification report - Regulatory proposal for the ACT electricity distribution network 2019–24 January 2018, p. 13.

72 Evoenergy, Response to information request #037, August 2018, pp. 1-2.

73 Evoenergy, Response to information requests #037 and 039, August 2018.

74 Evoenergy, Response to information request #037, August 2018, p. 2.

75 Evoenergy, Response to information request #039, August 2018, p. 7.

We reviewed Evoenergy's updated Net Present Value modelling. On the information before us, it would appear that Evoenergy may need to revise the timing and scope of the Molonglo Valley project. We consider it would be more appropriate to review the prudency and efficiency of the Molonglo Valley project in the following a revised proposal, once there is greater certainty on the load that would need to be supplied.

We recognise that Evoenergy will be required at a minimum to extend the length of existing feeders to the Molonglo Valley district, and have included Evoenergy's forecast of $4.055 million in our alternative forecast.

Project to defer construction of Strathnairn zone substation ($1.7 million, plus $1.8m for demand management (opex))

Evoenergy proposed to extend the existing 11kV O'Loghlen feeder to supply the first stage of Strathnairn, and engage in demand management, to defer construction of a zone substation in the Strathnairn area.[76] We reviewed the supporting documentation modelling and identified that on feeders surrounding the Strathnairn area, there was available capacity of 23.6MW (summer) and 21.1MW (winter), which would be sufficient to manage the increase in load.[77]

Evoenergy explained that this available capacity was based on an assumption that all seven feeders in the West Belconnen district are available to supply Strathnairn, whereas only two feeders, Latham and Macrossan, are available to supply the area.[78]

We note that it is common practice for distributors to rearrange adjacent feeders to share load between them. This can be performed using existing switchgear or by adding in new switching into the system. We consider there is potential to reconfigure feeders to transfer load currently on the Latham and Macrossan feeders to adjacent feeders with spare capacity. However, we recognise that a feeder reconfiguration may not be sufficient to address the forecast load in the Strathnairn area. We are satisfied that the proposed capex and the associated opex step change for demand management are prudent and efficient, and have included these expenditures in our alternative forecast. We note the acceptance of the opex step change in Attachment 6, Section 6.4.3.

For a future proposal for Strathnairn zone substation, would expect to see evidence that the potential to utilise available capacity on surrounding feeders has been accounted for through load transfers.

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76 AER analysis; Evoenergy, Appendix 5.24 Supply to Strathnairn project justification report - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 4.

77 AER analysis; Evoenergy, Appendix 5.24 Supply to Strathnairn project justification report - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 7.

78 Evoenergy, Response to information request #037, August 2018, p. 4.

Review of non-demand driven augmentation projects

We consider that Evoenergy has justified its proposed replacement and compliance-driven projects. It has undertaken an appropriate analysis of options in its business cases for these projects, which include:

- **Decommission Fyshwick Zone Substation and supply to Fyshwick ($3.8 million)** – Evoenergy proposed to retire the Fyshwick zone substation and service the existing load through three new feeders from the East Lake zone substation.[79] Evoenergy states that East Lake zone substation was established in 2013 in part to enable transfer of the Fyshwick load and retire the Fyshwick zone substation.

  Evoenergy's forecast of capex associated with the three new feeders justified and is reasonably likely to reflect prudent and efficient costs. We are satisfied with Evoenergy's explanation that the assets at Fyshwick substation would otherwise require replacement in the 2019–24 regulatory control period, and that Evoenergy's repex forecast does not contain any allowance for the replacement of those assets.

- **Second supply to ACT (additional reactive support equipment, $1.5 million)** – Evoenergy has proposed to install additional reactive support equipment, which is required in the northern part of its network to maintain supply voltage levels following a special contingency event.[80] The key driver of this project is to meet the requirements of the ACT Electricity Transmission Supply Code (the Supply Code), which specifies requirements to supply electricity at certain levels following the contingency event.[81]

  We have reviewed the proposed unit rates for 10MVAr capacitor banks and circuit breakers and are satisfied that the proposed costs are reasonable, recognising installation costs. We also recognise that Evoenergy is required to undertake the work in accordance with the Supply Code.

Review of Secondary systems augex and reliability capex

Evoenergy proposed $6 million for secondary systems augex, which includes expenditure on a number of projects including downstream communications infrastructure and cybersecurity measures. Evoenergy has justified that the majority of these projects are prudent and efficient and would form part of a total forecast capex allowance that reasonably reflects the capex criteria.

We have reviewed Evoenergy’s proposed capex for chamber substation SCADA ($1.5 million) augmentation. We have considered this project in conjunction with the proposed reliability capex for distribution substation monitoring ($6.2 million), due to the similarities between both projects. Evoenergy has not justified either of these

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79 Evoenergy, Appendix 5.21 Decommission Fyshwick zone substation project justification report, January 2018, p. 4.

80 Evoenergy, Appendix 5.25 Second supply to the ACT project justification report, January 2018, p. 4.

81 Evoenergy, Appendix 5.25 Second supply to the ACT project justification report, January 2018, p. 5.

projects, because it has not demonstrated the benefits of the projects have been reflected elsewhere in its regulatory proposal (for instance through reduced opex).

Evoenergy explained that it has obligations to maintain and control the quality of supply through the distribution and transmission networks under its control projects.[82] It has explained that with the increasing penetration of micro-generators such as PVs, fixed batteries and electric vehicle batteries, there will be an increasing need to extend network monitoring to lower levels of the distribution network. The substation monitors would provide Evoenergy with a permanent site solution that delivers real time data that Evoenergy will use to address power quality issues on a more proactive basis than current methods.[83]

We asked Evoenergy to identify and provide modelling showing the costs and benefits of these programs. The modelling indicated that Evoenergy expected both programs to generate significant savings on reliability (reduction in unserved energy), replacement and augmentation (better utilisation of existing assets), safety and opex (avoidance of manual network monitoring). [84] We also sought further information from Evoenergy to detail how it has incorporated these benefits into the overall regulatory proposal for the 2019–24 regulatory period. Evoenergy submitted that:[85]

> The quantifiable benefits of the projects have been considered in Evoenergy's expenditure and STPIS proposals in the context of the deterioration in Evoenergy's recent STPIS performance and that our proposal represents a significant reduction in repex relative to historical 'bottom-up' levels.
>
> …
>
> The avoided polylogging costs relate to avoided costs in relation to the expected increase in incidents and customer complaints arising from increased DER penetration, as responding to customer complaints attracts significant costs in polylogging.

Evoenergy has not demonstrated that it has accounted for the benefits of this expenditure in the overall proposal. This is because it has not shown quantitatively how its overall regulatory proposal is lower than it otherwise would be in the absence of these projects.

We note that Evoenergy has incentives to undertake these programs under the EBSS, CESS and STPIS due to the reduced expenditures it expects to incur elsewhere. These programs would provide Evoenergy with enhanced network capability to manage the operation and planning of the network in addition to ensuring compliance

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82 Evoenergy, Attachment 5 Capital expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, pp. 5–59.

83 Evoenergy, Response to information request #011 - Project justification report Distribution substation monitoring project, April 2018, p. 1.

84 Modelling provided in response to information request #028.

85 Evoenergy, Response to information request IR028, June 2018, p. 2.

with regulations. We consider that, in the absence of evidence that Evoenergy has factored these programs into the proposal, Evoenergy could appropriately fund these programs through the respective incentive schemes.

We are open to considering further information from Evoenergy, as part of its revised regulatory proposal, to demonstrate how it has identified the benefits of this expenditure and how it has accounted for these in its overall regulatory proposal, in particular by providing:

- analysis showing the counterfactual – Evoenergy's proposal on opex, augex, repex, etc. in the absence of the monitoring programs.
- evidence supporting the counterfactual. For example, evidence that replacement costs would have remained around historical levels in the absence of the monitoring programs.

In support of the projects, Evoenergy provided evidence that the presence of distributed generation (solar PV) has led to an increase in substantiated complaints from customers about high voltages.[86] Notably, Evoenergy shows that, between 2012-13 and 2016-17, the number of substantiated high voltage complaints was 20–40 per year; however, this had increased to 238 complaints in 2017-18 year-to-date.

With regard to the increase in power quality complaints, Evoenergy has suggested this is in part due to changes in customer behaviours and improved reporting processes.[87] Nevertheless, we accept that Evoenergy will be required to incur costs to manage voltage issues, and that these costs will increase in the future. However, we do not consider the information before us provides an accurate representation of the voltage risks that Evoenergy is currently managing on its network. We invite Evoenergy to provide information on historical expenditure that demonstrates expenditure it has incurred in managing power quality risks.

B.3 Forecast customer connections

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet the new customer demand. The connecting customer will generally provide a capital contribution towards the cost of the new connection assets, which decreases the revenue that is recoverable from all consumers.

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86 Evoenergy, Project justification report Chamber substation SCADA augmentation v0.2, April 2018, p. 3; Evoenergy, Project justification report Distribution substation monitoring project, April 2018, p. 3.

87 Evoenergy response to information request #024, May 2018, pp. 8–9.

B.3.1 Evoenergy's proposal

Evoenergy propose $85.7 million ($2018–19) for connections capex for the 2019–24 regulatory control period. The forecast is $6.3 million—or 7 per cent—lower than its actual expenditure of $92.4 million in 2014–19.[88]

Evoenergy's forecast connections capex includes:

- net expenditure (costs incurred by Evoenergy) of $57.4 million
- capital contributions of $28.3 million.

Net connections capex is $5.5 million—or 9 per cent—lower than actual expenditure of $62.9 million in 2014–19. We only roll net connections capex into the regulatory asset base when incurred.

B.3.2 Position

Evoenergy has demonstrated that its forecast connections capex of $85.7 million is efficient and prudent, and would form part of a total capex forecast that reasonably reflects the capex criteria. We have therefore included this amount in our substitute estimate of total capex. Table 5.5 summarises Evoenergy's proposed connections capex for 2019-24.

Table 5.5 – Evoenergy's proposed connections capex by category for 2019-24 ($2018-19, million, excluding overheads)

	2019-20	2020-21	2021-22	2022-23	2023-24	2019-24
Net connections capex	6.6	7.1	7.0	7.3	6.8	**34.8**
Capital contributions	5.4	5.7	5.7	5.8	5.6	**28.3**
Total	**16.2**	**17.1**	**17.5**	**17.7**	**17.2**	**85.7**

Source: Evoenergy

88 Evoenergy provided revised connections data to the AER on 5 April 2018. It shows the 2014–19 actual/estimated connections capex to be $92.4 million, including capital contributions of $29.5 million. This compares with $90.6 million and $26.7 million, respectively, as published in the Reset RIN and Evoenergy's proposal. The revised data also shows the 2019–24 forecast connections capex to be $85.7 million, including capital contributions of $28.3 million. This compares with $85.9 million and $26.7 million, respectively, as published in the Reset RIN and Evoenergy's proposal.

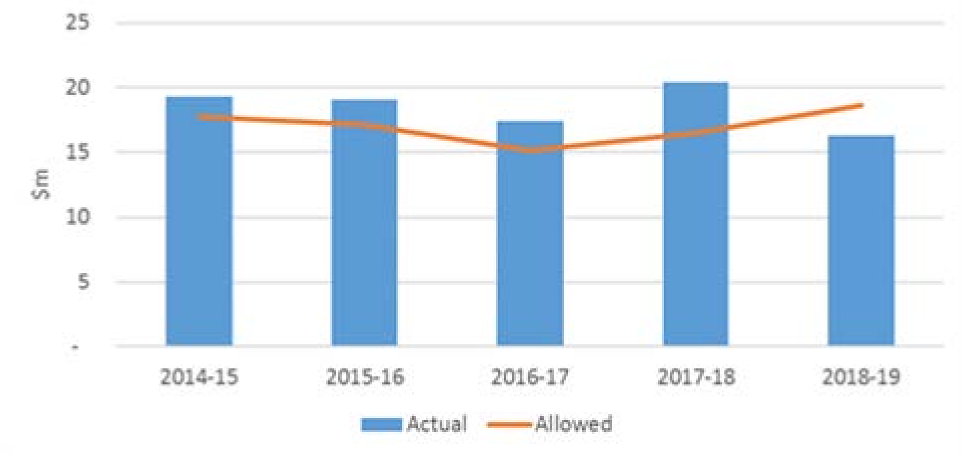
B.3.3 Reasons for our position

In coming to our position, we have looked at Evoenergy's methodology, historical costs and trends and expected customer growth. We have also looked at Evoenergy's forecast capital contributions and its proposed connection policy.[89]

B.3.3.1 Connections capex in 2014–19

Figure 5.4 compares Evoenergy's 2014–19 actual/estimated connections capex with the AER allowance. Evoenergy estimates connections capex of $92.4 million in 2014–19. This is 9 per cent higher than the AER's final determination allowance of $85.1 million.

Figure 5.4 – Annual gross connections capex, actual expenditure compared with AER allowance, 2014–19 (direct costs, $ millions, real $2019)



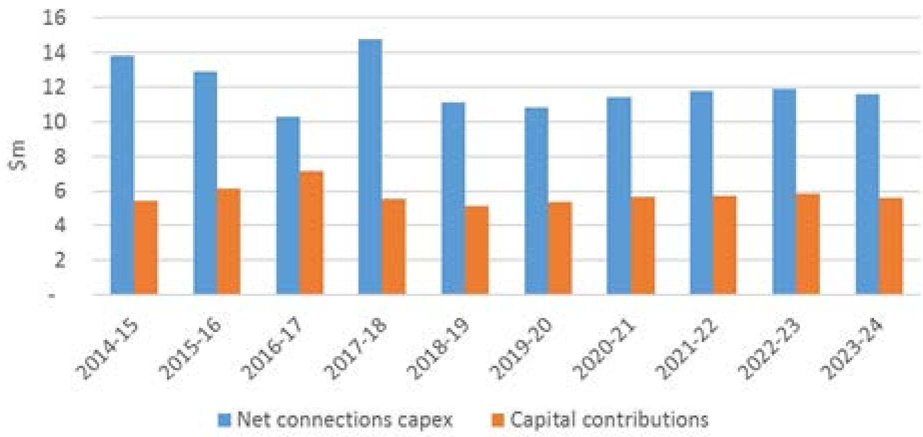
Source: Evoenergy and AER.

B.3.3.2 Forecast connections capex compared with current period

Figure 5.5 compares Evoenergy's 2019–24 forecast net connections capex and capital contributions with actual/estimated expenditure in 2014–19.

[89] Please refer to Attachment 17 of the draft decision for our assessment of Evoenergy's proposed connection policy.

Figure 5.5 – Annual net connections capex and capital contributions, 2014–15 to 2023–24 (direct costs, $ millions, real $2019)



Source: Evoenergy.

Evoenergy's proposed net connections capex and capital contributions for 2019–24 are both lower than the actual/estimated expenditure in the 2014–19 regulatory period. Evoenergy note that the reduction in connections capex compared with historical costs is driven by higher commercial vacancy rates and the expectation that forecast urban infill and new urban development will return to historic averages.[90]

B.3.3.3 Our assessment of forecast connections capex

Evoenergy has used a range of approaches to forecast its connections capex for 2019–24. The forecasting methodology is outlined in *Appendix 5.5: Customer Initiated Works Report*.

Historical costs basis

Evoenergy states that for several connection categories there is no clear market indicator upon which to forecast connections capex. Expenditure for these categories can be highly variable from one year to the next. For these categories, Evoenergy relies on historical average expenditure. These categories include community and associated developments, rural developments, special customer requests and embedded generation—medium to large. In calculating a historical average Evoenergy has removed outlier years that would unreasonably increase forecast capex, and has considered changes to expenditure trends over time. We are satisfied that these forecasts are reasonable.

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[90] Evoenergy, *Appendix 5.5: Customer Initiated Works Report*, p. 13.

Regression forecasting

Evoenergy uses regression analysis to forecast connections categories where it can identify a driver. This includes the forecast capex for industrial and commercial, new urban development, and urban infill categories.

We have some concerns that the regression models used are inadequate and may not the best forecasting tool in the circumstances. This is because the models are based on a limited dataset and the models may lack sufficient explanatory power (that is, have a relatively low adjusted R-squared value) to be considered robust.

To test the regression models we have performed a trend analysis and considered the forecast capex against historical expenditure, trends and expected growth. In performing a trend analysis we have had regard to a number of factors, including historical expenditure in these categories, trends and unit rate analysis. We have also looked at construction forecasts for detached dwellings, multi-unit dwellings and industrial and commercial premises.

Overall, we find that the expenditure predicted by the regression models for 2019–24 and put forward by Evoenergy is consistent with what we would expect to be reasonable expenditure, and therefore satisfies the capex criteria.

Unit rates by volume

For the Services category (relating to simple residential connections) Evoenergy uses an average unit rate multiplied by forecast connections. This is a reasonable approach for high-volume connection categories.

The unit rates for simple residential connections in 2019–24 are on average lower than the average unit rates in 2014–19. We have also assessed forecast residential new connection volumes to be reasonable—our reasons are explained below.

New connections volumes

Figure 5.6 compares Evoenergy's 2019–24 forecast with actual/estimated connections volumes from 2009–10 to 2023–24.

Figure 5.6 – Annual new connection volumes, 2009–10 to 2023–24

Source: Evoenergy, response to information request #020.

Evoenergy forecasts an average of around 1570 new connections per year over the 2019–24 regulatory period. Of these, 1276—or 81 per cent—are residential connections.

Evoenergy has forecast new residential connections based on forecast dwelling approval data provided by BIS Shrapnel.[91] We have compared historical BIS Shrapnel dwelling approval data with Evoenergy's historical residential connections. We find that, on average, Evoenergy's residential connections tend to be higher than BIS Shrapnel's dwelling approval numbers for that year. This is because residential connections includes multi-unit developments, whereas the BIS Shrapnel dwelling approvals series chosen by Evoenergy does not include medium- and high-density dwellings.

Because of this analysis, we are satisfied that the forecast residential connection volumes are reasonable.

For other connection categories, Evoenergy forecast its expenditure following the methodology described above. Evoenergy then estimates connection volumes by dividing forecast expenditure by forecast unit rates. We accept this approach because it is difficult to forecast the number of non-residential new connections, particularly for the smaller distributors. Furthermore, Evoenergy have not used its forecast new connections volumes in its methodology to forecast expenditure, and so its volume forecast does not affect forecast expenditure. However, in arriving at our position we have had regard to industry forecasts including BIS Shrapnel non-residential building commencements and ACT Government indicative land release data to confirm that the volume forecasts are broadly consistent with industry expectations.

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91 BIS Shrapnel, part of BIS Oxford Economics, are a provider of forecasting, modelling and quantitative analysis services.

B.3.3.4 Capital contributions

Capital contributions include the value of assets constructed by third parties that Evoenergy operates, and payments from customers who directly benefit from customer-initiated services. These contributions reduce the amount of capex that Evoenergy recovers from all other consumers.

Evoenergy forecast capital contributions to be $28.3 million for the 2019–24 regulatory period. To arrive at this forecast Evoenergy used the average actual contribution rates for each connection category in 2014–15 and 2015–16 and applied this to its forecast for gross connections expenditure. We have no concerns with this approach and consider that the resulting forecast will contribute to a capex that reasonably reflects the capex criteria. Forecast capital contributions are around 4 per cent lower than the 2014–19 regulatory period.

B.4 Forecast repex

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure;
- a condition assessment of the asset determines that it is likely to fail soon (or degrade in performance, such that it does not meet its service requirement) and replacement is the most economic option[92];
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network; and
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

The majority of network assets will remain in efficient use for far longer than a single five year regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period. Our assessment of repex seeks to establish the proportion of Evoenergy's assets that will likely require replacement over the 2019-24 regulatory control period and the associated capital expenditure.

B.4.1 Evoenergy's proposal

Evoenergy has proposed forecast repex of $91.6 million ($2018-19, excluding overheads). In summary, Evoenergy has submitted that the following needs drive this expenditure:[93]

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[92] A condition assessment may relate to assessment of a single asset or a population of similar assets. High value/low volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

- rapidly changing electricity market;
- ensuring reliability standards are adequately met and safety levels are maintained; and
- meeting requirements in relation to planning and system security regulations.

B.4.2 Position

We do not accept Evoenergy's proposed repex of $91.6 million ($2018-19, excluding overheads). Evoenergy has not demonstrated that its repex forecast forms part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $83.6 million ($2018-19, excluding overheads) in our substitute estimate of total capex. This represents a 9 per cent reduction. In coming to this position, we note:

- Evoenergy's forecast for modelled repex ($55.3 million) lies above our 'repex model threshold' ($47.1 million). Its repex forecast is broadly in line with our modelled results for all asset groups except underground cables.
- If a distributor's forecast exceeds our modelling results, we do not necessarily reject the forecast deterministically. We use our modelling results to target a more detailed bottom-up assessment. If the proposed repex is sufficiently justified and shown to be prudent and efficient, we will accept it. If sufficient justification has not been provided, we can use our modelling results to arrive at a substitute estimate.
- For Evoenergy, our modelling results informed a more detailed bottom-up assessment of the underground cable asset group. Evoenergy is forecasting a significant increase in both repex and replacement volumes for underground cables. In addition, our assessment indicates that Evoenergy has altered its replacement strategy for these assets and its underlying cost-benefit analysis includes conservative assumptions, resulting in an overstated repex forecast for underground cables.
- Evoenergy's forecast for unmodelled repex of $36.3 million ($2018-19) appears reasonable. Six asset categories in the poles, pole top structures and SCADA asset groups account for this unmodelled repex, which is not materially higher than historical trends. Evoenergy spent $35.8 million ($2018-19) on these six repex categories during the 2014-19 regulatory control period. Overall we consider that this repex component is justified and would form part of a total capex forecast that reasonably reflects the capex criteria.

B.4.3 Reasons for our position

We have applied several assessment techniques to assess Evoenergy's proposed repex forecast, as well as considering stakeholder submissions. These techniques include:

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[93] Evoenergy, *Regulatory proposal summary and overview* - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 22.

- trend analysis;
- repex modelling;
- bottom-up and top-down considerations; and
- network health indicator assessment.

Trend analysis

Trend analysis of a distributor's past expenditure allows us to make general observations about how a distributor is performing, as well as to provide a check against our predictive modelling results. This is consistent with the capex factor that requires us to have regard to the actual and expected capital expenditure during any preceding regulatory control period.[94]

For some aspects of our assessment where we have not relied on predictive modelling, we have considered historical levels of expenditure to assess forecast repex. In particular, where past expenditure was sufficient to achieve the capex objectives, this can be a reasonable indicator of whether an amount of forecast repex is prudent and efficient, and whether we would be satisfied this amount forms part of a total capex forecast that reasonably reflects the capex criteria.[95]

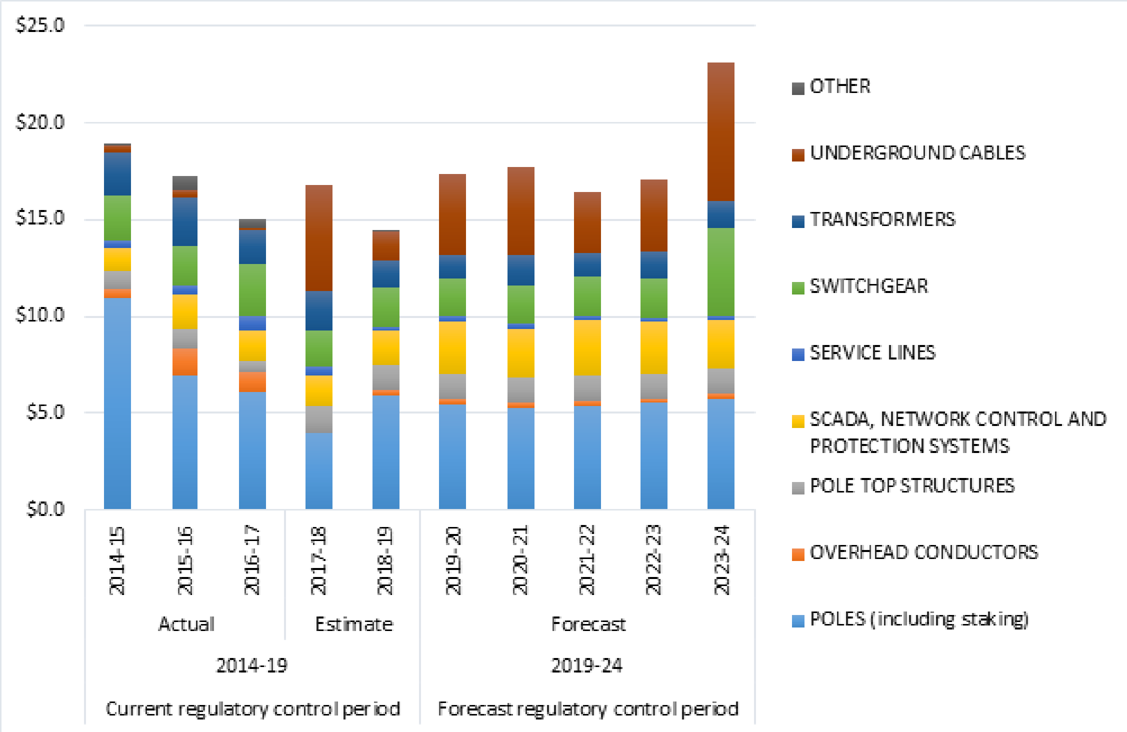
In coming to our position, we had regard to the following trends:

- Evoenergy's proposed repex forecast for the 2019-24 regulatory control period relative to its actual spend in the current regulatory control period (Figure 5.7); and
- Historical vs forecast repex and replacement volume trends at both the asset group and asset category level.

[94] NER, cl. 6.5.7(e)(5).

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

Figure 5.7 – Evoenergy's actual repex vs forecast repex ($2018-19, million, excluding overheads)



Source: AER analysis

Figure 5.7 indicates that Evoenergy has forecast a slight increase in repex in the 2019-24 regulatory control period. Average annual repex is forecast to increase from $16.5 million per annum in the 2014-19 regulatory control period to $18.3 million in the 2019-24 regulatory control period. A forecast step up in 2023-24 is primarily driving this trend. We have applied repex modelling and considered other material submitted by Evoenergy to assess this increase.

CCP10 noted in its submission that repex is the largest expenditure item for Evoenergy. CCP10 also noted that it expects forecast repex for the 2019-24 period to be higher than Evoenergy's actual repex during the 2014-19 regulatory control period.[96] Overall, CCP10 was "generally satisfied with the repex forecast", noting that repex as a proportion of total capex was lower for Evoenergy than for other network businesses.[97] The ACT Energy Consumers Policy Consortium made the only other submission on Evoenergy's 2019-24 forecast capex proposal and did not reference its repex forecast.

96 CCP10, *Advice on Evoenergy proposal,* 16 May 2018, p. 6.

97 CCP10, *Advice on Evoenergy proposal,* 16 May 2018, p. 6-7.

Repex modelling

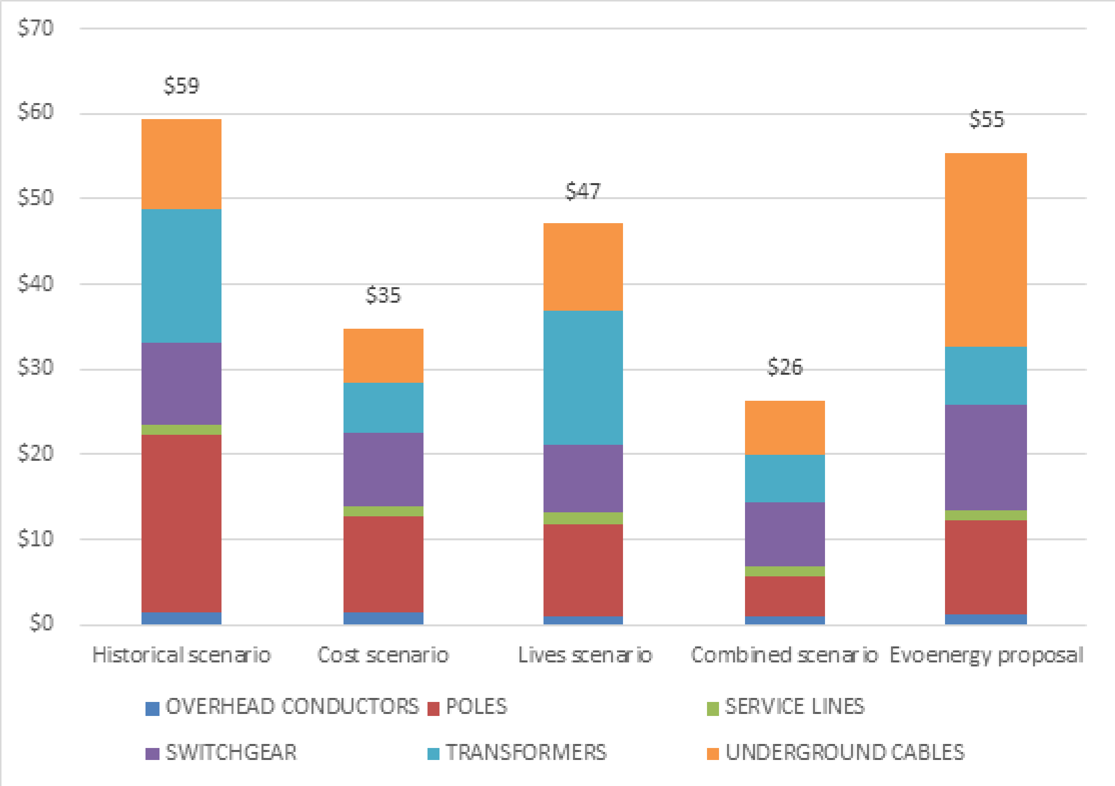
We can use the repex model to advise and inform us where to target a more detailed bottom-up review and define a substitute estimate if necessary. We can also use the model to compare a distributor against other distributors in the NEM[98]. In coming to our position, we also had regard to feedback from distributors on some of the underlying assumptions and modelling techniques.

We recognise that it may be difficult to model some categories of repex. Sometimes the repex model cannot forecast expenditure due to a non-age related reason for the asset replacement (such as a change in jurisdictional safety or environmental legislation) or there may not be sufficient data on particular repex categories. We rely on other evidence to assess the prudency and efficiency of this unmodelled repex.

In coming to our position, we assessed $55.3 million ($2018-19) of Evoenergy's total repex forecast using the repex model. This represents 60 per cent of Evoenergy's total repex forecast of $91.6 million. Figure 5.8 highlights that Evoenergy's modelled repex forecast is 18 per cent above our repex model threshold ('lives scenario').

98 This includes Power and Water Corporation.

Figure 5.8 – Evoenergy's repex model scenarios ($2018-19, million, excluding overheads)



Source: AER analysis

Note: the 'historical scenario' uses historical unit costs and calibrated expected asset replacement lives; the 'cost scenario' uses comparative unit costs[99] and calibrated expected asset replacement lives; the 'lives scenario' uses historical unit costs and comparative expected asset replacement lives;[100] the 'combined scenario' uses comparative unit costs and comparative expected asset replacement lives

Figure 5.8 reveals that Evoenergy's repex forecast for poles, overhead conductors, service lines and transformers is broadly in line with our repex modelling scenarios, while its forecast for switchgear slightly exceeds our scenarios. However, lower forecasts in other asset groups (primarily transformers) are offsetting this discrepancy in the switchgear asset group.

Figure 5.8 also reveals that Evoenergy's forecast repex proposal differs most significantly from our repex modelling scenarios in the underground cable asset group. Evoenergy's repex forecast for underground cables ($22.6 million) is 120 per cent higher than our repex model threshold for that asset group ($10.3 million).

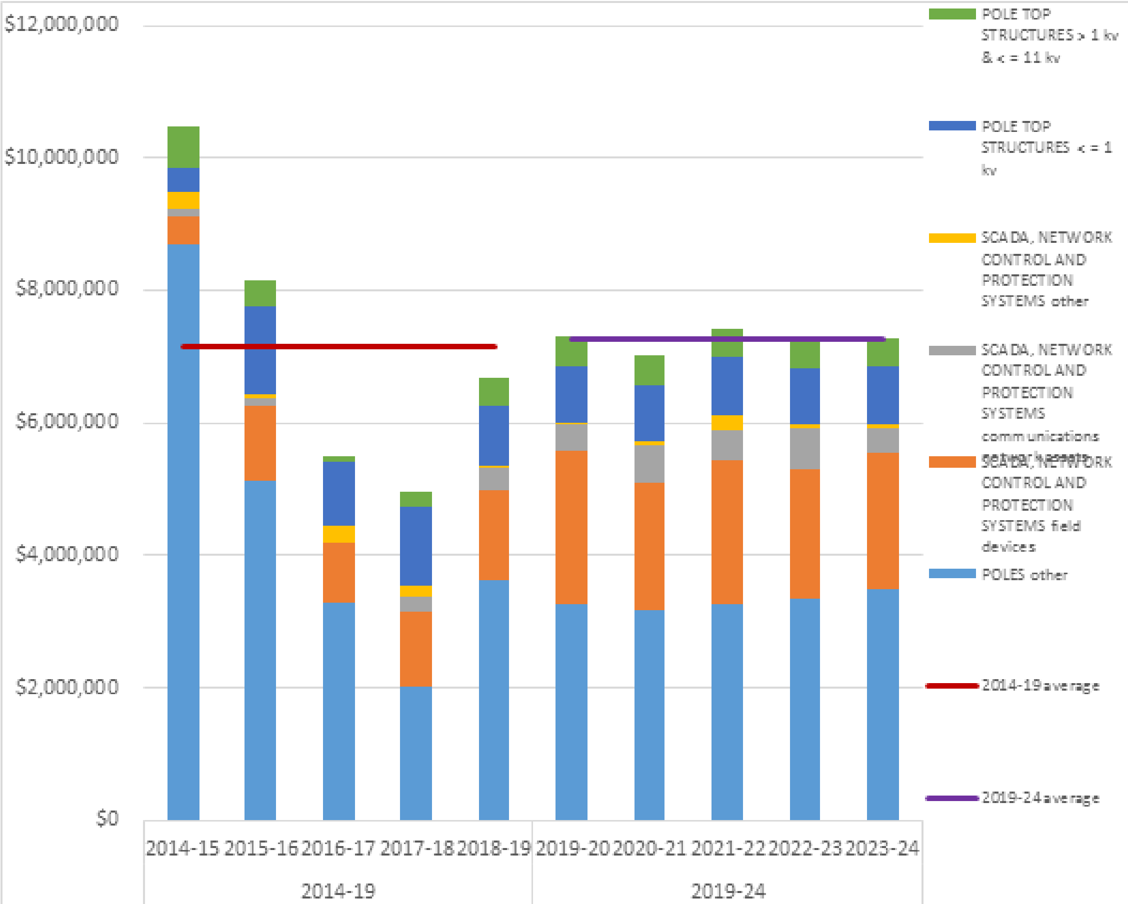
One underground cable category is driving the majority of this discrepancy, while it also contributes to the moderate total repex trend increase identified in Figure 5.7,

99 Minimum of historical, forecast and NEM median unit costs.

100 Maximum of calibrated and NEM median expected asset replacement lives.

particularly in 2023-24. Our repex model results prompted us to send Evoenergy an information request primarily relating to low and high-voltage underground cables.[101] Our consideration of Evoenergy's response and our assessment of its supporting materials are discussed below in 'bottom-up considerations'.

Figure 5.9 – Evoenergy's unmodelled repex trend ($2018-19, excluding overheads)



Source: AER analysis

Evoenergy has forecast $36.3 million of proposed repex for the 2019-24 regulatory control period that cannot be modelled using the repex model. Six asset categories account for this repex amount. Figure 5.9 outlines that the unmodelled repex is expected to remain largely on trend over the 2019-24 regulatory control period. Four asset categories are remaining largely on-trend, while a forecast decrease in repex on 'poles – other' is offsetting a forecast increase in repex on 'SCADA – field devices'.

In response to an information request, Evoenergy indicated that its historical and forecast repex in the 'poles – other' category relates to fibreglass poles.[102] We initially

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[101] AER information request 015, 13 April 2018.

[102] AER information request 017, 18 April 2018.

intended to include this category in the modelled repex analysis. However, Evoenergy is the only distributor that installs fibreglass poles, and we therefore cannot compare its historical and forecast unit costs, and calibrated expected asset replacement lives with other distributors across the NEM. We have therefore included this asset category in our unmodelled repex analysis.

Overall, our position in this draft decision is that Evoenergy's forecast of $36.3 million ($2018-19, excluding overheads) for unmodelled repex forms part of a total capex forecast that we are satisfied reasonably reflects the capex criteria.

Bottom-up and top-down considerations

Bottom-up considerations – underground cables

We sent Evoenergy an information request primarily relating to its repex forecast for low and high-voltage underground cables.[103] We sought supporting material for its proposed low-voltage underground cable replacement program, and the underlying risk reduction calculations[104] and further information relating to its proposed high-voltage underground cable replacement program.

For low-voltage underground cables, Evoenergy's response stated that its "strategies for managing assets are modelled in our asset management decision support database".[105] Evoenergy also outlined that it applies a run-to-failure strategy followed by reactive replacement for its low-voltage underground cables, with the exception of assets with known safety or reliability issues.[106]

Further, Evoenergy stated the "projected repex values in our proposal are based on recent historical experience and were then adjusted downwards following the application of a top-down challenge." Our trend analysis for this individual asset category revealed that both forecast repex and replacement volumes are expected to be largely on-trend over the 2019-24 regulatory control period.

For high-voltage underground cables, Evoenergy's proposal outlined that it was implementing "a significant change to the management strategy of underground cables".[107] Evoenergy plans to change its replacement strategy for these assets from "predominantly reactive approach" to a "condition-based monitoring approach".[108]

Evoenergy also provided feeder health scores, asset risk calculation inputs and assumptions, and additional information in response to our information request.[109] However, it did not provide the underlying risk cost calculations and cost-benefit

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[103] AER information request 015, 13 April 2018.

[104] Evoenergy, *Appendix 5.15: Primary assets – HV underground cables ASP,* November 2017, p. 29.

[105] Evoenergy, *Part 1 response to AER query 015 – Public,* April 2018, p. 2.

[106] Ibid.

[107] Evoenergy, *Appendix 5.15: Primary assets – HV underground cables ASP,* November 2017, p. 2.

[108] Ibid, p. 1.

[109] Evoenergy, *Part 2 response to AER query 015 – Public,* April 2018, p. 2.

analysis for these assets. We typically expect distributors to send these models and calculations in a format that allows us to assess them.

Nevertheless, we assessed the underlying inputs and assumptions that Evoenergy used in its cost-benefit analysis. We found that Evoenergy relied on conservative assumptions to calculate the safety risks in its underlying analysis. In addition, Evoenergy's response indicated that it based its probability of incidence calculation on a qualitative assessment, rather than using historical failure and incident rates for the specific assets being analysed.

To calculate safety risks, Evoenergy used a value for fatality per FTE[110] that is much higher than the values used by other distributors in the NEM. As a result, the quantified safety risks and therefore the quantified benefits of the replacement program are likely to be overstated. The subsequent optimal replacement timing for the underground cables is therefore likely to be later than proposed by Evoenergy. This factor, combined with its significant increase in forecast repex for underground cables in 2023-24 (outlined in Figure 5.7), may lead to significant deferred repex.

To be satisfied that the proposed repex for these assets is prudent and efficient, we need to assess the underlying cost-benefit analysis and relevant calculations. This includes assessing how Evoenergy has calculated the probability of failure and probability of consequence based on historical evidence, and assessing the cost of consequence and the primary risk driving an investment decision. If a safety risk is driving a replacement program, we need to be satisfied that the cost of mitigating this risk is not disproportionately larger than the quantified risk reduction.[111]

Therefore, our position in this draft decision is that Evoenergy's forecast of $55.3 million ($2018-19, excluding overheads) for modelled repex does not form part of a total capex forecast that we are satisfied reasonably reflects the capex criteria. We have included an amount of $47.1 million ($2018-19, excluding overheads) in our substitute estimate of modelled repex and total capex. We derive this reduction of $8.2 million (9 per cent) by reducing Evoenergy's forecast modelled repex threshold to our repex model threshold (Figure 5.8). Our substitute estimate of total repex ($83.6 million) is slightly higher ($0.2 million) due to subsequent modelling adjustments.

[110] Also referred to as value of statistical life.

[111] This approach is consistent with distributors' practice of eliminating risks so far as reasonably practicable (SFAIRP) or reducing risks to a level as low as reasonably practicable (ALARP).

Bottom-up considerations – other

We reviewed the supporting information for several of Evoenergy's key repex programs and projects. Most notably, we analysed Evoenergy's proposed Fyshwick zone substation decommissioning project.

Evoenergy identified that the preferred option for this project was to construct three new express 11kV cable feeders from East Lake to Fyshwick and decommission the existing 66kV Fyshwick assets, rather than replacing the existing assets like-for-like.[112]

We agree with Evoenergy's assessment that installing new assets, rather than replacing the existing 66kV assets, is the most cost-effective option and therefore this option forms part of a total capex forecast that reasonably reflects the capex criteria. Further discussion of this project is discussed in section B.2.

Top-down considerations

Our top-down considerations of Evoenergy's repex forecast include our repex modelling assessment and CutlerMerz's consideration of risk, submitted as Appendix 5.1 of Evoenergy's proposal.[113]

As outlined in the repex modelling section, Evoenergy's modelled repex forecast lies above our modelled repex threshold. However, for most asset groups, Evoenergy compared favourably with other distributors on both unit costs and expected replacement lives.

In our draft and final decisions for Evoenergy's (formerly ActewAGL) 2015-19 regulatory control period, we noted that its capex forecast did not apply a top-down assessment.[114] We also noted that in our view, applying a top-down assessment is a critical part of the process in deriving a forecast capex allowance.[115] We are therefore encouraged that Evoenergy has applied a top-down assessment to its 2019-24 forecast.

CutlerMerz's top-down modelling of Evoenergy's repex forecast considered four scenarios:

1. no planned repex
2. risk minimisation
3. maintaining acceptable risk at least cost
4. bottom up

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112 Evoenergy, *Appendix 5.21, Decommission Fyshwick zone substation,* January 2018, p. 4.

113 Evoenergy, *Appendix 5.1,* Consideration of risk - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018.

114 AER, *Draft decision, ActewAGL distribution determination, 2015-16 to 2018-19, Attachment 6: capital expenditure,* November 2014, p. 6-19.

115 AER, *Draft decision, ActewAGL distribution determination, 2015-16 to 2018-19, Attachment 6: capital expenditure,* November 2014, p. 6-19.

CutlerMerz used this scenario modelling process to execute a top-down challenge to Evoenergy's bottom-up expenditure profile. The top-down modelling undertaken by CutlerMerz revealed that there were opportunities to reduce expenditure to levels below that produced by the bottom-up estimates provided in the Asset Specific Plans, while still maintaining overall network risk.[116]

We are satisfied that Evoenergy has based its total repex forecast on this top-down challenge process and that Evoenergy has included sufficient efficiency and synergy gains in its forecast. This top-down assessment therefore supports our overall view that the majority of Evoenergy's repex forecast is prudent and efficient.

Network health indicators

The condition of assets currently in commission is an indicator of the health of Evoenergy's network, and in turn, its repex requirements. In assessing the health of Evoenergy's network, we have reviewed:

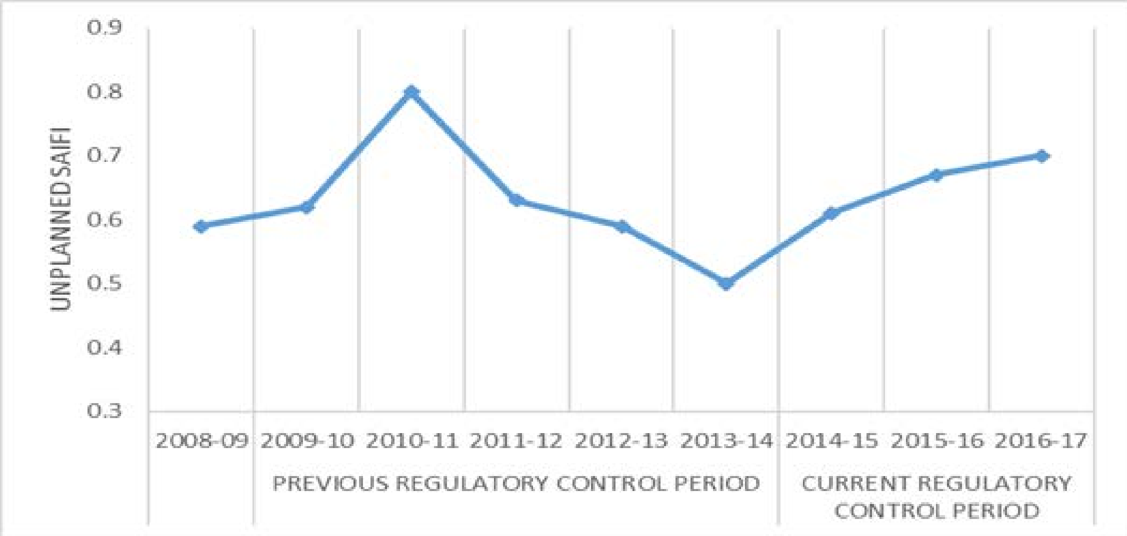
- measures of reliability on Evoenergy's network;
- the age profile of network assets and the age of these assets relative to other comparable distributors (where possible). Asset age is a reasonable proxy for asset condition, which affects a distributor's repex requirements; and
- utilisation of the Evoenergy network (where spare capacity should be correlated to asset condition). This measure provides an indication as to whether Evoenergy's assets are likely to deteriorate more or less than would be expected given the age of the assets.

Overall, we observe a consistent trend in Evoenergy's SAIFI, indicating that its current replacement practices are providing a consistent level of reliability on its network. We also observed that compared with other distributors, its network assets rank in the middle of the distribution. This would suggest that based on past practices, Evoenergy's historical repex has been sufficient to ensure a consistent level of reliability and asset utilisation.

[116] Evoenergy, *Appendix 5.1,* Consideration of risk - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 12.

Reliability trends (SAIFI)

Figure 5.10 – Evoenergy's whole-of-network unplanned SAIFI[117]



Source: Evoenergy (formerly ActewAGL) *Economic Benchmarking RIN - 3.6 Quality of service*,

Average asset age

We considered the average age of all Evoenergy's assets compared with other distributors in the NEM. Figure 5.11 below reveals that compared with other distributors, Evoenergy has a moderately aged network. Evoenergy is the 8th youngest network among the other distributors. It has an average asset age that is slightly above the industry average.

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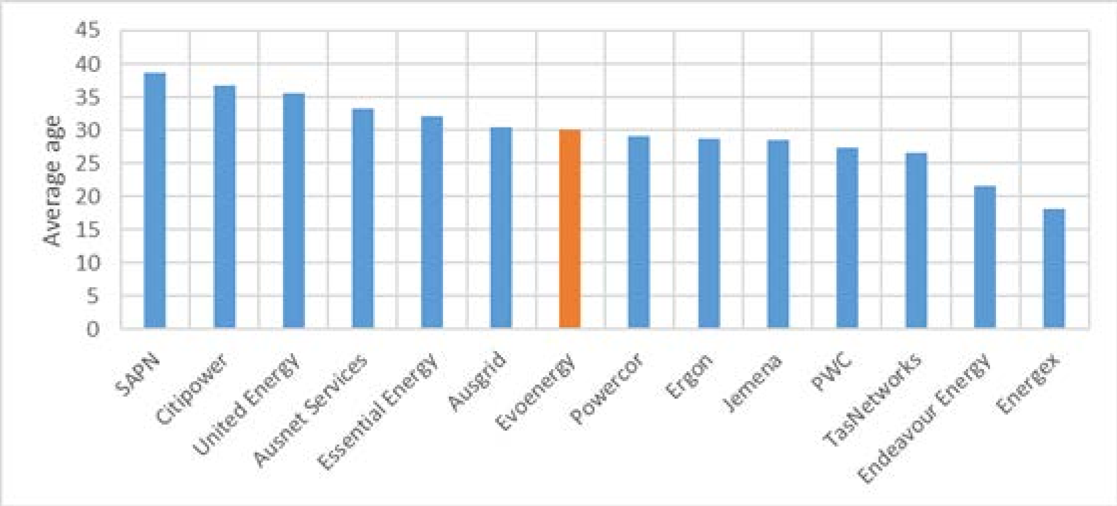
[117] System wide SAIFI excluding MEDs and excluded outages

Figure 5.11 – Electricity distributor average asset age



Source: AER analysis, 2016-2017 CA RINs - 5.2 Asset Age Profile

Asset utilisation

We consider that the degree of asset utilisation can have an impact on the condition of certain network assets. We note that the relationship between asset utilisation and condition can vary across asset types. The relationship between asset utilisation and condition is not necessarily a linear one and the condition of an asset may be difficult to determine. As a result, early-life asset failures may be due to utilisation or a combination of factors.

As highlighted in section B.2.3, Evoenergy has not experienced a significant shift in its utilisation profile from 2013-14 to 2017-18. The changes have seen a reduction in the maximum utilisation level for zone substations in 2017-18 compared with 2013-14. Overall, we expect a positive correlation between higher levels of asset utilisation and asset degradation. Given Evoenergy's asset utilisation profile, we would not expect that its assets would have experienced additional degradation due to higher use.

B.5 Forecast non-network capex

The proposed non-network capex for Evoenergy includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment.

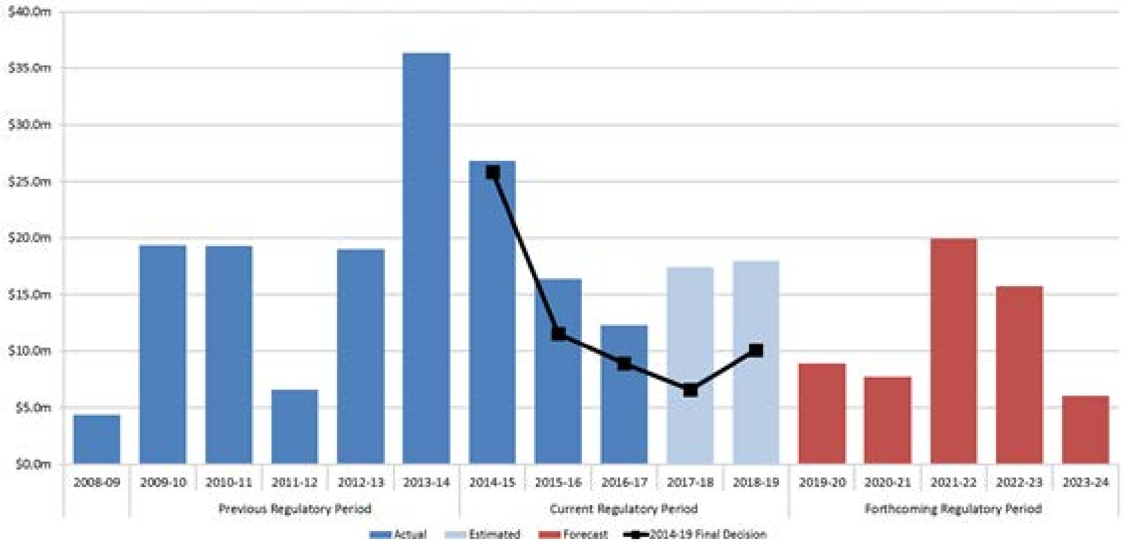
B.5.1 Evoenergy's proposal

Figure 5.12 shows Evoenergy's forecast non-network capex for each year of the 2019-24 regulatory control period. It also shows Evoenergy's actual and estimated non-network capex between 2008-09 to 2018-19 and allowed capital expenditure relating to non-network expenditure for the current regulatory period. Evoenergy's proposal is:

- $33 million, or 36 per cent less than total actual/estimated non-network capex of the current regulatory control period;

- $52 million, or 47 per cent less than total actual non-network capex incurred over the last 5 years (2012-13 to 2016-17).
- $5 million, or 7 per cent less than allowed capex relating to non-network expenditure for the current regulatory period.

Figure 5.12 – Evoenergy's non-network capex ($2018-19, million)



Source: Evoenergy, *RIN Responses*; AER, *Final Decision ActewAGL distribution determination - Evoenergy 2015 - Capex Model*; April 2015.

B.5.2 Position

Evoenergy' has not demonstrated that its forecast non-network capex of $58.3 million would form part of a total capex allowance that reasonably reflects the capex criteria. Instead, we have included an amount of $46.0 million ($2018-19) for non-network capex in our alternative estimate of total capex that we are satisfied, reasonably reflects the capex criteria taking into account the capex objectives. This is a reduction of $12.4 million or 21.2 per cent. In coming to this view, we have assessed:

- trends for each category of non-network capex comparing recent actual and forecast expenditure;[118]
- Evoenergy's total expenditure proposal to determine if any benefits identified from the proposed non-network investment are incorporated into the overall expenditure forecast;
- the project documentation accompanying Evoenergy's proposal and any further information provided by Evoenergy; and
- stakeholder submissions.[119]

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[118] NER, cl. 6A.6.7(e)(5).

Table 5.6 summarises Evoenergy's proposal and our alternative amount for non-network capex.

Table 5.6 – AER draft decision on Evoenergy's total forecast non-network capex ($2018-19, million)

	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Evoenergy's proposal	8.9	7.7	19.9	15.7	6.1	58.3
AER draft decision	8.5	6.1	8.5	16.9	6.0	46.0
Total adjustment	-0.4	-1.7	-11.4	+1.1	-0.0	-12.4
Total adjustment (%)	-4.4	-21.5	-57.4	+7.2	-0.6	-21.2

Source: Evoenergy, *Workbook 1 - Regulatory determination*, 31 January 2018; AER analysis.

Note: Numbers may not add up due to rounding.

Our findings are that:

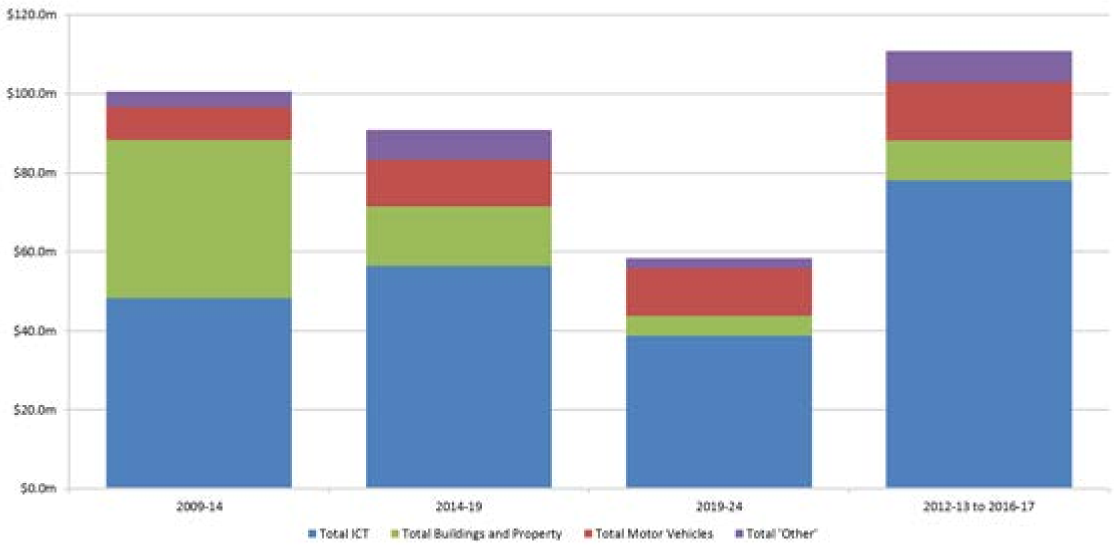
- categories of non-network capex are consistent or lower than historical expenditure for these categories.
- the information presented to date suggests that the proposed ICT capex does not reflect prudent and efficient costs of the basis that:
    - Evoenergy has included contingency costs in forming forecast capital expenditure for ICT replacement programs.
    - Evoenergy has not demonstrated that the upgrade of its advanced distribution management system (ADMS) is prudent and efficient in the forthcoming regulatory period. We also found no evidence that Evoenergy has accounted for any forecast benefits within its overall proposal.
    - Evoenergy has not demonstrated that proposed ICT asset extension programs are prudent and it has not demonstrated how it has incorporated any forecast benefits into its overall proposal.
- the information presented to date suggests that the proposed motor vehicle capex does not reflect prudent and efficient costs of the basis that:
    - Evoenergy's forecast assumed a target replacement age for elevated work platforms and heavy commercial vehicles lower than industry standard benchmarks.

[119] We received submissions from CCP10 and ACT Energy Consumers Policy Consortium concerning non-network expenditure.

B.5.3 Reasons for our position

We have assessed forecast expenditure in each category of non-network capex. This category analysis has informed our view of whether forecast non-network capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts, which may warrant further review.[120] Figure 5.13 shows Evoenergy's actual/estimated and forecast non-network capex by category for each regulatory period. As capex in the final two years of the current regulatory period are currently forecasts, Figure 5.13 also shows total actual non-network capex of the most recent five years (2012-13 to 2016-17). As shown, Evoenergy has forecast reductions in non-network capital expenditure compared to current period and the previous five years across all categories of non-network expenditure.[121]

Figure 5.13 – Evoenergy non-network capex by category ($2018-19, million)



Source: Evoenergy, *RIN Responses*.

We note that CCP10 has submitted, "whilst [non-network capital investment] is down from the current period (which we note overspends the allowance) the level of expenditure is still significant."[122] CCP10 also expressed that it considered that some aspects of Evoenergy's proposal were self-explanatory, such as Evoenergy's proposal to move its control centre from Fyshwick, but it wanted to ensure that the benefits of non-network investment was made clear.[123] In particular, CCP10 expressed that it considered that the IT capex forecast appeared high, and were unclear as to the

120 NER, cl. 6A.6.7(e)(5)

121 We note that Evoenergy's motor vehicle capex forecast is approximately equal to current period expenditure.

122 CCP10, *Advice on Evoenergy Proposal*, 16 May 2018, p. 8

123 CCP10, *Advice on Evoenergy Proposal*, 16 May 2018, p. 8

consumer benefit of the forecast.[124] We also note the submission of ACT Energy Consumers Policy Consortium that they were “keen to see Evoenergy maximise cost benefits to customers via the adoption of technologies, demand reduction strategies and development of distributed networks.”[125]

Our analysis of trends has identified that Evoenergy has forecast total ICT capex to be 31 per cent less than current period expenditure and 50 per cent less than expenditure over the previous five years. We note however, we have concerns with Evoenergy’s historical expenditure for this category, given that over the past five years Evoenergy has spent the highest total IT expenditure (capex and opex) per customer of all distributors in the NEM. On this basis, we have reviewed the supporting information provided for the non-network ICT capex forecast. In our analysis, we have compared the proposed expenditure for ICT to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure from historical expenditure. In doing so, we have considered the underlying drivers of expenditure. For example, in relation to ICT capex we have considered the investment lifecycle stage the business is in and its particular needs in the forthcoming period. Where we have decided to review individual projects or programs, we have examined available business cases and other supporting documentation provided by Evoenergy to assess whether the expenditure is prudent and efficient and would form part of a total forecast capex allowance that reasonably reflects the capex criteria.

Given that forecast expenditure for buildings and property capex is less than historical expenditure for this category, we have considered whether Evoenergy's forecast reduction in this category reflects the substitution possibilities between opex and capex for this category of expenditure.[126] For example, to some extent it is possible to substitute buildings and property asset replacement capex with increased opex for ongoing asset maintenance. We note however that at a totex level, Evoenergy's buildings and property forecast is 41 per cent lower than buildings and property totex of the current period and 16 per cent lower than buildings and property totex of the previous five years. Considering this, we are satisfied that Evoenergy's forecast reduction in buildings and property capex does not simply reflect a reallocation of expenditure from capex to opex.

Evoenergy has submitted that its forecast of $2.5 million for 'other' non-network capex reflects the cost of items of less than $1,000 and was based on historical expenditure.[127] As shown in Figure 5.13, Evoenergy's forecast is lower than historical expenditure for this category of non-network capex. On this basis, we are satisfied that

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124 CCP10, *Advice on Evoenergy Proposal*, 16 May 2018, p. 7

125 ACT Energy Consumers Policy Consortium, *AER issues paper on Evoenergy distribution determination 2019 to 2024*, 16 May 2018, p. 7

126 NER, cl. 6.5.7(e)(7).

127 Evoenergy, *Response to AER Information Request 004* - Regulatory proposal for the ACT electricity distribution network 2019–24, 02 March 2018, p. 6

Evoenergy's forecast capex for these categories of non-network expenditure is efficient and prudent.[128]

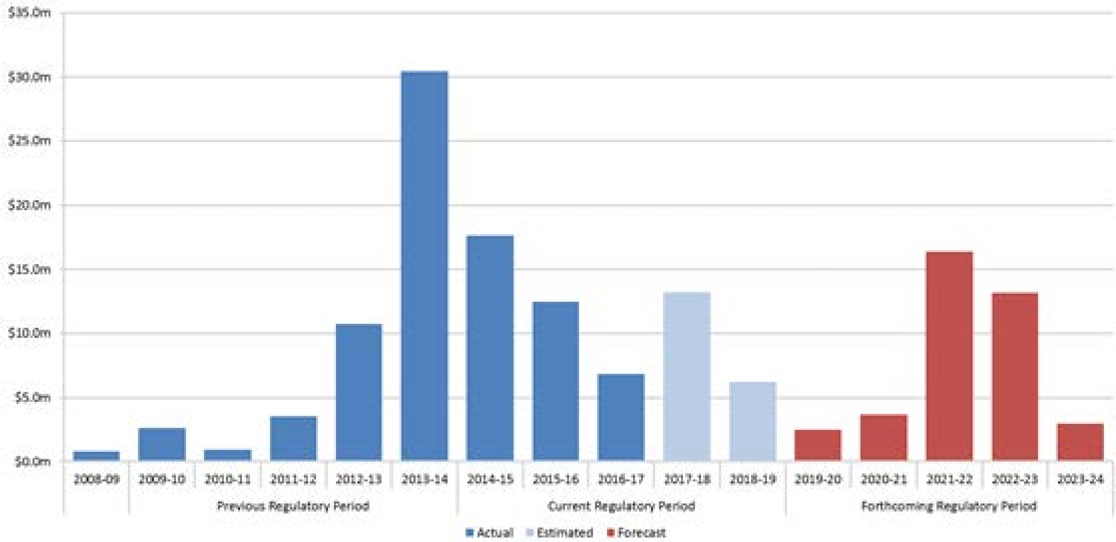
We discuss our assessment of Evoenergy's proposed capex for ICT and motor vehicles in further detail below.

B.5.3.2 Information and communications technology capex (ICT)

Figure 5.14 shows Evoenergy's forecast ICT capex for each year of the 2019-24 regulatory control period. It also shows Evoenergy's actual and estimated ICT capex between 2008-09 to 2018-19. Evoenergy's forecast of $39 million for non-network ICT capex is:

- 31 per cent less than total actual/estimated ICT capex over the current regulatory period;
- 50 per cent less than total ICT capex of the previous five years (2012-13 to 2016-17).

Figure 5.14 – Evoenergy's total actual/estimated and forecast ICT capex ($2018-19, million)



Source: Evoenergy, *RIN Responses*.

Evoenergy has submitted that its ICT proposal for the 2019-24 regulatory control period is consistent with the strategic directions and objectives set out in ActewAGL's ICT strategy and is aligned to its corporate vision, business strategy and goals.[129] To deliver this strategy, Evoenergy has identified nine non-network ICT capital expenditure programs to occur during the 2019-24 regulatory control period.

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[128] NER, cl. 6A.6.7(c).

[129] Evoenergy, *Appendix 5.9 - ICT Expenditure Proposal* - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 6

Evoenergy submitted that it selected these programs to "assist in stabilising operational costs and processes through efficiency initiatives, and to drive improvements in customer engagement to enhance the overall delivery of network services, while establishing the technology platforms suitable for industry transitions."[130]

B.5.3.3 Category Analysis of ICT capex

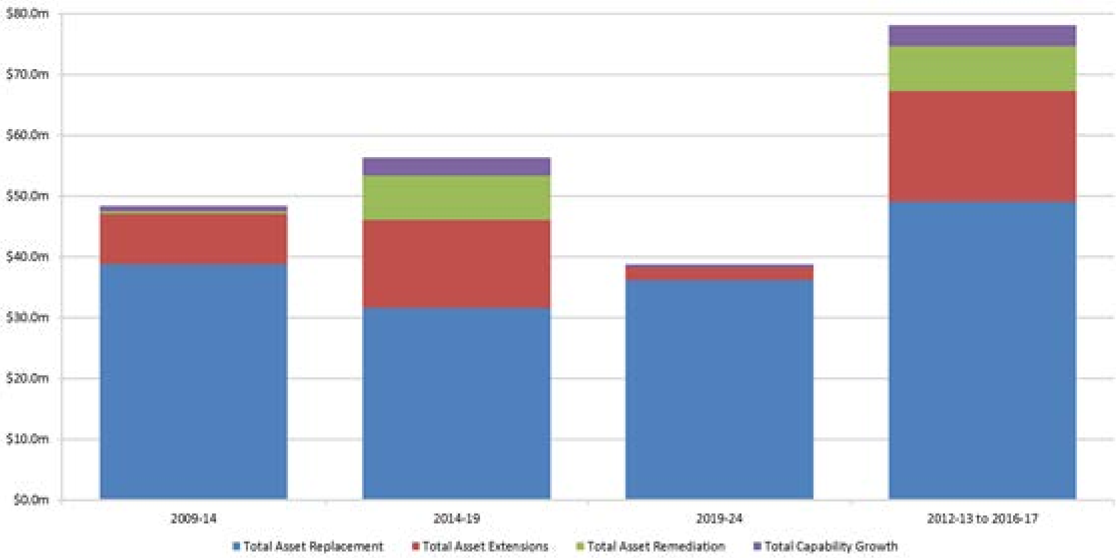
We have assessed ICT capex by its purpose. Evoenergy has allocated its historical and forecast non-network ICT capex into the following categories:

- Asset Extensions
  - The extension of existing ICT assets to broaden their functionality.
- Asset Remediation
  - The correction or optimisation of the performance of existing ICT assets that are not performing to the required service performance requirement.
- Asset Replacement
  - The replacement of an existing ICT asset with its modern equivalent where the asset has reached the end of its economic life. This capex has a primary driver of replacement if the factor determining the expenditure is the existing ICT asset has an inability to efficiently maintain its service performance requirement.
- Capability Growth
  - The acquisition, development and implementation of new ICT assets to meet a business purpose or capacity requirement.

Figure 5.15 shows Evoenergy's total actual, estimated and forecast non-network ICT capex per regulatory period by purpose. Figure 5.15 also shows total non-network ICT capex of the previous five years. The majority of Evoenergy's ICT capex forecast relates to the replacement of existing ICT assets, with minor capex forecast for the ICT asset extension. We note that forecast reductions in ICT capex relative to historical levels primarily reflects reductions to non-replacement ICT capex.

[130] Evoenergy, *Appendix 5.9 - ICT Expenditure Proposal* - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 6

Figure 5.15 – Evoenergy non-network ICT capex by purpose ($2018/19, million)



Source: Evoenergy, *Regulatory information notices*.

Our analysis of trend has identified that Evoenergy is forecasting higher ICT replacement capex in the 2019-24 regulatory control period than that of the current period. We have therefore reviewed the information provided by Evoenergy in support of its ICT replacement capex forecast to assess whether the increase in replacement expenditure is required over the 2019-24 regulatory control period.

We note that Evoenergy is also proposing minor expenditure to broaden the functionality of existing ICT assets. We have reviewed the information provided by Evoenergy in support of these programs to assess whether they have provided sufficient justification that these investments reasonably reflect the efficient costs a prudent operator would incur.[131] For programs that are economic benefit driven, we sought information from Evoenergy to understand how it had incorporated these benefits into their overall proposal such that we could be satisfied that any investment would result in lower costs. Where relevant, we have also taken into account submissions from the CCP10.

B.5.3.4 Review of Proposed ICT Replacement Capex

Figure 5.16 shows Evoenergy's forecast ICT replacement capex for each year of the forthcoming regulatory period. It also shows actual ICT replacement capex since 2008-09 and estimated ICT replacement capex for 2017-18 and 2018-19. Evoenergy's forecast ICT replacement capex of $36 million for the 2019-24 regulatory control period is:

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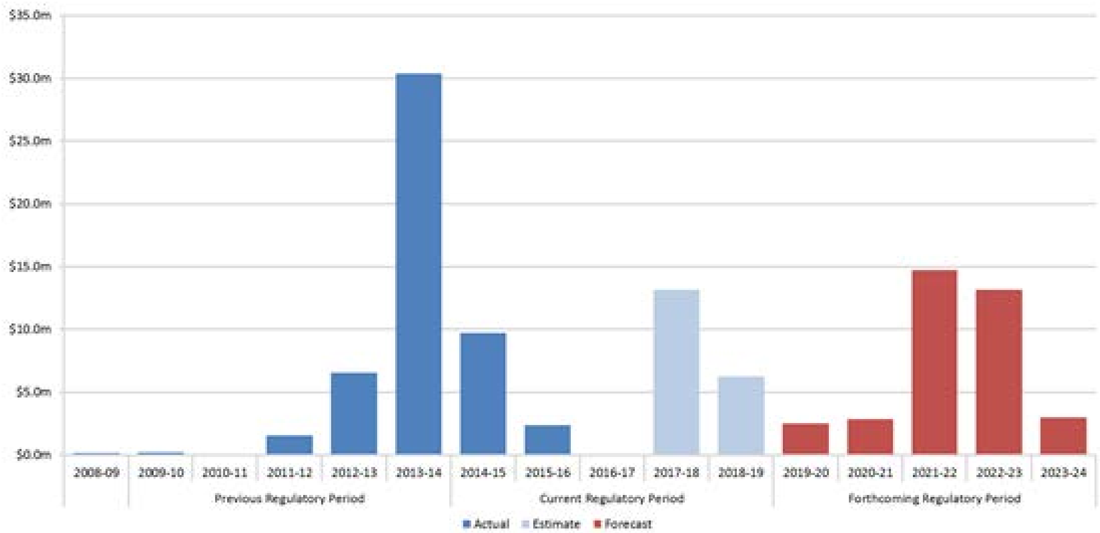
131 NER, clauses .6.5.7(c)(1) and 6.5.7(c)(2).

- 15 per cent higher than total actual/estimated ICT replacement capex of the current period;
- 26 per cent less than total actual ICT replacement capex of the previous five years.
- At an average level, proposed average yearly ICT replacement capex of $7.2 million is 28 per cent higher than average ICT replacement capex between 2008-09 and 2016-17.

Figure 5.16 – Evoenergy non-network ICT replacement capex ($2018/19, million)



Source: Evoenergy, *Regulatory information notices*.

Analysis of trends in historical expenditure has identified that Evoenergy is forecasting ICT replacement capex to be higher than that of the current period and of the historical average. We have therefore undertaken a review of the information provided in support of the forecast. In doing so, we have reviewed supporting business cases provided for individual ICT replacement programs and sought further information from Evoenergy where required. Our review has identified some issues with Evoenergy's ICT replacement forecast. These are:

- The inclusion of contingency costs to project forecasts; and
- Insufficient supporting information to demonstrate that the ADMS upgrade is prudent and efficient during the 2019-24 regulatory control period.

We accept capex for remaining programs on the basis that Evoenergy has justified that these programs reflect prudent and efficient costs. In particular, we have reviewed the supporting information provided for the proposed meter data and billing upgrade program and consider that Evoenergy has justified that this program is prudent and efficient. We discuss the issues we identified with Evoenergy's forecast ICT replacement capex in further detail below.

Contingency Allowances

Evoenergy submitted that it has included contingency costs within the cost forecasts for ICT replacement projects.[132] This included, allowances for risks such as:[133]

- magnitude of estimates prove to be incorrect resulting in changes to the project budget
- insufficient resources are available to perform the work
- the schedule is overly optimistic
- there is a high turnover of staff/resources on the project team
- friction occurs between the project team and the vendors/consultants
- solution does not integrate with other Evoenergy systems and interact correctly with the AEMO

We note that CCP10 has expressed concerns with Evoenergy's "conservative approach to contingency costs".[134]

We do not consider that the inclusion of contingency costs to ICT replacement, which are largely based on risk of forecasting error, are likely to result in the forecasts reflecting prudent and efficient costs. We also note that as Evoenergy based its forecasts on its experience with these systems or vendor quotes,[135] we would consider that estimation errors would likely be low as is. As such, our alternative of prudent and efficient total capex does not include capex for risk contingencies.

Advanced Distribution Management System Upgrade

Evoenergy has proposed to update its Advanced Distribution Management System (ADMS), which went live in February 2016. A Distribution Management System is a utility IT system capable of collecting, organising, displaying and analysing information on a distribution network. A Distribution Management System supports the planning and management of the distribution system. The Distribution Management System will typically interface with other IT systems such as geographic information systems (GIS), outage management systems (OMS), and customer information systems (CIS) to support an integrated view of the distribution system.

Evoenergy has cited that its current version of the ADMS "is not able to effectively model DER, including the expected growth in customer investment resulting in a reduction of; consumption, embedded generation, storage and control of their electricity via DER to support the customer's goals of independence, reliability, lower

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132 Evoenergy, *Response to AER Information Request 011*, 16 April 2018, p. 45.

133 Evoenergy, *Meter Data and Billing Regulatory Submission Business Case* - Regulatory proposal for the ACT electricity distribution network 2019–24, 14 March 2018, p. 19.

134 CCP10, *Response to Evoenergy Regulatory Proposal 2019-24 and AER Issues Paper*, May 2018, p. 8.

135 Evoenergy, *Responses to information request 004*.

costs and environmental goals."[136] Evoenergy also identified hardware and software end of life issues, though Evoenergy has submitted it will mitigate these issues in the short term through the purchase of "spare" servers and the extension of vendor support.[137]

We note that the CCP10 expressed that it considered that the benefits of deferral of the ADMS update could be significant and that it did not appear that Evoenergy had considered these in the proposal.[138] We reviewed the options analysis considered by Evoenergy in the business case provided. In the options analysis provided by Evoenergy, there was no consideration given to the deferral of the project. Therefore, Evoenergy did not provide any analysis of the optimal timing of the upgrade. The options Evoenergy considered were to upgrade or do-nothing. We requested that Evoenergy detail the scope for deferral of the project through the extension of vendor support. Evoenergy responded that:[139]

> … It is important to note that the currently installed version of ADMS at Evoenergy will impede the organisations transition to distribution service operator (DSO) functionality… Therefore even though extended support can be obtained, albeit with a higher level of risk, the organisation will be limited in its response to the move to demand management and leveraging distributed energy resources.

While we agree that any deferral may lead to higher risk, Evoenergy has not provided any evidence at this time that it has quantified this risk and thus demonstrated that this risk is high enough such that the ADMS upgrade is required by the date included in its proposal. Relevantly, we consider that a prudent operator in its options assessment would consider the trade-off between the increased risk of deferral with the benefit of deferred capex. Therefore, in the absence of evidence that the timing of the replacement is prudent and efficient to manage potential risk, we have assessed the program on the basis of the need to transition to DSO functionality within the forthcoming period.

We note solar and other forms of distributed energy resources (DER) have been a growing part of the national electricity grid for over 15 years. We expect it is likely that the growth of DER will continue and that electricity networks will need to continue to manage the increasing levels of these assets. The increasing knowledge and management requirements around DER is often referred to as the Distribution System Operator (DSO) model. The DSO model is not a new obligation on electricity networks, but represents a continuation of existing obligations to provide a safe, secure, reliable and efficient distribution service.

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136 Evoenergy, *Advanced Distribution Management System Regulatory Submission Business Case*, 21 March 2018, p. 5.

137 Evoenergy, *Advanced Distribution Management System Regulatory Submission Business Case*, 21 March 2018, p. 6.

138 CCP10, *Response to Evoenergy Regulatory Proposal 2019-24 and AER Issues Paper*, May 2018, p. 8

139 Evoenergy, *Response to information request 004 - part 2*, 05 March 2018, p. 5

Evoenergy (and ActewAGL before it) has been connecting solar PV installations for up to 15 years and more recently a number of storage devices have also been connected to the Evoenergy network. It therefore appears that Evoenergy is currently managing the impact of existing DER using its current system. We also note that the current levels of PV penetration in the ACT are quite modest and almost half of the penetration rates of Queensland and SA.[140] These distributors have not implemented advanced DSO functionality to manage these high levels of DER penetration. Given that the AEMO National Electricity Forecast Report[141] is forecasting the take-up rate of solar PV to slow and for only a very moderate uptake of DER storage, it would appear that over the forthcoming regulatory period PV penetration will remain below that already managed by the respective distributors in Qld and SA. As such, based on the information currently provided, we do not consider that Evoenergy has justified the need to upgrade to a more advanced DSO functionality within the forthcoming regulatory period. We consider that Evoenergy is well placed to observe and learn from the jurisdictions that have higher levels of PV penetration and use this information to guide future regulatory proposals.

We also note that Evoenergy's business case identified benefits of the upgrade relating to cost savings and reductions in outage times, such that the program will result in a positive net present value during the 2024-29 regulatory control period.[142] However, when we asked Evoenergy to provide the benefits attributable to the added capability and detail how it has incorporated these benefits into its overall submission, Evoenergy stated that it was unable to provide the capex/opex benefits associated to the project.[143] Hence, in the absence of this information we are unable to determine whether:

- there are likely to be net benefits of this additional expenditure; and
- the program is prudent and efficient.

Given that Evoenergy has not identified how the forecast benefits of the program were accounted for in the overall submission (i.e. identified deferral of augex and lower operational costs), Evoenergy has not evidenced that full capital funding is required for this program, as it appears that this program would in part, be self-funding through the CESS and EBSS incentive mechanisms.

On this basis, our draft decision is not to include capex associated with the ADMS upgrade within our substitute estimate of total capex required for the 2019-24 period. In our alternate estimate of total forecast capex we have substituted an amount equal to

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[140] Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from Pv-map.apvi.org.au on 20 June 2018.

[141] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2017-Electricity-Forecasting-Insights/Key-component-consumption-forecasts/PV-and-storage [accessed on 20 June 2018].

[142] Evoenergy, *Advanced Distribution Management System Regulatory Submission Business Case*, 21 March 2018, p. 7.

[143] Evoenergy, *Response to Information Request 012*, 11 April 2018.

the forecast costs associated with the 'do-nothing' option considered in the business case. However, we are open to considering further information from Evoenergy, as part of its revised regulatory proposal, to demonstrate the quantitative benefits of the ADMS upgrade and show how it has incorporated these into its proposal.

B.5.3.5 Review of Proposed ICT Asset Extensions Capex

Evoenergy submitted that two proposed ICT programs relate to 'the extension of existing ICT assets to broaden their functionality' rather than replacement of existing assets.[144] These two programs (Business Intelligence and ICT Platforms) account for approximately $2 million of Evoenergy's forecast ICT capex. We reviewed the business cases for these programs. For both programs, the estimated benefits adopted in the net present value calculation were zero, with each NPV negative. When asked to provide further information on the benefits of these programs, Evoenergy submitted that:[145]

> In its investment appraisal for these projects, Evoenergy did not include specifically forecasting and quantifying the expected benefits of these programs… Given the relatively small amount of spending proposed for these programs relative to the wider Capex program, Evoenergy has not given this task priority.

Given that Evoenergy has not provided us with a quantification of the benefits of these programs and that these programs do not reflect industry standard replacement practices, we do not consider that Evoenergy has demonstrated that these programs are prudent and efficient. We consider that a business case must support any non-replacement program that Evoenergy proposes by:

- detailing and quantifying the expected benefits of the program;
- providing NPV analysis demonstrating that incurring this additional expenditure results in the highest NPV compared to appropriate counterfactuals; and
- identifying how these benefits were incorporated into the overall proposal, (i.e. opex step-change).

In the absence of this information, we are unable to determine whether:

- there are likely to be net benefits of this additional expenditure; and
- the proposed non-replacement ICT capex is prudent and efficient.

Given that Evoenergy has not included in its overall proposal the benefits of these programs, Evoenergy has not evidenced that capital funding is required for these programs. We consider that for any corresponding efficiency improvement achieved through these programs, the expenditure incentive mechanisms such as the EBSS will

144 Evoenergy, *Response to information request 004*, 01 March 2018.

145 Evoenergy, *Response to information request 012*, 11 April 2018, p. 8.

reward Evoenergy. As such, our draft decision is therefore not to include these programs in our substitute estimate of capex for the 2019-24 regulatory control period.

B.5.3.6 Conclusion on information technology

Based on our review of both the total portfolio and individual projects, Evoenergy has not justified that its forecast non-network ICT capex is efficient and prudent and would form part of a total forecast capex allowance that reasonably reflects capex criteria.[146] In determining our substitute estimate of non-network ICT capex, we have considered the level of investment that is likely to be:

- prudent, having regard to Evoenergy's business needs in the 2019–24 regulatory control period
- efficient and justifiable, having regard to the economic evaluation provided.

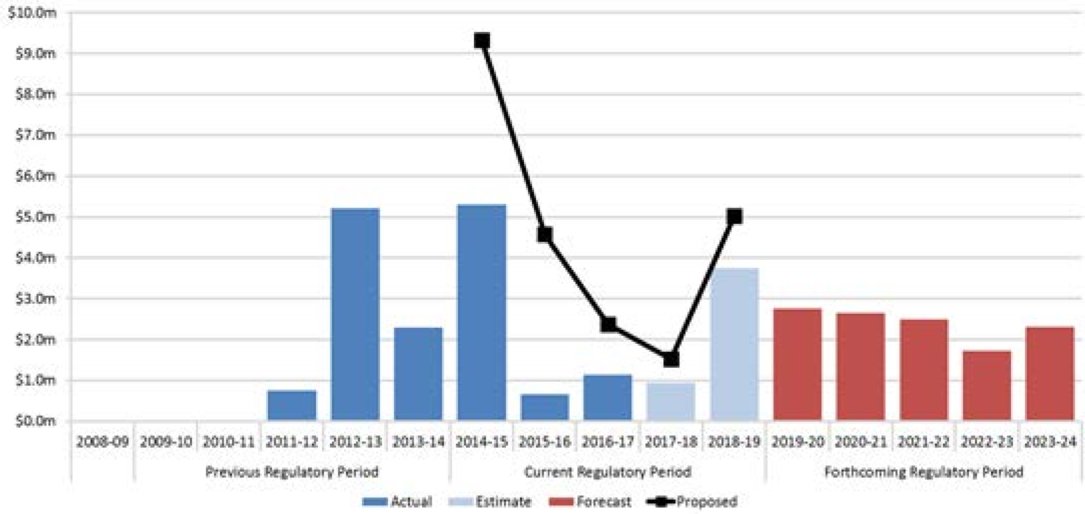
Our position in this draft decision, for the reasons outlined above, is that non-network ICT capex of $27 million ($2018-19) is efficient and prudent and would form part of a total forecast capex allowance that reasonably reflects the capex criteria. This is a reduction of $12 million or 32 per cent compared to Evoenergy's forecast non-network ICT capex.

B.5.3.7 Motor Vehicle Capex

Figure 5.17 shows Evoenergy's forecast motor vehicle capex for each year of the 2019-24 regulatory control period. It also shows Evoenergy's actual and estimated motor vehicle capex since 2008-09 as well as Evoenergy's proposed expenditure for the current period. Evoenergy's proposal of $12.9 million for motor vehicles is 10 per cent higher than total actual/estimated motor vehicle capex of the current period.

[146] NER, cl. 6.5.7(c).

Figure 5.17 – Evoenergy's total actual/estimated and forecast motor vehicle capex ($2018-19, million)



Source: Evoenergy, Regulatory information notices.

Evoenergy has submitted that the underspend on motor vehicle capex relative to allowance as shown in Figure 5.17 reflected reductions[147] in staff numbers during 2014-15, while also reflecting a preference for extended leases as opposed to replacements.[148] Evoenergy has submitted that it has based its forecast for the forthcoming regulatory period on like-for-like replacement of the current vehicles.[149] We note that Evoenergy has forecast motor vehicle opex and fleet numbers to remain constant over the forthcoming period.

We sought to understand the rationale for the forecast increase in motor vehicle capex from 2018-19 onwards because:

- the reduction in fleet numbers post 2014-15 was cited as the main driver for the underspend in motor vehicle capex
- Evoenergy is forecasting motor vehicle opex and fleet numbers to remain constant for the duration of the 2019-24 regulatory control period.

We reviewed the model provided by Evoenergy for which it has forecast fleet capex. On review of this information, we consider that the modelling provided is reasonable. However, we note that Evoenergy's model assumed a replacement age of 8 years for elevated work platforms and heavy commercial vehicles. This is lower than the replacement ages adopted by other NSW distributors, which for similar fleet components is 10 years. Evoenergy has not provided any information supporting its 8 year replacement cycle assumption and therefore it has not justified that its forecast proposal reasonably reflects the capex criteria. We have adjusted to Evoenergy's

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147 In 2014-15 Evoenergy had 194 fleet vehicles and 420 direct staff, this has been reduced to 149 fleet vehicles and 333 staff in 2016-17.

148 Evoenergy, *Response to information request 004 part 1*, 02 March 2018, p. 4.

149 Evoenergy, *Response to information request 004 part 1*, 02 March 2018, p. 5.

model to change the replacement ages from 8 to 10 years, consistent with industry practice.

Accounting for these changes, we arrived at an alternate estimate of $11.5 million for motor vehicle capex, a reduction of $1.5 million or 13 per cent. We have therefore included this amount in our substitute estimate of total capex for the 2019-24 regulatory control period.

B.6 Forecast capitalised overheads

Overhead costs are business support costs not directly incurred in producing output, or costs that are shared across the business and cannot be attributed to a particular business activity or cost centre. The allocation of overheads is determined by the Australian Accounting Standards and the distribution business's cost allocation methodology (CAM).

B.6.1 Evoenergy's proposal

Evoenergy's proposal of $75.6 million for capitalised overheads in 2019–24 is $7.4 million, or 11 per cent, higher than its expected expenditure in 2014–19 of $68.2 million.[150] Evoenergy explains that it expects higher overhead costs across its distribution business in 2019–24 due to:

- increased expenditure on ICT security capability
- an increase in labour costs and general inflation.[151]

B.6.2 Position

Evoenergy has not demonstrated that its forecast for capitalised overheads is prudent and efficient, and would form part of a total forecast capex allowance that reasonably reflects the capex criteria. We include in our substitute estimate of overall total capex an amount of $58.0 million ($2018-19) for capitalised overheads. This is 23 per cent lower than Evoenergy's proposal of $75.6 million ($2018-19).

B.6.3 Reasons for our position

To forecast capitalised overheads Evoenergy takes the fixed price service charge (FPSC) in 2017–18 as a starting point. The FPSC "represents the share of corporate costs incurred within the ActewAGL partnership that is borne by Evoenergy.[152] The

150 Evoenergy, Attachment 5: Capital Expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24, pp. 5-26. The RIN shows capitalised overheads in 2014–19 to be $69.4 million.

151 Evoenergy, *Response to information request 005 Part 2*, March 2018, p. 7.

152 Evoenergy, response to information request 005. The FPSC is equal to total corporate overheads as provided in Table 2.10.2 of the RIN.

FPSC is then divided by direct costs to calculate the capitalised overhead rate, in accordance with the formula: [153]

$$Capitalised\ Overhead\ \% = \frac{Fixed\ Price\ Service\ Charge_{Base\ Year} \times 5}{Total\ Forecast\ Direct\ Capex_{Regulatory\ Period} + Opex_{Base\ Year} \times 5}$$

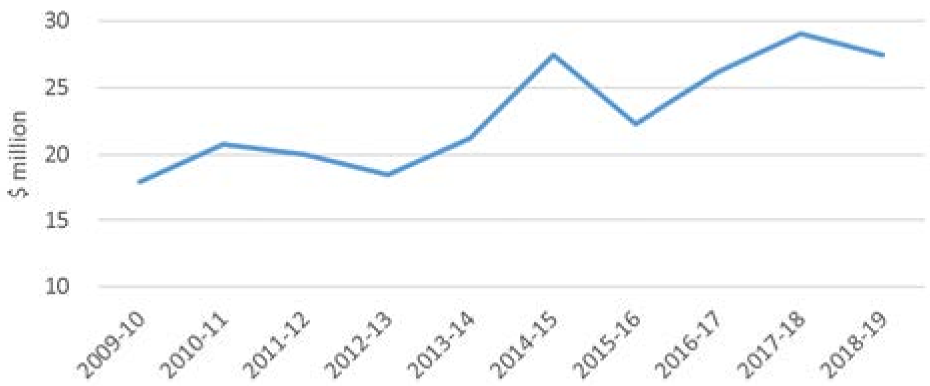
Evoenergy calculated the capitalised overhead rate to be 28 per cent. The rate is then applied to forecast direct costs for each year of the 2019–24 regulatory period at the project/program level. Overheads are not allocated to finance leases and the non-system assets program. By applying this methodology Evoenergy forecast $75.6 million for capitalised overheads in 2019–24.

We have analysed Evoenergy's methodology for forecasting capitalised overheads. We accept the general approach taken by Evoenergy and have used this as the basis for our alternative forecast. However, we have concerns with using 2017–18 as the base year for FPSC to calculate the capitalised overhead rate for 2019-24. At this time, the information Evoenergy has provided does not support its forecast increase in capitalised overheads. We discuss our concerns below.

Our concerns with the FPSC forecast

Figure 5.18 shows the actual and expected FPSC incurred by Evoenergy in the previous and current regulatory periods. While overheads generally do not vary to the extent that direct capex does, Figure 5.18 shows that basing forecast costs on a single base year may be problematic. The FPSC is expected to be higher in 2017–18 than in any other year in the current or previous regulatory period. For this reason, we consider that by using the 2017–18 FPSC as the basis for its forecast, Evoenergy may be overestimating expected capitalised overhead costs in 2019–24.

Figure 5.18 – Fixed price service charge, 2008–09 to 2018–19



Source: Evoenergy

153 Evoenergy, *Response to information request 005 Part 2*, March 2018, p. 7.

Evoenergy's reasons for expected higher overhead costs in 2019–24, as mentioned above, include higher costs associated with its ICT security program and higher labour costs. In response, we highlight:

- Evoenergy notes that the ICT expenditure represents "the ongoing operating expenditure associated with the expansion of the ICT security team and an expansion in the functions undertaken."[154] We consider that these additional costs should not be capitalised but instead be treated as direct operating overheads.
- The argument for higher wages as a driver for an increase in overheads is not well supported. Evoenergy have forecast direct capital labour to decrease by 6 per cent, and total direct labour to decrease by 1 per cent, in 2019–24 compared with the current period. We consider that a decrease in full-time equivalent labour should lead to a decrease in support requirements for the capital program. Furthermore, we would expect that higher wages should, at least in part, be balanced against labour productivity improvements.

In its submission in response to the AER issues paper for Evoenergy's 2019–24 proposal, the CCP10 also express concerns about Evoenergy's proposed capitalised overheads:

> Capitalised overheads…is also high being 11% higher than actual expenditure for this category in 2014–19 and 31% higher than the approved allowance for the current period. As with non-network costs, we consider that there are opportunities for cost savings in capitalised overheads.[155]

B.6.3.1 Our substitute estimate

We accept Evoenergy's methodology as the starting point. However, for the reasons described above, we consider that using a four-year average base year to forecast the FPSC is a more balanced approach and reduces the impact of year-to-year volatility of overhead costs.

- We take the average FPSC over the four years of the current regulatory period (to 2017–18) to determine a new 'base-year' FPSC.
- Then, we use the AER's alternative forecast direct capex and base-year opex to calculate the capitalisation rate. We calculate the capitalisation rate to be 26 per cent.
- Finally, we apply the capitalisation rate to the AER's alternative forecast direct system capex in accordance with Evoenergy's methodology.

Our alternative forecast for capitalised overheads is $58.0 million for 2019–24. We are satisfied this alternative forecast forms part of a total forecast capex allowance that reasonably reflects the capex criteria.

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154 Evoenergy, *Response to information request 025*, May 2018, p. 3.

155 *CCP10 Response to Evoenergy regulatory Proposal 2019–24 and AER Issues Paper: May 2018*, p. 7.

C Engagement and information-gathering process

Initial revenue proposal

Evoenergy lodged its revenue proposal on the 31 January 2018, which included the primary documents that relate to capex for the 2019-24 period. The initial proposal included the supporting documentation that usually accompanies a regulatory proposal. Evoenergy submitted their Asset Specific Plans; however, we note that Evoenergy did not provide us with business cases for specific asset replacement projects.[156]

Information-gathering process

During the review process, we have requested further information on Evoenergy's capex proposal through a number of AER's requests for information.

We have requested 17 information requests on its capex proposal.[157] The questions aimed to test our understanding of the material provided as well as clarify capex-related issues. Evoenergy responded to all the information requests. The majority of these questions were responded to within the agreed timeframe, however, we note that there were numerous requests for extension and a few request response that were delayed.

Engagement

We have engaged with Evoenergy and CCP10 on numerous occasions throughout the review process.

We have engaged with Evoenergy staff on the AER repex modelling approach on the 17 April 2018. This included a discussion on the latest modelling refinement, which is discussed in D.5 below, and how it impacted Evoenergy.[158] It was an opportunity for Evoenergy to understand the underlying assumptions of the repex model and how it affected their repex proposal. Evoenergy staff questioned the incorporation of risk in the repex model. The repex model is used in conjunction with bottom up techniques where we assess the distributors' approach to risk.

Similarly, we engaged with Evoenergy regarding the proposed augex with a meeting on 1 May 2018. Evoenergy requested the meeting to discuss the response an information request. In this meeting:

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156 Evoenergy advised that business cases will only be developed during the initiation stages of each project. Evoenergy – Part 2 of response to AER query 015 – 20180504 - Public

157 Each of these information requests had a series of questions.

158 Further information on the repex modelling refinement is found in Appendix D.

- we noted concerns that Evoenergy ACT supply standards do not prescribe deterministic planning standards, and as such, would look to assess Evoenergy's augmentation proposal applying a probabilistic assessment approach.
- we discussed the augex proposal project by project, as had been responded to in the information request response.

We have also had a meeting with Evoenergy staff to discuss its proposed Meter Data and Billing system upgrade project. The purpose of the meeting was to understand what impact the Power of Choice reforms has placed on Evoenergy with regard to meter data. Evoenergy clarified its responsibility in a subsequent information request response.

We engaged with CCP10 on 9 May 2018, to discuss the non-repex components of Evoenergy's proposal. The purpose of this meeting was to explain our assessment approach and to highlight our concerns with Evoenergy's proposed capex.

D Repex modelling approach

This section provides a guide to our repex modelling process. It sets out:

- relevant background information
- the data used to run the repex model
- the key assumptions underpinning our repex modelling approach
- the repex model outcomes under different scenarios.

D.1 Background to predictive modelling

In 2012, the AEMC published changes to the National Electricity and National Gas Rules.[159] Following these rule changes, the AER undertook a "Better Regulation" work program, which included publishing a series of guidelines setting out our approach to regulation under the new rules.[160]

The expenditure forecast assessment Guideline (Guideline) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distribution network service providers (distributors).[161] It lists predictive modelling as one of the assessment techniques we may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009–10 review of the Victorian electricity distributors' 2011–15 regulatory proposals and have also used it in subsequent electricity distribution decisions.

The technical underpinnings of the repex model are discussed in detail in the replacement expenditure model handbook.[162] At a basic level, the AER's repex model is a statistical tool used to conduct a top-down assessment of a distributor's replacement expenditure forecast. Discrete asset categories within six broader asset groups are analysed using the repex model. These six asset groups are poles, overhead conductors, underground cables, service lines, transformers and switchgear.

The repex model forecasts the volume of assets in each category that a distributor would be expected to replace over a 20-year period. The model analyses the age of assets already in commission and the time at which, on average, these assets would be expected to be replaced, based on historical replacement practices. A total replacement expenditure forecast is derived by multiplying the forecast replacement volumes for each asset category by an indicative unit cost.

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159 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

160 See AER *Better regulation reform program* web page at http://www.aer.gov.au/Better-regulation-reform-program.

161 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

162 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

The repex model can be used to advise and inform the AER and its consultants where to target a more detailed bottom-up review, and define an alternate repex forecast if necessary. The model can also be used to benchmark a distributor against other distributors in the National Electricity Market (NEM)[163].

As detailed in the AER's repex handbook, the repex model is most suitable for asset groups and categories where there is a moderate to large asset population of relatively homogenous assets. It is less suitable for assets with small populations or those that are relatively heterogeneous. For this reason, we exclude the SCADA and other asset groups from the modelling process and do not use predictive modelling to directly assess the asset categories within these groups.

Expenditure on and replacement of pole top structures is also excluded, as it is related to expenditure on overall pole replacements and modelling may result in double counting of replacement volumes. In addition, distributors do not provide asset age profile data for pole top structures in the annual category analysis RINs, so this asset group cannot be modelled using the repex model.

D.2 Data collection

The repex model requires the following input data:

- the age profile of network assets currently in commission
- expenditure and replacement volume data of network assets
- the mean and standard deviation of each asset’s expected replacement life.

This data is derived from distributors’ annual regulatory information notice (RIN) responses, and from the outcomes of the unit cost and expected replacement life benchmarking across all distribution businesses in the NEM. The RIN responses relied on are:

- annual category analysis RINs – issued to all distributors in the NEM
- reset RINs – distributors are required to submit this information with their regulatory proposal.

Category analysis RINs include historical asset data and reset RINs provide data corresponding to distributors’ proposed forecast repex over the upcoming regulatory control period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

Our current approach of adopting a standardised approach to network asset categories provides us with a dataset suitable for comparative analysis and better equips us to assess the relative prices of cost inputs as required by the capex criteria.[164]

163 This includes Power and Water Corporation.

164 NER, cl 6.5.7(c).

D.3 Scenario analysis

In this section we set out the broad assumptions used to run a series of scenarios to test distributors' distributor forecast modelled repex. The specific modelling assumptions applied for each distributor are outlined in each individual repex modelling workbook. The four scenarios analysed are:

1. historical unit costs and calibrated expected replacement lives
2. comparative unit costs and calibrated expected replacement lives
3. historical unit costs and comparative expected replacement lives
4. comparative unit costs and comparative expected replacement lives.

Comparative unit costs are defined as the minimum of a distributor's historical unit costs, its forecast unit costs and the median unit costs across the NEM. Comparative replacement lives are defined as the maximum of a distributor's calibrated expected replacement life and the median expected replacement life across the NEM.

D.4 Calibration

The calibration process estimates the average age at replacement for each asset category using the observed historical replacement practices of a distributor. The length of the historical period analysed during this process is referred to as the 'calibration period'. The inputs required to complete the calibration process are:

- the age profile of network assets currently in commission
- historical replacement volume and expenditure data for each asset category.

The calibrated expected replacement lives as derived through the repex model differ from the replacement lives that distributors report. During the calibration process, we assume the following:

- the calibration period is a historical period where a distributor's replacement practices are largely representative of its expected future replacement needs[165]
- we do not estimate a calibrated replacement life where a distributor did not replace any assets during the calibration period, because the calibration process relies on actual historical replacement volumes to derive a mean and standard deviation
- where a calibrated replacement life is not available, we substitute the value of a similar asset category.

D.5 Comparative analysis approach

Previous distribution determinations where we have used on the repex model have primarily focused on the 'historical scenario'. This scenario forecasts a distributor's

[165] Each distributors' specific repex modelling workbook outlines more detailed information on the calibration period chosen.

expected repex and replacement volumes based on their historical unit costs and asset replacement practices (which are used to derive expected replacement lives).

Our refined comparative analysis repex modelling approach builds on this previous analysis and now introduces the historical performances of other distributors in the NEM into the forecast period. The ‘cost, lives and combined’ scenarios rely on a comparative analysis technique that compares the performance of all distributors in the NEM. The technique analyses the two variable repex model inputs – unit costs and replacements lives.

The ‘cost scenario’ analyses the level of repex a distributor could achieve if their historical unit costs were improved to comparative unit costs. The ‘lives scenario’ analyses the level of repex a distributor could achieve if their calibrated expected replacement lives were improved to comparative expected replacement lives.

Unit costs

The comparative analysis technique compares a distributor’s historical unit costs, forecast unit costs and median unit costs across the NEM. Historical unit costs are derived from a distributor’s category analysis RIN and forecast unit costs are derived from a distributor’s reset RIN, which is submitted as part of its regulatory proposal.

The median unit costs across the NEM are based on each distributor’s historical unit cost for each asset category. The median unit cost is used for comparative analysis purposes because this approach effectively removes any outliers, either due to unique network characteristics or data reporting anomalies.

The United Kingdom's Office of Gas and Electricity Markets (Ofgem) has a similar approach to unit costs benchmarking, where Ofgem applies a unit cost reduction where the distributor's forecast unit cost was higher than industry median[166]. The unit cost input used in the ‘cost’ and ‘combined’ scenarios is the minimum of a distributor’s historical unit costs, its forecast unit costs and the median unit costs across the NEM.

Expected replacement lives

For expected replacement lives, the comparative analysis technique compares a distributor’s calibrated replacement lives (based on historical replacement practices) and the median expected replacement lives across the NEM. Median expected replacement lives are based on each distributor’s calibrated replacement lives for each asset category. Once again, using the median value effectively accounts for any outliers.

166 Ofgem, *Strategy decisions for the RIIO-ED1 electricity distribution price control - tools for cost assessment*, 4 March 2013.

The expected replacement life input used in the ‘lives’ and ‘combined’ scenarios is the maximum of a distributor’s calibrated replacement life and the median replacement life across the NEM.

Repex model threshold

Our ‘repex model threshold’ is defined taking these results and other relevant factors into consideration. For the 2019-24 determinations, our proposed approach is to set the repex model threshold equal to the highest result out of the ‘cost scenario’ and the ‘lives scenario’.[167] This approach gives consideration to the inherent interrelationship between the unit cost and expected replacement life of network assets.

For example, a distributor may have higher than average unit costs for particular assets, but these assets may in turn have longer expected replacement lives. In contrast, a distributor may have lower than average unit costs for particular assets, but these assets may have shorter expected replacement lives.

D.6 Non-like-for-like replacement – the treatment of staked wooden poles

The staking of a wooden pole is the practice of attaching a metal support structure (a stake or bracket) to reinforce an aged wooden pole.[168] The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like-for-like basis.

Replacement expenditure is normally considered to be on a like-for-like basis. When an asset is identified for replacement, it is assumed that the asset will be replaced with its modern equivalent and not a different asset.[169] The repex model forecasts the volume of old assets that need to be replaced, not the volume of new assets that need to be installed. This is simple to deal with when an asset is replaced on a like-for-like basis – the old asset is simply replaced by its modern equivalent. Where like-for-like replacement is appropriate, it follows that the number of assets that need to be replaced matches the number of new assets that need to be installed.

However, where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model forecasts the number of old assets that need to be replaced, it is necessary to make adjustments for the asset’s unit cost and calibrated

[167] Our modelling approach means the ‘historical scenario’ will always be higher than the ‘cost scenario’ and the ‘lives scenario’, and the ‘combined scenario’ will always be lower than the ‘cost scenario’ and the ‘lives scenario’.

[168] The equivalent practice for stobie poles is known as "plating", which similarly provides a low-cost life extension. SA Power Networks carries out this process. For simplicity, this section only refers to the staking process.

[169] For example, conductor rated to carry low voltage will be replaced with conductor of the same rating, not conductor rated for high-voltage purposes.

replacement life. For modelling purposes, the only category where this is significant is wooden poles.

Evoenergy also typically undertakes significant non-like-for-like replacement throughout its network. This is primarily because Evoenergy generally replaces older low-voltage wooden, steel or concrete poles with new fibreglass poles. The way these assets are accounted for in the repex modelling is similar to the explanation above and is explained in more detail in Evoenergy's specific repex modelling workbook.

Staked and unstaked wooden poles

Staked wooden poles are treated as different assets to unstaked poles in the repex model. This is because staked and unstaked poles have different expected replacement lives and different unit costs.

There are two asset replacements options and two associated unit costs that may be made by a distributor – a new pole could replace the old one or the old pole could be staked to extend its life.[170]

Also, there are circumstances where an in-commission staked pole needs to be replaced. Staking is a one-off process. When a staked pole needs to be replaced, a new pole must be installed in its place. The cost of replacing an in-commission staked pole is assumed to be the same as the cost of a new pole.

Unit cost blending

We use a process of unit cost blending to account for the non-like-for-like asset categories. For unstaked wooden poles that need to be replaced, there are two appropriate unit costs – the cost of installing a new pole and the cost of staking an old pole. We use a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[171]

For staked wooden poles, we ask distributors for additional historical data on the proportion of staked wooden poles that are replaced. The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of staked pole types that are replaced. Where historical data is not available, we use the asset age data to determine what proportion of the network each pole category represented and use this information to weight the unit costs.

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[170] When a wooden pole needs to be replaced, it will either be staked or replaced with a new pole. The decision on which replacement type will be carried out is made by determining whether the stake will be effective in extending the pole's life and is usually based on the condition of the pole base. If the wood at the base has deteriorated significantly, staking will not be effective and the pole will need to be replaced. If there is enough sound wood to hold the stake, the life of the pole can be extended and the pole can be staked, which is a more economically efficient outcome.

[171] For example, if a distributor replaces a category of pole with a new pole 50 per cent of the time and stakes this category of the pole the other 50 per cent of the time, the blended unit cost would be a straight average of the two unit costs. If the mix was 60:40, the unit cost would be weighted accordingly.

Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when determining their calibrated replacement lives. This is because historical replacement volumes are used in the calibration process. The RIN responses provide us with information on the volume of new assets installed over the calibration period. However, the repex model forecasts the volume of old assets being replaced. Since the replacement of staked poles is not on a like-for-like basis, we make an adjustment for the calibration process to function correctly.

We need to know the number of staked poles that reach the end of their economic life and are replaced over the calibration period, so an expected replacement life can be calibrated. The category analysis RINs currently only provide us with information on how many poles were staked each year, rather than how many staked poles were actually replaced. This additional information is provided by each of the distributors. Where this information is not available, we estimate the number of staked wooden poles replaced over the calibration period based on the data we have available.

E Demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure.[172] This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts and cost inputs required to achieve the capital expenditure objectives. Hence accurate, unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network.

This appendix sets out our decision on Evoenergy’s forecast network maximum demand for the 2019–24 regulatory control period. We consider Evoenergy’ demand forecasts at the system level and the more local level.

System demand represents total demand in the Evoenergy’s distribution network. System demand trends give a high-level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased network utilisation which may, once any spare capacity in the network is used up, lead to a requirement for growth capex. Conversely forecasts of stagnant or falling system demand will generally signal falling network utilisation, a more limited requirement for growth capex, and the potential for the network to be rationalised in some locations.

Localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments.

In our consideration of Evoenergy’s demand forecasts, we have had regard to:

- Evoenergy’s proposal
- AEMO's independent forecasts.

These are set out in more detail in the remainder of this appendix.

E.1 AER determination

We consider that Evoenergy’s demand forecasts are justified and reflect a realistic expectation of demand over the 2019-24 regulatory control period. Our findings are that:

- Both Evoenergy’s and AEMO’s forecast of summer peak demand indicate slightly negative growth, consistent with the broadly flat historical trend.
- Evoenergy’s winter peak demand forecast is also negative, which is in contrast to AEMO’s forecast, who forecast an increase in winter peak demand.

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172 NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

- From our review of Evoenergy's forecasting methodology, we note that it has adopted the same adjustment factors used by AEMO in its peak forecasting to account for the impact of electric vehicles, batteries, residential and business efficiency and solar PV.

These findings are discussed below.

Comparison between the AEMO forecasts and Evoenergy forecasts

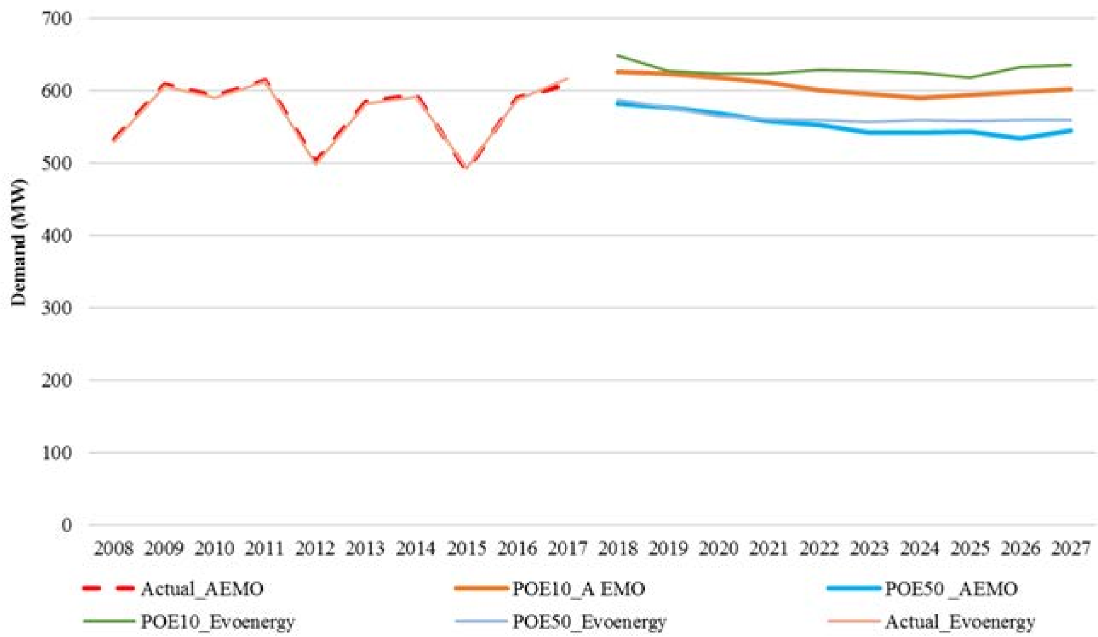
For like-with-like comparison, we have compared AEMO's non-coincident peak demand for the Canberra region with Evoenergy's coincident peak demand.[173] This is because the level of disaggregation and coincidence for measuring peak demand differs between AEMO modelling and Evoenergy modelling.

- For AEMO, non-coincident peak demand at a transmission connection point is measured non-coincidently to the maximum demand for the wider NSW/ACT system. It does not necessarily coincide with the time of the system peak, but is the maximum demand at a transmission connection point in the year or in the season. AEMO reports for the transmission connection point at the Canberra region, which covers Evoenergy's three bulk supply points at Canberra, Queanbeyan and Williamsdale.
- For Evoenergy, coincident peak demand at the three bulk supply points and/or the twelve zone substations represents the maximum demand of these substations at the time of the peak for its whole network. This corresponds to AEMO's non-coincident peak demand measured for the transmission connection point covering the Canberra region.

As shown in Figure 5.19 below, summer peak demand for the Evoenergy network has fluctuated over recent years, and it reached 617MW in 2017. Evoenergy forecasts summer peak to gradually fall from 587MW in 2018 before levelling off at 557MW in 2023. In comparison, AEMO forecasts summer peak to decline over the ten-year forecast period. As a result, the two set of forecasts are close in the first part of the forecast period, and start to diverge in 2022 onward. In percentage terms, Evoenergy forecast a 0.81 per cent annual decrease in summer peak demand between 2018 and 2024, whilst AEMO forecast a 1.19 per cent annual decrease over the same period.

[173] AEMO, *2017 AEMO Transmission Connection Point Forecasts for New South Wales, including the Australian Capital Territory*, September 2017; available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting [accessed on 6 March 2018].

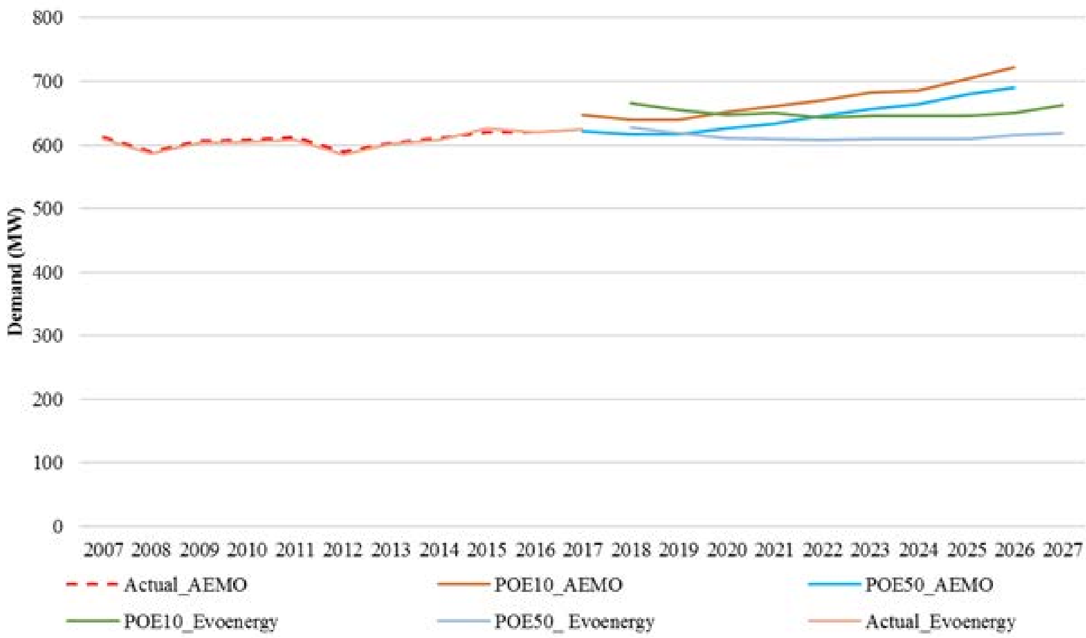
Figure 5.19 – Evoenergy network summer peak demand: AEMO and Evoenergy forecasts



Source: Evoenergy, 2017 Annual planning report, Appendix B; AEMO, 2017 NSW-ACT Dynamic Interface.

As a winter-peaking network, peak demand in winter is higher than that in summer for the Evoenergy network. As shown in Figure 5.20 below, winter peak demand has fluctuated but increased slightly in recent years, reaching 624MW in 2017. Evoenergy forecasts winter peak to fall slightly from 627MW in 2018 to 608MW in 2022 before recovering to 618MW in 2027. In contrast, AEMO forecasts the winter peak to increase considerably in the ten-year forecast period, reaching 690MW in 2027. In percentage terms, Evoenergy forecast a 0.47 per cent annual decrease in winter peak demand between 2018 and 2024, whilst AEMO forecast a 1.21 per cent annual increase over the same period.

Figure 5.20 – Evoenergy network winter peak demand: AEMO and Evoenergy forecasts



Source: Evoenergy, 2017 Annual planning report, Appendix B; AEMO, 2017 NSW-ACT Dynamic Interface.

The sharp increase in winter peak demand forecast by AEMO does not appear to align with the historical trend.

Part of the AEMO reconciliation process involves reconciling non-coincident connection point forecasts to the growth rate of the regional forecast using an index approach. Some explanations for AEMO's forecast sharp increase in winter peak demand has been offered by Evoenergy:[174]

> '…The bulk of this gap is introduced by our regional (NSW/ACT) reconciliation process, which this year has led to our connection point forecast 'chasing' our regional forecast, ie. we needed to increase our connection point forecasts in order to meet the total forecast regional demand. This effect has been particularly significant in winter.'

More specifically, under the AEMO reconciliation process, where the implied diversity factor is greater than one, the non-coincident forecast is recalculated to be equal to its coincident counterpart. Furthermore, AEMO applies a blending factor, weighted average of the growth rates for connection point forecasts and regional (NSW/ACT) forecasts with changing weights to allow the growth rate of the connection point forecast to dominate in earlier forecast period and the regional forecast growth rate to

[174] Evoenergy, *Annual Planning Report 2017*, December 2017, p. 61.

dominate in the later period.[175] Therefore, the AEMO's transmission connection point forecasts for Evoenergy appear to be more reflective of the growth perspectives of the wider NSW/ACT system.

Given the complication with AEMO's reconciliation to the NSW/ACT regional forecasts, we find that Evoenergy network forecast of limited and/or no growth in its seasonal system peak demand can be more reflective of demand drivers affecting its own network.

Review of Evoenergy's peak demand forecasting methodology

We have briefly reviewed Evoenergy's peak demand forecasting methodology and the assumptions regarding long-term trends and recent industry developments. These findings are noted below.

Forecasting methodology

Our high-level review finds that Evoenergy has applied the Monash Electricity Forecast Model (MEFM) to both bottom-up approach to modelling peak demand at the zone substation level (used in augmentation planning) and top-down approach to modelling system peak demand.[176] We note that the MEFM was developed by Monash University on behalf of AEMO for its top-down modelling of state-based system level peak demand. Although AEMO does not apply the MEFM to derive a bottom-up forecast (possibly due to data not being readily available), we take some reassurance from Evoenergy's forecast, as it has adopted a similar forecasting methodology as AEMO.

After applying individual diversity factors to each of the zone substation peak demand forecasts, the bottom-up aggregated peak demand forecasts are compared to the top-down system forecasts.[177] There are some discrepancies between the two sets of forecasts, in particular the 50 per cent POE winter peak forecasts derived from bottom-up approach are found to be, on average, 4 per cent lower than the corresponding top-down system forecasts over the period 2018 to 2027. Nevertheless, the top-down forecast is only used to provide a check that the reconciled bottom-up forecast is consistent with overall expectations for the ACT. We consider the zone substation peak demand forecasts to be reasonable, recognising these forecasts combined are approximately equal or lower to the system peak forecasts that we consider are justified.

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175 For details, see AEMO's description of its reconciliation process in AEMO (2016), *AEMO Connection Point Forecasting Methodology: Forecasting Maximum Electricity Demand in the National Electricity Market*, July, pp. 27-29.

176 Evoenergy, Appendix 3.2 Peak demand forecast for period 2018-2027 - Regulatory proposal for the ACT electricity distribution network 2019–24, December 2017, p. 5.

177 Evoenergy, Appendix 3.2 Peak demand forecast for period 2018-2027 - Regulatory proposal for the ACT electricity distribution network 2019–24, December 2017, pp. 5-6.

Long-term trends and structural changes

Evoenergy's consultant Jacobs, who were commissioned to assist in the development of demand forecasts, noted the concerns we raised in our review of the Victorian distributors' demand forecasts in the 2016-20 decisions.[178] These concerns arose from a lack of confidence that the models had captured the effects of long term trends and developments in the industry.

In developing the Evoenergy demand forecasts, Jacobs has assumed the same long-term projections on structural changes in the industry (such as the impact of solar photovoltaic technology (solar PV)) as adopted by AEMO in its 2017 National Electricity Forecasting Report:[179]

- On electric vehicles (used for residential and business purposes), AEMO projects gradually growing impact on operational demand over time and reaching more than 0.5 per cent in 2024. Jacobs note that large scale electrical vehicles (e.g., rail and bus) are forecast to increase demand by 9MW in 2019 growing to 15MW by 2022 and are accounted for under block loads forecasts.
- On batteries, AEMO's projection on the maximum demand is low with a reduction in maximum demand in summer by less than 0.5 per cent in 2024.
- On residential and business energy efficiency, AEMO projects a continuing reduction in electricity consumption by 12 per cent and 2 per cent respectively, in 2022 relative to 2016.
- On solar PV systems, AEMO projects the PV share of underlying maximum demand to grow over time and reach 4 to 5 per cent by 2027.

We consider that the structural changes made to Evoenergy's demand forecasts are reasonable. We consider that AEMO's forecasts reflect independent industry knowledge and judgement of forthcoming trends, and it is appropriate for Evoenergy to adopt these trends in its own demand forecast.

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[178] Evoenergy-Jacobs, Appendix 3.3 Demand forecasting update and support - Regulatory proposal for the ACT electricity distribution network 2019–24, December 2017, pp. 9, 12.

[179] Evoenergy-Jacobs, Appendix 3.3 Demand forecasting update and support - Regulatory proposal for the ACT electricity distribution network 2019–24, December 2017, pp. 13–24.

F Real material cost escalation

Real material cost escalation is a method for accounting for expected changes in the costs of key material inputs to forecast capex.

F.1 Position

Evoenergy has not demonstrated that its proposed real material cost escalators, which form part of its total capex forecast, reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2019–24 regulatory control period.[180] Evoenergy's proposed real material cost escalators would lead to cost increases above CPI.

We consider that zero per cent real cost escalation is likely to reasonably reflect the capex criteria and is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2019–24 regulatory control period. This is consistent with previous decisions.

For this draft decision, the reasons for our position are outlined below:

- There is the potential for significant commodity forecast inaccuracy. We therefore consider that zero per cent real material cost escalation is likely to provide a more reliable estimation for the price of input materials used by Evoenergy to provide network services.
- We are not satisfied with the reasonableness of the methodology used to estimate material input prices. In particular, there is little evidence to support how accurately Evoenergy's material escalation forecasts reasonably reflect changes in prices paid by Evoenergy for physical assets.
- We have not been presented with evidence that Evoenergy has taken into account a number of substitution possibilities and other actions that might mitigate real material cost escalation.

Our approach to real material cost escalation does not affect the application of labour and construction cost escalators, which will continue to apply to capital and operating expenditure for standard control services. Further details on our consideration of labour cost escalators are discussed in Attachment 6, Section 6.4.2.

F.2 Evoenergy's proposal

Evoenergy applied material and labour cost escalators to various asset classes in its capex forecast for the 2019-24 regulatory control period.[181] The proposed material cost

180 NER, cl. 6.5.7(a).

181 Evoenergy, Attachment 5 Capital Expenditure - Regulatory proposal for the ACT electricity distribution network 2019–24, January 2018, p. 31.

escalation increased Evoenergy's capex proposal by $1.59 million ($2018-19) or 0.5 per cent.

Evoenergy engaged both BIS and GHD to determine material cost escalation factors. BIS was engaged to forecast input material cost escalators, which GHD subsequently used to forecast cost escalators for Evoenergy's assets. GHD did not review the cost escalation indices forecast by BIS.

F.2.1 BIS report

BIS Oxford Economics derived real cost escalation indices for the following commodities:[182]

- aluminium;
- copper;
- steel;
- crude oil; and
- construction costs.

Table 5.7 outlines BIS' real material cost escalation forecasts.

Table 5.7 – BIS' real material cost escalation forecasts—inputs (per cent)

	2019–20	2020–21	2021–22	2022–23	2023–24
Aluminium	-4.0	-1.8	-2.0	-1.6	7.0
Copper	-0.2	-0.5	-4.2	-3.7	4.9
Steel beams and sections PPI	-2.4	1.2	2.9	3.2	1.2
Oil	0.8	0.0	-4.1	-3.7	4.9
Non-hydroelectricity construction IPD	-1.8	-0.9	-1.3	-1.2	0.2
Non Residential Building Work Done IPD	0.3	0.4	0.8	0.7	0.5

Source: Evoenergy – BIS Oxford – Appendix 5.6 – Real cost escalation forecasts to 2023-24, September 2017, pp. 3 and 31.

[182] Evoenergy – BIS Oxford Economics, Appendix 5.6, *Real cost escalation forecasts to 2023/24,* September 2017, pp. 31–34.

Exchange rate forecasts

BIS forecast input materials in US dollars, which were converted to Australian dollars using BIS' own forecast exchange rates. BIS used their own forecasts due to a 'lack of official forecasts over the long term'.[183]

BIS' exchange rates are compared below in Table 5.8 with exchange rates forecast by the Australian Bureau of Agricultural and Resource Economics (ABARE) and the Office of the Chief Economist (OCE). ABARE and OCE have not forecast exchange rates for 2022-23 and 2023-24.

Table 5.8 – BIS $US to $AUS Exchange Rate Forecast Comparison

	2019–20	2020–21	2021–22	2022–23	2023–24
BIS Oxford Economics	0.749	0.791	0.844	0.801	0.740
ABARE	0.740	0.740	0.740		
Office of the Chief Economist	0.720	0.720	0.720		

Source: Evoenergy - BIS Oxford - Appendix 5.6 – Real cost escalation forecasts to 2023-24, September 2017, p. 32.

We recognise that BIS' higher exchange rate forecasts results in Australian dollar commodities that would be more conservative than if ABARE or OCE forecasts were adopted. This does not change our view that there is considerable potential for inaccuracy when forecasting both material cost escalators and exchange rates.

F.2.2 GHD Report

On the basis of the individual material and labour cost escalators provided by BIS, Evoenergy's consultant, GHD Advisory, calculated escalation factors specific to various asset classes. These escalation factors are intended to reflect the effect (via a percentage weighting) that each cost driver has on the asset.[184] Table 5.9 outlines Evoenergy's real cost escalation indices, which apply the escalation factors, by asset class.

[183] Evoenergy – BIS Oxford – Appendix 5.6 Real cost escalation forecasts to 2023-24 – September 2017, p. 31.

[184] Evoenergy – GHD Advisory – Appendix 5.7 Cost escalation factors – 3 November 2017, p. 2.

Table 5.9 – Evoenergy's real material and labour cost escalation forecast (indices)

Asset Classes	2019–20	2020–21	2021–22	2022–23	2023-24
Transmission overhead	0.991	1.005	1.007	1.009	1.019
Transmission underground (copper)	1.004	1.008	1.005	1.006	1.018
Distribution overhead lines	1.006	1.012	1.015	1.016	1.017
Distribution underground lines (aluminium)	1.006	1.011	1.013	1.014	1.017
Zone substation switchgear	1.006	1.012	1.010	1.012	1.021
Zone substation transformer	0.999	1.009	1.006	1.008	1.027
Zone substation electronics/other	1.020	1.022	1.019	1.019	1.027
Zone substation civils	0.987	0.995	0.992	0.993	1.004
Distribution substations	1.009	1.014	1.013	1.014	1.023
Meters	1.014	1.017	1.018	1.018	1.021
Relays (Protection and Control)	1.011	1.015	1.017	1.018	1.018
IT & communication systems (Network)	1.014	1.017	1.019	1.019	1.018
Other non-system assets (Corporate)	1.000	1.000	1.000	1.000	1.000
Other non-system assets (Networks)	1.000	1.000	1.000	1.000	1.000
Motor vehicles	1.000	1.000	1.000	1.000	1.000

Source: Evoenergy – GHD Advisory – Appendix 5.7 Cost escalation factors, 3 November 2017, p. 2.

GHD considered the following factors influenced their cost escalators:[185]

- commodity prices – copper, aluminium, steel and oil (provided by BIS);
- foreign exchange rates (provided by BIS);
- foreign price inflation index;
- construction costs;
- Australian trade-weighted index (TWI); and
- Australian consumer price index (CPI).

F.3 Reasons for our position

We assessed Evoenergy's proposed real material cost escalators as part of our overall capex assessment. We must accept Evoenergy's capex forecast if we are satisfied it reasonably reflects the capex criteria.[186] We must be satisfied the forecast material cost escalators reasonably reflect a realistic expectation of inputs costs required to achieve the capex objectives.[187]

Our approach to assessing forecast material costs is set out in our Expenditure Forecast Assessment Guideline (the Guideline).[188] We have followed the same approach for this draft decision. In the Guideline, we state that we have seen limited evidence demonstrating that the commodity input weightings used by service providers to generate material input cost forecasts have produced unbiased forecasts that are reflective of what service providers actually paid for manufactured materials.[189]

We consider that it is important that this evidence is provided, because changes in the prices of manufactured materials are not solely influenced by changes in the raw materials that are used.[190] As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast manufactured material cost changes is likely to reasonably reflect changes in raw material input costs.

Evoenergy has not demonstrated that its capex forecast, which includes real material cost escalation, is reasonable. In particular, we are not convinced that Evoenergy's proposed real material cost escalation is based on a sound and robust methodology.

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185 Evoenergy – GHD Advisory – Appendix 5.7 Cost escalation factors – 3 November 2017, p. 8.

186 NER, clause 6.5.7(c).

187 NER, clause 6.5.7(c)(3).

188 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline,* November 2013, pp. 50-51.

189 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

190 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

We therefore consider that including this escalation would not reasonably reflect the capex criteria.[191] This is because it has not demonstrated:

- that there is a genuine interlinkage between the cost of material inputs and the prices Evoenergy pays for physical assets;
- the reasonableness of the methodology used to estimate material input prices; and
- that it has taken into account a number of substitution possibilities and other actions that might mitigate real cost material escalation.

Interlinkage between cost of material inputs and the prices Evoenergy pays for physical assets

Evoenergy's material input cost model does not demonstrate how and to what extent material inputs have affected the cost of inputs such as underground cables and transformers. In particular, there is no supporting evidence to substantiate how accurately Evoenergy's material escalation forecasts reasonably reflected changes in the prices they paid for assets in the past.

Evoenergy was provided an opportunity to respond to this concern through information request 019.[192] Evoenergy contended this was not a “sound comparison” that wasn’t intended to be applied at a granular level.[193] However, we consider input material escalators need to be shown to reasonably reflect changes in the prices paid for Evoenergy’s assets.

Evoenergy's material cost input model assumes a weighting of commodity inputs for each asset class but does not provide information that explains the basis for the weightings or that the weightings applied have produced unbiased forecasts. For these reasons, we cannot conclude that these forecasts are reliable.

In the response to information request 019, Evoenergy responded to this concern by stating that GHD applied input cost weightings based on Evoenergy’s historical project costs. [194] However, we were not provided with information indicating how historical project costs were used to determine the weightings of commodity inputs. As a result, we cannot be reasonably certain that the weightings used by Evoenergy are unbiased.

Material input cost model forecasting

Evoenergy has used its consultants' reports to estimate cost escalation factors to assist in forecasting future operating and capital expenditure. These cost escalation factors include commodity inputs for capital expenditure. Evoenergy has assumed a high-level relationship between commodity inputs and the physical assets purchased.

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191 NER, cl. 6.5.7(c).

192 Evoenergy – AER information request 019 response, 9 May 2017.

193 Evoenergy – AER information request 019 response, 9 May 2017, p. 2.

194 Evoenergy – AER information request 019 response, 9 May 2017, pp. 3-4.

We have several concerns with the forecasting methodology that are outlined below:

- Evoenergy did not provide sufficient justification that its historical commodity prices reasonably predict future commodity prices. Without sufficient historical justification of forecasting techniques, we cannot be assured that Evoenergy's proposed material input indices reasonably reflect future prices. Evoenergy did not provide any further historical justification in the response to information request 019.[195]
- The limited number of material inputs included in Evoenergy's material input escalation model may not be representative of the full set of inputs or input choices affecting the prices of assets purchased by Evoenergy. Evoenergy's material input cost model may also be biased to the extent that it may include a selective subset of commodities that are forecast to increase in price during the 2019-2024 regulatory control period.

  In its response to information request 019, Evoenergy stated that GHD considered aluminium, copper and steel were the main components of the core asset types. GHD stated other inputs such as nickel were considered, but their influence was significantly less than the three main commodities used in the GHD model. [196]

  We consider that no evidence indicating how materials other than aluminium, copper and steel contribute to the costs of Evoenergy's assets was supplied. We therefore cannot be reasonably certain that Evoenergy's choice of input materials is fully reflective of the materials used in its assets and its model could therefore be biased.
- We would also expect that a reasonable forecasting methodology would attempt to account for key factors that are likely to influence the relationship between the cost of material inputs and the price paid by Evoenergy for these assets. Evoenergy has not provided any supporting information that indicates whether the forecasts have taken into account any material exogenous factors that may impact on the reliability of material input costs.

  Such factors may include changes in technologies that affect the weighting of commodity inputs, suppliers of the physical assets changing their sourcing for the commodity inputs, and the general volatility of exchange rates. In the information request 019 response, Evoenergy stated that no exogenous factors were considered by GHD in its model.[197]
- The GHD report acknowledges that there are a variety of factors that could cause business conditions and results to differ materially from their cost escalation forecasts.[198] This is consistent with our view that there is considerable potential for inaccuracy when forecasting material cost escalators.

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195 Evoenergy – AER information request 019 response, 9 May 2017, p. 1.

196 Evoenergy – AER information request 019 response, 9 May 2017, pp. 3-4.

197 Evoenergy – AER information request 019 response, 9 May 2017, pp. 4-5.

198 Evoenergy – GHD Advisory – Appendix 5.7 Cost escalation factors – 3 November 2017, p. 6.

Evoenergy responded to this concern in information request 019. Evoenergy stated that forward looking forecasts are speculative and are subject to change due to exogenous factors, which could generate different cost escalation factors than those provided by GHD.[199] We consider Evoenergy's response supports our view that there is considerable potential for inaccuracy when forecasting material cost escalators.

More generally, we consider that there is significant uncertainty in forecasting commodity input price movements. GHD acknowledged that forward-looking statements are inherently uncertain.[200] This is consistent with our view that there is a considerable degree of potential inaccuracy of commodity forecasts. In particular, we note that there is difficulty in forecasting nominal exchange rates (used to convert most materials that are priced in $US to $AUS). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.[201]

Material input cost mitigation

We consider that there is potential for Evoenergy to mitigate the magnitude of any overall input cost increases. This could be achieved by:

- Applying hedging strategies or price escalation provisions in their contracts with input suppliers (e.g. by including fixed prices in long-term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution possibilities between operating and capital expenditure,[202] we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.
- Potential commodity input substitution by the electricity service provider and the input supplier. An increase in the price of one commodity input may result in input substitution to an appropriate level providing there are no technically fixed proportions between the inputs. Although there will likely be an increase in the cost of production for a given output level, the overall cost increase will be less than the weighted sum of the input cost increase using the initial input share weights due to substitution of the now relatively cheaper input for this relatively expensive input.

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199 Evoenergy – AER information request 019 response, 9 May 2017, pp. 4-5.

200 Evoenergy – GHD Advisory – Appendix 5.7 Cost escalation factors – 3 November 2017, p. 6.

201 R. Meese, K. Rogoff, (1983), *Empirical exchange rate models of the seventies: do they fit out of sample?*, Journal of International Economics, 14, B. Rossi, (2013), *Exchange rate predictability*, Journal of Economic Literature, 51(4), E. Fama, (1984), *Forward and spot exchange rates*, Journal of Monetary Economics, 14, K. Froot and R. Thaler, (1990), Anomalies: Foreign exchange, the Journal of Economic Perspectives, Vol. 4, No. 3, CEG, *Escalation factors affecting expenditure forecasts*, December 2013, and BIS Shrapnel, *Real labour and material cost escalation forecasts to 2019/20, Australia and New South Wales*, Final report, April 2014.

202 NER, clause 6.5.7(e)(7).

We are aware of input substitution occurring in the electricity industry during the late 1960s when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. However, we do recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies that may not be substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby potentially reducing the total expenditure requirements of an electricity service provider.[203]

- The substitution potential between opex and capex when the relative prices of operating and capital inputs change.[204] For example, Evoenergy has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs.
- The scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency.
- Increases in productivity that have not been taken into account by Evoenergy in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2019-2024 regulatory control period, we consider that there is potential for an upward bias in estimating material input cost escalation by maintaining the base year cost commodity share weights.

[203] NER, clause 6.5.7(e)(7).

[204] NER, clause 6.5.7(e)(6).

G Ex post statement of efficiency and prudency

We are required to provide a statement on whether the roll forward of the regulatory asset base from the previous period contributes to the achievement of the capital expenditure incentive objective.[205] The capital expenditure incentive objective is to ensure that where the regulatory asset base 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 regulatory asset base.[206]

The NER require that the last two years of the previous regulatory control period (for the purposes of this decision, the 2017–19 regulatory years) are excluded from the ex-post assessment of past capex. Further, the NER prescribe that the review period does not include the regulatory year in which the first Capital Expenditure Incentive Guideline was published (2013–14) or any regulatory year that precedes that regulatory year.[207] Accordingly, our ex-post assessment only applies to the 2014–17 regulatory years.

We may exclude capex from being rolled into the RAB in three circumstances:[208]

1. Where the distribution business has spent more than its capex allowance;
2. Where the distribution business has incurred capex that represents a margin paid by the distribution business, where the margin refers to arrangements that do not reflect arm's length terms; and
3. Where the distribution business's capex includes expenditure that should have been classified as opex as part of a distribution business's capitalisation policy.

G.1 Position

We are satisfied that Evoenergy's capital expenditure in the 2014-15, 2015-16 and 2016-17 regulatory years should be rolled into the RAB.

G.2 AER approach

We have conducted our assessment of past capex consistent with the approach set out in our capital expenditure incentive guideline (the Guideline). In our Guideline we outlined a two stage process for undertaking an ex-post assessment of capital expenditure:[209]

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205 NER, cl. 6.12.2(b).

206 NER, cl. 6.4A(a).

207 NER, cl.11.60.5.

208 NER, cl. S6.2.2A(b).

209 AER, *Capital Expenditure Incentive Guideline*, November 2013, pp. 19-22.

- Stage one - initial consideration of actual capex performance
- Stage two - detailed assessment of drivers of capex and management and planning tools and practices.

The first stage considers whether the distribution business has overspent against its allowance and past capex performance. In accordance with our Guideline, we would only proceed to a more detailed assessment (stage two) if:

- a distribution business had overspent against its allowance
- the overspend was significant; and
- capex in the period of our ex-post assessment suggests that levels of capex may not be efficient or do not compare favourably to other transmission businesses.

G.3 AER assessment

We have reviewed Evoenergy's capex performance for the 2014-15, 2015-16 and 2016-17 regulatory years. This assessment has considered Evoenergy’s capex relative to the regulatory allowance given the incentive properties of the regulatory regime for a distribution business to minimise costs.

Evoenergy incurred total capex below its forecast regulatory allowance in these regulatory years. Therefore, the overspending requirement for an efficiency review of past capex is not satisfied.[210] We also consider that the 'margin' and 'capitalisation' RAB adjustments are not satisfied.

We have also had regard to some measures of input cost efficiency as published in our latest annual benchmarking report.[211] We recognise that there is no perfect benchmarking model, however we consider that our benchmarking models are the most robust measures of economic efficiency available and we can use this measure to assess a distribution business's efficiency over time and compared with other distribution businesses.

The results from our most recent benchmarking report suggest that Evoenergy's overall efficiency increased significantly in 2015 and 2016. Evoenergy was ranked eleventh of thirteen on our multilateral total factor productivity score, but it has improved its productivity and is now ranked seventh as at 2016.[212] We note that while this provides relevant context, we have not used our benchmarking results in a determinative way for this capex draft decision, including in relation to this Ex-post efficiency and prudency review.

In assessing the prudency and efficiency of Evoenergy's capex in the ex post review period, we may only take into account information and analysis that Evoenergy could

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

211 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2017.

212 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2017, p. 9.

reasonably be expected to have considered or undertaken at the time that it undertook the relevant capex.[213] We have therefore not taken into account the information and analysis relied upon in other areas of this draft decision, for example our concerns with deterministic planning highlighted in our assessment of Evoenergy’s augex proposal, for this ex-post efficiency and prudency review.

For the reasons set out above, we are satisfied that Evoenergy's capital expenditure in the 2014-15, 2015-16 and 2016-17 regulatory years should be rolled into the RAB.

[213] NER, cl. S6.2.2A(h)(2).