FINAL DECISION
Evoenergy
Distribution Determination

2019 to 2024

Attachment 5
Capital expenditure

April 2019

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's final 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 final decision, which includes the following documents:

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all attachments. The attachments have been numbered consistently with the equivalent attachments to our longer draft decision. In these circumstances, our draft decision reasons form part of this final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 15 – Alternative control services

Attachment A – Negotiated framework

Attachment B – Pricing methodology

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 to 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 final decision on Evoenergy's revised total capex forecast. Further detailed analysis is provided in the following appendices:

- Appendix A – Assessment techniques
- Appendix B – Assessment of capex drivers
- Appendix C – Repex modelling approach

5.1 Final decision

In assessing forecast capex, we are guided by the National Electricity Objective (NEO) and underpinning capex criteria and objectives set out in the National Electricity Rules (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.[2]

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.[3]

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.[4]

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.[5]

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[1] NER, cl. 6.4.3(a).7

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

[3] NER, cl. 6.5.7(c)(1).

[4] NER, cl. 6.5.7(a).

[5] NER, cl. 6.12.1(3)(ii).

We accept Evoenergy's revised total net capex forecast—subject to one modelling amendment—of $314.3 million ($2018-19) for the 2019-24 regulatory control period.[6] Table 5.1 outlines Evoenergy's revised total capex forecast and our final decision.

Table 5.1 – Final decision on Evoenergy’s total capex forecast ($2018–19, million)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Evoenergy's revised proposal	57.6	60.2	74.3	64.7	59.8	316.5
AER final decision	57.3	59.8	73.8	64.2	59.2	314.3
Difference	(0.3)	(0.4)	(0.4)	(0.5)	(0.6)	(2.3)
Percentage difference (%)	(0.6%)	(0.6%)	(0.6%)	(0.8%)	(1.0%)	(0.7%)

Source: Evoenergy capex model.

Note: Numbers may not add due to rounding.

Note: The above figures do not include equity raising costs. For our assessment of equity raising costs, see the overview of our Final Decision.

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

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. As discussed in Appendix B, we have concerns with some aspects of Evoenergy’s revised proposal, particularly some of the evidence used to support components of the augex and ICT capex programs.

Notwithstanding these concerns, Evoenergy’s total forecast capex reasonably reflects the capex criteria, taking into account the capex factors and the revenue and pricing principles.[7] As set out in Appendix B, we are satisfied that Evoenergy's total capex forecast forms part of an overall distribution determination that will contribute to achieving the NEO to the greatest degree.

Table 5.2 – Summary of AER findings and reasons

Issue	Reasons and findings
Total capex forecast	Evoenergy proposed a total capex forecast of $316.5 million ($2018–19) in its revised proposal. Subject to the modelling error identified, Evoenergy has justified that its revised proposal reasonably reflects the capex criteria. The reasons for this decision

6 In its November 2018 revised proposal, Evoenergy presented a total capex forecast of $316.5 million. We subsequently identified that Evoenergy’s revised connections capex forecast did not account for an earlier revision that it provided in April 2018. The final decision modifies Evoenergy’s revised connections proposal based on the earlier revision.

7 NER, cl. 6.5.7(c) and (d); NEL s. 7A.

	are summarised in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	Evoenergy’s key assumptions and forecasting methodology are generally reasonable. With the exception of the modelling adjustment referred to above, Evoenergy’s approach results in an overall capex forecast that reasonably reflects the capex criteria.
Augmentation capex	In our draft decision, we did not accept Evoenergy's proposed demand-driven augex due to concerns around Evoenergy's deterministic planning approach to augex. In response to our draft decision, Evoenergy reproposed a majority of the projects from its initial proposal with some minor adjustments to some feeders and cost escalation. Evoenergy updated its cost benefit analysis model and reproposed projects where the benefits exceed the costs. Evoenergy's revised augex forecast of $54.9 million ($2018–19) reasonably reflects the capex criteria, however we have ongoing concerns with some components of its proposed augex.
Customer connections capex	Evoenergy has demonstrated that its connections capex forecast of $106.2 million ($2018–19) reasonably reflects the capex criteria. However, we have made a small adjustment in our final decision estimate to correct a modelling error. Our substitute estimate for gross connections capex is $105.9 million. This includes capital contributions of $48.5 million ($2018-19). Evoenergy has included an additional $20.2 million for capital contributions, relating to a government project. Evoenergy has justified this additional capital contribution requirement.
Replacement capex (repex)	Evoenergy has demonstrated that its repex forecast of $91.8 million ($2018–19) reasonably reflects the capex criteria. In our draft decision, we accepted that most of Evoenergy’s initial repex forecast reasonably reflected the required expenditure for this driver, but we noted that Evoenergy had not justified that its repex forecast for the underground cable asset group was prudent and efficient. In response to our draft decision, Evoenergy provided additional information and analysis, including risk quantification and cost-benefit analysis, to support its underground cable repex forecast. In addition, Evoenergy corrected several historical data reporting issues that initially contributed to significant differences between Evoenergy's modelling for this asset category and our repex model results.
Non-network capex	In our draft decision, we accepted that most of Evoenergy's initial non-network capex forecast reasonably reflected the required expenditure for this driver, but noted Evoenergy had not justified aspects of its ICT and fleet capex forecast as being prudent and efficient. Evoenergy largely accepted our draft decision on non-network capex, with the exception of the ICT capex forecast. In response to our draft decision, Evoenergy provided additional information in support of the ICT projects, including revised business cases and cost-benefit analysis. Evoenergy's revised non-network capex forecast of $56.0 million ($2018-19) reasonably reflects the capex criteria, however we have ongoing concerns with some aspects of its proposed ICT capex.
Capitalised overheads	Evoenergy has demonstrated that its capitalised overheads of $66.4 million ($2018–19) reasonably reflects the capex criteria. Evoenergy's forecast largely reflects the approach we used for our draft decision.

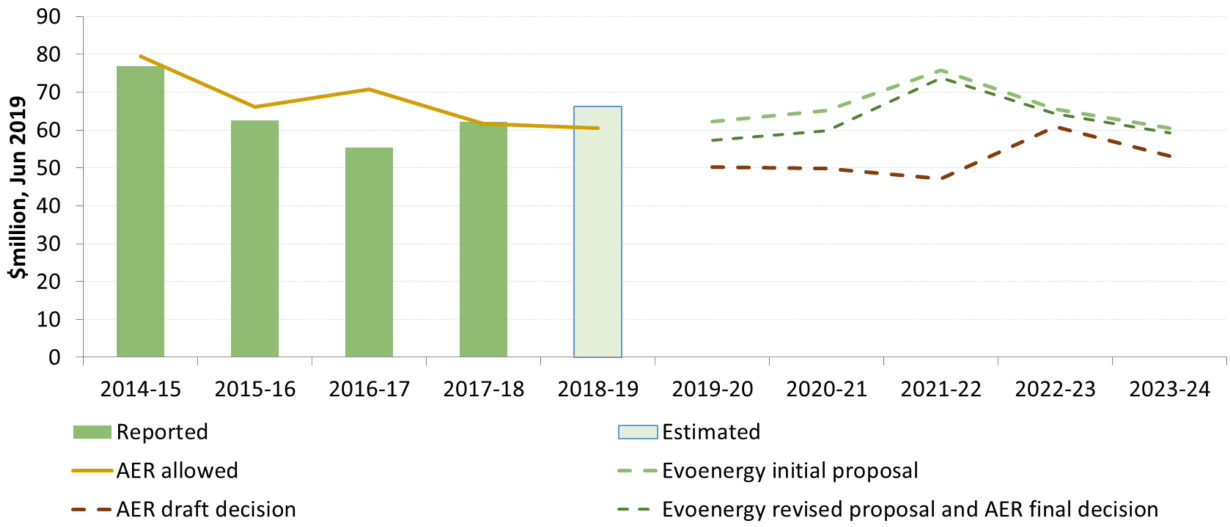
Source: AER analysis.

5.2 Evoenergy's revised proposal

For the 2019–24 regulatory control period, Evoenergy proposes total forecast net capex of $314.3 million ($2018–19). Evoenergy’s 2019–24 capex forecast is $8.9 million

(2.8 per cent) lower than its actual capital expenditure of $323.2 million over the 2014–19 regulatory control period. Figure 5.1 outlines Evoenergy's historical capex trend, its initial and revised forecasts for the 2019–24 regulatory control period, and our draft decision.

Figure 5.1 – Evoenergy's historical, initial and revised capex forecasts, including 2014–19 allowance and 2019–24 AER draft decision ($2018–19)



Source: AER analysis

Note: Net capex

The key drivers of Evoenergy's revised capex proposal are:

- Augmentation and reliability – $54.9 million (16 per cent)
- Net customer connections – $57.5 million (18 per cent)
- Replacement – $91.8 million (29 per cent)
- Non-network – $56.0 million (17 per cent)
- Capitalised overheads – $66.4 million (21 per cent)

The reasons for our final 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.

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.

More broadly, we also take into account the revenue and pricing principles set out in the National Electricity Law (NEL).[8] 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:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[9]

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.[10]
- past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[11]

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 revised 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.[12] 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 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

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

9 NEL, s. 7A.

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

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

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

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.[13] 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.[14]

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

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13 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.

14 NEL, s. 16(1)(c).

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.[15]

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 final 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 final decision 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 revised 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.[16]

For some elements, such as capitalised overheads, we will consider the proposed capex in the context of total expenditure. For other elements, such as capability growth, we may consider any opex-capex trade-offs to determine whether the capex 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.[17] 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.[18]

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15 NER, r. 6.6.

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

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

18 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.

5.4 Reasons for final decision

We applied the assessment approach set out in section 5.3 and Appendix A to Evoenergy. Table 5.3 sets out the capex amounts by driver that Evoenergy has justified would reasonably reflect the capex criteria. Our findings and reasons for each capex driver are summarised below.

Table 5.3 – Assessment of required capex by driver 2019–24 ($2018–19, million)

Category	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Augmentation and reliability	10.8	13.7	15.2	7.9	7.2	54.9
Connections	22.9	30.6	17.5	17.7	17.2	105.9
Replacement	17.3	17.6	16.4	17.2	23.3	91.8
Non-network	8.4	6.6	17.6	16.6	6.7	56.0
Capitalised overheads	13.0	14.9	14.4	12.3	11.8	66.4
Gross capex (includes capital contributions)	72.4	83.5	81.0	71.8	66.3	375.0
Less capital contributions	(14.9)	(23.6)	(7.0)	(7.2)	(6.9)	(59.6)
Less disposals	(0.2)	(0.1)	(0.1)	(0.4)	(0.2)	(1.2)
Net capex	57.3	59.8	73.8	64.2	59.2	314.3

Source: Evoenergy's revised proposal and AER analysis.

Notes: Numbers may not add up due to rounding. Net capex = gross capex less capcons less disposals. Capital contributions in this table include an overheads component.

Augmentation:

- In our draft decision, we had concerns with Evoenergy's deterministic planning approach to augex and considered several demand driven augmentation projects should be deferred.
- Evoenergy provided updated modelling and demand forecasts to support its revised proposal. We have reviewed these models. Although we have identified some issues in relation to Evoenergy's updated model, we are satisfied that the benefits of demand driven augmentation exceeds the cost of the projects.
- Evoenergy's revised augex forecast of $54.9 million ($2018–19) reasonably reflects the capex criteria, however we have ongoing concerns with some components of its proposed augex.

Customer connections capex:

- Evoenergy has largely justified that its connections capex forecast of $106.2 million ($2018–19) reasonably reflects the capex criteria. However, we have made a small adjustment in our final decision estimate to correct a modelling error.

- Our substitute estimate for gross connections capex is $105.9 million. This includes capital contributions of $48.5 million ($2018-19).
- Compared with its initial proposal, Evoenergy has included an additional $20.2 million for capital contributions, relating to the construction of a zone substation to provide additional supply to HMAS Harman. Evoenergy has provided us with sufficient information to justify this additional capital contribution requirement.

Repex:

- Evoenergy's proposed repex of $91.8 million ($2018–19) appears to be a reasonable estimate of the prudent and efficient costs required for this capex category.
- In our draft decision, we accepted that most of Evoenergy's initial repex forecast reasonably reflected the required expenditure for this driver, but we noted that Evoenergy had not justified that its repex forecast for the underground cable asset group was prudent and efficient.
- In response to our draft decision and following extensive constructive engagement, Evoenergy provided additional information and analysis, including risk quantification and cost-benefit analysis, to support its underground cable repex forecast. We conducted a detailed bottom-up review of Evoenergy's underground cable cost-benefit analysis model and supporting documentation.
- In addition, Evoenergy corrected several historical data reporting issues that initially contributed to significant differences between Evoenergy's modelling for this asset category and our repex model results. We used this updated data to rerun our repex modelling results and Evoenergy's repex forecast now sits below our updated repex model threshold.
- Overall, Evoenergy has justified that its repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.

Non-network capex:

- In our draft decision we accepted that most of Evoenergy's initial non-network capex forecast reasonably reflected the required expenditure for this driver, but noted Evoenergy had not justified aspects of its ICT and fleet capex forecast as being prudent and efficient.
- Evoenergy largely accepted our draft decision on non-network capex, with the exception of the ICT capex forecast. In response to our draft decision, Evoenergy provided additional information in support of the ICT projects including revised business cases and cost-benefit analysis.
- Evoenergy's revised non-network capex forecast of $56.0 million ($2018-19) reasonably reflects the capex criteria, however we have ongoing concerns with some aspects of its proposed ICT capex.

Capitalised overheads:

- Evoenergy's proposed capitalised overheads of $66.4 million ($2018–19) appears to be a reasonable estimate of the prudent and efficient costs required for this capex category.

- Evoenergy used the same general approach to forecast capitalised overheads as it did for its initial proposal. Changes to its forecasts for direct capex and opex resulted in a lower forecast for capitalised overheads compared with its initial proposal.
- Evoenergy addressed a concern we raised in the draft decision by adopting a four-year average to calculate the fixed price service charge (FPSC), in line with the methodology we used in our draft decision.

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 sets 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).[19]

Below we outline the assessment techniques we used to assess Evoenergy's revised 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.[20] 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.[21] 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 will also drive connections-related capex.

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

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

[21] NER, cl. 6.5.7(a).

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 National Electricity Market (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 NEM[22]. 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; and
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 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.

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[22] This includes Power and Water Corporation.

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'.[23]

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 C.

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

In assessing whether Evoenergy's revised capex forecast is prudent and efficient, we examined the forecasting methodology and underlying assumptions used to derive their forecast. Our industry practice application note[24], which relates to asset replacement planning, aims to assist network businesses with this bottom-up 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.

23 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'.

24 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.

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.[25] The NER requires us to have regard to the annual benchmarking report, as it is one of the capex factors.[26] 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.[27]

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.[28] The AEMC stated:

> "Benchmarking is a critical exercise in assessing the efficiency of an NSP".[29]

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.[30] 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.

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

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

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

28 NER, cl. 6.5.7(c).

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

30 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.

A.6 Other assessment factors

We considered several other factors when assessing Evoenergy's revised 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, including consumer groups; and
- other information provided by Evoenergy.

B Assessment of capex drivers

This appendix outlines our detailed analysis of the categories of Evoenergy’s revised 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 have discussed earlier in this attachment, Evoenergy has justified that its revised total capex forecast reasonably reflects the capex criteria. In this appendix, we set out further analysis in support of this view and the different assessment techniques we relied on to form this view. The structure of this appendix is:

- Section B.1 – forecast augex and reliability capex;
- Section B.2 – forecast customer connections capex, including capital contributions;
- Section B.3 – forecast repex;
- Section B.4 – forecast non-network capex; and
- Section B.5 – forecast capitalised overheads.

B.1 Forecast augex and reliability capex

Network augmentation (augex) is directed at increasing the capacity of the existing network to meet the demand of existing and future customers. It can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

B.1.1 Evoenergy's revised proposal

Evoenergy's revised proposal includes $54.9 million for augex and reliability capex. This is $30.1 million higher than our draft decision and $1.5 million higher than its initial proposal.

Evoenergy reproposed a majority of the projects from its initial proposal with some minor adjustments to some feeders and cost escalation.[31] Evoenergy noted that in our draft decision we were open to considering new information that demonstrates the efficiency and prudency of its augex.

For demand driven augex, Evoenergy responded by amending its planning approach, moving from a deterministic planning approach to a two stage deterministic and probabilistic planning approach.[32]

[31] Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 41.

[32] Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 28.

Evoenergy also noted that due to development accelerating faster than it originally considered in its initial proposal, it has revised its demand forecasts in light of new information.[33]

For secondary systems augex and reliability capex, Evoenergy considered the programs it has reproposed that were not included in our draft decision were related to avoiding future increases in costs rather than efficiency of current activities.[34]

B.1.2 Final decision position

We are satisfied that Evoenergy's forecast augex and reliability capex of $54.9 million ($2018–19) forms part of a total capex forecast that reasonably reflects the capex criteria. In coming to this view, we have assessed:

- Evoenergy's updated demand forecasts; and
- the project documentation accompanying Evoenergy's revised proposal and any further information provided by Evoenergy.

Our findings are:

- Evoenergy has established that its proposed augex forms part of a capex forecast that reasonably reflects the capex criteria.
- Evoenergy has justified its demand driven augex projects with additional supporting evidence. This includes its updated cost benefit analysis models and demand forecasts.
- Evoenergy has not shown that its monitoring program is required to achieve the capex objectives. Specifically, Evoenergy has not identified the benefits to customers nor accounted for these benefits in other parts of its revised proposal. However, this does not change our positon on Evoenergy's capex forecast overall.

B.1.3 Reasons for position

In our preliminary decision on Evoenergy's augex forecast, we considered the trend of historical and forecast expenditure, the accompanying demand forecast and asset utilisation. We then focussed on the project documentation accompanying Evoenergy's proposal and any further information Evoenergy provided on its augex proposal.

For our final decision, we focussed on the incremental differences between our preliminary decision and Evoenergy's revised proposal. The areas of difference relate to:

- demand driven augex projects
- secondary systems augex and reliability capex.

We discuss these two areas in the sections below.

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33 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 32, p. 35.

34 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 39.

Demand-driven augex and non-demand driven augmentation

We consider Evoenergy's demand driven and non-demand driven augmentation projects are prudent and efficient.

In our draft decision, we considered Evoenergy's non-demand driven augmentation projects were prudent and efficient. However, we did not include some demand driven augmentation projects in our preliminary decision forecast.

We noted Evoenergy did not demonstrate that its use of deterministic planning standards would result in augmentation proposals that are prudent and efficient. In particular, Evoenergy's approach relies on a pre-determined set of triggers for initiating augmentation works, which did not necessarily take into account the benefits to consumers. We considered an application of probabilistic planning standards would result in a more efficient use of existing assets.

Consistent with a probabilistic planning approach, we considered several demand driven augmentation projects should be deferred due to the costs of the project exceeding the value of unserved energy. We also noted that we were open to further information from Evoenergy demonstrating that it would be prudent to undertake these projects in the 2019–24 regulatory control period.[35]

In response to our draft decision, Evoenergy reviewed projects with low values of unserved energy. Due to updated demand information, Evoenergy reproposed a majority of projects not included in our draft decision as they were now justified under a probabilistic methodology.[36]

We have undertaken an assessment of Evoenergy's modelling approach and consider the proposed projects are consistent with a probabilistic planning approach. We anticipate Evoenergy will continue to propose projects that are consistent with a probabilistic planning approach in future regulatory proposals.

Review of demand-driven augmentation projects

We have reviewed a number of Evoenergy's proposed demand-driven augmentation projects.

In our draft decision, consistent with our view on probabilistic planning, we considered several demand-driven projects could be efficiently deferred beyond the 2019–24 regulatory control period. This was due to the costs exceeding the benefits of the project.[37]

In response to our draft decision, Evoenergy has updated its cost benefit analysis model and reproposed projects where the benefits exceed the costs.

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[35] AER, *Draft decision - Attachment 5 - Capital expenditure*, September 2018, p. 37.

[36] Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 29.

[37] AER, *Draft decision - Attachment 5 - Capital expenditure*, September 2018, p. 36.

The main driver of increased value of unserved energy, which is the basis of the benefits of each project, are an increase in block load applications. We have reviewed these block load applications and we consider these applications and the associated demand forecast are reasonable.

Evoenergy also changed its modelling approach. The main changes in its methodology were:

- moving from a typical residential feeder load profile curve to using the actual historical load profile curve for each feeder plus the expected load profile curve of forecast loads.
- reduced load transfer capability to reflect the geographical constraints for each feeder.
- in circumstances where the feeder approaches its thermal rating, control measures would be taken to shed load and prevent the feeder from tripping. Therefore, only the load above the thermal rating would not be supplied rather than all load supplied.[38]

We have assessed Evoenergy's updated model and we have identified the following issues:

- It was not apparent if Evoenergy's adjustment factors for block load applications had been accurately taken into account. Adjustment factors for new loads take into account when the connection is expected to proceed. This results in projects that are expected to be undertaken towards the end of the 2019–24 regulatory control period having a higher adjustment factor reflecting the greater uncertainty of the project.
- It was not apparent that Evoenergy had taken into account load transfers in the modelling.

In assessing Evoenergy's models, we tested these assumptions by adjusting the growth in forecast demand. By reducing the growth in forecast demand, it would have the same impact as adjusting for the issues identified above.

Our analysis indicates that the reduction in demand required for the costs to exceed the benefits is greater than if the above issues were fully accounted for in Evoenergy's modelling.

Based on this analysis we are satisfied that Evoenergy has justified its demand driven augmentation. This is because the benefits of undertaking the demand driven augmentation in the 2019–24 regulatory control period exceed the costs of the projects.

We note in future regulatory proposals, Evoenergy's modelling should reflect these issues as part of its probabilistic planning approach.

CCP10 considered Evoenergy had not justified its proposed augex, this is because a 'top down' assessment based on customer demand did not support the increase in augmentation

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38 Evoenergy, *Response to information request 040*, 12 December 2018, p. 2.

relative to the current regulatory control period. CCP10 also considered Evoenergy should be pursuing non-network initiatives to traditional network development.[39]

We agree with CCP10's comments about overall demand. We noted this in our draft decision as part of our trend analysis. However, Evoenergy noted that although there is a decreasing trend in system-wide demand there is no direct causal link between system peak demand and a need for augmentation of zone substations.[40]

We consider an assessment of demand trends on the overall network level provides us with an indication of the overall need for investment. However, we recognise that localised network constraints contrary to overall network trends may require network investment. In this circumstance, Evoenergy's demand driven augmentation is driven by large increases in demand in some zone substations. Based on this new information we have assessed the projects at a more localised level.

Review of Secondary systems augex and reliability capex

We consider that Evoenergy's augex forecast reasonably reflects the capex criteria, however we have concerns with its proposed augex for its distribution substation monitoring and chamber substation programs. We raised these concerns in our draft decision, however they remain unresolved in Evoenergy's revised proposal.[41]

We noted that Evoenergy has incentives to undertake these programs under the EBSS, CESS and STPIS due to the reduced expenditure 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 with regulations. 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.[42]

We also acknowledged that Evoenergy did experience an increase in power quality complaints in part due to changes in customer behaviours and improved reporting processes. However, the information provided to us was not an accurate representation of the voltage risks that Evoenergy is currently managing on its network.[43]

In its revised proposal, Evoenergy noted that the purpose of the programs was to avoid increases in future operating costs. As it has not included these costs in its opex forecast, Evoenergy considered it would be inappropriate to adjust its opex forecasts for these benefits. Evoenergy also noted that it was clear that the purpose of these programs is not to realise efficiencies from current activities. Evoenergy noted that solar penetration is

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[39] CCP10, *CCP10 Response to the Evoenergy Revised Regulatory Proposal 2019–24 and AER draft determination*, January 2019, p. 37.

[40] Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 38.

[41] AER, *Draft decision - Attachment 5 - Capital expenditure*, September 2018, p. 40.

[42] AER, *Draft decision - Attachment 5 - Capital expenditure*, September 2018, p. 40.

[43] AER, *Draft decision - Attachment 5 - Capital expenditure*, September 2018, p. 41.

expected to increase from 12 per cent to 23 per cent over the next five years, which will create reverse power flow issues. Evoenergy considered its preferred option is the least cost option to managing the impact of distributed energy resources (DER).[44]

Evoenergy also provided additional cost benefit analysis and project justification reports in support of its proposed programs.

We have undertaken an assessment of the reasons for undertaking the program and an assessment of the cost benefit analysis.

As noted in our draft decision, we recognise that Evoenergy incurs costs related to power quality complaints. However, we consider Evoenergy has overstated the need for this program. We note all distribution networks are managing the steady increase in solar PV penetration on the electricity networks. However, current solar PV penetration on Evoenergy's network is significantly lower than other networks. For example, Energex,[45] Ergon Energy[46] and SAPN's[47] currently have solar PV penetration rates of 40 per cent, 23 per cent and 24 per cent respectively.

We note these networks have higher solar penetration and are only beginning to include these types of investments to address DER related issues in their regulatory proposals. We also note that Evoenergy is a more urban network, which is less affected by PV induced voltage rises compared to more rural lines in SAPN and Ergon Energy's networks.

We have also assessed Evoenergy's cost benefit analysis. We note that overall, the costs exceeded the benefits for all options considered by Evoenergy.

We consider Evoenergy has also overstated the benefits in its cost benefit analysis, in particular, the growth rate in power quality complaints has not been justified and inconsistent with long term historical reporting over the past 10 years.[48]

Evoenergy has also not considered other lower cost options for addressing high voltage issues. For example, other alternatives such as LV load balancing, phase switching and open point movement, which are lower cost alternatives to Evoenergy's proposed options.[49]

We do not consider Evoenergy has demonstrated that consumers are better off with this project.

We consider the issues we have identified above also relate to Evoenergy's chamber substation augmentation project. Further, we note this program relates to installing

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44 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 39.

45 Energex, Appendix 7.094 Strategic Proposal – Power quality, January 2019, p. 7.

46 Ergon Energy, Appendix 7.095 Strategic Proposal – Power quality, January 2019, p. 12.

47 SA Power Networks, Attachment 5.10 – Distribution System Planning Report, January 2019, p. 23.

48 Evoenergy, Appendix 4.14 Distribution Substation Monitoring and Supply Voltage Optimisation Program PJR, November 2018, p. 7.

49 Evoenergy, Appendix 4.14 Distribution Substation Monitoring and Supply Voltage Optimisation Program PJR, November 2018, pp. 19–22

monitoring in commercial buildings. However, the voltage issues appear to relate to residential lines.

CCP10 did not consider Evoenergy had made a strong case that this investment will be of benefit to customers and there had not been a meaningful discussion regarding possible alternative risk mitigation measures.

We agree with CCP10's assessment of these programs, in particular we have also noted that Evoenergy has not considered other lower cost non-network alternatives. As noted in our draft decision, we consider Evoenergy should account for improvements in its overall proposal. Based on the information provided, we do not consider Evoenergy requires these projects at this stage. However, we acknowledge there will there will be ongoing power quality issues as solar PV uptake increases and Evoenergy may be required to undertake ongoing investment to address these issues after the 2019–24 regulatory control period.

B.2 Forecast customer connections capex

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.

B.2.1 Evoenergy's revised proposal

Evoenergy’s revised proposal included $106.2 million for gross connections capex. This is $20.5 million higher than our draft decision and Evoenergy’s initial proposal.

In our draft decision, we considered that Evoenergy’s forecast connections capex was justified and reasonably reflected the capex criteria. Evoenergy accepted our position in its revised proposal; however, it included an additional $20.5 million for capital contributions. The additional capital contributions relate to the construction of a zone substation to provide additional supply to HMAS Harman.

Evoenergy’s revised forecast connections capex includes:

- net expenditure (costs incurred by Evoenergy) of $59.3 million
- capital contributions of $46.9 million.

Net connections capex is $3.6 million—or 6 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.2.2 Final decision position

Evoenergy has largely demonstrated that its forecast connections capex of $106.2 million is efficient and prudent, and would form part of a total capex forecast that reasonably reflects the capex criteria. In particular, it has justified the additional forecast capital contributions to provide additional supply to HMAS Harman. However, we have made an adjustment to

Evoenergy's forecast to include the changes that it submitted to us ahead of our draft decision.[50] These changes were not reflected in Evoenergy's proposal.

Table B.2.1 summarises Evoenergy's revised forecast connections capex, and our final decision substitute estimate, for 2019–24.

Table B.2.1 – Evoenergy's proposed connections capex for 2019-24 ($2018-19, million)

	Evoenergy's proposal	Substitute estimate	Difference
Net connections capex	59.3	57.5	-1.8
Capital contributions	46.9	48.5	+1.6
Gross connections capex	106.2	105.9	-0.3

Source: Evoenergy capex model, AER analysis.
Note: Data in this table may not add up due to rounding.

B.2.3 Reasons for our position

In coming to our draft decision, we looked at Evoenergy's methodology, historical costs and trends and expected customer growth. We asked Evoenergy to provide supporting documentation including project timing, business cases and options analyses for the proposed construction of a zone substation to provide additional supply to HMAS Harman.

B.2.3.1 Our assessment of forecast connections capex

Evoenergy 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*, which Evoenergy submitted as part of its initial proposal. Our draft decision discussed Evoenergy's methodology and our assessment for each element of its connections forecast.

In our draft decision we noted that, overall, Evoenergy had justified its forecast for connections capex. However, in our draft decision we accepted Evoenergy's revised connections capex that it provided to us on 7 April 2018 as part of its response to information request 020. Compared with its initial proposal, Evoenergy's revised forecast for net connections capex was $1.8 million lower, and its revised forecast for capital contributions was $1.6 million higher.

50 Evoenergy provided revised connections data to the AER on 7 April 2018 as part of its response to information request 020. These revised data were accepted in our draft decision.

In its revised proposal, Evoenergy took the connections capex forecast that it put forward in its initial proposal as a starting point, and added $20.2 million in additional capital contributions for the HMAS Harman project. We pointed out to Evoenergy the difference between its initial proposal and the capex we accepted in our draft decision, and asked Evoenergy to confirm the correct starting point for its revised connections capex forecast. It replied that it "accepts that the starting point should be the AER's estimate of connections capex as per its draft decision."[51]

On this basis, our substitute estimate for connections capex is the same as Evoenergy's revised proposal, with adjustments to reflect the differences between Evoenergy's initial proposal and revised data. These are shown in Table B.2.1.

B.2.3.2 Our assessment of 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 $46.9 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, as it did for its initial proposal. It also included an additional $20.2 million for the construction of a zone substation to provide additional supply to HMAS Harman. Evoenergy submitted that:[52]

> "A Commonwealth Government department is currently in the early stages of planning for a new data centre in Canberra. The expected increase in load on Evoenergy's network (19.3 MVA by 2024) requires the construction of a new 132/11 kV zone substation and sections of the 132 kV transmission line. These works are estimated to cost $27 million, to be fully funded by the department involved."

Evoenergy noted in its revised proposal that "the delivery and timing of the project are mandated by government and are outside of Evoenergy's control." Noting these concerns, we requested further information from Evoenergy regarding the timing of the project, business cases and options analyses.

In its response, Evoenergy provided:[53]

- information from the Department of Defence confirming project approval, and that existing supply to HMAS Harman will be exceeded by mid-2021
- an options analysis report detailing project need and fully-costed options analyses

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51 Evoenergy, *Response to AER information request 041*, 17 January 2019, p. 3.

52 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 41.

53 Evoenergy, *Response to AER information request 041*, 17 January 2019.

- assurance that it expects capital contributions for the project to be incurred in the 2019–24 regulatory period.

We consider that Evoenergy has justified its forecast capital contributions. We have also included an additional $1.6 million to reflect Evoenergy’s updated connections forecast as outlined in section B.2.3.1.

B.3 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;[54]
- 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 capex.

B.3.1 Evoenergy's revised proposal

Evoenergy has proposed forecast repex of $91.8 million ($2018–19) in its revised proposal. This repex forecast is unchanged from Evoenergy's initial proposal. In our draft decision, we accepted most of Evoenergy’s initial repex forecast, but we noted that Evoenergy had not justified its repex forecast for the underground cable asset group, specifically its high-voltage underground cable assets.

In response to our draft decision and following constructive engagement, Evoenergy provided additional information and analysis, including risk quantification and cost-benefit analysis, to support its underground cable repex forecast in its revised proposal.

54 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.

B.3.2 Final decision position

We accept Evoenergy's repex forecast of $91.8 million ($2018–19). Evoenergy has justified that this repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.

B.3.3 Reasons for our position

Following our draft decision, our final assessment primarily focused on Evoenergy's high-voltage underground cable forecast of $16.7 million ($2018–19). We conducted a detailed bottom-up review of Evoenergy's underground cable cost-benefit analysis model and supporting documentation that was provided in its revised proposal.

In addition, Evoenergy corrected several historical data reporting issues that initially contributed to significant differences between Evoenergy's modelling for this asset category and our repex modelling results. We used this updated data to rerun our repex modelling results and Evoenergy's repex forecast now sits below our updated repex model threshold.

Bottom-up and top-down considerations

Bottom-up considerations

Following our draft decision, Evoenergy provided a high-voltage underground cable cost-benefit analysis model and a supporting business case review from its consultant, CulterMerz, on 29 October 2018. We met with Evoenergy and CutlerMerz via teleconference, where they outlined the broad structure of its cost-benefit analysis modelling and sought preliminary feedback on its approach. We commend Evoenergy for seeking to engage so soon after the draft decision and organising to meet with us prior to submitting its revised proposal. We found it constructive to discuss the outstanding repex issue early on in the process.

Our review of Evoenergy's high-voltage underground cable cost-benefit analysis model[55] and business case identified that Evoenergy's repex forecast of $16.7 million ($2018–19) would form part of a total capex forecast that reasonably reflects the capex criteria. Evoenergy's business case states that its:

> "evaluation process aligns with industry practices and consists of four key areas of assessment:
>
> - current asset health condition and expected deterioration over time;
> - the probability of failure associated with each health condition;
> - the expected cost of failure considering the likelihood and severity of the consequence; and

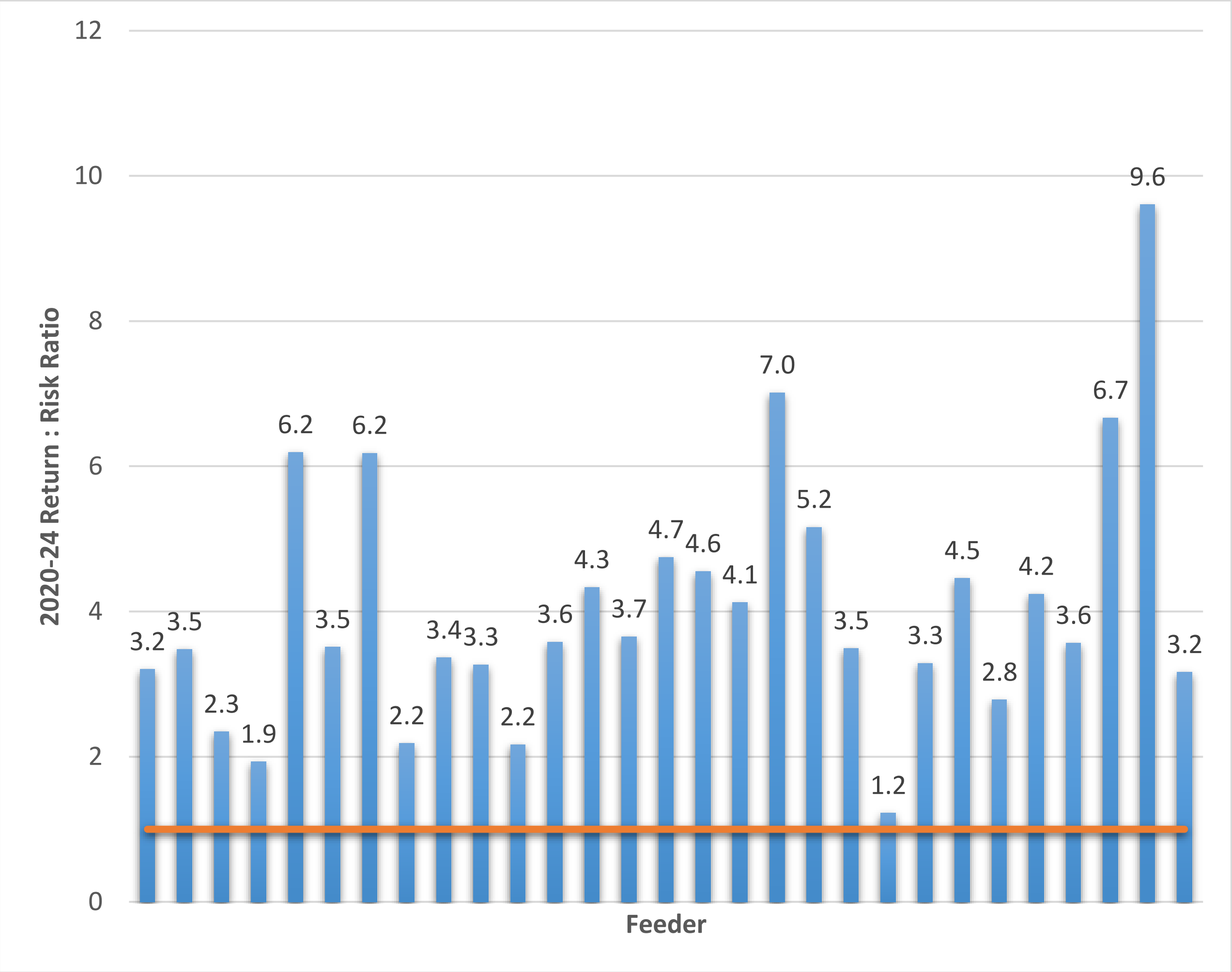
[55] Evoenergy, *Revised proposal, Appendix 4.13, HV cable modelling – CONFIDENTIAL,* November 2018.

- the calculated risk associated with no investment versus the risk after investment."[56]

Evoenergy has justified that the proposed quantified benefits of its high-voltage underground cable replacement program, via risk reduction, are likely to exceed the proposed costs. Our draft decision raised concerns with the general safety risk assumptions in Evoenergy's cost-benefit analysis, but its HV cable model clarified that the primary risk associated with its high-voltage underground cables is unserved energy risk.

Overall, Evoenergy's cost-benefit analysis demonstrated that each of its 29 individual high-voltage feeders were cost-benefit positive, i.e. the expected quantified annual risk reduction for each feeder was likely to exceed the annualised program cost over the 2019–24 forecast period.[57] These results are summarised below in Figure B.3.1.

Figure B.3.1 – Feeder level cost-benefit outcomes



Source: Evoenergy, *Revised proposal, appendix 4.12, HV cables business case, Figure 9,* November 2018, p. 15.

[56] Evoenergy, *Revised proposal, Appendix 4.12, HV cables business case,* November 2018, p. 11.

[57] Evoenergy, *Revised proposal, Appendix 4.12, HV cables business case, Figure 9,* November 2018, p. 15.

Top-down considerations

In our draft decision, we stated our top-down considerations of Evoenergy's repex forecast included our repex modelling assessment and CutlerMerz's consideration of risk, submitted as Appendix 5.1 of Evoenergy's initial proposal.[58]

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

In our draft and final decisions for Evoenergy's 2015–19 regulatory control period, we noted that its capex forecast did not apply a top-down assessment.[59] 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.[60] As we stated in our draft decision, we commend Evoenergy for applying 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; and
4. bottom up.

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.[61]

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 Evoenergy's repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.

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

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

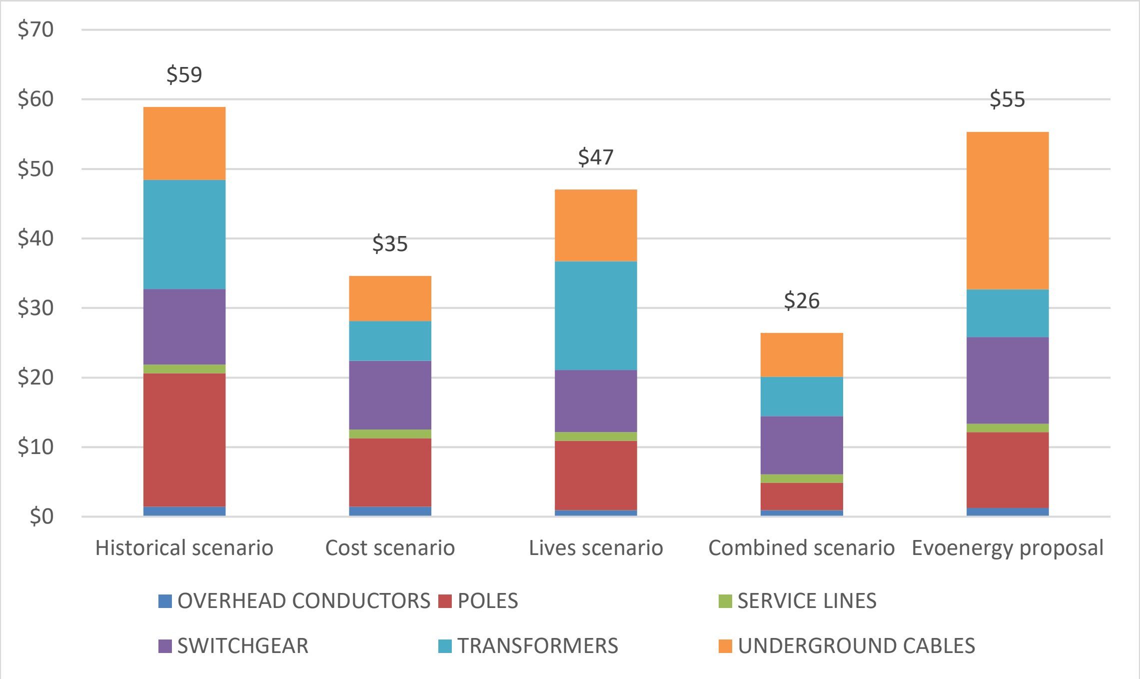
[60] AER, *Draft decision, ActewAGL distribution determination, 2015-16 to 2018-19, Attachment 6: capital expenditure,* November 2014, p. 6-19.

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

Repex modelling

In our draft decision, we presented our initial repex modelling results against Evoenergy's modelled repex forecast. These initial results are outlined below under Figure B.3.2.

Figure B.3.2 – Initial repex modelling results ($2018–19, million)



In our draft decision, we highlighted that Evoenergy's forecast repex differed most significantly from our initial repex modelling scenarios in the underground cable asset group (again highlighted in Figure B.3.2). In response to our draft decision, Evoenergy raised concerns with the repex modelling inputs, specifically the historical unit cost and calibrated expected replacement life, used for its high-voltage underground asset category.[62]

During the initial proposal stage, we sent Evoenergy an information request in an effort to clarify these underlying data inputs.[63] Evoenergy's response indicated that "some expenditure on cable and overhead conductor replacements may not have been captured"[64] in this historical data, but no recast data was provided. Following our draft decision during our engagement with Evoenergy, we advised that these inputs were based on Evoenergy's historically reported category analysis RIN data.

In response to our draft decision and this engagement, Evoenergy stated:

> "The unit cost applied by the AER has been based on Regulatory Information Notice (RIN) data provided by Evoenergy. A review of the RIN submitted over the period

[62] Evoenergy, *Revised regulatory proposal main document,* November 2018, p.44.

[63] AER, *Information request 017,* 18 April 2018.

[64] Evoenergy, *Response to AER information request 017,* 10 May 2018, p. 2.

> 2013–14 to 2016–17 identified an anomaly in the HV cable data. Expenditures associated with HV Cable replacement projects were incorrectly categorised as augmentation investments as result of their scale, resulting in an under-representation of the replacement cost of HV cables."[65]

To rectify this data reporting issue, Evoenergy provided updated historical data for its high-voltage underground cable asset category in its revised proposal.[66] This updated data was used to rerun our repex modelling results, which are presented below in Figure B.3.3.

Figure B.3.3 – Revised repex modelling results ($2018–19, million)

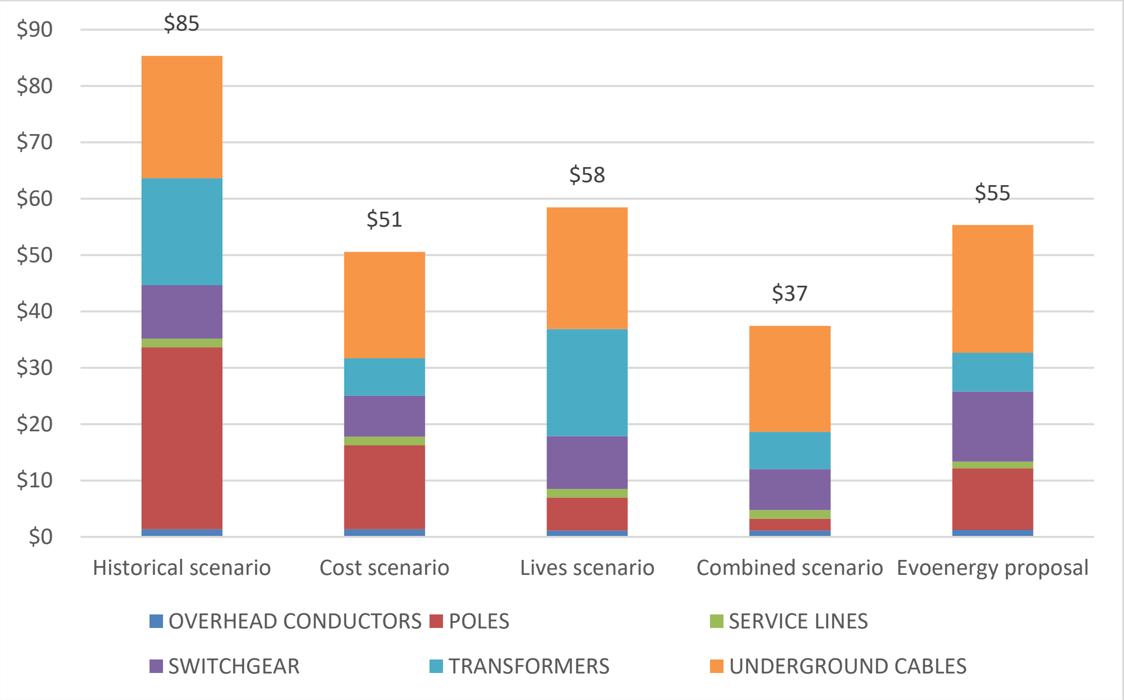


Figure B.3.3 highlights that Evoenergy's modelled repex forecast falls slightly below our updated repex model threshold when more representative repex model inputs are used. The modelled amounts for the underground cable asset group increase most significantly from the initial repex modelling results by adjusting the underlying unit cost and expected asset replacement parameters.

Specifically, a more representative high-voltage underground cable unit cost underpins the results in Figure B.3.3. In addition, using the updated replacement volume data provided produces an inferred calibrated expected replacement life of 87 years, compared with the figure of 100 years used in the draft decision. In its revised proposal, Evoenergy noted:

> "Evoenergy's investment forecast indicated that the expected life for Evoenergy's HV cable asset life would be around 88 years. This represents a 30 year, or 53% life extension from the industry standard life and significantly longer than the industry

65 Evoenergy, *Revised proposal, Appendix 4.2, HV cables business case,* November 2018, p. 8.

66 Evoenergy, *Revised proposal, Appendix 4.2, HV cables business case - CONFIDENTIAL,* November 2018, p. 8.

> average from modelling the AER has performed on other networks. These findings point to the reasonableness of Evoenergy's HV cable forecast expenditure."[67]

We agree with Evoenergy's findings and note that our updated modelling results produce a high-voltage underground cable forecast that is more aligned with Evoenergy's forecast. We appreciate that Evoenergy engaged with our repex modelling results and advised us where it had areas of concerns with the modelling inputs following the draft decision.

Overall, we accept Evoenergy's high-voltage underground cable repex forecast of $16.7 million ($2018–19) and its total repex forecast of $91.8 million ($2018–19). Evoenergy has justified that this repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.

B.4 Forecast non-network capex

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

B.4.1 Evoenergy's revised proposal

Evoenergy's revised proposal includes forecast non-network capex of $56 million ($2018–19). This is a reduction of $2.3 million from Evoenergy's initial proposal of $58.3 million, and an increase of $10 million from our draft decision of $46 million.[68]

Evoenergy's revised proposal:

- did not accept our draft decision on proposed ICT capex. Evoenergy's revised proposal:
  - agreed with our draft decision to remove contingency costs from ICT project forecasts;[69]
  - disagreed with our draft decision to not include proposed capex for its Advanced Distribution Management System (ADMS) upgrade project. Evoenergy retained proposed capex for the ADMS upgrade in its revised proposal;
  - disagreed with our draft decision to not include proposed capex for its corporate ICT asset extensions expenditure (Business Intelligence and IT Platforms projects). Evoenergy retained proposed capex for these projects in its revised proposal.
- accepted our draft decision on fleet and plant capex;
- proposed additional forecast capex of $2 million for physical security expenditure. We accepted Evoenergy's initial proposal for buildings and property and 'other' non-network capex, as part of our draft decision.[70]

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[67] Evoenergy, *Revised proposal, Appendix 4.2, HV cables business case,* November 2018, p. 10.

[68] Evoenergy, *Revised regulatory proposal main document*, November 2018, p. 57.

[69] Evoenergy, *Response to AER Information Request 043*, 20 December 2018, p. 3.

We received one submission on Evoenergy's revised non-network capex proposal. CCP10 submitted that with the exception of ICT capex, it "accepts and supports" Evoenergy's proposal. CCP10 submits:[71]

> “Inherent in the proposal is the suggestion that the ICT investment will improve network reliability, reduce overhead costs, improve customer services and permit a greater penetration of DER. However, these benefits are poorly articulated, largely as a result of the volume of technical information presented as part of the proposal and a lack of clarity around the performance measures and customer outcomes that will flow from the investment.
>
> On that basis, it is difficult to support the full amount of the proposed expenditure on ICT and therefore non-network capital expenditure as being prudent and in customers’ interests. Our expectation is that a prudent level of expenditure will be an amount less than the proposed $56M.”

B.4.2 Final decision position

We are satisfied that Evoenergy's forecast non-network capex of $56 million ($2018–19) forms part of a total capex forecast that reasonably reflects the capex criteria. In coming to this view, we have assessed the project documentation accompanying Evoenergy's revised proposal and any further information provided by Evoenergy.

Our findings are that:

- Evoenergy has established that its proposed non-network capex forecast part of a capex forecast that reasonably reflects the capex criteria.
- Evoenergy has not sufficiently demonstrated its ICT capex forecast against the capex criteria. However, this does not change our position on Evoenergy’s forecast capex overall.
- Evoenergy has justified its proposed physical security capex.

B.4.3 Reasons for our position

For our final decision, we focussed on the incremental differences between our preliminary decision and Evoenergy's revised proposal. The areas of difference relate to:

- ADMS upgrade project;
- ICT asset extensions capex; and
- physical security capex.

We discuss these three areas in the sections below.

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70 AER, *Evoenergy 2019-24 - Draft Decision - Attachment 5 - Capital expenditure*, September 2018.

71 CCP10, *Submission on AER draft decision and Evoenergy revised proposal*, January 2019, p. 39.

ADMS Upgrade

We consider that Evoenergy's non-network capex forecast reasonably reflects the capex criteria, however we have concerns with its proposed capex for the ADMS upgrade project. We consider that it would be more prudent for Evoenergy to undertake the 'do-nothing' option and commence the upgrade in following regulatory control periods.

While we do not accept or approve certain projects, we note that if Evoenergy decides to undertake this project in the forthcoming period, it is our expectation that Evoenergy documents closely the benefits arising from this expenditure and that these are reported in subsequent regulatory proposals.

In our draft decision, we considered that Evoenergy had not demonstrated that the proposed upgrade was required for the 2019-24 regulatory control period, and was therefore not reflective of the costs of a prudent and efficient operator.[72] Our draft decision noted that we were open to consider further information from Evoenergy to demonstrate the benefits of the upgrade.[73] We also advised Evoenergy to incorporate any identified benefits into its overall revised proposal.

In its revised proposal, Evoenergy maintained its initial proposal of $11.2 million for a full upgrade of its ADMS. In response to our draft decision, Evoenergy submitted a revised business case and cost-benefit analysis in support.

We have undertaken an assessment of the revised business case and cost-benefit analysis in support of the project. Our findings are outlined below.

Insufficient options analysis

We do not consider that Evoenergy has undertaken a sufficient options analysis. While Evoenergy has now considered and assessed a deferral option, which is an improvement to its initial proposal, Evoenergy has no longer assessed a 'do-nothing' option. In a section of the business case, 'Other options considered but not feasible', Evoenergy discusses an option called 'Permanent deferral'. Evoenergy submitted that this option is not feasible as:[74]

> “It is not reasonable to forecast the long-term support and maintenance costs for the existing ADMS, including supporting software and hardware. Risk exposure and growth in direct costs to maintain the system are reasonably expected to grow exponentially over time.”

We do not agree with Evoenergy that it cannot forecast these costs. Many other DNSPs have been able to do so with similar projects, for example Ausgrid has analysed the cost of maintaining its system (which has been operational since the 1990’s) in its ADMS Upgrade business case.[75] As such, we consider that Evoenergy has incorrectly rejected a 'do-nothing' option from its analysis.

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72 NER. 6.5.7 (c)(1).

73 AER, *Evoenergy 2019-24 - Draft Decision - Attachment 5 - Capital expenditure*, September 2018, p. 5-70

74 Evoenergy, *Revised Proposal - Appendix 4.18 ADMS Business Case*, November 2018, p. 22

75 Ausgrid, *Revised Regulatory Proposal Attachment 5.13.N.1 - ADMS Business Case*, January 2019.

We also note the acquisition of third party support can mitigate potential risks of maintaining the current system. In the business case, Evoenergy submits that:[76]

> "Third-party providers may be able to fill some of the security and functionality gap left by the end of Microsoft extended support, but the cost is expected to be high."

Evoenergy however does not attempt to quantify the cost of this support. We consider this is evidence that Evoenergy has not adequately considered and assessed the costs of third party support. Evoenergy has therefore not evidenced its claim that its chosen option is the lowest cost and therefore the most prudent and efficient option in line with the capex objectives.

Unsupported quantified benefits

Evoenergy has quantified the following benefits from implementing the ADMS:

- $500k p/a reduction in resourcing costs due to installing the GIS module;
- $400k p/a reduction in avoided DER and transmission modelling costs as a result of the EMS module;
- $425k p/a reduction in 'ADMS fixes' avoided by removing the need to implement annual fixes that are currently applied;
- $100k avoided due to reduced cost of hardware/software support.

We sought further information from Evoenergy to understand these benefits in greater detail. From review of Evoenergy's responses we consider that each benefit assumption has been supported, with the exception of the 'ADMS fixes' assumption.

Evoenergy has submitted that it currently incurs an annual cost of $425k for 'ADMS Fixes'.[77] Evoenergy has submitted that a benefit of the upgrade will be:[78]

- Once funding approved is obtained, it will not invest in ADMS fixes and would wait for the next baseline version; and
- ADMS fixes will not be required for the three years following the upgrade.

Evoenergy has not supported these assumptions. Firstly, we would consider that if upgrades were found in the years before the upgrade it would be likely that Evoenergy would naturally implement these upgrades as required. It is also unlikely that these decisions would align with funding approvals, or as Evoenergy has assumed, revenue determinations. We also note that this is not a benefit of the upgrade, but rather an assumption by Evoenergy about whether it will decide to implement improvements/enhancements to its existing system in the lead up to an upgrade. Evoenergy has provided no evidence to validate this claim.

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76 Evoenergy, *Revised Regulatory Proposal - Appendix 4.18 ADMS Business Case*, November 2018, p. 17.

77 Evoenergy has submitted that 'ADMS fixes' refer to "improvements to allow compliance with industry rules and/or benefits to be extracted from more efficient operation".

78 Evoenergy, *Response to AER Information Request 044*, 11 January 2019, p. 5.

Secondly, we note that Evoenergy's current system went live in February 2016. Evoenergy provided[79] historical expenditure for ADMS fixes for the past 3.5 years (since April 2015). This historical evidence contradicts Evoenergy's submission as it has incurred 'ADMS fixes' expenditure within three years of implementing its current system.

Insufficient evidence benefits have been accounted for in overall proposal

A finding of our draft decision was that Evoenergy had not demonstrated how the expected benefits from the upgrade were used to inform the overall proposal. While Evoenergy has identified these various benefits, Evoenergy has provided no evidence that these have been accounted for in its revised proposal. This is evidence that a portion of the investment cost should not be funded by consumers as Evoenergy will receive pay-back on the investment through the CESS and EBSS incentive schemes.

Additional benefit from deferral

In our draft decision, we also expressed that Evoenergy could benefit from not being an early adopter of the ADMS. Given ACT's lower PV penetration rates compared to SA and QLD, we considered Evoenergy could benefit from information sharing with those distributors rather than being an early adopter itself.

We note that Evoenergy has proposed a change in the timing of the project relative to its initial proposal, submitting that:[80]

> "[Its initial proposal] was based on an earlier version of the ADMS business case, where it was expected that the upgrade could happen earlier in the regulatory period. This would have resulted in a higher NPV as the benefits could be gained for a longer period. However, the earlier implementation was ultimately not supported by Evoenergy due to changes in internal capability to efficiently manage the investment and the need to ensure that the ADMS, in particular the SCADA and DERMS modules, would be sufficiently tested by other utilities."

This is evidence that Evoenergy has somewhat considered the benefit of deferral. However, these benefits are not discussed in the business case.

We note that the implementation of technology solutions to improve visibility of the low voltage network, apply dynamic management of the low voltage network and communicate with DER consumers in real-time represents a significant change in the current IT systems of a DNSP. These proposed services would represent cutting edge developments for a network business and therefore carry an attendant risk in terms of cost and time to implement. We consider that Evoenergy is in the enviable position of being able to defer these IT system upgrades and learn from the experiences of other network businesses that are already dealing with DER penetration rates that are more than double those of the ACT. These learnings from other DNSPs will only become greater the longer Evoenergy decides to defer this project. In short, we consider that a more prudent approach would be to delay the upgrade into subsequent regulatory control periods.

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79 Evoenergy, *Response to AER Information Request 044*, 11 January 2019, pp. 4-5.

80 Evoenergy, *Response to AER Information Request 050*, 25 January 2019, p. 3.

ICT Asset Extensions Capex

We consider that Evoenergy's non-network capex forecast reasonably reflects the capex criteria, however we have concerns with its proposed capex for ICT asset extensions.

In our draft decision, we were not satisfied that Evoenergy's proposed $2.0 million for ICT asset extensions capex, comprised of *Business Intelligence* and *IT Platforms* projects, were required to meet the capex objectives for the 2019-24 regulatory control period. In coming to this view, we observed that the benefits identified in the business cases for these projects was zero, with the subsequent NPV of each investment negative. We suggested in our draft decision that Evoenergy provide a sufficient business case for this investment, which would include adequate cost-benefit analysis and a demonstration of how claimed benefits were incorporated into the overall proposal (i.e. opex step-change).

Evoenergy’s revised proposal resubmits the two projects. In response to our draft decision, Evoenergy provided revised business cases in support of the proposed investment.

We have undertaken a business case review of the two projects. Our findings are outlined below.

Lack of information demonstrating benefit

In the revised business cases provided, the benefits incorporated into the investment appraisal remain at zero, with the subsequent NPV of the investment as negative. Evoenergy has therefore not demonstrated if:

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

We subsequently asked Evoenergy to provide any further information available on the benefits of these projects. Evoenergy submitted that for the Business Intelligence project:[81]

> “The benefits arising from Business Intelligence expenditure are derived through better analytics, which makes identifying tangible, financial benefits prior to actionable insights difficult. Benefits, while not financially quantified, are clearly identified in the relevant business cases with respect to the NER Criteria.”

Evoenergy submits that the project will "Improve the ability to analyse and inform decisions regarding demand for standard control services"[82]. This contradicts capex objective 6.5.7(a)(1), which only requires Evoenergy to meet or manage the expected demand for standard control services over that period. Evoenergy also submits that the project satisfies clause 6.5.7(c)(1) (the efficient costs of achieving the capital expenditure objects) as:[83]

> “The preferred option focuses on reducing the manual processes associated with the current reporting, reducing reliance on external contracts to develop BI and reporting

[81] Evoenergy, *Response to AER Information Request 050*, 25 January 2018, p. 2.

[82] Evoenergy, *Revised Regulatory Proposal – Appendix 4.19 Business Intelligence Business Case*, November 2018, p. 7.

[83] Evoenergy, *Revised Regulatory Proposal – Appendix 4.19 Business Intelligence Business Case*, November 2018, p. 8.

> capabilities, and increasing the quality of the reporting. The project will support the achievement of efficient cost to achieve reporting and business intelligence objectives."

However, because Evoenergy has not provided analysis to demonstrate that these benefits exceed the forecast costs, Evoenergy has not demonstrated that this project satisfies clause 6.5.7(c)(1) of the criteria. On this basis, Evoenergy has not sufficiently justified its proposed Business Intelligence capex.

For the ICT Platforms project, Evoenergy submits:[84]

> "that ICT Security is a growing concern in the energy industry as evidenced by the Finkel Review (recommendation 2.10 and sub-recommendations). The benefit from establishing and maintaining contemporary ICT Security systems is realised through maintaining the safety and security of supply services, rather than bankable benefits."

We recognise that the cyber security landscape is one of continuing complexity and increased risk. The NER requires Evoenergy to comply with all relevant regulatory obligations and requirements[85] as well as maintain the security of supply of standard control services.[86]

Evoenergy has submitted that recent reviews have demonstrated that additional investment is required to mature and develop its ICT security capabilities. In particular, AEMO has reviewed Evoenergy's ICT security against the Electricity Subsector Cybersecurity Capability Maturity Model.

Evoenergy has submitted that this expenditure will ensure that its ICT security capability will be maintained in line with industry peers to ensure Evoenergy is able to maintain the security of critical network infrastructure. Evoenergy has also submitted that changes to the *Electricity Supply Act 1995* (NSW) require it to maintain a level of ICT security at a higher standard that previous regulatory periods.[87] We therefore accept the ICT security component of the project as reflective of the capex criteria.

We note however that under the ICT Platforms program, Evoenergy has proposed two other platforms, Mobility Infrastructure and Digital Content Management. Evoenergy has not demonstrated any incremental benefit from this added investment. As such, we do not consider that Evoenergy has demonstrated the scope of the overall project reflects the capex criteria.

Insufficient evidence benefits have been accounted for in overall proposal

While Evoenergy has identified these various efficiency benefits, no evidence has been provided that these have been accounted for in its revised proposal. We consider this is evidence that a portion of the investment cost should not be funded by consumers as

84 Evoenergy, *Response to AER Information Request 050*, 25 January 2018, p. 2.

85 NER, cl. 6.5.7(a)(2)

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

87 Evoenergy, *Revised regulatory proposal main document*, November 2018, p. 54.

Evoenergy will receive pay-back on in the investment through the CESS and EBSS incentive schemes.

Physical Security Capex

Evoenergy has demonstrated that its proposed physical security capex is part of a capex forecast that reasonably reflects the capex criteria.

Evoenergy's revised proposal includes an additional $2 million for physical security capex. Evoenergy submitted that as a result of its recently completed revision of is Security Management Plan, various recommendations were made in regards to the upgrade of physical security measures at certain sites. Based on these recommendations, Evoenergy has proposed to implement various security measures, which include upgrades/replacements for CCTV, lighting, signage and electronic access systems.[88]

We consider that the management of the security and safety of Evoenergy's network is an ongoing requirement for Evoenergy. We asked Evoenergy to provide historical physical security capex.[89] Evoenergy's forecast is 30 per cent lower than what Evoenergy forecasts to spend over the current regulatory control period and is in line with longer-term historical levels. We therefore consider that trend analysis comparing forecast physical security capex to historical expenditure supports Evoenergy's proposal. [90]

We have also reviewed project documentation provided and further information provided in response to an information request. Evoenergy provided:

- a Project Justification Report (PJR) and accompanying excel spreadsheet outlining the options analysis and cost estimates used to form the forecast;
- a copy of the revised Security Management Plan which outlined Evoenergy’s risk assessment approach and provided site reports for each building.
- a copy of its internal Physical Security Standard.[91]

We consider that this documentation provides sufficient information to support the proposed expenditure. Evoenergy has provided detailed information on the current state of physical security at each site and has outlined the recommended security measures as required by its Standard. Evoenergy has also evidenced that it has considered the relative underlying risk at each site and has recommended security upgrades accordingly.

We also note that Evoenergy engaged Jacobs consulting to independently review the security upgrade PJR. Jacobs endorsed the original scope of security upgrades developed by Evoenergy but suggested various adjustments to the assumed costings.[92] Evoenergy subsequently adopted the costings recommended by Jacobs in forming its proposal. As

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88 Evoenergy, *Revised regulatory proposal main document*, November 2018, pp. 57-58.

89 Evoenergy, *Response to AER Information Request 043*, 20 December 2018

90 NER, cl. 6.6A.7(c).

91 Evoenergy, *Response to AER Information Request 43*, 20 December 2018

92 Evoenergy, *Response to AER Information Request 43*, 20 December 2018, p. 2

such, we are satisfied from a bottom-up perspective that Evoenergy's forecast reasonably reflects Evoenergy's capex requirements to meet the capex objectives.

B.5 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.5.1 Evoenergy's revised proposal

Evoenergy's revised proposal for capitalised overheads in 2019–24 is $66.4 million. This is $9.2 million, or 12 per cent, lower than its initial proposal and $8.4 million, or 14 per cent, higher than our draft decision.[93] Evoenergy's revised forecast is higher than our draft decision because of the higher direct capex against which capitalised overheads are forecast. It also incorporates an adjustment to correct a methodological error we made when calculating the base-year opex in the overhead capitalisation rate in our draft decision. The increase was partially offset by a higher revised forecast for opex, so that a lower proportion of overheads are allocated to capex.[94]

B.5.2 Final decision position

Evoenergy has 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.

B.5.3 Reasons for our position

In its revised proposal, Evoenergy used the same general approach to forecast capitalised overheads as it did for its initial proposal. However, there are a number of important differences including:[95]

- adoption of a four-year average to calculate the fixed price service charge (FPSC), in line with the methodology we used in our draft decision
- a reduction in forecast direct capex compared with Evoenergy's initial proposal (but higher than in our draft decision)
- an increase in the base-year opex means that a smaller proportion of the FPSC is allocated to capex.[96]

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93 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 61.

94 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 61.

95 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 61.

96 The fixed price service charge represents total corporate overheads across Evoenergy's business. The allocation of these overheads to capex is impacted by forecast direct capex as a share of totex.

Changes in forecast direct capex and opex influence the capitalised overheads forecast

Evoenergy forecasts its capitalised overheads requirement with respect to forecast direct capex, and capex as a proportion of totex. Compared with its initial proposal, Evoenergy has:

- increased its forecast for opex, resulting in a lower capitalised overhead rate
- decreased its forecast for capex, resulting in the capitalised overhead rate being applied to a lower amount of direct capex.

Evoenergy has addressed our concerns about the FPSC forecast

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.[97] The FPSC is then divided by direct costs to calculate the capitalised overhead rate, in accordance with the formula: [98]

$$Capitalised\ Overhead\ \% = \frac{Fixed\ Price\ Service\ Charge_{Base\ Year} \times 5}{Direct\ Totex_{Reg\ Period}}$$

$Where$:

$$Direct\ Totex_{Reg\ Period} = Total\ Forecast\ Capex_{Reg\ Period} + Direct\ Opex_{Base\ Year} \times 5$$

A key concern for us in our draft decision was Evoenergy's use of 2017–18 as the base-year FPSC to calculate the capitalised overhead rate. We considered that by using the 2017–18 FPSC as the basis for its forecast, Evoenergy may have overestimated its required capitalised overhead costs in 2019–24.[99]

In its revised proposal, Evoenergy has addressed this concern by adopting our draft decision approach of using a four-year average for the FPSC.

Correction of the base-year opex calculation in the draft decision

Following the release of our draft decision, Evoenergy engaged with us to discuss our substitute estimate for capitalised overheads in more detail. It identified that in our calculation we had included indirect costs for opex, which Evoenergy had excluded in its own forecasting methodology. Evoenergy subsequently provided further information which clarified how it arrived at its forecast for the FPSC and consequently for the capitalised overhead rate. Evoenergy sufficiently demonstrated the methodology behind its capitalised overheads forecast in the initial proposal, and we are satisfied that its methodology allowed it to arrive at a revised forecast for capitalised overheads is prudent and efficient.

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

98 Evoenergy, *Revised regulatory proposal main document,* November 2018, p. 58.

99 AER, *Draft decision - Evoenergy distribution determination 2019-24, Attachment 5: Capital expenditure*, pp. 5-75.

C 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; and
- the repex model outcomes under different scenarios.

C.1 Background to predictive modelling

In 2012, the AEMC published changes to the NER and National Gas Rules (NGR).[100] 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.[101]

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).[102] 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.[103] 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 repex forecast is derived by multiplying the forecast replacement volumes for each asset category by an indicative unit cost.

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

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

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

103 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 NEM.[104]

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.

C.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; and
- 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 that are issued to all distributors in the NEM; and
- reset RINs that 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.[105]

104 This includes Power and Water Corporation.

105 NER, cl 6.5.7(c).

C.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; and
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.

C.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; and
- 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;[106]
- 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; and
- where a calibrated replacement life is not available, we substitute the value of a similar asset category.

C.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 expected repex

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

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.[107] 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.

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.

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

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’.[108] 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.

C.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.[109] 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.[110] 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 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

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108 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’.

109 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.

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

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.[111]

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.[112]

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.

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

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[111] 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.

[112] 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.

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.

D Engagement process

Information requests

Evoenergy submitted its revised proposal on 29 November 2018. Throughout our assessment of Evoenergy's revised proposal, we requested further information via several information requests. We sent seven information requests relating to Evoenergy's revised capex forecast. These questions aimed to test our understanding of the revised material provided and to request additional supporting information, particularly relating to Evoenergy's revised demand forecasts and ICT proposal.

Engagement

We have engaged with Evoenergy and other key stakeholders on several occasions throughout our assessment of its revised proposal. These interactions are summarised below:

- 25 September 2018 – Evoenergy updated us with details relating to a potential Department of Defence project that may be included in its revised proposal as a capital contribution.
- 25 October 2018 – We had a teleconference with Evoenergy to discuss its forecast methodology for capitalised overheads. Evoenergy subsequently provided us with additional information which supported our assessment of its revised capitalised overheads proposal.
- 30 October 2018 – We met with Evoenergy and its consultant, CutlerMerz, to discuss our draft decision and Evoenergy's proposed HV underground cable replacement program. Evoenergy provided its cost-benefit analysis model and supporting business case document prior to the meeting to help inform the discussion.
- 27 November 2018 – We met with Evoenergy to discuss its HV underground cable replacement program and to clarify some data reporting issues that we sought to clarify in the initial proposal stage. Evoenergy provided additional information relating to three recent significant HV cable replacement projects and advised that this information would also be available in its revised proposal.

E Forecast demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex and to our assessment. 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 capex objectives.[113] Accurate demand forecasts are therefore important inputs to ensure efficient levels of network investment.

We are satisfied that the system demand forecast in Evoenergy's revised regulatory proposal for the 2019–24 regulatory control period reasonably reflects a realistic expectation of demand. However, in this decision we note some concerns arising from changes Evoenergy has made to its model specifications. We acknowledge that demand forecasting is not a precise science and that Evoenergy's forecasts will inevitably contain errors.

In the draft decision, we considered Evoenergy's demand forecasts at the system level and the localised zone substation level. We accepted the demand forecasts based on the following observations: [114]

- Both Evoenergy's and AEMO's forecasts of summer peak demand indicated slightly negative growth, consistent with the broadly flat historical trend.
- Evoenergy's winter peak demand forecasts were also negative, reflecting network-specific growth rather than the wider NSW/ACT trend forecast by AEMO.
- Evoenergy applied the Monash Electricity Forecast Model (MEFM) to modelling peak demand, a similar forecasting methodology to that used by AEMO for modelling state-based system level peak demand.
- Evoenergy's aggregated peak demand forecasts derived from the bottom-up approach at the zone substation level were on average four per cent lower than the corresponding top-down system forecasts over the period 2018 to 2027.

However, using the given localised demand forecasts, we considered that some of the proposed demand-driven augmentation capex program was not sufficiently justified.[115]

Evoenergy has revised its demand forecasts in its revised proposal. While top-down system peak demand forecasts remain trending downward (at least up to the end of 2023-24), the localised demand forecasts are revised upward substantially for some zone substations, which are used in support of Evoenergy's revised capex program.

We note that the resulting aggregated zone substation peak demand forecasts for both summer and winter indicate a strong upward trend. By the end of 2023-24, the aggregated

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113 NER, cll. 6.5.6(c)(3), 6.5.7(c)(1)(iii).

114 AER, *AER Draft Decision – Evoenergy Distribution Determination 2019-24*, *Attachment 5: Capital Expenditure*, September 2018, pp. 5-86 to 5-91.

115 AER, *AER Draft Decision – Evoenergy Distribution Determination 2019-24, Attachment 5: Capital Expenditure,* September 2018, pp. 5-26 to 5-38.

zone substation summer forecast (at POE50%) is higher than the corresponding top-down system forecasts by 5 per cent. We also note that Evoenergy and its consultant, Jacobs, have made substantial changes to model specifications for seasonal average demand at some zone substations. These changes include (but may not be limited to):

- using monthly data instead of quarterly data for modelling seasonal average demand;
- changes in the form of dependent variable (original versus log);
- changes in the set of explanatory variables included and/or their compilation.

We found that Evoenergy's average demand forecasts appear to be sensitive to model specification, and theoretical justifications for the chosen model specifications have not been sufficiently provided.

For illustrative purpose, we undertook further review of Evoenergy's revised demand forecasts for Woden zone substation. The revised demand forecasts show:

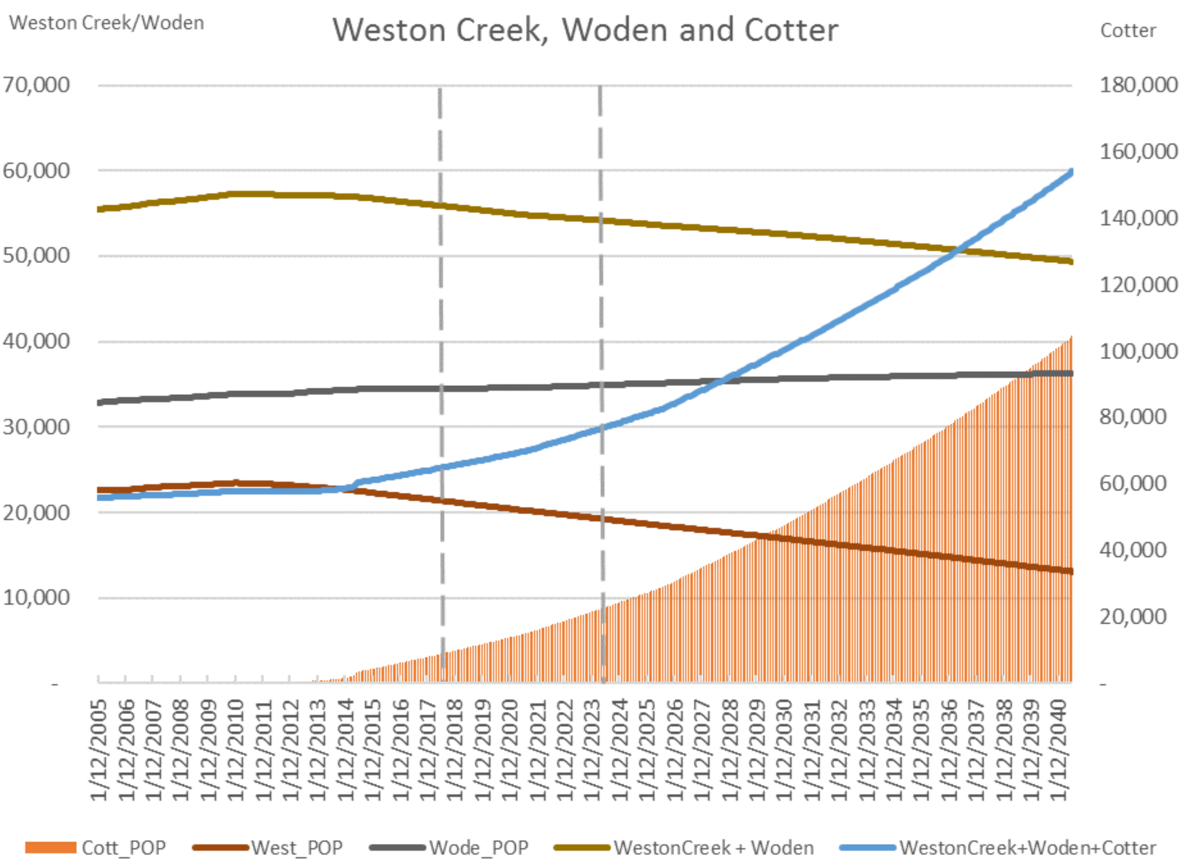
- without block load adjustment, there is no clear trend for either summer or winter peak demand.
- post-modelling adjustments are made for block loads for Molonglo Valley development, which is forecast to rise from 1.45MVA in summer 2019 to 12.92MVA in winter 2028.
- the summer two-hour emergency rating (95MVA) is forecast to be (marginally) exceeded under the 10 per cent probability of exceedance (POE) forecast by 2022. Demand at 10 per cent POE is forecast to reach 99MVA in summer 2024, 4.2 per cent higher than the stated emergency rating.

We note that one of the changes made in the seasonal average demand modelling for Woden zone substation is to use the population variable for Woden only.[116] This fails to capture correctly the underlying population being served by Woden zone substation; i.e., two established districts at Weston Creek and Woden respectively, and the newly developed district at Cotter. Using data submitted by Evoenergy,[117] the three districts differ in terms of population size and growth path historically and going forward. See Figure E-1 and Table E-1 below.

[116] In its initial proposal, Evoenergy used a population variable for Cotter. The use of Cotter population is also problematic and may produce incorrect demand forecasts as this population driver fails to capture correctly the underlying population being served. However, the demand forecasts are not necessarily biased upward due to the logged form used for the population variable.

[117] Evoenergy, Response to information request #45 – 'Energy Volumes Master Data 12102018_eviews.xls, 14 January 2019.

Figure E-1: Population by district – Woden zone substation (2006 – 2028)



Source: AER analysis using population data supplied by Evoenergy under IR#45.

Table E-1: Population by district - Woden zone substation (2014–2028)

	Cotter		Weston Creek		Woden		CWW		CWW*	
	(#)	(% growth)	(#)	(% growth)	(#)	(% growth)	(#)	(% growth)	(#)	(% growth)
2014	1,703	122.0%	22,698	-1.0%	34,276	0.2%	58,677	1.3%	58,677	1.3%
2015	4,351	155.5%	22,308	-1.7%	34,434	0.5%	61,093	4.1%	61,093	4.1%
2016	6,132	40.9%	21,939	-1.7%	34,458	0.1%	62,529	2.4%	62,529	2.4%
2017	7,962	29.9%	21,571	-1.7%	34,490	0.1%	64,023	2.4%	64,023	2.4%
2018	9,853	23.8%	21,201	-1.7%	34,520	0.1%	65,574	2.4%	64,818	1.2%
2019	11,814	19.9%	20,829	-1.8%	34,542	0.1%	67,185	2.5%	64,468	-0.5%
2020	13,853	17.3%	20,454	-1.8%	34,563	0.1%	68,871	2.5%	64,114	-0.5%
2021	16,146	16.5%	20,098	-1.7%	34,630	0.2%	70,873	2.9%	63,825	-0.5%
2022	18,818	16.6%	19,756	-1.7%	34,747	0.3%	73,321	3.5%	63,599	-0.4%

2023	21,572	14.6%	19,399	-1.8%	34,860	0.3%	75,832	3.4%	63,356	-0.4%
2024	24,407	13.1%	19,036	-1.9%	34,972	0.3%	78,415	3.4%	63,105	-0.4%
2025	27,315	11.9%	18,667	-1.9%	35,074	0.3%	81,056	3.4%	62,838	-0.4%
2026	30,691	12.4%	18,314	-1.9%	35,181	0.3%	84,186	3.9%	62,592	-0.4%
2027	34,781	13.3%	17,985	-1.8%	35,296	0.3%	88,061	4.6%	62,377	-0.3%
2028	38,972	12.1%	17,648	-1.9%	35,406	0.3%	92,027	4.5%	62,151	-0.4%

Source: Evoenergy, Response to information request #045, ' Energy Volumes Master Data 12102018_eviews.xls'.

Notes: 1. CWW is the sum of the population for Cotter, Weston Creek and Woden. Cotter currently covers the areas of Urriarra and Nmadgi

2. CWW* holds population at Cotter constant from August 2018 onwards.

3. Year refers to calendar year ending in December

Woden district has experienced stable population growth historically and is projected to grow at an annual rate of 0.1 per cent to 0.3 per cent for the 2019-24 regulatory control period. In contrast, Weston Creek—the smaller established district—has experienced population decline since 2011 and is projected to accelerate the declining trend to over –1.7 per cent per annum. Cotter (incorporating the Molonglo Valley development area) shows rapidly rising population from a very small population base to about 8,000 by the end of 2017. Its population is projected to grow strongly to nearly 38,000 by the end of 2028, with annual addition rising from 2,000 to 4,000 over that period.

We consider that the population driver used in the demand modelling should be based on the entire population to be served by the specific zone substation rather than relying on a subset of the population within the service area that exhibits a different growth path in the past or future. For Woden zone substation, we consider the population of three districts—Weston Creek, Woden and Cotter—to be more appropriate. The forecast overall population growth rate across these three areas is between 2.5 and 3.5 per cent over the 2019-24 regulatory control period.

However, under Evoenergy's approach to forecasting spatial demand, residential and non-residential load in the Molonglo Valley development is being treated as a block load and therefore as a post-modelling adjustment to the baseline forecasts, rather than within the modelling itself. To be consistent with this approach, we have assumed that zero population growth in Cotter from August 2018 in our alternative testing for the baseline without forecast block loads. The last two columns in Table E-1 show that by holding the Cotter population constant from that point in time, total population for the three districts are projected to decline by about 0.4 per cent per annum.

Therefore, using only the Woden population as the driver for demand fails to correctly capture the underlying population being served by Woden zone substation. This is likely to have two effects on the demand modelling and forecasting:

- firstly, the relationship between population and demand (i.e., demand elasticity with respect to population in this case as log-log form is adopted) may not be correctly estimated. To the extent that other explanatory variables are correlated, they may also be affected. In this case, we find limited effect on econometric results as historically, both Woden and the broader region have shown positive population growth.

- secondly, the failure to reflect the continuous decline in Weston Creek population in driving baseline demand for Woden zone substation has the potential to over-forecast average demand and thus peak demand as the population driver is projected to grow steadily instead of decline overall. When projected forward using the adjusted population for the three districts, our baseline average demand is generally lower compared to Evoenergy's forecasts based on Woden population only.

We consider that Evoenergy should review its general approach to modelling seasonal average demand, which provides a critical input to its peak demand forecasts. For future applications, Evoenergy should ensure that it has developed theoretical justifications for the model specifications chosen and apply them more systematically to its spatial demand forecasting. We consider it important for the set of economic and demographic factors used, particularly the population driver, to be representative of the service area served by the respective zone substations.