Draft Decision

ActewAGL distribution determination

2015–16 to 2018–19

Attachment 6: Capital expenditure

November 2014

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Note

This attachment forms part of the AER's draft decision on ActewAGL’s 2015–19 distribution determination. It should be read with other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection methodology

Attachment 19 – Pricing methodology

Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	aggregate service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium

Shortened form	Extended form
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

6 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of standard control services.[1] The return on and of forecast capex are two of the building blocks that form part of ActewAGL's total revenue requirement.[2]

We generally categorise capex as either network or non-network capex. Network capex includes growth-driven capex and non-load driven capex. Growth-driven capex includes augmentations and new connections. Non-load driven capex includes replacement and refurbishment capex. Non-network capex covers expenditure in areas other than the network and includes business information technology (IT) and buildings/facilities.

This Attachment sets out our draft decision on ActewAGL's proposed total forecast capex. Further detailed analysis is in the following appendices:

Appendix A - Assessment of forecast capex drivers

Appendix B - Overview of our assessment approaches

Appendix C - Demand and consumption forecasts

Appendix 6.4.5D Predictive modelling approach and scenarios

Appendix 6.4.5E Real material cost escalation

Appendix 6.4.5F Operating and environmental factors

6.1 Draft decision

We are not satisfied that ActewAGL's proposed total forecast capex of $372.2 million ($2013–14) reasonably reflects the capex criteria. Our alternative estimate of ActewAGL's total forecast capex for the 2014–2019 period that we are satisfied reasonably reflects the capex criteria is $244.2 million ($2013–14).[3] Table 6-1 outlines our draft decision.

Table 6-1 Our draft decision on ActewAGL's total forecast capex (million $2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
ActewAGL's proposal	75.3	70.3	85.8	74.5	66.3	372.2
AER draft decision	59.2	47.8	51.8	44.8	40.6	244.2
Difference	-16.1	-22.5	-34.0	-27.7	-25.7	-128.0
Percentage difference (%)	-21.4	-32.0	-39.6	-39.9	-38.8	-34.4

Source: AER analysis.
Note: Numbers may not total due to rounding.

1 These capital expenses include expenditure for standard control services provided by a DNSP by means of, or in connection with, its dual function assets. A dual function asset is any part of a network that is owned, operated or controlled by a DNSP which operates between 66kV and 220 kV and which operates in parallel and provides support to a transmission network: see NER, clause 6.24.

2 NER, clause 6.4.3(a).

3 This amount is subject to removal of ActewAGL's labour cost adjustment based on real cost escalation and replacement with labour cost adjustment based on the historical average.

A summary of our reasons and findings that we present in this Attachment and Appendix A are set out in Table 6-2. It is important to recognise that our decision is about ActewAGL's total forecast capex for the 2014–19 period. We are not approving a particular category of capex or a particular project, but rather an overall amount. However, as part of our assessment, we necessarily review the categories of expenditure and some particular projects in order to test whether ActewAGL's proposed total forecast capex reasonably reflects the capex criteria. This is explained further in our assessment approach at Appendix B. It follows that our findings and reasons on the capex associated with specific capex drivers, as set out below and in Appendix A, are part of our broader analysis and are not intended to be considered in isolation.

Table 6-2 Summary of AER reasons and findings

Issue	Reasons and findings
Forecasting methodology, key assumptions and past capex performance	Our concerns with ActewAGL's forecasting methodology and key assumptions are material to our view that we are not satisfied that its proposed total forecast capex reasonably reflects the capex criteria. In particular: ▪ ActewAGL's forecasting methodology applies a bottom-up assessment but not a top-down assessment. We consider a top down assessment critical in deriving a total forecast capex allowance that reasonably reflects the capex criteria. We also find that ActewAGL's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex. ▪ We have concerns with how ActewAGL has formulated and applied its key assumptions in relation to demand and customer forecasts and forecast materials escalation rates and labour escalation rates. We also observe that ActewAGL's past capex performance reveals is lower than that achieved by a number of other distribution networks. This suggests that efficient reductions in capex are achievable. This observation provides context for our analysis of specific capex drivers in Appendix A.
Augmentation capex (augex)	We have not accepted ActewAGL's proposed augex forecast of $99.5 million ($2013–14), excluding overheads. On the basis of the information before us, these amounts are overstated and exceed the amount required to achieve the capex objectives. For certain projects in its augex program, we consider ActewAGL did not provide sufficient evidence that the proposed projects were the efficient solutions to network constraints. We have instead included an amount of $61.7 million ($2013–14) of forecast augex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. This amount is 38 per cent less than ActewAGL's proposal. To arrive at this reduction we excluded ActewAGL's forecast for five augmentation projects, the most significant of which were: ▪ Molonglo zone substation and associated feeders—we consider ActewAGL did not provide sufficient evidence that its proposed Molonglo zone substation is the efficient solution to growth in the Molonglo valley area. ActewAGL did not demonstrate it considered and quantified solutions such as demand management or feeder solutions from Woden zone substation. ActewAGL also did not quantify the benefits of the Molonglo zone substation, even though it considered an alternative project with a lower net present cost. ▪ Belconnen zone substation— ActewAGL used an out-dated substation emergency rating to justify the need for this augmentation project. Therefore, there appears to be no need for this augmentation project.
Customer connections capex	We have accepted ActewAGL's proposed customer-initiated capex forecast of $91.4 million ($2013–14) as it is consistent with key indicators of construction activity expected in the

	2014–19 regulatory period. This amount includes $41.16 million of capital contributions. On the basis of the information before us, we are satisfied this amount reasonably reflects the capex criteria and will allow ActewAGL to achieve the capex objectives. We note these figures do not reconcile with ActewAGL's proposed RIN summary sheet 2.1. Given the differences in capital contribution figures across multiple sources of ActewAGL's proposal, we have adopted the proposed capital contribution amounts in the PTRM for modelling consistency with ActewAGL proposed maximum allowable revenue requirements. Additionally, we consider the capital contribution amount stated in ActewAGL's PTRM is likely to account for the total forecast cost of customer relocations and other works which are identifiable to groups of specific users. As such, we ActewAGL's proposed capital contribution forecast as $41.16 million.
Replacement capex (repex)	We have not accepted ActewAGL's proposed repex of $132.3 million ($2013–14). On the basis of the information before us, these amounts are overstated and exceed the amount required to achieve the capex objectives. In particular, ActewAGL's proposal is around 26 per cent higher than its historical trend and it compares unfavourably on our benchmarking of repex. This suggests that ActewAGL's proposal is relatively high when compared with historical expenditure. Our predictive modelling also suggests that ActewAGL's proposal is likely to be overstated and that its asset replacement requirements are likely to be materially lower. However, we recognise that the lower end of the reasonable range which uses benchmarked unit costs needs to be treated with caution, as some environmental characteristics of ActewAGL's network, most notably backyard reticulation of the low voltage power supply are unique to ActewAGL. Finally, the network health indicators concerning the condition of ActewAGL’s assets do not support a significant increase in repex relative to the longer term trend of actual repex that ActewAGL has spent in past regulatory control periods. We have instead included an amount of $98.6 million ($2013–14) in our alternative estimate for the 2014–2019 period. This amount is at the upper end of the reasonable range resulting from our predicitive modelling. We have chosen this amount given the caution we identified above in respect of the lower end of the reasonable range. In our view, this amount will allow ActewAGL to achieve the capex objectives. It is also consistent with our view of ActewAGL’s long-term repex requirements as evidenced by its past expenditure and will provide ActewAGL with a reasonable opportunity to recover at least its efficient costs.
Non-network capex	We have accepted and included ActewAGL's forecast non-network capex of $37.9 million ($2013-14) in our alternative estimate. We find that ActewAGL’s forecast non-network capex is 38 per cent lower than actual non-network capex during the 2009–2014 regulatory control period. We also find that the longer term trends in non-network capex suggest that ActewAGL has forecast capex returning to levels consistent with historical expenditure in this category.
Capitalised overheads	We have not accepted ActewAGL's proposed forecast capex of $52.2 million ($2013-14) for capitalised overheads. This proposal is not consistent with the reduced amounts of capex associated with other capex drivers that we have included in our alternative estimate. It is also not consistent with the 3 per cent average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period. We have instead included an amount of $7.6 million ($2013-14) in our alternative estimate. This amount is consistent with the other amounts of capex that we have included in our alternative estimate and the amount of actual capitalised overheads that ActewAGL spent in the 2009–2014 regulatory control period. We expect ActewAGL to clarify in their revised regulatory proposal as to whether the increased overhead reflects any changes in its capitalisation policy from the 2009-14 regulatory control period.
Real cost escalators	We have not accepted ActewAGL’s proposed real escalation of commodity prices. We also have not accepted ActewAGL’s proposed real escalation of labour prices. Our reasons for

	this are:
	
	▪ The degree of the potential inaccuracy of commodities forecasts due to:
	
	    ▪ recent studies which show that forecasts for example of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse
	
	    ▪ evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts; and
	
	    ▪ the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $USD to $AUD). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.
	
	▪ The limited evidence available to us neither supports or confirms how accurately ActewAGL's commodities escalation forecasts are likely to reasonably reflect changes in prices paid by TransGrid for physical assets in the past. Therefore, it is not open to us to conclude that ActewAGL's forecasts are reliable and accurate.
	
	▪ ActewAGL has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that may affect the commodities forecast.
	
	Our alternative estimate instead incorporates a real cost escalation of zero per cent which, on the basis of the information before us, we consider is likely to provide a more reliable estimation for the price of cost inputs used by ActewAGL to provide prescribed services.
	
	We have also not accepted ActewAGL's proposed real escalation of labour prices on the basis of our reasoning in the opex rate of change Appendix. In particular, we have forecast labour price change for the 2014–2019 period based on an average of the forecasts for the electricity, gas, water and waste services sectors from Deloitte and Independent Economics. Historically, an average has better reflected actual labour price changes for the electricity, gas, water and waste services sectors. We have not reduced ActewAGL's total forecast capex to reflect this reduction in labour rates as we require further information (i.e. labour costs as a proportion of total forecast capex). We expect ActewAGL to provide this information in its revised regulatory proposal

Adjustments and unaccounted for capex.	ActewAGL proposed total gross capex of $413 million ($2013-14) for the 2014-19 period. We note there is a discrepancy between the amount of proposed capital contributions in the RIN ($25.6 million) and ($41.2 million) in the PTRM. In addition, we found a discrepancy between the amount proposed for non-network capex in the RIN ($50.7 million) and ($37.9 million) in the PTRM. This resulted in an overall discrepancy of $34 million ($2013-14). We have allocated this amount to augex, connections and repex by the proportion of each driver to total capex. Overall these adjustments have resulted in an increased amount for the proposed capex drivers as set out below. ▪ Augex proposed $95.5 million (amended to $99.5 million) ▪ Connections capex proposed $78.8 million (amended to $91.4 million) ▪ Repex proposed $114.4 (amended to $132.3 million). We expect ActewAGL to clarify the proposed amount of proposed capital contributions and non-network capex in its revised regulatory proposal.

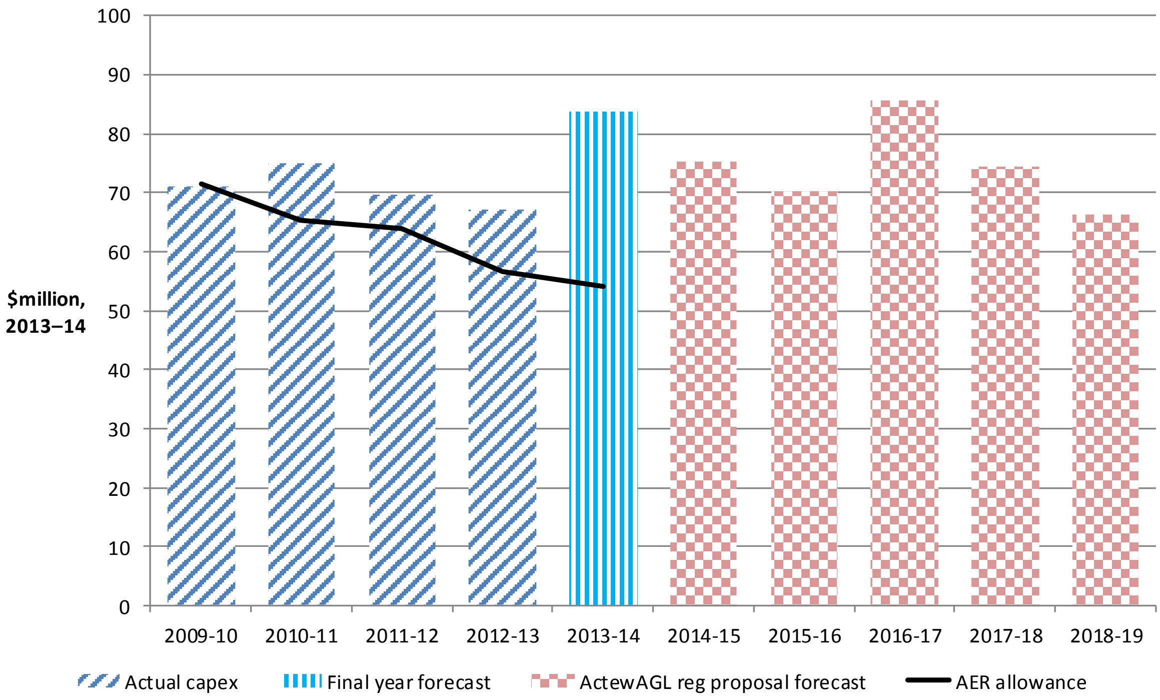
Source: AER analysis.

6.2 ActewAGL's proposal

ActewAGL proposed total forecast capex of $372.2 million ($2013–14) for the 2014–2019 period.

Figure 6-1 shows the reduction between ActewAGL's proposal for the 2014–2019 period and the actual capex that it spent during the 2009–2014 regulatory control period.

Figure 6-1 ActewAGL's total and forecast capex 2004–2019



Source: Historical: ACT ICRC Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010/11–2013/14); 2014–2019 period: ActewAGL Reset RIN, Table 2.1.1 - Standard control services capex).

6.3 Assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, outlines our assessment techniques, and explains how we build an alternative estimate of total forecast capex against which we compare that proposed by the service provider.

We will accept ActewAGL's proposed total forecast capex if we are satisfied that it reasonably reflects the capex criteria.[4] If we are not satisfied, we substitute it with our alternative estimate of a total forecast capex that we are satisfied reasonably reflects the capex criteria.[5] The capex criteria are:

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

4 NER, clause 6.5.7(c).
5 NER, clause 6.5.7(d).

The Australian Energy Market Commission (AEMC) noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[6] The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to: [7]

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

Importantly, our assessment is about the total forecast capex and not about particular categories or projects in the capex forecast. The Australian Energy Market Commission (AEMC) has expressed our role in these terms:[8]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that ActewAGL's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors. The capex factors are:[9]

- the AER's most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient DNSP over the relevant regulatory control period
- the actual and expected capex of the DNSP during the preceding regulatory control periods
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the capex forecast is consistent with any incentive scheme or schemes that apply to the DNSP
- the extent to which the capex forecast is referable to arrangements with a person other than the DNSP that, in the opinion of the AER, do not reflect arm's length terms
- whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project
- the extent to which the DNSP has considered, and made provision for, efficient and prudent non-network alternatives.

In addition, the AER may notify the DNSP in writing, prior to the submission of its revised regulatory proposal, of any other factor it considers relevant.[10]

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6 AEMC Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, p. 113 (AEMC Economic Regulation Final Rule Determination).

7 NER, clause 6.5.7(a).

8 AEMC Economic Regulation Final Rule Determination, p. vii.

9 NER, clause 6.5.7(e).

In taking these factors into account, the AEMC has noted that:[11]

> …this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

For transparency and ease of reference, we have included a summary of how we have had regard to each of the capex factors in our assessment at the end of this attachment.

More broadly, we also note that in exercising our discretion, we take into account the revenue and pricing principles which are set out in the National Electricity Law.[12]

Recent AEMC rule changes

The rule changes the AEMC made in November 2012 require us to make and publish an Expenditure Forecast Assessment Guideline for Electricity Distribution (released in November 2013). The Guideline sets out the AER's proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For ActewAGL, our framework and approach paper (published in January 2014) stated that we would apply the guideline, including the assessment techniques outlined in it. We may depart from our Guideline approach and if we do so, need to explain why. In this determination we have not departed from the approach set out in our Guideline.

As part of these rule changes, the AEMC also emphasised the role of benchmarking in our assessment of capex. In particular, we are now required to produce annual benchmarking reports. This is also a capex factor that we are now required to consider in assessing a capex proposal.[13] The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER.[14]

Building an alternative estimate of total forecast capex

Our starting point is the service provider's proposal.[15] We then considered the service provider's performance in the previous regulatory control period to inform our alternative estimate. We also reviewed the proposed forecast methodology and the service provider's reliance on key assumptions that underlie its forecast.

We then applied our specific assessment techniques, outlined below, to develop and estimate and assess the economic justifications that the service provider put forward. The specific techniques that we have used in this draft decision include:

- economic benchmarking—to assess a business's overall efficiency (and trends in efficiency) compared with other businesses, drawing on our annual benchmarking report[16]

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10 NER, clause 6.5.7(e)(12).

11 AEMC Economic Regulation Final Rule Determination, p. 115.

12 NEL, sections 7A and 16(2).

13 NER, clause 6.5.7(e)(4).

14 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 97.

15 AER Expenditure Forecast Electricity Distribution Guideline, p. 9; see also AEMC Economic Regulation Final Rule Determination, pp. 111 and 112.

16 As part of the 2012 rule changes, the AEMC emphasised the role of benchmarking in our assessment of capex. In particular, we are now required to produce annual benchmarking reports. This is also a capex factor that we are now required to consider in assessing a capex proposal. The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER: AEMC, National Electricity

- trend analysis—forecasting future expenditure based on historical information, especially for recurrent and predictable categories of expenditure
- category level analysis—to allow for the development of metrics which can be benchmarked over time and between businesses
- predictive modelling—including the replacement capex (repex) model and augmentation capex (augex) model
  - the repex model is used to assess whether the business' repex proposal is reasonable given assumed and benchmarked asset lives and unit costs
  - the augex model is used to assess whether the proposed amount of augex is reasonable given the level of demand growth.
- engineering review—including review of a DNSP's governance and risk and asset management processes, review of specific projects/programs and cost-benefit analysis to test whether the proposed expenditure is efficient and prudent.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, the techniques that focus on sub-categories are not conducted for the purpose of determining at a detailed level what projects or programs of work the service provider should or should not undertake. They are but one means of assessing the overall total forecast capex required by the service provider. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve projects. Once we approve total revenue, which will be determined by reference to the AER's analysis of the proposed capex, the service provider will have to prioritise its capex program given the prevailing circumstances at the time (such as demand and economic conditions that impact during the regulatory period). Most likely, some projects or programs of work that were not anticipated will be required. Equally likely, some of the projects or programs of work that the service provider has proposed for the regulatory control period will not be required. We consider that acting prudently and efficiently, the service provider will consider the changing environment throughout the regulatory period and make sound decisions taking into account their individual circumstances.

As explained in our Guidelines:

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.[17]

In arriving at our estimate, we have had to weight the various techniques used in our assessment. How we weight these techniques will be determined on a case by case basis using our judgement as to which techniques are more robust. We also need to take into account the various interrelationships between the total forecast capex and other components of a service provider's distribution determination. The other components that directly affect the total forecast capex are forecast opex, forecast demand, the service target performance incentive scheme, the capital expenditure sharing

Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 97; NER, clauses 6.5.7(c) and 6.5.7(e)(4).

17 AER Expenditure Forecast Electricity Distribution Guideline, p. 12.

scheme, real cost escalation and contingent projects. We discuss how these components impact the total forecast capex in section 6.4.4.

Underlying our approach are two general assumptions:

- Capex criteria relating to a prudent operator and efficient costs are complementary such that 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.[18]
- Past expenditure was sufficient for ActewAGL to manage and operate its network in that previous period, in a manner that achieved the capex objectives.[19]

After applying the above approach, we arrive at our estimate of the total capex forecast.

Comparing the service provider's proposal with our estimate

Having established our estimate of the total forecast capex, we can test the service provider's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the service provider's forecast total. The service provider's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[20]

> The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

We have not relied solely on any one technique to assist us in forming a view as to whether we are satisfied that a service provider's capex proposal reasonably reflects the capex criteria. We have necessarily drawn on a range of techniques as well as our assessment of demand, real cost escalators and contingent projects.

Where we approve a service provider's proposed total forecast capex or where we substitute our alternative estimate of total forecast capex, it is important to recognise that the service provider is not precluded from undertaking unexpected capex works, if the need arises, and despite the fact that such works did not form part our assessment in this determination. As noted above, we anticipate that a service provider will prioritise their capex program of works. Where an unexpected event leads to an overspend of the capex amount approved in this determination as part of total revenue, a service provider will only be required to bear 30 per cent of this cost if the expenditure is found to be prudent and efficient. Further, for significant unexpected capex, the pass-through provisions provide a means for a service provider to pass on such expenses to customers where appropriate. For these reasons, in the event that the approved total revenue underestimates the total capex required, we do not consider that this should lead to undue safety or reliability issues. Conversely, if we overestimate the amount of capex required, the stronger incentives put in place by the AEMC in 2012 should lead to a business spending only what is efficient, with the benefits of the underspend being shared between businesses and consumers.

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18 AER Expenditure Forecast Electricity Distribution Guideline, pp. 8 and 9.
19 AER Expenditure Forecast Electricity Distribution Guideline, p. 9.
20 AEMC Economic Regulation Final Rule Determination, p. 112.

6.4 Reasons for draft decision

We are not satisfied that ActewAGL's proposed total forecast capex reasonably reflects the capex criteria. We compared ActewAGL's proposal to our alternative estimate that we constructed using the approach and techniques outlined above. ActewAGL's proposal is materially higher than ours. For that reason and the reasons outlined below and in Appendix A, we are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6-3 sets out the capex amounts by capex driver that we have included in our alternative estimate of ActewAGL's total forecast capex for the 2014–2019 period.

Table 6-3 Our assessment of required capex by capex driver (million $2013–14)

Capex driver	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Augmentation	12.3	10.5	17.7	13.9	7.3	61.7
Connections	20.4	17.9	16.2	16.9	20.1	91.5
Replacement	21.5	19.8	20.2	18.9	18.1	98.5
Non-Network	12.5	7.9	6.3	4.6	6.6	37.9
Capitalised overheads	1.8	1.5	1.6	1.4	1.3	7.6
Materials escalation adjustment	-1	-1.5	-2.5	-3.2	-3.7	-11.9
Gross capex	**67.5**	**56.1**	**59.4**	**52.6**	**49.8**	**285.4**
Customer contributions	8.3	8.4	7.6	7.7	9.2	41.2
Net capex	**59.2**	**47.8**	**51.8**	**44.8**	**40.6**	**244.2**

Source: AER analysis.
Note: We have allocated an amount of expenditure to reflect the discrepancy between customer contributions and non-network capex within the regulatory proposal to network system capex by the proportion of each driver to total capex. Our assessment of each capex driver in the appendices incorporates this reallocation.
Numbers may not add up due to rounding.

Our assessment of ActewAGL's forecasting methodology, key assumptions and past capex performance are discussed in the section below.

6.4.1 Forecasting methodology

ActewAGL is required to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[21] It is also required to include this information in its regulatory proposal.[22]

[21] NER, clauses 6.8.1A and 11.56.4(o); ActewAGL, Electricity Distribution Network Expenditure Forecasting Methodology, November 2013.
[22] NER, clause S6.1.1(2); ActewAGL, Regulatory Proposal, pp 161–166 and Attachment B19.

The main points of ActewAGL's forecasting methodology are:[23]

- There are 6 categories of capex: asset renewal/replacement, augmentation, reliability and quality improvements, network OT and non-network assets. ActewAGL's assets are overseen by an asset management plan which is constituted by individual asset specific plans.
- In 2012, ActewAGL implemented RIVA asset management software to prepare a signficiant amount of its forecast capex. ActewAGL also engaged Sinclair Knight Mertz to undertake reviews of its cost escalators and unit rates.
- ActewAGL has used a bottom up assessment to derive its forecast capex for all its categories of capex except for non-network assets, in which it has used a combination of bottom-up and top-down assessments.
- The key inputs into determining its forecast capex for each capital plan include demand forecasts, customer connection growth, cost escalation and costing of the works, which is primarily based on historical costs.

We have identified two aspects of ActewAGL's forecasting methodology which indicate that its methodology is not a sufficient basis on which to conclude that its proposed total forecast capex reasonably reflects the capex criteria.

Firstly, ActewAGL's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories (except for information and communications technology). It does not involve applying a top-down assessment. In our view, applying a top-down assessment is a critical part of the process in deriving a forecast capex allowance. It indicates that some level of overall restraint that has been brought to bear. This is an important factor for us to consider in deciding whether we are satisfied that a proposed forecast capex allowance reasonably reflects the capex criteria. In particular, to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide any evidence that the estimate is efficient. Bottom-up assessments have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level. Whereas reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency. Whilst in certain very limited circumstances, a bottom up build may be a reasonable approach to justifying expenditure, this is not the case when looking at aggregated areas of expenditure or at the portfolio level. However, simply aggregating estimates is unlikely to result in a total forecast capex allowance that we are satisfied reasonably reflects the capex criteria. Our view reflects the submission made by the National Generators Forum (which is relevant not only to the NSW DNSPs but to ActewAGL as well):[24]

> Historically, regulatory assessments of capital expenditure programs have predominantly incorporated bottom up assessments of a sample of projects and / or programs, with minimal top down assessment of the overall level of capex, underlying drivers and impacts on network prices. Given the substantial information asymmetry between DNSPs and regulators, past approaches have had limited success in determining an efficient overall level of capex for NSW DNSPs. It is far more difficult for a regulator to reject capital expenditure proposals on an individual project-by-project basis compared to setting a top down overall efficient level of capex within which DNSPs can prioritise individual projects.

23 ActewAGL, Regulatory Proposal, Attachment B9.
24 National Generators Forum, Submission to the Revenue Determinations (2014–2019) of the NSW Distribution Network Service Providers, p. 9.

As we stated in our Forecast Expenditure Guidelines, we intend to assess forecast capex proposals through a combination of top down and bottom up modelling.[25] Our top-down assessment of ActewAGL's proposed forecast is a material consideration in determining whether we are satisfied if it reasonably reflects the capex criteria. For example, trend analysis is a top-down assessment that can be applied in the context of a distribution network. This technique is able to test whether an estimate that results from a bottom-up assessment might be efficient. We have used this technique in this determination.

A top-down assessment should also clearly evidence a holistic and strategic consideration or assessment of the entire forecast capex program at a portfolio level. It should also demonstrate how the forecast capex proposal has been subject to governance and risk management arrangements. In turn, these arrangements should demonstrate how the timing and prioritisation of certain capital projects or programs has been determined over both the short and the long-term. It should also demonstrate that the capex drivers, such as asset health and risk levels, are well defined and justified. In particular, asset health and risk level metrics are key elements of capex drivers.

ActewAGL's forecast methodology does not demonstrate any of these points (except for non-network assets).

The range of assessment techniques available to us provides for a top-down assessment. These techniques enable us to test whether an estimate that results from a bottom-up assessment might be efficient. We have applied top down assessments to the overall level of expenditure as well as each major sub-category of capex. The combination of our techniques informs our decision of as to whether the proposed total capex forecast reasonably reflects the capex criteria.

Secondly, ActewAGL's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is overly conservative. The focus is on reducing its business risks instead of risks to consumers. This is evident in ActewAGL's failure to fully justify the timing and priority of its proposed forecast capex. Ultimately, this overly conservative approach to risk means that ActewAGL is forecasting more capex in the 2014–2019 period than is necessary to achieve the capex objectives. In particular, ActewAGL does not demonstrate that it has properly considered the extent to which its programs or projects can be deferred to the 2020–2025 regulatory control period. An overly conservative risk approach is likely to result in a forecast capex allowance that is greater than what is required to achieve the capex objectives.

The concerns that we outline below were material to forming the view that we are not satisfied that ActewAGL’s forecast capex reasonably reflects the capex criteria.

6.4.2 Key assumptions

The NER require ActewAGL to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex and a certification by its directors that those key assumptions are reasonable.[26]

ActewAGL's key assumptions are:[27]

25 AER Expenditure Forecast Electricity Distribution Guideline, p. 17.
26 NER, clauses S6.1.1(4) and (5); ActewAGL, Regulatory Proposal, Attachments A6 and F4.
27 ActewAGL, *Regulatory Proposal*, p 54; ActewAGL, Regulatory Proposal, Attachment 0.06.

- Most of ActewAGL’s forecast capex is derived by using a zero-based forecasting approach (or bottom up assessment) except for plant equipment and some non-system assets, which are derived from historical estimates
- The cost escalators used have been independently verified
- Material and labour cost escalators have been applied to various asset classes using independently verified weightings
- Forecast capital contributions are based on ActewAGL’s approved connection policy.
- 10 year forecasts of maximum summer and winter load demands at all zone substations and weather normalised energy forecasts for four customer segments

We have assessed ActewAGL's key assumptions in the appendices to this capex attachment.

6.4.3 ActewAGL's capex performance

We have looked at a number of historical metrics of ActewAGL's capex performance against that of other DNSPs in the NEM. We also compare ActewAGL's proposed forecast capex allowance against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis undertaken using data provided by the DNSPs for the annual benchmarking report. This includes ActewAGL's relative partial and multilateral total factor productivity (MTFP) performance, capex and RAB per customer and maximum demand, and ActewAGL's historic capex trend.

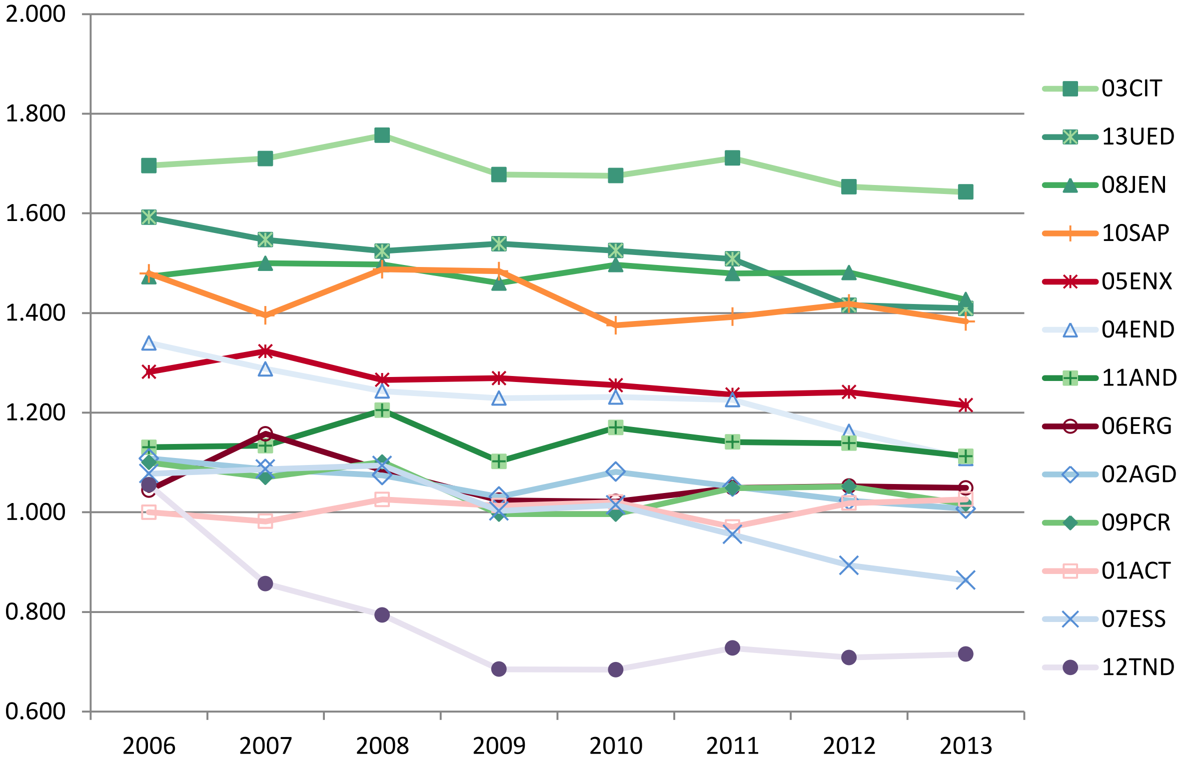
Together, these metrics suggest that there is the potential for efficiencies to be found in ActewAGL's proposed forecast capex for the 2014–2019 period. ActewAGL performs better than the other NSW DNSPs both in relation to its historical capex and its proposed capex for the 2014-19 period. Nonetheless, these metrics suggest that capex reductions of up to 24 per cent for ActewAGL to bring it in line with the Victorian and South Australian DNSPs.

While these results are not a direct input into our alternative estimate of ActewAGL's capex forecast, they inform us of ActewAGL's relative capital efficiency and whether efficient reductions to its capex forecast are achievable. We consider that it is reasonable to benchmark ActewAGL's capex efficiency against the other DNSPs in the NEM in this way. This is because in our view, the differences in operating and environmental factors between the DNSPs are not material. We discuss this in Appendix 6.4.5F.

Partial factor productivity of capital and multilateral total factor productivity

Figure 6-2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. ActewAGL is broadly consistent with Ausgrid and Endeavour, and a number of the Victorian DNSPs, but is significantly lower than the remaining Victorian and South Australian DNSPs.

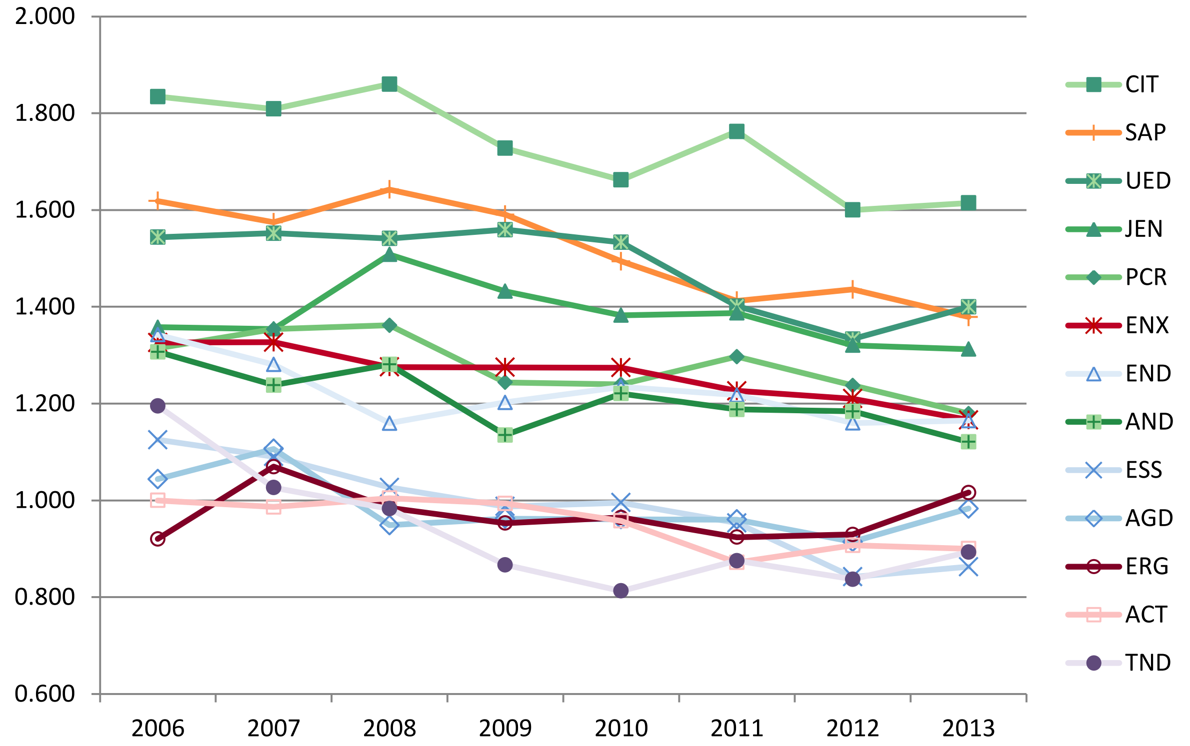
Figure 6-2 **Partial factor productivity of capital (transformers, overhead and underground lines)**



Source: AER annual benchmarking report.

Figure 6-3 shows that ActewAGL recorded the third lowest level of MTFP in the NEM across the DNSPs. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). Across all of these measures, the Victorian and South Australian DNSPs significantly outperformed ActewAGL.

Figure 6-3 Multilateral total factor productivity



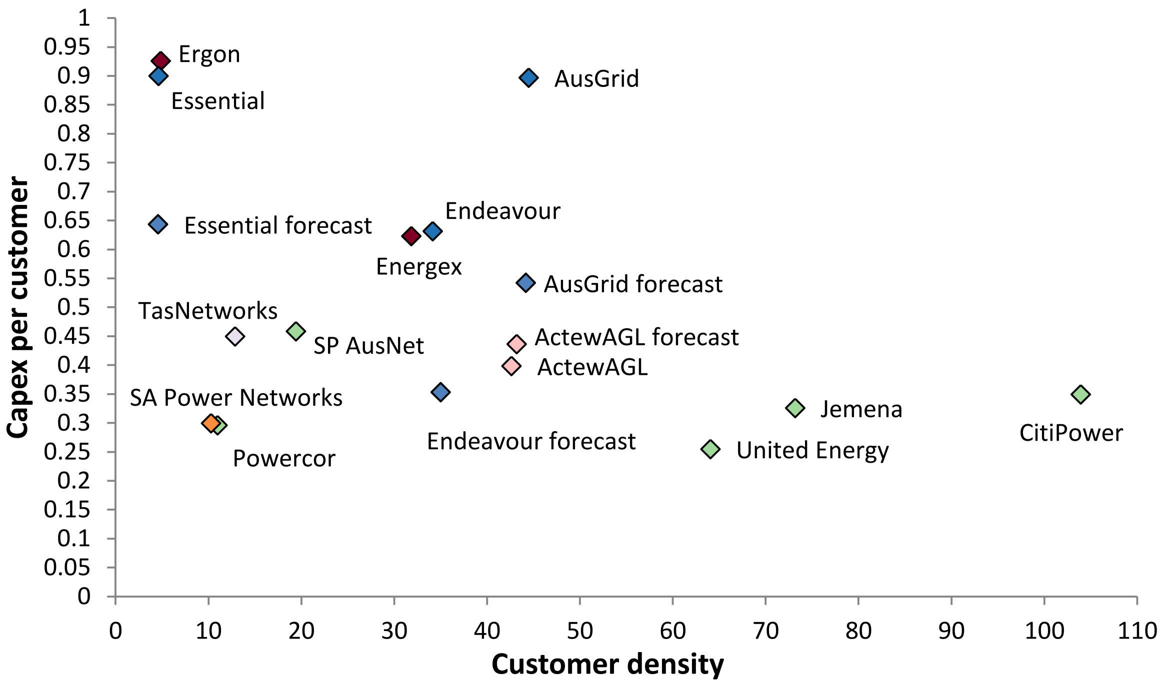
Source: AER annual benchmarking report.

Relative capex efficiency metrics

Figure 6-4 and Figure 6-5 show capex per customer and per maximum demand, against customer density. Capex is taken as a five year average for the years 2008-12. For the NSW DNSPs and ActewAGL, we have also included the businesses' proposed capex for the 2014–2019 period. We have considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6-4 shows that ActewAGL had a lower capex per customer than the NSW DNSPs for the 2008-2012 period. ActewAGL's capex per customer will increase slightly for the 2014–2019 period based on their proposed forecast capex. However, ActewAGL's forecast capex per customer is still higher than with the Victorian and South Australian DNSPs. ActewAGL's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 24 per cent in order for its capex per customer to be comparable to that the average $3,300 per customer achieved by the Victorian and South Australian DNSPs in 2008-2012.

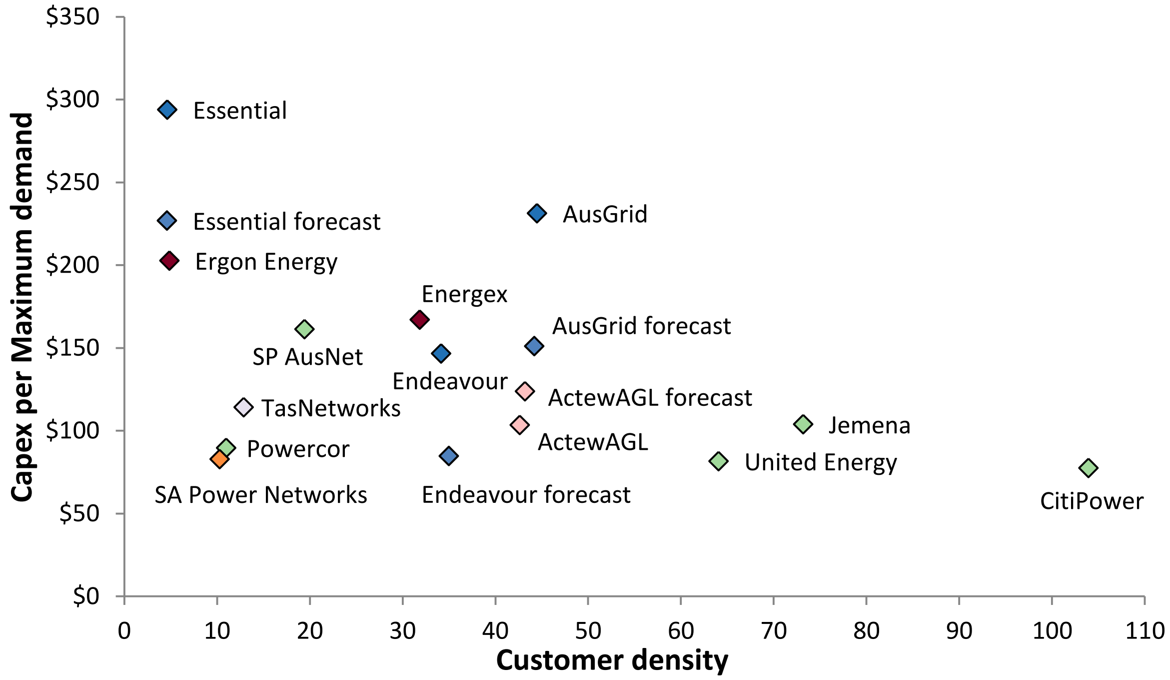
Figure 6-4 Capex per customer (000s, $2013-14), against customer density



Source: AER analysis.

Figure 6-5 similarly shows that ActewAGL had a lower capex per maximum demand than the NSW DNSPs for the 2008-2012 period. ActewAGL's forecast capex per maximum demand is forecast to increase on the next period. ActewAGL's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 19 per cent in order for its capex per maximum demand to be comparable to the average of $99,500 per maximum demand achieved by the Victorian and South Australian DNSPs in 2008–2012.

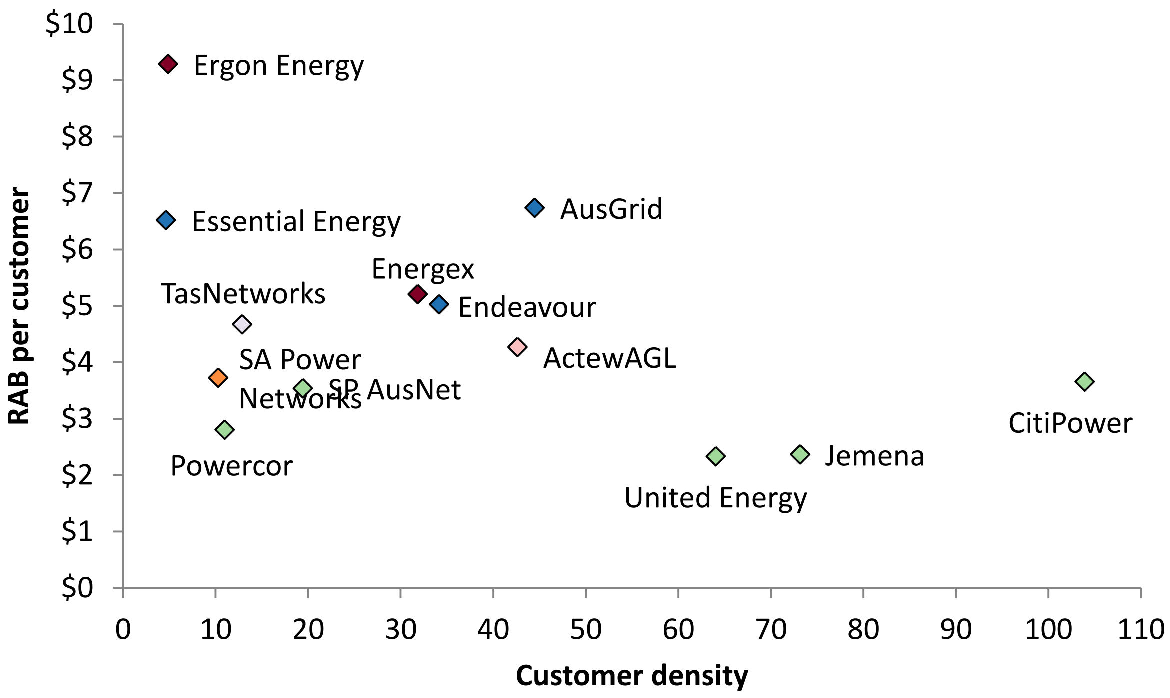
Figure 6-5 Capex per maximum demand (000s, $2013-14), against customer density



Source: AER analysis.

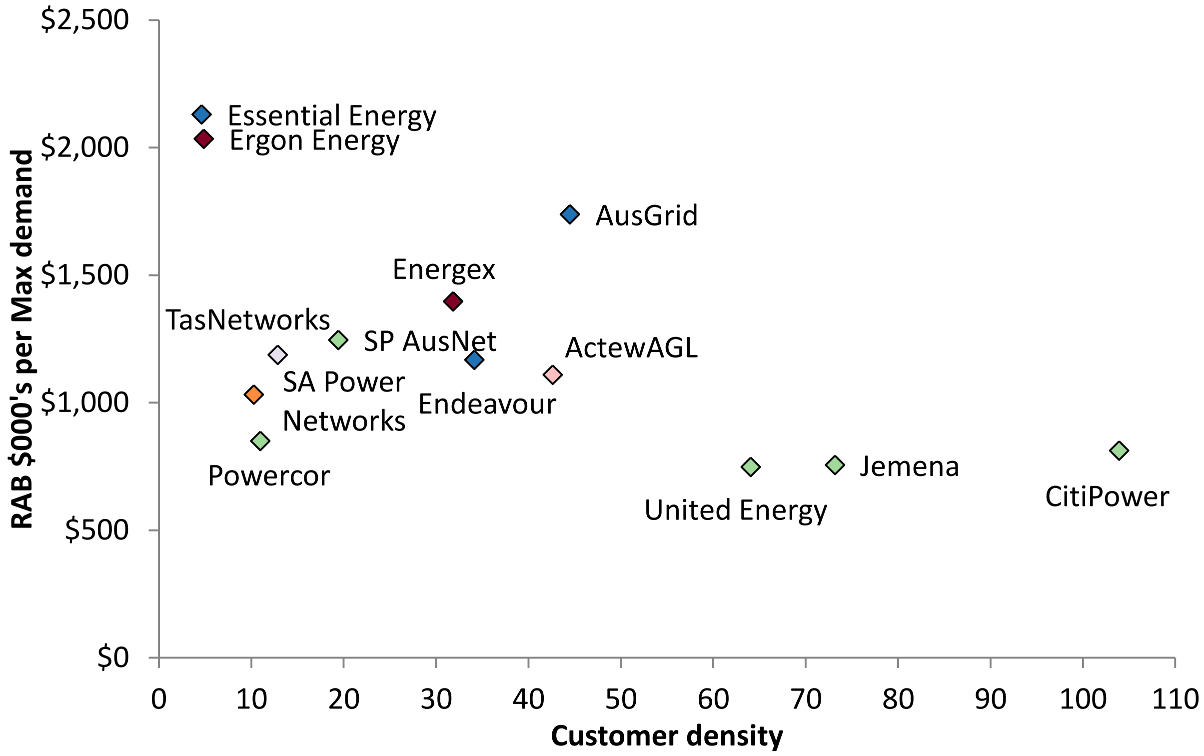
Figure 6-6 and Figure 6-7 show that the comparative ranking for the DNSPs is similar when the RAB is used instead of capex. Specifically, as at 2013, ActewAGL's RAB per customer and RAB per maximum demand was higher than the Victorian and South Australian DNSPs, on average, but below the NSW DNSPs.

Figure 6-6 RAB per customer (000s, $2013-14), against customer density



Source: AER analysis.

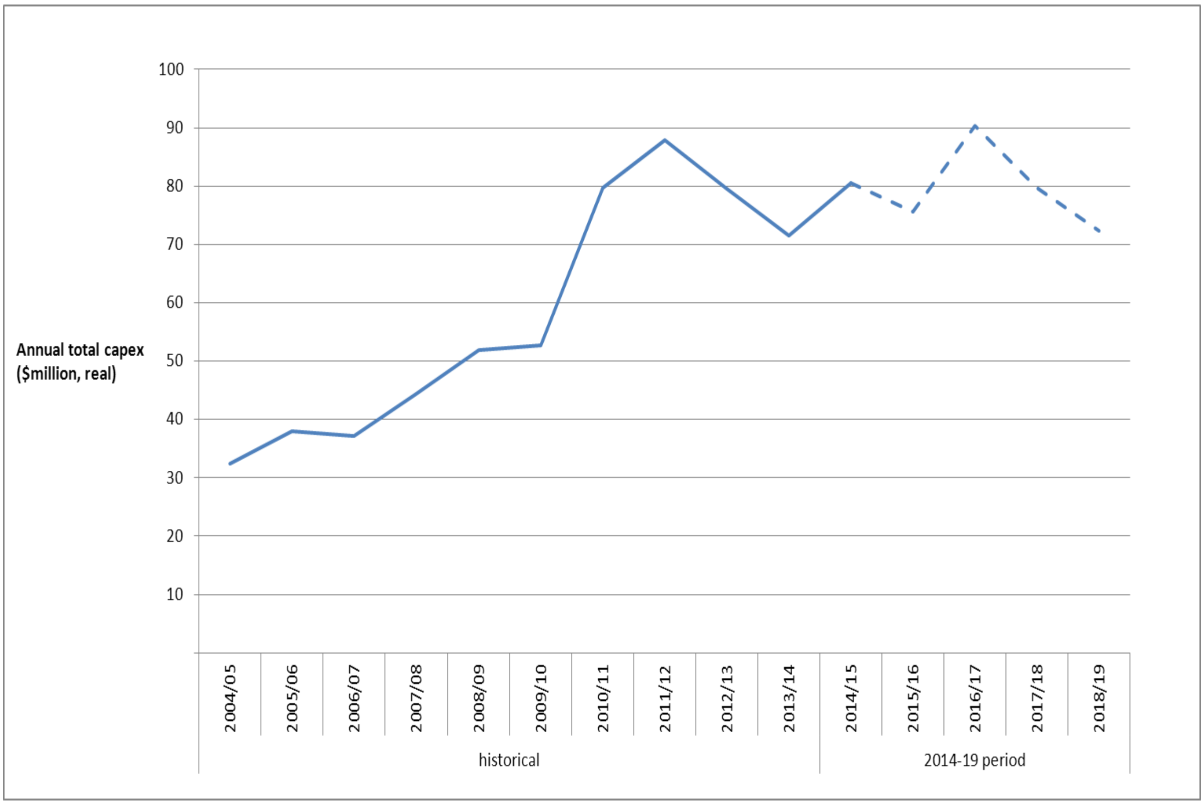
Figure 6-7 RAB per maximum demand (000s, $2013-14), against customer density



Source: AER analysis.

We have also considered ActewAGL's historical capex performance. Figure 6-8 shows actual historic capex and proposed capex between 2001-12 and 2018-19. This figure shows that ActewAGL's average proposed capex for the 2014–2019 period is slightly higher than the previous period, and substantially higher than the historical average.

Figure 6-8 ActewAGL total capex (including overheads)—historical and forecast for 2014–2019 period



Source: Historical: ACT ICRC Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010/11 to 2013/14) 2014-19 period: ActewAGL Reset RIN, Table 2.1.1 - Standard control services capex).

6.4.4 Interrelationships

There are a number of interrelationships between ActewAGL's total forecast capex for the 2014–2019 period and other components of its distribution determination that we have taken into account in coming to our draft decision. Table 6-4 summarises these other components and their interrelationships with ActewAGL's total forecast capex.

Table 6-4 Interrelationships between total forecast capex and other components

Other component	Interrelationships
Total forecast opex	There are elements of ActewAGL's total forecast opex that are related to its total forecast capex. These are: ▪ the labour cost escalators that we approved in Appendix 6.4.5E ▪ the amount of maintenance opex that is reflected in ActewAGL's opex base year that we approved in the opex rate of change Appendix. The labour cost escalators are related because ActewAGL's total forecast capex includes expenditure for capitalised labour. As to the amount of maintenance opex, although we did not approve a specific amount of maintenance opex as part of assessing ActewAGL's total forecast opex, it is interrelated. This is because the amount of maintenance opex that is reflected in ActewAGL's opex base in part determines the extent to which ActewAGL needs to spend repex during the 2014–2019 period.

Forecast demand	Forecast demand is related to the amount of forecast growth driven capex that is included in ActewAGL's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
CESS	The CESS is related to ActewAGL's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, or that it reasonably reflects the capex criteria. As we noted in [the capex criteria table above], this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from ActewAGL's regulatory asset base. In particular, the CESS will ensure that ActewAGL bears at least 30 per cent of any overspend against the capex allowance. Similarly, if ActewAGL can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, ActewAGL risks having to bear the entire overspend.
STPIS	The STPIS is related to ActewAGL's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2014–2019 period. This is because such expenditure should be offset by rewards provided through the application of the STPIS (of which our incentive rates ensures that such rewards reflect the value customers place on reliability improvement).
Contingent project	A contingent project is related to ActewAGL's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of ActewAGL's total forecast capex for the 2014–2019 period. We did not identify any contingent projects for ActewAGL during the 2014–2019 period.

Source: AER analysis.

6.4.5 Consideration of the capex factors

In applying our assessment techniques to determine whether we are satisfied that ActewAGL's proposed total forecast capex and our alternative estimate reasonably reflects the capex criteria, we have had regard to the capex factors. Where relevant, we have also had regard to the capex factors in assessing the forecast capex associated with its underlying capex drivers as set out in Appendix A. Table 6-5 summarises how we have taken into account the capex factors.

Table 6-5 AER's consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient DNSP over the relevant regulatory control period	We have had regard to our most recent benchmarking report in assessing ActewAGL's proposed total forecast capex and in determining our alternative estimate for the 2014–2019 period. This can be seen in the metrics we used in our assessment of ActewAGL's capex performance.
The actual and expected capex of the ActewAGL during any preceding regulatory control periods	We have had regard to ActewAGL's actual and expected capex during the 2009–2014 and preceding regulatory control periods in assessing its proposed total forecast capex and in determining our alternative estimate for the 2014–2019 period. This can be seen in our assessment of ActewAGL's capex performance. It can also be seen in our assessment of the forecast capex associated with each of the capex drivers that underlie ActewAGL's total forecast capex. In these cases, we have applied trend analysis which is reasonably

	likely to be recurrent in nature (e.g. compliance related expenditure, non-network related expenditure and replacement related expenditure).
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by ActewAGL in the course of its engagement with electricity consumers	We have had regard to the extent to which ActewAGL's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by ActewAGL. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which ActewAGL's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.
The relative prices of operating and capital inputs	We have had regard to the relative prices of operating and capital inputs in assessing ActewAGL's proposed real cost escalation factors for materials. We discuss this in Appendix E.
The substitution possibilities between operating and capital expenditure	We have had regard to the substitution possibilities between opex and capex. We have considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between ActewAGL's total forecast capex and total forecast opex in Table 6-1 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to ActewAGL	We have had regard to whether ActewAGL's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between ActewAGL's total forecast capex and the application of the CESS and the STPIS in Table 6-4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the DNSP that do not reflect arm's length terms	We have had regard to whether any part of ActewAGL's proposed total forecast capex or our alternative estimate that is referable to arrangements with a person other than ActewAGL that do not reflect arm's length terms. We did not identify any parts of ActewAGL's proposed total forecast capex or our alternative estimate that is referable in this way.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We have had regard to whether any amount of ActewAGL's proposed total forecast capex or our alternative estimate that relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriate be included as a contingent project.
The extent to which ActewAGL has considered and made provision for efficient and prudent non-network alternatives	We have had regard to the extent to which ActewAGL made provision for efficient and prudent non-network alternatives as part of our assessment of the capex associated with the non-network capex driver. We discuss this further in Appendix A.
Any relevant final project assessment report (as defined in clause 5.10.2 of the NER) published under clause 5.17.4(o), (p) or (s)	There are no final project assessment reports relevant to Endeavour Energy for us to have regard to..
Any other factor the AER considers relevant and which the AER has notified ActewAGL in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

A Assessment of forecast capex drivers

As we discuss in the capex attachment, we are not satisfied that ActewAGL's proposed total forecast capital expenditure (capex) reasonably reflects the capex criteria. This conclusion is based in part on our analysis of the capex drivers that underlie ActewAGL's forecast capex for the 2014–2019 period as set out in this Appendix. This analysis also explains the basis for our alternative estimate of ActewAGL's total forecast capex that we are satisfied reasonably reflects the capex criteria.

This Appendix A considers each capex driver as follows:

- Section A.1: augmentation capex (augex)
- Section A.2: customer connections capex
- Section A.3: asset replacement capex (repex)
- Section A.4: non-network capex
- Section A.5: capitalised overheads
- Section A.6: demand management.

A.1 AER findings and estimate for augex

Growth driven capex is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.

A.1.1 Position

ActewAGL proposed forecast augex of $99.5 million ($2012–13) for the 2014–2019 period, excluding overheads.[28] We do not accept ActewAGL's proposal. We have instead included an amount of $61.7 million ($2013–14) in our alternative estimate, a reduction of 38 per cent.

This amount should provide ActewAGL with a reasonable opportunity to recover at least the efficient costs of building its network to meet demand and reliability requirements.

In coming to our view of not accepting ActewAGL's proposal and including $61.7 million ($2013–14) for forecast augex in our alternative estimate, we first applied trend analysis (see appendix B). We compared the proposed augex with historic expenditure levels. This took into account changes in demand, network capacity and design and planning standards to assess whether the forecast is within a reasonable range to allow ActewAGL to meet expected demand, and comply with relevant regulatory obligations. The trend analysis shows that ActewAGL has proposed a slight increase in augex in comparison to the augex it spent during the 2009–2014 regulatory control period. Also, unlike the NSW DNSPs, utilisation of ActewAGL's network did not fall significantly in the 2009–2014 regulatory control period. Notwithstanding this, there is likely to be excess capacity in the network that could be utilised ahead of additional augmentation investment. Furthermore, there is evidence to suggest that ActewAGL has used overly conservative criteria when making augmentation decisions on zone substations. Therefore it is likely that ActewAGL's proposed forecast capex is overstated.

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[28] In its reset RIN, ActewAGL's augex forecast for the 2014–2019 period amounted to $94.5 million. We derived the $99.5 million after allocation of the balancing item and other expenditures (see capex attachment).

We then undertook an engineering review of ActewAGL's major augex projects. This assessed whether ActewAGL's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives. Based on this engineering review, we made reductions to the following projects:

- Molonglo zone substation and associated feeders—reduction of $24.6 million ($2013–14)
- Belconnen zone substation—reduction of $12.7 million ($2013–14)
- Zone substation earth grid upgrade—reduction of $2.619 million ($2013–14)
- Gold Creek 11 kV switchboard extension—reduction of $0.77 million ($2013–14)
- Mitchell zone substation—reduction of $0.6 million ($2013–14).

We detail our reasons for the reductions to these zone substation augmentation projects in the sections below. The expenditure figures in these sections include corporate overheads.

Table A-1 below sets out the revised augex forecast based on a 38 per cent reduction to ActewAGL's augex forecast.

Table A-1 AER's alternative estimate of augex ($2013–14, million)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
ActewAGL augex forecast	12.73	16.22	32.06	24.18	14.34	99.53
AER adjustment[29]	-0.46	-5.69	-14.39	-10.25	-7.01	-37.81
Revised augex forecast	**12.27**	**10.53**	**17.67**	**13.92**	**7.33**	**61.72**

Source: AER analysis; ActewAGL RIN.

Trend analysis

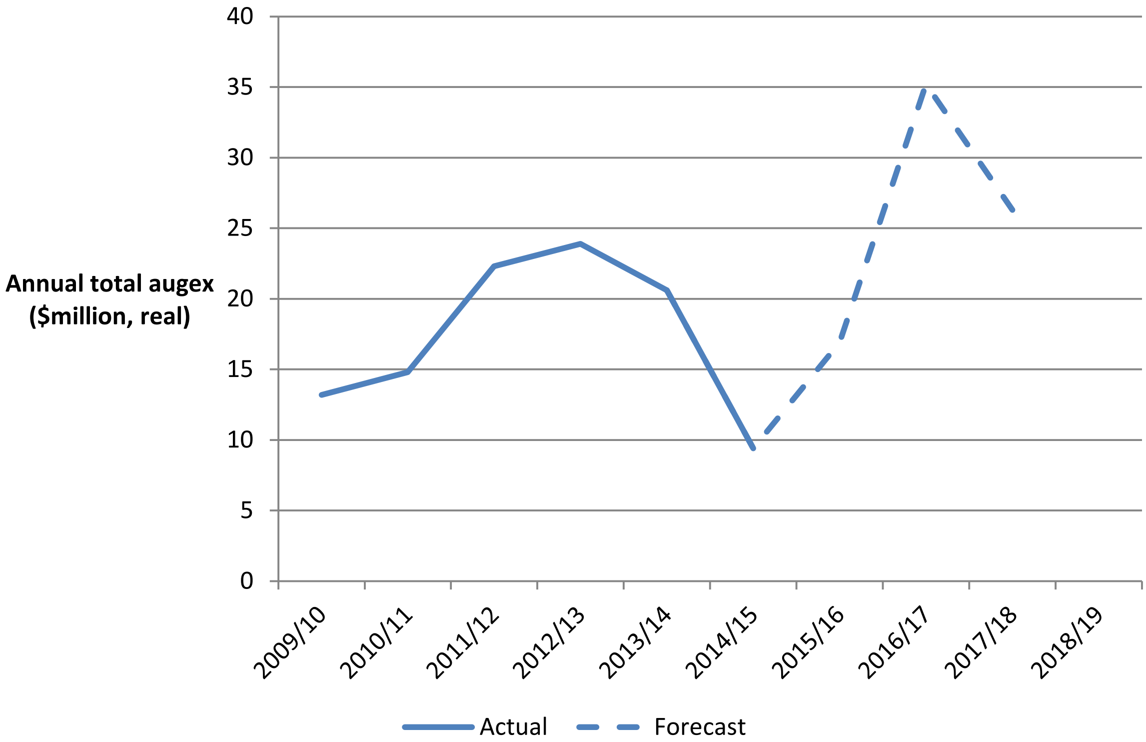
Figure A-1 shows that this is a slight increase in augex compared to the actual augex of $94.6 million ($2013–14) that ActewAGL spent during the 2009–2014 regulatory control period.[30] ActewAGL stated that this reflects the continuation of augex it commenced in the 2009–2014 regulatory control period, which followed a sustained period of very low investment.[31]

[29] These are the annual reductions from the projects we mentioned above (Molonglo zone substation, Belconnen zone substation and so on), after adjusting for the balancing item and other expenditures as well as corporate overheads.

[30] ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 181 and 183.

[31] ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 183.

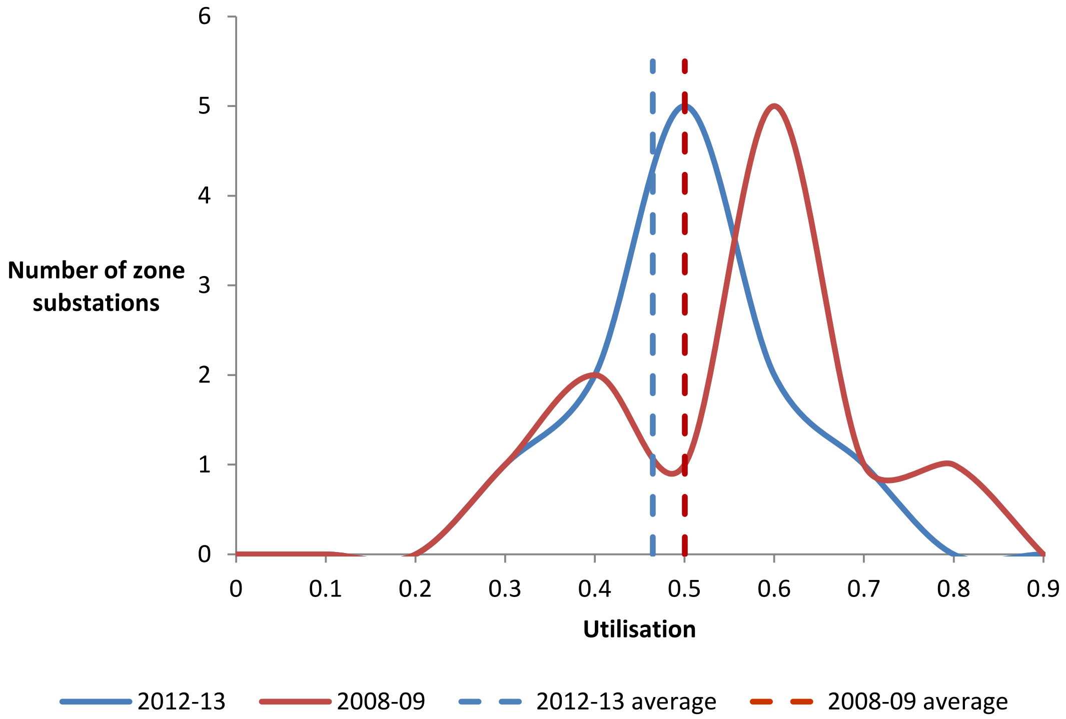
Figure A-1 ActewAGL augex—actual and forecast (including corporate overheads)



Source: ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 181 and 183.

Unlike the NSW DNSPs, utilisation of ActewAGL's network did not fall significantly in the 2009–2014 regulatory control period. Figure A-2 shows average utilisation of zone substations fell from 50 per cent in 2008–09 to 46 per cent in 2012–13. Figure A-3 show average utilisation actually rose slightly for HV feeders.

Figure A-2 Zone substation utilisation 2008–09 and 2012–13

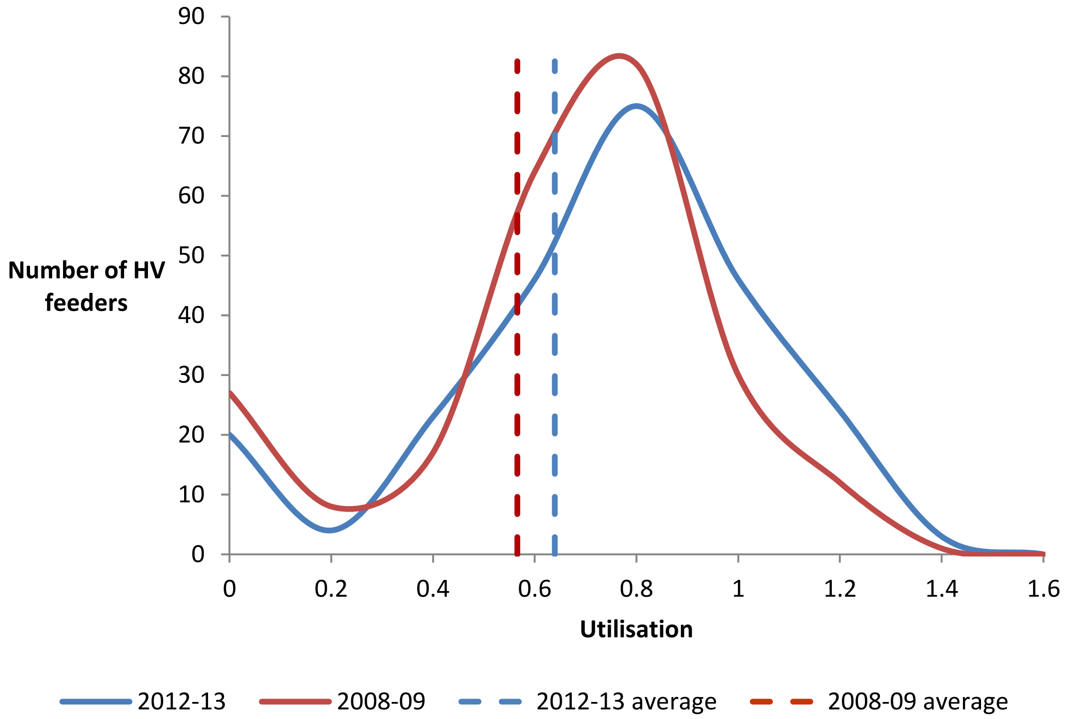


Source: AER analysis; augex model.

Note: Utilisation is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.[32] Figure A-2 shows the number of ActewAGL's total zone substations at each utilisation band.

[32] Normal cyclic rating is the maximum peak loading based on a given daily load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear.

Figure A-3 HV feeder utilisation 2008–09 and 2012–13



Source: AER analysis; reset RIN.
Note: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years.[33] Figure A-3 shows the number of ActewAGL's total HV feeders at each utilisation band.

It appears that ActewAGL has used overly conservative criteria when making augmentation decisions on zone substations. In our view, this has affected the scope and unnecessarily advanced the timing of projects. For example, clause 6.2.2 of ActewAGL's distribution network augmentation standard states:

> Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 10% PoE under N-1 conditions is to exceed the two-hour emergency rating.
>
> Major zone substation augmentation such as installation of additional transformer will not be considered unless other constraints that limit the transformer loading are removed.[34]

That is, ActewAGL augments zone substations when it expects maximum demand 10 per cent POE forecast to exceed the substation's two hour emergency rating.

These criteria do not incorporate the change in the ACT Electricity Distribution Supply Standards Code (2013), which removed the requirement on supply capacity. The criteria also do not provide an assessment framework for evaluating and managing risks associated with expected unserved energy. Instead, the criteria require network capacity to fully meet expected maximum demand with no cost benefit assessment.

We also note ActewAGL proposed values of customer reliability (VCR) in its regulatory proposal that are higher than the VCR AEMO recently published for NSW (including the ACT). For example, ActewAGL's proposed VCR for the residential sector was $40.15 per kWh, compared to AEMO's VCR

[33] Thermal rating is the maximum rating assigned to a line or cable under normal operational conditions, that is, resulting in a normal life expectancy.

[34] ActewAGL, *Regulatory proposal: Appendix D5: Distribution network augmentation standard*, 26 May 2014, p. 3.

of $26.53/kWh.[35] Table A-2 summarises AEMO's 2014 VCR results for the NEM and for the NSW region, including the ACT. As we noted in the opex appendix, we consider it is more appropriate to adopt AEMO's VCR as they are the most current values and were derived using robust and transparent methods. We consider, therefore, AEMO's VCR better reflects customers' current value for reliability.

Table A-2 2014 AEMO VCR results

VCR ($ per kWh)	NEM-wide	NSW	Previous study: 2007 NSW VCRs*
Overall	39.00	38.35	43.25
Residential	25.95	26.53	21.19
Agricultural (average)	47.67	47.67	84.32
Commercial (average)	44.72	44.72	84.32
Industrial (average)	44.06	44.06	39.52

Source: AEMO, *Value of customer reliability review: Final report*, September 2014, pp. 2, 18 and 31; Oakley Greenwood, *Valuing reliability in the National Electricity Market*, March 2011, pp. 32–33.
Note: The 2007 NSW VCR results have been adjusted for inflation.

If ActewAGL used its proposed VCR as an input into its planning process, then its augex forecast may be inefficiently high. This is because a lower VCR such as AEMO's values should result in a lower augex forecast. In essence, it reduces the benefit value in many project cost/benefit assessments. This increases the likelihood that any given project becomes uneconomic (where the project's costs are higher than benefits in net present value terms).

However, it is not clear whether ActewAGL has used its proposed VCR as an input in its planning process. ActewAGL appeared to refer to its proposed VCR only in the context of the STPIS.[36] We have therefore not used AEMO's lower VCR to adjust ActewAGL's augex forecast in this draft decision. However, we expect ActewAGL would identify the impact of AEMO's lower VCR on its augex (and other expenditure) forecasts in its revised regulatory proposal. We would consider this in our final decision.

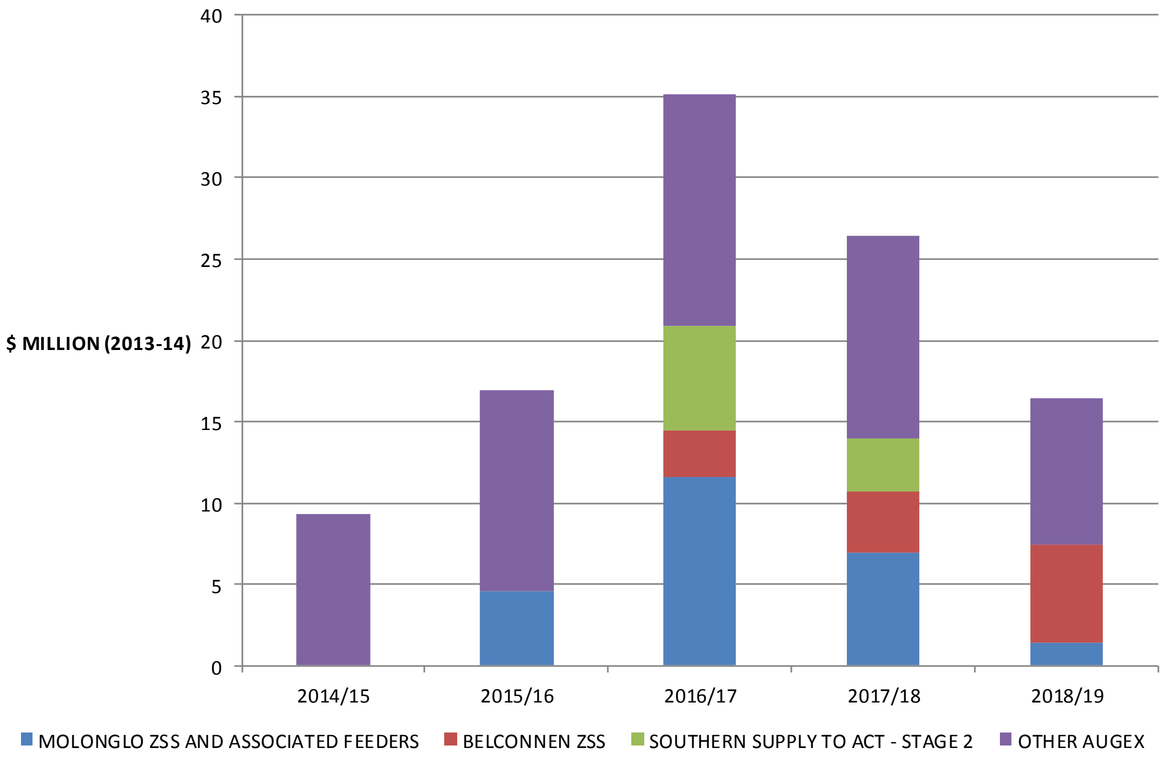
Engineering review of ActewAGL's major augex projects

Figure A-4 shows the following three major projects comprise 45 per cent of ActewAGL's augex forecast for the 2014–2019 period:

- Molonglo zone substation and associated feeders—$24.6 million ($2013–14)
- Belconnen zone substation—$12.7 million ($2013–14)
- Southern supply to ACT (stage 2)—$9.7 million ($2013–14).[37]

[35] ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 371–374.
[36] ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014).
[37] ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 183–184.

Figure A-4 ActewAGL forecast augex—composition (including corporate overheads)



Source: ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 183–184.

We have reviewed the proposed capex for these three projects, plus two other smaller projects, that together contribute a major proportion of ActewAGL's forecast augex for the 2014-19 period.

Molonglo zone substation

ActewAGL proposed to establish a new Molonglo zone substation to service projected growth in the Molonglo valley area.[38] We acknowledge the potential growth in the Molonglo Valley area, and that ActewAGL would have to service that growth. However, ActewAGL did not provide sufficient evidence that its proposed Molonglo zone substation is the efficient solution. As we discuss below, ActewAGL did not demonstrate it considered and quantified solutions such as demand management or feeder solutions from the Woden zone substation. ActewAGL also did not quantify the benefits of the Molonglo zone substation, even though it considered an alternative project with a lower net present cost (NPC) (see below).

Given the lack of information from ActewAGL, we are not in a position to assess whether the proposed Molonglo zone substation is an efficient solution. In turn, we are not in a position to assess alternative solutions and provide an alternative forecast. Hence, we consider a reduction of $24.6 million ($2013–14) to the augex forecast is appropriate. However, ActewAGL may provide further justification for this project in its revised proposal, which we will consider in our assessments for the final decision.

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38 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 184.

ActewAGL stated the ACT Planning and Land Authority is promoting the Molonglo Valley for residential and retail development over the next 20 years. ActewAGL expects electrical demand to reach 15MVA by about 2020.[39] As a result, ActewAGL projected feeder capacity shortage to the Molonglo area to be 6.4 MVA by 2021/22.[40]

ActewAGL presented two options to meet this projected shortage:

1. establish a new Molonglo zone substation by the end of 2017/18
2. upgrade existing 11kV feeders from the Civic zone substations, and defer the new Molonglo zone substation by three years.[41]

ActewAGL stated it also investigated feeder options from other adjacent zone substations.[42] However, ActewAGL discounted these options early in the process and did not progress and document these options in detail. ActewAGL stated long distances from the zone substations prohibit suitable 11kV feeder implementation and load forecasts for these substations are approaching the substation reliability ratings.[43]

ActewAGL concluded option 1 is its preferred option even though it has higher net present cost (NPC) than option 2. ActewAGL stated there are intangible benefits it considers outweigh the NPC differences between options 1 and 2. ActewAGL considers option 1 to provide the greatest customer benefit, be the most practical solution, have the lowest network losses and deliver higher reliability in the electricity network.[44]

However, ActewAGL did not provide any details on these 'intangible benefits'. As we noted above, we consider AEMO's lower VCR is more appropriate for this distribution determination. ActewAGL may therefore be overstating the benefits of this project. Further, ActewAGL's options analysis did not include any assessments of the 'do nothing' option and of non-network solutions.[45] While non-network solutions are unlikely to sufficiently displace the need for network augmentation, they potentially contribute to deferment of expenditure for a major zone substation. ActewAGL's documentation did not identify any potential non-network solutions nor provided any analysis of the cost/benefit of those solutions. Hence, ActewAGL's risk assessment appears to have significant gaps.

In addition, it does not appear ActewAGL sufficiently investigated distribution feeder augmentation solutions from the Woden zone substation. ActewAGL projected spare capacity of 10 MVA at Woden zone substation, which is sufficient to supply the initial load the Molonglo Zone Substation would provide for. ActewAGL can also raise the capacity of Woden Zone Substation by about 20 MVA for a comparatively smaller cost. This would require a transformer tail cable upgrade, similar to what

39 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 184.

40 ActewAGL, *Regulatory proposal: Appendix B16.1: Regulatory investment test: Molonglo zone substation*, 26 May 2014, p. 11.

41 ActewAGL, *Regulatory proposal: Appendix B16.1: Regulatory investment test: Molonglo zone substation*, 26 May 2014, pp. 14–15.

42 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 184.

43 ActewAGL, *Operating and capital expenditure 'site visit' clarifications: 2015–19 Subsequent regulatory control period*, 3 October 2014, p. 73.

44 ActewAGL, *Regulatory proposal: Appendix B16.1: Regulatory investment test: Molonglo zone substation*, 26 May 2014, p. 19.

45 ActewAGL, *Regulatory proposal: Appendix B16.1: Regulatory investment test: Molonglo zone substation*, 26 May 2014.

ActewAGL carried out at the Belconnen zone substation.[46] This alternative would potentially provide a more efficient solution. However, it does not appear ActewAGL investigated this option.

When developing the demand forecasts relevant to this project, it is unclear from ActewAGL's documentation whether it has considered the time lag between:

- the year(s) of land release, and
- the year(s) when the land is fully occupied and expected load eventuates.

This lag can take up to several years and would influence the timing of augmentation needs.

While ActewAGL presented a forecast that demand may exceed existing network capacity, ActewAGL did not present any analysis on the probability of the risk and associated cost of unserved energy. Had ActewAGL conducted such risk assessment, the outcome could have informed ActewAGL in its decision to balance the risk to supply and cost to consumers.

In addition, we note ActewAGL's costing for the project included $3.99 million for risk allowances to manage the uncertainty associated with the accuracy of the project estimate.[47] It also included internal management costs of $2.63 million.[48] We consider risk allowances are not a part of augex and NSPs should not pass such items on to the consumer since actual expenditure may be either higher or lower than the estimates. We did not assess the cost efficiency of the internal management cost. However, our view is the total internal management cost $2.63 million is at the very high end of the normal range for project management.

In conclusion, we consider ActewAGL's documentation on this project did not demonstrate prudent investment and proactive risk management practice. While there may be a long-term need for additional capacity in the Molonglo area, we consider that:

- ActewAGL's risk and options analysis is inadequate
- ActewAGL did not adequately justify the timing of the project
- the project costs are high and incorporate inefficient practices.

Belconnen zone substation

ActewAGL proposed to install a third transformer at Belconnen zone substation because potential block load increases could result in capacity constraints towards the end of the 2014–2019 period.[49] ActewAGL explored a number of other options including establishing a new zone substation and demand management solutions. ActewAGL concluded that there is a need to install the third transformer starting in 2016–17 and commissioning in 2018–19.[50] However, it appears ActewAGL used an out-dated substation emergency rating to justify the need for this augmentation project. Therefore, there appears to be no need for this augmentation project and we consider a reduction of $12.7 million ($2013–14) to the augex forecast is appropriate.

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46 ActewAGL, ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, pp. 4 and 13.

47 ActewAGL, *Regulatory proposal: Appendix B16.Project brief: Molonglo zone substation*, 29 May 2014, pp. 9 and 11.

48 ActewAGL, *Regulatory proposal: Appendix B16.Project brief: Molonglo zone substation*, 29 May 2014, p. 11.

49 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 185.

50 ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, pp. 14–16.

ActewAGL stated the Belconnen zone substation previously had a two hour emergency rating of 63MVA in summer. Recent work at the substation increased the summer two hour emergency rating to 74MVA.[51]

ActewAGL forecasted demand at the Belconnen zone substation will be 64.5 MVA in the years 2015 to 2023, up from 60MVA in 2014 (Table A-3). ActewAGL stated 'this forecast contains the full impact of the downturn in summer loads in 2012 and 2013, and minimal block load increases.'[52] Hence, ActewAGL's forecast at the 10 per cent probability of exceedance (POE) level is 9.5MVA below the substation's updated summer two hour emergency rating.

Table A-3 Belconnen zone substation summer demand forecast

	2014	2015	2016	2017	…..	2023
10% POE (MVA)	60.0	64.5	64.5	64.5	…..	64.5
50% POE (MVA)	55.8	60.3	60.3	60.3	…..	60.3

Source: ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, p. 12.
Note: 'POE' denotes probability of exceedance.

ActewAGL stated the following in the justification document for the augex project:

> The baseline demand forecast, excluding known and probable demand increases beyond 12-18 months and ignoring historical demand growth trends exceeds the cyclic rating of the transformers of 63 MVA by 2015. Including probable loads and historical growth trends the demand forecast approaches the newly established two hour emergency rating of the substation.[53]

The meaning of the latter sentence is unclear. ActewAGL did not include any demand forecasts for Belconnen zone substation in its regulatory proposal that 'approaches the newly established two hour emergency rating of the substation. In its reset RIN, ActewAGL forecasts demand to be 66MVA for the 2014–2019 period (at 10 per cent POE).[54]

In response to our information request, ActewAGL stated an uncharacteristically mild 2012 summer artificially suppressed its demand forecast for Belconnen zone substation, leading to a flat forecast. ActewAGL further stated 'the flat profile is highly unlikely' and that revised forecasts over the next few years will show a significant load at risk.[55] However, ActewAGL did not provide the revised load forecasts for Belconnen zone substation in its response. As we noted in appendix C, we anticipate the NSW/ACT DNSPs will provide updated demand forecasts in their revised regulatory proposal. We will assess the updated load forecast ActewAGL provides in relation to this project in our final decision.

ActewAGL also stated there are constraints to its capacity to transfer load to other zone substation to cope with major transformer failure at Belconnen zone substation. However, ActewAGL did not

51 ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, pp. 12–13.
52 ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, p. 12.
53 ActewAGL, *Regulatory proposal: Appendix B16.3: Project justification report: Belconnen transformer augmentation*, 30 May 2014, p. 13.
54 ActewAGL reset RIN.
55 ActewAGL, *Operating and capital expenditure 'site visit' clarifications: 2015–19 Subsequent regulatory control period*, 3 October 2014, p. 76.

provide details on these constraints.[56] For example, the adjacent Latham zone substation has substantial spare capacity over the next 10 years and is only 3.5 km away. It is unclear why ActewAGL did not consider additional feeders and feeder ties from Latham. The cost of feeder solutions would be substantially lower than zone substation augmentation.

With the removal of capacity requirement from the Supply Standards Code, ActewAGL is not obliged to provide capacity to meet the anticipated maximum demand. Instead, it could estimate the probability and cost of load curtailment in the event of capacity shortage. The estimate would inform ActewAGL on the most economical solution to balance the supply risks and costs at Belconnen zone substation.

On the evidence presented, it appears ActewAGL concluded the need and timing for Belconnen transformer augmentation work based on the out-dated emergency rating of 63MVA. In addition, we do not consider ActewAGL demonstrated it performed adequate risk and options analysis to arrive at an efficient solution. On this basis, it appears there is no justification for the third transformer before 2023.

Zone substation earth grid upgrade

ActewAGL proposed to upgrade earth grids at its zone substations.[57] ActewAGL stated the earth grid condition of its zone substations is largely unknown, so it is prudent to estimate a cost for refurbishment. However, we consider ActewAGL could have provided evidence of earth grid failures or degradation of performance if there were such an increasing trend. The absence of this evidence suggests there are no immediate or material issues with the overall condition and performance of these assets. Hence, we consider a reduction of $2.619 million ($2013–14) to the augex forecast is appropriate.

ActewAGL stated:

> The physical condition of the earth grids, particularly those of the greatest age, is largely unknown. In the absence of condition assessments of the earth grids at the time of submitting capital budget estimates, the age of the asset was used to estimate four different levels of refurbishment that may be required to be undertaken. This is a prudent method to estimate expenditure, as it is not likely to understate expenditure (given the age of assets) nor overstate it, until the outcome of the condition monitoring assessment is available.[58]

We consider it is not prudent to propose a capital expenditure to be paid by the consumers without a clear scope or any level of certainty of the need for the expenditure.

Gold Creek 11 kV switchboard extension

ActewAGL proposed $0.77 million of expenditure on a new switchboard because the substation does not have spare switch bays for connection of new feeders.[59]

However, we understand it is a common industry solution to double up the cable termination box on the existing switchboard when facing a shortage of switch bays. This provides an additional

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56 ActewAGL, *Operating and capital expenditure 'site visit' clarifications: 2015–19 Subsequent regulatory control period*, 3 October 2014, pp. 76–77.

57 ActewAGL, *Regulatory proposal: Attachment D3: Customer initiated capital works plan, Network augmentation capital works plan, Asset management plan*, 30 May 2014, pp. 18–19.

58 ActewAGL, *Operating and capital expenditure 'site visit' clarifications: 2015–19 Subsequent regulatory control period*, 3 October 2014, pp. 17–18.

59 ActewAGL, *Regulatory proposal: Attachment D3: Customer initiated capital works plan, Network augmentation capital works plan, Asset management plan*, 30 May 2014, pp. 18–19.

connection terminal for new feeders at comparatively low cost. ActewAGL did not explain why it did not investigate such alternative lower cost solutions.

ActewAGL's data manual shows that Gold Creek Substation has 20 feeders with firm operational ratings around 5.5 MVA each. The current substation maximum demand of about 50MVA suggests the existing feeders have substantial spare capacity for current and future load. However, ActewAGL offered no information why it did not investigate distribution feeder reconfiguration and load transfers. These solutions could free up some existing feeders or feeder bays for potential new load in the coming years.

We consider the proposed expenditure is not prudent. Hence, we consider a reduction of $0.77 million ($2013–14) to the augex forecast is appropriate.

Mitchell zone substation

ActewAGL included $0.6 million ($2013–14) in its augex forecasts on the future Mitchell zone substation.[60] However, ActewAGL did not provide any information on the purpose and scope of this expenditure. In the absence of such relevant information, we consider a reduction of $0.6 million ($2013–14) to the augex forecast is appropriate.

A.2 AER findings and estimates for customer-initiated capital works (customer connections capex)

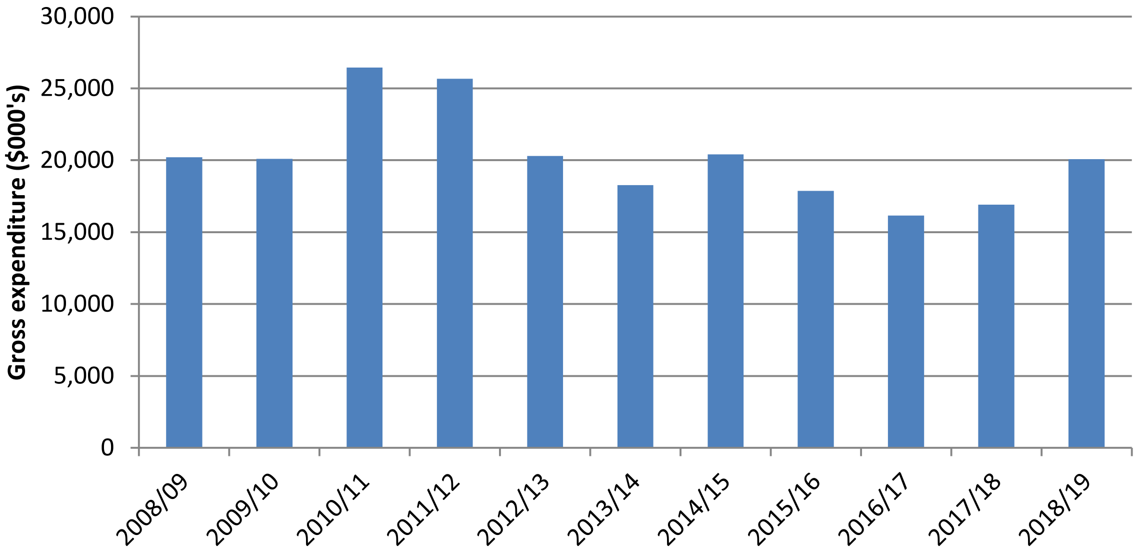
Customer-initiated capital expenditure refers to work that ActewAGL must undertake either when a new customer connects to the distribution network or an existing customer seeks to amend their connection.

A.2.1 Position

ActewAGL proposed $91.42 million ($2013–14) for forecast customer-initiated capex. Figure A-5 shows that this is 40 per cent less than the actual customer-initiated capex that ActewAGL spent during the 2009–2014 regulatory control period.

[60] ActewAGL, *Regulatory proposal: Attachment D3: Customer initiated capital works plan, Network augmentation capital works plan, Asset management plan*, 30 May 2014, pp. 18.

Figure A-5 Customer initiated capex profile



Source: Actew AGL RIN
Notes: We have allocated the balancing item to Actew AGL's forecast connections capex as a percentage of total capex.

ActewAGL attributes this to weaker underlying demand for construction in the ACT resulting from public sector budget reductions.[61]

We accept ActewAGL's proposal and have included it in our alternative estimate. This is sufficient to allow ActewAGL to build its network to meet demand and reliability requirements. However, we consider that a higher proportion of the customer-initiated service cost will be recovered through customer contributions rather than as a shared cost in standard control services. This adjustment to the recovery of the allowance is discussed below.

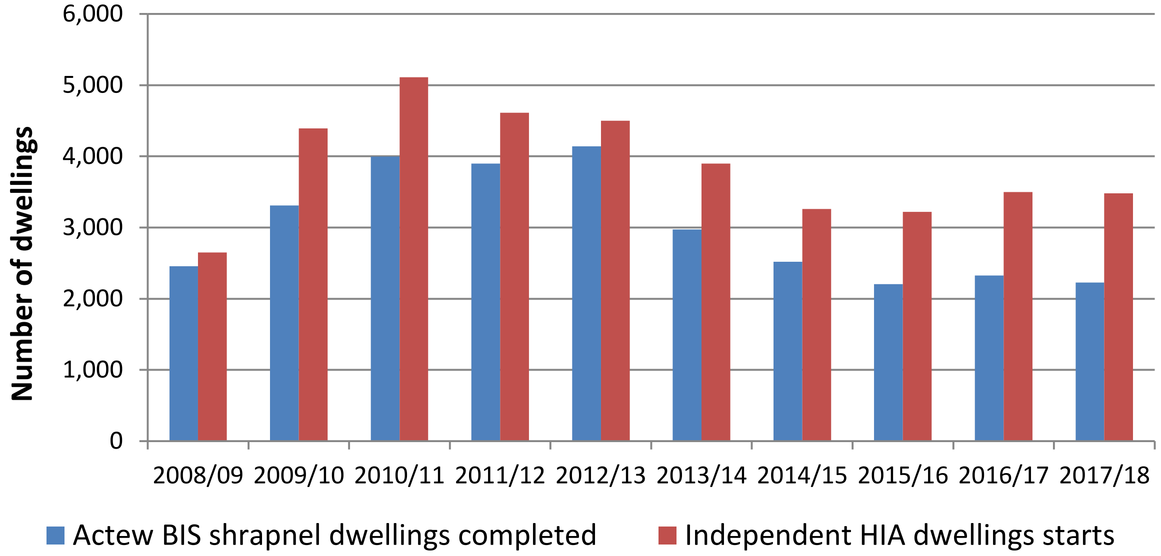
ActewAGL's proposal is driven by connecting residential and commercial premises and new commercial and industrial and residential estates. Where the service cost can be allocated to a customer, ActewAGL may recover the cost directly from customers in the form of a capital contribution. We have therefore assessed ActewAGL's proposal net of customer contributions.

ActewAGL's proposal was largely estimated by trending the latest annual capex of individual customer-initiated services relative to forecasts of construction activity. The capex trend was derived on the basis of a regression analysis which established a relationship between ActewAGL's past customer-initiated capex and construction activity. Those customer-initiated services which did not demonstrate a relationship with construction activity were trended from an average of historical capex, as no clear driver could be identified.

We assessed the inputs of ActewAGL's regression analysis. In our view, these inputs are consistent with independent estimates of construction activity and are therefore reasonable. Figure A-6 compares the inputs of ActewAGL's analysis against independent forecasts of construction activity in the ACT. This reveals that ActewAGL's forecasts are not excessive and are consistent with the subdued trend of construction activity in the 2015–2019 period relative to the 2009–2014 regulatory control period.

[61] *ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 179.

Figure A-6 Construction activity in NSW



Source: BIS Shrapnel,[62] Housing Industry Association.[63]

However, we are concerned about the potential for double counting for relocation services of network assets. These are services that should be funded entirely by the customer requesting the service. This is consistent with our position in the ACT Framework and Approach paper which emphasised that it would be inappropriate for all customers to pay for services provided to an identifiable group of users.[64]

We sought clarification from ActewAGL about the potential overlap of relocation services across standard and alternative control services. In response, ActewAGL stated that relocations include elements of new connection works which are difficult to forecast and require shared funding from customers under standard control services.

In our view, ActewAGL has not demonstrated the need to recover costs above that directly charged to customers requesting the service and above the service scope of alternative control relocation services. There also appears to be sufficient scope for ActewAGL to fund capex for relocations services from customers directly as either capital contributions or as an alternative control relocation service.

As we discuss below, we have adopted the capital contribution amount stated in ActewAGL's PTRM. This results in a higher proportion of the customer-initiated service cost being forecast to be recovered through customer contributions rather than as a shared cost in standard control services compared with the level of contributions reported in Actew AGL's RIN.

In addition, the Consumer Challenge Panel's submission encouraged us to assess ActewAGL's revenue proposal to ensure consumers were not burdened with an unreasonable amount of new development costs.[65] Our assessment of ActewAGL's connection policy indicates that ActewAGL

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62 BIS Shrapnel, Building in Australia 2013–2028, table 4.33.

63 Housing Industry Association, http://hia.com.au/en/businessinfo/economicinfo/housingforecasts.aspx, accessed 18 November 2014.

64 AER, *Stage 1: Framework and approach paper: ActewAGL: Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, p. 15

65 CCP, *CCP1 submission to AER re ActewAGL regulatory proposal, 2014–19: Jam tomorrow?*, August 2014, pp. 17–18.

does not provide connections to new estates on unfair or unreasonable terms. We consider that ActewAGL's connections policy is consistent with the connection charge principles of Chapter 5A of the NER and our connection charge guidelines.[66]

A.2.2 Customer contributions

We accept ActewAGL's proposed capital contributions forecast of $41.16 million as stated in its PTRM.

We note these figures do not reconcile with Actew AGL's proposed RIN summary sheet 2.1. Given the differences in capital contribution figures across multiple sources of Actew AGL's proposal, we have adopted the proposed capital contribution amounts in the PTRM for modelling consistency with Actew AGL proposed maximum allowable revenue requirements.

Additionally, as discussed in section A.2, we consider that the amount of capital contributions sourced from Actew AGL's PTRM is likely to be consistent with the total cost of customer relocations. This results in less customer-initiated costs shared among customers as part of standard control services than if capital contributions amounts from the RIN was used to calculate a net capex allowance.

Table A-4 Actew AGL capital contributions ($2013/14, million)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Actew AGL proposed	8.29	8.37	7.61	7.72	9.17	41.16
AER approved	8.29	8.37	7.61	7.72	9.17	41.16

Source: ActewAGL PTRM.
Notes: Capital contribution figures were sourced from Actew AGL's PTRM. We note these figures do not reconcile with Actew AGL's proposed RIN summary sheet 2.1. Given the differences in capital contribution figures across multiple sources of Actew AGL's proposal, we have adopted the proposed capital contribution amounts in the PTRM for modelling consistency with Actew AGL's proposed maximum allowable revenue requirements and funding for relocation services.

A.3 AER findings and estimates for replacement capital expenditure

Replacement capital expenditure (repex) is non-demand driven capex. It involves replacing an asset with its modern equivalent where the asset has reached the end of its economic life. Economic life takes into account existing asset's age, condition, technology or operating environment. In general, we classify capex as repex where the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance requirement.

A.3.1 Position

ActewAGL's proposed $114.5 million ($2013-14) of forecast repex (excluding overheads).

We do not accept ActewAGL's proposal. We have instead included an amount of $98.6 million in our alternative estimate.

In determining our alternative estimate we applied the following assessment techniques:

[66] AER, *Connections charge guidelines for electricity retail customers under chapter 5A of the NER*, June 2012.

- benchmarking at the expenditure category level and trend analysis of historical actual and expected repex
- review of ActewAGL's major repex projects
- predictive modelling of replacement expenditure requirements.

In summary, we find that:

- ActewAGL's proposed forecast repex exceeds its long term average and ActewAGL has not provided supporting evidence for this increase.
- Controlling for network scale characteristics, ActewAGL's historical repex does not compare favourably to that of other service providers in the NEM and appears high.
- Measures of asset health suggest that ActewAGL has not demonstrated that the likely condition of its assets supports its proposed forecast repex. In addition, ActewAGL's unplanned SAIFI (USAIFI) from 2009 to 2013, which measures frequency of unplanned outages, has been kept at a steady level well below reliability target 67. This suggests that the overall asset conditions have not deteriorated which does not support the increased expenditure.
- Our review of ActewAGL's major repex programs has identified that ActewAGL's proposal may overstate the prudent and efficient amount required to meet the capex objectives for certain asset categories. In particular, we do not consider that ActewAGL has justified step increases in repex for its underground cable, overhead conductor or pole top structure replacement programs. For overhead conductors and pole top structures, which were not included in the repex model (see "Unmodelled repex" section below) we considered that ActewAGL's actual repex from the 2009–14 regulatory control period was appropriate to meet the capex criteria. The underground cable asset group was included in the repex model. Our ultimate view on underground cable was reached by taking into account the findings from our major project review, along with the predictive modelling outcomes and our observations from trend analysis.
- Our predictive modelling also suggests that ActewAGL's proposal is likely to be overstated. This demonstrates that ActewAGL's asset replacement requirements are likely to be materially lower. The range of reasonable outcomes based on our modelling analysis is between $58 million and $76 million, excluding capitalised overheads (refer to appendix). This is a 5 to 28 per cent reduction in ActewAGL's proposed repex that has been modelled, excluding capitalised overheads. However, the lower number in the range needs to be treated with caution, as some environmental characteristics of ActewAGL's network, most notably backyard reticulation of the low voltage power supply, may add cost that are not included in a benchmarked unit cost.
- For categories that were not included in predictive modelling, we are satisfied that a total of $22.5 million is likely to be a prudent and efficient level of repex. When added this amount to the modelled component, this gives a reasonable range for total repex of between approximately $70 million and $98 million.

The amount of forecast repex that we have included in our alternative estimate is $98.6 million ($2013-14), excluding overheads. This is 13.6 per cent less than ActewAGL's proposal. Our estimate for repex is at the upper end of our reasonable range. This takes into account that the lower end of our range needs to be treated with some caution, as noted above. It also ensures that ActewAGL will

[67] ActewAGL revenue proposal table 16.3.

be provided with a reasonable opportunity to recover at least its efficient costs. It will also minimise the potential for ActewAGL to over-invest or under-invest in repex during the 2014–19 period.[68] We have included this amount of repex in our alternative estimate of forecast total capex.

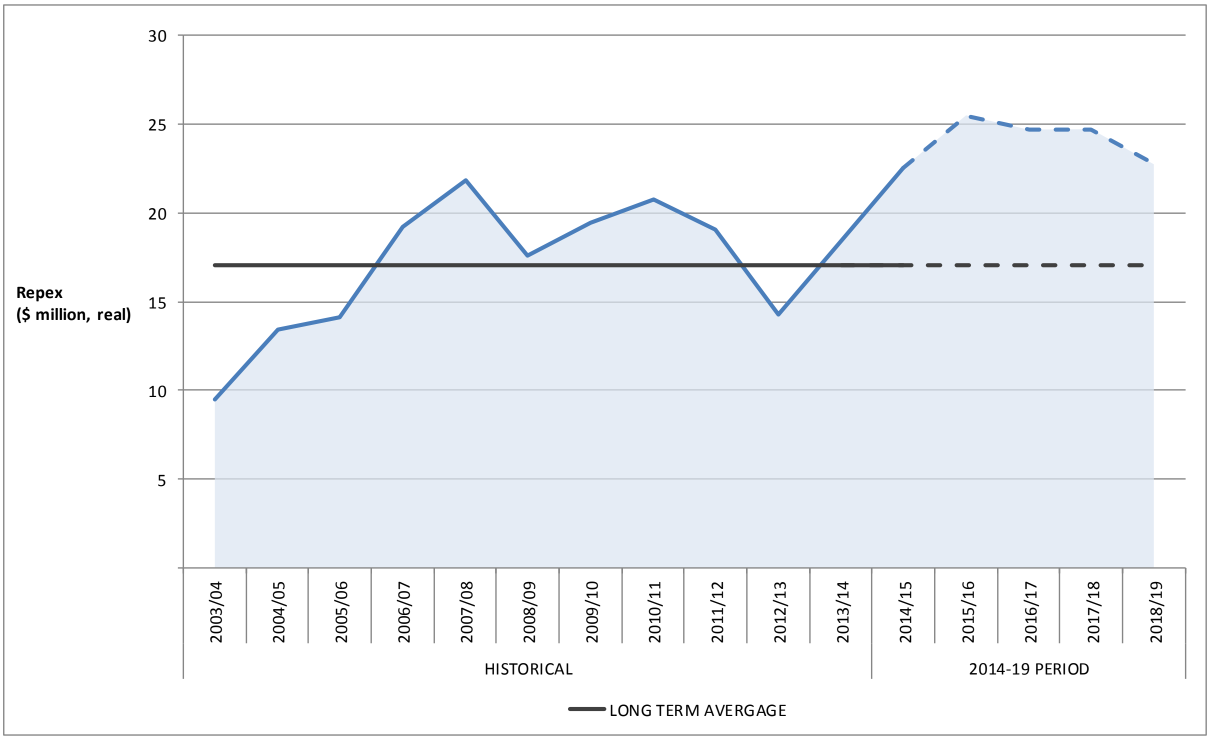
Trend analysis and benchmarking

ActewAGL's proposed forecast repex for the 2014–19 period exceeds its historical trend (based on the time series data available). Notably, its historical repex is also relatively high in comparison to other service providers in the NEM. Specifically, we have considered:

- trends in ActewAGL's actual repex over time to allow comparison with actual repex in previous regulatory control periods
- ActewAGL's actual repex relative to other service providers in the NEM for selected performance metrics that may provide an indication of relative efficiency
- relevant indicators used to inform us of the condition of ActewAGL's network assets.

Figure A-7 shows the trend in ActewAGL's historical and proposed repex. It also shows ActewAGL's actual long term average across the same time period.

Figure A-7 ActewAGL's repex including overheads historic actual and proposed for 2014-19 period (real $ million June 2014)



Source: Historical: ACT Independent Competition and Regulatory Commission - Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010/11 to 2013/14)
2014-19 period: ActewAGL's Reset RIN, Table 2.1.1 - Standard control services capex (allocating capitalised network and corporate overheads on the basis of repex as proportion of total capex)

68 National Electricity Law, 7A(6)

As we discuss in capex attachment ., during the 2009–2014 regulatory control period ActewAGL incurred repex consistent with its historical trend. In our view, the long term trend provides a relevant baseline regarding ActewAGL's underlying repex requirements. Origin Energy noted:

> Notably, asset renewal and replacement expenditure for the 2014–19 regulatory period is expected to be almost 50 per cent higher than in the 2009–14 period. ActewAGL highlights that the key driver of its replacement capex is its ongoing pole replacement program. In addition, ActewAGL also intends to commence replacement of underground cables as assets reach the end of their useful life or where replacement becomes an economic alternative to reactive maintenance and replacement. In particular, the program will address an increase in underground cable faults incurred during the current period. Using an enhanced web based software tool (Riva DS), ActewAGL can manage its assets and their replacement programs more efficiently than in the past, including individually optimised treatment plans and associated life cycle expenditure forecasts for each asset class.[69]

Figure A-7 shows that ActewAGL's proposed forecast repex of $114 million (real $2013-14) for the 2014–19 period significantly exceeds its long term average.[70] This is a 26 per cent increase above its long term average repex[71] and a 20 per cent (real) increase in the amount incurred in the most recent regulatory control period.[72]

Relationship between total repex and network scale

Network scale characteristics, such as the number of customers a service provider serves, its size, operating environment and asset mix, have a bearing on the amount of repex a service provider incurs. For this reason, in assessing the relative efficiency of ActewAGL's historical repex against that of other service providers, we have applied a series of normalisation factors to account for the impact of network size when making comparisons of total repex

In particular, we have used two measures of network density namely customer density and capacity density.[73] These measures account for the number of network assets across a physical area. We have also applied these measures to the total repex for each service providers across the 2008-13 period to assess the relationship between total repex and network scale. Figure A-8 shows this for customer density across service providers.

[69] Origin Energy - Submission to ActewAGL's regulatory proposal p. 2-3.

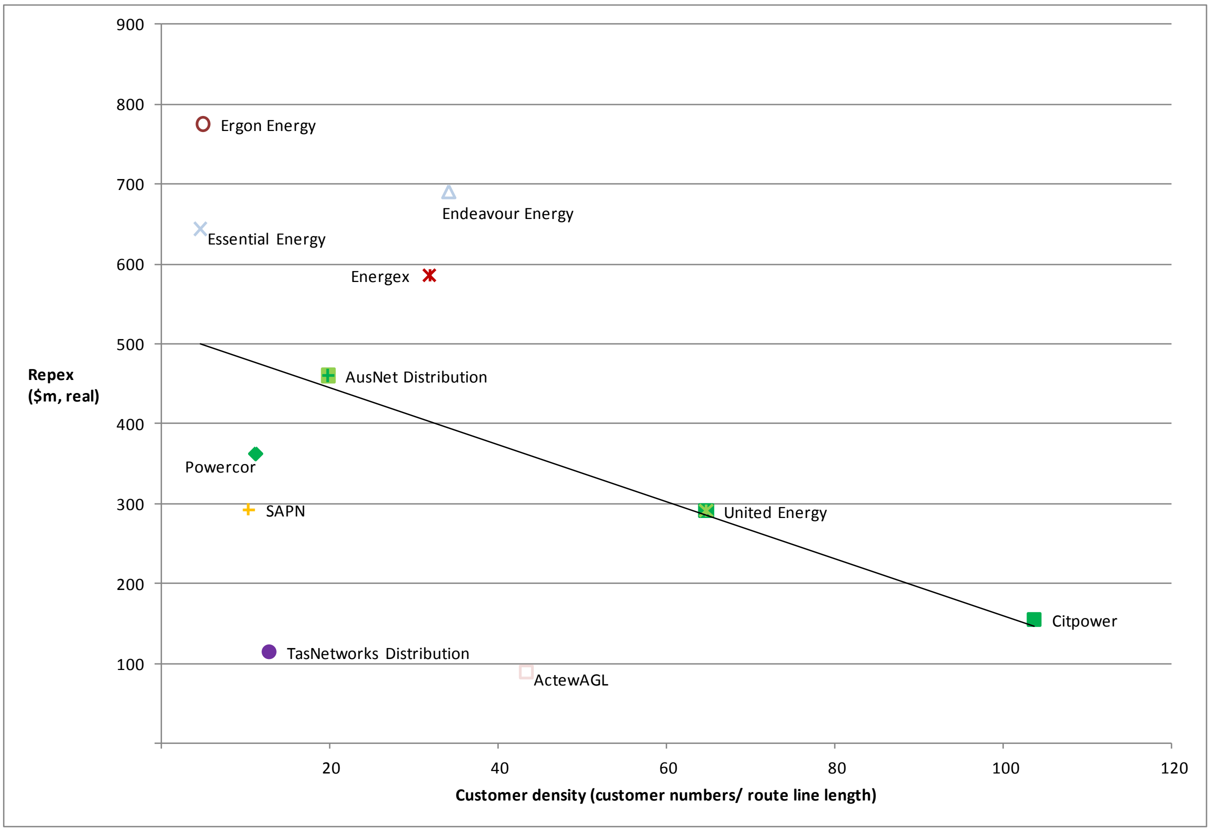
[70] ActewAGL's Reset RIN - Table 2.1.1 - Standard control services capex and Table 2.1.5 - Dual Function assets capex. (after allocating capitalised network and corporate overheads on the basis of repex as proportion of total capex).

[71] The long term average is calculated as the average actual repex (including overheads) between 2001/02 and 2013/14, sourced from IPART Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010/11 to 2013/14).

[72] ACT ICRC - Regulatory Accounts (2009/10) and AER Annual RINs (2010/11 to 2013/14)

[73] Customer density is customer numbers divided by route line length.

Figure A-8 Repex across the NEM normalised for customer density



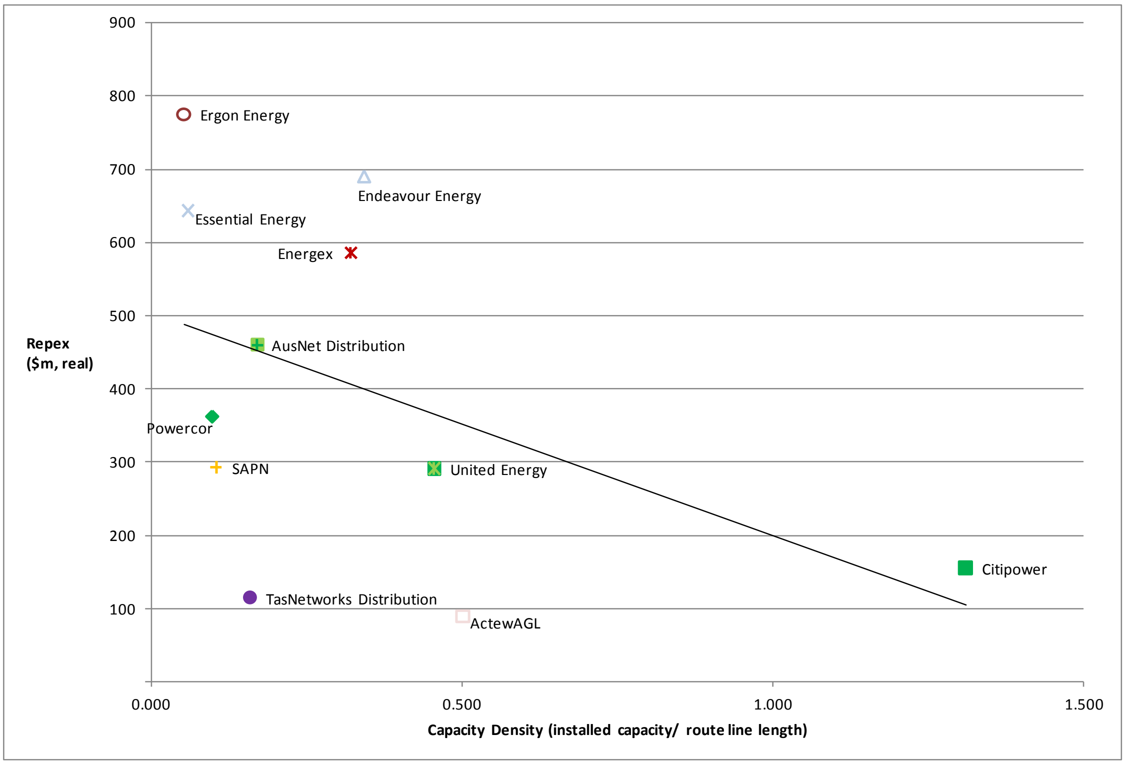
Source: Total Repex: Category analysis and Reset RINs
Customer Numbers and Route Line Length: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence)
(Ausgrid excluded as it is a significant outlier)

In general, Figure A-8 shows that total repex decreases as customer density increases. When we average repex normalised for customer density across the 2008-13 period, we observe a wide range across the service providers. Notably, Ergon Energy and Essential Energy (predominantly rural networks) incur relatively more repex than service providers with a similar customer density. When considering these metrics we have been mindful that ActewAGL has no assets on rural long feeders (compared to around 50 per cent for the predominately rural networks) with only 12.5 per cent and 87.5 per cent of its assets on rural long and urban feeders respectively.[74]

We received feedback from some service providers that normalising total repex for capacity density is important to understanding the impacts of network scale on total repex.[75] We understand capacity density to be the quotient of installed capacity and network length. Figure A-9 shows the relationship between repex and capacity density across the service providers.

74 Length of lines assets (overhead conductors and underground cables) by feeder type.
75 NSP Responses to AER Category Analysis 15 August 2014.

Figure A-9 Repex across NEM normalised for capacity density



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Installed capacity: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence)
(Ausgrid excluded as it is a significant outlier)

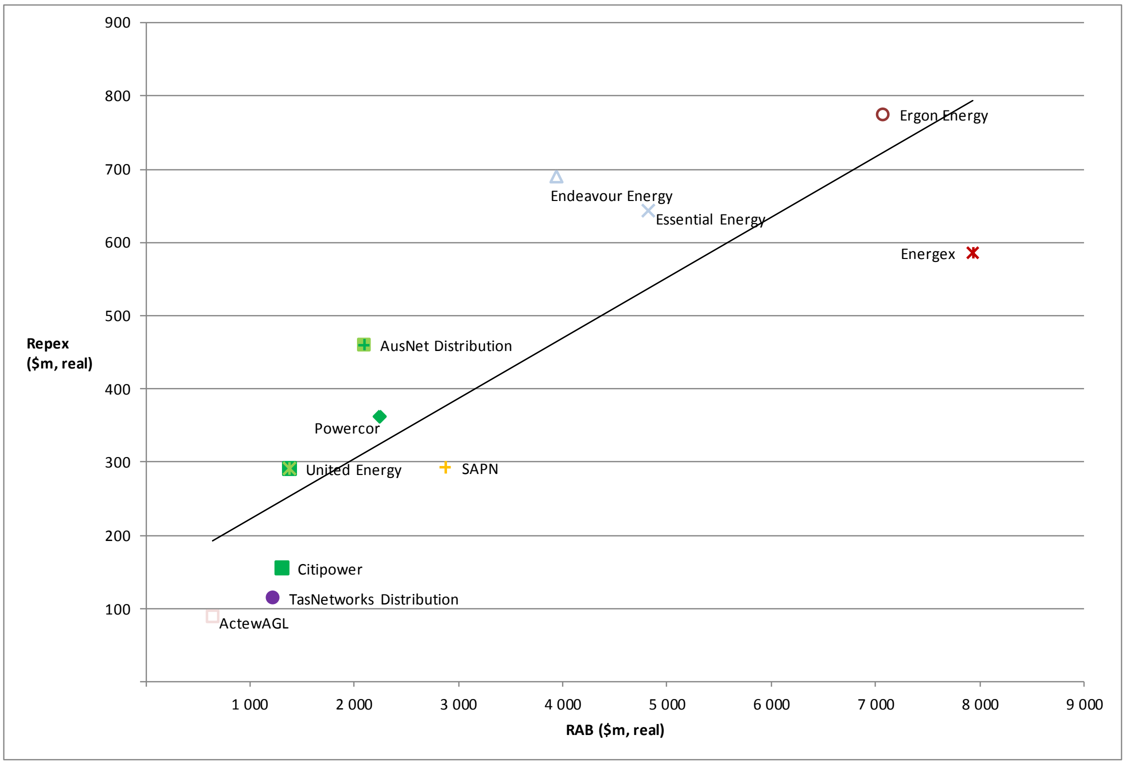
Comparing Figure A-8 with Figure A-9 shows that there are similar relationships when normalising total repex by customer density and capacity density.

ActewAGL compares unfavourably under both density measures. Further, these measures suggest that predominately rural based networks incur higher repex than urbanised networks. When considering whether a network is relatively rural or urban we have also taken into account the length of lines in commission by feeder type. That is, the length of overhead conductors and underground cables installed on CBD, urban, rural short and rural long feeders. As noted above, we have been mindful that ActewAGL has a no assets on rural long feeders and is likely to incur relatively less repex when compared with more predominantly rural service providers.

Size of asset base

In addition, the size of a service provider's regulatory asset base (RAB) will affect the amount of repex it incurs. This is because the more assets that exist on a network, the more there are that will eventually need to be replaced. Figure A-10 compares service providers on the basis of the cumulative repex incurred across the 2008-13 period as a proportion of their opening RABs, which we have used to proxy the number of assets that exist on a network.

Figure A-10 Proportion of asset base replaced in the 2008-13 period



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
RAB: EBT and Reset RINs - 3.4 Operational data
We have approximated each distributors asset base as its initial RAB as at 2008
Jemena redacted as data commercial in confidence
(Ausgrid excluded as it is a significant outlier).

Figure A-10 shows there is a positive correlation between the size of a RAB and the repex service provider incurs.

The service providers have submitted that repex depends not only on the size of their RABs, but the characteristics of their RAB as well.[76] Some service providers also submitted that this measure fails to account for the age and condition of the RAB, any capex and opex trade-offs, whether a service provider employs a deterministic or probabilistic replacement strategy and the stage of a service provider's particular investment cycle (noting the limited number of years used to determine service providers propensity for replacement (repex being the aggregate of only five years of expenditure as shown in figure)).[77]

Whilst we acknowledge the limitations outlined above, this measure indicates that ActewAGL has incurred average proportion of repex relative to the size of its RAB when compared with other service providers.

Asset Health Indicators

A relevant determinant of ActewAGL's repex requirements is the condition of its assets in commission. In assessing this, we have considered:

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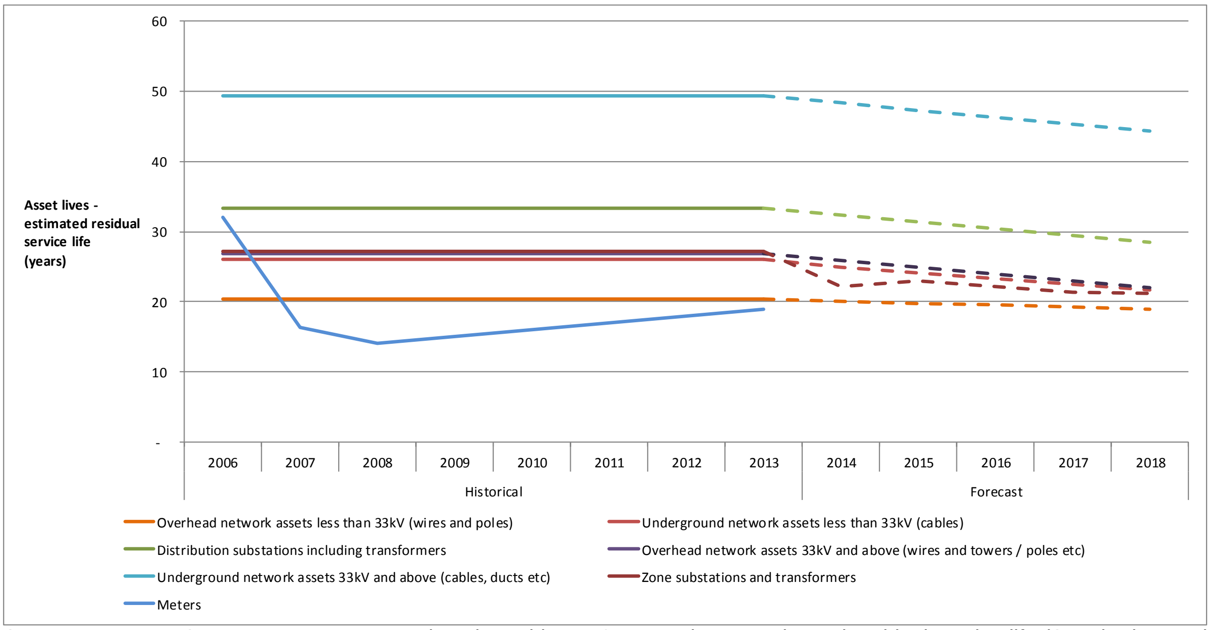
- the age of ActewAGL's network; and
- utilisation of the network (where spare capacity should be positively correlated to asset condition).

Asset age

Asset age is a high-level proxy for asset condition which can be used statistically (i.e. on a population basis) to model the repex requirements of the network. We consider that it is industry practice for service providers to include an assessment of asset age when determining its forecast repex requirements where asset condition data is not available. Further we note ActewAGL uses asset age as an input to how it determines its asset management strategies.[78]

Figure A-11 shows for ActewAGL the estimated residual service life of different asset classes.

Figure A-11 ActewAGL Asset Lives – estimated residual service life



Source: ActewAGL- EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services) for historical and ActewAGL Reset RIN - 2014-19 3.3 Assets (RAB) Table 3.3.4.2

Figure A-11 shows that the trend in residual lives of ActewAGL's assets has been steady over time. However, we also note that ActewAGL is forecasting a decline in residual service lives.

78 ActewAGL, *Regulatory Proposal*, p.167

Figure A-12 ActewAGL Asset Age Profile

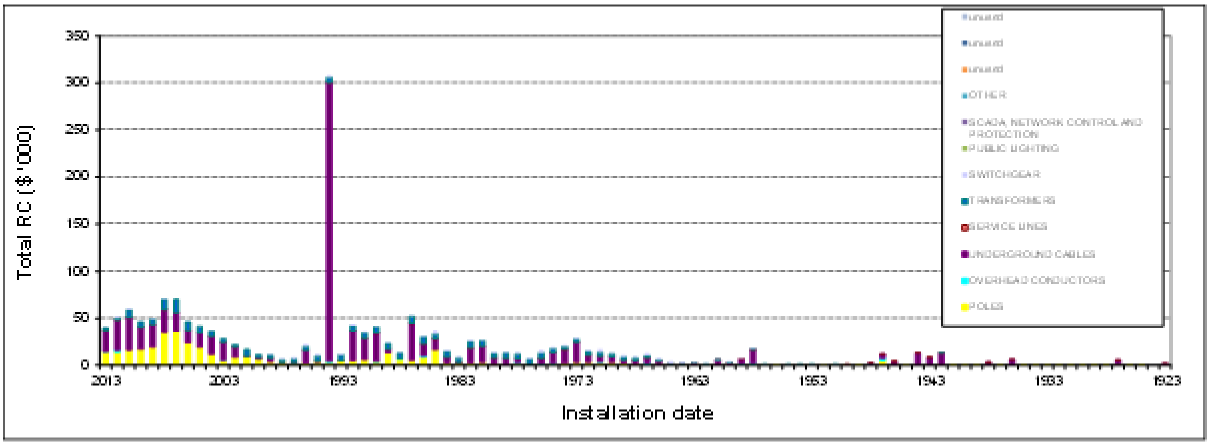


Figure A-12 shows the age of five of ActewAGL's asset groups, weighted by their replacement value. It demonstrates ActewAGL has a lumpy spread in the commissioning of assets on its asset base across time. We note that over the last ten years there has been a spike in the commissioning of assets, following a period of historically low network investment. ActewAGL's stock of older assets is low, with few assets still in service from the 1950s or earlier.

The asset groups that comprise Figure A-12 are presented in Figure A-13 - Figure A-17 below. ActewAGL's proposed average annual repex for the 2014-19 period is also presented as a line in these charts. For poles, there are relatively few instances where the value of assets installed in a given year exceeds the average forecast repex for the 2014-19 period, while there are no instances where service lines exceed this figure. For transformers and swithcgear, there are a number of instances where the value of assets in commission are above the average. However, the majority of these assets were installed relatively recently in the 1980s. For underground cables, the scale is distorted by a very large observation in the mid-1990s.

Figure A-13 Asset age profile – Poles

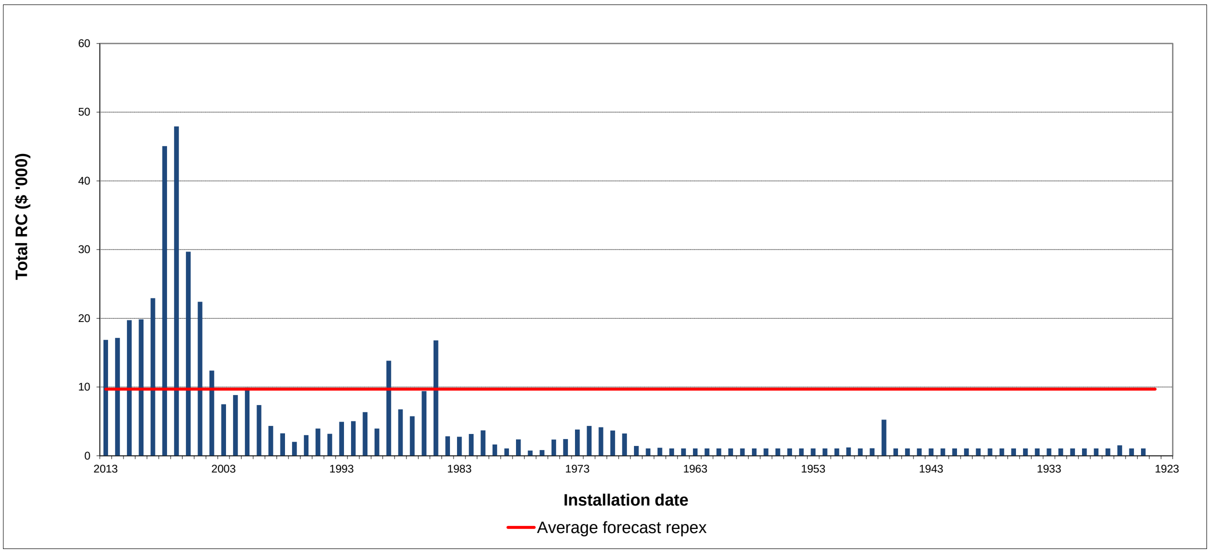


Figure A-14 Asset age profile – Underground cables

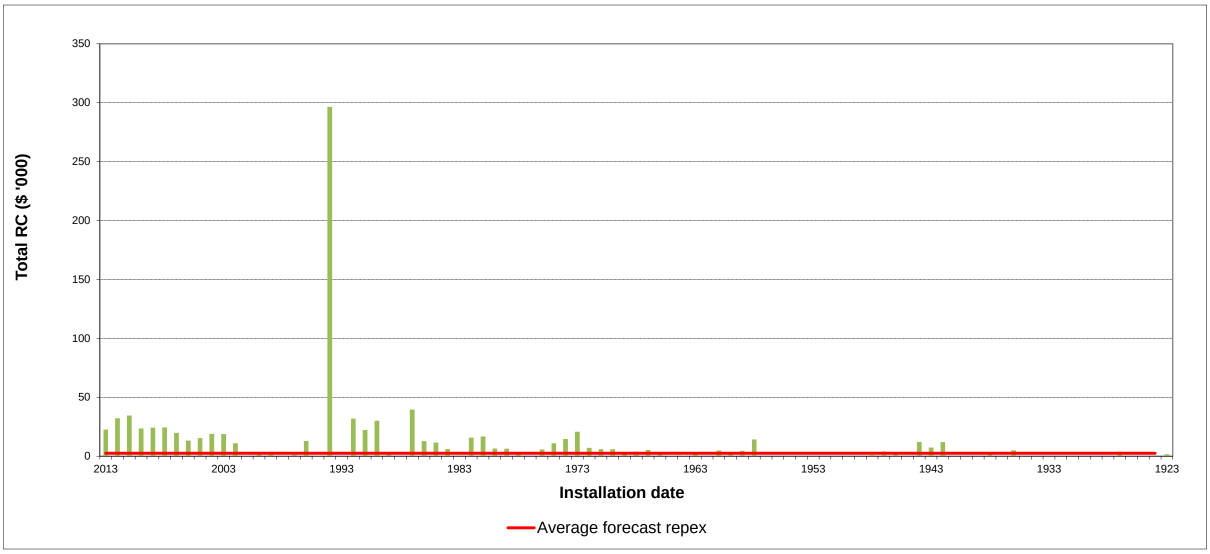


Figure A-15 Asset age profile – Service lines

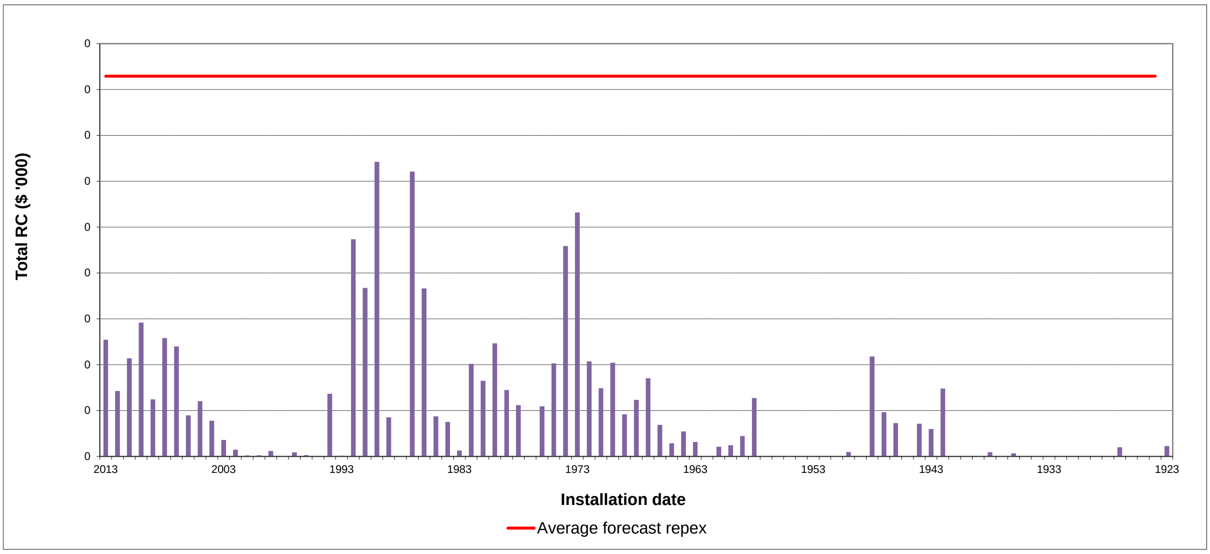


Figure A-16 Asset age profile – Transformers

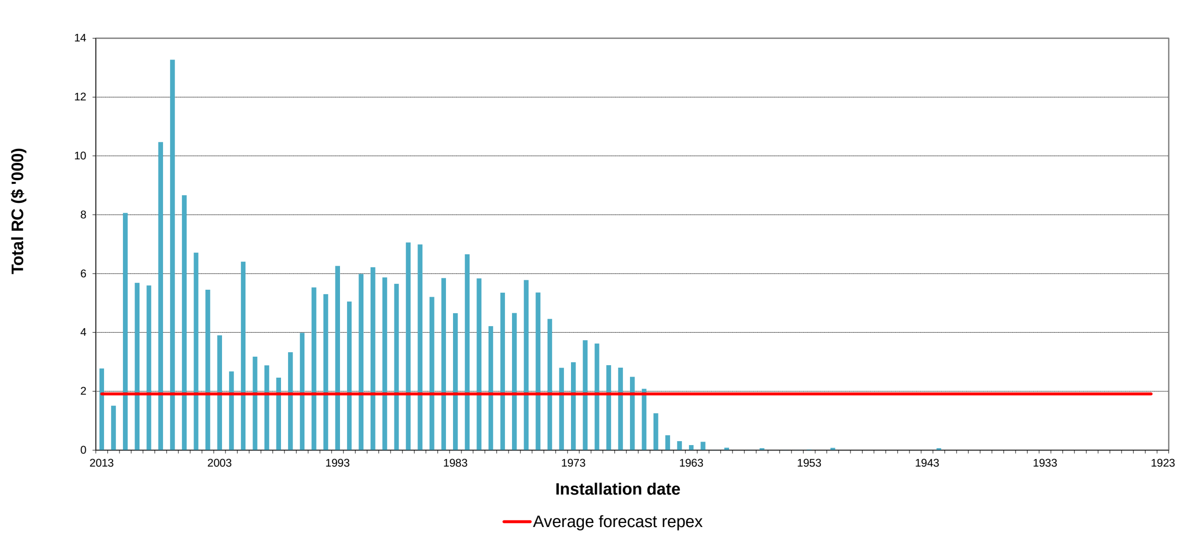
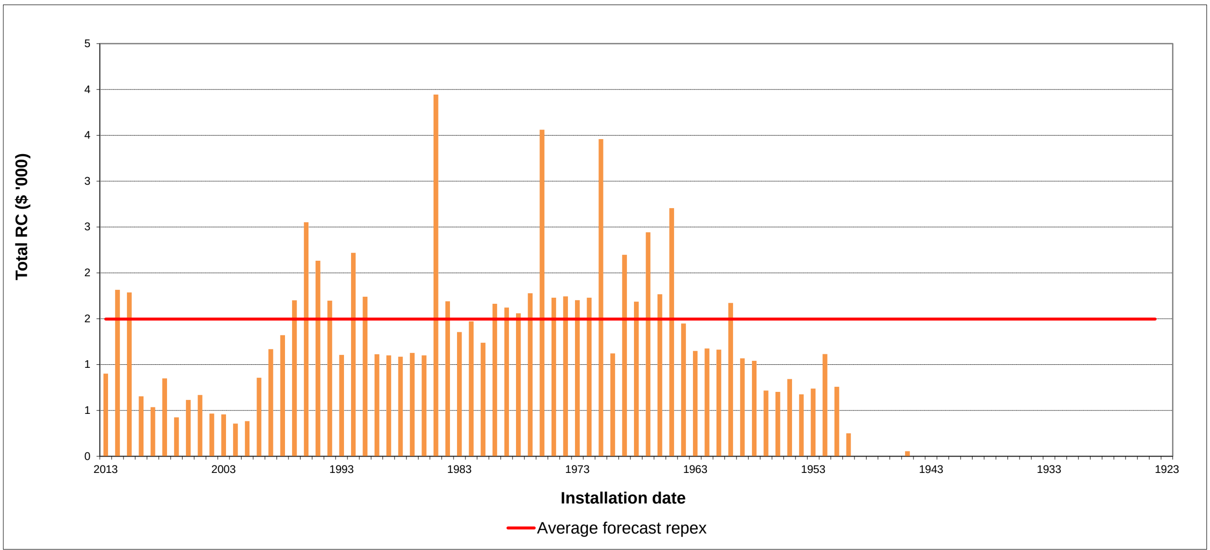


Figure A-17 Asset age profile – Switchgear



ActewAGL's major repex programs

We examined ActewAGL's proposed forecast repex for the poles, overhead conductors, pole top structures and underground cables categories. These categories are major repex programs representing over half of ActewAGL's proposed forecast repex.

We are satisfied that ActewAGL has provided justification for its proposed forecast repex for pole replacements. However, we are not satisfied that ActewAGL's has provided justification for its proposed forecast repex for underground cables, overhead conductors or pole top structures. This is because we are not satisfied that ActewAGL has justified the significant increase in repex for these categories as prudent and efficient, when compared to expenditure in the 2009–14 regulatory control period.

Our review of ActewAGL's major repex program forms part of our overall analysis on repex. Our view on whether ActewAGL's forecast repex is prudent and efficient is based on our assessment of the major repex programs, along with the trend analysis presented above, and our predictive modelling.

Poles

We are satisfied that ActewAGL's proposed forecast repex for the poles category reasonably reflects the capex criteria. ActewAGL has sufficiently maintained its pole replacement programs within its forecast repex during the 2009–14 regulatory control period reporting underspending on repex in each year. ActewAGL's proposed repex on poles is similar for the 2014–19 period compared to what it spent in this category for the 2009–14 period. We are satisfied ActewAGL needs to maintain this amount of repex for poles.

ActewAGL appears to have installed virtually all its non-wood poles (concrete, stobie, fibreglass and steel) within the last 40 years.[79] Poles made from these materials have relatively long economic lives, and we would not expect ActewAGL to replace a significant number of these assets in the 2014–19 period. The focus of ActewAGL's pole replacement program is its wood poles. ActewAGL reports its pole population is 63 per cent wood (or around 30,000 wood poles) and that 38 per cent of those wood poles are staked.[80] SKM report that over the last four years, on average 60 per cent of the poles ActewAGL condemned were reinforced, and that this ratio is forecast to increase modestly during the next regulatory period.[81]

ActewAGL's strategy for wood pole replacement is not like-for-like replacement. That is, rather than replacing a wood pole with another wood pole, it either stakes the wood pole or replaces it with a pole made of another material. ActewAGL uses concrete poles in urban street or rural areas, fibreglass poles in urban backyard areas, or tanalith poles (a type of wood) in heritage areas.[82] ActewAGL provided economic analysis demonstrating the lower cost of a concrete or fibreglass pole over their lifetime compared to a wood pole to support its pole replacement strategy.[83]

In choosing fibreglass for urban backyard areas, ActewAGL submits that its low voltage network is dominated by back of block overhead reticulation where heavy vehicle access is not possible. ActewAGL requires heavy vehicle access to install new wood poles. The steel and fibreglass poles ActewAGL selects are multi part assemblies allowing it to install the pole in sections.[84] These can be carried to the back of a block and installed manually. Additionally, for poles at the rear of blocks ActewAGL also considers that fibreglass poles offer more safety since they are electrical insulators, and are also considerably lighter than wood and steel poles.[85]

Typically, we observe that wooden poles are the least expensive type of pole for use in low voltage applications. ActewAGL's fibreglass pole unit cost is higher than the unit cost that a benchmark average service provider would typically pay for a wooden pole. If these costs were applied to ActewAGL's proposed replacement volumes, it would result in a lower forecast of capex for low voltage pole replacement. However, we accept that the predominance of backyard reticulation in ActewAGL's low voltage networks means that the cost of procurement and installation of replacement low voltage poles is likely to be higher for ActewAGL than other service providers. In particular, ActewAGL needs more labour and less equipment to replace poles in its low voltage network. On balance, we do not consider it appropriate to apply a benchmark cost to ActewAGL's low voltage pole assets.

79 Actew asset plan poles, p. 19.
80 Actew asset plan poles, p. 6.
81 SKM report, pp. 8–9.
82 Actew Pole asset management attachment, pp. 6–7, 15; SKM, pp. 8–9.
83 Actew supporting materials and info request.
84 SKM, p. 12.
85 Actew Pole asset management attachment, p. 12.

Finally, our predictive modelling also supports the pole replacement volumes ActewAGL has proposed for the 2014–19 period. We discuss this further in the predictive modelling section. Overall we are satisfied ActewAGL needs to spend a similar amount on pole replacement in the 2014–19 period to what it spent in the 2009–14 period.

Underground cables

We are not satisfied that ActewAGL's proposed forecast repex for underground cables reasonably reflects the capex criteria. ActewAGL sufficiently maintained its underground cable replacement programs within its forecast repex during the 2009–14 period reporting underspending on repex in each year. ActewAGL's proposed repex on underground cables is around three and a half times higher for the 2014–19 period compared to what it spent in this category for the 2009–14 period. We are not satisfied ActewAGL has justified the need for this significant increase in expenditure.

ActewAGL reports that HV underground cable replacements have increased in the period between 2008 and 2013. We observe that the number of faults during the 2009–14 period varied modestly upwards and downwards from year to year, with the average number of faults around 29 per year. ActewAGL has provided a high and low estimate of the number of number of faults forecast for the 2014–19 period. The low estimate is an average of 27 faults per year, and the high estimate an average of 44 faults per year.[86] At best the number of failures will be similar to the 2009–14 period and at worst will increase by one and a half times. ActewAGL did not provide any further information to indicate its expectations within the range of estimates. We do not consider this information supports an increase in failures in the 2014–19 period compared to the 2009–14 regulatory control period.

Further, ActewAGL has not explained the methodology it applied to derive the forecast rates. ActewAGL appears to have derived the upward trend in failures by applying trend lines to extrapolate future failure rates per kilometre. ActewAGL then appears to have applied these failure rates to its forecast of underground cable length for each year of the 2014-19 period to arrive at a forecast of total underground cable failures in that period.[87] This assumption would predict failures in newly laid cables as well as older cables. We are not satisfied this is a reasonable method of forecasting failure rates. This is because it assumes that a portion of newer assets will fail in proportion to an observed trend in the network.

ActewAGL's practice has been to run underground cables to failure. It now intends to change its asset management strategy for HV underground cables from 'run to failure' to condition monitoring with prioritised replacement.[88] ActewAGL has not provided economic justification or cost-benefit analysis for this change in asset management strategy to support a significant increase in repex for this category.

Finally, the asset age profile of ActewAGL's underground cable population does not appear to support the proposed increase in expenditure. ActewAGL considers its HV underground cables have an average service life of 50 years. We discuss the magnitude of ActewAGL's economic lives further in the section on predictive modelling. Notwithstanding this, the majority (72 per cent) of ActewAGL's high voltage underground cables are reported as younger than 40 years. Hence these are unlikely to require replacement in the 2014–19 period. During the 2009–14 period ActewAGL reported that around 27 per cent of its high voltage underground cables were older than 50 years. ActewAGL appears to have sufficiently maintained its underground cable replacement programs during this

86 Actew UG asset plan, p. 12.
87 SKM, p. 16., Actew UG asset plan, p. 12
88 Actew UG asset plan, p. 12; SKM report, pp. 17–18.

period, reporting underspending on repex in each year. ActewAGL expects a further 11 per cent of high voltage underground cables to exceed 50 years in age over the next ten years.[89] That is, the population of high voltage underground cables aged over 50 years will increase by one and a half times over the next ten years. We are not satisfied that this justifies a three and a half fold increase in proposed repex over the next five years.

Overhead conductors and pole top structures

We are not satisfied that ActewAGL's proposed forecast repex for the overhead conductor category reasonably reflects the capex criteria. We note ActewAGL appears to have reported expenditure for both overhead conductors and pole top structure assets under this category. We have assessed both these groups of proposed expenditure together under the category of overhead conductors. ActewAGL maintained its replacement programs in this category within its forecast repex during the 2009–14 period, reporting underspending on repex in each year. ActewAGL's proposed repex in this category is more than three times higher for the 2014–19 period compared to what it spent in these categories for the 2009–14 period. We are not satisfied ActewAGL has justified the need for this significant increase in expenditure.

The major components ActewAGL reports under the replacement program for this category include:[90]

- Rural pole top upgrade
- Pole top hardware renewal/cross-arm replacement
- Cast iron LV pothead replacement

ActewAGL has not provided justification for an increase in expenditure for the first two programs. We understand that these are ongoing repex programs. ActewAGL has not shown that its replacement circumstances have changed for the 2014-19 period, such that it requires a step increase in expenditure for these programs.

ActewAGL reports an average failure rate of two potheads per year over the last five years. It proposes to change its asset management strategy from opportunistic replacement (replacing potheads when replacing other equipment) to a prioritised replacement program based on failure risk and consequence. There are approximately 500 potheads remaining which ActewAGL proposes to replace over the next 10 years (so around 50 per year). We question whether an average failure rate of two potheads per year supports the need for replacing 50 per year over the next ten years. ActewAGL does not indicate how changing its approach to pothead replacement will impact the number of replacements or expenditure, nor the economic need for this change in activity. We do not consider this supports a significant increase in repex for overhead conductors.

Additionally, ActewAGL reports that the majority of its overhead lines are in 'as new' condition.[91] This does not support a significant increase in repex for this category.

Overall, we consider that ActewAGL has not justified the need for an increase proposed repex for overhead conductors and pole top structures for the 2014–19 period.

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89 SKM report, pp. 14–15.
90 Actew proposal, pp. 174–175; Actew asset plan for OH, pp. 11–13.
91 Actew asset plan OH, p. 17.

A.3.2 Predictive modelling

This section sets out our assessment of the findings from the predictive modelling of repex (the repex model).[92] The repex model is used to predict likely asset replacement volumes and expenditure based on the number and age of assets in service, the assumed age of replacement of these assets and their corresponding unit costs. The model uses age as a proxy for the many factors that drive individual asset replacement.[93] Our approach to developing outputs from the repex model is detailed in appendix D.

The model allows us to estimate a range of outcomes based on different inputs. We have adopted a robust approach to assessing the inputs used in the model with reference to our other techniques where relevant.

We have also adopted a robust approach to scrutinising the outcomes of the model. By examining whether both inputs and outcomes are robust, we have narrowed the range within which expenditure is likely to reasonably reflect the capex criteria. This range, in conjunction with our other analytical techniques, inform our alternative estimate.[94]

Asset groups included in the model

The repex model has been used to model replacement in five asset groups, being poles, underground cable, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories. The process for collecting and using this data is discussed in detail in Appendix D.

In total, the assets modelled represent $80 Million or 70 per cent of ActewAGL's proposed repex.

Pole top structures and SCADA, along with specialised categories of capex defined by ActewAGL that were not classified under the five groups above. ActewAGL provided incomplete asset age profile data for overhead conductors. This category has also been excluded from the repex model. We can model this asset group if ActewAGL provides this information as part of its revised proposal.

The process for collecting and using this data is discussed in detail in Appendix D.

Analysis of the reasonable estimation range

As outlined in Appendix D, we have utilised several different replacement age and unit cost inputs in our repex modelling to derive a range of estimates. The following analysis provides our view on whether these inputs are likely to lead to reasonable outcomes, having regard to our other assessment techniques. These include our benchmarking results for total capex and repex, analysis of ActewAGL's long term repex trends and of its repex programs for poles, underground cables and overhead conductor. The inputs used in the model are:

- replacement life and age information, and expenditure and replacement volume information provided by ActewAGL (the base case model);

92 We have also used the model as part of previous distribution determinations. We first used the predictive model to inform our assessment of the Victorian DNSPs' expenditure proposals in 2010 and we have undertaken extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline.

93 AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, p. 10.

94 AER Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013.

- replacement life information derived by using ActewAGL's replacement volumes from the last five years (referred to as “calibrated lives”); and
- unit costs and replacement lives derived by comparing information from all service providers across the NEM (benchmarked replacement lives and unit costs).

The process used to develop the calibrated replacement lives and benchmarking inputs is included in appendix D.

The base case model

The base case model uses replacement life information inputs provided by ActewAGL in its RIN (i.e. the average asset replacement life and the standard deviation of the replacement life). We applied two base case models. The first base case model was based on ActewAGL's observed costs in the past five years (historical unit cost), and the other on costs derived from its forecast expenditure (forecast unit cost). The estimates derived from these two models were $212 million and $205 million, respectively. These estimates are higher than ActewAGL's forecast of $80 million for the five modelled asset groups.

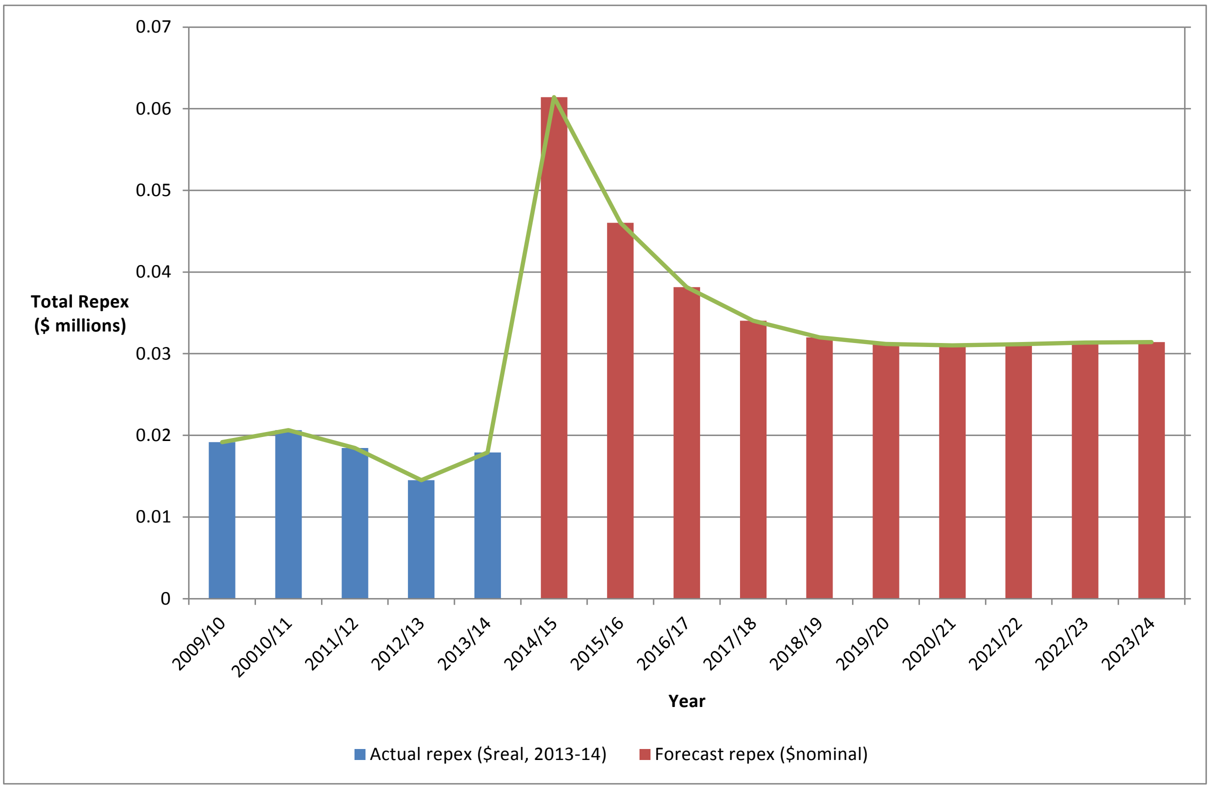
Table A-5 Base case model outcomes

Unit cost	Model outcome
Historical	$211.6
Forecast	$205.7

Source: AER analysis

The replacement profile predicted by the repex model under the base case scenario features a sharp step-up in expenditure in the first year of the forecast, which then declines over the remainder of the period (see Figure A-18). This replacement profile indicates that a significant portion of the asset population currently in commission has survived to an older age than would be expected using the base case replacement life figures submitted by ActewAGL. Using ActewAGL's base case replacement lives causes the model to immediately predict the replacement of this stock of assets. This, in turn, results in a large stock of predicted asset replacements in the first year of the forecast, which then declines over time.

Figure A-18 ActewAGL's replacement expenditure from 2009–14 and expenditure predicted by the base case model



Source: ActewAGL, AER analysis.

In scrutinising the discrepancy between ActewAGL's forecast of $80 million and our base case outcomes, we consider that the base case outcomes are not credible or reliable for the reasons outlined below.

First, if ActewAGL's actual replacement lives were consistent with their base case replacement lives, we would not expect to see the observed asset replacement profile. This is because, if ActewAGL's actual asset replacement profile followed its base case replacement lives, the older assets would have:

- already reached the end of their economic (replacement) lives and so would have already been largely replaced; and
- would therefore not be expected to be in the asset age profile, or be in such insignificant volumes that it would not materially affect the outcome of repex modelling.

The 'step-up/trend down' replacement profile observed from the base case model suggests that a significant proportion of the asset population has survived longer than would be expected using ActewAGL's data. The 'survivor' assets have a material effect on the observed outcome. This outcome suggests that the base case replacement lives are shorter than those achieved in practice.

We have undertaken further analysis to determine replacement life information that matches ActewAGL's actual replacement practices.[95] This work is outlined in Appendix D.

Second, our assessment of ActewAGL's replacement programs for underground cables, overhead conductor and pole top structures has identified a lack of justification for proposed increases in forecast repex. Furthermore, our assessment of ActewAGL's repex trends over the past 11 years showed its forecast repex to be significantly above its long-term trend. Based on these assessments, our expectation is that the prudent and efficient level of repex is likely to be materially below the outcomes in the base case modelling and materially lower than ActewAGL's forecast.

Third, further analysis of the base case model results reveals the replacement life inputs are the main drivers of the base case outcome. If the base case replacement life information is substituted with calibrated lives (as explained below) the model outputs are $71 million for historical unit costs and $76 million for forecast unit costs. Taken together with the information from our other analytical techniques and our concerns that the base case lives do not reflect ActewAGL's actual replacement practices, we consider that the base case replacement life information provided by ActewAGL's will not result in a reasonable range for repex.

The calibrated model

The calibrated model uses replacement lives and standard deviations based on ActewAGL's replacement volumes from the past five years. We applied the repex model using the calibrated replacement life data in combination with historical, forecast and benchmarked unit cost values (the outcomes using the benchmarked unit costs are discussed in the benchmark model section below).

Table A-6 Calibrated model outcomes

Unit cost	Model outcome
Historical	$71.1
Forecast	$76.1
Benchmark average	$58.2
Benchmark first quartile	$44.6
Benchmark lowest	$31.0

Source: AER analysis.

Using calibrated replacement lives and ActewAGL's forecast unit costs gives an output of $71 million when historical unit costs are used and $76 million when forecast unit costs are used.

The calibrated replacement life estimate provides a lower predicted volume and expenditure forecast than ActewAGL's forecast, despite essentially trending forward ActewAGL's observed replacement practices from the 2009-14 regulatory control period. It may be expected that trending forward average replacement lives from the 2009-14 regulatory control period will lead to a similar outcome to the last period – which would in turn be similar to ActewAGL's forecast. However, the historically high volume of asset replacement work that ActewAGL's has carried out over the last five years is likely to have changed its asset age profile from five years ago. That is, by spending a large amount on repex

95 To take into account ActewAGL's actual asset replacement practices we have used recent historical replacement practices to approximate the mean asset replacement lives and standard deviation. This process is referred to as calibration, and is described in appendix D.

in the last regulatory control period, ActewAGL is expected to have replaced a significant number of its older assets. This in turn may be expected to reduce the overall age of its network. If the average replacement life and standard deviation stays the same, but the network's overall age is reduced, fewer assets will need to be replaced in the next period.

Networks NSW has noted concerns with the use of calibrated lives. These concerns were raised in the context of the NSW distribution service provider's revenue proposals, but are nonetheless relevant to our assessment of ActewAGL. Networks NSW's concerns are related to its general concerns relating to the usability and accuracy of the repex model.

> In previous determinations, the AER has used 'calibration' functions when the base case suggests that a far higher level of expenditure is warranted. In these cases, the AER has used most recent historical data or substituted benchmarking data to 'refit' the model to derive alternative outcomes. When the AER has re-calibrated the models they have found that DNSP's proposed forecasts exceed the predicted values of the model.
>
> In our view this raises significant concerns with the validity of the model given that the 'base case' could produce results that the AER considered were invalid. In these cases, it would be incorrect to use a flawed model with different input data (either benchmark of past expenditure) to derive a conclusion that the AER considered was not anomalous. In our view, this is a type of backsolve to validate the use of the model. [footnote page 11 of Networks NSW doc]

In our Explanatory Statement to the Expenditure Forecast Assessment Guideline, we addressed concerns with the model and updated the Replacement expenditure model handbook to address specific issues.[96] This concern as raised by Networks NSW in this determination was not submitted at the time we consulted on our Guideline but we acknowledge that with any modelling there is always room for disagreement. In our Explanatory Statement to our Guideline we expressly recognised that we will attempt to resolve issues with the repex model as they arise.

After considering the concerns raised by NSW Networks, our view is that these concerns are unfounded. The model is based on well-established principles of probability and normal distribution. It has been used by the AER previously and has similar characteristics to the model used by OFGEM.[97] We do not accept that the model is flawed because we use different input data. In our view, it is good practice to scrutinise the inputs having regard to the outcomes and when viewed against the regulatory proposal which is the subject of our determination.

We further note, as foreshadowed in the Explanatory Statement to our Guideline that we will use the repex model as a first pass model, in combination with other techniques.[98] It is not used in isolation, but one of a number of analytical tools.

In this instance, for ActewAGL, the base case outcomes may be "invalid" as NSW Networks might describe our findings, but nonetheless this assists us in narrowing the range of what is reasonable by assessing the robustness of the inputs used.

Using the previous five years of data to derive a replacement life gives us an estimation of ActewAGL's actual replacement practices, informing us when an asset might be expected to be replaced due to age/condition reasons. It provides a counterpoint to the base case lives, which, as discussed above, do not accord well with the age of ActewAGL's assets in commission.

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96 AER Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013, p. 277-283.

97 OFGEM, Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment, March 2013, p. 44.

98 AER Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013, p. 289.

We are satisfied that the use of recent historical behaviour to derive a replacement life is a reasonable approach to finding an input for the purposes of establishing a reasonable range of repex for the 2014–2019 period. Compared to the base case lives supplied by ActewAGL, the calibrated lives estimates a lower volume of replacement, which is more in line with the results from our other assessment techniques. However, we also consider it appropriate to test the outcomes of the calibrated model against benchmarked inputs derived from other service providers.

The benchmarked model

The benchmarked model uses unit costs, replacement lives and standard deviations based on observations from all distribution service providers in the NEM. The derivation of these inputs is discussed in Appendix D.

Benchmark of uncalibrated service provider submitted replacement lives

Using benchmarked replacement life inputs supplied by all service providers in the NEM (the uncalibrated benchmark replacement life) results in a large forecast volume of replacement works, and a “step-up/trend down' repex profile. This is similar to our observations of the base case above. This may indicate a systemic bias across the NEM towards reporting conservative replacement life estimates. As with the base case, the weight of evidence points towards ActewAGL over forecasting its replacement volumes, particularly our analysis of ActewAGL's major repex programs and our observation of ActewAGL's long-term repex trend. Given this, we do not consider the uncalibrated benchmark replacement life information supplied by the service providers is suitable for use in finding a reasonable range.

Table A-7 Benchmarked model outcome – Uncalibrated average replacement life

Unit cost	Model outcome
Historical	$179.1
Forecast	$178.3
Benchmark average	$177.8
Benchmark first quartile	$109.4
Benchmark lowest	$52.5

Source: AER analysis.

Table A-8 Benchmarked model outcome – Uncalibrated first quartile replacement life

Unit cost	Model outcome
Historical	$64.6
Forecast	$64.6
Benchmark average	$64.6
Benchmark first quartile	$64.6
Benchmark lowest	$64.6

Source: AER analysis.

Table A-9 Benchmarked model outcome – Uncalibrated longest observed replacement life

Unit cost	Model outcome
Historical	$149.0
Forecast	$148.1
Benchmark average	$155.8
Benchmark first quartile	$106.0
Benchmark lowest	$64.6

Source: AER analysis.

Benchmark of calibrated replacement lives

We also calculated calibrated replacement life information for each service provider and derived benchmarks from these observations. Using the benchmarked average calibrated replacement life information from all service providers in the NEM in the repex model results in a repex estimate of $66 million (using forecast unit costs). Using replacement lives one quartile above the mean gives an estimate of $42 million, while using the longest observed replacement life in the NEM gives an estimate of $30 million.

The average benchmarked calibrated replacement life observation from ActewAGL is slightly lower than ActewAGL's own calibrated model outcomes. The first quartile observation is substantially lower than the average, while the longest observed replacement life gives a very low estimate of repex.

While the calibrated benchmark replacement lives provide a useful set of results for analytical purposes, we have decided not to include them in the reasonable range. The calibrated benchmark replacement lives will reflect to some extent the circumstances of a service provider (such as their age profile) and so we have only used this information to check ActewAGL's calibrated model outcomes, and we will consider using this benchmarked data in future regulatory decisions.

Table A-10 Benchmarked model outcome – Calibrated average replacement life

Unit cost	Model outcome
Historical	$64.8
Forecast	$65.7
Benchmark average	$63.3
Benchmark first quartile	$40.8
Benchmark lowest	$22.1

Source: AER analysis.

Table A-11 Benchmarked model outcome – Calibrated first quartile replacement life

Unit cost	Model outcome
Historical	$40.4
Forecast	$41.5
Benchmark average	$39.3

Benchmark first quartile	$25.3
Benchmark lowest	$14.2

Source: AER analysis.

Table A-12 Benchmarked model outcome – Calibrated longest observed replacement life

Unit cost	Model outcome
Historical	$29.0
Forecast	$30.1
Benchmark average	$28.0
Benchmark first quartile	$18.5
Benchmark lowest	$11.2

Source: AER analysis.

Unit costs

Using a replacement unit cost based on an average benchmark results in an estimate of $58 million for the five modelled asset groups. This is lower than the outcome of either ActewAGL's historical or forecast unit costs. We have included this unit cost benchmark in the reasonable range. We acknowledge that unit cost benchmarking is less applicable to ActewAGL's low voltage pole network In particular, the amount of backyard reticulation is likely to affect ActewAGL's cost of replacing low voltage poles in comparison with other service providers in the NEM. We have taken account of this when considering when deciding whether ActewAGL's efficient repex is likely to sit closer to the higher or lower end of the reasonable range.

We have also decided to exclude the outcomes of both the first quartile ($45 million) and the lowest unit cost unit price benchmarking($31 million). Using the lowest observed unit cost or a unit cost one quartile below the mean results in a much lower estimate of repex for ActewAGL. At the lowest unit cost, or the frontier, we are relying on a single observation, whereas the average benchmark is based on all observations from the NEM (after controlling for outliers, as discussed in Appendix D). We consider the average, which is based on a number of observations, is a better point of comparison between service providers.

Table A-13 Benchmarked model outcome – Unit costs

Replacement life	Unit cost	Model outcome
Calibrated	Forecast	$76.1
Calibrated	Benchmark average	$58.2
Calibrated	Benchmark first quartile	$44.6
Calibrated	Benchmark lowest	$31.0
NSP benchmark average (calibrated)	Forecast	$65.7

NSP benchmark average (calibrated)	Benchmark average	$63.3
NSP benchmark average (calibrated)	Benchmark first quartile	$40.8
NSP benchmark average (calibrated)	Benchmark lowest	$22.1

Source: AER analysis.

The reasonable range

The discussion above established the inputs that we consider provide a reasonable estimate of repex for ActewAGL. Based on our predictive modelling, we are of the view that an efficient level of repex for those categories that have been modelled is likely to be in the range of $58 million to $76 million. The final estimate of efficient repex will involve the weighing up of all information, and assessment techniques.

Unmodelled repex

Repex categorised as: overhead conductor; supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA); pole top structures and "other" in ActewAGL's RIN response was not included in the repex model. As noted in Appendix D, we did not consider these asset groups were suitable for inclusion in the model, either because of lack of commonality, or because we did not possess sufficient data to include them in the model. Together, these categories of repex account for $34.3 million (or 30 per cent) of ActewAGL's proposed repex.

Because we are not in a position to directly use predictive modelling for these asset categories, we have placed more weight our analysis of long term trends and our review of ActewAGL's major projects. Our analysis of these is included below.

Overhead conductor and pole top structure

ActewAGL forecast $10.6 million of repex for overhead conductor and $7.3 million for pole top replacement. In the 20014-19 period, ActewAGL's repex for overhead conductor was $2.3 million and its repex for pole top replacement was $3.7 million. As noted in our review of ActewAGL's major repex programs, we are not satisfied that ActewAGL has justified the need for a step increase in its overhead conductor and pole top replacement program. We consider a repex allowance similar to the 2009-14 regulatory control period is sufficient to meet the capex criteria in the 2014-19 period. Consequently, we are satisfied that repex of $2.3 million for overhead conductor and $3.7 million for pole top replacement is sufficient to meet the capex criteria in the 2014-19 period.

SCADA, network control and protection

ActewAGL has proposed repex of $6.9 million for SCADA, network control and protection (referred to as SCADA). This is higher than its SCADA repex of $2.3 million in the 2009-14 regulatory control period. Our observations from trend analysis indicate that this expenditure may be overstated. However, given the materiality of this proposed increase on total capex we have not made any adjustment to ActewAGL's forecast of repex for SCADA.

Other

ActewAGL included a single category of repex as "other", being Other substation and equipment. ActewAGL forecast $9.6 million of repex for these assets for the 2014-19 period. ActewAGL's repex for these assets in the 2009-14 regulatory control period was $12 million. The reduction in expenditure in this asset group compares favourably with ActewAGL's past expenditure. We are therefore satisfied that the total of $9.6 million in the "other" asset group is likely to be a prudent and efficient level of repex.

A.4 AER findings and estimates for non-network capex

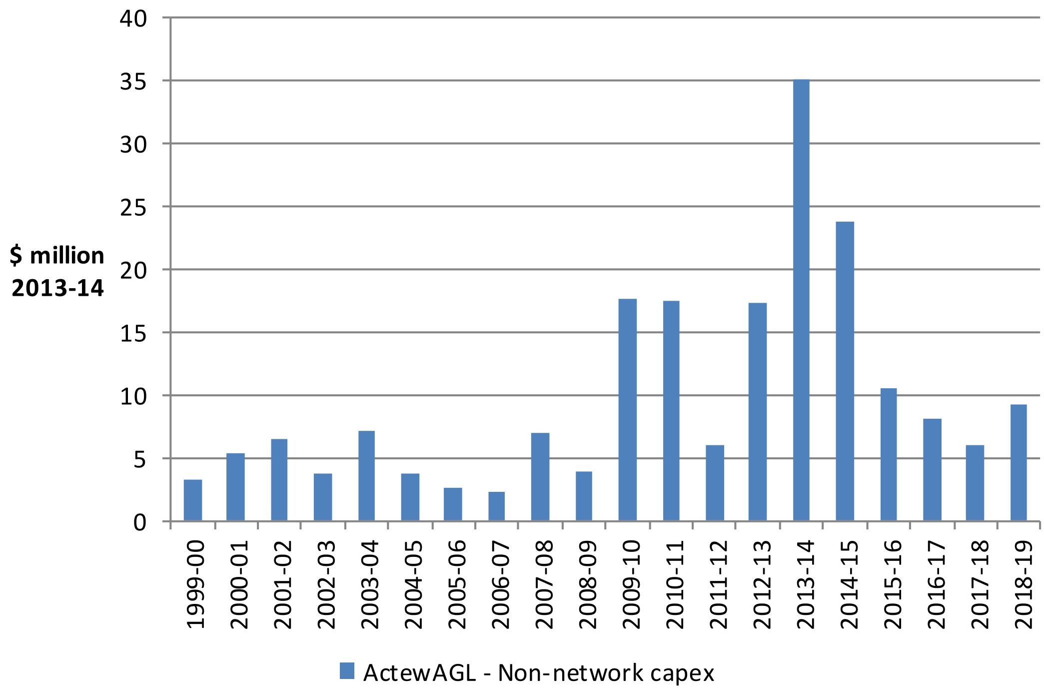
Non-network capex includes capex on information and communications technology (ICT), motor vehicles, buildings and property, and tools and equipment.

A.4.1 Position

ActewAGL forecast total non-network capex of $50.7 million ($2013-14) for the 2014-19 period.[99] We accept that ActewAGL's forecast of non-network capex is a reasonable estimate of the efficient costs required for this capex category. We have included it in our estimate of total capex for the 2014-19 period.[100]

Figure A-19 shows ActewAGL's historical non-network capex for the regulatory control periods from 1999-00 to 2013-14, and forecast capex for the 2014-19 period.

Figure A-19 ActewAGL's non-network capex 1999-00 to 2018-19 ($million, 2013-14)



Source: ActewAGL, *Regulatory information notice*, template 2.6; ActewAGL, *RIN response for 2009-14 regulatory control period, template 2.2.1*; AER analysis.

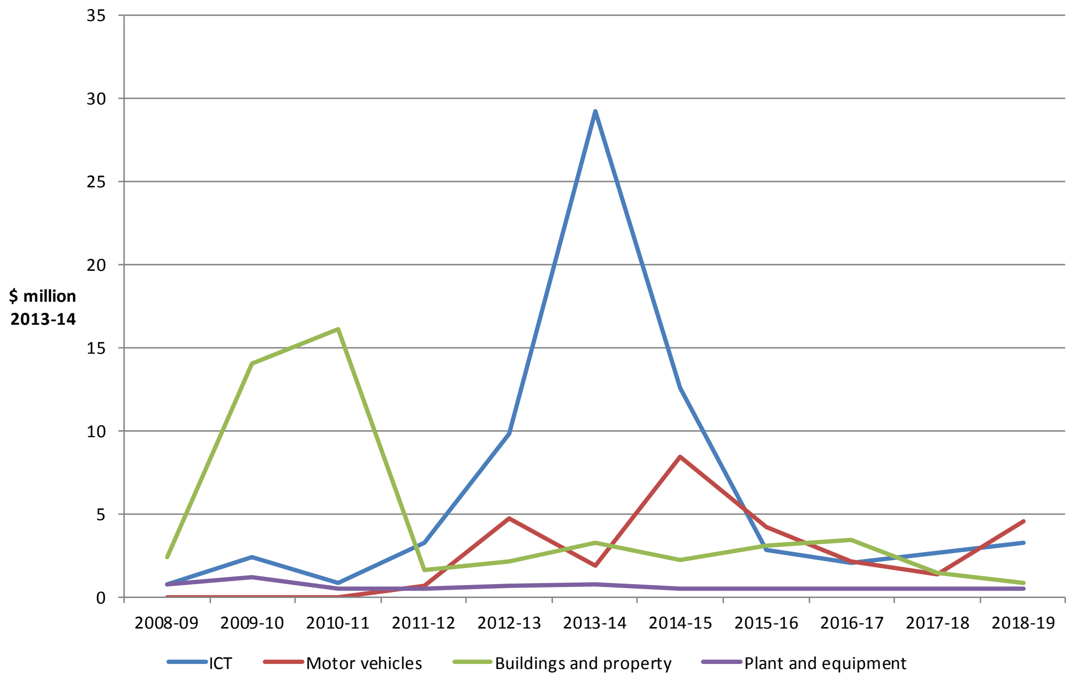
ActewAGL's forecast non-network capex for the 2014-19 period is approximately 38 per cent lower than actual and expected capex in the 2009-14 regulatory control period. This compares to ActewAGL's forecast increase in total capex of one per cent.[101] Our analysis of longer term trends in non-network capex suggests that ActewAGL has forecast capex for this category returning to levels consistent with expenditure in the period prior to the 2009-14 regulatory control period. For example, non-network capex in 2017-18 is forecast to be lower in real terms than expenditure in 2001-02,

[99] ActewAGL, *Regulatory proposal*, 10 July 2014, p. 200. This includes both network and non-network ICT capex, but excludes capitalised overheads.
[100] NER, cl. 6.12.1(3)(ii).
[101] ActewAGL, *Regulatory proposal*, 10 July 2014, p. 39.

2003-04 and 2007-08. However, as noted by Origin Energy[102], forecast non-network capex in the 2014-15 and 2015-16 years remains high relative to historical levels of expenditure in this category.[103] We therefore consider that ActewAGL's forecast non-network capex program warrants further review to confirm the need and timing for the proposed expenditure, with particular focus on the 2014-15 and 2015-16 years.

We have also assessed forecast expenditure in each category of non-network capex. Analysis at this level has been used to inform our view of whether forecast capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.[104] Figure A-20 shows ActewAGL's actual and forecast non-network capex by sub-category for the period from 2008-09 to 2018-19.

Figure A-20 ActewAGL's non-network capex by category ($million, 2013-14)



Source: ActewAGL, *Regulatory information notice*, template 2.6; AER analysis.

ActewAGL has forecast capex to reduce substantially across the ICT, buildings and property, and plant and equipment categories of non-network capex in the 2014-19 period. The forecast reductions in expenditure for these categories of non-network capex range from 27 per cent for plant and equipment up to 71 per cent for buildings and property.[105] The relatively high level of non-network capex forecast in the 2014-15 and 2015-16 years is driven by a spike in motor vehicles capex and continued investment in ICT assets, albeit reducing from the peak experienced in 2013-14. We therefore consider that ActewAGL's forecast motor vehicles and ICT capex programs warrant further review to confirm the need and timing of the proposed expenditure.

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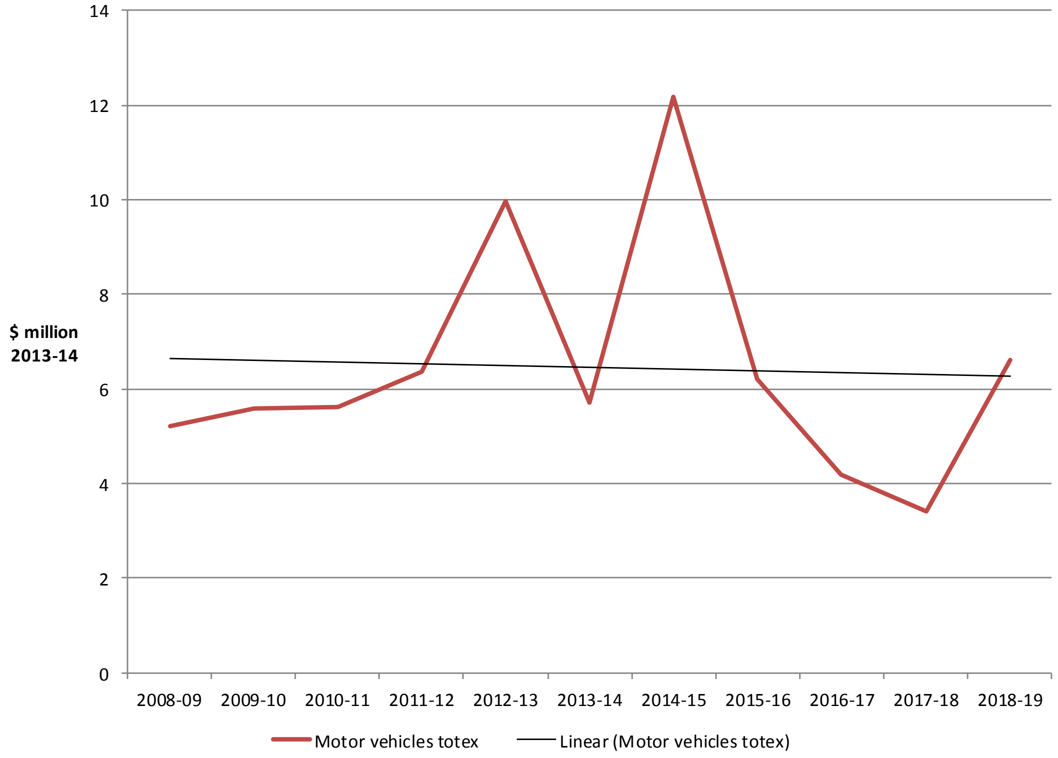
102 Origin Energy, *Submission to ActewAGL's regulatory proposal*, 20 August 2014, p. 4.
103 NER, cl. 6.5.7(e)(5).
104 NER, cl. 6.5.7(e)(5).
105 ActewAGL, *Regulatory information notice*, template 2.6; AER analysis.

Motor vehicles

ActewAGL's forecast capex of $18.3 million ($2013-14) for motor vehicles is approximately 187 per cent higher than capex in the 2009-14 regulatory control period.[106] ActewAGL submitted that this level of expenditure reflects the ongoing transfer of its network vehicle fleet from operating lease arrangements (opex) to finance leases (capex) as existing leases expire. ActewAGL considers this change is consistent with standard industry treatment of leased vehicles, and will align its treatment of motor vehicle expenditure with that of other service providers. [107] We sought further information from ActewAGL to understand the rationale for this change and its effect on forecast expenditure.[108]

The historical trend analysis of motor vehicle capex presented in Figure A-20 does not account for ActewAGL's substitution of motor vehicles expenditure from opex to capex, which commenced in 2012 and is continuing in the 2014-19 period. In order to account for this substitution, we considered the trend in total motor vehicle expenditure across both opex and capex in the same period.[109] This is set out in Figure A-21 below.

Figure A-21 ActewAGL's total motor vehicle expenditure ($million, 2013-14)



Source: ActewAGL, *Regulatory information notice*, template 2.6; AER analysis.

As can be seen in Figure A-21, despite the significant increase in forecast capex for motor vehicles, the trend in total motor vehicles expenditure, accounting for both capex and opex, is declining. Total motor vehicles expenditure in the 2014-19 period is forecast to be 2 per cent lower in real terms than

106 Excludes capitalised overheads.
107 ActewAGL, *Regulatory proposal*, 10 July 2014, p. 200.
108 AER, *Information request ACTEW015*, 29 July 2014.
109 NER, cl. 6.5.7(e)(7).

actual expenditure in the 2009-14 regulatory control period.[110] The forecast 187 per cent increase in motor vehicles capex is more than offset by a forecast reduction in motor vehicles opex.

ActewAGL has forecast total vehicle numbers to remain steady across the 2014-19 period, and approximately in line with fleet numbers in 2011 prior to the change in leasing arrangements.[111] The slight decline in total vehicle expenditure is consistent with the vehicle number forecast, indicating that ActewAGL's switch from operating to finance lease arrangements is not expected to lead to unit cost increases in the fleet program. The forecast expenditure profile is volatile, with particularly high expenditure experienced in 2012-13 and forecast for 2014-15. This volatility in expenditure reflects the timing of different classes of vehicles being transitioned to finance lease arrangements. We anticipate that the volatility of motor vehicle expenditure will reduce in future as leases are renewed on a more ad hoc basis.

Having considered the information provided by ActewAGL, we are satisfied that the significant increase in motor vehicles capex forecast in the 2014-19 period is a result of ActewAGL's switch from operating to finance lease arrangements, rather than inefficiencies or unit cost increases in the fleet program. Total motor vehicles expenditure is forecast to decline in the 2014-19 period, and is consistent with forecast vehicle numbers. We therefore accept that ActewAGL's forecast of motor vehicles capex is a reasonable estimate of the efficient costs required for this category.

ICT

ActewAGL forecast ICT capex of $20.6 million ($2013-14) in the 2014-19 period, a reduction of 49 per cent from the 2009-14 regulatory control period.[112] More than half of the forecast capex is scheduled for the 2014-15 year. Following this initial investment, ActewAGL submitted that ICT capex for the remaining years provides for the ongoing maintenance of the established ICT environment.[113]

In the 2009-14 regulatory control period, ActewAGL undertook a substantial program of investment in both network and non-network systems through the Operational Systems Replacement Program (OSRP) and Core Systems Replacement Program (CSRP). In summary, these investment programs addressed the following business needs:[114]

- CSRP: replace and consolidate systems for business critical functions, including billing, finance and human resources systems
- OSRP: equip ActewAGL with a modern network management capability based on a new SCADA system, a new maintenance planning system, and works management system.

The key ICT projects contributing to expenditure in the 2014-15 year are those related to network operational systems, extending and integrating the OSRP projects completed in the 2009-14 regulatory control period. Key projects include:[115]

- Real time networks monitoring: extending the high voltage Advanced Distribution Management System (ADMS) to support network activities on the low voltage network
- Networks field force mobility: implementation of Cityworks Mobility to enable remote access to network geographical information, asset data and works management information. This also

110 ActewAGL, *Regulatory information notice*, template 2.6; AER analysis.
111 ActewAGL, *Regulatory information notice*, template 2.6; AER analysis.
112 This includes expenditure on both network and non-network related ICT assets, but excludes capitalised overheads.
113 ActewAGL, *Attachment D10 - ActewAGL Distribution ICT Expenditure Proposal Summary*, May 2014, p. 35.
114 ActewAGL, *Attachment D10 - ActewAGL Distribution ICT Expenditure Proposal Summary*, May 2014, p. 27.
115 ActewAGL, *Regulatory proposal*, 10 July 2014, pp. 194-196.

includes establishing a mobile interface to ActewAGL's incident management system, and the purchase of mobile devices.

There is also a smaller amount of corporate services non-network ICT capex scheduled for 2014-15. This includes phase two of the financial information management system project undertaken in the 2009-14 regulatory control period, and an upgrade of the Fyshwick data centre which is expected to reach capacity in 2015.[116]

ActewAGL submitted that its forecast ICT capex is skewed to the initial year of the 2014-18 period as a continuation and extension of the CSRP and OSRP programs of work in the 2009-14 regulatory control period. ActewAGL considers this timing will allow it to utilise existing vendor contracts and resources with an in-depth knowledge of the new systems gained through delivery of the OSRP and CSRP.[117] On this basis, we are satisfied that the proposed capex reasonably reflects the efficient costs of achieving the capex objectives. The purpose of ActewAGL's proposed timing is to provide for the efficient delivery of the forecast ICT capex program.[118]

ActewAGL submitted that its cost estimates for the operational ICT projects in 2014-15 have been validated using vendor provided costings.[119] ActewAGL has also used current vendor information and infrastructure choices to develop the cost estimates for the corporate ICT infrastructure projects.[120] On this basis, we are satisfied that ActewAGL's cost estimates for these projects are likely to reflect a realistic expectation of the required cost inputs for the specified functional requirements.[121] However, we have not assessed whether the functional requirements for the ICT infrastructure are efficient and prudent.

In summary, we are satisfied that ActewAGL's forecast of ICT capex is a reasonable estimate of the efficient costs required for this category. ICT capex is forecast to decline significantly in the 2014-19 period, with a historically low and stable level of investment forecast from the 2015-16 year. The additional expenditure in the 2014-15 year relates to the CSRP and OSRP programs of work largely completed in the 2009-14 regulatory control period, and leverages off those programs to provide for efficient costs and project delivery. We therefore accept that ActewAGL's forecast of ICT capex is a reasonable estimate of the efficient costs required for this category.

A.5 AER findings and estimates for capitalised overheads

Capitalised overheads are costs associated with capital works that have been appropriately capitalised in accordance with ActewAGL's capitalisation policy. They are generally costs shared across different assets and cost centres. The amount of capitalised overheads incurred is a function of and the amount of capital works that is undertaken.

A.5.1 Position

ActewAGL proposed $52.2 million ($2013-14) of forecast capitalised overheads. We do not accept ActewAGL's proposal. We have instead included an amount of $7.6 million in our alternative estimate. This is 80 per cent less than ActewAGL's proposal. In coming to this view, we applied trend analysis to assess ActewAGL's proposal by reference to the actual capitalised overheads it incurred during the 2009–2014 regulatory control period.

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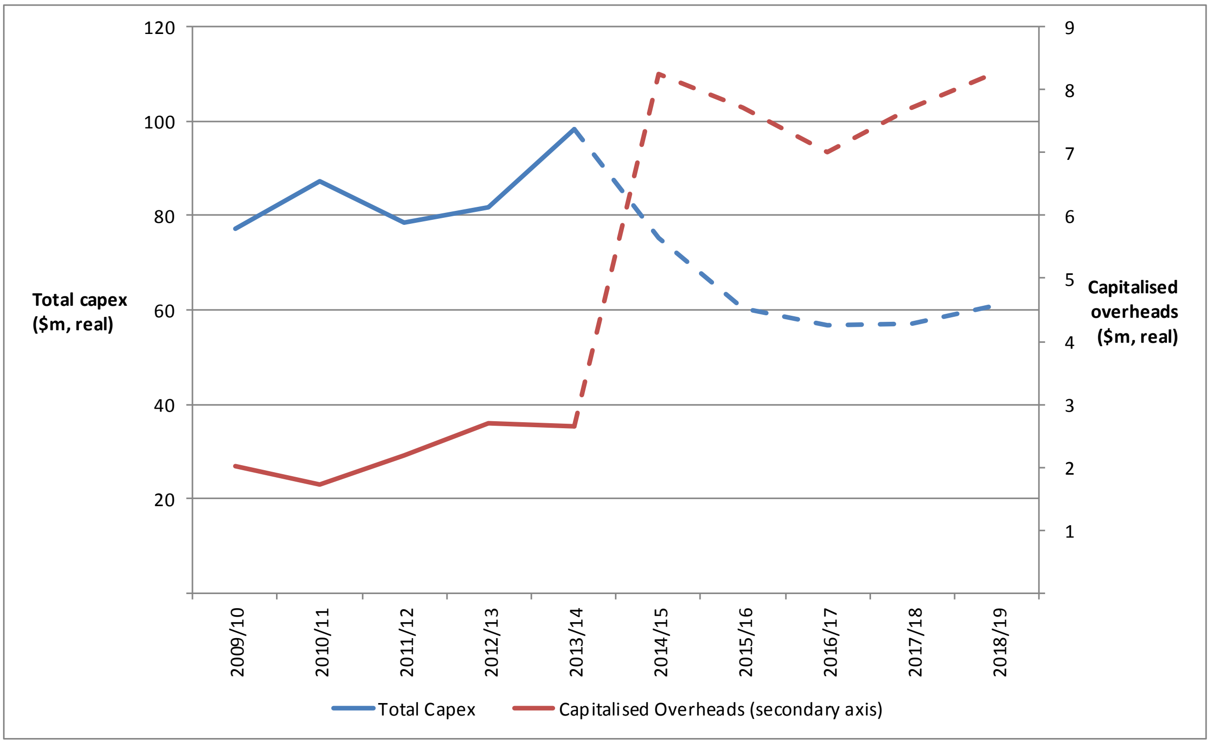
116 ActewAGL, *Regulatory proposal*, 10 July 2014, p. 201.
117 ActewAGL, *Attachment D10 - ActewAGL Distribution ICT Expenditure Proposal Summary*, May 2014, p. 35.
118 NER, cl. 6.5.7(c)(1).
119 ActewAGL, *Attachment D10 - ActewAGL Distribution ICT Expenditure Proposal Summary*, May 2014, p. 32.
120 ActewAGL, *Attachment D10 - ActewAGL Distribution ICT Expenditure Proposal Summary*, May 2014, p. 33.
121 NER, cl. 6.5.7(c)(3).

ActewAGL proposed $52.2 million of forecast capitalised overheads is an increase from the actual capitalised overheads that it spent during the 2009–2014 regulatory control period. As Figure A-22 shows, the increase itself is consistent with the increase ActewAGL's proposed total forecast capex compared to the actual (and estimated) capex that it spend during the 2009–2014 regulatory control period.

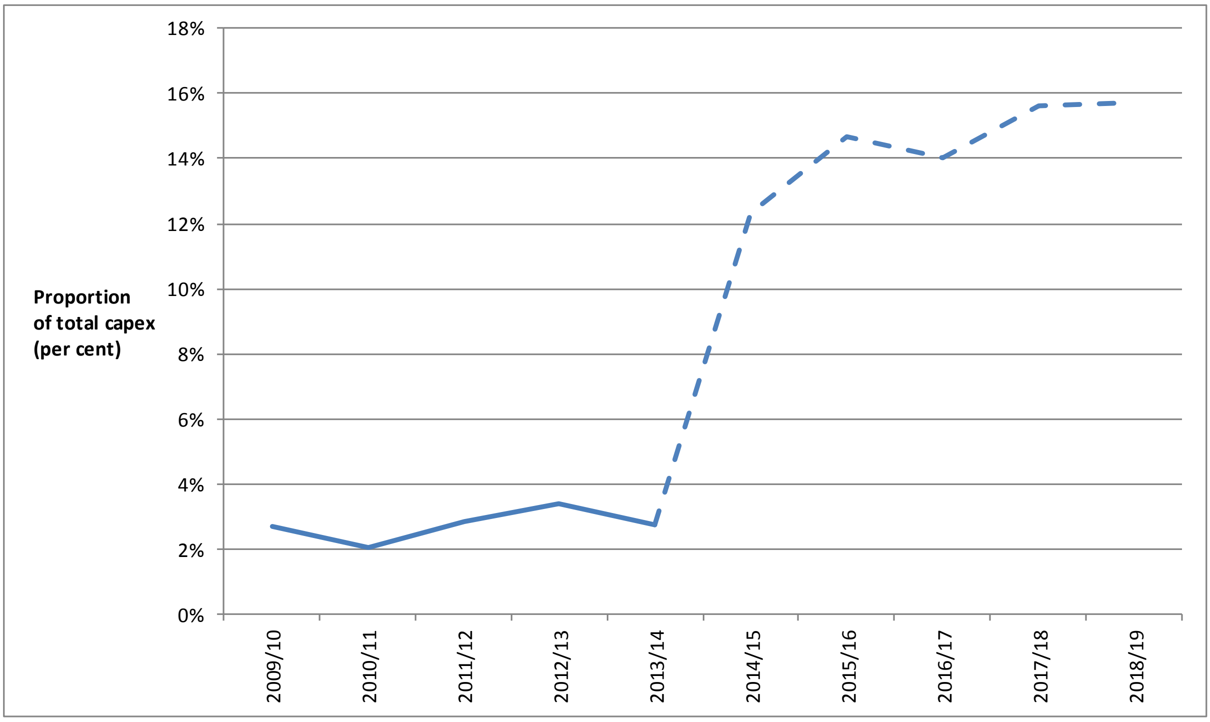
Figure A-22 ActewAGL - total capex and capitalised overheads ($ million - real June 2014



Source: ActewAGL - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex and Table 2.1.5 Dual function assets capex (capitalised overheads aggregate corporate and network capitalised overheads)

Figure A-23 shows that the average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period and that which is forecast over the 2014–19 period is around 3 per cent and 15 per cent, respectively.

Figure A-23 ActewAGL - capitalised overheads as a proportion of total capex (per cent)



Source: ActewAGL - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex and Table 2.1.5 Dual function assets capex (capitalised overheads aggregate corporate and network capitalised overheads)

However, ActewAGL's proposal of $39.0 million for capitalised overheads as a proportion of proposed capex of 15 per cent is not consistent with its historical proportion of total capex of 3 per cent. We note that ActewAGL has not identified any changes to it capitalisation policy that would support the increases capitalisation of overheads in the 2014-19 period.

We have not accepted ActewAGL's proposed amount of capitalised overheads on the basis that:

- This increased capitalised overheads in the 2014-19 period does not appear to have been supported by any changes to ActewAGL's capitalisation policy
- We expect that ActewAGL's capitalised overheads should be lower given we have reduced ActewAGL's 'base' opex such that a lower amount of overheads need to be capitalised; and
- We have not accepted ActewAGL's capex proposal such that the proposed amount for capitalised overheads is not consistent with our alternative estimate.

A.6 AER findings and estimates for demand management

Demand management refers to any strategy to address growth in demand and/or peak demand. Demand management can have positive economic impacts by reducing peak demand and encouraging the more efficient use of existing network assets, resulting in lower prices for network users, reduced risk of stranded network assets and benefits for the environment. Demand management is an integral part of good asset management for network businesses. Network owners can seek to undertake demand management through a range of mechanisms, such as incentives for customers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply (such as distributed or embedded generation and energy storage).

In some circumstances demand management can provide efficient alternatives to network investments, by deferring the need for augmentations to relieve network constraints. For example, a demand offset as a result of a demand management project may result in the deferral of construction of a new line, which would allow the existing network assets to meet growing demand in a particular area. Costs of network augmentation projects can be significantly greater than the costs of conducting demand management projects to defer an augmentation project. Deferral of network investment may result in efficiency benefits, as the same level of reliability and service is provided by a smaller, better utilised network. Demand management can also reduce the cost and impact on the timing of replacement capex. This was confirmed by NSW network business, Ausgrid, in its regulatory proposal.[122]

A.6.1 Position

Our draft decision is to not include an explicit reference in the capex or opex forecasts for demand management. Based on the available information, we are currently of the view that it is most appropriate to rely on the incentive framework, together with the new requirements around the Regulatory Investment Test for Distribution (RIT-D) and the distribution Annual Planning Report, to drive the efficient use of demand management and share the benefits with consumers through the Capital Expenditure Sharing Scheme (CESS).

A.6.2 Our assessment

ActewAGL stated in its proposal that it:

> …aims to encourage customers and potential non-network service providers to participate in ActewAGL Distribution demand management activities with the objective that future network problems can be met by a full range of solutions to achieve optimal economical and technical outcomes.[123]

To facilitate this, ActewAGL is currently finalising a demand management plan and establishing a demand management team to implement the plan. It also stated that it will specifically focus on 'developing and implementing non-network solutions to efficiently defer supply side (network) capital expenditure' through both targeted and broad-based projects and other work. [124]

Comparison with demand management activities of peers during 2009–14

In forecasting what amount of capex could be deferred by ActewAGL's demand management plan that it is currently developing we have considered the evidence of other activities by its peers. Analysis of Ausgrid's demand management activities in the 2009–14 period found that it was able to achieve a deferral of $334 million or 9.2% of its system capex portfolio based on an $8 million investment.

During 2009-14, Ausgrid spent $5,020 million (2013–14) on direct system capex (replacement and augmentation expenditure). Of this, between $1,526 million and $1,924 million (an average of $1,725 million) was spent on meeting the now rescinded "schedule 1" requirements[125]. Removing this expenditure (on the assumption that demand management was not applicable to expenditure to meet

122 Ausgrid 2014-19 revenue proposal Attachment 6.12, p. 29.

123 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 142.

124 ActewAGL, *Regulatory proposal: 2015–19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 142.

125 The network design standards were set in its NSW licence condition. The design requirements specified in schedule 1 of the licences led to significant augmentation investment over 2009-14, increasing the levels of network capacity and redundancy. The NSW Government repealed the design standards (schedule 1) of the licence conditions in July 2014.

this standard) leaves a net $3,295 million on direct system capex during 2009-14. The capital deferred through the targeted demand management in 2009-14 represents 9.2 per cent of Ausgrid's system capex.

This gives a cost benefit ratio of 2.5 times its demand management investment. This result aligns with the Productivity Commission's expected demand management benefits, which estimated a medium cost benefit ratio of 2.7 for the two most relevant scenarios ("regional rollout in peaky and constrained areas", and "direct load control without smart meters").[126]

As such, we consider that the Ausgrid experience in demand management in 2009-14 might represent a reasonable benchmark to assess the capex that may be deferred by ActewAGL in the 2014-2019 period.

Value of demand management in low demand growth environment

As discussed in Appendix C section, demand growth is likely to be relatively flat across the 2014–19 period. In this demand growth environment there is a stronger economic case for the use of demand management as investment in long-life network assets can be deferred until there is a more certain need, reducing the risk of stranded network assets. Further, the option value of demand management also increases. This was confirmed by Ausgrid in its regulatory proposal:

> Across the NEM and in Ausgrid's supply area peak demand growth has slowed in recent years, departing from the previous trend of steady year-on-year growth. This has led to lower forecast growth in augmentation capital expenditures but also increased the uncertainty about the optimal capital investment strategy compared to the last regulatory period. In this more uncertain environment, the "option value" of demand management programs is enhanced for the coming years.
>
> …
>
> Lower load growth scenarios can create opportunities for DM because the demand reduction requirements to achieve capital deferrals are lower (making them easier to achieve and more cost effective), which can compensate for the less frequent opportunities for DM.

That is, rather than the value of demand management falling in times of uncertain or flat demand, its option value is likely to increase. This is primarily driven by the demand management alternatives being able to be readily renegotiated or re-purposed. For example, if a small embedded generator is used to offset the need for network reinforcement and the expected demand does not eventuate, the generator can readily be moved to another location. However, had a network solution been utilised, the investment is sunk with limited or no ability for it to be used for any other purpose, resulting in stranded or underutilised assets.

Demand management as part of business as usual

Demand management should be an integral part of good asset management for all network business. The primary driver for historical incentive schemes for demand management is an intention to change the past practices of the network businesses to be more accepting of demand management. The distribution Annual Planning Report and the regulatory investment test for distribution (RIT-D) require DNSPs to consider and adopt non-network solutions where economic to do so. We are also required to have regard to the extent of non-network alternatives that a DNSP has considered and made provision for in assessing whether the capital expenditure criteria are met.

126 Productivity Commission, 9 April 2013, 'Electricity Network Regulatory Frameworks, Supplement to Inquiry Report, The costs and benefits of demand management for households', pp. 30.

A.6.3 Conclusion on demand management

We have considered whether it is appropriate for us to determine an explicit amount of capex that could be deferred through demand management, based on the scale and positive outcomes achieved by Ausgrid during 2009–14 and the Productivity Commission report. Using this approach we could apply an explicit systems capex forecast offset for ActewAGL of 9.2%, or approximately $15 million ($2013–14). However, we would also need to assess the efficient opex required to support this capex offset. The frontier firms used in setting the efficient benchmark for our opex forecast included some allowance for demand management activities. While this demand management expenditure was forecast, we do not currently have actual expenditure data from which to accurately calculate a capex/opex trade-off.

Therefore, our draft decision is to not include an explicit reference in the capex or opex forecasts for demand management. Based on the available information, we are currently of the view that it is most appropriate to rely on the incentive framework, together with the new requirements around the RIT-D and the distribution Annual Planning Report, to drive the efficient use of demand management and share the benefits with consumers through the CESS.

However, we welcome views on whether this is the most appropriate approach in providing incentives for the optimal amount of demand management. To the extent that stakeholders consider that the long term interests of consumers may be better promoted through explicit recognition of demand management and consequential adjustments to capex and opex, we seek views on the appropriate capex/opex trade-off that should be included.

B Assessment approaches

This Appendix discusses the assessment approaches we have applied in assessing ActewAGL's proposed forecast capex.

B.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. We are required to consider as it is a capex factor under the NER.[127] Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to environmental factors.[128] It allows us to compare the performance of a DNSP against its own past performance, and the performance of other DNSPs. Economic benchmarking helps us to assess whether a DNSP's capex forecast represents efficient costs.[129] As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[130]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a DNSP's efficiency with consideration given to its inputs, outputs and its operating environment. We have considered each DNSP's operating environment insofar as there are factors that are outside of a DNSP's control but which affect a NSP's ability to convert inputs into outputs.[131] Once such exogenous factors are taken into account, we expect DNSPs to operate at similar levels of efficiency. One example of an exogenous factor that we have taken into account is customer density. For more on how we have forecast these measures, see our annual benchmarking report.[132]

We have calculated economic benchmarks based on actual data from the previous regulatory control period. We consider these are relevant to determining allowances for the forthcoming regulatory control period as a DNSP's capex and expenditure efficiency in the previous regulatory control period is a good indicator of its likely efficiency in the next regulatory control period. Further, any benchmark efficient level of capex in the previous period will be a useful starting point for setting the efficient level of capex in the upcoming regulatory control period, taking into account any apparent trends.

In addition to the measures in the annual benchmarking report, we have considered how DNSPs have performed on a number of overall capex metrics, including:

- capex per customer, and capex per maximum demand
- the regulatory asset base (RAB) per customer, and RAB per maximum demand.

For the purposes of this analysis, capex (calculated as a five year average) or the RAB is taken as an input. We have considered both capex and the RAB as these represent different ways of measuring how efficient a network business is in respect of capital. Measures based on capex demonstrate how efficiently a business is using capex at a particular point in time. In contrast, the RAB reflects the stock of capital and hence, a DNSP's past capex efficiency.

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127 NER, clause 6.5.7(e)(4)
128 AER, Explanatory Statement: Expenditure Forecasting Assessment Guidelines, November 2013.
129 NER, clause. 6.5.7(c)
130 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 25.
131 See AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.
132 AER, Annual Benchmarking Report,2014.

Customer numbers and maximum demand are used as proxies for output.[133] We have looked at customer numbers and maximum demand as these are two of the key outputs for capex. Higher customer numbers or maximum demand will both increase capex requirements. Lower cost per customer or maximum demand (other things being equal) will suggest higher capex efficiency.

For the above measures, we have normalised for customer density. Customer density is the most significant environmental factor which drives capex.[134] It is generally positively related to efficiency: a DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear less efficient than the higher density DNSP.

The results from the economic benchmarking give an indication of the relative efficiency of each of the DNSPs, and how this has changed over time. It indicates the likely range of forecast capex that would be required by an efficient and prudent DNSP taking into account network characteristics. However, we accept that it is difficult to fully account for exogenous factors particular to each DNSP. To the extent that we are unable to adequately account for exogenous factors, we have factored this into the weighting that we have given our benchmarking, as applied to each DNSP.[135] Also, we have not relied solely on economic benchmarking. It is one technique in a wide range of techniques to assist in forming our view on the reasonableness of a DNSP's proposed forecast and where required, an alternative estimate.

B.2 Trend analysis

We have considered past trends in actual and forecast capex. This is one of the capex factors that we are required to have regard to.[136]

Trend analysis involves comparing DNSPs' forecast capex and work volumes against historic levels. Where forecast capex and volumes are materially different to historic levels, we have sought to understand what has caused these differences. In doing so, we have considered the reasons given by the DNSPs in their proposals, as well as changes in the circumstances of the DNSP.

In considering whether a business' capex forecast reasonably reflects the capex criteria, we need to consider whether the forecast will allow the business to meet expected demand, and comply with relevant regulatory obligations.[137] Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex required by a DNSP.

Maximum demand is a key driver of augmentation or demand driven expenditure. As augmentation often needs to occur prior to demand growth being realised, forecast rather than actual demand is relevant when a business is deciding what augmentation projects will be required in an upcoming regulatory control period. However, to the extent that actual demand differs from forecast, a business should reassess the need for the projects. Growth in a business' network will also drive augmentation

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133 For more on these measures, see the AER's annual Benchmarking Report.

134 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers Report prepared for Australian Energy Regulator*, 25 June 2013, p. 73. Energy density and maximum demand density are also potential operating environment factors. However, these are correlated to customer density so we have chosen to use customer density.

135 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 113.

136 NER, clause 6.5.7(e)(5).

137 NER, clause 6.5.7(a)(3).

and connections related capex. For these reasons it is important to consider how trends in capex (and in particular, augex and connections) compare with trends in demand (both maximum 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 in 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 a DNSP's capex requirements.

We have looked at trends in capex across a range of levels including at the total capex level, for growth related capex, for replacement capex, and for each of the categories of capex, as relevant. We have also compared these with trends in demand and changes in service standards over time.

B.3 Engineering review

We have relied on internal engineering expertise to assist with our review of ActewAGL's capex proposals. This has involved reviewing ActewAGL's processes, and specific projects and programs of work.

In particular, in respect of augex and repex, our engineers considered whether ActewAGL's:

- Forecast is reasonable and unbiased, by assessing whether the DNSP’s proposed capex is a reasonable forecast of the unbiased efficient cost of maintaining performance at the required or efficient service levels.
- Risk management is prudent and efficient, by assessing whether the business manages risk such that the cost to the customer of achieving the capex objectives at the required or efficient service levels is commensurate with the customer value provided by those service levels.
- Costs and work practices are prudent and efficient, by assessing whether the DNSP uses the minimum resources reasonably practical to achieve the capex objectives and maintain the required or efficient service levels.

We have considered these factors as they relate directly to our assessment of whether the DNSP's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives:[138]

- If a capex forecast is reasonable and unbiased, the forecast should reflect the efficient costs required to meet the capex objectives. That is, there should be no systemic biases which result in a forecast that is greater than or less than the efficient forecast. Further, the forecast should be reasonable in that it reflects what a prudent operator would incur to achieve the capex objectives.
- If ActewAGL's risk management is prudent and efficient, ActewAGL's forecast is likely to reflect the costs that a prudent operator would require to achieve the capex objectives. A prudent operator would consider both the probability of a risk eventuating and the impact of the risk (if it were to occur) in determining whether to undertake work to mitigate the risk.[139]
- If ActewAGL's costs and work practices are prudent and efficient, Essential Energy will have the appropriate governance and asset management practices to ensure that ActewAGL has

[138] NER, s. 6.5.7(c) (version 58).
[139] This approach is supported by NERA Economic Consulting, see NERA, Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules, Supplementary Report, Ausgrid submission, 8 May 2014, p. 7.

determined an efficient capex forecast that is based on a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

Accordingly, the engineering review was tasked with assessing whether there were any systemic issues arising from ActewAGL's governance and risk assessment framework and whether there is evidence that indicates that the forecasts are biased. The engineering reviews focused on ActewAGL's major replacement and augmentation programs and adopted a sampling approach in considering the above factors. Where this revealed concerns about systemic issues, we asked the engineers to quantify the likely impact of these biases. This review covered an assessment of:

- the options the NSP investigated to address the economic requirement (for example, for repex projects the review included an assessment of the extent to which the NSP considered sub options for replacements)
- whether the timing of the project is efficient and prudent (including replacement strategies at a portfolio level)
- unit costs and volumes, including comparisons with past trends in expenditure
- longer term asset replacement strategies (including replacement strategies at a portfolio level rather than at a project level)
- the relative prices of operating and capital inputs and the substitution possibilities between operating and capital expenditure
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers. This is most relevant to core network expenditure (augex and repex) and may include the NSP's consideration of the value of customer reliability (VCR) standard or a similar appropriate standard.
- In some cases we have also reviewed specific capex projects or programs of work to determine whether these meet the capex criteria. These reviews have been undertaken in respect of particular capex categories related to proposed asset replacement expenditure.

C Demand

This appendix sets out our observations of growth trends in ActewAGL's network for the 2014–2019 period.[140] In particular we set out our observations on demand (section C.1) and consumption (section C.2).[141]

C.1 Demand

Demand forecasts are fundamental to a NSP's forecast capex and opex, and to the AER's assessment of that forecast expenditure. ActewAGL must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. When ActewAGL invests in its network to meet demand and increases in electricity consumption, it incurs capex. In particular, the expected growth in demand is an important factor driving network augmentation expenditure and connections expenditure (growth capex).[142] ActewAGL uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. ActewAGL also incurs opex in relation to the new assets it builds to meet demand.

System demand represents total demand in the ActewAGL distribution network. This attachment considers demand forecasts in ActewAGL's network at the system level. These observations give an indication of overall demand trends and for the first time include a comparison to AEMO's independent demand forecasts. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased requirement for growth capex, and converse for forecasts of stagnant or falling system demand.[143] Accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network. For example, overly high demand forecasts may lead to inefficient expenditure as NSPs install unnecessary capacity in the network.

However, localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments. Accordingly, there may also be a need to consider spatial demand forecasts as part of determining the requirement for growth capex for the 2014–2019 period. Appendix A.1 discusses this analysis in more detail.

AER position on system demand trends

We are satisfied the system demand forecasts in ActewAGL's regulatory proposal for the 2014–2019 period reasonably reflects a realistic expectation of demand.[144] The demand forecasts in ActewAGL's regulatory proposal for the 2014–2019 period exhibit similar growth trends to its regulatory proposal for the 2009–2014 regulatory control period.[145] We note that, unlike the NSW DNSPs, ActewAGL's

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140 In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated. 'Consumption' refers to annual consumption of electricity in gigawatt hours (GWh) unless otherwise indicated.

141 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).

142 Sections A.1 and A.2 discusses our consideration of ActewAGL's augex and connections expenditure.

143 Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.

144 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).

145 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 106; ActewAGL, *ActewAGL distribution determination 2009–14: Regulatory proposal to the Australian Energy Regulator*, June 2008, p. 92.

augex forecast for the 2014–2019 period is higher than actual augex for the 2009–2014 regulatory control period (see augex appendix A.1).[146]

However, we understand the NSPs are in the process of further updating their demand forecasts. We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will consider updated demand forecasts and other information in the final decision to reflect the most up to date data. We would also expect ActewAGL's expenditure forecasts to reflect updates to its demand forecasts. For example, we would expect a downward revision of ActewAGL's expenditure forecast with a downward revision in the demand forecast (noting spatial demand is the main driver for growth capex).

The Australian Energy Market Operator (AEMO) forecasted similar trends of system demand growth for ActewAGL's network and for the NSW region more generally.[147] We note AEMO downgraded its demand forecast for the NSW region in its most recent report.[148]

The sub-sections below discuss these observations in more detail.

AER approach

Our consideration of demand trends in ActewAGL's network relied primarily on comparing demand information from the following sources:

- ActewAGL's regulatory proposal
- forecasts from AEMO.

ActewAGL's proposal

ActewAGL's proposal described their demand forecasting methods, including approaches to:

- weather correction
- accounting for spot loads
- accounting for transfers
- accounting for embedded generation.[149]

ActewAGL produced both top-down and bottom-up demand forecasts.[150] It appears that ActewAGL has not modelled the future impacts of energy efficiency measures, demand side participation and demand management.

AEMO forecasts

In July 2014, AEMO published the first edition of transmission connection point (CP) forecasts for New South Wales and Tasmania.[151] These forecasts are AEMO's independent electricity maximum

146 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 157–159.

147 AEMO included the Australian Capital Territory in the NSW region in its demand forecasting reports. See AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, p. 1.

148 AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014, p. 4-4.

149 ActewAGL, *Regulatory proposal: Attachment C1: Peak demand forecast*, 2 June 2014.

150 ActewAGL, *Regulatory proposal: Attachment C1: Peak demand forecast*, 2 June 2014, pp. 3, 5–6.

151 AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, p. 6.

demand forecasts at transmission CP level, over a 10-year outlook period.[152] The Standing Council on Energy Resources (SCER) intended these demand forecasts to inform our regulatory determinations.[153] In addition, AEMO has published the National Electricity Forecasting Report (NEFR) since 2012, and published the latest edition in June 2014 (2014 NEFR).[154] The NEFR includes AEMO's summer and winter demand forecasts for all regions (states) in the National Electricity Market.

AEMO described the key steps to its CP forecasting methodology as:

- Data preparation (including demand and weather data)
- Weather normalisation
- Determination of starting point
- Determination of growth rate
- Determination of baseline forecasts (application of growth rate to the starting point)
- Adjust for rooftop photovoltaics and energy efficiency
- Reconciliation of CP forecasts with the relevant state forecast from the 2014 NEFR.[155]

As part of our consideration of system demand forecasts, we compared ActewAGL's system demand forecast to the sum of AEMO's CP forecasts for ActewAGL's network. We undertook further investigation to understand ActewAGL's demand forecasts where they differed significantly from AEMO's CP forecasts. This included making enquiries of ActewAGL and AEMO to determine any differences in the composition of the datasets they each used and to ascertain the reasons for discrepancies.

The sub-section below sets out our comparisons of AEMO's CP forecasts with ActewAGL's demand forecasts and takes into account stakeholder submissions.

AER considerations on system demand trends

The demand forecasts in ActewAGL's regulatory proposal for the 2014–2019 period exhibit similar growth trends to its regulatory proposal for the 2009–2014 regulatory control period.[156] We note that, unlike the NSW DNSPs, ActewAGL's augex forecast for the 2014–2019 period is higher than actual augex for the 2009–2014 regulatory control period (see section A.1).[157] ActewAGL's forecast demand growth rates display a similar trend to AEMO's forecasts, although the absolute values of ActewAGL's demand forecasts are higher than AEMO's forecasts.

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152 AEMO, Website: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts, accessed 3 September 2014.

153 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 182.

154 AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014.

155 AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, pp. 7–8; AEMO, *Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2014.

156 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 106; ActewAGL, *ActewAGL distribution determination 2009–14: Regulatory proposal to the Australian Energy Regulator*, June 2008, p. 92.

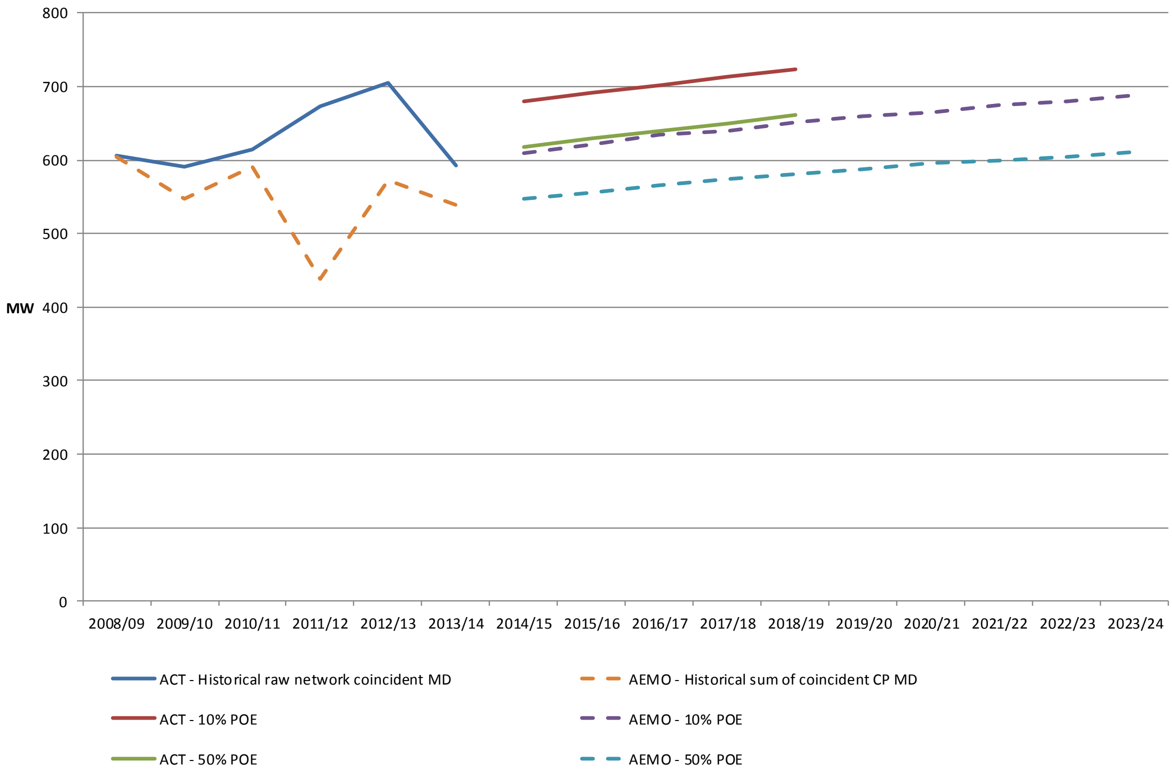
157 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 157–159.

Figure C-1 shows our comparison between ActewAGL's system demand and AEMO's CP demand for the ActewAGL network.[158] It shows the growth trend for ActewAGL's system demand forecast is consistent with AEMO's CP forecasts for the 2014–2019 period. This is despite having different datasets and forecasting approaches (see below). This gives us a level of confidence the trend in ActewAGL's forecasts are realistic.

Figure C-1 also indicates there are differences in ActewAGL's and AEMO's historical data. In addition, ActewAGL's forecasts are consistently higher than AEMO's forecasts. Indeed, ActewAGL's forecast at 50 per cent probability of exceedance (PoE) is consistently above AEMO's 10 per cent PoE forecasts.

We liaised with ActewAGL and with AEMO to ascertain the reasons for the discrepancies. We also asked ActewAGL whether they would adjust their demand forecast to match AEMO's CP forecasts, given the latter are the latest available forecasts.[159]

Figure C-1 Comparison of ActewAGL demand and AEMO CP demand



Source: ActewAGL reset RIN; AEMO, *Dynamic interface for connection points in New South Wales and Tasmania*, 31 July 2014.

ActewAGL, and the other NSW/ACT DNSPs, noted several differences in the datasets it used to derive its forecasts and AEMO's datasets. These included:

- Different treatment of major customers and embedded generation
- Different timing: several NSPs stated they used financial years whereas AEMO used seasons to define their data.

158 We summed AEMO's coincident demand figures for each CP in ActewAGL's network for each year.
159 AER, *Email to ActewAGL: AER Actew 023 - maximum demand*, 13 August 2014.

- Different levels of coincidence: ActewAGL noted AEMO's coincident demand figures are coincident to the NSW regional demand. On the other hand, ActewAGL's coincident demand was coincident to its own system demand.[160]

The NSPs also noted differences in forecasting methods as possible explanations in differences between their demand forecasts and AEMO's.[161]

More specifically, ActewAGL noted AEMO's historical and forecast demand are coincident to the NSW system demand, whereas ActewAGL's are coincident to its own system demand. AEMO's demand figures are therefore lower than ActewAGL's.[162]

ActewAGL stated planned capital projects rely on localised demand forecasts, rather than forecasts coincident to the NSW demand. Hence, ActewAGL does not propose to amend its demand forecast to be consistent with AEMO's CP demand forecasts.[163]

AEMO acknowledged the factors the NSW/ACT DNSPs identified explain some of the differences between its dataset and those of the NSW/ACT DNSPs, including ActewAGL. AEMO also noted the NSW/ACT DNSPs did not raise the treatment of rooftop photovoltaics, energy efficiency and large industrial customer activity in their responses. AEMO expected different handling of these issues would result in differences in the datasets and demand forecasts.[164]

We are satisfied ActewAGL's responses adequately explain at least some of the differences between its demand figures and those of AEMO.

We note AEMO reconciled the transmission CP forecasts with its NSW regional forecasts, and so those are not demand forecasts that are 'tailor made' for ActewAGL's network. Nevertheless, we consider they provide a useful reference point for assessing ActewAGL's demand forecasts.

We understand AEMO has begun consultation with some DNSPs in reconciling their datasets.[165] AEMO also indicated it would explore developing demand forecasts at the DNSP level in the future.[166] We anticipate these processes will result in more comparable datasets in future regulatory determinations.

Past forecasting inaccuracies

The Energy Market Reform Forum (EMRF) noted the electricity market experienced falling demand and consumption since the previous NSW distribution determination. Indeed, regular reviews of forecasts saw continual downward adjustments in demand and consumption.[167] Among other things,

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160 ActewAGL, *Response to AER: Information request AER ActewAGL 023*, 20 August 2014; Ausgrid, *Response to AER: Information request AER Ausgrid 021*, 1 September 2014; Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014; Essential, *Response to AER: Information request AER Essential 012*, 21 August 2014.

161 ActewAGL, *Response to AER: Information request AER ActewAGL 023*, 20 August 2014; Ausgrid, *Response to AER: Information request AER Ausgrid 021*, 1 September 2014; Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014; Essential, *Response to AER: Information request AER Essential 012*, 21 August 2014.

162 ActewAGL, *Response to AER: Information request AER ActewAGL 023*, 20 August 2014, pp. 1 and 4.

163 ActewAGL, *Response to AER: Information request AER ActewAGL 023*, 20 August 2014, p. 7.

164 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, p. 1.

165 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, pp. 6–8.

166 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 182.

167 EMRF, *NSW electricity distribution revenue reset: Applications from Ausgrid, Endeavour Energy and Essential Energy: A response*, July 2014, pp. 8 and 11.

falling demand and consumption led to higher prices and revenue for the 2009–14 regulatory control period, especially when compared with earlier periods.[168]

We acknowledge demand forecasting is not a precise science and will inevitably contain errors. However, consistent over-forecasting, as the submission above noted, may indicate a systemic bias in a NSP's demand forecasting approach.[169] Our analysis in Figure C-1 indicates ActewAGL's demand forecasts exhibit growth patterns consistent with AEMO's. However, we will monitor the accuracy of ActewAGL's demand forecasts in future regulatory years to check for any indications of bias. This in turn would aid in monitoring potentially inefficient expenditure levels in the network.

C.2 Consumption

In this section, we discuss our considerations of whether ActewAGL's consumption forecasts can be relied upon for the purposes of determining ActewAGL's revenue.

Clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs as part of its draft distribution determination for ActewAGL. The AER uses consumption forecasts to determine the amount of electricity delivered over a period of time. It is a key input into determining X factors under an average revenue cap, which applies to ActewAGL.[170]

AER position on consumption

We are not satisfied the consumption forecasts in ActewAGL's regulatory proposal for the 2014–2019 period represent appropriate amounts, values or inputs for the ActewAGL distribution determination.[171] We have concerns regarding ActewAGL's consumption forecasting method and consider the resulting forecasts are not appropriate inputs into the PTRM.

Table C-1 contains consumption forecasts we consider represent appropriate amounts, values or inputs for the ActewAGL distribution determination.[172] Our alternative consumption forecasts are on average 124GWh, or 4.48 per cent, higher than ActewAGL's forecast per year.

The sub-sections below discuss our assessment in more detail.

Table C-1 AER position on ActewAGL consumption forecast (GWh)

	2014-15	2015-16	2016-17	2017-18	2018-19
ActewAGL regulatory proposal	2,737	2,730	2,761	2,791	2,804
AER alternative forecast	**2,849**	**2,849**	**2,874**	**2,916**	**2,955**
Difference (GWh)	113	119	113	125	151
Difference (per cent)	4.12%	4.35%	4.08%	4.47%	5.38%

168 EMRF, *NSW electricity distribution revenue reset: Applications from Ausgrid, Endeavour Energy and Essential Energy: A response*, July 2014, pp. 8, 11–14.

169 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 176.

170 AER, *Stage 1: Framework and approach paper: ActewAGL: Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, p. 28.

171 NER, clause 6.12.1(10).

172 NER, clause 6.12.1(10).

Source: AER analysis; ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 110.

AER approach

Our consideration of ActewAGL's consumption forecast relied primarily on the documentation and information ActewAGL provided in its regulatory proposal.[173] We assessed whether ActewAGL's consumption forecasting method reflected good industry practice. This included assessing:

- ActewAGL's approaches to weather normalisation
- ActewAGL's econometric modelling of different customer categories
- whether ActewAGL included appropriate explanatory variables of consumption in its models.

We also liaised with ActewAGL to obtain more detailed information, including the datasets ActewAGL used to derive its models and the calculation of model coefficients and accompanying test statistics. We retained the services of an econometrician to assist with this analysis.

ActewAGL proposal

Appendix C3 of ActewAGL's regulatory proposal provided the details of its consumption forecasting method. The report described:

- the variables used in the modelling
- the number of years of data used in the actual estimation process
- the coefficients used as the basis of the forecasts (and their statistical significance)
- the assumptions underpinning the forecasts
- the process used to select the preferred models.[174]

ActewAGL analysed consumption and produced separate models for the following four categories:

- Residential general purpose (GP)
- Residential off-peak (OP)
- Non-residential low-voltage (LV)
- Non-residential high voltage (HV).

After weather normalising historical consumption, ActewAGL tested a range of models utilising historical values of potential explanatory variables. From this, ActewAGL identified its preferred

[173] ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp.108–111; ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014.

[174] ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014.

models.[175] These were generally the models with the lowest error or highest R^2, subject to specific criteria, such as statistically significant model coefficients.[176]

AER considerations on ActewAGL consumption forecasts

In its regulatory proposal, we consider ActewAGL transparently described its modelling approach to forecasting consumption for its distribution network.[177] We are satisfied its broad approach is consistent with common industry practice. That is, ActewAGL used an econometric analysis of the drivers of weather-normalised historical consumption (by customer type) as the basis of its consumption forecasts. Further, ActewAGL made adjustments to account for the impact of policy measures.

As we noted above, however, we have concerns regarding certain aspects of ActewAGL's consumption forecasting method. In particular, we are concerned that:

- ActewAGL's approach to model selection suffers from the biasing effects of autocorrelation
- ActewAGL's preferred models do not include price as an explanatory variable, which we consider is important in determining consumption levels
- ActewAGL's specification of the dependent variable in their preferred models
- ActewAGL did not consider the drivers of customer forecasts in sufficient detail, including how the profile of customers may change over the forecast period.

We also note that ActewAGL should conduct tests to ensure it has not double-counted energy efficiency schemes. This is especially important in the Residential GP category where energy efficiency has a particularly strong effect.

The subsections below discuss these concerns in more detail. We then discuss how we account for these issues to derive the alternative consumption forecasts in Table C-1.

We note that ActewAGL's approach to forecasting Residential OP is based on the extrapolation of a linear trend through 2008 to 2013 actual consumption. We consider this is a reasonable approach given the steady decline for this category since 2002.[178] ActewAGL explained this was due to the non-replacement of failed off-peak water heaters.[179] Hence, the issues we discuss in the subsections below do not apply to ActewAGL's consumption models and forecasts for the Residential OP category.

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175 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 45–57.

176 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.108; ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 44–45.

177 ActewAGL, *Regulatory Proposal: 2015–19 Subsequent regulatory control period: Distribution services provided by the ActewAGL distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp.108–111; ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014.

178 See table 3.6 in ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 30.

179 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 51.

Presence of autocorrelation

Our analysis of model residuals and calculation of Durbin Watson statistics revealed that some of the models ActewAGL put forward for selection suffered from an autocorrelation problem.[180]

We noted earlier that ActewAGL selected its preferred model using certain criteria such as the overall models' R^2 values and the model coefficients' t-statistics.[181] However, the presence of autocorrelation means the standard errors of the coefficients (and subsequently the t-statistics and R^2) may not be correct and are likely to be overestimated. Hence, ActewAGL's approach to selecting the preferred model is not appropriate.

For commercial LV, our analysis indicated ActewAGL's preferred model (LV6) did not suffer from an autocorrelation problem.[182] However, two of the models that ActewAGL compared the LV6 model to did have an autocorrelation problem. Hence, we consider ActewAGL's approach to selecting its preferred model is still not appropriate.

Absence of price as explanatory variables in the preferred models

ActewAGL's preferred models do not include price as an explanatory variable and the subsequent failure to undertake post-model adjustments to account for the effect of price on consumption. Given the acknowledged importance of price in determining consumption, it is common practice to account for price either directly in the regression model or as a post-model adjustment.[183] With the reduction in price following the removal of the CPRS the consumption forecasts may be too low without explicit price adjustments.

Furthermore, it does not appear ActewAGL considered the potential effect of gas price on consumption for the Residential GP category. We consider accounting for the cross-price elasticity effect would have been informative in the model derivation process.

Specification of the dependent variable

ActewAGL's preferred model for the Residential GP category modelled consumption per person.[184] However, we understand it is standard procedure to conduct consumption forecasts on the basis of consumption per customer as this accounts for factors such as disconnections and customer density.[185] Changes in population will not necessarily translate into increased customers if, for example, population change is driven by births as it does not result in new households. Furthermore, using population as the basis of consumption forecasts does not adequately address the increasing trend towards higher density living and the implications of this trend for the nature of energy consumption.

For the Commercial LV category, ActewAGL modelled total annual consumption.[186] We understand it is also standard practice to forecast commercial consumption on a consumption per customer basis for the Commercial LV category. By not conducting the analysis using consumption per customer,

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180 For the residual plots, see figures 5.1–5.6 and 5.8–5.12 in ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 46–57.

181 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 44–45.

182 For the residual plot, see figure 5.9 in ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 54.

183 See for example AEMO (2014), Forecasting methodology information paper, available from http://www.aemo.com.au/Electricity/Planning/Forecasting

184 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 51.

185 See for example ACIL Tasman, *Energy consumption forecasts 2011-12 to 2016-17: Energy consumption forecasts for Aurora Energy covering six customer classes: Prepared for Aurora Energy*, April 2012.

186 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 52.

ActewAGL implicitly assumed that trends in historical commercial connections and consumption per customer will continue. However, an analysis of non-residential customers reveals that this is not a linear series. Between 2003 and 2004, commercial LV customer numbers fell by 4.7 per cent, from 13,403 to 12,797. Therefore, without validation, it may not be reasonable to assume that historical trends will continue.

For the Commercial HV category, ActewAGL also modelled total annual consumption.[187] We note customer numbers have been almost flat over the historical period, with 22 customers in 2000, 23 in 2002 and 24 in 2013. Given this, we consider it is reasonable to produce the forecasts on a total consumption basis (rather than consumption per customer).

Customer forecasts

We consider ActewAGL did not consider the drivers of customer forecasts in sufficient detail, including potential changes to customer profiles over the 2014–2019 period. We therefore consider ActewAGL should further investigate the factors we describe below when developing its customer number forecasts.

ActewAGL assumed growth in Residential GP customer numbers will mimic the moderation in population growth (using forecasts from BIS Shrapnel) in the 2014–2019 period. That is, ActewAGL assumed customer numbers increase at an annual rate of 1.36 per cent. As we describe below, this may be a simplistic way to forecast customer numbers. We note, for example, that growth in customer numbers between 2000 and 2013 was 1.9 per cent per annum, with growth at 2.4 per cent per annum between 2009 and 2013.

ActewAGL did not disaggregate its customer number projections by new connections, existing connections and disconnections. We understand disaggregating forecasts in this way is standard practice when developing consumption forecasts. Customer number forecasts should also incorporate changing trends in housing density by separating new connections into estates and medium/high density dwellings.

Furthermore, the forecasts do not account for trends in customers switching from entirely electricity-based consumption to electricity and gas-based consumption. By excluding this from the analysis, ActewAGL are implicitly assuming that the historical trend will continue over the forecast period. However, with developments in the gas market, and recent gas price rises, we would not expect this to be the case.

In addition, it appears the customer numbers time series ActewAGL used to derive its consumption forecasts differs from the time series it provided in the economic benchmarking RINs. We will investigate this inconsistency as part of our assessments for the final decision.

Further investigation on effects of energy efficiency

ActewAGL incorporates the impacts of energy efficiency policies and PV uptake in the modelling in two different ways:

- The first approach removes the impact of energy efficiency from the historical consumption series and conducts the regression analysis on 'zero efficiency' consumption. The 'zero efficiency'

[187] ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 54.

forecasts are then adjusted for forecast energy efficiency improvements and PV output. ActewAGL adopted this approach for its preferred models.

- The second approach includes the annual improvements in energy efficiency as an explanatory variable in the regression.

ActewAGL assumes the impact of ACT energy efficiency policies will not affect the impact of Commonwealth policies in the short term and therefore combines the future impacts of both ACT and Commonwealth energy efficiency policies. As AEMO noted, there is potential for double counting and scheme interactions when adjusting consumption forecasts for energy efficiency policies at the state and national level.[188] ActewAGL, however, argue that ACT policies just bring the impact of Commonwealth policies forward and, as such, will not result in double counting over the 5 year forecast period.[189]

Changes in energy efficiency over history and the forecast period have a large impact on the energy consumption forecasts. We consider ActewAGL should have conducted a sensitivity analysis on the strength of the energy efficiency assumption. This is consistent with the AEMO's rapid, moderate and slow uptake scenarios.[190]

By 2019 ActewAGL assumed Residential GP consumption will be 26 per cent lower than if energy efficiency policies were not in place.[191] The assumption that ACT policies can be combined with Commonwealth policies over the forecast period (without double counting) is therefore important in the consumption forecasting process. While there is insufficient evidence to conclude this is an unreasonable assumption, we consider its effect should be tested. Furthermore, AEMO's report (on which ActewAGL based its analysis) was written prior to the removal of CPRS. Given the interaction between price incentives and the uptake of energy efficient appliances, there may be some double counting.

AER adjustments

Given concerns we described above, we consider ActewAGL's process of model selection is not appropriate. We are not satisfied the consumption forecasts in ActewAGL's regulatory proposal for the 2014–2019 period are appropriate for the ActewAGL distribution determination.[192] We therefore selected from ActewAGL's models those we consider address our concerns. Below, we describe the models we used to derive our alternative consumption forecast in Table C-1.

Given the presence of autocorrelation, we do not consider it is appropriate to use indicators such as R^2 values and t-statistics as the basis for selecting models. We selected the models with widely accepted explanatory variables with reasonable coefficient values. In particular, we consider consumption models should include price as an explanatory variable given its acknowledged importance of price in determining consumption (as we discussed above). Following on from this, we used the following models to derive our alternative consumption forecast:

- For the Residential GP category, we have used ActewAGL's model, R17, which regressed consumption per customer against household disposable income per customer and residential prices.[193] As we noted previously, we consider ActewAGL's method for forecasting customer

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188 AEMO, *2013 Forecasting methodology information paper: National electricity forecasting*, 2013, p. 5-45.
189 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 62–63.
190 AEMO, *2013 Forecasting methodology information paper: National electricity forecasting*, 2013, p. C-9.
191 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, p. 63.
192 NER, clause 6.12.1(10).
193 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 48–51.

numbers was insufficient. Further, we found consistency issues with the time series from ActewAGL. We will look at resolving these issues in our assessment for the final decision.

- For the Commercial LV and Commercial HV categories, we have used ActewAGL's models LV9 and HV9, respectively. These models include price, as well as GSP, in the regression equation.[194] We noted above that Commercial LV should ideally also use consumption per customer. However, ActewAGL did not provide such models during consultation so we have kept model LV9's original specification of using total annual consumption as the independent variable. We will look at resolving this issue in our assessment for the final decision.

Table C-2 summarises the models we used to derive our alternative consumption forecasts.[195] We consider the explanatory variables for each model are appropriate. We also consider both the magnitude and direction of the coefficients are consistent with expectations: the models indicate residential customers are more price responsive than commercial customers and commercial LV and HV customers are more responsive to economic conditions.

Table C-2 AER's preferred models (used to derive our alternative consumption forecasts)

Customer category	ActewAGL model code	Intercept	Household disposable income	GSP	Price
Residential OP	R17	8.83	0.13	-	-0.18
Commercial LV	LV9	-2.89	-	1.02	-0.14
Commercial HV	HV9	-1.22	-	0.73	-0.11

Source: ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 48–56.
Note: Models R17, LV9 and HV9 are log-log models.

194 ActewAGL, *Regulatory proposal: Attachment C3: Trends in ACT electricity consumption*, 12 May 2014, pp. 52–56.
195 Full descriptions of these models are available from the AER's website (http://www.aer.gov.au/node/11482).

D Predictive modelling approach and scenarios

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

- the background to the repex modelling techniques
- discussion of the data required to apply the repex model
- detail on how this data was specified
- description of how this data was collected and refined for inclusion in the repex model
- the outcomes of the repex model under various input scenarios

This supports the detailed and multifaceted reasoning outlined in Appendix A.

D.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and Gas Rules.[196] In light of 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.[197]

The Expenditure Forecast Assessment Guideline (EFAG) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[198] It lists predictive modelling as one of the assessment techniques the AER may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009 review of the Victorian electricity DNSPs' 2011–15 regulatory proposals and have also used it subsequently.[199]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[200] At a basic level, the model predicts the volume of a distributor's assets that may need to be replaced over each of the next 20 years. This prediction is made by looking at the age of assets already in commission, and the time at which, on average, these assets would be expected to be replaced. The unit cost of replacing the assets is used to provide an estimate of replacement expenditure. The data used in the model is derived from the distributor’s regulatory information notice (RIN) responses and from the outcomes of the unit cost and replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

D.2 Data specification process

Our repex model requires the following input data on a distributor's network assets:

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

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

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

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

199 AER Determinations for 2011–15 for CitiPower, Jemena, Powercor, SP AusNet, and United Energy.

200 AER, Electricity network service providers, Replacement expenditure model handbook, November 2013.

Given our intention to apply unit cost and replacement life benchmarking techniques, we defined the model's input data around a series of prescribed network asset categories. We collected this information by issuing, in March 2014, two types of RINs:

1. "Reset RINs" which we issued to distributors requiring them to submit this information with their upcoming regulatory proposal

2. "Category analysis RINs" which we issued to all/other distributors in the NEM.

The two types of RIN request the same historical asset data for use in our repex modelling. The Reset RIN also collects data corresponding to the distributors proposed forecast repex over the 2014-19 period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

For background, we note that in past determinations, our RINs did not specify standardised network asset subcategories for distributors to report against. Instead, we required the distributors to provide us data that adhered to broad network asset groups (eg. poles, overhead conductors etc.). This allowed the distributor discretion as to how its assets were subcategorised within these groups. The limited prescription over asset types meant that drawing meaningful comparisons of unit costs and replacement lives across distributors was difficult.[201]

Our changed 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 capital inputs as required by the capex criteria.[202]

When we were formulating the standardised network assets, we aimed to differentiate the asset categorisations where material differences in unit cost and replacement life existed. Development of these asset subcategories involved extensive consultation with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.[203]

D.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what the AER requires to deploy our assessment techniques. Networks NSW questioned whether the data collected by the AER was of sufficient quality to use in the repex model or for benchmarking purposes.[204] We consider that the data refinement and consultation undertaken after the RINs were received, along with the extensive consultation carried out during the Better Regulation process provide us with reasonable assurance of the data's quality for use in this part of our analysis.

To aid distributors, an extensive list of detailed definitions was included as an appendix to the RINs. Where possible, these definitions included examples to assist distributors in deciding whether costs or activities should be included or excluded from particular categories. We acknowledge that, regardless of how extensive and exhaustive these definitions are, they cannot cater for all possible circumstances. To some extent, distributors needed to apply discretion in providing data. In these

201 The repex model has been applied in the Victorian 2011–15 and Aurora Energy 2012–17 distribution determinations; AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013.

202 NER, clause 6.5.7(e)(6).

203 See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.

204 Networks NSW, *Report - REPEX Model Review*, May 2014.

instances, distributors were required to clearly document their interpretations and assumptions in a "basis of preparation" statement accompanying the RIN submission.

Following the initial submissions, we assessed the basis of preparation statements that accompanied the RINs to determine whether the data submitted complied with the RINs. We took into account the shift in data reporting obligations under the new RINs when assessing the submissions. Overall, we considered that the repex data provided by all distributors was compliant. We did find a number of instances where the distributors' interpretations did not accord with the requirements of the RIN but for the purpose of proceeding with our assessment of the proposals, these inconsistencies were not substantial enough for a finding of non-compliance with the NEL or NER requirements.[205]

Nonetheless, in order that our data was the most up to date and accurate, we did inform distributors, in detailed documentation, where the data they had provided was not entirely consistent with the RINs, and invited them to provide updated data. Refining the repex data was an iterative process, where distributors returned amended consolidated RIN templates until such time that the data submitted was fit for purpose.

D.4 Benchmarking repex asset data

As outlined above, we required the following data on distributors' assets for our repex modelling:

- age profile of network assets currently in commission
- expenditure, replacement volumes and failure data of network assets
- the mean and standard deviation of each asset's replacement life.

All NEM distributors provided this data in the Reset RINs and Category analysis RINs under standardised network asset categories.

To inform our expenditure assessment for the distributors currently undergoing revenue determinations,[206] we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

In this section we explain the data sets we constructed using all NEM distributors' data, and the benchmark unit costs and replacement lives we derived for the standardised network asset categories.

D.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:[207]

- benchmark unit costs

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205 NER, clause 6.9.1.
206 NSW and ACT distribution network service providers—Ausgrid, Endeavour Energy, Essential Energy, and ActewAGL.
207 We did not derive benchmark data for some standardised asset categories where no values were reported by any distributors, or for categories distributors created outside the standardised asset categories.

- benchmark means and standard deviations of each asset's replacement life (referred to as "uncalibrated replacement lives" to distinguish these from the next category)
- benchmark calibrated means and standard deviations of each asset's replacement life.

Our process for arriving at each of the benchmarks was as follows. We calculated a unit cost for each NEM distributor in each asset category in which it reported replacement expenditure and replacement volumes. To do this:

- We determined a unit cost for each distributor, in each year, for each category it reported under. To do this we divided the reported replacement expenditure by the reported replacement volume.
- Then we determined a single unit cost for each distributor for each category it reported under. We first inflated the unit costs in each year to June $2014 using the CPI index.208 We then calculated a single June $2014 unit cost. We did this by first weighting the June $2014 unit cost from each year by the replacement volume in that year. We then divided the total of these expenditures by the total replacement volume number.

We formulated two sets of replacement life data for each NEM distributor:

- The replacement life data all NEM distributors reported in their RINs.
- The replacement life data we derived using the repex model for each NEM distributor. These are also called calibrated replacement lives. The repex model derives the replacement lives that are implied by the observed replacement practices of a distributor. That is, based on the data a distributor reported in the RIN on its replacement expenditure and volumes over the most recent five years, and the age profile of its network assets currently in commission. The calibrated lives the repex model derives can differ from the replacement lives a distributor reports.

We derived the benchmarks for an asset category using each of the three data sets above. That is, we derived a set of benchmark unit costs, benchmark replacement lives, and benchmark calibrated replacement lives for an asset category. We applied the method outlined below to each of the three data sets.

We first excluded Ausgrid's data, since it reported replacement expenditure values as direct costs and overheads. Therefore these expenditures were not comparable to all other NEM distributors which reported replacement expenditure as direct costs only. We then excluded outliers by:[209]

- calculating the average of all values for an asset category
- determining the standard deviation of all values for an asset category
- excluding values that were outside plus or minus one standard deviation from the average.

Using the data set excluding outliers we then determined the:

- Average value:

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208 We took into account whether the distributor reported on calendar or financial year basis.

209 For the calibrated mean replacement lives we performed two additional steps on the data prior to this. We excluded any means where the distributor did not report corresponding replacement expenditure. This was because zero volumes lead to the repex model deriving a large calibrated mean which may not reflect industry practice and may distort the benchmark observation. We also excluded any calibrated mean lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years in the asset age profile.

    - benchmark average unit cost
    - benchmark average mean and standard deviation replacement life
    - benchmark average calibrated mean and standard deviation replacement life.
- One quartile better than the average value:
    - benchmark first quartile unit cost
    - benchmark first quartile mean replacement life
    - benchmark first quartile calibrated mean replacement life.
- 'Best' value:
    - benchmark best (lowest) unit cost
    - benchmark best (longest) mean replacement life
    - benchmark best (highest) calibrated mean replacement life.[210]

D.5 Repex model scenarios

As noted above, our repex model uses an asset age profile, expected replacement life information and the unit cost of replacing assets to develop an estimate of replacement volume and expenditure over a 20 year period.

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.[211] However, we have multiple data sources for replacement lives and unit costs, being the data provided by the distributors, data that can be derived from their performance over the last five years, and benchmark data from all distributors across the NEM. The range of different inputs allows us to run the model under a number of different scenarios, and develop a range of outcomes to assist in our decision making.

We have categorised three broad input scenarios under which the repex model may be run. These are explained in greater detail within our Replacement expenditure model handbook.[212] They are:

(1) The Base model – the base model uses inputs provided by the distributor in their RIN response. Each distributor provided average expected life data as part of this response. As the businesses did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years in the base model.

(2) The Calibrated model – the process of “calibrating” the expected replacement lives in the repex model is described in the AER’s replacement expenditure handbook.213 The calibration involves

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210 We did not determine quartile or best values for the standard deviation and calibrated standard deviation replacement lives. This is because we used the benchmark average replacement lives (mean and standard derivation) for comparative analysis between the distributors. However, the benchmark quartile and best replacement life data was for use in the repex model sensitivity analysis. The repex model only requires the mean component of an asset's replacement life as an input. The repex model then assumes the standard deviation replacement life of an asset is the square root of the mean replacement life. The use of a square root for the standard deviation is explained in more detail in our Replacement expenditure model handbook; AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

211 It has been necessary for some service providers to make assumptions on the asset age profile to remove double counting. This is detailed at the end of this appendix.

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

determining a replacement life and standard deviation that matches the distributor's recent historical level of replacement (in this case, the five years from 2009/10 to 2014/15). The calibrated model benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked model – the benchmarked model uses unit cost and replacement life inputs from the category analysis benchmarks. These represent the observed costs and replacement behaviour from distributors across the NEM. As noted above, we have made observations for an “average”, “first quartile” and “best performer” for each repex category, so there is no single "benchmarked" model, but a series of models giving a range of different outputs.

It is also possible to combine life and unit cost inputs between the three broad scenarios to further expand the range of scenarios under which the model is run (e.g. replacement lives from the calibrated model with unit costs from the benchmarked model). The model also takes account of different wooden pole staking rate assumptions (see Section D.7 for more information on this process). A full list of the scenarios modelled is provided in the next section.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the service provider did incur any expenditure on an asset category in the 2009–14 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2014–19 period (used to derive forecast unit costs). If both these inputs were not available, we used the benchmarked average unit cost as a substitute input.

In addition, we did not use a calibrated asset replacement life where the service provider did not replace any assets during the 2009–14 regulatory control period. This is because the calibration process relies on replacement volumes over the five year period to derive a mean and standard deviation, and using a value of zero may not be appropriate for this purpose. In the first instance, we substituted these values with the average benchmark of calibrated replacement lives across service providers. Where this was not available, we used the base case observation from the service provider.

Unmodelled repex

As detailed in the AER's repex handbook, the repex model is most suitable for asset categories and groups with 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 chose to exclude certain data from the modelling process, and did not use predictive modelling to directly assess these categories. We decided to exclude SCADA repex from the model for this reason. Expenditure on pole top structures was also excluded, as we do not have asset age profile data to assess this expenditure against. Other excluded categories are detailed in Appendix A.3 of this draft decision.

D.6 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. 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

[213] AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, pp. 20–21.

like basis. To understand why this requires special treatment, we have described the normal like-for-like assumption used in the repex model, why staked poles do not fit well within this assumption, and how we adapt the model inputs to take account of this.

D.6.1 Like-for-like repex modelling

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. 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 model predicts 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 a new asset of the same kind. It follows that the volume of assets that needs to be replaced where like-for-like replacement is appropriate match the volume of new assets to be installed. The cost of replacing the volume of retired assets is the unit cost of the new asset multiplied by the volume of assets that need to be replaced.

D.6.2 Non-like-for-like replacement

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 predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles.

Staked and unstaked wooden poles

The life of a wooden pole may be extended by installing a metal stake to reinforce its base. Staked wooden poles are treated as a different asset in the repex model to unstaked poles. This is because staked and unstaked poles have different expected lives and different costs of replacement.

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 too far, 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 a stake can be installed. Consequently, there are two possible asset replacements (and two associated unit costs) that may be made by the distributor – a new pole to replace the old one or nailing a stake the old pole.

The other non-like-for-like scenario related to staking is 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 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 a new pole; and the cost of staking an old pole. We have used a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[214] We ran the model under a variety of different weightings - including the observed staking rate of the business and observed best practice from the distributors in the NEM. We also tested the sensitivity of the model to a small change in the staking rate, which is presented in the sensitivity testing section of this appendix.

For staked wooden poles being replaced, in the first instance, we used historical data from the distributors on the proportion of different voltage staked wooden poles being replaced to approximate the volume of each new asset going forward.[215] The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

D.7 Adjustment to the asset age profile to net out staking

Actew AGL reported its staked wooden poles twice in its asset age profile: once as "staking of a wooden pole" and a second time under one of the six wooden pole categories. This resulted in the double counting of 12417 wooden poles.[216] Using the data "as is" in the repex model would result in the double counting of these assets. Consequently, we made an adjustment to ActewAGL's wooden pole data to net out the double counted assets.

The adjustment required involves subtracting the total number of staked poles from the total number of wooden poles in commission. We decided to do carry out this adjustment proportionally across the wooden pole asset base. We also assumed that no new pole installed after 1999 would have required staking (or the number would be negligible) so the adjustment would be applied to the pre-1999 asset base.

To make this adjustment, the total number of wooden poles in commission (with an installation date of 1999 or before) was calculated. Then we found the proportion of the total that each category of wooden poles made up in each year (e.g. wooden poles with a maximum rating of 1Kv that were installed in 1999/2000 make up 0.6 per cent of poles in commission). The total number of staked poles was multiplied by these proportions to give an adjustment figure (e.g. for wooden poles with a maximum rating of 1Kv, the adjustment required was 12417*0.006132=76). This figure was then subtracted from the age profile (e.g. for wooden poles with a maximum rating of 1Kv, the adjustment required was the total number of poles (182) - the netting out proportion (76) = the netted out data (105 - difference is due to rounding)).

Our approach smears the adjustment across each year of the age profile, rather than attempting to make targeted adjustments at particular years, or bias the adjustment in favour of older poles. Given the expected lives of wooden poles (40+ years), it is likely that a greater number of the stakings were carried out on the older poles in the asset base than newer poles (that is, a pole that is over 40 years old is more likely to be staked than a pole that is under 40). Assuming this is correct, applying a constant smearing of the staking to all pre-1999 poles may result in a greater number of newer poles being netted out and fewer old poles being netted out than we would expect in practice. Under this circumstance, we would expect the repex model to calculate a greater volume of replacements than it

[214] For example, if a distributor replaces a pole with a new pole 50% of the time, and stakes the pole the other 50% 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.

[215] Poles with different maximum voltages have different unit costs. An assumption needs to be made to determine, for example, how many new ">1kv poles" and how many new "1kv-11kv" need to be installed to replace the staked wooden poles.

[216] ActewAGL, reponse to AER information request 35, 17 September 2014.

would if the adjustments were distributed with an asymmetric bias towards older poles. Consequently, the approach does not disadvantage ActewAGL, as it is not likely to result in an underestimation of their replacement requirements, and is more likely to skew in favour of replacement.

D.8 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when finding replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced - so an adjustment needs to be made for the calibration process to function correctly. We sought this information directly from the distributors. ActewAGL, Essential and Ausgrid provided the information on the number of old assets being replaced, which allowed us to calibrate the model. Endeavour did not provide us the information.[217] In the absence of this information, it was necessary to make assumptions to allow us to calibrate the repex model. We considered Ausgrid's data would act as a good proxy for Endeavour's, given the similarities in location of the networks and similarities in the overall size of their wooden pole population.[218] We determined the proportion of Ausgrid's old staked poles replaced in the last period, and applied the observation to Endeavour's population of staked poles to give an estimate of the number of disposals over the last five years. It should be noted that staking of wooden poles is a relatively recent activity, and we have not observed a large number of historical replacements of these assets by the distributors.

[217] Endeavour has classified its staking as Opex, and did not provide the requested data for this reason; Endeavour Energy, Response to AER information request 021, 18 November 2014.

[218] The use of Ausgrid's data to weight Endeavour's wooden pole replacements may give a different outcome than what we would see if we had been able to use Endeavour's actual data. If Endeavour provides this data in its revised proposal, we will re-run the model using its actual figures.

E Real material cost escalation

Real material cost escalation is a method for accounting for expected changes in the costs of key material inputs to forecast capex. The materials input cost model submitted by ActewAGL includes forecasts for changes in the prices of commodities such as copper, aluminium, steel and crude oil, rather than the prices of physical inputs themselves (e.g., poles, cables, transformers) which are the inputs directly sourced by ActewAGL in the provision of its network services. ActewAGL has also escalated construction costs in its cost of materials forecast.

E.1 Position

We are not satisfied that ActewAGL's proposed real material cost escalators (leading to cost increases above CPI) which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period.[219] Instead we consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period. We have arrived at this conclusion on the basis that:

- the degree of the potential inaccuracy of commodities forecasts is such that we consider that zero per cent real cost escalation is likely to provide a more reliable estimation for the price of input materials used by ActewAGL to provide network services
- there is little evidence to support how accurately ActewAGL's materials escalation model forecasts reasonably reflect changes in prices paid by ActewAGL for physical assets in the past and by which we can assess the reliability and accuracy of its forecast materials model. Without this supporting evidence, it is difficult to assess the accuracy and reliability of ActewAGL's material input cost escalators model as a predictor of the prices of the assets used by ActewAGL to provide network services, and
- ActewAGL has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that are not captured by the material input cost models used by ActewAGL.

Our approach to real materials cost escalation discussed above does not affect the proposed application of labour and construction cost escalators which apply to ActewAGL's standard control services capital expenditure. We consider that labour and construction cost escalation as proposed by ActewAGL is likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria given these are direct inputs into the cost of providing network services.[220]

E.2 ActewAGL's proposal

ActewAGL applied material and labour cost escalators to various asset classes in forecasting its capex for the 2014-19 period.[221] Real cost escalation indices for the following material cost drivers were calculated for ActewAGL by Competition Economists Group (CEG):[222]

- aluminium

219 NER, clause 6.5.7(a).
220 NER, clause 6.5.7(c)(3).
221 ActewAGL, *Revenue proposal*, p. 163.
222 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.

- copper
- steel
- crude oil; and
- construction - both engineering and non-residential.

CEG sourced forward rates from Bloomberg up to 2023 to convert commodities traded on international markets priced in United States dollars to Australian dollars.[223]

Table E-1 outlines ActewAGL's real materials cost escalation forecasts.

Table E-1 ActewAGL's real materials cost escalation forecast—inputs (per cent)

	2014–15	2015–16	2016–17	2017–18	2018–19
Aluminium	4.2	5.8	5.0	4.2	3.6
Copper	-0.9	1.1	0.3	-0.3	-0.7
Steel	0.6	3.2	0.6	0.3	-0.1
Crude oil	-0.5	2.8	2.6	2.1	1.8
Construction costs - engineering	0.5	0.7	0.5	0.4	0.1
Construction costs - non-residential	0.5	0.7	0.5	0.4	0.1

Source: ActewAGL, Revenue proposal, Attachment B12, CEG Escalation factors affecting expenditure forecasts, December 2013, pp. 21, 24, 27, 30 and 31.

On the basis of these individual material (and labour) cost escalators, ActewAGL through its consultant Sinclair Knight Mertz (SKM, now Jacobs SKM), calculated escalation factors specific to various asset classes. These escalation factors were determined by applying a percentage contribution, or weighting, by which each of the underlying cost drivers were considered to influence the total price of each asset.[224] Table E-2 outlines ActewAGL's real cost escalation indices by asset class.

Table E-2 ActewAGL real materials and labour cost escalation forecast (indices)

	2014–15	2015–16	2016–17	2017–18	2018–19
Asset classes					
Transmission overhead	1.008	1.021	1.016	1.014	1.011

223 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 9.
224 ActewAGL, *Revenue proposal*, p. 164.

Transmission underground (copper)	1.003	1.013	1.014	1.013	1.012
Distribution overhead lines	1.006	1.017	1.020	1.019	1.019
Distribution underground lines (aluminium)	1.006	1.017	1.020	1.020	1.019
Zone substation switchgear	1.003	1.011	1.010	1.009	1.008
Zone substation civil engineering	1.005	1.009	1.008	1.007	1.005
Distribution substations	1.003	1.013	1.011	1.010	1.009
Meters	1.003	1.012	1.014	1.013	1.013
Other non-system assets (corporate)	1.000	1.000	1.000	1.000	1.000
IT and communication systems (networks)	1.004	1.007	1.010	1.010	1.010
Motor vehicles	1.000	1.000	1.000	1.000	1.000
Other non-system assets (networks)	1.000	1.000	1.000	1.000	1.000
Zone substation transformer	1.004	1.018	1.010	1.007	1.005
Relays (protection and control)	1.004	1.013	1.017	1.017	1.016
Zone substation electronics/other	1.001	1.007	1.007	1.006	1.006

Source: ActewAGL, Revenue proposal, p. 166.

E.3 Assessment approach

We assessed ActewAGL's proposed real material cost escalators for the purpose of assessing its proposed total capex forecast against the National Electricity Rules (NER) requirements. We must accept ActewAGL's capex forecast if we are satisfied it reasonably reflects the capex criteria.[225] Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.[226]

225 NER, clause 6.5.7(c).
226 NER, clause 6.5.7(c)(3).

We have applied our approach as set out in our Expenditure Forecast Assessment Guideline (Expenditure Guideline) to assessing the input price modelling approach to forecast materials cost.[227] In the Expenditure Guideline we stated that we had seen limited evidence to demonstrate that the commodity input weightings used by service providers to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the service providers paid for manufactured materials.[228] We considered it important that such evidence be provided because the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used.[229] As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast manufactured material cost changes is likely to reasonably reflect changes in raw material input costs.

In our assessment of ActewAGL's proposed material cost escalation, we:

- reviewed the CEG report commissioned by ActewAGL[230]
- reviewed the materials input cost model used by ActewAGL; and
- reviewed the approach to forecasting manufactured material costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.
- We received no stakeholder submissions on this issue.

E.4 Reasons

We must be satisfied that a forecast is based on a sound and robust methodology in order to accept that ActewAGL's proposed total capex reasonably reflects the capex criteria.[231] This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[232] In making our assessment, we do recognise that predicting future materials costs for electricity service providers involves a degree of uncertainty. However, for the reasons set out below, we are not satisfied that the materials forecasts provided by ActewAGL satisfy the requirements of the NER. Accordingly, we have not accepted it as part of our substitute estimate in our draft decision on total forecast capex. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this has been taken into account into our substitute estimate.

Materials input cost model

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

In our Expenditure Guideline, we requested service providers should demonstrate that their proposed approach to forecast materials cost changes reasonably reflected the change in prices they paid for

227 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline,* November 2013, pp. 50-51.
228 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
229 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
230 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.
231 NER, clause 6.5.7(c).
232 NER, clause 6.5.7(c)(3).

physical inputs in the past. ActewAGL's proposal does not include supporting data or information which demonstrates movements or interlink-ages between changes in the input prices of commodities and the prices ActewAGL paid for physical inputs. ActewAGL's material cost input model assumes a weighting of commodity inputs for each asset class but does not provide information which explains the basis for the weightings or that the weightings applied have produced unbiased forecasts of the costs of ActewAGL's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable. In summary, ActewAGL has not demonstrated that their proposed approach to forecast materials cost changes reasonably reflects the change in prices they paid for assets in the past.

Materials input cost model forecasting

ActewAGL has used its consultants' reports to estimate cost escalation factors in order to assist in forecasting future operating and capital expenditure. These cost escalation factors include commodity inputs in the case of capital expenditure. The consultants have adopted a high level approach hypothesising a relationship between these commodity inputs and the physical assets purchased by ActewAGL. Neither the consultants' reports nor ActewAGL have successfully attempted to explain or quantify this relationship, particularly in respect to movements in the prices between the commodity inputs and the physical assets and the derivation of commodity input weightings for each asset class.

We recognise that active trading or futures markets to forecast prices of assets such as transformers are not available and that in order to forecast the prices of these assets a proxy forecasting method needs to be adopted. Nonetheless, that forecasting method must be reasonably reliable to estimate the prices of inputs used by service providers to provide network services. ActewAGL has not provided any supporting information that indicates whether the forecasts have taken into account any material exogenous factors which may impact on the reliability of material input costs. Such factors may include changes in technologies which affect the weighting of commodity inputs, suppliers of the physical assets changing their sourcing for the commodity inputs, and the general volatility of exchange rates.

Materials input cost mitigation

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

- potential commodity input substitution by the electricity service provider and the supplier of the inputs. An increase in the price of one commodity input may result in input substitution to an appropriate level providing there are no technically fixed proportions between the inputs. Although there will likely be an increase in the cost of production for a given output level, the overall cost increase will be less than the weighted sum of the input cost increase using the initial input share weights due to substitution of the now relatively cheaper input for this relatively expensive input.

  We are aware of input substitution occurring in the electricity industry during the late 1960's when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do however recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies with which some inputs are not substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby potentially reducing the total expenditure requirements of an electricity service provider[233]

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.[234] For example, ActewAGL has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs
- the scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency, and
- increases in productivity that have not been taken into account by ActewAGL in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2014-2019 period, we consider that there is potential for an upward bias in estimating material input cost escalation by maintaining the base year cost commodity share weights.

Forecasting uncertainty

The NER requires that an electricity service provider's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[235] We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. The following factors have assisted us in forming this view:

- recent studies which show that forecasts of crude oil spot prices based on futures prices do not provide a significant improvement compared to a ‘no-change’ forecast for most forecast horizons, and sometimes perform worse[236]
- evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than ‘no change’ forecasts;[237] and
- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $US to $AUS). A review of the economic literature of exchange rate forecast models suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.[238]

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

234 NER, clause 6.5.7(e)(6).

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

236 R. Alquist, L. Kilian, R. Vigfusson, *Forecasting the Price of Oil*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1022, July 2011 (also published as Alquist, Ron, Lutz Kilian, and Robert J. Vigfusson, 2013, *Forecasting the Price of Oil*, in Handbook of Economic Forecasting, Vol. 2, ed. by Graham Elliott and Allan Timmermann (Amsterdam: North Holland), pp. 68-69 and pp. 427–508) and International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, pp. 25-31.

237 International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, p. 27, Chinn, Menzie D., and Olivier Coibion, *The Predictive Content of Commodity Futures*, Journal of Futures Markets, 2014, Volume 34, Issue 7, p. 19 and pp. 607-636 and T. Reeve, R. Vigfusson, *Evaluating the Forecasting Performance of Commodity Futures Prices*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1025, August 2011, pp. 1 and 10.

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

Strategic contracts with suppliers

We consider that electricity service providers can mitigate the risks associated with changes in material input costs by including hedging strategies or price escalation provisions in their contracts with suppliers of inputs (e.g. by including fixed prices in long term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution possibilities between operating and capital expenditure,[239] we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.

Cost based price increases

Allowing individual material input costs that constitute cost escalation reflects more cost based price increases. We consider this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex. In taking into account the revenue and pricing principles, we note that this approach would be less likely to promote efficient investment.[240] It also would not result in a capex forecast that was consistent with the nature of the incentives applied under the CESS and the STPIS to ActewAGL as part of this decision.[241]

Selection of commodity inputs

The limited number of material inputs included in ActewAGL's material input escalation model may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by ActewAGL. ActewAGL's materials input cost model may also be biased to the extent that it may include a selective subset of commodities that are forecast to increase in price during the 2014-2019 period.

Commodities boom

The relevance of material input cost escalation post the 2009 commodities boom experienced in Australia when material input cost escalators were included in determining the approved capex allowance for electricity service providers. We consider that the impact of the commodities boom has subsided and as a consequence the justification for incorporating material cost escalation in determining forecast capex has also diminished.

E.5 Review of independent expert's reports

We have reviewed the CEG report commissioned by ActewAGL. We consider that this review, along with our review of two other reports detailed below, provides further support for our position to not accept ActewAGL's proposed materials cost escalation.

CEG report

- CEG acknowledge that forecasts of general cost movements (e.g. consumer price index or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs (e.g. energy costs and

239 NER, clause 6.5.7(e)(7).
240 NEL, Part 1, section 7.
241 NER, clause 6.5.7(e)(8).

equipment leases etc.).[242] This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity service provider's intermediary input costs.

- CEG acknowledge that futures prices will be very unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[243] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the material input cost models used by ActewAGL.

- CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:[244]

  > While futures prices are not accurate predictors of future spot prices, they nevertheless reflect current beliefs of market participants about forthcoming price developments.

  This supports our view that there is a reasonable degree of uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of assets used by NSPs to provide network services. Whilst the IMF may conclude that commodity futures prices reflect market beliefs on future prices, there is no support from the IMF that futures prices provide an accurate predictor of future commodity prices.

- Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.[245] Analysis of this data shows that the longer the futures projection period, the less accurate are LME futures in predicting actual commodity prices. Given the next regulatory control period covers a time span of 60 months we consider it reasonable to question the degree of accuracy of forecast futures commodity prices towards the end of this period.

  Figures 1 and 2 also show that futures forecasts have a greater tendency towards over-estimating of actual aluminium and copper prices over the 20 year period (particularly for aluminium). The greatest forecast over-estimate variance was about 100 per cent for aluminium and 130 per cent for copper. In contrast, the greatest forecast under-estimate variance was about 44 per cent for aluminium and 70 per cent for copper.

- In respect of forecasting electricity service providers future costs, CEG stated that:[246]

  > There is always a high degree of uncertainty associated with predicting the future. Although we consider that we have obtained the best possible estimates of the NSPs' future costs at the present time, the actual magnitude of these costs at the time that they are incurred may well be considerably higher or lower than we have estimated in this report. This is a reflection of the fact that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.

  This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.[247]

- CEG also acknowledge that its escalation of aluminium prices are not necessarily the prices paid for aluminium equipment by manufacturers. As an example, CEG referred to producers of

242 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
243 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4-5.
244 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.
245 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5-6.
246 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.
247 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

electrical cable who purchase fabricated aluminium which has gone through further stages of production than the refined aluminium that is traded on the LME. CEG also stated that aluminium prices can be expected to be influenced by refined aluminium prices but these prices cannot be expected to move together in a 'one-for-one' relationship.[248]

GEG provided similar views for copper and steel futures. For copper, CEG stated that the prices quoted for copper are prices traded on the LME that meet the specifications of the LME but that there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.[249] For steel futures, CEG stated that the steel used by electricity service providers has been fabricated, and as such, embodies labour, capital and other inputs (e.g. energy) and acknowledges that there is not necessarily a 'one-for one' relationship between the mill gate steel and the steel used by electricity service providers.[250]

These statements by CEG support our view that the input cost estimation models used by ActewAGL has not demonstrated how and to what extent material inputs have affected the cost of intermediate outputs. We note, as emphasised by CEG, there is likely to be significant value adding and processing of the raw material before the physical asset is purchased by ActewAGL.

- CEG has provided data on historical indexed aluminium, copper, steel and crude oil actual (real) prices from July 2005 to December 2013 as well as forecast real prices from January 2014 to January 2021 which were used to determine its forecast escalation factors.[251] For all four commodities, the CEG forecast indexed real prices showed a trend of higher prices compared to the historical trend. Aluminium and crude oil exhibited the greatest trend variance. Copper and steel prices were forecast to remain relatively stable whist aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

In addition to our review of the CEG Report, we have also received submissions from TransGrid and Jemena Gas Networks on other resets that are currently being undertaken from TransGrid and Jemena Gas Networks. We have considered the relevance of those submissions to the issues raised by ActewAGL in order to arrive at a position that takes into account all available information. Our views on these reports are set out below. Overall, both these reports lend further support to our position to not accept ActewAGL's proposed materials cost escalation.

SKM report

- SKM caution that there are a variety of factors that could cause business conditions and results to differ materially from what is contained in its forward looking statements.[252] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the cost of assets that are not captured by ActewAGL's material input cost models.

- SKM stated it used the Australian CPI to account for those materials or cost items for equipment whose price trend cannot be rationally or conclusively explained by the movement of commodities prices.[253]

- In its modelling of the exchange rate, SKM has in part adopted the longer term historical average of $0.80 USD/AUD as the long term forecast going forward.[254] This is consistent with our view that

[248] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
[249] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
[250] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.
[251] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, Figures 3, 4 and 5, pp. 23, 25 and 28.
[252] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.
[253] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.

longer term historical commodity prices should be considered when reviewing and forecasting future prices. In general, we consider that long term historical data has a greater number of observations and as a consequence is a more reliable predictor of future prices than a data time series of fewer observations.

- SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.[255] SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.[256]

- SKM stated that in respect to the reliability of oil future contracts as a predictor of actual oil prices, futures markets solely are not a reliable predictor or robust foundation for future price forecasts. SKM also stated that future oil contracts tend to follow the current spot price up and down, with a curve upwards or downwards reflecting current (short term) market sentiment.[257] SKM selected Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.[258] The decision by SKM to adopt an economic forecast for oil rather than using futures highlights the uncertainty surrounding the forecasting of commodity prices.

BIS Shrapnel report

- BIS Shrapnel has forecast prices of gas service provider related materials to increase, in part due to movements in the exchange rate. BIS Shrapnel are forecasting the Australian dollar to fall to US$0.77 from mid-2016 to mid-2018[259]. This is significantly lower than the exchange rate forecasts by SKM of between US$0.91 to US$0.85 from 2014-15 to 2018-19.[260] CEG did not publish its exchange rate forecasts in its report but state that for the purposes of the report it sourced forward rates from Bloomberg until 2023.[261] BIS Shrapnel stated that exchange rate forecasts are not authoritative over the long term.[262]

  We consider the forecasting of foreign exchange movements during the next regulatory control period to be another example of the potential inaccuracy of modelling for material input cost escalation.

- In its forecast for general materials such as stationary, office furniture, electricity, water, fuel and rent, BIS Shrapnel assumed that across the range of these items, the average price increase would be similar to consumer price inflation and that the appropriate cost escalator for general materials is the CPI.[263] This treatment of general business inputs supports our view that where we cannot be satisfied that a forecast of real cost escalation for a specific material input is robust, and cannot determine a robust alternative forecast, zero per cent real cost escalation is

254 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
255 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.
256 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p.16.
257 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.
258 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.
259 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 6.
260 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.
261 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
262 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.
263 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

reasonably likely to reflect the capex criteria and under the PTRM the electricity service provider's broad range of inputs are escalated annually by the CPI.

Comparison of independent expert's cost escalation factors

To illustrate the potential uncertainty in forecasting real material input costs, we have compared the material cost escalation forecasts derived by the consultants as shown in Table E-3.

Table E-3 Real material input cost escalation forecasts ($ real 2012-13)

	2014–15 (%)	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)
Aluminium					
CEG	4.2	5.8	5.0	4.2	3.6
SKM	4.69	4.88	3.09	4.42	2.97
BIS Shrapnel	1.4	5.6	3.9	11.0	-6.5
Range (low to high)	1.4 to 4.69	4.88 to 5.8	3.09 to 5.0	4.2 to 11.0	-6.5 to 3.6
Copper					
CEG	-0.9	1.1	0.3	-0.3	-0.7
SKM	-0.17	0.17	-1.15	-0.16	-1.45
BIS Shrapnel	-0.9	-1.5	0.3	9.3	-8.7
Range (low to high)	-0.9 to 0.17	-1.5 to 1.1	-1.15 to 0.3	-0.3 to 9.3	-8.7 to -0.7
Steel					
CEG	0.6	3.2	0.6	0.3	-0.1
SKM	2.84	2.45	-0.35	0.38	-1.11
BIS Shrapnel1	5.1	1.0	-0.2	8.0	-8.9
Range (low to high)	0.6 to 5.1	1.0 to 3.2	-0.35 to 0.6	0.3 to 8.0	-0.1 to -8.9
Oil					
CEG	-0.5	2.8	2.6	2.1	1.8
SKM	-5.11	-0.79	0.74	1.85	0.51
BIS Shrapnel2	1.4	-1.1	-0.2	6.5	-6.2
Range (low to high)	-5.11 to 1.4	-1.1 to 2.8	-0.2 to 2.6	1.85 to 6.5	-6.2 to 1.8

Source: CEG, Escalation factors affecting expenditure forecasts, December 2013, pp. 21, 24 and 27, SKM, TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19, 9 December 2013, p. 2 and BIS Shrapnel, Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales, April 2014, p. iii.

[1] Asian market price as BIS Shrapnel believes the Asia market is more appropriate.[264]
[2] BIS Shrapnel have forecast plastics prices based on price changes in Nylon-11 and HDPE (Polyethylene). BIS Shrapnel state that Castor Oil is the key raw material of Nylon-11 and because it does not have any historical data on Castor Oil, it has approximated Nylon-11 by using HDPE growth rates. HDPE (Polyethylene) prices are proxied by BIS Shrapnel using Manufacturing Wages, General Materials, and Thermoplastic Resin prices. BIS Shrapnel state that Thermoplastic Resin is primarily driven by Crude Oil.[265]

As Table E-3 shows, there is considerable variation between the consultant's commodities escalation forecasts. The greatest margin of variation is 10.1 per cent for aluminium in 2018-19, where CEG has forecast a real price increase of 3.6 per cent and BIS Shrapnel a real price decrease of 6.5 per cent. BIS Shrapnel's forecasts exhibit the greatest margin of variation but there also considerable variation between CEG and SKM's forecasts. These forecast divergences between consultants further demonstrate the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services. This supports our view that ActewAGL's forecast real material cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 regulatory control period.[266]

E.6 Conclusions on materials cost escalation

We are not satisfied that ActewAGL has demonstrated that the weightings applied to the intermediate inputs have produced unbiased forecasts of the movement in the prices it expects to pay for its physical assets. In particular, ActewAGL has not provided sufficient evidence to show that the changes in the prices of the assets they purchase are highly correlated to changes in raw material inputs.

CEG, in its report to ActewAGL, identified a number of factors which are consistent with our view that ActewAGL's input cost model has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. CEG acknowledged that forecasts of general cost movements (e.g. CPI or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs.[267] CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[268] CEG also stated that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.[269]

Recent reviews of commodity price movements show mixed results for commodity price forecasts based on futures prices. Further, nominal exchange rates are in general extremely difficult to forecast and based on the economic literature of a review of exchange rate forecast models, a "no change" forecasting approach may be preferable.

It is our view that where we are not satisfied that a forecast of real cost escalation for materials is robust, and we cannot determine a robust alternative forecast, then real cost escalation should not be

264 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 40.
265 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii.
266 NER, clause 6.5.7(a).
267 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
268 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.
269 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

applied in determining a service provider's required capital expenditure. We accept that there is uncertainty in estimating real cost changes but we consider the degree of the potential inaccuracy of commodities forecasts is such that there should be no escalation for the price of input materials used by ActewAGL to provide network services.

In previous AER decisions, namely our Final Decisions for Envestra's Queensland and South Australian networks, we took a similar approach. This was on the basis that as all of Envestra's real costs are escalated annually by CPI under its tariff variation mechanism, CPI must inform the AER's underlying assumptions about Envestra's overall input costs. Consistent with this, we applied zero real cost escalation and by default Envestra's input costs were escalated by CPI in the absence of a viable and robust alternative. Likewise, for ActewAGL, we consider that in the absence of a well-founded materials cost escalation forecast, escalating real costs annually by the CPI is the better alternative that will contribute to a total forecast capex that reasonably reflects the capex criteria.

The CPI can be used to account for the cost items for equipment whose price trend cannot be conclusively explained by the movement of commodities prices. This approach is consistent with the revenue and pricing principles of the NEL which provide that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.[270]

E.7 Labour and construction escalators

Our approach to real materials cost escalation does not affect the application of labour and construction cost escalators, which will continue to apply to standard control services capital and operating expenditure.

We consider that labour and construction cost escalation more reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[271] We consider that real labour and construction cost escalators can be more reliably and robustly forecast than material input cost escalators, in part because these are not intermediate inputs and for labour escalators, productivity improvements have been factored into the analysis (refer to the opex attachment).

Construction costs can be forecast with greater precision because the drivers (construction and manufacturing wages, plant equipment and other fabricated metal products, and plant and equipment hire) are reasonably transparent and can be predicted with some degree of accuracy.

Further details on our consideration of labour cost escalators are discussed in Attachment 7.

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270 NEL, section 7(2).
271 NER, clauses 6.5.6(c)(3) and.6.5.7(c)(3).

F Operating and environmental factors

Our draft decision for ActewAGL draws upon the annual benchmarking results and other capital expenditure comparisons between DNSPs. While these results are not a direct input into our alternative estimate of ActewAGL's capex forecast, they inform us of ActewAGL's relative capital efficiency and whether efficient reductions to its forecast is achievable.

This appendix considers the operating and environmental factors identified by DNSPs that will affect the applicability of using the benchmarking results. For the reasons outlined in this appendix, in our view, any differences in operating and environmental factors should not lead to material cost advantage or disadvantage between the DNSPs in the NEM. Hence, it is reasonable to compare ActewAGL's capital efficiency relative to the other DNSPs in the NEM.

The factors considered in this appendix are:

- Existing network design
- Network scale
- Physical and environmental factors
- Regulatory factors, including building requirements, environmental regulations, health regulations, network licence conditions, State/City development policies and traffic management requirements.

F.1 Existing network design

Proportion of 22kV and 11kV lines

The high-voltage networks are the key means for the distribution of electricity over middle distances such as between suburbs and across small regional areas. Simplistically, a doubling of the voltage will provide a doubling of the capacity of the line. In the case of high-voltage lines, a 22kV line will potentially have twice the capacity of an 11kV line. However, higher voltage assets are typically more expensive.

The NSW and ACT DNSPs operate a high-voltage distribution network that is predominantly 11kV (although 22kV forms a significant proportion of some NSW networks). The proportion of 22kV in NSW is 39% and 19% is 22kV.

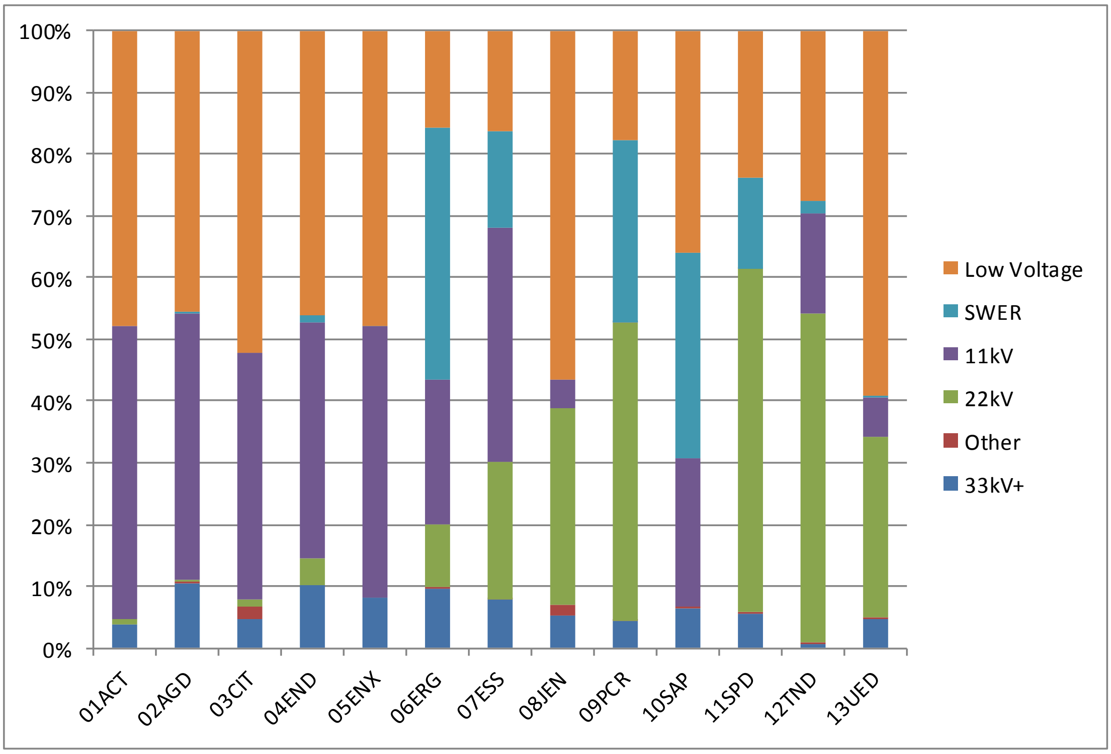
The Victorian DNSPs have mostly migrated their high-voltage networks to a 22kV model with the notable exception of CitiPower. CitiPower reported mostly 11kV high-voltage assets with a very small proportion of 22kV. The proportion of 22kV network in Victoria is 47% of the total network length and just 2% is 11kV.

In South Australia, SAPN reported a high-voltage network that was exclusively 11kV[272]. Queensland on average also had a higher proportion of 11kV to 22kV lines than NSW.

Figure F-1 shows the line voltages operated by the DNSPs as a proportion of total line length.

[272] Single Wire Earth Return (SWER) lines are considered separately.

Figure F-1 Line voltages by length



Source: AER analysis.

Ausgrid's consultants Evans and Peck have claimed that because Victoria operates a 22 kV high-voltage distribution system they have a cost advantage over DNSPs that operate 11kV distribution systems.[273] They claim that this represents a cost advantage and will manifest itself in lower operation, maintenance and repex costs. [274]

Table F-1 provides an overview of the costs and benefits of the differing high-voltage network types.

Table F-1 high-voltage network voltage assessment

11kV networks		22kV networks	
Costs	Benefits	Costs	Benefits
Larger number of feeders	Lower cost feeders, particularly underground	Higher cost feeders, particularly underground	Smaller number of feeders
	Lower cost distribution substations	Higher cost distribution substations	
Larger number of zone substations	Lower cost substations	Higher cost zone substations	Fewer zone substations

[273] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 17.

[274] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

Greater number of civil and protection assets	Improved reliability from shorter feeders	Reduced reliability from greater feeder exposure (or greater costs in sectionalising)	Lower costs for fewer civil and protection assets
Increased maintenance (subtransmission lines, # circuit breakers, etc)	Decreased maintenance (11kV lines, smaller capacity Z/S transformers, circuit breakers, etc)	Increased maintenance (22kV lines, larger capacity Z/S transformers, circuit breakers, etc)	Decreased maintenance (subtransmission lines, #circuit breakers, etc)

Source: AER analysis.

From the above it is evident that there are both advantages and disadvantages associated with the higher capacity high-voltage networks. It would appear that 22kV networks may have a higher capital and reliability cost, and a lower maintenance cost.

It is not inherently obvious whether the overall life-cycle costs of a 22kV network are greater or less than a similar 11kV network. We note that the South Australian and Victorian DNSPs represent the two extremes in terms of 11kV and 22kV networks respectively - Powercor and SP AusNet are predominantly 22kV systems and SAPN has a predominantly 11kV system. If this factor were material to the costs of the DNSPs we would expect this to be most apparent when comparing these two jurisdictions. The benchmarking data indicates that SAPN, Powercor and SP AusNet have very similar levels of expenditure and performance suggesting that this factor is not material to overall performance.

Within Victoria, CitiPower has a predominantly 11kV high-voltage network while SP AusNet and Powercor have predominantly 22kV networks. Were 11kV networks inherently more expensive to operate and maintain we would expect to see a material difference in performance between these Victorian DNSPs. In the majority of the benchmark analysis, CitiPower expenditures are consistent or better than those of Powercor and SP AusNet. Noting that the customer density of these businesses is very different, this again raises questions as to whether 11kV networks have a material or detrimental impact on performance.

We also note that new major network extensions in all DNSPs continue to be undertaken at the existing voltage levels. If there were a distinct cost advantage from 11kV or from 22kV networks we would expect to see networks adopting plans and longer terms strategies to move to the more efficient voltage levels. We may also expect to see major network extensions or additions to be reflecting the more efficient voltage levels. The absence of any such changes is suggestive that the cost difference between the two voltages is not sufficient to warrant the incremental cost of the change.

F.1.1 Subtransmission variations

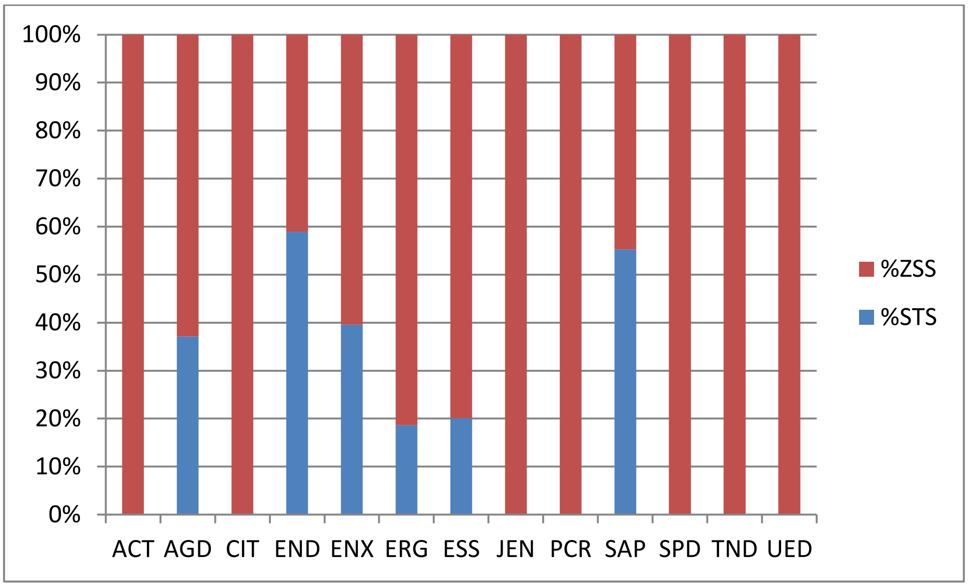
Ausgrid, Endeavour, and Essential have all raised subtransmission network configuration as an operating environment factor that will affect benchmarking results with other DNSPs.[275] [276] [277]

The transition point between transmission and distribution varies across jurisdictions and also within DNSPs. All DNSPs take supply from transmission Grid Exit Points (GXPs) across a range of voltages. Figure F-2 identifies the proportion of subtransmission capacity on the DNSP networks that is

[275] Ausgrid, *Attachment 5.33* to *Revenue proposal*, p. 5.
[276] Endeavour, *Attachment 0.12* to *Revenue proposal*, p. 5.
[277] Essential *Attachment 5.4* to *Revenue proposal*, p. 5.

operating at higher transformation levels. The blue shaded bars indicate the higher voltage transformation capacity.

Figure F-2 Subtransmission capacity



Source: AER analysis.

Ausgrid has said that because it has a higher proportion of subtransmission assets their cost structures are inherently higher for providing services to their customers.

Ausgrid's consultants Evans and Peck have said that Victoria and Tasmania have a natural cost advantage because they have a shorter total length of installed subtransmission cables.[278] They have also said that Victoria has a natural cost advantage over all other states because it has less subtransmission transformer capacity installed.[279] Evans and Peck have also said that because there is only one transformation step in Victorian subtransmission networks the Victorian DNSPs will have a cost advantage over all other DNSPs.[280] As a result, Evans and Peck conclude that this factor has a positive impact on Victorian benchmarks, particularly in terms of the existing asset base on a per customer base..

We agree with the above observations that the NSW DNSPs own and operate a proportionally larger group of assets at the higher voltages. Queensland GXPs are also typically at the higher voltage levels than those of other states. Tasmania has the lowest GXP voltages of all the NEM DNSPs on average.

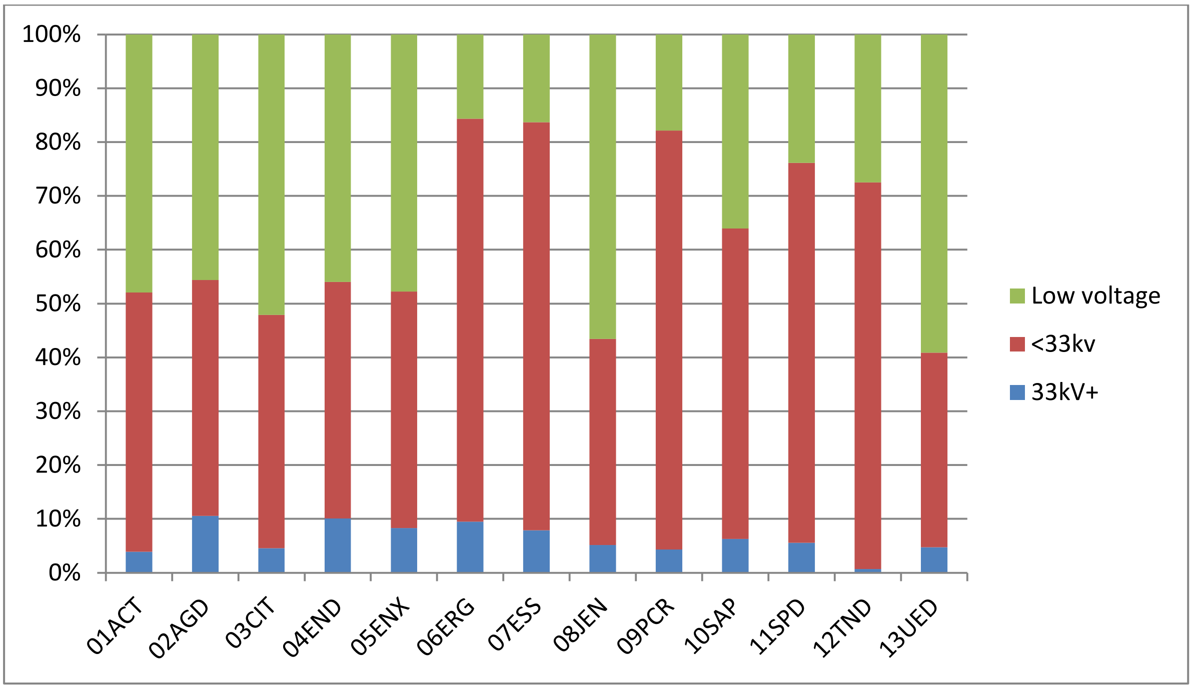
We also note the dual sub-transmission transformation step that accompanies the higher sub-transmission voltages. NSW, Queensland and South Australia have all reported dual transformation assets. One consideration is that the use of the higher transformation substations (STS) is driven by lower load density and size. In more densely populated areas, 132/11kV zone substations are used and there is little need for the intermediate 66kv and 33kVA subtransmission. As load density is

278 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 14.
279 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 18.
280 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 21.

already accounted for in the customer density normalisation, there may be a risk of double-counting the STS assets.

Figure F-3 provides the overall line lengths for each of the major voltage levels across each DNSP.

Figure F-3 Voltage line lengths



Source: AER analysis.

The above figure shows that sub-transmission lines represent a small proportion of total network line length. Ausgrid has the greatest proportion of sub-transmission lines - representing 10.6% of the network. Endeavour Energy reported a value of 10.1% and Essential Energy 7.9%. The average proportion of Victorian and South Australian sub-transmission lines was 5.4%.

This suggests that relative to the comparison firms, ActewAGL has a cost advantage. However, ActewAGL's size and the voltage of its subtransmission system may offset this. Being a relatively small service provider, ActewAGL may not be able to achieve the same economies of scale that the larger comparison firms may be able to in their subtransmission networks. Additionally, ActewAGL's subtransmission network is exclusively 132kV, while in general the subtransmission networks of the comparison firms are 66kV. These things in combination may offset the advantage of having less subtransmission, relative to the comparison firms.

F.1.2 Hardwood poles

Wood poles have been the primary asset for most DNSPs for over a hundred years.[281] In Australia, most DNSPs relied on the use of hardwood poles until the availability and cost of hardwood poles began to make other concrete, steel, fibreglass and softwood poles more cost effective. Each pole type has distinct advantages and disadvantages in terms of overall costs and performance

281 Noting that South Australia has pioneered the use of the Stobie pole since commencement of the distribution system in that state.

The replacement of a pole is at the discretion of the DNSP. The replacement of a hardwood pole does not require another hardwood pole. The choice of replacement is at the discretion of the DNSP and would reflect the overarching asset management strategy of the business.

ActewAGL has identified the proportion of hardwood poles as an operating environment factor that is likely to affect their benchmarking results.[282] Because hardwood poles have a shorter asset life and require more maintenance than steel or concrete poles, ActewAGL says that it will have higher replacement capex and maintenance costs.[283]

We disagree with ActewAGL's statement that hardwood poles have a shorter life than concrete and steel poles. Experience from other DNSPs as reported in the CA RINs shows average asset lives for wood poles to be as long as for steel and concrete. The average expected life for hardwood poles that have been staked or nailed is even longer than that for concrete and steel poles. The climatic conditions in the ACT are also considered more favourable for the life of wooden poles than other DNSPs along the eastern coastlines.

The current replacement volumes for hardwood poles as reported by ActewAGL reveal that ActewAGL is currently replacing wood poles with an effective life similar to concrete and steel. This suggests that ActewAGL is in fact achieving an average asset life for wood poles that is similar to that for steel and concrete poles.

ActewAGL has the highest proportion of underground assets of all the DNSPs in the NEM. The maintenance required of underground assets is significantly less than that required for overhead assets. On this basis we would expect ActewAGL to be advantaged on any overall benchmark of operating or maintenance expenditures.

Overall we consider that the proportion of hardwood poles reported by ActewAGL would not result in any increase in costs relative to its peers and the high proportion of underground assets may provide ActewAGL with a material benefit in terms of overall maintenance expenditures.

F.1.3 Backyard reticulation

Backyard reticulation is a description for the ACT practice of running overhead lines along the rear property boundaries in urban residential areas. This practice was halted in favour of undergrounding a number of decades ago, but there remains a legacy of backyard reticulation lines many ACT suburbs. Backyard reticulation is only applicable to low voltage overhead lines in the ACT.

Typically the pole line is run in parallel with the adjoining property boundaries of the residential properties. This keeps the overhead lines from being viewed from the street and was considered to increase the visual amenity of the suburb.

ActewAGL has identified backyard reticulation as an operating environment factor that is likely to affect their benchmarking results. ActewAGL considers that backyard reticulation increases their replacement capex.

ActewAGL has reported a total network length of 5,088km. Table F-2 shows the proportion of backyard reticulation of this network.

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[282] ActewAGL, *Revenue proposal*, p. 243.
[283] ActewAGL, *Revenue proposal*, p. 171.

Table F-2 Proportion of backyard reticulation

Network component (circuit length)	(km)	Proportion (%)
ActewAGL Total network	5,088	
ActewAGL overhead network	2,394	47%
ActewAGL low-voltage overhead network	1,184	23%
ActewAGL backyard reticulation network	755	15%

Source: AER analysis.

The primary implications for electricity distribution of backyard reticulation are in terms of access to the line. In most Australian DNSPs, local electricity reticulation is via the road easement; typically the nature strip or adjacent to the centre roadway. The road easement is typically public land, whereas the backyard reticulation is typically run in privately owned land. The nature strip provides a useful location for access to overhead assets as it is usually relatively flat and directly easily accessible from the roadway. This allows for the ready access for personnel and vehicles to the assets.

Backyard reticulation places an uncertain set of barriers between the assets and ready access. These can include gates, fences, gardens, pools and animals. Not all backyard reticulation will have access issues, but it is more likely than not.

We agree with ActewAGL that backyard reticulation will have impacts on the costs associated with asset replacement. We consider that backyard reticulation will add costs to the replacement of poles and that there are also savings associated with pole replacement in backyards.

Over the current regulatory control period, overall asset replacement represents 21 per cent of total annual capital expenditure and pole replacement represents approximately 50 per cent of this. As discussed above, ActewAGL reported that less than one-third of their overhead network is located in backyards.

On this basis, the issue of backyard reticulation is a matter that relates to approximately 3.5 per cent of capital expenditure. Backyard reticulation poles are exclusively low-voltage poles and will therefore not incur the additional costs associated with replacement of high-voltage or sub-transmission poles.

The potential additional costs for backyard reticulation pole replacement would include negotiations with landowners, access, specialised materials and remediation. As backyard reticulation pole replacement takes place off the street, there would be a related reduction in costs associated with traffic management.

Typical pole replacement works would utilise heavy machinery. Backyard reticulation areas would limit the use of heavy machinery. Without heavy plant to dig hole and lift the poles and conductors etc., the work would be more labour intensive and slower. This would result in some saving in plant costs, but would result in labour costs that would be higher.

Overall we consider that there may be additional overall costs associated with pole replacement in backyard reticulation areas. However, we consider that the overall impact of these costs will be partially mitigated by reduced traffic management and that the resultant impact on overall capex costs will be very small.

F.2 Scale factors

F.2.1 Customer density

Customer density is a useful proxy for identifying the distance between customers. As each DNSP has an obligation to serve existing customers, we assume that this is therefore an exogenous factor.

Customer density, in and of itself, does not drive costs. There are factors that are proportional to customer density that are the underlying cost drivers including:

- Asset spacing - The need to service customers that are spaced further apart will require additional length of lines or cables to provide the same level of service.
- Asset exposure - A shorter line will have be less exposed to degradation from the elements and damage from third parties.
- Travel times - the time taken to travel between customers or assets increases as those assets or customer are spaced further apart.
- Traffic management - traffic management requirements typically increase proportionally to the volumes of traffic on, or adjacent, to the worksite.
- Asset complexity - The complexity of assets in a given location - for example; multiple circuits on a pole, or circuits in a substation.
- Proximity to third party assets - Increased urban density results in more third-party overhead and underground asset being in proximity to electrical assets. This proximity requires increased co-ordination, planning, and design.
- Proportion of overhead and underground - Increased urban density can result in greater obligations or constraints on the DNSPs in relation to the augmentation or construction of underground/overhead assets. Maintenance of underground assets is typically reduced compared with overhead.
- Topographical conditions - Adverse topographical conditions such as swamps, mountainous terrain, etc, will typically result in less habitable areas and increased costs associated with access to these areas.

Each of the above factors will impact network costs differently. It is obvious that some will have more of an adverse effect on rural services, while others will have a more adverse impact on urban services. Table F-3 summarises our assessment of whether the factors are likely to benefit or adversely impact networks depending on their respective customer density.

Table F-3 customer density factor impacts

Factor	Capex benchmark benefit
Asset spacing	Urban networks
Asset exposure	Urban networks

Travel times	Urban networks
Traffic management	Rural networks
Asset complexity	Rural networks
Proximity to third-party assets	Rural networks
Proportion of overhead and underground	Rural networks
Topographical conditions	Rural networks

Source: AER analysis.

It is not evident from the above chart whether the overall impact of the above measures would favour urban networks or rural networks. For example, comparing the asset cost per customer between 2009 and 2013 (Figure 16 of our annual benchmarking report), there is relatively little cost difference between the Victorian rural and urban distribution networks.

We have considered a number of measures for aggregating the impacts from the above factors. Historically, industry benchmarks have used a number of representative measures including:

- Customer density measured as customers per (circuit) km of line (cust/km)
- Energy density measured as energy delivered per (circuit) km of line (kWh/km)
- Demand density measured as demand per (circuit) km of line (MVA/km)
- Customer density measured a customers per square kilometre of service territory

The use of service territory has proven problematic and is not recommended for use. This is due to the difficulty in accurately measuring service territory items such as lakes, national parks, unpopulated areas, etc. As the networks do not incur costs for areas that are un-serviced, this is not considered as a useful measure for expenditure or service comparisons.

A number of benchmarking studies and reviews have considered the relative merits of the different remaining density measures identified above (customer, energy and demand).[284][285][286] As the ratios of energy and demand are relatively similar on a per customer basis, it is not clear whether there is any greater intrinsic benefit from any one of these density measures.

As customer density per kilometre is a relatively easy concept to understand, we have adopted this as our standard approach.

F.2.2 Load shape

Service providers design electricity networks to taking into account the expected peak demand for electricity services. While the actual energy usage on a network is important from a billing

284 Benchmarking Opex and Capex in Energy Networks, Working Paper no.6, May 2012, p18

285 Western Power: Transmission & Distribution Network cost analysis & Efficiency benchmarks Volume II, Theoretical framework June 2005, Benchmark Economics

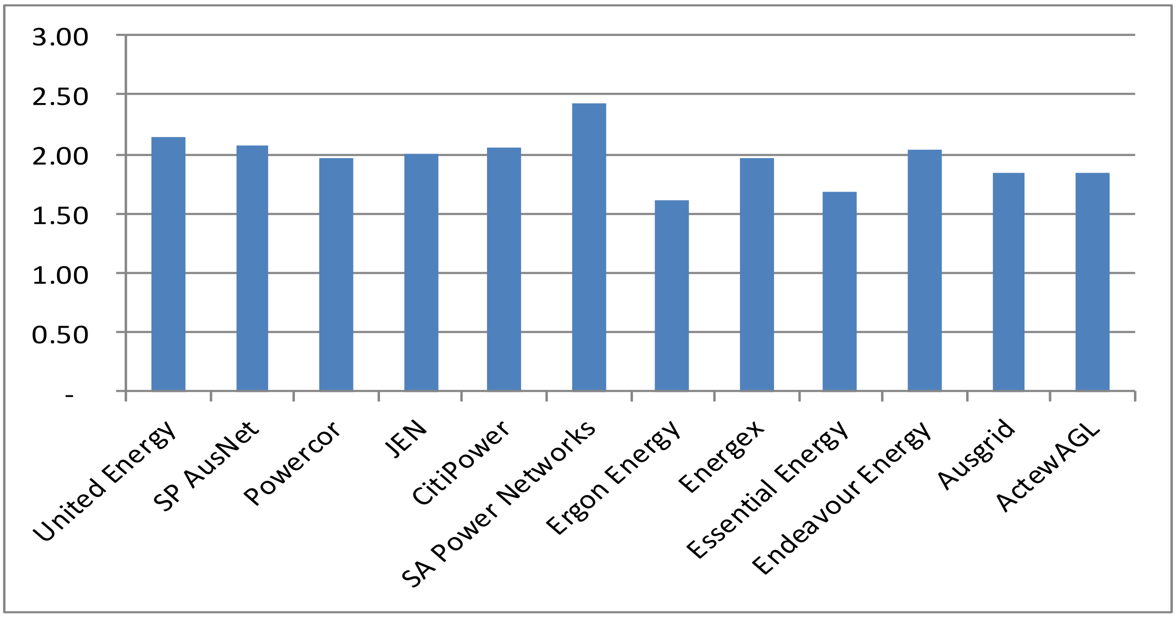
286 Aurora Energy, A comparative analysis: Aurora Energy's Network cost structure, Benchmark Economics

perspective, energy is not the driver for capital expenditure. The higher peak demand, the more assets will be required to accommodate those peaks.

Evan's and Peck say that the load factor and duration for SA and Victoria give DNSPs in those states a natural cost advantage.[287] Because DNSPs in SA and Victoria have lower load factors it means that probabilistic planning is more applicable to those businesses.

Figure F-4 shows the ratio of network demand to average energy (five year average) for each of the NEM DNSPs. This figure shows that South Australian customers have the most peaky electricity demand, while Queensland has the lowest. This means that SAPN is required to provide a more assets to meet the peak demand on its network when compared to the average electricity delivered. This would impact the expenditure required to build and replace assets as well as the ongoing operations and maintenance associated with those assets. However, as we have seen, SAPN appears as relatively efficient in overall benchmarks as well as in both capex and opex benchmarking indicators.

Figure F-4 Network load factor



Source: AER analysis.

We disagree with the Evan's and Peck statement in relation to probabilistic planning. We consider that probabilistic planning is the efficient approach for all network businesses, irrespective of their energy or load factors. Deterministic planning does not consider the cost and benefits of individual projects and will therefore result a less cost effective outcome in the longer term.

On this basis, we consider that peakier network loads such as those on South Australia and Victoria should result in higher costs to the networks operating within them in relation to energy throughput, but not in relation to maximum demands.

287 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, pp. 26-27.

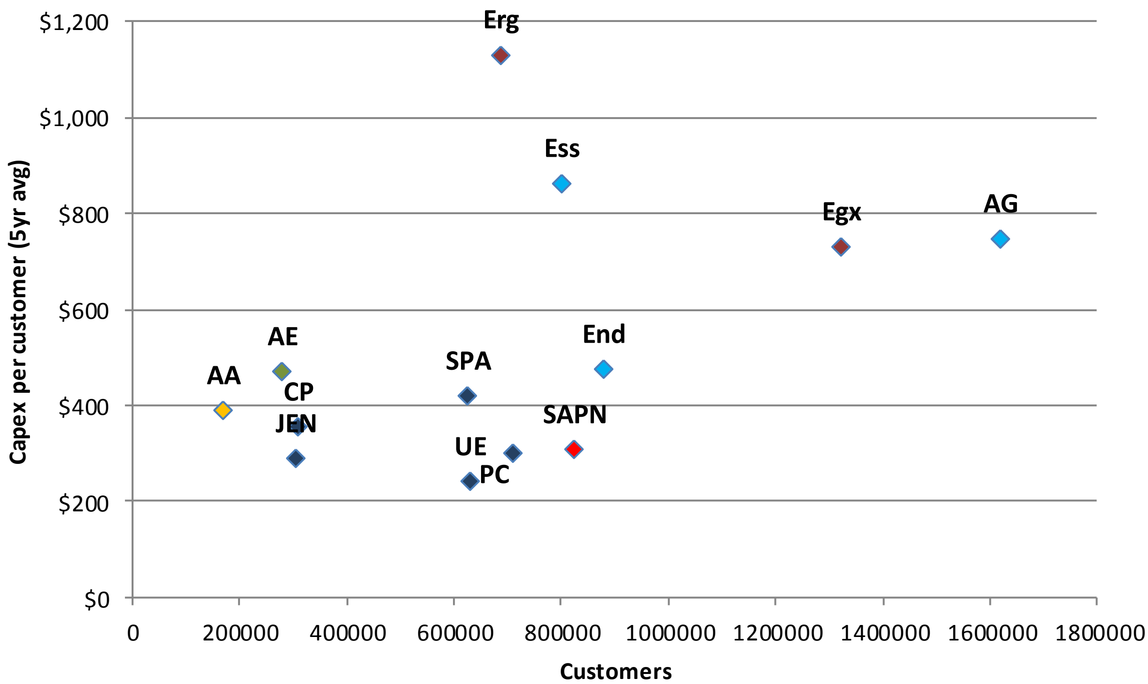
F.2.3 Economies of scale

There is a wealth of literature highlighting the potential for economies of scale across all industries. Economies of scale do exist and may well have a material impact. Many of the DNSP submissions refer to the existence of economies of scale.

ActewAGL has claimed that because it is the smallest DNSP it does not have access to the same economies of scale as other DNSPs. As a result their costs will appear to be higher than for all other DNSPs that have access to greater economies of scale.[288]

Figure F-5 show that the larger DNSPs tend to be more expensive than the smaller ones when using customer numbers as a proxy for scale.

Figure F-5 Capital expenditure per customer



Source: AER analysis.

The above charts are not fully representative of the scale opportunities that are present for each company. For example:

- ActewAGL has the potential for scale opportunities through the relationship with its retail, gas and water operations.
- The NSW DNSPs are seeking to drive additional scale opportunities through the Network NSW merger.
- Powercor, CitiPower and SAPN share ownership and some management structures.
- Tasmanian Networks has been formed in part to drive efficiencies through shared services

288 ActewAGL, *Revenue proposal*, p. 243.

- AusNet Services operates transmission and distribution networks under a single management structure.

On this basis of the above information, we consider the economies of scale do exist, but are difficult to accurately assess and are at present significantly less material than many other factors impacting DNSP performance.

F.3 Physical environment factors

F.3.1 Bushfires

Evans and Peck state that on the basis of a Fire Danger Index published by the Australasian Fire and Emergency Service Authorities that NSW, the ACT, and Victoria have an equal risk of Fire Danger. Evans and Peck then conclude that DNSPs in NSW, the ACT, and Victoria have natural cost disadvantages due to the risk of bushfires.

We agree with Evans and Peck that "the impact and underlying tragedy of (the 2009 Victorian bushfires) are not to be understated or overlooked in any way". Bushfire risk is a very serious concern for all Australians and represents a significant risk for all DNSPs.

However, it is unclear if ActewAGL will face greater bushfire risk than the comparison service providers. Some of the information available suggests that bushfire risk is higher in the ACT than in Victoria and South Australia, while some suggests that Victoria and South Australia are higher risk. Although some of our comparison service providers are not likely to face high bushfire risks, such as CitiPower, we have weighted ActewAGL's efficiency target according to the number of customers that the comparison service providers have. This means that the efficiency target is weighted towards predominantly rural service providers with higher bushfire risk.

Forecasts from Deloitte Access Economics of the total economic costs of bushfires for 2014, in Table A.24 below, suggests that the forecast economic cost of bushfires is higher for the ACT than for Victoria and South Australia. We have normalised the forecast cost of bushfires by Gross State Product. This is to prevent population and physical size from interfering with comparisons. While not a perfect measure, we are satisfied that it is preferable to normalising by area or population.

Table F-1 Forecast economic cost of bushfires 2014

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
GSP ($m 2013)	35 088	476 434	290 158	95 123	24 360	337 493
Forecast cost of bushfires 2014 ($m 2013)	55	43	0.0	44	40	172
% of GSP	0.16%	0.01%	0.00%	0.05%	0.17%	0.05%

Source: Deloitte Access Economics[289] and ABS[290 291].

However, major bushfires have tended to occur more frequently in South Australia and Victoria than the ACT. Table F-4 below, which shows the location, and impacts, of major Australian bushfires of the 1900 to 2008 period, demonstrates this.

289 DEA, Scoping study of a cost benefit analysis of bushfire mitigation: Australian Forest Products Association, May 2014, p. 12.

290 ABS, 5220.0 - Australian National Accounts: State Accounts, 2012-13

291 ABS, 6401.0 - Consumer Price Index

Table F-4 Significant bushfires and bushfire seasons in Australia 1900-2008

Date	States	Homes destroyed	Deaths
February 14, 1926	Victoria	550	39
January 8-13, 1939	Victoria and NSW	650	79
Summer 1943-44	Victoria	885	46
February 7, 1967	Tasmania	1557	64
January 8, 1969	Victoria	230	21
February 16, 1983	Victoria and SA	2253	60
February 18, 2003	ACT	530	4
January 11, 2005	South Australia	93	9

Source: Haynes et al.[292].

Also when normalised by population, South Australia, and Victoria experienced more deaths as a result of bushfire than the ACT. We have normalised by population rather than area because bushfires in unpopulated areas will not cause any deaths and are unlikely to damage to property. This is shown in Table F-5 below.

Table F-5 Deaths as a result of bushfires per 100,000 people by state 1900 to 2008

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
Deaths	5	105	17	44	67	296
Average population 1900-2008[293]	122 524	3 804 434	1 688 122	911 524	324 896	2 818 053
Deaths per 100,000 residents	4.1	2.8	1.0	4.8	20.6	5.1

Source: Haynes et al[294] and ABS[295].

On balance, we consider that it is uncertain whether the ActewAGL's network faces greater or lesser risk of bushfire than the comparison service providers, which are located in South Australia and Victoria. Because of this uncertainty, we consider that there is not enough evidence at this stage to suggest that ActewAGL or the comparison service providers have a relative cost advantage or disadvantage due to bushfire risk.

F.3.2 Climate

Evans and Peck say that climate can affect asset failure rates and line design requirements. They do not explain, how or which DNSPs would be affected. [296]

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292 We used the average population over 1900 to 2008 rather than the current population to account for how population size may have changed over the period.

293 We used the average population over 1900 to 2008 rather than the current population to account for how population size may have changed over the period.

294 Haynes, K. et al.,Australian bushfire fatalities 1900-2008: exploring trends in relation to the 'prepare, stay and defend or leave early' policy, Environmental Science & Policy, vol. 13 no. 3, May 2010, p. 188.

295 3105.0.65.001 - Australian Historical Population Statistics, 2014

296 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

We agree that the DNSPs are required to consider the regional climate in designing, constructing and maintaining their assets. As an example, DNSPs that service alpine areas will need to consider the local climate in their design standards to ensure that the lines and poles can bear the expected weight of snows and ice. In addition, the lower temperatures in these areas will allow for higher ratings of lines and substations.

With the exception of cyclones and bushfires, we are not aware of any Australian climatic conditions that are extensive enough such that they would require such a material change in design, construction or maintenance as to represent a material impact on overall expenditures.

F.3.3 Corrosive environments

Evans and Peck raise the issue of corrosion as an operating environment factor. They say that the presence of corrosive atmospheres containing things such as salts (in coastal environments) and acid sulphates (in soils) impact on maintenance costs and replacement decisions. [297]

While assets in coastal areas more exposed to corrosive materials, assets in inland areas are more exposed to dusts. These differences may lead to differences in design and operational considerations. However there is not sufficient evidence to conclude that this lead to material differences in costs.

F.3.4 Grounding conditions

Electricity distribution requires the use of earthing or grounding connection to aid in the protection and monitoring of the network. In rural areas, service providers use the earth as the return path for some forms of electricity distribution[298]. These systems require service providers to create an electrical earth, usually from embedding conductors or rods in the ground. The effectiveness of these earths varies depending on the soil type and the amount of moisture in the soil.

Evans and Peck say that rocky terrain and high resistivity soils make the installation of earth grid, to provide effective protection, more complex.[299] Evans and Peck provide no further information on how this will affect service providers differently.

The installation and maintenance of earth grids are a very small part of service provider's costs. Further, all service providers will have areas of their networks that provide more challenging grounding conditions than others do. It is likely that there is a greater degree of difference in grounding conditions within networks than between networks. Although there may be differences in grounding costs between networks, there is not sufficient evidence to conclude that these differences are material.

Earthing and grounding assets represent a very small proportion of overall network asset costs. On this basis, and the lack of any clear distinctions between the DNSP areas we do not consider that soil resistivity represents a material expenditure consideration.

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297 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

298 Single Wire Earth Return (SWER)

299 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

F.3.5 Shape factors

Evans and Peck say that natural boundaries, such as water and national park, surrounding electricity networks impose costs on DNSPs.[300] These costs manifest themselves through imposing constraints on network planning.

Electricity networks are designed to provide electrical services to customers. Over time the networks have grown to match the expansion of the population and industry. This expansion was often along waterways and then later along the roads and highways. Natural boundaries limit the expansion of the population and as a result the networks also naturally terminate at these boundaries.

While these natural boundaries might represent a cost implication for transmission networks who are required to span them, this is not the case for distribution networks. Small waterways, channels, rail lines, and easements are a cost implication for all distribution networks. Large national parks, lakes and deserts are typically unpopulated and do not require electricity distribution.

Our position is that shape factors are unlikely to have any material effect on the benchmarking results. This is because all DNSPs have boundaries and obstacles in their operating areas. Larger obstacles create a natural barrier to population and industrial growth and do not require servicing from the distribution networks.

F.3.6 Topographical conditions

Ausgrid, Endeavour, and Essential have all raised topographic conditions as an operating environment factor that will affect the benchmarking results.[301] [302] [303]

Evans and Peck, in the report commissioned by Ausgrid, state that DNSPs in NSW and Victoria have a natural cost advantage due to the topography of those regions.[304] They do not explain why they consider this to be the case.

We consider that topographical conditions will not materially affect costs at a total network level. This is because the effect of adverse topography on costs can be reduced or eliminated through prudent network planning. Further the majority of population centres in Australia are located on relatively flat terrain. While DNSPs may have asset across more topographically difficult areas, they are immaterial in volume compared to the size of their networks. Therefore the majority of distribution assets are located in areas with similar topography.

F.4 Regulatory factors

F.4.1 Building requirements

The Building Code of Australia (BCA) provides a set of nationally consistent, minimum necessary standards of relevant safety (including structural safety and safety from fire), health, amenity and sustainability objectives for buildings and construction.[305]

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300 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 45 and p. 46.

301 Ausgrid, *Attachment 5.33* to *Revenue proposal*, p. 5.

302 Endeavour, *Attachment 0.12* to *Revenue proposal*, p. 5.

303 Essential *Attachment 5.4* to *Revenue proposal*, p. 5.

304 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 44.

305 ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

Ausgrid's consultant Evans and Peck identified differences in building regulations as an operating environment factor that may affect benchmarking results.[306] Evans and Peck do not provide any explanation as to how this may impede like for like comparisons.

The Australian Building Codes Board (ABCB) is a Council of Australian Government standards writing body that is responsible for the National Construction Code (NCC) that comprises the BCA and the Plumbing Code of Australia (PCA). It is a joint initiative of all three levels of government in Australia and was established by an inter-government agreement (IGA) signed by the Commonwealth, States and Territories on 1 March 1994. Ministers signed a new IGA, with effect from 30 April 2012.[307] The BCA contains technical provisions for the design and construction of buildings and other structures, covering such matters as structure, fire resistance, access and egress, services and equipment, and energy efficiency as well as certain aspects of health and amenity.[308]

Evans and Peck say that building code requirements can affect comparisons across networks. They do not explain, how or which DNSPs would be affected. [309]

While there are differences between the building codes, these building codes generally conform to and maintain a sufficient level consistency with national guidelines. We consider there will not be material differences in costs between service providers in different jurisdictions due to building regulations. This is because the BCA applies in all states of Australia

F.4.2 Environmental regulations

Ausgrid's consultant Evans and Peck identified differences in environmental regulations as an operating environment factor that may affect benchmarking results.[310] Evans and Peck did not provide any explanation as to how this may impede like for like comparisons.

We investigated how environmental regulations may lead to material differences for the costs that service providers require, but were unable to find any reliable evidence that such differences exist. The way various jurisdictions administer environmental regulation varies considerably.[311] While the commonwealth has some involvement, most environmental planning functions are carried out by state or local governments. We consider it is likely that differences in environmental regulations faced by service providers will lead to differences in costs, but we do not have any evidence to suggest that these differences will be material.

F.4.3 Occupational health and safety regulations

Ausgrid's consultant Evans and Peck identified differences in OH&S regulations as an operating environment factor that may affect benchmarking results.[312] Evans and Peck did not provide any explanation as to how this may impede like for like comparisons. ActewAGL noted that in 2011 the implementation of the Work Health and Safety Act 2011(ACT) imposed additional costs on it that had

306 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 5.

307 ABCB, About the Australian Building Codes Board, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

308 ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

309 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

310 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

311 Productivity Commission, *Performance Benchmarking of Australian Business Regulation: Local Government as Regulator*, July 2012, p. 386-390.

312 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

not existed previously.[313] It also notes that NSW and Victoria already had many of these more stringent requirements before the implementation of the harmonised OH&S legislation.

In the NEM, all jurisdictions, except Victoria, have enacted the Work Health and Safety Act and Work Health and Safety Regulations.[314] While enforcement activities may vary slightly across jurisdictions the main cost driver of OH&S costs will be the regulations and law with which businesses must comply. In this respect, we are satisfied that there will not be material cost differences between jurisdictions that have enacted the model laws. However, there is likely to be a cost differential between service providers in Victoria and those in other jurisdictions. Because the comparison firms are predominantly Victorian, this is likely to likely to lead to cost differentials between the comparison firms and ActewAGL.

F.4.4 State/City development policy

Evans and Peck say that state and city development policy can affect comparisons across networks.[315] They say that in Sydney costs are higher due to council requirements.[316] Specifically, they say that requirements for laying and relaying of concrete pavements are more onerous in Sydney than other parts of Australia. They say that the concrete in Sydney is thicker and therefore more costly. They also say that councils in NSW do not allow businesses to reseal roads themselves after works. Instead councils reseal the roads themselves and charge businesses a fee.

We are not aware of any evidence that concrete is thicker in Sydney. Even if this was the case and there was an overall average difference in concrete depths, this would not represent a material difference in overall projects costs let alone at the overall capex level.

The practice of certain councils requiring road and pavement reinstatement to be undertaken by the council and not the DNSP is relatively common across most urbanised municipalities. All major capital cities include streetscape environments that they seek to maintain to their specific standards. As discussed above, these additional costs do not represent a material component of overall capex. The customer density normalisation on the PPI benchmarks will include any potential impacts of the urban reinstatement process.

Reinstatement is a very small component of overall operating expenditures and most urban municipalities maintain specific streetscape requirements. On this basis we consider that this area will have no material impact on the overall or category benchmarks.

F.4.5 Traffic management requirements

Evans and Peck say that traffic management regulations can affect comparison of opex and capex across networks. They do not explain, how or who would be affected.[317]

Traffic management is a factor that is generally related to the volume of traffic in the vicinity of the worksite. We consider that traffic management will have a greater impact on expenditure in higher

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313 ActewAGL, Capital and-operating expenditure 'site visit' clarifications, 3 October 2014, pp. 38.
314 Safework Australia, Jurisdictional progress on the model work health and safety laws, available at: thehttp://www.safeworkaustralia.gov.au/sites/swa/model-whs-laws/pages/jurisdictional-progress-whs-laws. [last accessed 4 September 2014]
315 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.
316 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 39-40.
317 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

density areas than in lower density areas. We consider that the potential impacts of traffic management are recognised in the customer density normaliser that is used in the PPI benchmarking.

We recognise that each Australian state and territory has different standards for the development and implementation of traffic control plans at road work sites. This includes issues such as signage, speed zones, etc. Each of the states and territories has different levels of training requirements including:

- traffic management planners (approvers and designers),
- worksite supervision and control.

However, State and territory road authorities generally base their traffic control at road work sites requirements on AS1742 Part 3: Guide to traffic control devices for works on roads.[318]

Overall we consider that differences in traffic management regulations and traffic management needs are unlikely to materially affect costs at the total cost level. Differences in traffic management regulations are likely to represent a small portion of the total difference between traffic management costs. Traffic management costs are only a portion of project costs. Not all projects incur traffic management costs.

[318] National Approach to Traffic Control at Work Sites, Publication no: AP-R337/09, Austroads 2009, p. 1.