PRELIMINARY DECISION CitiPower distribution determination 2016−20

Attachment 6 − Capital expenditure

October 2015

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's preliminary decision on CitiPower's revenue proposal 2016–20. It should be read with all other parts of the preliminary decision.

The preliminary 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

Attachment 14 - Control mechanism

Attachment 15 - Pass through events

Attachment 16 - Alternative control services

Attachment 17 - Negotiated services framework and criteria

Attachment 18 - f-factor scheme

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNSP	distribution network service provider
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
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

Shortened form	Extended form
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and 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 investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return of and on capital) as part of the building blocks that form CitiPower's total revenue requirement.[1]

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

- Appendix A - Assessment Techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Demand
- Appendix D - Predictive modelling approach.

6.1 Preliminary decision

We are not satisfied CitiPower's proposed total forecast capex of $848.0 million ($2015) reasonably reflects the capex criteria. This is 4.8 per cent lower than the AER's allowance for the 2011–15 regulatory control period ($890.5 million) and 13.4 per cent greater than actual capex for the 2011–15 period ($747.6 million). We substituted our estimate of CitiPower's total forecast capex for the 2016–20 regulatory control period. We are satisfied that our substitute estimate of $659.0 million ($2015) reasonably reflects the capex criteria. Table 6.1 outlines our preliminary decision.

Table 6.1 Our preliminary decision on CitiPower's total forecast capex ($2015, million)

	2016	2017	2018	2019	2020	Total
CitiPower's proposal	170.6	200.3	186.6	161.7	128.8	848.0
AER preliminary decision	148.7	151.7	128.5	122.7	107.4	659.0
Difference	–21.9	–48.6	–58.1	–39.0	–21.4	–189.0
Percentage difference (%)	–12.8	–24.3	–31.1	–24.1	–16.6	–22.3

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 96; AER analysis.

Note: Numbers may not add up due to rounding.

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

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

Table 6.2 summarises our findings and the reasons for our preliminary decision.

These reasons include our responses to stakeholders' submissions on CitiPower's regulatory proposal. In the table we present our reasons by 'capex driver' (for example, augmentation, replacement, and connections). This reflects the way in which we tested CitiPower's total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques, we found CitiPower's capex forecast across all categories was higher than an efficient level, inconsistent with the NER. We are not satisfied that CitiPower's proposed total forecast capex is consistent with the requirements of the NER.[2]

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our preliminary decision concerns CitiPower's total forecast capex for the 2016–20 period. We do not approve an amount of forecast expenditure for each capex driver. However, we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 6.3 for a detailed discussion). We are satisfied that our estimate represents the total forecast capex that as a whole reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	CitiPower proposed a total capex forecast of $848.0 million ($2015) in its proposal. We are not satisfied this forecast reflects the capex criteria. We are satisfied our substitute estimate of $659.0 million ($2015) reasonably reflects the capex criteria. Our substitute estimate is 22.3 per cent lower than CitiPower's proposal. The reasons for this decision are summarised in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	We consider CitiPower's key assumptions and forecasting methodology are generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment and section 6.4.2.
Augmentation capex	We do not accept CitiPower's forecast augex of $203.3 million ($2015) as a reasonable estimate for this category. We consider that $119 million ($2015) is a reasonable estimate for CitiPower to meet its augmentation requirements and satisfy the capex criteria, including for augex relating to the VBRC. In coming to this view, we do not accept that CitiPower's demand forecast reflects a realistic expectation of demand over the 2016–20 regulatory control period. Our estimate partly reflects the augex necessary for CitiPower to meet a lower forecast of demand. We accept the capex that CitiPower proposes to augment the security of the Melbourne CBD network in compliance with its regulatory obligations. However we have not included CitiPower's proposed capex associated with decommissioning its 22kV sub-transmission network in our alternative estimate of augex. This is because this capex is not primarily associated with a need to expand the capacity or capability

2 NER, cll. 6.5.7(c) and (d).

Issue	Reasons and findings
	of the network.
Customer connections capex	We do not accept CitiPower's' forecast gross connections capex of $333.1 million ($2015) as a reasonable estimate for this category. We consider our substitute estimate of $236.2 million ($2015) will allow CitiPower to meet the capex objectives and have included this amount in our substitute gross connections capex estimate. We are not satisfied that the approach CitiPower has adopted to generate the forecast represents an reasonable estimate of the capex required.
Asset replacement capex (repex)	We do not accept CitiPower's forecast repex of $260 million ($2015) as a reasonable estimate for this category. We consider our alternative estimate of $199 million ($2015) will allow CitiPower to meet the capex objectives and have included this amount in our alternative estimate. Our alternative estimate is 23 per cent lower than CitiPower's proposed repex. We do not accept CitiPower's proposed increase to repex for categories it has reported under "other" repex. We are of the view CitiPower has not undertaken robust cost-benefit analysis in support of the increased repex, has not established why large portions of the repex should not be regarded as "business as usual" and so fall within the repex model, or demonstrated why the growth in the "other" category is significantly higher than the growth in the prescribed asset groups.
Non-network capex	We do not accept CitiPower's proposed non-network capex of $104.0 million ($2015). We have instead included an amount of $88.1 million ($2015), excluding overheads. We accept CitiPower's forecasts for buildings and property, fleet, and tools and equipment capex as reasonably reflecting required expenditure in these categories. We do not accept CitiPower's forecast for IT capex. In our view, CitiPower's IT forecast does not reflect the efficient costs of a prudent operator. We consider that some elements of the forecast IT capex program have not been fully justified or are speculative in nature. We are satisfied our alternative estimate reasonably reflects the capex criteria.
Capitalised overheads	We do not accept CitiPower's proposed capitalised overheads of $93.5 million ($2015). We have instead included in our substitute estimate of overall total capex an amount of $86.5 million ($2015) for capitalised overheads. We reduced CitiPower's capitalised overheads to reflect the reductions we made to their total capex forecast, particularly those components with overheads.
Real cost escalators	We consider CitiPower's forecast of zero real cost escalation for materials costs over the 2016–20 regulatory control period is reasonable. We are not satisfied CitiPower's proposed real labour cost escalators 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 2016–20 regulatory control period. We discuss our assessment of forecast our labour price growth for CitiPower in attachment 7. The difference between the impact of the real labour cost escalation proposed by CitiPower and that accepted by the AER in its capex decision is $11.2 million ($2015).

Source: AER analysis.

We consider that our overall capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides CitiPower a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and

- complying with its regulatory obligations and requirements.[3]

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the national electricity objective (NEO). We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives.[4] In making our preliminary decision, we specifically considered the impact our decision will have on the safety and reliability of CitiPower's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in CitiPower's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.2 CitiPower's proposal

CitiPower proposed total forecast capex of $848.0 million ($2015) for the 2016–20 regulatory control period.[5] This is $100.5 million ($2015) above CitiPower's actual capex of $747.6 million ($2015) for the 2011–15 regulatory control period.[6]

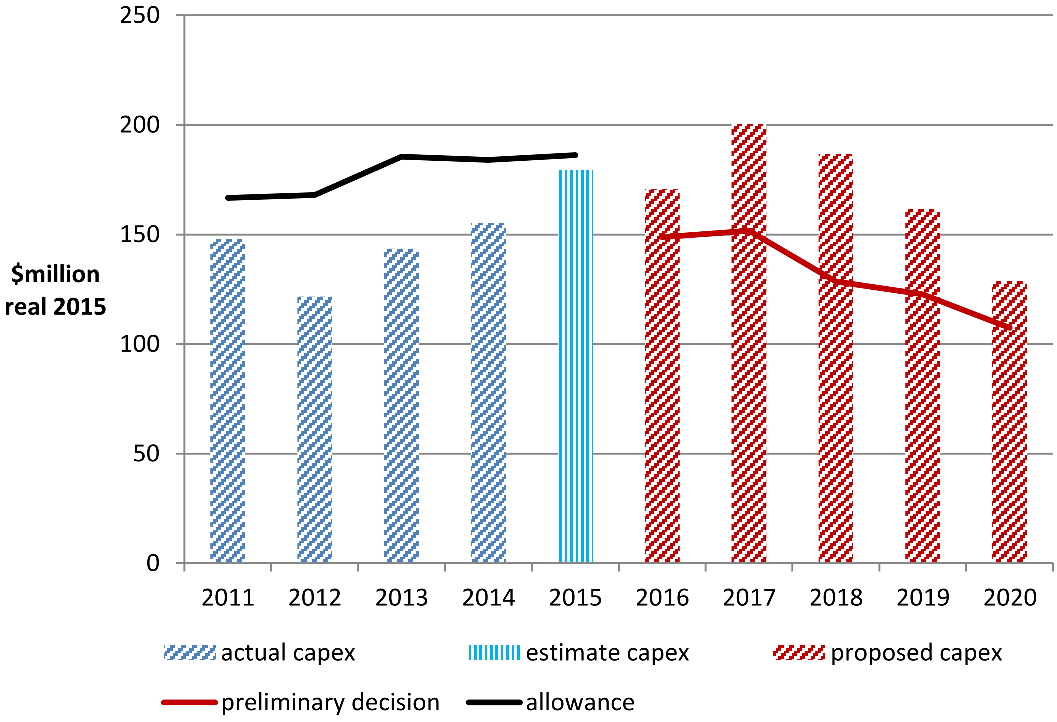
CitiPower expects new customer connections to be the largest capex category, accounting for approximately 37 per cent of its total forecast capex. Replacement expenditure (repex) is also significant, accounting for approximately 29 percent of the total capex forecast. CitiPower stated the main drivers for its capex program include:[7]

- completing the Central Business District (CBD) Security Upgrade and Metro projects
- connections and customer-driven works associated with specific urban renewal projects
- IT expenditure to deliver a smarter network, and replacing the billing system to support Power of Choice initiatives and innovative tariffs.

Figure 6.1 shows CitiPower's forecast capex for each year of the 2016–20 regulatory control period. It also shows CitiPower's actual capex for each year of the 2011–15 regulatory control period.

3 NEL, s. 7A.
4 NER, cl. 6.5.7(a).
5 This is net capex, which does not include customer contributions.
6 This includes estimated capex for the 2015 regulatory year.
7 CitiPower, *Regulatory proposal 2016–2020*, 30 April 2015, pp. 94–98.

Figure 6.1 CitiPower's total actual and forecast capex 2011–2020



Source: AER analysis.

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The information CitiPower provided in its regulatory proposal, including its response to our RIN, is a vital part of our assessment. We also took into account information that CitiPower provided in response to our information requests, and submissions from other stakeholders.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is the distributor's regulatory proposal.[8] We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.[9] It also provides us with an

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8 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

9 NER, cl. 6.5.7(c).

alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.

- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to:[10]

- 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.

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.[11] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:[12]

- 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.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[13] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular

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10 NER, cl. 6.5.7(a).

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

12 NER, cl. 6.5.7(c).

13 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113.

categories or projects informs our assessment of the total capex forecast. The AEMC stated:[14]

> 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 CitiPower's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[15] In taking the capex factors into account, the AEMC noted:[16]

> …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.

Table 6.5 summarises how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[17] In particular, we take into account whether our overall capex forecast provides CitiPower a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[18]

Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).[19] We released our Guideline in November 2013.[20] The Guideline sets out our 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 CitiPower, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.[21] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

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

15 NER, cl. 6.5.7(e).

16 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 115.

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

18 NEL, s. 7A.

19 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 114.

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

21 AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 119–120.

We note that RIN data form part of a distributor's regulatory proposal.[22] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.[23] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.1 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is the distributor's proposal.[24] We review the proposed forecast methodology and the key assumptions that underlie the distributor's forecast. We also consider the distributor's performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that the distributor puts forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendix A and appendix B contain further details on each of these techniques.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.[25]

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision-making.

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22 NER, cll. 6.8.2(c2) and (d).

23 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

24 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

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

As we explained in our Guideline:[26]

> 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.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor's capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our preliminary decision on overall capex. Our preliminary decision clearly sets out the extent to which we accept our consultants' findings. Where we apply our consultants' findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of CitiPower's proposal.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6.4.

Underlying our approach are two general assumptions:

- The capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term

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26 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[27]

- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[28]

6.3.2 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor'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:[29]

> 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.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a distributor's actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent

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27 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013 , pp. 8 and 9. The Australian Competition Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by Energy Australia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by CitiPower Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA).

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

29 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 112.

and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[30] Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted, the distributor and consumers share the benefits of the underspend and the costs of an overspend under the regulatory regime.

6.4 Reasons for preliminary decision

We applied the assessment approach set out in section 6.3 to CitiPower. In this preliminary decision, we are not satisfied CitiPower's total forecast capex reasonably reflects the capex criteria. We compared CitiPower's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. CitiPower's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of CitiPower's total forecast capex for the 2016–20 regulatory control period.

30 NER, r. 6.6.

Table 6.3 Our assessment of required capex by capex driver 2016–20 ($2015, million)

Category	2016	2017	2018	2019	2020	Total
Augmentation	39.8	38.7	13.3	13.1	14.1	119.0
Connections	51.6	49.6	44.2	46.0	44.8	236.2
Replacement	37.5	38.3	47.9	43.9	31.7	199.3
Non-Network	17.8	23.5	19.2	15.8	11.8	88.1
Capitalised overheads	16.5	16.6	16.9	17.9	18.6	86.5
Labour escalation adjustment	-1.0	-2.4	-2.4	-2.7	-2.7	-11.2
Gross Capex (includes capital contributions)	162.2	164.4	139.1	133.9	118.3	718.0
Capital Contributions	13.5	12.7	10.6	11.2	10.8	58.8
Net Capex (excluding capital contributions)	148.7	151.7	128.5	122.7	107.4	659.1

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of CitiPower's forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers are in appendices A and B. These set out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER requires CitiPower to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. CitiPower must also provide a certification by its Directors that those key assumptions are reasonable.[31]

The key assumptions that underlie CitiPower's capex forecast include:[32]

- stakeholder engagement feedback
- labour escalation forecast
- contract escalation forecast

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[31] NER, cll. S6.1.1(2), (4) and (5).

[32] CitiPower, *Regulatory proposal 2016–2020, Attachment 0.1: Certification of reasonableness of key assumptions*, 30 April 2015, p. 2.

- current or impending regulatory obligations
- replacement program is appropriate to meet the capital expenditure objectives of the NER
- spatial peak demand growth forecast
- augmentation expenditure forecast consistent with compliance obligations under the Victorian Electricity Distribution Code
- network capacity program is appropriate to meet the capital expenditure objectives of the NER
- customer connection forecast, where customer contributions are based on Electricity Industry Guideline 14 requirements.

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

6.4.2 Forecasting methodology

The NER requires CitiPower to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[33] CitiPower must include this information in its regulatory proposal.[34]

The main points of CitiPower's forecasting methodology are:[35]

- CitiPower's capex forecast comprise the following categories consistent with the Expenditure Assessment Guideline: replacement, augmentation, connection and customer driven works, and non-network. CitiPower also included an additional category related to the Victorian Bushfires Royal Commission (VBRC).
- CitiPower developed its capex forecast having reference to asset management plans, and planning policies and guidelines across a range of expenditure categories. CitiPower also engaged independent, expert advice to review and support its plans, processes and expenditure forecasts.
- CitiPower modelled expenditure for a range of capex categories. These base capex models contain direct costs only. CitiPower subsequently applied escalations and other factors through other models to arrive at the final capex forecast.
- CitiPower developed a deliverability plan to ensure it is able to deliver its capex forecast. The deliverability plan will utilise internal labour resources, supplemented by external subcontractors, as required.

We consider CitiPower's forecasting methodology is generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment.

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33 NER, cll. 6.8.1A and 11.60.3(c).

34 NER, cl. S6.1.1(2).

35 CitiPower, *Regulatory proposal 2016–2020, Appendix E: Capital expenditure*, 30 April 2015, pp. 12–17.

The Victorian Energy Consumer and Use Alliance (VECUA) considered the Victorian distributors overly relied on bottom up methodologies with insufficient regard to top down methods.[36] Origin Energy supported the application of both a top down and bottom up assessment:[37]

> to demonstrate that a level of overall restraint has been brought to bear. This dual exercise is necessary to ensure that forecast costs, including unit rates, have not been overstated and that inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level are adequately accounted for.

As we noted in previous determinations, the drawback of deriving a capex forecast through a bottom-up assessment is it does not of itself provide sufficient evidence that the estimate is efficient. Bottom up approaches tend to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency.[38]

6.4.3 Interaction with the STPIS

We consider our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we should not set the capex allowance such that it would lead to CitiPower systematically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient service provider in CitiPower's circumstances to maintain performance at the targets set under the STPIS. As such, it is appropriate to apply the STPIS as set out in attachment 11.

In making our preliminary decision, we specifically considered the impact our decision will have on the safety and reliability of CitiPower's network.

In its submission, the Consumer Challenge Panel (CCP) noted the following explanation from the AEMC:[39]

> …operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated to that role. Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which

[36] VECUA, *Submission: Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2015, p. 19.

[37] Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 8.

[38] For example, see AER, *Preliminary decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, pp. 22–23.

[39] CCP, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal*, August 2015, p. 27.

> would undermine the role of the standard setting body, and create uncertainty and duplication of roles.
>
> NSPs are still free to make incremental improvements over and above the regulatory requirements at their own discretion. Such additional expenditure will not generally be recoverable, through forecast capital and operating expenditure. However, DNSPs are also provided with annual financial incentives to improve reliability performance under the STPIS.

We consider our substitute estimate is sufficient for CitiPower to maintain the safety, service quality and reliability of its network consistent with its obligations. Our provision of a total capex forecast does not constrain a distributor's actual spending—either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to spend particular capital expenditure differently or in excess of the total capex forecast in our decision. However, such additional expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

Under our analysis of specific capex drivers, we explained how our analysis and certain assessment techniques factor in safety and reliability obligations and requirements.

6.4.4 CitiPower's capex performance

We looked at a number of historical metrics of CitiPower's capex performance against other distributors in the National Electricity Market (NEM). We also compared CitiPower's capex forecast against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis using data the distributors provided for the annual benchmarking report. The report includes CitiPower's relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and CitiPower's historical capex trend.

The NER sets out that we must have regard to our annual benchmarking report.[40] This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of CitiPower's proposal in a broader context. However, in our capex assessment we have not relied on the high level benchmarking metrics set out below other than to gain a high level insight into CitiPower's proposal. We have not used this analysis deterministically in our capex assessment.

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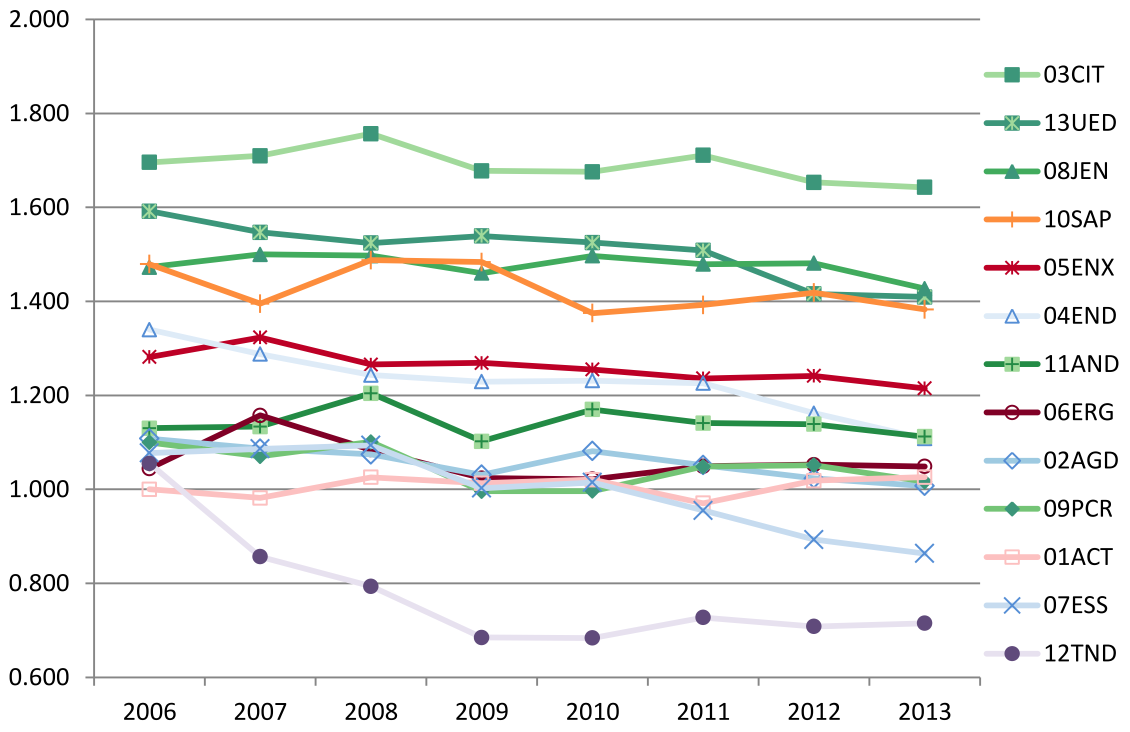
40 NER, cl. 6.5.7(e).

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. CitiPower is the top performer for this measure among the distributors in the NEM.

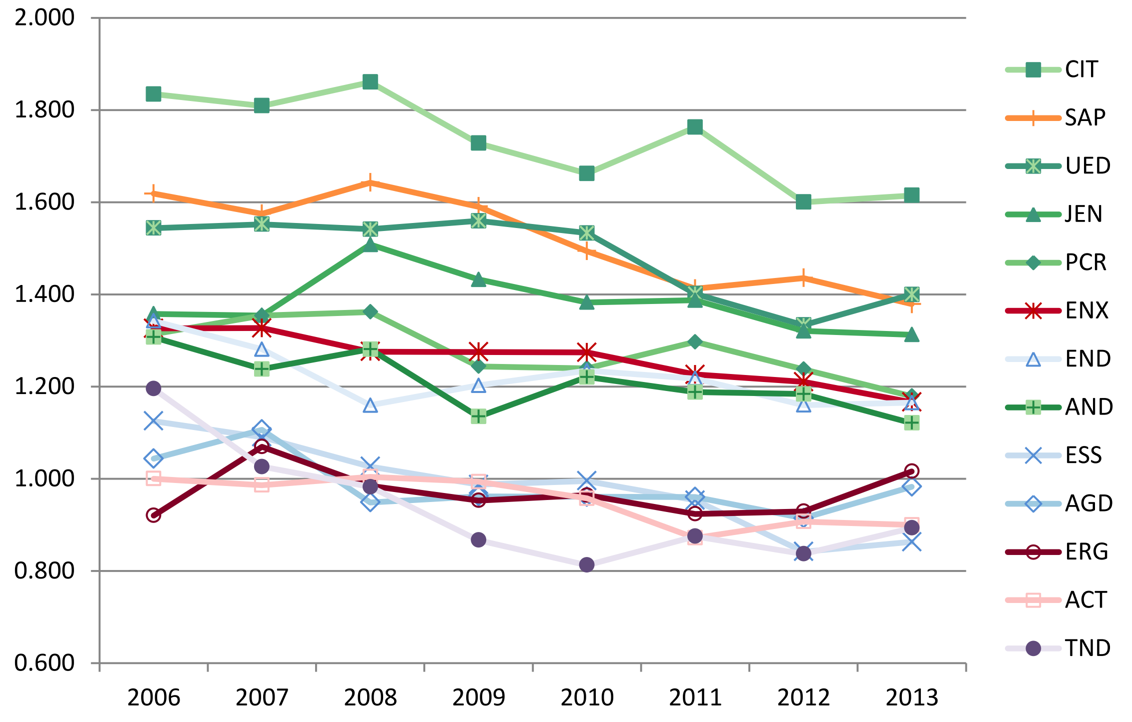
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows that CitiPower ranks similarly on MTFP. 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).

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

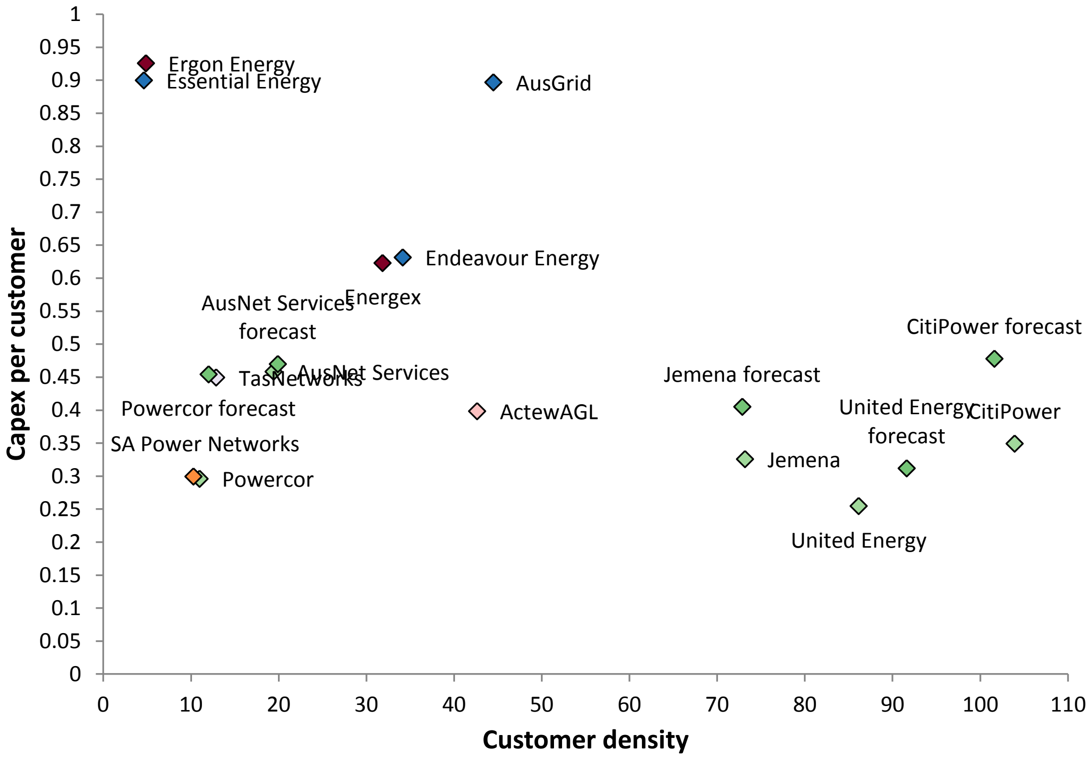
6.4.4.1 Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–12. We considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6.4 and Figure 6.5 show the Victorian distributors generally performed well in these metrics compared to other distributors in the NEM in the 2008–12 years. For completeness, we also included the other Victorian distributors' proposed capex for the 2016–20 regulatory control period in the figures. However, we do not use comparisons of CitiPower's total forecast capex with the total forecast capex of the other Victorian distributors as inputs to our assessment. We consider it is appropriate to compare CitiPower's forecast only with actual capex. This is because actual capex are 'revealed costs' and would have occurred under the incentives of a regulatory regime.

Figure 6.4 shows CitiPower is an outlier in that it has by far the highest customer density of the distributors in the NEM. In the 2008–12 years, it spent more capex per customer than Jemena and United Energy (the closest to CitiPower in terms of customer density). Further, CitiPower's capex per customer will increase in the 2016–20 period based on their proposed forecast capex. CitiPower's capex per customer will be relatively high in the 2016–20 regulatory control period even when taking customer density into account.

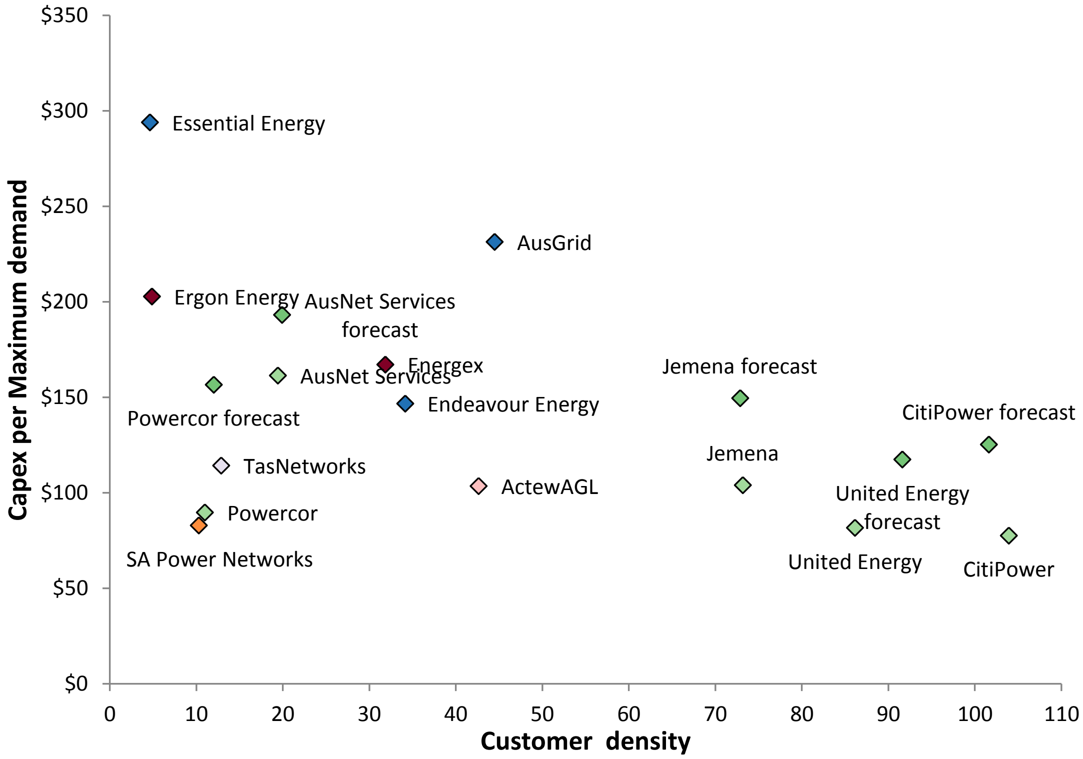
Figure 6.4 Capex per customer (000s, $2013–14), against customer density



Source: AER analysis.

Figure 6.5 shows CitiPower spent less on capex per maximum demand in 2008–12 than Jemena and United Energy. Similar to figure 6.4, capex per maximum demand will increase in the 2016–20 period based on their proposed forecast capex.

Figure 6.5 Capex per maximum demand (000s, $2013–14), against customer density



Source: AER analysis.

The Consumer Utilities Advocacy Centre (CUAC) expressed concern about the large increases in capex some Victorian distributors proposed and the decline in productivity in recent years.[41]

The Victorian Greenhouse Alliances (VGA) noted the increases in the capex forecast of the Victorian distributors. The VGA considered the increased capex forecasts were concerning given over-investment over recent regulatory periods has led to excess levels of network capacity and declining network utilisation. The VGA also expressed concern that the Victorian distributors proposed such high levels of capex at a time of:[42]

- declining capacity utilisation
- reduced average asset age for most asset categories
- static or falling demand and consumption

41 CUAC, *Submission: Victorian electricity distribution pricing review (EDPR) 2016 to 2020*, 13 July 2015, p. 2.

42 VGA, *Submission: Local Government response to the Victorian electricity distribution price review (EDPR) 2016–20*, July 2015, p. 33.

- reductions in the reliability standards.

The Department of Economic Development, Jobs, Transport and Resources (DEDJTR) and the VECUA made similar points in their submissions.[43]

Appendix B details our assessment of CitiPower's capex categories. These assessments, along with the high level analysis in this section 6.4.4, were inputs into our preliminary decision on CitiPower's total capex for the 2016–20 regulatory control period. We consider our assessment has taken into account the issues and concerns stakeholders raised in their submissions. Figure 6.1 shows our preliminary decision capex forecast is 11.8 per cent lower than CitiPower's actual capex in the 2011–15 regulatory control period. By comparison, CitiPower's proposed capex is 13.4 per cent higher than its actual capex for the 2011–15 regulatory control period.

To arrive at our preliminary decision, we considered the issues noted in these submissions, such as lower demand and declining utilisation in the network. For example, we consider CitiPower's demand forecast does not reflect a realistic expectation of demand over 2016–20 and substituted a lower demand forecast. Our assessment of CitiPower's augex forecast reflects this lower demand forecast (see appendix C). Importantly, our assessment considered many other factors such as asset age and condition. We discuss these, and other issues relevant to CitiPower's capex proposal, in detail in appendix B.

CitiPower’s historical capex trends

We compared CitiPower’s capex proposal for the 2016–20 regulatory control period against the long term historical trend in capex levels.

Figure 6.6 shows actual historical capex and proposed capex between 2001 and 2020. This figure shows that CitiPower's forecast is significantly higher than historical levels (actual spend), particularly for the first three years of the regulatory control period. CitiPower's capex forecast falls towards the end of the regulatory control period (to bring it back in line with the average levels of the 2011–15 regulatory control period).

The CCP noted capex in the current period occurred under the 'old' national electricity rules, which the CCP considered overtly incentivised investment.[44] The CCP further noted the NER did not apply in Victoria prior to 2011. Despite the lower incentive in prior to 2011, the CCP noted that reliability did not suffer.[45]

Our detailed assessment in appendix B examined whether the increase is reasonably reflective of the capex criteria.

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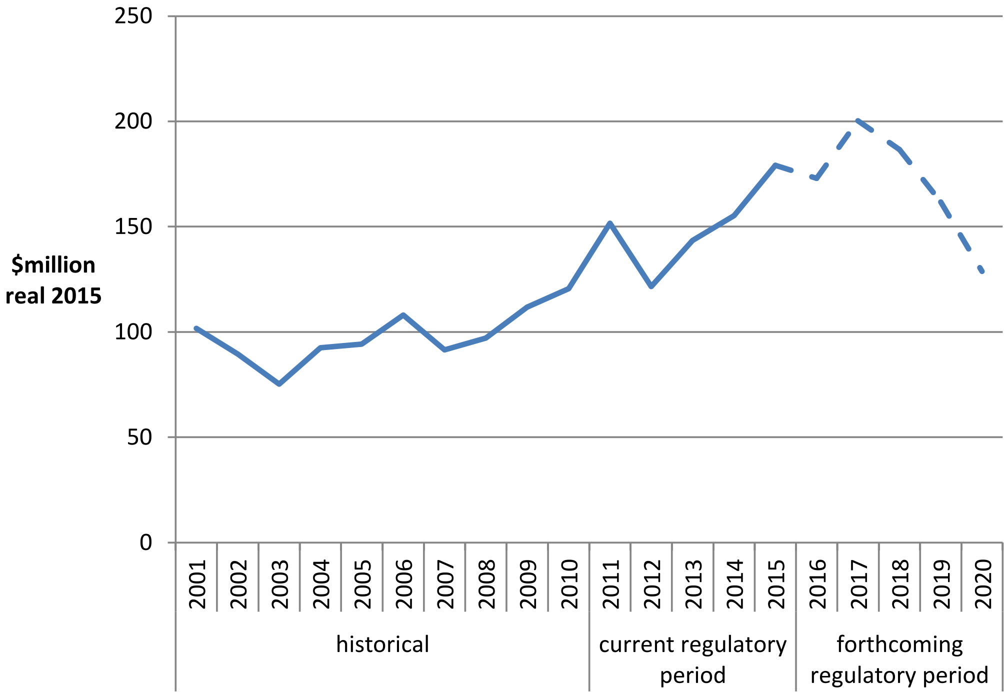
43 DEDJTR, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6; VECUA, *Submission: Victorian distribution networks’ 2016–20 revenue proposals*, 13 July 2105, pp. 6 and 18.

44 That is, prior to the AEMC's changes to the NER in November 2012.

45 CCP, *Submission: Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 5 August 2015, p. 41.

Figure 6.6 CitiPower total capex - historical and forecast for 2001–2020



Source: AER analysis.

6.4.5 Interrelationships

There are a number of interrelationships between CitiPower's total forecast capex for the 2016–20 regulatory control period and other components of its distribution determination (see table 6.4). We considered these interrelationships in coming to our preliminary decision on total forecast capex.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	There are elements of CitiPower's total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in Attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex. More generally, we note our total opex forecast will provide CitiPower with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex CitiPower needs to spend during the 2016–20 regulatory control period.
Forecast demand	Forecast demand is related to CitiPower'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.
Capital Expenditure Sharing Scheme	The CESS is related to CitiPower's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it

Other component	Interrelationships with total forecast capex
(CESS)	reasonably reflects the capex criteria. As we note in the capex criteria table below, 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 CitiPower's regulatory asset base. In particular, the CESS will ensure that CitiPower bears at least 30 per cent of any overspend against the capex allowance. Similarly, if CitiPower 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, CitiPower risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	The STPIS is interrelated to CitiPower'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 2016–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow CitiPower to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to CitiPower systematically under or over performing against its targets.
Contingent project	A contingent project is interrelated to CitiPower'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 CitiPower's total forecast capex for the 2016–20 regulatory control period. We did not identify any contingent projects for CitiPower during the 2016–20 period.

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing CitiPower's total capex forecast.[46] Table 6.5 summarises how we have taken into account the capex factors.

Where relevant, we also had regard to the capex factors in assessing the forecast capex associated with capex drivers such as repex, augex and so on (see appendix B).

Table 6.5 AER 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 distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing CitiPower's proposed total forecast capex and in determining our alternative estimate for the 2016–20 regulatory control period. This can be seen in the metrics we used in our assessment of CitiPower's capex performance.
The actual and expected capex of CitiPower during any preceding regulatory control periods	We had regard to CitiPower's actual and expected capex during the 2011–15 and preceding regulatory control periods in assessing its proposed total forecast. This can be seen in our assessment of CitiPower's capex

46 NER, cll. 6.5.7(c), (d) and (e).

Capex factor	AER consideration
	performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie CitiPower's total forecast capex. For some elements of non-network, augex and connections capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by CitiPower in the course of its engagement with electricity consumers	We had regard to the extent to which CitiPower's proposed total forecast capex includes expenditure to address consumer concerns that CitiPower identified. CitiPower has undertaken engagement with its customers and presented high level findings regarding its customer preferences. These findings suggest that consumers value lower prices and are satisfied with current levels of reliability.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing CitiPower's proposed real cost escalation factors. In particular, we have not accepted CitiPower's proposal to apply real cost escalation for labour.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We 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 CitiPower's total forecast capex and total forecast opex in table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to CitiPower	We had regard to whether CitiPower's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between CitiPower'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 distributor that do not reflect arm's length terms	We had regard to whether any part of CitiPower's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than CitiPower that do not reflect arm's length terms. We do not have evidence to indicate that any of CitiPower's arrangements 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	We had regard to whether any amount of CitiPower's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.
The extent to which CitiPower has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which CitiPower made provision for efficient and prudent non-network alternatives as part of our assessment . In particular, we considered this within our review of CitiPower's augex proposal..
Any other factor the AER considers relevant and which the AER has notified CitiPower 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 techniques

This appendix describes the assessment approaches we applied in assessing CitiPower's total forecast capex. We used a variety of techniques to determine whether the CitiPower total forecast capex reasonably reflects the capex criteria. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure we are assessing. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:[47]

> Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.
>
> Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

Below we set out the assessment techniques we used to asses CitiPower's capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.[48] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[49] It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.[50] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[51]

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

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

[48] NER, cl. 6.5.7(e)(4).

[49] AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines,* November 2013.

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

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

overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.[52] Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.[53]

In addition to the measures in the annual benchmarking report, we considered how distributors performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We calculated these economic benchmarks using actual data from the previous regulatory control period.

The results from economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We considered past trends in actual and forecast capex as this is one of the capex factors under the NER.[54]

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.[55] 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 the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the

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

53 AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

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

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

need for the projects. Growth in a business' network will also drive connections related capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in demand (and customer numbers).

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

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

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

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we use in assessing repex.

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

A.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model (used in a qualitative sense)

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.[56] The models draw

56 NER, cl. 6.5.7(c).

on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.[57]

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. If we consider a distributor’s proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[58] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.[59] In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.[60]

For our preliminary decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation, and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of CitiPower's augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of CitiPower’s capex proposals.[61] We also relied on the technical review of our consultant, Energeia, to assist with our review of distributors' capex proposals. These involved reviewing CitiPower’s processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of CitiPower's capex forecast.

Origin Energy submitted the AER must continue to apply technical assessments in concert with its benchmarking techniques to ensure a prudent balance between asset risk and input costs.[62]

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

58 Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

59 For more information, see: AER, *Guidance document: AER augmentation model handbook,* November 2013.

60 AER, *'Meeting summary – distributor replacement and augmentation capex', Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution),* 8 March 2013, p. 1.

61 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

62 Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 1.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of CitiPower's forecast capex for the 2016–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2016–20 period. These drivers are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

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

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

- Section B.1: alternative estimate
- Section B.2: forecast augex
- Section B.3: forecast customer connections capex, including capital contributions
- Section B.4: forecast repex
- Section B.5: Victorian Bushfires Royal Commission
- Section B.6: forecast capitalised overheads
- Section B.7: forecast non-network capex

In each of these sections, we examine sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined CitiPower's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to CitiPower's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in this appendix B.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 Forecast augex

CitiPower proposes a forecast of $203.3 million ($2015) for augmentation capex (augex), excluding overheads. This is a 9.5 per cent increase compared to actual augex incurred in the 2011–15 regulatory control period.

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

As set out in Table 6.6, CitiPower's proposed augex forecast is comprised of capex to meet demand, capex for non-demand projects, and a small amount of capex for bushfire safety (listed as VBRC). Non-demand capex comprises the largest component of CitiPower's augex, which includes completing the Melbourne CBD security upgrade and decommissioning the CitiPower 22kV sub-transmission network.

Table 6.6 CitiPower's proposed augex ($2015, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Demand	13.6	14.6	10.4	10.2	10.4	59.2
Non-demand	28.0	50.5	35.2	16.8	3.8	134.3
VBRC	0.6	2.6	2.2	2.3	2.1	9.8
Total augex proposal	42.3	67.7	47.8	29.3	16.3	203.3

Source: CitiPower reset RIN; CitiPower regulatory proposal, April 2015; CitiPower response to AER CitiPower 002, 22 June 2015 and 26 June 2015; and CitiPower response to AER CitiPower 018, 5 August 2015,

Note: Numbers may not add up due to rounding.

Our estimate of required augex for CitiPower for the 2016–20 period is $119 million ($2015), which is 41 per cent less than CitiPower's proposal. This is based on removing the $74.7m for the de-commissioning of the 22kV sub-transmission network because we are not satisfied it is required to address a network augmentation driver, and our finding that CitiPower's forecast for maximum demand likely does not reflect a realistic expectation of demand over the 2016–20 period.

We formed this view after reviewing all of the material submitted by CitiPower in its regulatory proposal, its supporting documentation and responses to requests for further information, and submissions from stakeholders. Our review used a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that CitiPower will require to meet its obligations given expected demand growth and other augmentation drivers. This is consistent with the overall approach set out in our Expenditure Forecast Assessment Guideline.[63] First, we considered CitiPower's proposed expenditure in the context of past expenditure, demand and current network utilisation.[64] As set out in section appendix C, we found that CitiPower's forecasts of maximum demand likely do not reasonably reflect a realistic expectation of demand over the 2016–20 period. The available evidence suggests that maximum demand will remain generally flat over the 2016–20 period, which is consistent with the Australian Energy Market Operator's (AEMO) independent forecasts for CitiPower's network.

On the basis of our analysis, and information provided by CitiPower, we consider that a forecast of $49.8 million reflects the prudent and efficient amount to meet a realistic expectation of demand over the 2016–20 period. This is 15 per cent less than CitiPower's proposal, which is due to reductions in CitiPower's forecast augex for high voltage feeders and its low voltage network.

Second, we undertook a technical review of CitiPower's major non-demand projects — its Melbourne CBD security project and its 22kV sub-transmission network decommissioning project. In undertaking these technical reviews, we draw on engineering and other technical expertise within the AER.

On the basis of our analysis, we find that:

- CitiPower's proposed $36.7 million for its proposed Melbourne CBD security project reasonably reflects the capex criteria. CitiPower is required under the Victorian Electricity Distribution Code to upgrade the network security of the Melbourne CBD network. As set out in section B.2.2, based on CitiPower's supporting information, we are satisfied that the proposed capex reflects a prudent and efficient amount to meet this obligation.
- CitiPower's $74.7 million for the 22kV sub-transmission network decommissioning project is not required to address an augmentation driver, and we have not included it in our alternative estimate. As set out in section B.2.2, given CitiPower's documentation relates to asset condition rather than meeting a capacity constraint on the network, we have not included this capex within our alternative estimate of augex. If CitiPower is of the view that, given the condition of the assets, it requires more than business as usual repex to meet the capex objectives then it should provide supporting information to this effect in its revised proposal.

Finally, we separately reviewed CitiPower's proposed capex to implement the recommendations of the Victorian Bushfires Royal Commission (VBRC). Our analysis is contained in section B.5. On the basis of the reasons set out in that appendix, we have included CitiPower's proposed $9.8 million within our alternative estimate of augex.

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63 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, p. 82.

64 This is supported by the AER's augex model to generate trends in asset utilisation. We have not otherwise used the augex model to estimate forecast augex.

It is important to note that our overall capex decision does not approve or reject funding for individual projects. Rather, as set out in our Expenditure Forecast Assessment Guideline, we conduct technical project reviews to help us assess the efficient overall capex required for network augmentation, in conjunction with other techniques such as trend analysis.[65] Within the overall capex and revenue allowance we provide in this preliminary decision, it is up to CitiPower to allocate its capital and operating budget to meet its obligations (including as circumstances changes over time).

Table 6.7 sets out a breakdown of the amount of forecast augex we have included in our alternative estimate, including the differences to CitiPower's proposal.

Table 6.7 AER's alternative estimate of augex ($2015, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
CitiPower proposal	42.3	67.7	47.8	29.3	16.3	203.3
Adjustment to demand-augex	-1.5	-1.8	-1.9	-2.0	-2.2	-9.4
Removal of 22kV augex	-0.8	-27.2	-32.6	-14.2	0.0	-74.7
AER alternative estimate	40.0	38.7	13.3	13.1	14.1	119.2
Difference	-5.4%	-42.8%	-72.1%	-55.3%	-13.5%	-41.4%

Source: AER analysis.

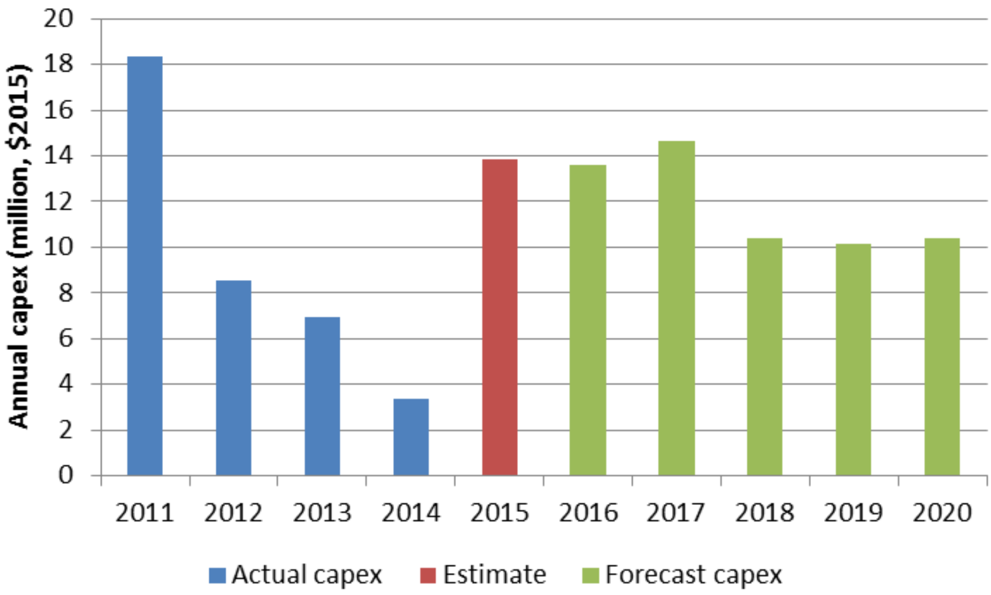
B.2.1 Demand-driven augmentation

CitiPower proposed a forecast of $59.2 million ($2015) for augex, excluding overheads. Figure 6.7 shows that CitiPower's demand-related augex forecast is 16 per cent higher when compared to its actual demand-driven augex in the 2011–15 regulatory control period. This expenditure is approximately six percent of CitiPower's proposed total network capex program for the 2016–20 regulatory period.[66]

65 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, pp. 128–130.

66 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 119–120.

Figure 6.7 CitiPower's demand-driven capex historic actual and proposed for 2016–20 period ($2015, million, excluding overheads)



Source: AER analysis; CitiPower's response to AER CitiPower 002 and 018; CitiPower capex model MOD 1.16.

As set out in Table 6.8, CitiPower has forecast that demand-driven augex is predominantly required for the installation of high-voltage feeders and capex for its low-voltage network (e.g. feeders and distribution substations). It also forecast some augex for zone substations and sub-transmission line augmentation.

Table 6.8 CitiPower demand-augex forecast ($2015, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
Zone Substation	0.1	1.0	0.0	0.0	0.0	1.1
Subtransmission Lines	3.7	3.8	0.3	0.0	0.0	7.8
HV Feeders	6.6	6.7	6.8	6.9	7.0	34.1
Low Voltage	3.1	3.2	3.2	3.3	3.3	16.2
Demand Augex	13.6	14.6	10.4	10.2	10.4	59.2

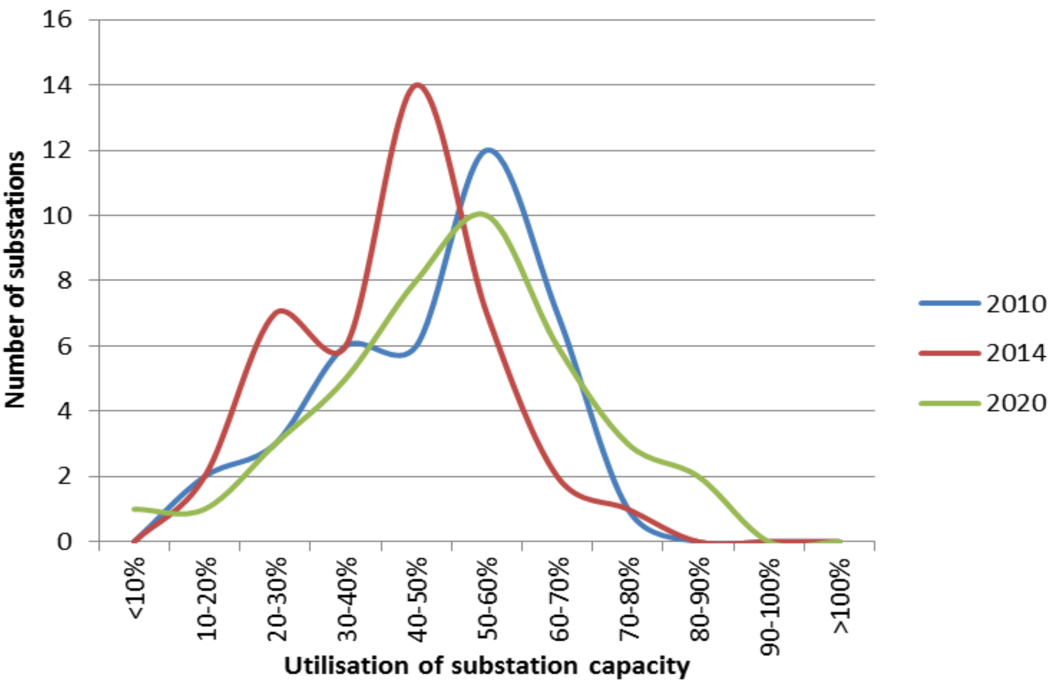
Source: CitiPower regulatory proposal capex model 1.16, April 2015 (updated 11 August 2015 in response to AER information request 018).

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

Figure 6.8 shows CitiPower's zone substation utilisation between 2010 and 2014, and forecast utilisation in 2020 (at the end of the regulatory period). Between 2010 and 2014 CitiPower undertook zone substation augmentation, which is shown in a significant decrease in the number of substations operating above 60 per cent of their maximum capacity. The flattening of maximum demand between 2010 and 2014 also contributed to reduction in the utilisation of the network. As of 2014, there are no substations operating above 80 per cent of their maximum capacity.

The forecast of zone substation utilisation in 2020 is based on CitiPower's forecast demand at each substation and existing levels of capacity (without additional augmentation). The increase in utilisation across its network reflects CitiPower's expectations on demand growth between 2015 and 2020 (shown in Figure 6.8 as a shift to the right in network utilisation forecast in 2020).

Figure 6.8 CitiPower zone substation utilisation 2010 and 2014 actual, and 2020 forecast



Source: AER analysis, CitiPower's reset RIN.

Note: Utilisation is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.[67] Figure 6.8 shows the number of CitiPower's total zone substations at each utilisation band.

CitiPower's proposed demand-driven augmentation is consistent with its forecast of relatively high growth in maximum demand over the 2016–20 period. However, as we

[67] 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.

outline in appendix C, we consider that the available evidence points to flatter demand growth for the 2016–20 period. This suggests that CitiPower's proposed demand augex may be overstated when compared to a more realistic expectation of demand over the 2016–20 period.

To determine the likely overestimation of CitiPower's demand augex, we:

- determined a realistic demand forecast for CitiPower over the 2016–20 period
- compared this to CitiPower's demand forecasts to calculate the likely overestimation in demand forecasts, and
- assessed the impact of adopting a realistic demand forecast to CitiPower's demand-related proposal.

First, based on information available at the time of making this preliminary decision, we consider that the Australian Energy Marker Operator's (AEMO) 2014 connection point forecasts for CitiPower reflect a realistic expectation of demand over the 2016–20 period. This is for the reasons set out in appendix C.

Second, based on a comparison with CitiPower's demand forecasts for the 2016–20 period, we determined the likely overestimation of forecast demand. On the basis of our comparison, Table 6.9 shows that CitiPower's demand forecast is approximately 20 per cent higher than AEMO's by the end of the regulatory period.

Table 6.9 Comparison between AEMO and CitiPower maximum demand forecasts for 2016–20 (MW, POE10, non-coincident)

Category	2016	2017	2018	2019	2020
AEMO	1530.5	1536.9	1546.8	1547.7	1538.5
CitiPower	1803.1	1868.1	1905.8	1935.1	1953.7
Differences in demand	15.1%	17.7%	18.8%	20.0%	21.3%

Source: CitiPower reset RIN; AEMO Victorian 2014 connection point forecasts.

Note: AEMO publishes a demand forecast for each connection point in CitiPower's network. To calculate network-level forecast for CitiPower we summed up each connection point demand forecasts for each year.

Third, to determine the impact of adopting a realistic demand forecast to CitiPower's demand-related proposal, we asked CitiPower to explain the sensitivity of its augex to forecast maximum demand.[68] In particular, we asked CitiPower to demonstrate the change in these capex forecasts for a +/- five per cent change in maximum demand. We asked this because recent evidence we received during our assessment of (NSW

[68] We focused our request on CitiPower's proposed augex for high-voltage feeders and its low-voltage network. CitiPower's augex for a new zone substation and sub-transmission lines forecast is to be incurred in the initial years of the 2016–20 period, and therefore a change in demand is unlikely to defer this capex beyond 2020. For this reason we have not made any adjustments to this capex based on a reduction in CitiPower's demand forecast.

distributor) Ausgrid's augex forecasts for the 2014–19 regulatory control period suggested that there may be linear relationships between changes in demand forecasts and augex for its high voltage network.[69]

In CitiPower's response, it stated that to a five per cent reduction to demand forecasts will have the following effect for augex:

- High voltage feeders — "5 per cent reduction in peak demand forecast: it is expected that a small decrease in forecast peak demand will reduce the number of projects requiring augmentation, possibly to a proportional level. Although this reduction would vary depending on the concentration of the new connections in the growth areas."[70]
- Low voltage network — "5 per cent decrease in peak demand forecast: it would be expected that a small reduction in the forecast peak demand may result in a reduction of 3 to 5 per cent of demand related projects, and thus may decrease the expenditure by around 3 to 5 per cent. These costs would ultimately depend upon the mix of projects to address the overload conditions in that specific area of the network."[71]

This information suggests that reducing demand forecasts may lead to a proportionate reduction in forecast capex for high and low voltage feeders (e.g. five per cent reduction in demand forecasts will lead to a five per cent reduction in capex). This is consistent with evidence we received during our assessment of Ausgrid's augex forecasts for the 2014–19 regulatory control period. We note that this is not necessarily precise, and it may vary in reality as circumstances change. However, in the absence of other information about the quantification of the relationship between forecast demand and augex, we consider that it is reasonable to conclude that there is a proportionate and linear relationship between forecast demand and augex for high voltage feeder and low voltage capex.

On this basis, our alternative estimate for CitiPower's demand-related augex forecast is $49.8 million, which we consider results in a prudent and efficient amount to meet a realistic expectation of demand over the 2016–20 period. In coming to this, we reduced CitiPower's proposed capex for high voltage feeders and low voltage capex proportionate to the reduction in demand forecasts between CitiPower and AEMO's forecasts over the 2016–20 period. These results are set out in Table 6.10. This indicates a reduction in demand driven augex of $9.4 million over the period.

[69] Analysis of Ausgrid's modelling demonstrated that there was a positive linear relationship between a change in forecast demand and a change in its expenditure requirements for HV feeders. See AER, *Draft decision Ausgrid distribution determination, Attachment 6*, November 2014, p. 6.

[70] CitiPower response to AER CitiPower 022, 19 August 2015, p. 2.

[71] CitiPower response to AER CitiPower 022, 19 August 2015, p. 2.

Table 6.10 Adjustment in augex due to reduction in demand forecasts ($2015, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
HV Feeders	-1.0	-1.2	-1.3	-1.4	-1.5	-6.4
Low Voltage	-0.5	-0.6	-0.6	-0.7	-0.7	-3.0
Total	-1.5	-1.8	-1.9	-2.0	-2.2	-9.4

Source: AER analysis.

We understand that CitiPower is in the process of updating its demand forecasts as part of the 2015 distribution annual planning report. We also note AEMO will publish updated connection point demand forecasts for Victoria. We will consider updated demand forecasts and other information (such as AEMO's revised connection point forecasts) in our final decision to reflect the most up to date data.

A number of submissions commented on network utilisation:

- The Consumer Challenge Panel submitted that CitiPower's existing utilisation data and declining peak demand supports a view that there is little need for augmentation capex.[72] The CCP accepted that each Victorian DNSP identifies that there are pockets of demand growth in its network that require augmentation. However, it also notes that there are also pockets of declining usage, meaning there is the potential to utilise assets no longer needed in some parts of the network and relocate them to where growth is being experienced.[73]
- The VECUA and the Victorian Greenhouse Alliances also submitted that there were significant investments in the Victorian networks over recent regulatory periods which have led to excess levels of network capacity and declining network utilisation.[74] Both submitted that we should consider this evidence closely in our capex assessment.

As noted by these stakeholders, we agree that current levels of network utilisation are important factors to consider in reviewing augmentation requirements over time. However, in terms of determining a level of augex for the 2016–20 period, it is also necessary to consider future demand and forecast network utilisation over this period. We considered this above.

[72] CCP 3, *Response to proposals from Victorian electricity distribution network service providers – overview, 10 August 2015*, p. 17.

[73] CCP 3, *Response to proposals from Victorian electricity distribution network service providers – overview, 10 August 2015*, p. 17.

[74] VECUA, *Submission to the AER Victorian Distribution Networks' 2016–20 Regulatory Proposals*, 13 July 2015, p. 4 and 22–24; Victorian Greenhouse Alliance, *Local Government Response to the Victorian Electricity Distribution Price Review 2016–20*, 13 July 2015, pp. 33–34.

We note the comments of CCP in relation to the ability to relocate assets. Advice from our technical and engineering staff suggests that it is generally not technically or economically feasible to relocate distribution assets to other parts of the network. We understand that any ability to relocate assets would be rare and would not impact materially on the required expenditure for the 2016–20 period.

B.2.2 Non-demand augex

CitiPower proposes $134 million ($2015) for non-demand related capex projects over the 2016–20 period. Table 6.11 sets out the components that comprise CitiPower's non-demand augex proposal.

Table 6.11 CitiPower's proposed non-demand augex ($2015, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
CBD security project	20.4	16.3	0.0	0.0	0.0	36.7
WMTS 22kV decommissioning project	0.8	27.2	32.6	14.2	0.0	74.7
SCADA	2.7	2.5	2.6	2.6	3.1	13.6
Other	4.1	4.5	0.0	0.0	0.8	9.3
Total non-demand augex	28.0	50.5	35.2	16.8	3.8	134.3

Source: CitiPower, *Regulatory proposal 2016–20*, April 2015; CitiPower response to AER CitiPower 002, 22 June 2015 and 26 June 2015; CitiPower response to AER 018, 5 August 2015; CitiPower regulatory proposal, capex model MOD 1.14, April 2015 (updated 11 August 2015).

Note: Numbers may not add up due to rounding.

We have assessed CitiPower's two largest non-demand projects — the Melbourne CBD security of supply upgrade and decommissioning of the West Melbourne Terminal Station 22kV sub-transmission network. Our assessment of these two projects is contained in the remainder of this section.

Our alternative estimate of CitiPower's non-demand augex is $60 million ($2015). In coming to this view, we consider that the capex associated with decommissioning CitiPower's WMTS 22kV sub-transmission network is driven by asset condition rather than a need to increase capacity in the network. Therefore, our alternative estimate removes this capex from CitiPower's proposed augex forecast.

Decommissioning WMTS 22kv sub-transmission network

CitiPower proposes $74.7 million ($2015) as part of a large new project to decommission its 22kV sub-transmission network and upgrade its 66kV sub-transmission network. This project is comprised of two sub-components:

- $30.9 million to upgrade the 66kV sub-transmission network to allow transfers from the existing 22kV network

- $43.7 million to upgrade the 11kV network to support the sub-transmission upgrade.

This project relates to the CitiPower's 22kV sub-transmission network supplied from the West Melbourne Terminal Station (WMTS). This 22kV system includes zone substations at Bouverie Street, Dock Area, Spencer St, and Laurens Street, and a supply to Vic Rail. CitiPower submitted that these substations are "all ageing, in poor condition and will require significant capital investment in the near term to maintain reliable supply to the inner areas of Melbourne."[75] CitiPower proposes to upgrade the 66kV sub-transmission network connected to WMTS, decommission three of these zone substations entirely and transfer supply to the 66kV network. This will also require augmentation to 11kV feeders to support the transfer of supply to the new network.[76]

CitiPower noted that AusNet Services (Transmission) is planning to rebuild the WMTS as part of the WMTS redevelopment project by 2019. CitiPower stated that decommissioning its 22kV sub-transmission network will allow AusNet Services to avoid replacing the 22kV switchyard and 220/22kV transformers in the terminal station. CitiPower estimated that AusNet can avoid $41 million ($2015) capex, if CitiPower decommissions its 22kV sub-transmission network as proposed.[77]

As noted, CitiPower stated that its 22kV sub-transmission network and associated zone substations are reaching the end of their life. In particular, CitiPower stated that the need for this capex is due to:

- many of the ageing assets are in poor condition, including transformers and indoor switchboards,[78] and
- some of the zone substations have secondary voltages of 6.6kV, which limits network flexibility, has technical limitations and is inconsistent with the present 11kV standard in the CBD and inner suburbs.[79]

Based on CitiPower's documentation, we are not satisfied that this project is justified by the need to expand the capacity or capability of the network. It is not clear that CitiPower would have proposed this augmentation project if it were not for CitiPower's assessment of the condition of the relevant assets. As CitiPower has not appropriately justified the need for the expenditure on the basis of an augmentation driver, we have not included it within our alternative estimate of augex.

In appendix B.4, we assess and provide an estimate of CitiPower's likely repex requirements in the next period, largely based on continuing asset replacement

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75 CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.47*, April 2015 (updated 5 August 2015), p. 1.

76 CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.47,* April 2015 (updated 5 August 2015), p. 1.

77 CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.47*, April 2015 (updated 5 August 2015), p. 11.

78 CitiPower states that its 22kV sub-transmission network has been in service since the 1940s. It also states that many assets in the Bouverie Street, Spencer St, and Laurens Street zone substation (e.g. transformers) are due to be replaced by at least 2020. See CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.47*, April 2015 (updated 5 August 2015).

79 CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.47*, April 2015 (updated 5 August 2015), p. 3.

practices that it undertook to meet the capex objectives into the next period (i.e. business as usual repex). If CitiPower is of the view that, given the condition of the assets, it requires more than business as usual repex to meet the capex objectives, then it should provide supporting information to this effect in its revised proposal (including updating any historical and forecast expenditure of this type in the form of an updated response to RIN template 2.2, and other supporting material such as business cases, options analysis and cost benefit analysis).

CBD security and capacity project

CitiPower proposed $36.7 million ($2015) for its Melbourne CBD security and capacity project. This project is to upgrade the security of electricity supply in the Melbourne CBD to an 'N-1 Secure' standard. This is intended to mitigate the risk to electricity supply in the CBD from faults on CitiPower's sub-transmission network.

We have assessed the following proposed capex for this project:[80]

- $16.3 million for switchgear and protection equipment at the CBD Waratah Place zone substation, and associated feeder upgrades (classified by CitiPower as the 'CDB Security of Supply' project)[81]
- $17.7 million to finalise the rebuild of the Waratah Place zone substation (which is necessary to complete the security of supply capital works)[82]
- $2.7 million to establish new sub-transmission connections between the Brunswick Terminal Station and the CBD.[83]

CitiPower is required to upgrade the security of the Melbourne CBD in accordance with clause 3.1A of the Victorian Electricity Distribution Code. This Code is set by the Essential Services Commission of Victoria (ESCV) and compliance with this Code is a condition of CitiPower's distribution licence. In summary, clause 3.1A requires that:

- CitiPower must take steps to strengthen the security of supply in the Melbourne CBD.
- CitiPower must submit to the ESCV an upgrade plan that specifies objectives and capital works to strengthen the Melbourne CBD security of supply.

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80 This capex is identified in CitiPower's capex model (MOD 1.14, updated on 5 August 2015), Attachment E.46 to its regulatory proposal, and its response to AER information requests 002 and 018. We had some difficulty determining the total proposed capex for this project due to differences in the way the capex is set out in CitiPower's capex model and the supporting documents. To determine the total capex for this project, we examined the specific capital works within CitiPower's supporting documents and reconciled this with the relevant projects in the capex model. If we have mischaracterised the total proposed cost for this project, CitiPower can identify this within its revised proposal.

81 Referred to as 'Security of Supply' in CitiPower's capex model (updated on 11 August 2015).

82 Referred to as 'RTS Offloading of the 22kV system' in CitiPower's capex model (updated on 11 August 2015).

83 Referred to as 'Transmission connection point' in CitiPower's capex model (updated on 11 August 2015).

- If approved by the ESCV, CitiPower must carry out the scope and timing of the capital works within the plan and ensure that it maintains the security of supply in the Melbourne CBD.

The ESCV accepted CitiPower's CBD security of supply upgrade plan in 2008 and CitiPower subsequently commenced capital works on this project.[84] The upgrade plan approved by the ESCV sets out prescribed capital works and requires that work be completed by 2017. CitiPower stated that it intended to complete this project in the current regulatory control period, but this was delayed due to issues with obtaining a planning permit for the Brunswick Terminal Station works.

We have compared the scope of works sets out in CitiPower regulatory proposal (and supporting documentation) with the scope of works in the CBD security of supply upgrade plan as approved by the ESVC. We are satisfied that the scope and timing of regulatory proposal accords with the CBD security of supply upgrade plan's scope and timing of work. Because the upgrade sets out prescribed capital works, we consider that there are no reasonably alternative prudent options other than undertaking the work set out in the plan.

The Victorian Department of Economic Development of Economic Development, Jobs, Transport and Resources submitted that we should consider whether CitiPower's CBD security of supply capex should be classified as a contingent project. This is because of "delays in the CBD security upgrade and metro projects arising from community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station".[85]

We asked CitiPower about the status of the planning permit for the Brunswick Terminal Station works, and how further delays in obtaining a permit will impact on the proposed capex. CitiPower stated that AusNet Services (which is responsible for constructing the station) obtained a planning permit for the upgrade of Brunswick Terminal Station from the Moreland City Council in September 2014, and construction work has commenced.[86] CitiPower confirmed that it "expects to complete its CBD Security of Supply works in 2017 when the required 66kV switching will be available at Waratah Place zone substation to switch load between Richmond Terminal Station and Brunswick Terminal Station".[87]

We are satisfied with CitiPower's response and consider the project is likely to be completed within the 2016–20 period. We also note that the threshold for capex to be included as a contingent project is $30 million or 5 per cent of the annual revenue requirement in the first year of the regulatory period.[88] The specific capex associated with the Brunswick Terminal Station (e.g. sub-transmission connections) is less than

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[84] CitiPower, *Regulatory Proposal 2016–2020*, *Attachment E.46*, April 2015, pp. 5–6.

[85] DEDJTR, *Submission to Victorian electricity distribution pricing review 2016 to 2020*, 13 July 2015, p. 7.

[86] CitiPower response to AER CitiPower 021, 14 August 2015, p. 1.

[87] CitiPower response to AER CitiPower 021, 14 August 2015, p. 2.

[88] NER, cl. 6.6A.1(b)(2)(iii).

$30 million and therefore it does meet the threshold to be included as a contingent project.

On the basis of the reasons set out above, we accept the proposed $36.7 million ($2015) forecast for this project and will include it in our alternative estimate of total capex.

B.3 Forecast customer connections capex, including capital contributions

Connections capex is incurred by CitiPower to connect new customers to its network and where necessary augment the shared network to ensure there is sufficient capacity to meet the new customer demand.

New connection works can be undertaken by CitiPower or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer contribution, CitiPower is required to take into account the forecast revenue anticipated from the new connection. These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all consumers. Customer contributions are sometimes referred to as capital contributions or capcons.

The mix between net capex and capcons is important as it determines from whom and when CitiPower recovers revenue associated with the capex investment. For works involving a customer contribution, CitiPower recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where CitiPower recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the calculation of CitiPower's annual revenue requirement.[89] CitiPower recovers net capex investment across the life of the asset through revenue received for the provision of standard control services. CitiPower has forecast gross connections capex of $265.1 million ($2015) for the 2016–20 period, with $91.3 million ($2015) forecast to be recovered from customer contributions. Table 6.12 shows CitiPower's forecast for connections.

Table 6.12 CitiPower proposed connections capex ($2015-16, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Gross connections capex	60.7	51.7	48.8	51.5	52.3	265.1
Customer contributions	22.8	18.7	15.9	17.1	16.7	91.3
Net connections capex	37.9	33.0	32.9	34.4	35.5	173.8

Source: CitiPower, Response to AER information request 013, 30 July 2015.

89 For more information on the building blocks included in the determination of CitiPower's annual revenue requirement see our attachments on the regulatory asset base and regulatory depreciation.

B.3.1 AER Position

We do not accept CitiPower’s forecast for connections capex. We have instead included an amount of $236.2 million ($2015−16) in our substitute estimate of forecast gross connections capex. Further we do not accept CitiPower's customer contributions forecast and have included an amount of $58.8 million ($2015−16). Our substitute estimate is shown in Table 6.13.

In summary, we are not satisfied CitiPower’s forecasting methodology for gross capex or capital contributions represents a better estimate of CitiPower’s capex requirements than trending forward historical expenditure from the 2011–15 regulatory control period. However, we note that this approach results in a net impact of our substitute estimate being broadly consistent with the net connections capex forecast by CitiPower.

Given the tax treatment of customer contributions, we have used our estimate of gross capex and capital contributions in this preliminary decision. We note that CitiPower receives a tax building block in the determination of its revenue cap for the customer contributions it is forecast to receive. We note, while the CitiPower does not earn a return on or return of capital for the value of customer contributions (i.e. it is not rolled into the RAB) CitiPower does receive an immediate positive cash flow through the tax building block. With this in mind, we consider it is important that the components of net capex are robustly estimated and reasonably reflect the required gross expenditure or likely receipts.

Table 6.13 AER adjusted connections capex ($2015-16, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Gross connections capex	51.6	49.6	44.2	46.0	44.8	236.2
Customer contributions	13.5	12.7	10.6	11.2	10.8	58.8
Net connections capex	38.1	37.0	33.6	34.8	34.0	177.4

Source: AER analysis.

To reach our substitute estimate of CitiPower's connections forecast, we considered:

- the trends in CitiPower’s connections capex across time, and
- CitiPower’s forecast methodology and the data relied on to produce the forecast.

We note that stakeholders have raised some concerns with the classification of connection services.[90] Our assessment of service classification is discussed in the classification of services chapter (see Attachment 13).

90 Consumer Challenge Panel 3 – Victorian DNSPs revenue reset comments on DNSPs proposal, pp. 54–56;

B.3.2 Trend analysis

As we note in section A.2, when assessing CitiPower’s connections capex we have considered the trends in actual and forecast capex.[91] We have used this analysis to provide context to CitiPower’s proposal, in particular trend analysis has allowed us to:

- gauge the degree to which CitiPower’s proposal is consistent with past connections capex
- understand variations between CitiPower’s capex allowances for connections and that incurred in the 2011–15 regulatory control period, and
- the basis of the key drivers underlying CitiPower’s forecast methodology connections capex for the 2016–20 regulatory control period.

As explained in the next section, we have also used trend analysis as a basis for our substitute estimate where our analysis has shown that the forecast methodology used by CitiPower may lead to a biased estimate.

B.3.3 Basis of AER’s substitute estimate

In determining our alternative estimate of required net connections capex and customer contributions for the 2016–20 regulatory control period, we have:

- adopted CitiPower's forecast for connection types we consider reasonable
- where we are not satisfied with CitiPower's approach we have substituted the historical trend in expenditure.

With respect to the forecasts of low volume connections, we are satisfied that CitiPower’s forecast approach provides a realistic expectation of the connections capex it requires for the 2016–20 regulatory control period. Accordingly, we have included CitiPower's forecast for low volume connections in our alternative estimate.

However, for the reasons set out in the following sections, we consider that CitiPower's methodology for estimating the high volume categories overstates the required expenditure. To determine a substitute for these categories we have trended forward the actual expenditure from the 2011–15 regulatory control period.

While we note that there are pockets of growth in the CitiPower network, as discussed below in appendix C, peak demand growth across the whole of CitiPower’s network is likely to be relatively flat. We consider that forecast stability in peak demand indicates that observed trends in network growth capex (including connections) are reasonable indicators of future capex requirements. We are satisfied that it is reasonable to rely on recently observed trends as a basis for establishing a substitute estimate.

Vector, *Submission on the AER’s Issues Paper on Victorian Electricity Distribution Pricing Review for 2016–2020*, 13 July 2015, pp. 4–5.

[91] This is one of the capex factors to which we are required to have regard to under the NER (NER, cl. 6.5.7(a)(5)).

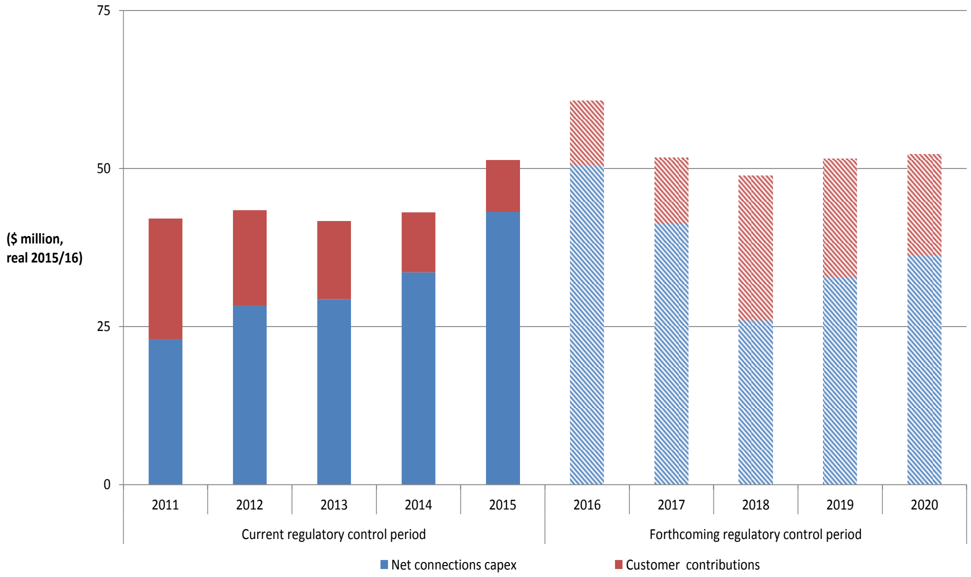
We further note that CitiPower has relied on trending the low volume connection projects for which there are no known projects. We are satisfied that this approach is reasonable and consider it valid for all categories where volumes and unit costs are likely to be relatively constant.

We recognise that our substitute estimate cannot perfectly predict CitiPower's connections capex for the 2016–20 regulatory control period, in the same way that no prediction of future needs will be absolutely precise. We do, however, consider our approach is based on verifiable data. Further, we are satisfied historical capex is an appropriate basis on which to determine forecast connections capex because the drivers of customer connections remain relatively constant across regulatory control periods.

Actual and forecast customer connections

Figure 6.9 shows the trend in CitiPower's actual and forecast gross connections capex by both net connections capex and customer contributions.

Figure 6.9 CitiPower connections capex and capital contributions - actual historical and 2016-20 regulatory control period forecast ($2015-16, million)



Source: CitiPower, *Response to AER information request IR# 012*, 24 July 2015.

Figure 6.9 shows that between 2011 and 2014 gross connections capex was relatively stable. There has been a relatively small decline in capital contributions, resulting in increases in the prominence of net capex.

We note there is a timing mismatch as CitiPower is required to submit its regulatory proposal before the calendar year 2015 is complete.[92] This means the expenditure and volumes that CitiPower has reported for 2015 are estimates and represent a significant increase on previous years spend. Given this, we have not used the 2015 data for the purposes of comparing actual expenditure observed in the last regulatory control period with the expenditure forecast by CitiPower for the next regulatory control period. Excluding the estimated 2015 year, we consider CitiPower's capex proposal for the 2016–20 regulatory control period represents, on average, annual increases of 31.0 per cent in net connections capex and an 11.4 per cent increase in annual capital contributions.[93]

Historic spend

In determining whether we are satisfied that CitiPower's forecast connections capex meets the criteria in the rules we must also have regard to CitiPower's actual and expected capex during any preceding regulatory periods.[94] We note that CitiPower is forecasting to overspend its connections regulatory allowance in the 2011–15 regulatory control period by 2 per cent.[95] CitiPower considers the actual expenditure is broadly consistent with the AER's allowance, and it appears that the broader economic slowdown did not have a significant impact on building activity in inner Melbourne.[96] Figure 6.10 compares CitiPower's actual connections capex and customer contributions in the 2011–15 regulatory control period with the allowances included in the determination.

92 CitiPower submitted its regulatory proposal to the AER on 30 April 2015, in advance of the actuals for calendar year 2015 being finalised.

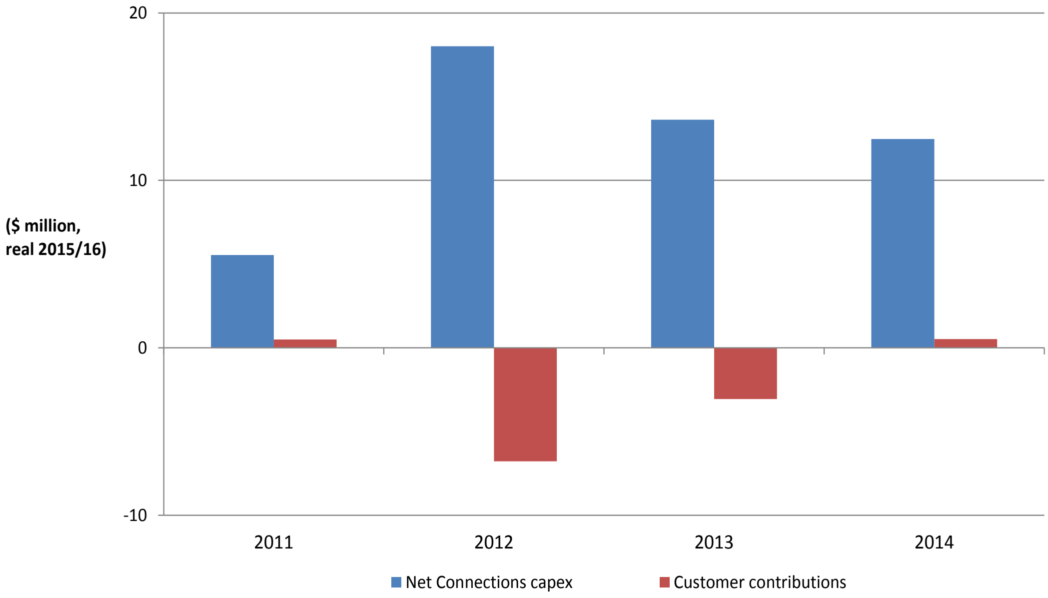
93 Averaging the 2011–14 actual in place of the 2015 estimate.

94 NER cl. 6.5.7(e)(5).

95 CitiPower, *2016–20 Price Reset Appendix E Capital Expenditure,* April 2015, p. 113.

96 CitiPower, *2016–20 Price Reset Appendix E Capital Expenditure,* April 2015, p. 113.

Figure 6.10 Difference between actual and forecast connections capex and customer contributions 2011–15 regulatory control period ($2015/16, million)



Source: CitiPower, Response to AER information request 013, 30 July 2015.

We note that across time, changes to definitions of expenditure, service classifications or cost allocation methods can impact the availability of comparable data. On this basis we sought feedback from CitiPower on whether changes to service classifications or cost allocation methods may explain the differences illustrated in figure B–4. CitiPower noted the differences between the 2011–15 forecast and actuals figures were a result of their previous forecasting the volume of connections.[97] CitiPower considers that changes in the classifications of services did not have an impact.[98]

In determining whether we are satisfied that CitiPower's forecast connections capex meets the criteria in the rules we must also have regard to CitiPower's actual and expected capex during any preceding regulatory periods. We note that CitiPower is forecasting to overspend its connections regulatory allowance in the 2011–15 regulatory control period by 2 per cent. CitiPower considers the actual expenditure is broadly consistent with the AER's allowance, and it appears that the broader economic slowdown did not have a significant impact on building activity in inner Melbourne. Figure 6.10 compares CitiPower's actual connections capex and customer contributions in the 2011–15 regulatory control period with the allowances included in the determination.

Figure 6.10 shows that compared with its allowance in the 2011–15 regulatory control period, CitiPower overspent on net connections capex and received fewer customer

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97 CitiPower, *Response to AER Information Request IR# 013*, 30 July 2015.

98 CitiPower, *Response to AER Information Request IR# 013*, 30 July 2015.

contributions than forecast. This resulted in a forecast of CitiPower's gross connections capex that was relatively close to actual capex. We note that a major feature of the regulatory framework is the incentives CitiPower has to achieve efficiency gains whereby actual expenditure is lower than the allowance. Differences between actual and allowed connections capex could be the result of efficiency gains, forecasting errors or some combination of the two. CitiPower noted it has improved its forecasting methodology for the 2016–20 regulatory control period by incorporating economic modelling as well as utilising key economic and demographic variables.[99] On this basis CitiPower considers it is not appropriate to compare the actual and allowed standard control connections capex.[100] We have considered CitiPower's forecasting methodologies when considering if the proposed expenditure forecast is justified.[101]

B.3.4 CitiPower's forecasting methodology

CitiPower has combined two separate methodologies for forecasting customer connections, depending on whether the category of connection has a high or low volume of activity:

- for connection activities with high volumes, CitiPower has adopted a two stage process. CitiPower relied on an external consultant, the Centre for International Economics (CIE) to produce volume forecasts to which CitiPower applied historical unit rates to generate a gross capex forecast [102] , and
- for low volume categories of connections CitiPower has generated its forecast using a bottom-up build of major projects.[103]

These forecasts are in gross terms, that is, they include customer contributions. CitiPower has derived a customer contribution rate by sampling historical projects that it applied to the gross forecasts to produce forecasts of net connections capex and customer contributions.[104]

Table 6.14 shows CitiPower's forecasts for connections capex.

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[99] CitiPower – Response to AER Information Request 013, 30 July 2015.

[100] CitiPower – Response to AER Information Request 013, 30 July 2015.

[101] As per NER cl. 6.5.7.

[102] CitiPower *2016–20 Price Reset Appendix E Capital Expenditure*, April 2015, p. 109, Table 5.1. High volume categories of connection follow the RIN definitions of residential complex at LV, residential complex HV works connected at LV, and commercial/industrial HV works connected at LV.

[103] Low volume categories of connection follow the RIN definitions of commercial/industrial connected at HV, embedded generation, and recoverable works (reported as quoted services). In determining its forecasts for these low volume categories, CitiPower used forecasts of customer connections estimated using a bottom-up build of major projects.

[104] CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 110.

Table 6.14 CitiPower proposed connections capex ($2015-16, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
High volume categories forecasts						
Gross connections capex	51.2	44.1	46.7	47.5	49.5	239.0
Customer contributions	19.2	15.9	15.2	15.8	15.8	82.0
Net connections capex	31.9	28.2	31.5	31.7	33.6	156.9
Low volume categories forecast						
Gross connections capex	9.6	7.6	2.2	4.0	2.8	26.1
Customer contributions	3.6	2.7	0.7	1.3	0.9	9.3
Net connections capex	6.0	4.9	1.5	2.7	1.9	16.9

Source: CitiPower, *Response to AER information request IR# 013*, 30 July 2015.

In determining whether we are satisfied CitiPower's forecast meets the capex criteria, we have assessed the above forecasting methodologies.

High volume categories of connections

CitiPower derives its high volume forecast by multiplying volumes as calculated by the CIE by its estimate of unit costs.[105] CIE produced forecasts for residential and commercial/industrial volume categories.[106] It did this by:

- assessing historical correlations between each connection type and economic and demographic variables, identifying population growth, dwelling growth and economic activity as key drivers of connections expenditure on CitiPower's network[107]
- isolating the sensitivity of changes in these variables have on the amount of connection activity[108], and
- applying the sensitivities to independent forecasts of the identified key drivers.[109]

105 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014.

106 CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC ATT 9.13 - The Centre for International Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, Chapter 7.

107 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E*: *Capital Expenditure*, April 2015, p. 108.

108 CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC ATT 9.13 - The Centre for International Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, Chapter 5.

109 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E*: *Capital Expenditure* ,April 2015, p. 110.

To determine whether we are satisfied this methodology produces a forecast of capex that CitiPower requires to achieve the capex objectives, we have assessed:

- the correlations of observable trends in the economic and demographic variables and CitiPower's historic connections volumes
- the projections of the economic and demographic variables underlying the forecast relied on by CitiPower, and
- the use of historical unit costs on each of the volume projections.

We describe our assessments for each forecast of residential and commercial/industrial connection categories in the following discussion.

Residential Connections

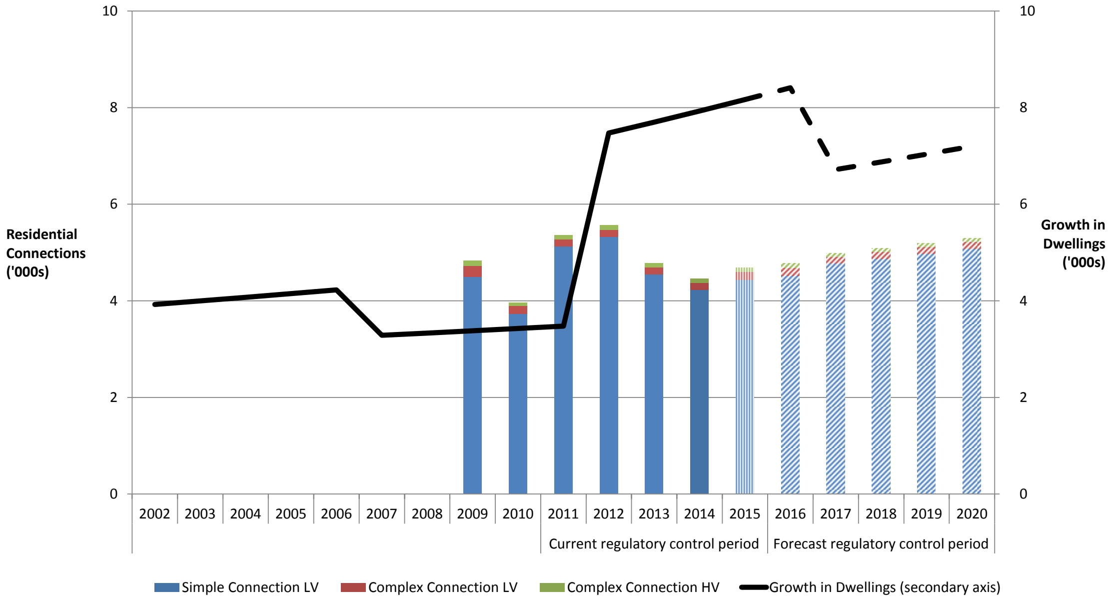
We are not satisfied that CitiPower has demonstrated that the forecast volumes of residential type connections represent a realistic expectation of this type of connection activity that CitiPower will be required to undertake over the 2016–20 regulatory control period. In determining this we consider that CIE may not have:

- accurately identified the key drivers of residential connection activities, and
- relied on a consistent historical and forecast dataset.

Figure 6.11 below shows the historical residential customer connections on CitiPower's network and the volumes forecast for the 2016–20 regulatory control period. We have also included the trends in dwelling growth as this is the variable CIE identified as the key driver of the number of residential connections projects.[110]

[110] CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014.

Figure 6.11 CitiPower residential connections and identified key drivers



Source: AER analysis.[111]

CIE is forecasting the number of residential connections for both LV and HV to grow in line with the forecasts of dwelling approvals.[112] The historical dwelling data is published by the ABS once every five years. To produce the trend shown in Figure 6.11, CitiPower interpolates this data to produce the yearly time series shown.[113]

We note Figure 6.11 shows an increasing trend in the growth of dwellings in CitiPower's distribution area. Further, we note there are significant positive and negative spikes that coincide with the periodic publication of the ABS dwelling data. Given the timing of these spikes we consider the historical data CIE has relied on represents the average change in total dwellings across time rather than the actual year on year trend in total dwellings.

Further, we note the time series data beyond 2011 applies the same interpolation technique to a different source than the earlier years, the 2016 projection of dwellings made by the Victorian Department of Transport, Planning and Local Infrastructure.

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111 Connection data: CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC RIN 1.1*; CitiPower, Vic Reset RIN 2016–20 - Consolidated Information, CP PUBLIC RIN 1.19 CitiPower, 2009–2013 Category Analysis RIN and CP PUBLIC RIN 1.20 CitiPower, 2014 Category Analysis RIN.

Dwelling growth: CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC MOD 1.50 - CIE customer number forecasts February 2015 and years prior to 2006, AER application of CIE interpolation method.

112 CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC ATT 9.13 - The Centre for International Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 38.

113 CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC MOD 1.50 - CIE customer number forecasts February 2015, "C. Dwelling forecasts".

The projections of total dwellings form a key input into CIE's forecast of residential connections. In turn, these dwelling projections rely on historical and forecasts of the estimated resident population (ERP) within CitiPower's network.

After establishing the trend and the projections of changes in population and dwelling growth, CIE then determined the correlation of these variables to the number of residential connections.[114] CIE noted that there are difficulties associated with the limited amount of time series data available and the inherent volatility and potential inaccuracy of data at a local and regional level.[115] CIE applied statistical modelling techniques to overcome these difficulties, from which CIE determined a model fit which it considered most appropriate for forecasting residential customer connections.[116]

For each connection type CIE compared how this model fit performed in predicting residential connections when inputting the selected driver variables.[117] In doing so CIE determined that:

- the number of private sector house approvals is the key driver of residential complex LV projects, and[118]
- the change in population is the key driver of residential complex HV projects.[119]

We note that in determining these relationships, CIE has relied on a limited series of observations comparing the predicted connections with the actual residential connections.[120] Also, CIE's model for LV connections, which uses housing approvals as its key driver, shows a weaker predictive power than the HV connection model that relies on population growth.[121] Further, we consider the actual data used to observe the relationship between the drivers and residential connections is not consistent with the projections used in the forecast.

However, despite these identified shortcomings in the modelling techniques, we have found that the impact on the gross connections capex forecast was minimal. As shown

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114 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International* Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 9.

115 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 13.

116 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 14–15.

117 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 14.

118 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 15.

119 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 16.

120 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 15–17.

121 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, comparing Figure 2.13 and 2.15.

in Table 6.15, the main difference in net capex for residential connections is a significant step-up in customer contributions forecast by CitiPower.

Table 6.15 CitiPower residential connections, actual and proposed (million, $2015-16, excluding overheads)

	2011–15 expenditure	2016–20 proposal
Gross connections capex	152.4	155.8
Customer contributions	35.9	53.5
Net connections capex	116.5	102.3

Source: CitiPower, *Response to AER information request IR# 012* (averaging the 2011-14 actual in place of the 2015 estimate), 24 July 2015.

We discuss the basis of our substitute estimate in a section B.3.3 and in the section below on our estimate of customer contributions.

Commercial/industrial Connections

We are not satisfied that CitiPower uses a realistic expectation of the volume of commercial/industrial type connection activities that it will be required to undertake over the 2016–20 regulatory control period. In estimating the volume of commercial/industrial connection activities, CitiPower have again relied on statistical modelling undertaken by CIE.

In summary:

- CIE relies on econometric modelling that identifies that together the value of non-residential building approvals and Gross State Product (GSP) are statistically significant indicators of connection activity.[122] We note CIE has only used GSP in the forecasting process as independent building approvals data is unavailable
- We accept it is plausible for there to be a correlation between GSP and commercial/industrial connection activities. However, we are not satisfied the CIE model has reliably proven a quantitative link that can be used to reliably forecast commercial/industrial connection volumes, and
- CIE relies on inconsistent GSP forecasts to determine the value of the coefficient in its model and in applying this model to determine a forecast.

Given these shortcomings we have trended forward past expenditure levels as we consider that this better reflects the expenditure likely to be required by CitiPower to meet its commercial/industrial connection activities.

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122 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 23.

CIE econometric modelling

Figure 6.12 below shows the actual historical commercial/industrial customer gross connections capex and CitiPower's forecast for the 2016–20 regulatory control period. We have also included the trend in GSP as CitiPower relied on this as a key input into its forecasts of these types of connections projects.[123]

Figure 6.12 CitiPower commercial/industrial customer connections historic actual and proposed for 2016–20 regulatory control period

Source: AER analysis.[124]

In its report CIE notes:

> The key determinant of the number of commercial/industrial electricity connections is the number of employing businesses, which is partly driven by GSP growth. A rise in the number of businesses will generally increase demand for non-residential buildings and in turn connection projects.

CIE assessed the historic correlation between connection projects and the change in population, the number of dwelling approvals, and state final demand across the

123 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015.

124 Connection data: CitiPower, CP PUBLIC RIN 1.1 CitiPower, Vic Reset RIN 2016–20 - Consolidated Information, CP PUBLIC RIN 1.19 CitiPower, 2009–2013 Category Analysis RIN and CP PUBLIC RIN 1.20 CitiPower, 2014 Category Analysis RIN.

GSP – *AEMO National Electricity Forecasting Report (NEFR) 2015*, NEFR Supplementary Information, 2015.

electricity networks of Victoria, South Australia and Queensland. CIE determined there is a moderately positive correlation between commercial/industrial connection projects and the change in population, building approvals and economic activity.[125]

CIE has applied statistical modelling techniques to determine a model fit which it considered most appropriate for forecasting commercial/industrial customer connections. CIE tested the model by comparing its performance in predicting connections using the change in GSP and the total value of non-residential building approvals as the driver variables. CIE determined there is a statistically significant relationship between these driver variables and the number of connections. However, when CIE fits the model only with GSP, it does not find a significant relationship between change in GSP and commercial /industrial connections.[126] Despite this finding, given the availability of independent forecast data, CIE has only used projections of GSP to forecast commercial/industrial connections. CIE appear to acknowledge the shortcoming in this approach and state that they have placed higher weight on historical averages than the forecast GSP growth. However, from the information provided it is not clear how this weighting process was undertaken.[127]

We note in its report, CIE does not find a significant univariate relationship between change in GSP and the level of commercial/industrial connection activity.[128] With this in mind, we are not satisfied the quantitative relationship between GSP and commercial/industrial connections has been identified.

Use of different GSP forecasts

Once CIE determined the model specification for forecasting commercial/industrial connections, it used forecasts of GSP relied on by the Australian Energy Market Operator (AEMO) as part of its National Electricity Forecasting Report.[129] Further, CIE has relied on qualitative analysis from the Victorian Treasury of the drivers of the forecast GSP growth.[130] Given the GSP used by AEMO has a different profile to that forecast by Victorian Treasury, we consider that the drivers underlying the two forecasts are not necessarily the same. As such, we are not satisfied that the forecasts of GSP relied on to produce CitiPower's forecast of commercial/industrial customer connections have been justified.

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125 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 22.

126 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 25.

127 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 29.

128 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 25.

129 AEMO, *National Electricity Forecasting Report Supplementary Information 2015* - AEMO commissioned KPMG to develop forecasts of Gross State Product.

130 CitiPower, *Regulatory Proposal* 2016–20, *Attachment: CP PUBLIC ATT 9.13 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 30.

For these reasons, we are not satisfied producing a commercial/industrial connections forecasts expenditure profile that purely uses GSP forecasts is appropriate.[131] We have instead included in our substitute capex estimate an amount which trends forward the average of the actual residential connections to CitiPower's network over the 2011-14 period. Table 6.16 compares CitiPower's proposal with the actual expenditure over the 2011–15 regulatory control period for commercial/industrial connections.

Table 6.16 CitiPower commercial/industrial connections, actual and proposed ($2015-16, million, excluding overheads)

	2011–15 expenditure	2016–20 proposal
Gross connections capex	54.2	83.1
Customer contributions	17.0	28.5
Net connections capex	37.2	54.6

Source: CitiPower, *Response to AER information request IR# 012* (averaging the 2011–14 actual in place of the 2015 estimate), 24 July 2015.

We discuss the basis of our substitute estimate in section B.3.3.

Unit Costs

CitiPower mapped the volume forecasts generated by CIE for residential and commercial/industrial categories to its internal reporting codes and multiplied these by applicable unit rates.[132] CitiPower derived each unit rate by dividing the relevant total expenditure and volumes for over the 2011-14 period.[133] CitiPower notes this approach reflects historic costs for similar projects and are reflective of the risks and uncertainties that will be present in the forecast volumes.[134]

We have assessed the CitiPower mapping of the residential, commercial/industrial and subdivision categories and the descriptions of the internal function codes. Overall we consider that the mapping represents a reasonable allocation between the residential, commercial/industrial and subdivision connection categories and CitiPower's internal function codes. For example:

- the majority of the residential connections of less than 63kVA are mapped as LV connections—consistent with an urban distributor such as CitiPower. There was also a large proportional allocation of connections greater than 63kVA to residential customers reflecting the connection of multi-dwelling and high-rise apartments

[131] CitiPower, *Regulatory Proposal* 2016–20, *Attachment:* CP PUBLIC ATT 9.13 - The Centre for International Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 35.
[132] CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 110.
[133] CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 110.
[134] CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 110.

- commercial connections were mapped across a range of activities from complex LV through to complex HV connections
- subdivision costs were allocated to complex HV connections (upstream), highlighting that basic subdivision works are performed by third parties, and
- all co-generation function codes were allocated to small capacity HV embedded generation.

Low volume categories of connections

Separate to the high volume forecasts, CitiPower has undertaken forecasts of categories of connections where there are typically low volumes.[135]

CitiPower considers these types of connection activities are often determined by government policy or specific customer needs and have therefore adopted a combination of bottom-up builds and trending forward historical expenditure.[136] In particular for projects:

- that cost less than $2.5 million, CitiPower has adopted a forecast approach that involves trending forward the 2011-14 actual historical expenditure. CitiPower considers the volumes of these smaller projects to be consistent across time.[137]
- costing $2.5 million or more, CitiPower has identified known projects to occur over the forecast period. Based upon correspondence with the customer, CitiPower considers the project is highly likely to proceed and have included the connection in the forecast.[138] For connection categories where there is currently no known major project for the forecast period, CitiPower has assumed expenditure based on the average major project expenditure in that category for the 2011-2014 period.[139]

For forecasts where CitiPower has trended forward historical connection expenditure, we are satisfied these forecasts reasonably reflects the capex criteria. [140] We agree with CitiPower that these projects have consistent volumes across time and we have included this expenditure in our determination for the 2016–20 regulatory control period.

With respect to CitiPower’s forecasts of known major projects, we consider it is good industry practice when forecasting customer initiated work to account for the probability of delays or cancellations in projects. For example, with respect to the embedded generation projects, we note changes to the renewable energy target can impact on the demand for renewable projects. Any increase in renewable funding will act to

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135 The low volume forecasts have been prepared for commercial/industrial connections connected at HV, embedded generation and recoverable works (reported as quoted services).

136 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 111.

137 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 111.

138 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 111.

139 CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 111.

140 CitiPower included business cases for each known project.

increase the likelihood of the projects proceeding as described, while adverse changes will see the projects delayed or possibly cancelled.

We requested CitiPower provide further detail for its major projects, in particular we sought that it identify how the forecast recognises the probability of project deferrals.[141] CitiPower referenced customer correspondence which it considered provided the necessary surety of each projects completion.[142] We consider that while such correspondence does not guarantee the project will be undertaken we are satisfied that on balance this represents a realistic expectation of the expenditure CitiPower will be required to undertake.

We have therefore included this amount in our substitute capex estimate. Table 6.17 compares CitiPower's proposal with the actual expenditure over the 2011–15 regulatory control period for the low volume connection categories.

Table 6.17 CitiPower low volume connections ($2015-16, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
Gross connections capex	9.6	7.6	2.2	4.0	2.8	26.1
Customer contributions	3.6	2.7	0.7	1.3	0.9	9.3
Net connections capex	6.0	4.9	1.5	2.7	1.9	16.9

Source: CitiPower, Response to AER information request 012, 24 July 2015.

Customer Contributions

We have assessed CitiPower's forecast for customer contributions by:

- assessing the extent that the forecast was prepared in accordance with the relevant connection charge guideline
- comparing the forecast to the trends in actual customer contributions, and
- assessing the reasonableness of CitiPower's forecasting methodology.

Connection Charge Guideline

In Victoria, the Essential Services Commission's (ESCV) Guidelines 14 and Guideline 15 determine the customer connection charges.

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141 AER, *Information Request to CitiPower IR# 013*, 16 July 2015.

142 CitiPower quoted a number of confidential material project business cases as well as some publicly available documents: CitiPower, *CP PUBLIC APP E.61 - CitiPower, Material Project, CUST 16 RTS AusNet Services relocations*, April 2015.
CitiPower, *CP PUBLIC APP E.62 - CitiPower, Material Project, CUST 17 WMTS AusNet Services relocations*, April 2015.

In its proposal, CitiPower noted it was unclear at this stage whether it will be required to comply with the AER's Connection Charge Guideline or the ESCV's Guidelines 14 and Guideline 15 when determining connection charges, including capital contributions. We note that in June 2012, the Victorian Government announced it will defer its transition to the National Energy Customer Framework (NECF).[143] A transition to the NECF would give effect to CitiPower needing to comply with the AER's Connection Charge Guideline.

We addressed this in our framework and approach for the 2016–20 regulatory control CitiPower determination where we noted that the size of customer contributions will be calculated as provided for in Guideline 14 or, if Chapter 5A applies, the AER's connection guideline.[144]

The CCP in its submission noted:

> Victoria has not yet ratified NECF so the connections policies embedded in NECF do not apply to the Victorian DNSPs and should use the ESCV guidelines for new connections. The AER has a guideline for new connections, developed from NER Chapter 5A and the F&A seems to imply that ESCV guideline should apply. Despite this, some of the DNSPs. seem to indicate that they have followed the AER guideline. This issue needs to be clarified.[145]

CitiPower notes in its proposal that in calculating the customer contributions for the capital expenditure forecasts, CitiPower has assumed that Guidelines 14 and 15 will continue to apply.[146] We are satisfied that CitiPower has prepared its forecasts in accordance with the prevailing connection charge guideline.

Actual and forecast customer contributions

Figure 6.13 shows the trend in CitiPower's actual and forecast customer contributions.

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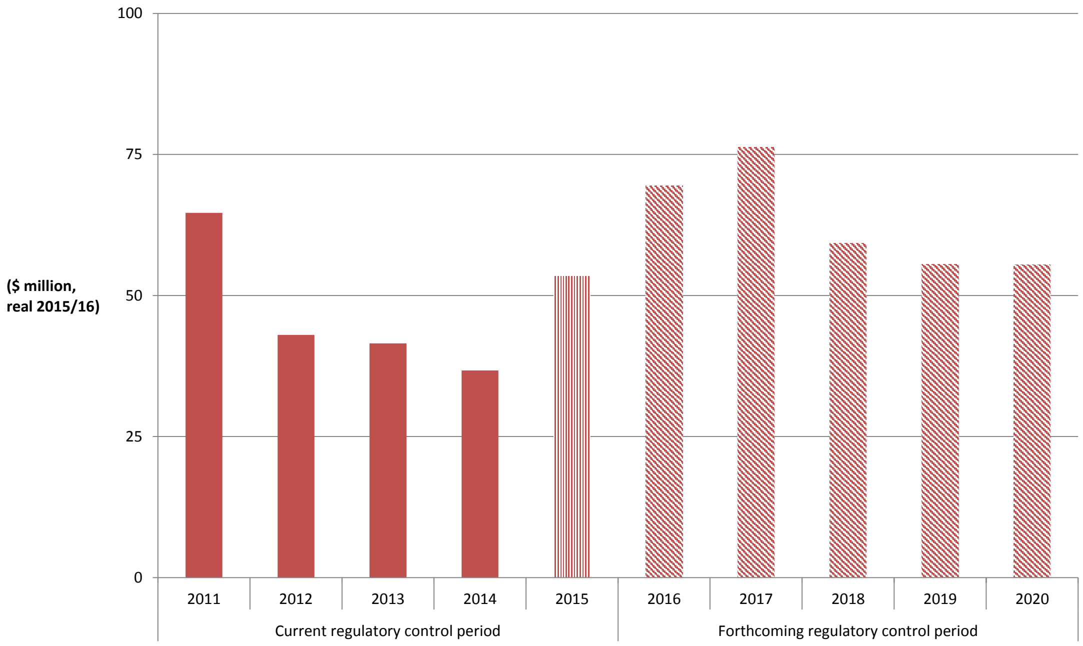
143 For more information see: http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/national-energy-customer-framework.

144 AER, *Final Framework and approach for the Victorian Distributors Regulatory Period commencing 1 January 2016,* 24 October 2014, p. 42.

145 CCP, *Consumer Challenge Panel 3 – Victorian DNSPs revenue reset comments on DNSPs proposal*, p. 54.

146 CitiPower*, Regulatory Proposal 2016–20*, *Appendix E*: *Capital Expenditure*, April 2015, p. 106.

Figure 6.13 CitiPower customer contributions historic actual and proposed for 2016–20 regulatory control period ($2015-16, million)



Source: CitiPower, Response to AER information request 013, 30 July 2015

We note that actual customer contributions have been steady over the 2011–15 regulatory control period before a significant forecast uptick in 2016. As noted previously, the timing mismatch whereby CitiPower submits its regulatory proposal before the calendar year 2015 is complete means that this 2015 year is inherently an estimate.[147] For the reasons discussed above we are not satisfied that the 2015 year can be used to accurately gauge the trend in customer contributions, although we note that the estimate is similar to the other years in the 2011–15 regulatory control period.

Comparing customer contributions for the 2011-14 period with CitiPower's forecast for the 2016–20 regulatory control period, we note that the forecast represents, on average, a 81.7 per cent increase in the annual amount of customer contributions.[148] In determining whether we are satisfied this forecast meets the capex criteria, we have assessed the methodology used by CitiPower to produce this forecast below.

CitiPower forecast methodology

CitiPower's forecast of customer contributions relies on multiplying a derived contribution rate to the high and low volume gross connection capex forecasts.[149] The model CitiPower submitted accompanying its regulatory proposal takes a sample of 82 customer projects on CitiPower's network in 2013 to calculate the contribution rate.

[147] See discussion of probability of project deferral in our assessment of CitiPower's low volume forecast.

[148] When comparing the 2011–14 annual average with the annual average being forecast for the 2016–20 period.

[149] CitiPower, *Regulatory Proposal 2016–20*, April 2015, p. 135.

The sample projects are from across various internal reporting categories or function codes of connection projects.[150]

We sought further information from CitiPower to clarify the rationale behind the selection of the sample. In particular, we sought clarification on why the sample was restricted to projects undertaken in 2013 as well how the sample relates to the forecast projects.[151] In its response, CitiPower noted that the model was originally built in the latter part of 2013 and as such the sample of projects was selected from 2013. CitiPower stated that Further noting the year does not have an impact on the modelling.[152] CitiPower referred to the following explanation of this:

> The sample selection was based on typical projects within each category and is representative of history. The size of the sample is deemed adequate for the projection of projects going forward as it represented the same customer contribution percentage for that year.
>
> The details of each sample projects such as incremental load, customer directly attributed cost and MCR level were used to complete a detailed analysis such that there are no outliers that could unduly influence the contribution rates. This analysis was then used to project contribution rates going into 2016–20.[153]

We are not satisfied that CitiPower has demonstrated that the sample used to generate the contribution rate is reflective of the projects included in its forecast. In particular, as we note above in our discussion of low volume connections, the drivers of customer initiated work can change across time and we would expect a sampling approach to select projects across a number of years.

We have instead included in our substitute capex estimate an amount which trends forward the average of customer contributions to CitiPower's network over the 2011-14 period. Table 6.18 compares CitiPower's proposal with the actual customer contributions over the 2011–15 regulatory control period.

Table 6.18 CitiPower customer contributions actual and proposed ($2015–16, million)

2011–15 actual customer contributions	50.2
CitiPower's proposed 2016–20 customer contributions	91.3

Source: CitiPower, Response to AER information request 013 (averaging the 2011-14 actual in place of the 2015 estimate).

[150] CitiPower, *Regulatory Proposal 2016–20*, *Appendix E Capital Expenditure,* April 2015, p. 107.

[151] AER, *information request IR# 013*, 16 July 2015.

[152] CitiPower, *Response to AER information request IR# 013*, 30 July 2015.

[153] CitiPower, *Response to AER information request IR# 013*, 30 July 2015.

B.4 Forecast repex

Repex is driven by the inability of network assets to meet the needs of consumers and the overall network. The decision to replace can be based on cost, quality, safety, reliability, security, or a combination of these factors. In the long run, a service provider's assets will no longer meet the requirements of consumers or the network and will need to be replaced, refurbished or removed.[154] Replacement is commonly driven when the condition of the asset means that it is no longer economic or safe to be maintained. It may also occur due to jurisdictional safety regulations, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network. Technological change may also advance the timing of the replacement decision and the type of asset that is selected as the replacement.

Electricity network assets are typically long-life assets and the majority will remain in use for far longer than a single five year regulatory period. Many of these assets have economic lives of 50 years or more. As a consequence, a service provider will only replace a portion of its network assets in each regulatory control period. The majority of network assets will remain in commission well beyond the end of any single regulatory control period.

Our assessment of repex seeks to establish the portion of CitiPower's assets that will likely require replacement over the 2016–20 regulatory control period, and the associated expenditure. CitiPower's forecast of repex does not include capex to comply with safety obligations implemented in response to the 2009 Victorian Bushfires Royal Commission (VBRC).

B.4.1 Position

We do not accept CitiPower's proposed repex of $260 million. We have instead included in our alternative estimate of overall total capex, an amount of $199 million ($2015) for repex, excluding overheads. This is 77 per cent of the amount that CitiPower proposed. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 CitiPower's proposal

CitiPower's proposed forecast repex is $260 million. CitiPower submitted that this expenditure is driven by:[155]

- completion of refurbishment works which they intended to take place during the current regulatory period but were delayed

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[154] Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

[155] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 106.

- increasing replacement of poles and cross-arms and other key assets in line with increasing defect rate
- compliance with environmental regulations
- replacement of protection relays and lines based on condition
- replacement or refurbishment of large plant and equipment based on condition.

We address CitiPower's submission as part of our assessment below.

B.4.3 AER approach

We have applied several assessment techniques to assess CitiPower's forecast of repex against the capex criteria. These techniques were:

- analysis of CitiPower's long term total repex trends
- predictive modelling of repex based on CitiPower's assets in commission
- review of CitiPower's approach to forecasting replacement expenditure to meet its safety and reliability obligations
- consideration of various asset health indicators and comparative performance metrics.

We use predictive modelling to assist us in assessing approximately 50 per cent of CitiPower's proposed repex. This assessment is considered in combination with the findings of our consultant, Energeia, who provided technical advice on CitiPower's repex forecast. For the remaining categories of expenditure, we may use predictive modelling where suitable asset age data and historical expenditure are available, but will also rely on analysis of historical expenditure. We explain the reasons for this approach in the "other repex categories" section below.

We note that the assessment of long term trends, the consideration of asset health indicators and comparative metrics are also considered as part of our assessment process. However, we have not ultimately used these to reject CitiPower's forecast of repex or develop our alternative estimate. Our findings from these assessment techniques are consistent with our overall conclusion.

In its report on the Victorian distributor's the CCP considered that the suite of approaches we use in our assessment or repex provides a much better top down approach to identifying the upper bounds for efficient capex proposals than appears to be the view of the distributors'.[156]

We recognise the limitations of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a distributor may have a lumpy asset age profile or legislative obligations may change over time). In recognising these

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[156] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 38.

limitations, we have used this analysis to draw general observations in relation to the modelled categories of repex. However, we have relied on trend analysis to assist our assessment of the unmodelled categories of repex.

Predictive modelling

Our predictive model, known as the repex model, can be used to predict a reasonable amount of repex CitiPower would require if it maintains its current risk profile for condition-based replacement into the next regulatory period. Using what we refer to as calibrated replacement lives in the repex model gives an estimate that reflects CitiPower's 'business as usual' asset replacement practices. We explain the calibrated replacement life scenario, along with other input scenarios, below.

As part of the 'Better Regulation' process we undertook extensive consultation with service providers on the repex model and its inputs. The repex model we developed through this consultation process is well-established and was successfully implemented it in a number of revenue determination processes including the recent NSW/ACT decisions. It builds on repex modelling we undertook in previous Victorian and Tasmanian distribution pricing determinations.[157] The CCP countered the view of the distributors that there are significant shortcomings in our repex modelling approach. The CCP recognised that predictive modelling is part of our overall approach which also uses other techniques such as trend analysis.[158]

The repex model has the advantage of providing both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and once aggregated it provides a well-founded high level assessment of that data. The model can also be calibrated using data on CitiPower's entire stock of network assets, along with CitiPower's recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

Notably, we can use the calibrated repex model to capture a number of the drivers put forward by CitiPower's in its submission. This includes replacement drivers related to the deterioration in asset condition; environmental conditions; fleet problems; asset failure risk; risk of collateral asset damage; safety risk to public and field personnel, environmental damage from asset failure; technical obsolescence; and third party damage. This is because the calibrated repex model captures the replacement practices from the last period, which include each of these drivers listed above.

We recognise that predictive modelling cannot perfectly predict CitiPower's necessary replacement volumes and expenditure over the next regulatory period, in the same

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[157] We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT, QLD and SA distributors.

[158] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 38.

way that no prediction of future needs will be absolutely precise. However, we consider the repex model is suitable for providing a reasonable statistical estimate of replacement volumes and expenditure for certain types of assets, where we are satisfied we have the necessary data. We note that the service providers (including CitiPower) rely on similar predictive modelling to support their forecast amount for repex.

We use predictive modelling to estimate a value of ‘business as usual’ repex for the modelled categories to assist in our assessment. However, predictive modelling is not the only assessment technique we have relied on in assessing CitiPower’s proposal. Our other techniques, which are qualitative in nature, allow us to form a view on whether or not ‘business as usual’ expenditure appropriately reflects the capex criteria.

Any material difference from the 'business as usual' estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age.

Technical review

We engaged Energeia to perform a technical review of CitiPower’s proposed repex. Energeia assessed CitiPower’s approach to forecasting, in particular, whether CitiPower’s forecast repex in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. In doing so, Energeia took account of indicators of safety and reliability, forecast expenditure, and qualitative information from CitiPower on the matters it has regard to when forecasting repex. Energeia’s review was limited to the six asset categories included in the repex model.

As set out above, we considered Energeia's findings in assessing whether CitiPower’s forecast will allow it to prudently and efficiently maintain the safety and reliability of its network. all Victorian network businesses have used predictive modelling as part of their initial proposal. this allows us to have confidence that the use of the repex model is suitable in either accepting a network business’s proposal, or in arriving at our alternative estimate.

Asset health indicators and comparative performance metrics

We have used a number of asset health indicators with a view to observing asset health. While providing some context for our decision, we have not relied on these indicators to any extent to inform our alternative estimate, they have provided context for our decision and the findings are consistent with our overall conclusion.

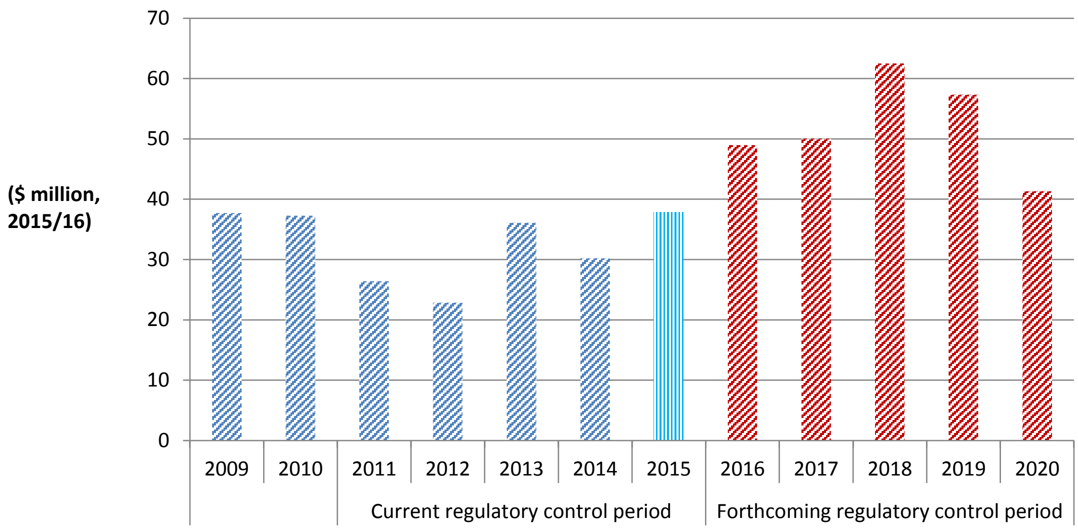
Similar to trend analysis, our use of these high level benchmarks has been to inform the relative efficiency of CitiPower’s previous repex. However, we have not used this analysis in rejecting CitiPower’s proposal and in developing our alternative estimate. We used this analysis as a cross-check with the findings of other techniques.

B.4.4 AER repex findings

Trends in historical and forecast repex

We have conducted a trend analysis of repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.[159] Our use of trend analysis is to gauge how CitiPower's historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.14 shows CitiPower's repex spend has been variable across time, and is forecast to increase above historical levels for the 2016–20 regulatory control period.

Figure 6.14 CitiPower - Actual and forecast repex ($ million, 2015)



Source: CitiPower, CP PUBLIC RIN 1.1 CitiPower, Vic Reset RIN 2016–20 - Consolidated Information, CitiPower, CP PUBLIC RIN 1.19 CitiPower, 2009–2013 Category Analysis RIN, and CitiPower, CP PUBLIC RIN 1.20 CitiPower, 2014 Category Analysis RIN.

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure. In particular we are mindful that during the 2011–15 regulatory control period, CitiPower forecasts to underspend its regulatory allowance for replacements by 22 per cent.[160] We note that a major feature of the regulatory framework is the incentives CitiPower has to achieve efficiency gains whereby actual expenditure is lower than the allowance. Differences between actual and allowed repex could be the result of efficiency gains, forecasting errors or some combination of the two. CitiPower notes this underspend is due to:[161]

- the impact of the delayed upgrade to Brunswick Terminal Station (BTS)

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

[160] CitiPower *2016–20 Price Reset Appendix E Capital Expenditure,* April 2015, p. 42.

[161] CitiPower, *2016–2020 Price Reset - Appendix E: Capital Expenditure*, April 2015, p. 42.

- network strategies to align major plant replacements and network augmentations.

We have examined the material accompanying CitiPower's proposal regarding the BTS project.[162] We are satisfied CitiPower's deferrals of expenditure in the 2011–15 period avoided unnecessary plant replacement costs. Similarly, we are satisfied that CitiPower has demonstrated good industry practice in reconfiguring network load in cost-effective way to avoid unnecessary repex.[163]

We are satisfied that expenditure levels in the 2011-2015 years of Figure 6.14 can in part be attributed to the factors outlined above.

An increasing or decreasing trend does not, in and of itself, indicate that a service provider has proposed repex that is likely to reflect or not reflect the capex criteria. In the case of CitiPower, which has proposed an increase in repex from the last regulatory period, we must consider whether it has sufficiently justified that this increase is required to reflect the capex criteria. We use our predictive modelling, the advice of our consultants, the views of stakeholders, and the material put forward by CitiPower's in support of its forecast to help us form a view on whether CitiPower has sufficiently justified its increase in repex from the last period.

Predictive modelling

We use predictive modelling to estimate how much repex CitiPower is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories.

We have sufficient replacement volume, cost and asset age data for these modelled categories at a granular level. This gives us the ability to assess the outcomes of benchmark data across all distributors in the NEM. For other categories, we do not necessarily have sufficient data to allow such comparison, for example, repex without an associated age profile. In this instance, we rely more heavily on other assessment techniques such as business cases and high level justifications put forward by the service providers. However, where we have age and historical volumes, we may still choose to use the repex model to test both the service provider's proposal and our own findings. Our predictive modelling process is described further at appendix E. In total, the assets in these six categories represent 66 per cent of CitiPower's proposed repex.

We consider the best estimate of business as usual repex for CitiPower is provided by using calibrated asset replacement lives and unit costs derived from CitiPower's recent forecast expenditure. This estimate uses CitiPower's own forecast unit costs, but it effectively 'calibrates' the proposed forecast replacement volumes to reflect a volume

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162 CitiPower, *E.47 - CitiPower, Material Project, AUG 10 WMTS 22kV decommissioning,* April 2015, pp. 4–5.

163 CitiPower, *2016–20 Price Reset Appendix E Capital Expenditure,* April 2015, p. 42.

of replacement that is consistent with CitiPower's recent observed replacement practices, rather than relying on a purely aged based indicator. We have assessed this finding in the context of our technical review before forming a view as to the appropriate repex component of capex for CitiPower. We set out below our views on their suitability for use in our assessment.

In total for all six modelled categories we have accepted CitiPower's forecast for these categories of $131 million included this amount in our alternative estimate of total forecast capex. We have assessed our findings in the context of our technical review before forming a view as to the appropriate repex component of capex for CitiPower. We set out below our views on the modelling input scenarios, and our views on their suitability for use in our assessment.

Our technical consultant, Energeia, assessed CitiPower's approach to forecasting, In particular, whether CitiPower's forecast repex was necessary in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. Energeia states that CitiPower claims its repex focuses on the drivers of asset failure more than the consequences of those failures. While CitiPower provided evidence of policies and procedures for trading-off on the basis of risk adjusted costs, it did not evidence that this process was followed by providing a ranking of potential safety repex options by category. Energeia could not conclude that CitiPower's proposed repex was prudent and efficient due to the number and degree of significant risks and/or issues identified.[164]

Our modelling estimates future repex by allowing CitiPower's the opportunity to continue its current replacement practices in the next period. This is the approach that CitiPower has undertaken to maintain the safety and reliability of its network and meet the capex objectives. In our modelling, we found that CitiPower's forecast for the modelled categories was consistent with our estimate of business as usual repex, and have accepted CitiPower's forecast for these repex categories. We explain in the section on business as usual repex why we consider trending forward CitiPower's current practices results in an estimate which reflects the capex criteria. We also explain later in the section on other repex categories where we have not accepted some of CitiPower's proposed forecast repex.

Model inputs

The repex model uses the following inputs:

- The asset age profile input is the number of assets in commission and when each one was installed.
- The replacement life input is a mean replacement life and standard deviation (i.e. on average, how old assets are when they are replaced).

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[164] Energeia, *Review of Victorian Distribution Network Service Provider's Initial Replacement Capex Proposals 2016–2020*, September 2015, pp. 32–33.

- The unit cost input is the unit cost of replacement (i.e. on average, how much each asset costs to replace).

In appendix E, we describe using the repex model to create three scenarios. In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data for the final two inputs.

Under all scenarios, the first input is CitiPower's asset age profile (how old CitiPower's existing assets are). This is a fixed input in all three scenarios.

The second and third inputs can be varied by using different input assumptions about:

- how long we expect an asset to last before it needs replacing; and
- how much it costs to replace it.

The repex model takes the replacement life input for each asset category and applies it to the actual age of the assets in each asset category. In doing this it calculates how many assets are likely to need replacement in the near future.[165] The model then applies the unit cost input to calculate how much expenditure is needed for that amount of replacement in each asset category. This is aggregated to a total repex forecast for each of the next 20 years.

In the remaining part of this section, we outline the replacement lives and unit cost inputs we tested in the repex model to assess CitiPower's proposed repex. As part of our assessment, we compared the outcomes of using CitiPower's estimated replacement lives and its unit costs, both forecast and historical, with the replacement lives and unit costs achieved by other NEM distributors. We also used the repex model to determine calibrated replacement lives that are based on CitiPower's past five years of actual replacement data. These reflect CitiPower's immediate past approach to replacement.[166] We calculated historic unit costs by dividing historic expenditure by historic volumes and forecast unit costs by dividing forecast expenditure by forecast volumes. Detail on how we prepared the model inputs is at appendix E of this preliminary decision.[167]

'Business as usual' repex

The calibrated asset life scenario gives an estimate based on CitiPower's current risk profile, as evidenced by its own replacement practices. Our estimate brings forward the current replacement practices that CitiPower has used to meet the capex objectives in the past. Calibrated replacement lives use CitiPower's recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives

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[165] The repex model predicts replacement volumes for the next 20 years.

[166] For discussion on how we prepared each of the inputs see AER, *Preliminary decision, Energex distribution determination Attachment 6: Capital expenditure*, *Appendix E* :*Predictive modelling approach and scenarios*, May 2015.

[167] AER, *Preliminary decision, Energex distribution determination, Attachment 6: Capital expenditure, appendix E*, May 2015.

are calculated by using CitiPower's past five years of replacement volumes, and its current asset age profile (which reveals how many, and how old, CitiPower's assets are), to find the age at which, on average, CitiPower's replaces its assets.

The calibrated replacement life may be different to the "nameplate" or nominal replacement age of the asset (which we considered under the "base case" scenario). CitiPower reports these expected asset lives as part of its RIN response. However these reflect expectations of lives from engineering and manufacturing information, rather than observations of the economic lives achieved on the network. Using the lives provided in the RIN response in the repex model provides estimates of repex that greatly exceed CitiPower's own expectation of its replacement needs over the next period. From this, we observe that, in general, these technical estimates of asset life tend to understate the actual lives achieved on the network, and are a conservative estimate of the observable economic life of the assets, when compared to the calibrated replacement life.

The calibrated asset life scenario has been our preferred modelling scenario in recent reviews of other service providers.[168] This is because we considered the calibrated replacement lives formed the basis of a business as usual estimate of repex, as they are derived from the service provider's actual replacement practice observed over the past five years and the observable (or revealed) economic replacement lives of the assets.

A service provider decides to replace each asset at a certain time by taking into account the age and condition of the asset, its operating environment, and its regulatory obligations. If the service provider is currently meeting its network reliability, quality and safety requirements by replacing assets when they reach a certain age, then by adopting the same approach to replacement in future they are likely to continue to meet its obligations. Consequently, the estimates derived from the model reflect the replacement practices that CitiPower has used in the past to meet the capex objective of maintaining the safety and reliability of the network.

If underlying circumstances are different in the next regulatory control period, then this approach to replacement may no longer allow a service provider to meet its obligations. We consider a change in underlying circumstances to be a genuine change in the underlying risk of operating an asset, genuine and justifiable evidence that there has been a change in the expected non-age related condition of assets from the last regulatory control period, or a change in relevant regulatory obligations (e.g. obligations governing safety and reliability).

If we are satisfied that there is evidence of a change in a service provider's underlying circumstances, we will accept that future asset replacement should not be based on a business as usual approach. This means that where there is evidence that a service provider's obligations have changed then it may be necessary to provide a forecast of

[168] See AER final decision for NSW and ACT and preliminary decisions for Queensland and South Australian distributors, April 2015.

repex different to the business as usual estimate. This alternative forecast would be required in order to satisfy us that the amount reasonably reflects the capex criteria.

Where there are new obligations (or fewer obligations) we can use the service provider's past practices as a first step before estimating the impact of the change. The new safety obligations arising from the VBRC recommendations represent a change in circumstances from the 'business as usual' practices of the last period. The impact of these are set out in appendix B.5. But, as noted above, CitiPower submitted there was no VBRC expenditure included in its forecast repex. We do not consider that CitiPower has identified other new obligations for the next regulatory period that cannot be captured by adopting the 'business as usual' forecast of repex. Consequently, we have relied on our estimate from the calibrated repex model, in combination with our findings in relation to the new safety obligations, in assessing whether CitiPower's proposed repex reasonably reflects the capex criteria.

As noted above, we are satisfied that with the exception of additional funding to address the impact of new safety obligations a business as usual approach to repex will provide CitiPower with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system.

That said, we have also considered whether the service provider's replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for expenditure over and above what is necessary to satisfy the capex objectives. In considering the efficiency of recent replacement practices, we place some weight on the ex-ante capex incentive framework under which the service providers' operate.

There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a service provider reacting to these incentives will undertake efficient capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider's past replacement practices are likely to reflect efficient and prudent costs, such that business as usual asset replacement approach is likely to be consistent capex objectives.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service providers' asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Calibrated scenario outcomes

The calibrated repex model scenario, which was described in the last section, provides an estimate of replacement volumes for the next period. In order to estimate how much repex is required to replace this estimated volume of assets, we must multiply the volume by the cost of replacing a single asset (unit cost). We tested two unit cost assumptions, based on data provided by CitiPower:

We have modelled the calibrated lives using two unit cost assumptions, being:

- CitiPower's own historical unit costs from the current regulatory period. These reflect the unit costs CitiPower has incurred over the last five years.
- CitiPower's own forecast unit costs for the next regulatory period. These reflect the unit costs CitiPower expects to incur over the next five years.

Applied to the forecast volumes predicted from the calibrated replacement lives, the repex model estimates $130 million of repex when using CitiPower's historical unit costs, and $235 million using forecast unit costs. CitiPower's own proposed forecast repex is $131 million for the six modelled asset categories. This suggests that CitiPower's forecast is likely to be a reasonable estimate of business as usual repex for these categories and we have included this amount in our alternative estimate of total forecast capex.

We compared CitiPower’s unit costs to benchmark unit costs from across the NEM. These are based on the unit costs of all NEM distributors across the consistent asset categories we use in the repex model. These are based on our category analysis data. In summary, we take unit cost observations from across the NEM and find an average unit cost, a lower quartile unit cost, and the lowest unit cost in the NEM for each asset category.

When applied in the repex model with calibrated asset lives, average benchmark unit costs produced an outcome of $77 million. This is lower than when using CitiPower's historical and forecast unit costs. We consider the benchmark unit costs provide a useful comparison with the cost of other distributors in the NEM. This supports our conclusion that CitiPower's forecast for the modelled categories reflects the capex criteria.

In summary, CitiPower's own forecast repex of $131 for the six modelled categories is consistent with our calibrated scenario modelling outcomes. Therefore we are satisfied CitiPower's forecast repex reasonably reflects its business as usual replacement requirements and we have included this amount in our alternative estimate of total forecast capex.

Other repex categories

Repex categorised as supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA); pole top structures; and assets identified in the "other" category have generally not been included in the repex model in recent decisions. Given the availability of data for CitiPower and the significant increase in expenditure proposed in the next regulatory period, we have considered a qualitative review of CitiPower's proposal on these expenditure items and comparison with historical trends. Together these categories of repex account for $68 million (34 per cent) of CitiPower's proposed repex.

As noted in appendix E, we did not consider pole top structures were suitable for inclusion in the model because of their relationship to pole replacement. That is, when a pole is replaced, it usually includes the structure, such that it is difficult to predict the number of structures that will be replaced independent of the pole category. Where we are unable to directly use predictive modelling for pole top structures we have placed more weight on an analysis of historical repex, trends, and information provided by CitiPower in relation to these categories. Our analysis of these is included below.

We consider that the replacement of network assets is likely to be relatively recurrent between periods. We recognise there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we cannot model, historical expenditure is our best high level indicator of the prudency and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria it can be a good indicator of whether forecast repex reasonably reflects the capex criteria. This is due to the predictable and recurrent nature of repex.[169]

For unmodelled asset categories we consider that if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the distributor's forecast is likely to satisfy the capex criteria. If forecast repex exceeds historical expenditure, we would expect the distributor to sufficiently justify the increase.

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

We have accepted CitiPower's proposed repex for pole top structures ($20 million) and SCADA ($21 million). However, we do not accept CitiPower's proposed repex for "other" repex categories of $88 million and are instead satisfied that CitiPower's repex on "other" categories from the 2010–15 period of $28 million reflects the capex criteria. We explain the reasons for our decision below.

There is also support from submissions that CitiPower's proposed total repex may not reasonably reflect the capex criteria. While we are satisfied that CitiPower's proposed repex for the six modelled categories reasonably reflects the capex criteria, our assessment of the remainder of CitiPower total forecast repex does not support the entirety of its proposed increase to repex.

The CCP stated that it is consumer experience that should be the core drive of repex levels, concluding that consumers are satisfied with current levels of repex and therefore they see no need for a step increase in repex. It considered that the distributors' proposed overall level of repex is not justified as current reliability levels do not suggest there is a need to increase repex. The CCP was of the view that the residual ages of the distributors' assets have maintained or improved over time, opex spending has been increasing, and condition based assessments appear subjective and likely conservative.[170]

The CCP questioned the Victorian distributor's arguments that condition based monitoring has identified more assets at risk than occurred in the past, necessitating more repex. It considered that unless there are exogenous reasons causing faster deterioration of assets than what occurred in the past, the only reason for significant increases in repex would be:

- a more conservative approach is being used to establish asset condition
- distributors are applying less care in their maintenance practices.

Since the Victorian distributors' have not had an overall reduction in network performance the CCP considers that the first cause above is more likely. This leads the CCP to conclude that greater conservatism is being applied to condition assessments than was applied in the past.[171]

The CCP was also concerned with the approach of the service providers to assessing asset health, considering that the bulk of assessments are being made on a subjective qualitative basis. For example, visual inspections which will vary between individuals, and that the context for an inspection may produce greater conservatism like

[170] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 47.

[171] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 52.

performing an assessment following bushfires. The CCP also questioned the assertion that increased failure rates have driven the increased proposed repex.[172]

The Victorian Greenhouse Alliance was concerned with the significant increases to repex the Victorian distributors are proposing. It considered this was concerning given that over-investment in the networks over recent regulatory periods has led to excess levels of network capacity and declining network utilisation. It is also found it concerning that high revenue proposals were being put forward at a time of declining capacity utilisation, a reduced average asset age for most asset categories, static or falling demand and consumption, and reductions in the excessive reliability standards.[173] The Victorian Greenhouse Alliance also noted there was little information in the proposals on asset condition. It considered this makes it difficult to assess the validity of the distributors' claims, and that the distributors should provide greater transparency on asset age trends and asset condition data.[174]

Our assessment of “other” repex revealed concerns with the levels proposed, consistent with the concerns raised in submissions. We do not accept CitiPower’s proposed repex of $88 million for these categories. We are instead satisfied that an amount of $28 million reflects the capex criteria.

In relation to the six modelled categories, the assessment we have conducted essentially provides expenditure for a continuation of the replacement practices that CitiPower has used in the last regulatory period to meet the capex objectives. The ex-ante efficiency incentives embedded in the regulatory regime, provides a degree of assurance that a service provider responding to these incentives in the past will have engaged in replacement practices are prudent and efficient.

Pole top structures

CitiPower has forecast $20 million of repex on pole top structures over the 2016–20 regulatory control period. This is a 14 per cent per cent decrease over its pole top structures repex in the 2011–15 period.

As noted above, we consider repex is likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing CitiPower's forecast.

Given CitiPower’s forecast is lower than its expenditure in the last period, we are satisfied that CitiPower’s forecast repex for pole top structures of $20 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

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172 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 47.

173 Victorian Greenhouse alliance, *Local Government Response To The Victorian Electricity Distribution Price Review (EDPR) 2016–20*, July 2015, p. 7.

174 Victorian Greenhouse alliance, *Local Government Response To The Victorian Electricity Distribution Price Review (EDPR) 2016–20*, July 2015, p. 34.

SCADA, network control and protection

CitiPower's proposal includes $21 million for replacement of SCADA, network control and protection (collectively referred to as SCADA). This is a $6 million increase over the 2010–15 regulatory control period. We consider the proposed increase is relatively low in materiality. The increase is driven by CitiPower’s proposal to increase the rate of replacement of its protection relays to address reduce the risk to safety and equipment condition.[175]

CitiPower provided data demonstrating that, without this increase in replacement volume, an estimated 664 relays, or 45 per cent of the population, would be in the high to very high category in 2020. CitiPower submits that this risk is unacceptable for a prudent network operator to accept.[176]

We are satisfied that CitiPower’s forecast SCADA repex of $21 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex. The increase is modest compared to the last period, and CitiPower has provided supporting information that demonstrates the need for greater volume replacement of these assets.

Other repex

CitiPower categorised a number of assets under an "Other" asset group in its RIN response. CitiPower forecast $88 million of repex for these assets for the 2016–20 regulatory control period. This is more than three times higher than its repex on other categories in the 2011–15 regulatory control period, or $61 million, as shown in Figure 6.15. The assets include:[177]

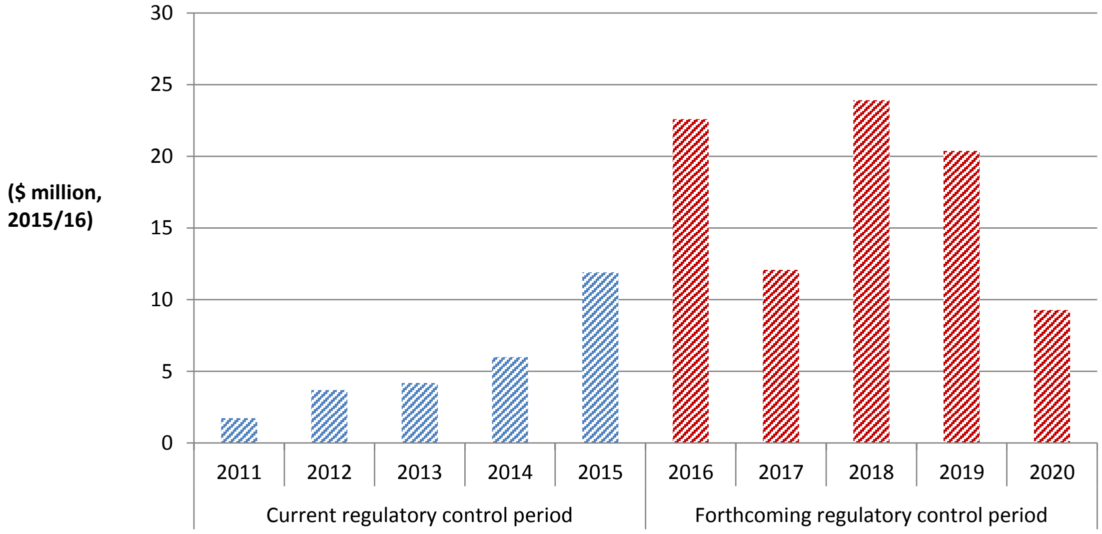
- environmental management
- Yarra Valley water asset relocation
- plant and stations miscellaneous
- zone substation major building / property / facilities
- Television signal interference replacement capital.

175 CitiPower, *REPL 05 Protection relay replacement*, p. 1.

176 CitiPower, *REPL 05 Protection relay replacement*, p. 3.

177 CitiPower, Regulatory proposal 2016–20, *Capex attachment*, April 2015, p. 50.

Figure 6.15 CitiPower's actual and proposed "other" repex ($2015)



Source:

As repex in the forecast period is significantly higher than historical expenditure, we have examined the supporting material provided by CitiPower to assist us in forming a view on whether the increase has been sufficiently justified. As noted above, we consider repex is likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing CitiPower's forecast. There are limited historical examples of expenditure of the type identified by CitiPower. We acknowledge that some non-recurrent replacement may occur. However, we must be reasonably satisfied that CitiPower has established that it requires this expenditure to meet the capex criteria.

CitiPower did not provide an age profile for these assets so we were unable to test them in the repex model. However, we note the significant step up from historical repex does not accord with the increases in the six modelled categories and pole top structure categories considered above.

Further, many of these replacements relate to assets that we consider could be included in the modelled categories, such as transformers. These assets may be at the end of life, but it is not clear why they are being treated separately from the general modelled repex assets. CitiPower submits these assets should be considered outside the repex model. However, it does not identify why these fall outside a business as usual estimate of repex. For example, CitiPower identified transformer replacements to address issues of noise pollution. However, the need to manage network noise does not represent a new obligation. The replacement of assets in the past for noise related issues would be expected to fall within CitiPower's current safety/environmental obligations, and form a part of business as usual repex.

We assessed CitiPower's business cases in support of its proposed expenditure. We concluded these were not sufficient to support the proposed replacement expenditure.

The majority of the business cases contained three options: asset replacement; a form of non-replacement remediation; or do nothing. These options were not supported by cost-benefit analysis, with only the chosen option costed. The reasons for not selecting the other options were qualitative, and mentioned potential avoided costs without quantification,

We consider it good industry practice to consider the lowest cost approach to addressing a potential network risk. We do not consider the business cases provided by CitiPower establish that the cost-benefit associated with the different options was sufficiently considered, nor that CitiPower has established that it is addressing these issues at the lowest cost.

We do not consider CitiPower's proposed repex of $88 million reflects the capex criteria. As noted above, we do not consider CitiPower has undertaken robust cost-benefit analysis in support of the increased capex, has not established why large portions of the repex should not be regarded as "business as usual" and so fall within the repex model, or demonstrated why the growth in the "other" category is significantly higher than the growth in the prescribed asset groups (poles, transformers, etc). For these reasons, we do not consider there is persuasive evidence to depart from CitiPower's historical repex from the last regulatory period. We are satisfied that CitiPower's repex on "other" categories from the 2011–15 period of $28 million is sufficient to meet the capex criteria.

Network health indicators

As noted above, we have looked at network health indicators and benchmarks to form high level observations about whether CitiPower' past replacement practices have allowed it to meet the capex objectives. While this has not been used directly either to reject CitiPower' repex proposal, or in arriving at an alternative estimate, the findings are consistent with our overall findings on repex. In summary we observed that:

- the measures of reliability and asset failures show that outages on CitiPower' network have been relatively stable or declining across time with the exception of a sharp decrease in 2010(see Trends in reliability and asset failure, along with Table 1 and Figure 1)
- measures of CitiPower' network assets residual service lives and age show that the overall age of the network is being maintained. Using age as a high level proxy for condition, this suggests that historical replacement expenditures have been sufficient to maintain the condition of the network (see Trends in the remaining service life and age of network assets, along with Figure 2)
- asset utilisation has reduced in recent years which means assets are more lightly loaded, this is likely to have a positive impact on overall asset condition (see Asset utilisation discussion below).

Further, the value of customer reliability has recently fallen. Other things being equal, this fall should result in the deferral of repex as the value customers place on reliability for replacement projects has fallen.

The above indicators generally suggest that replacement expenditure in the past period has been sufficient to allow CitiPower to meet the capex objectives. This is consistent with our overall findings on repex from our other assessment techniques. The asset health indicators are discussed in more detail below.

Trends in reliability and asset failure

Asset failure is a significant contributor to the volume of sustained interruptions on CitiPower's network. Table 6.19 shows that, over the 2009–14 period 72.6 per cent of total interruptions on CitiPower's network were caused by the failure of assets.[178]

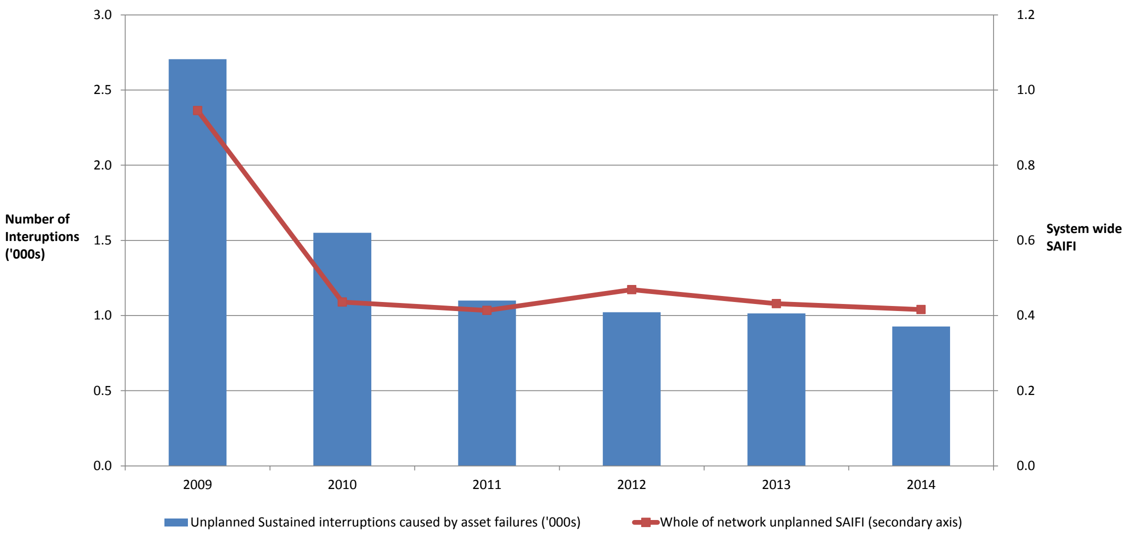
Table 6.19 CitiPower - contribution of asset failures to non-excluded sustained interruptions (per cent)

	2009	2010	2011	2012	2013	2014
Sustained interruptions caused by asset failures	86.1	73.9	67.6	66.1	65.1	62.5

Source: CitiPower, CA RIN – 6.3 Sustained Interruptions

Figure 6.16 compares sustained interruptions caused by asset failure with the System Average Interruption Frequency Index (SAIFI), which is an aggregate measure of the frequency of sustained interruptions on the network.[179]

Figure 6.16 Relationship between system wide SAIFI and non-excluded interruptions caused by asset failures



[178] These measures do not include planned outages, momentary outages, major event days and excluded events.

[179] SAIFI: The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

Source: CitiPower- CA RIN – 6.3 Sustained Interruptions and EBT RIN - Whole of network unplanned SAIFI

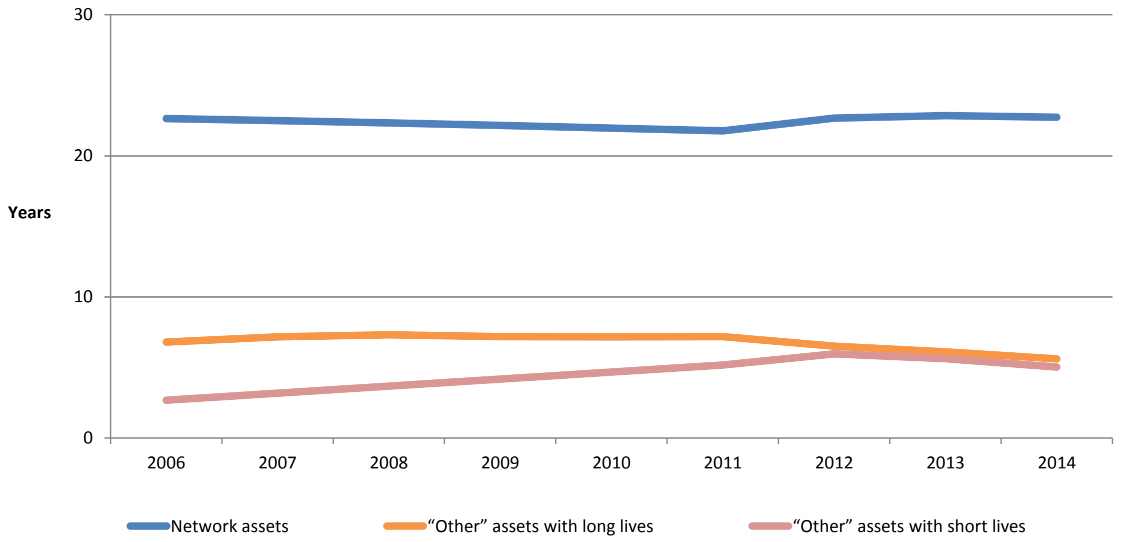
Figure 6.16 shows CitiPower's both outages due to asset failures and SAIFI have generally been flat across time, with the exception of a significant decrease in 2010. The overall stability in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives.

Trends in the remaining service life and age of network assets

Another factor which we have considered when assessing CitiPower's repex requirements for the 2016–20 period is the trend in CitiPower's residual asset life across time. We are satisfied that residual service life is a reasonable high-level proxy for asset condition. Asset condition is a key driver of replacement expenditure.

Figure 6.17 shows that CitiPower's residual asset lives have been flat over the period 2006-2013. This means that, on average, CitiPower's network assets are staying the same age.

Figure 6.17 CitiPower estimated residual service life network assets



Source: CitiPower, EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services)

We acknowledge limitations exist when using estimated residual service life to indicate the trend in the underlying condition of network assets. Large volumes of network augmentation and connections can result in a large stock of new assets being installed in the network, which may bring down the network's average age. In this way, the residual service life of the assets may increase without necessarily addressing any underlying asset condition deterioration.

Noting the above, the flat trend in residual lives (where age is a proxy for asset condition) suggests that the health of CitiPower's asset base has been maintained.

Asset utilisation

We consider the degree of asset utilisation can impact asset condition for certain network assets. As set out in the [section augex], we note CitiPower has experienced a steady decrease in utilisation levels at its zone substations between 2010 and 2014. CitiPower undertook zone substation augmentation projects between 2010 and 2014 that led to a decrease in the number of substations operating above 60 per cent of their maximum capacity. We note that the flattening of demand between 2010 and 2014 may have contributed to a reduction in the utilisation of the network. As of 2014, there are no substations operating above their maximum capacity.

We are satisfied this demonstrates that CitiPower's network has spare capacity in its network based on past investments. All things being equal, we expect a positive correlation between asset condition and lower network utilisation exists for certain asset classes.

However we recognise that:

- The relationship between asset utilisation and condition is not uniform between asset types. For example; poles and fuses.
- The relationship is not necessarily linear (e.g. condition may not be materially impacted until a threshold point is reached).
- The condition of the asset may be difficult to determine (e.g. overhead conductor). As such early-life asset failures may be due to utilisation or, more commonly, a combination of factors (e.g. utilisation and vibration).

While noting these issues, we consider that CitiPower's asset utilisation has not been high, and we do not expect any material deterioration of CitiPower's network assets is likely to have occurred in recent years due to high utilisation of the assets.

B.5 Victorian Bushfires Royal Commission

B.5.1 Bushfire safety-related capital expenditure

CitiPower proposed a forecast of $9.419 million ($2015) for bushfire safety-related capex (excluding overheads and escalation). This is driven by a mandatory bushfire safety mitigation program for the 2016–20 regulatory control period.

We accept CitiPower's proposed $9.419 million ($2015) forecast and have included this amount in their replacement capital expenditure.

In coming to this view, we have assessed the CitiPower bushfire safety capex proposals. Based on our assessment, we find that the proposed capex for the bushfire safety programs reasonably reflect the capex objectives and therefore we have included the proposed capex in our estimate of CitiPower's capex requirements.

Our assessment of this program is contained in the section below.

This proposed capex amount for the program is incremental to CitiPower's business as usual capex related to bushfire risk management. Table 6.20 sets out the proposed components of the program.

Table 6.20 CitiPower's proposed capex for a fire mitigation program ($2015, million, excluding overheads & escalation)

Strategy	Proposed capex
LBRA Armour Rods & Dampers Retrofit	7.674
LBRA Multi-circuit survey cost	0.635
LBRA Multi-circuit Repairs (Fitting of Spacers)	0.379
LBRA Multi-circuit Rebuilds	0.732
Total	**9.419**

Source: CitiPower, *PUBLIC MOD 1.17 - CP Capex consolidation*, *'Base Capex Forecast', FC 167* – VBRC, April 2015.

AER assessment approach

For bushfire safety related capex there are three potential bases for consideration of a funding requirement. These are:

1. Business As Usual (BAU): Capex which we assess along with other capex in attachment 6. We use the tools outlined in attachment 6 to assess the efficiency of the forecast. These capex projects relate to maintaining the quality, reliability or security of supply of standard control services or the reliability or security of the distribution system through the supply of standard control services or the safety of the distribution system through the supply of standard control services.[180]
2. Approved projects are set out in the companies' Electrical Safety Management Scheme (ESMS) or Bushfire Mitigation Plan (BMP). We rely on Energy Safe Victoria to establish need. We then assess the efficiency of the forecast cost. These projects are assessed in accordance with the capital expenditure objectives to determine if they are necessary to comply with applicable regulatory obligations or requirements associated with the provision of standard control services.[181]
3. Pending regulations from the Victorian Government which will implement aspects of recommendation 27 of the Victorian Bushfires Royal Commission (VBRC). The timing and scope of the regulations are not yet known. We want to provide the distributor with a mechanism to recover the prudent costs associated with any new obligations while ensuring that consumers pay no more than necessary for the implementation of these.

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180 NER, cll. 6.5.7(a)(3) and (4).

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

Our first order of assessment is to consider whether a proposed expenditure fits into one of these broad categories. This helps us to determine which are the most appropriate tools to assess whether a proposal satisfies the capital expenditure objectives.[182] We also consider if the amount sought is compliant with the capital expenditure criteria, particularly if the cost is prudent and efficient.[183]

Assessment of CitiPower proposal

Based on the evidence submitted by CitiPower and other information before us, we are satisfied that the bushfire mitigation program is required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be a prudent and efficient investment in the network.

In summary, we consider that:

- CitiPower's proposed capex is required to maintain the reliability and safety of its network and to comply with applicable regulatory obligations or requirements.
- This obligation arises from CitiPower's Electrical Safety Management Scheme. The scheme includes a mandatory Bushfire Management Plan. This plan incorporates actions to respond to two directions received from Energy Safe Victoria (ESV). The Directions require CitiPower to take measures to fit additional vibration dampers, armour rods and line spacers throughout its network by 1 November 2020.
- CitiPower's proposed capex is a prudent and efficient investment. The costs to be incurred are derived from actual contract outcomes from its sister business, Powercor. The volume estimates are derived from the CitiPower GIS system and are consistent with the directions issued by ESV. Accordingly, the resultant cost estimate reasonably reflects the capex criteria.
- As the obligation to undertake this work is mandatory CitiPower have not undertaken a cost benefit analysis of the program.
- CitiPower's VBRC proposal does not include any BAU capex.
- CitiPower has not proposed a mechanism to fund future obligations associated with potential regulations to implement recommendation 27 of the VBRC.

For these reasons, we accept CitiPower's' proposed capex for the fire mitigation program satisfies the capex criteria. Each of these reasons is discussed further below.

Regulatory obligation

Victorian electrical safety framework

In Victoria, the safety obligations of major electricity companies are contained in the Electricity Safety Act 1998 (Vic). Section 99 of this Act mandates that major electricity

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

[183] NER, cll. 6.5.7(c)(1) & (2).

companies must submit an approved Electricity Safety Management Scheme (ESMS) to Energy Safe Victoria for acceptance.[184] These schemes are regulated by Energy Safe Victoria. Each of the five Victorian distributors is classed as a 'major electricity company' under this Act.

It is compulsory for CitiPower to comply with the accepted ESMS for its network.[185] Further, the Act requires that each major electricity company must submit a Bushfire Mitigation Plan for its network to Energy Safe Victoria and must comply with that plan.[186] The Bushfire Mitigation Plan forms part of an accepted ESMS.[187] This legislated requirement applies notwithstanding that the CitiPower network is located in urban areas and is therefore unlikely to cause a bushfire. However, we note a major fire in an urban area would be potentially devastating to that area, were it to occur.

On 4 January 2011 Energy Safe Victoria issued two directions under s 141 of the Electricity Safety Act to CitiPower. A major electricity company must comply with a direction under s 141 of this Act that applies to it.[188] The first direction required that CitiPower inspect all powerlines in its network and fit armour rods and vibration dampers by 1 November 2020 where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[189] The second direction required the fitting of spacers where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[190]

Two mechanisms exist for a major electricity company to address a safety concern of when it arises. The first is to voluntarily propose to address the safety hazard by including an undertaking in their ESMS or the Bushfire Mitigation Plan to undertake a specific activity to address the hazard. If a proposed change to their ESMS is approved by the safety regulator, the activity becomes an obligation which must be carried out.

The second mechanism is the creation of a new regulatory obligation by the Government or an action by a Government agency under existing legislation. The issuance of a direction by Energy Safe Victoria falls into this category. CitiPower's VBRC capex proposal is wholly in response to regulatory obligations imposed by the directions of ESV. The proposal has been assessed on this basis.

We note that CitiPower has not proposed a mechanism to address possible future obligations in the next regulatory control period. We discuss this later in this section.

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184 *Electricity Safety Act 1998* (Vic), s. 99.

185 *Electricity Safety Act 1998* (Vic), s. 106.

186 See *Electricity Safety Act 1998* (Vic), ss. 113A, 113B and 113C.

187 *Electricity Safety Act 1998* (Vic), s. 113D.

188 *Electricity Safety Act 1998,* s. 141(4).

189 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of armour rods and vibration dampers*, 4 Jan 2011.

190 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of spacers*, 4 Jan 2011.

The mandatory safety obligations of CitiPower relate to armour rods, vibration dampers, spacers and line clearance, which we now assess.

CitiPower proposal

CitiPower has asked that the AER fund its VBRC related obligations as follows:[191]

> *VBRC expenditure is driven by specific obligations that have been imposed on us by ESV. The obligations relate to the installation of:*
>
> - *armour rods and vibration dampers to specific conductors which is intended to reduce wear on conductors and the effects of wind-induced vibration on powerlines, in accordance with our Electricity Safety Management Scheme (ESMS);*
> - *conduct a survey of multi-circuit lines to assess whether the conductor clearance is sufficient, in accordance with our ESMS; and*
> - *spacers in aerial lines to maintain conductor clearances and stop conductor clashing in windy conditions, in accordance with our ESMS.*

If a regulatory obligation exists in an ESMS or BMP it follows that the activity is also required to maintain the reliability and safety of the network. These obligations are contained in the accepted CitiPower Bushfire Mitigation Plan dated 14 July 2014 at section 8.5.[192] Accordingly, CitiPower has demonstrated it has a regulatory obligation or requirement to undertake this work in the next regulatory control period.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by CitiPower. We are satisfied this is a discrete program of work that does not fall within CitiPower's business as usual level of capex to manage asset fire safety.

We next assess whether the proposed allowance satisfies the capex criteria.[193] To determine the volume of works to satisfy the obligation CitiPower must undertake a survey of its network. This survey is scheduled to commence in July 2015 but will not be completed until July 2019.

> We updated our ESMS with a plan to undertake a survey of spans in LBRA by July 2019, and to complete any identified works to install spacers or reconstruct the span to comply with the separation requirements by 1 November 2020. We must comply with the updated ESMS as compliance is enforceable by ESV.[194]

Therefore, CitiPower has prepared forecasts for vibration dampers, armour rods and spacers based on based on consideration of its Geographical Information System (GIS) and the treatment rate of similar spans experienced by its sister business, Powercor. We have reviewed this methodology and are satisfied it is appropriate. As

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[191] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 138.

[192] CitiPower, *Bushfire Management Strategy Plan 2014–2019 – Issue 2*, 15 July 2014, p. 16.

[193] NER, cll. 6.5.7(c)(1) and (2).

[194] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 140.

CitiPower and Powercor are under a common ownership and management structure, the staff involved in this work are common to both businesses. The construction standards of overhead assets are also common to both businesses. Although the geographical environments of the two businesses differ significantly, CitiPower and Powercor share common service provider contracts for this type of work. Consequently, their estimate has assumed that CitiPower will incur a unit rate cost equal to the unit rate to be incurred by Powercor under existing contract arrangements.

Although relative to CitiPower, Powercor may face higher costs for expenses such as travel and site supervision, it is also likely that traffic management and outage costs may be higher in the urban environment faced by CitiPower. These differences are likely to counteract each other, which explains why CitiPower is able to obtain the same rate as Powercor.

CitiPower also noted that it is not possible to fit spacers to all spans of their network. This is known to be an issue with 66kV lines because no suitable spacer exists. Consequently, a small number of spans will require reconstruction to comply with the direction. We have reviewed the methodology used by CitiPower to formulate this estimate and are satisfied it is appropriate. We are satisfied that CitiPower's estimate of the number of spans to be reconstructed is reasonable.

The costs to be incurred for each activity are derived from actual contract rates used by CitiPower and Powercor. In comparison to the blended unitised rates of other Victorian distributors for the installation of vibration dampers and armour rods, the combined rate proposed by CitiPower is lower than the rates of either AusNet Services or United Energy. All the unitised rates proposed by CitiPower are derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. Each unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the CitiPower unitised rates are efficient. The volume estimates derived from the CitiPower GIS system are consistent with the directions issued by ESV. We are satisfied the methodology used to derive the volume estimates is sound. Accordingly, the resultant cost estimates reasonably reflect the capex criteria.

We accept CitiPower's capex proposal to spend $9.419 million ($2015, excluding overheads and escalation) on the accepted BMP applying to its network.

Future regulatory obligations

Following the Victorian Bushfires Royal Commission (VBRC) 67 recommendations were made, of which eight relate directly to the safety of electrical distribution networks in Victoria. One of these relevant recommendations is recommendation 27:

> The State amend the Regulations under Victoria’s Electricity Safety Act 1998 and otherwise take such steps as may be required to give effect to the following:
>
> - the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other

technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives

- the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.

The Victorian Government is developing a regulatory requirement to give effect to recommendation 27. In particular, work is being undertaken by the Victorian Government to develop suitable regulatory standards for the use of new technologies such as Rapid Earth Fault Current Limiting (REFCL) devices and a new type of insulated line as major tools to reduce the risk of powerline faults igniting bushfires.

These regulations are expected to apply in High Bushfire Risk Areas (HBRA) of the State and will involve a mandatory program of installing REFCLs and a change to the design standards that apply to new line construction and the reconstruction of assets in certain areas (Codified Areas). However, this Victorian Government program is not yet in place. The timing and scope of the regulations are not currently known.

CitiPower has not addressed this impending development in their regulatory proposal. AusNet Services proposed to apply a regulatory change pass through event to any regulatory change or changes that apply in the next regulatory control period.[195] However, we note that Powercor has proposed that the pending regulatory changes be dealt with as contingent projects.[196] We have therefore, considered whether either approach is preferable (contingent project or pass through event) and the trigger event which should apply to a contingent project.

Having considered the respective proposals of AusNet Services and Powercor, we consider a contingent project approach is preferable. Our preference is to apply a common regulatory approach to all affected service providers. We prefer to deal with the costs of the Victorian government regulations consistently across distributors. This ensures that the cost of the regulation is recovered from customers in the same manner. It also allows us to compare the costs and impacts on customers more transparently so that we can ensure that consumers pay no more than necessary for the implementation of the regulation. This is particularly important because the cost and timing of the regulation are not yet known.

Until the Victorian Government regulations are developed and promulgated it will remain unclear whether there is likely to be an impact on CitiPower. If, in their substitute determination regulatory proposal CitiPower applies for one or more contingent projects in response to these impending regulations, our intention is to

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195 AusNet Services, *Regulatory proposal 2016–2020*, April 2015, p. 260.

196 Powercor, *Regulatory proposal 2016–2020*, April 2015 p. 143.

apply a common regulatory approach to that proposal, including the applicable trigger event.

B.6 Forecast capitalised overheads

Capitalised overheads are costs associated with capital works that have been capitalised in accordance with CitiPower's capitalisation policy. They are generally costs shared across different assets and cost centres.

B.6.1 Position

We do not accept do not accept CitiPower's proposed capitalised overheads. We instead included in our alternative estimate of overall total capex an amount of $86.5 million ($2015) for capitalised overheads. This is seven per cent lower than CitiPower's proposal of $93.5 million ($2015). We are satisfied that this amount reasonably reflects the capex criteria.

B.6.2 Our assessment

We consider that reductions in CitiPower's forecast expenditure should see some reduction in the size of its total overheads. Our assessment of CitiPower's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in CitiPower's regulatory proposal. It follows that we would expect some reduction in the size of CitiPower's capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

Our assessment in the Queensland distribution determinations found Energex's overheads comprised 75 per cent fixed and 25 per cent variable components. We consider this split of fixed and variable overheads components is also reasonable for CitiPower. If CitiPower does not consider this split is reasonable for its circumstance, it may provide a more appropriate split, with evidence, in its revised regulatory proposal.

We have also considered the relationship between opex and capex, specifically whether it is necessary to account for the way the CAM allocates overheads between capex and opex in making this decision. We considered this was not necessary in order to satisfy the capex criteria. This is because our opex assessment sets the efficient level of opex inclusive of overheads. It has accounted for the efficient level of overheads required to deliver the opex program by applying techniques which utilise the best available data and information for opex.

The starting point of our capitalised overheads assessment is CitiPower's proposal, which is based on their CAM. As such, CitiPower’s forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of CitiPower's approved capex based on assessment techniques best suited to each of the capex drivers. In doing so we have accounted for there being a fixed proportion of capitalised overheads.

As a result of a $241.0 million ($2015) reduction in CitiPower's direct capex that attract overheads, we consider a reduction of $7.0 million ($2015) reasonably reflect the capex criteria.

B.7 Forecast non–network capex

The non-network capex category for CitiPower includes expenditure on information technology (IT), buildings and property, motor vehicles, and tools and equipment. CitiPower proposed $104.0 million ($2015) for non-network capex, compared to actual expenditure of $53.8 million for the 2011–15 regulatory control period. It proposed $81.1 million for IT capex, compared to $40.2 million in the previous period. It has also proposed $22.9 million for the other non-network capex categories, compared to $13.5 million in the previous period. We have not accepted CitiPower's proposal. Instead we have included an amount of $88.1 million for non-network capex, comprised of $65.2 million for IT capex and $22.9 million for other non-network capex.

B.7.1 Position

CitiPower forecast total non-network capex of $104.0 million ($2015) for the 2016–20 regulatory control period.[197] We do not accept CitiPower's proposal. We have instead included an amount of $88.1 million ($2015) for forecast non-network capex in our estimate of total capex which we consider reasonably reflects the capex criteria. This is a reduction of around 17 per cent.

In coming to this view, we have found that CitiPower's forecast non-network IT capex of $81.1 million ($2015) does not appropriately reflect the efficient costs of a prudent operator. We consider that non-network IT capex of $65.2 million ($2015) reasonably reflects CitiPower's required capex for this category in the 2016–20 regulatory control period. This is a reduction of 19.6 per cent.

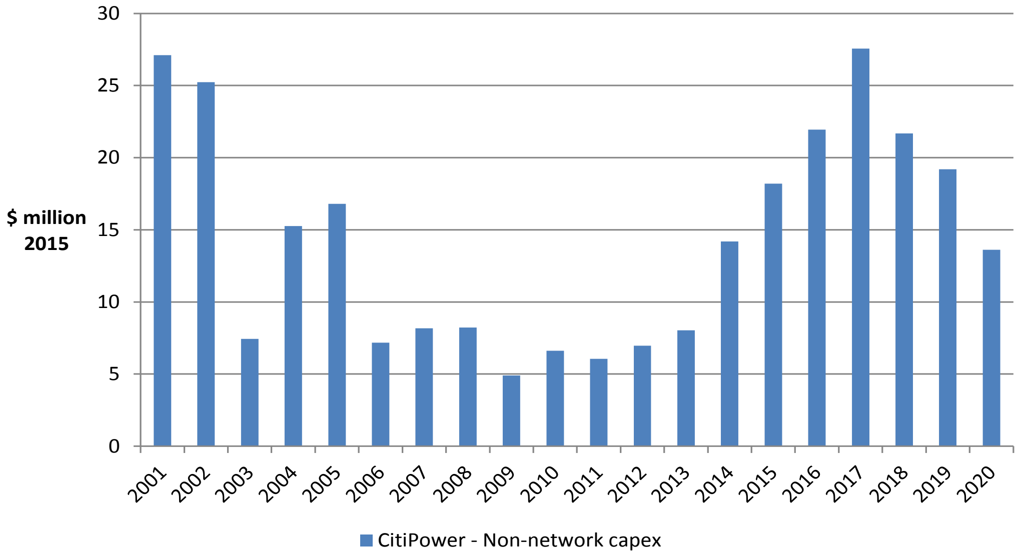
In modelling CitiPower's required revenue for the 2016–20 regulatory control period, we have also accounted for forecast disposals of fleet assets which CitiPower omitted from its regulatory proposal.

B.7.2 CitiPower's proposal

Figure 6.18 shows CitiPower's actual and expected non-network capex for the period from 2001 to 2015, and forecast capex for the 2016–20 regulatory control period.

197 CitiPower, Regulatory information notice, template 2.6.

Figure 6.18 CitiPower's non-network capex 2001 to 2020 ($million, 2015)



Source: CitiPower, *Regulatory information notice*, *template 2.6*; CitiPower, *Category Analysis RIN 2014*, *template 2.6*; CitiPower, *RIN response for 2011-2015 regulatory control period, template 2.1.1*; AER analysis.

CitiPower's forecast non-network capex for the 2016–20 regulatory control period is 94 per cent higher than actual and expected capex in the 2011–15 regulatory control period.[198]

Our analysis of longer term trends in non-network capex suggests that CitiPower has forecast capex for this category at historically high levels for most of the regulatory control period. Non-network capex in the first four years of the 2016–20 regulatory control period is forecast to be higher than expenditure in any year of the 2011–15 regulatory control period, and higher than any year since 2002. Non-network capex has been increasing since 2009 and while it peaks in 2017, it does not return to pre-2014 levels in the period. We therefore consider that CitiPower's forecast non-network capex program warrants further review to confirm the need for and timing of the proposed expenditure.

We have 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.[199] Figure 6.19 shows CitiPower's actual and forecast non-network capex by sub-category for the period from 2009 to 2020.

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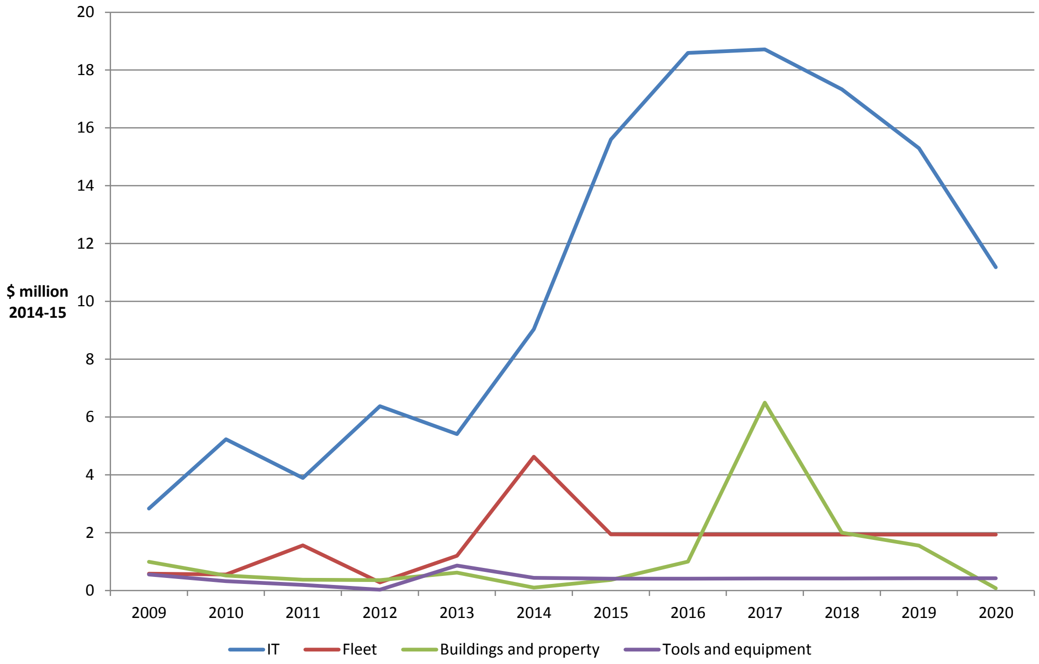
198 CitiPower, Regulatory information notice, template 2.6; CitiPower, Category Analysis RIN 2014, template 2.6; AER analysis.

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

Figure 6.19 CitiPower's non-network capex by category ($million, 2015)



Source: CitiPower, *Regulatory information notice*, *template 2.6*; CitiPower, *Category Analysis RIN 2014*, *template 2.6*; AER analysis.

CitiPower has forecast an increase in IT capex in the 2016–20 regulatory control period of 101 per cent. Forecast capex in the smaller buildings and property category is also increasing significantly associated with a spike in expenditure in 2017. The forecast expenditure for motor vehicles and tools and equipment capex is consistent with historical levels of expenditure in these categories.

We therefore undertook a detailed review of the justification for CitiPower's forecast IT and buildings and property capex to confirm the need and timing of the forecast expenditure. Our conclusions on each of these categories of non-network capex are summarised below.

B.7.3 Information technology capex

CitiPower has forecast non-network IT capex of $81.1 million ($2015) for the 2016–20 regulatory control period.[200] This is an increase of $40.9 million or 101 per cent from actual and estimated expenditure in the 2011–15 regulatory control period.

CitiPower stated that its IT program is in a cyclical upswing for 2015–2017, followed by a period of consolidation in 2018–2020 with these changes caused by the combination of: regulatory change, continued movement to a smarter network, expanded use of mobility devices, generational change in a number of its systems, increased usage and

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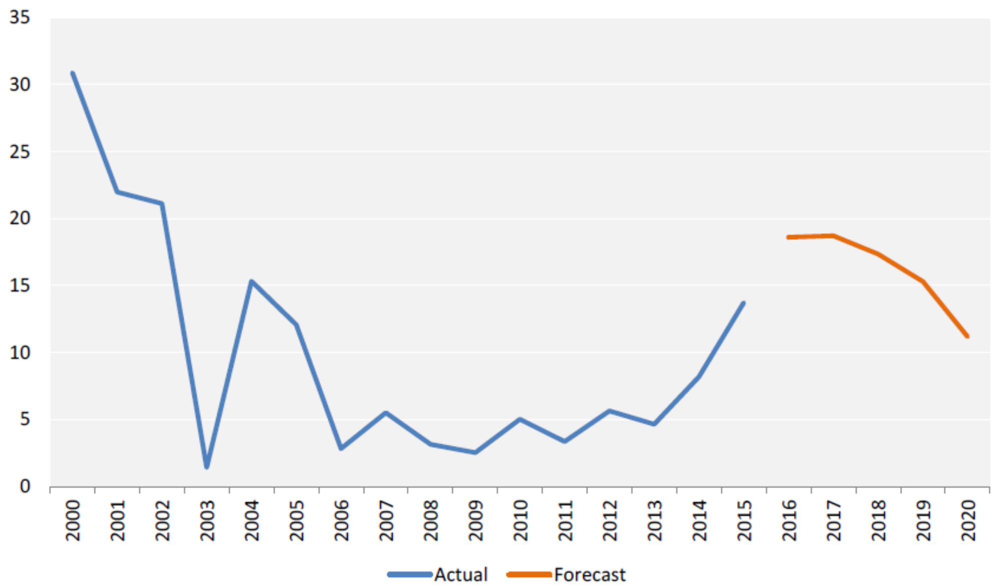
[200] CitiPower, *Regulatory Proposal 2016–20*, April 2015, p. 96.

storage of data, and fundamental changes in its IT security requirements. This upswing and consolidation in CitiPower's IT capex can be further shown in Figure 6.20.[201]

Figure 6.20 CitiPower's non-network capital expenditure ($ million, 2015)



Source: CitiPower, 2016-20 Price Reset Appendix E Capital Expenditure, April 2015, p. 134.

Changes from historical expenditure

As highlighted above, CitiPower is forecasting to more than double its IT capex compared the 2011–15 regulatory control period. The Consumer Challenge Panel noted that IT capex, across the Victorian businesses, in the 2011–15 regulatory control period was generally higher than IT capex for the 2006–2010 regulatory control period because of one off adjustments. It considers that the levels from the 2006–10 period still has significance in setting the IT capex for the 2016–20 regulatory control period because the 'one off' adjustments in the current period do not need to be replicated going forward.[202] In conclusion, the Consumer Challenge Panel suggested that IT capex should be reduced from its current levels, to bring it 'back to reasonable levels' of the 2006–2010 period.[203] While we have concerns about the proposed levels of IT capex, we accept that the appropriate level may be higher than that of the 2006–2010 period due to changes in the operating environment for businesses, such as the introduction of smarter grids and additional regulatory obligations.

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201 CitiPower, Regulatory Proposal *2016–20, Appendix E: Capital Expenditure*, April 2015, pp. 133–134.

202 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 57–58.

203 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 58–59.

Origin Energy stated that it is concerned by the persistently high levels of proposed IT capex compared to the period 2011–15 and suggested that proposed IT capex should be closely scrutinised.[204]

We have assessed CitiPower's forecast IT capex using both trend analysis and individual business cases. In our trend analysis, we have compared the proposed expenditure to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure. In doing so, we have considered the underlying drivers of expenditure, including the investment lifecycle stage the business is in and its particular IT needs. Where we have decided to review individual projects or programs, we have examined any business cases and other supporting documentation provided by the business to assess whether the expenditure reasonably reflects the capex criteria.

CitiPower divided its expenditure into recurrent and non-recurrent expenditure. Recurrent expenditure is for replacement, upgrades and maintenance of existing functionality and systems. Non-recurrent expenditure is for new functionality or new (not replacement) systems that will be introduced.[205]

CitiPower submitted that 73 per cent, or $59.2 million, of its forecast IT capex for the 2016–20 regulatory control period is recurrent. However, this is 47 per cent, or $19 million, more than CitiPower's combined non-recurrent and recurrent IT capex for the 2011–15 regulatory control period. Given how CitiPower has defined recurrent expenditure, it is not clear why the forecast recurrent IT capex is almost 50 per cent higher than the previous period's total IT capex. This increase may be driven in large part by upgrades to existing systems.

As the Consumer Challenge Panel noted, with the exception of the 'Smarter Grid' project, CitiPower has proposed IT capex only for functions that CitiPower has always had. In the Consumer Challenge Panel's view, current levels of IT capex should be sufficient to provide the services identified.[206]

CitiPower's forecast IT capex program consists of more than 100 individual projects, including implementing new customer relationship management and billing systems, and a number of 'Smarter Grid' projects to optimise network management, introduce smart analytics, and allow for network innovation. The projects span CitiPower's IT landscape and include a large number of interdependencies. CitiPower has forecast the necessary labour to implement its IT forecast, and proposed more than half of the labour to come from external sources, additional to its internal IT staff.[207]

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[204] Origin Energy, *Submission to Victorian Electricity Distributors Regulatory Proposals*, 13 July 2015, p. 8.

[205] CitiPower, *Revenue Proposal, CP PUBLIC APP E Capital expenditure, April 2015,* p. 134.

[206] Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 58–59.

[207] CitiPower, *Revenue Proposal 2016–20, CP PUBLIC APP E Capital expenditure,* April 2015, pp. 136–137.

Based on our high level review, we cannot conclude that CitiPower's IT capex program is prudent and efficient. We are concerned that the proposed program is a large scale, complex and interdependent program of works which impacts broadly across core IT systems. Therefore, we have sought to further assess the proposed program through individual project reviews, below.

Project review

CitiPower divided its IT capex forecast into seven streams: compliance, currency and capacity, customer engagement, device replacement, infrastructure, security, and smarter networks.

These streams are divided into more than one hundred smaller projects, all of which are supported by documentation setting out estimated costs, options and justification for the preferred option.[208] Additionally, some of the larger projects are supported by specific project cost/benefit analyses.

The Consumer Challenge Panel submitted that new IT systems should only be implemented when there is a clear benefit to consumers and that the benefits are integrated into the capex and opex forecasts.[209] The Victorian Energy Consumer and User Alliance noted that for a number of businesses, the capex programs were poorly justified with inadequate provision of cost benefit analyses and insufficient justification of prioritisation and timing of projects. They also stated a concern that businesses placed an overreliance on bottom up forecasting, therefore inadequately taking into account interrelationships between projects.[210]

We have reviewed the documentation and further clarification submitted by CitiPower in support of its proposed IT capex projects, to assess whether the forecast capex reflects the efficient costs that a prudent operator would incur.[211]

Four major projects that CitiPower has proposed for the 2016–20 regulatory control period make up about 60 per cent of its IT capex forecast:

1. a new customer relationship management and billing system,
2. a program to deliver a 'Smarter Grid',
3. expenditure to meet RIN requirements, and
4. a program of IT security improvements.

208 CitiPower, *Response to AER Information Request IR # 012*, 24 July 2015; CitiPower, *Response to AER Information Request IR # 020*, 12 August 2015.

209 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 56 and 59.

210 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 19.

211 NER, cll. 6.5.7(c)(1) and 6.5.7(c)(2).

Of these projects, only the documentation for the new billing system and the 'Smarter Grid' project show that the projects provide an economic return (positive NPV). The business case for the 'Smarter Grid' project shows that the sub projects each provide an economic return individually and as a total package.

The Consumer Challenge Panel's submission on CitiPower's new billing system focused on the fact that CitiPower did not include the associated consumer benefits in its opex and capex forecasts.[212] The Victorian Government supported CitiPower's expenditure on a new customer relationship management system and web portal to allow consumers to obtain information from the businesses because these businesses are the only Victorian distributors that do not currently have an online customer portal.[213]

We accept that this expenditure reasonably reflects the criteria. While we agree with the Consumer Challenge Panel that there will be associated benefits through reduction in opex and capex, we find it reasonable that such benefits may not emerge within this regulatory period. We also support the prudence and efficiency of the costs to provide this new system and have included an allowance for such a system in our forecast.

The 'Smarter Grid' project, as noted above, provides a positive economic return, both as a total package and as individual sub projects. We are satisfied that this project reflects the efficient costs that a prudent operator would incur to achieve the capex objectives. Therefore, we have included an allowance for this project in our forecast.

The documentation for the expenditure to meet RIN requirements and for IT security do not show whether or not these projects provide an economic return in that they disclose the costs, but not the economic benefits of the projects. An economic justification is not the sole basis for proceeding with a capex project that may be otherwise necessary to meet the capex objectives of the NER.[214] For example, a particular capability may be necessary to comply with a regulatory obligation or to maintain the quality, reliability and security of supply. However, we must be satisfied that the forecast capex reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.[215] Based on our review, the evidence provided by CitiPower for these two projects does not support this conclusion.

Specifically, we have concerns about the magnitude of expenditure proposed for each of the projects. The expenditure to meet RIN requirements is supported by a business case that estimates the costs of the project for CitiPower and Powercor, combined, at

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212 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 56-57, 59, citing Deloitte Access Economics on behalf of CitiPower and Powercor, *Investing in a new billing and customer relationship management system*, 16 December 2014.

213 Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 4.

214 NER, cl. 6.5.7(a).

215 NER, cl. 6.5.7(c).

$28.6 million.[216] United Energy and SA Power Networks have also proposed IT capex for compliance with the RINs. However, AusNet Services, Jemena, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Energex and Ergon Energy have either not proposed any IT capex for this or only proposed very small amounts.

While we understand that IT capability may be different across different businesses, we would expect that the costs associated with RIN obligations would be relatively consistent across businesses. Further we sought information from network service providers on the cost of compliance when we were consulting on RIN obligations, but were not provided with any estimates.[217] Absent this information when establishing the requirements, we would find it reasonable to assume that the cost would not be material.

We recognise that each business is starting from a different position regarding its existing systems and data availability. CitiPower stated that the category analysis RIN and the economic benchmarking RIN impose new requirements on it, which, to date, it has complied with by collecting information from outside existing systems and making estimates. However, the obligations on businesses going forward to provide actuals will require CitiPower to reprogram its systems for RIN compliance.[218] CitiPower's preferred option involved developing an automated approach to RIN compliance.[219] While we accept that CitiPower may incur costs above those forecast by other companies in complying with RIN obligations, the amounts set out by CitiPower are of a sufficient magnitude that we are not satisfied that they reflect prudent and efficient expenditure. As such and in the absence of further information, we do not accept the forecast of $8.6 million in this preliminary decision.

CitiPower has proposed $10.5 million for IT security projects. We accept the need to ensure that CitiPower's IT network is secure and is able to detect and address any security threats. However, CitiPower has not provided information to quantify the cost of the risk it is attempting to address, or provided a cost benefit or options analysis. As such, our preliminary decision does not include the full forecast amount of $10.5 million.

The remaining 40 per cent of CitiPower's forecast IT capex is spread across multiple small projects across the compliance, currency and capacity, customer engagement, device replacement, infrastructure IT streams. The documentation CitiPower provided for these projects did not include numerical cost benefit analyses, but did include costings and qualitative benefits. Some of the projects are to upgrade existing systems

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216 KPMG on behalf of CitiPower and Powercor, *Business Case for expenditure to meet RIN requirements*, April 2015, p. 7. CitiPower's proposed expenditure is 30 per cent of the total or $8.6 million.

217 AER, *Better Regulation: Explanatory Statement: Final regulatory information notices to collect information for category analysis*, March 2014, pp. 1–2, 8. AER, *Better Regulation: Explanatory Statement: Regulatory information notices to collect information for economic benchmarking*, November 2013, p. 9.

218 CitiPower, *Revenue Proposal, CP PUBLIC APP E Capital Expenditure*, April 2015, pp. 149–150.

219 KPMG on behalf of CitiPower and Powercor, *Business Case for expenditure to meet RIN requirements*, April 2015, p. 12.

to the currently available version, and will ensure that CitiPower's systems are not vulnerable due to out of support applications.[220] In these cases, we are satisfied that these are the efficient costs of a prudent operator based on the documentation of costings and systems requirements provided by CitiPower.

Other projects in the compliance stream are to make changes to systems due to potential, but not yet defined, regulatory change. In the absence of information on the scope and costs of potential regulation, we are not satisfied that these reflect the efficient costs of a prudent operator required to achieve the capex objectives. If there are regulatory changes during the upcoming regulatory control period that are not currently defined, CitiPower may make a cost pass through application to us for any material change in costs as these would likely be regulatory change events.[221]

Conclusion on information technology

Based on our review of both the total portfolio and individual projects, we are not sufficiently satisfied that CitiPower's non-network IT capex forecast reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.[222] In determining our alternative estimate of non-network IT capex, we have considered the level of investment that is likely to be:

- prudent, having regard to CitiPower's business needs in the 2016–20 regulatory control period
- efficient and justifiable, having regard to the economic evaluation of alternative investment options.

For this preliminary decision, we consider that non-network IT capex of $65.2million ($2015) reasonably reflects CitiPower's required capex for this category in the 2016–20 regulatory control period. This is a reduction of $15.9 million or 19.6 per cent compared to CitiPower's forecast non-network IT capex. We derived our estimate by removing the expenditure for RIN compliance and making proportional reductions: for projects that have not been sufficiently justified, for projects that are speculative and therefore cannot be accurately costed, and for projects where some of the expenditure is not justified. Those reductions total to 10 per cent of the expenditure remaining after the removal of the RIN compliance project. Our estimate provides for a 62 per cent increase from actual non-network IT capex in the 2011–15 regulatory control period.

In determining our alternative estimate of non-network IT capex, we examined the overall trend in IT capex as well as individual projects to arrive at a forecast of capex that is based on efficient costs. It is now up to CitiPower to determine how best to allocate this budget throughout the 2016–20 regulatory control period We are satisfied that the forecast capex of $65.2 million ($2015) reasonably reflects the efficient costs

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220 These projects include projects in the currency and capacity, customer engagement, device replacement, and infrastructure IT streams.

221 NER, cl. 6.6.1.

222 NER, cl. 6.5.7(c).

that a prudent operator would require to the capex criteria.[223] We will make an allowance for it in our estimate of total capex for the 2016–20 regulatory control period.

B.7.4 Buildings and property capex

CitiPower's forecast non-network buildings and property capex of $11.2 million ($2015) reflects a bottom up build of expenditure requirements at its Richmond depot. CitiPower's Richmond depot houses approximately 330 employees. The main office accommodation has a building age approaching 100 years and has not been refurbished for approximately 25 years.[224]

CitiPower has proposed to redevelop the existing depot at Richmond in order to:[225]

- refurbish depot offices
- undertake structural, plumbing and electrical works to rectify defects
- remediate environmental site issues, including soil and groundwater contamination relating to prior use of the site as a tannery and chemical manufacturing plant
- replace office furniture
- install a lift to improve site access.

We reviewed the business case and other documentation submitted by CitiPower in support of the Richmond depot project. In general, we found that CitiPower had provided appropriate evidence to support the preferred Richmond redevelopment option, including:

- a detailed description of the need for investment, with supporting evidence as to the nature of asset obsolescence and other specific site condition, contamination and compliance issues
- evidence that a range of alternative options has been considered
- a comparison of costs and benefits for the options considered.

However, the Richmond depot project business case did not specifically assess the costs and benefits of the 'do nothing' option, or provide an analysis of the lifecycle costs and benefits of the options considered which supports selection of the preferred option from an economic perspective. We therefore sought further information from CitiPower to confirm that the proposed redevelopment option was justified with regard to the 'do nothing' option and other development options, and was therefore likely to reflect prudent and efficient expenditure.[226]

223 NER, cll. 6.5.7(c)(1) and 6.5.7(c)(2).

224 CitiPower, *Regulatory Proposal 2016–20, Appendix E.64: Material Project PROP19 Rooney Street remediation*, April 2015, pp. 2–4.

225 CitiPower, *Regulatory Proposal 2016–20, Appendix E:- Capital expenditure*, April 2015, pp. 163–164.

226 AER, *Information request to CitiPower IR# 017*, 27 July 2015.

CitiPower submitted that the 'do nothing' option was not viable for the Richmond site because:[227]

- the existing premises are in a state of disrepair and provide sub-optimal amenity
- access for mobility impaired staff, contractors and visitors is not compliant with current standards due to a lack of ramps and a lift in the main accommodation building
- site safety hazards and ongoing maintenance costs are likely to increase over time as buildings and fittings deteriorate further
- the site is at capacity, such that some staff are currently accommodated in sheds without kitchen or bathroom facilities, which is not sustainable over the short to medium term

CitiPower's assessment of possible options also shows that other development options, such as demolition and rebuild of the existing office building, are not viable due to the heritage status of the existing building. CitiPower considers that relocation to a new site is also not viable due to the strategic location of the Richmond site, and the difficulty in finding a site of similar size and layout that can accommodate office, project and operational staff.[228]

In response to our request, CitiPower provided a breakdown of the proposed project costs and their basis of estimation, which shows that the majority of the costs proposed relate to the site remediation and drainage issues rather than the building repair and fit-out costs.[229] The local authority planning process associated with the building repair work will trigger an existing 'environmental significance' overlay on the property title. As a result, conditions will be imposed on CitiPower under the *Planning and Environment Act 1987 (Vic)* to address the latent environmental contamination issues at the site.[230] Given these requirements, and as the building repair work will involve disturbing the surrounding soil and concrete slab, we are satisfied that a prudent operator would undertake the environmental remediation works at the same time as the building redevelopment project.

On the basis of the information submitted by CitiPower, we are satisfied that the proposed redevelopment of the Richmond depot, including the site environmental remediation work, is likely to be necessary in the 2016–20 regulatory control period. This conclusion reflects the existing site age, condition, safety, contamination and compliance issues identified by CitiPower. In our view, the information submitted by CitiPower sufficiently demonstrates that the need for investment to redevelop the Richmond depot building and provide for its ongoing efficient operation as CitiPower's

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[227] CitiPower, *Response to Information Request CitiPower IR# 017*, 10 August 2015, pp. 1–3.

[228] CitiPower, *Regulatory Proposal 2016–20, Appendix E.64:- Material Project PROP19 Rooney Street remediation*, April 2015, p. 8.

[229] CitiPower, *Response to Information Request CitiPower IR# 017*, 10 August 2015, p. 3; and CitiPower, *CP CONFIDENTIAL Rooney St redevelopment IR0#17.xlsx*, 10 August 2015.

[230] CitiPower, *Response to Information Request CitiPower IR# 017*, 10 August 2015, p. 2.

sole depot site. On this basis, we have included the forecast costs associated with this project in our estimate of forecast capex which reasonably reflects the capex criteria.

B.7.5 Fleet asset disposals

CitiPower did not account for any disposals of fleet assets in its regulatory proposal. In assessing CitiPower's forecast non-network capex, we sought further information regarding CitiPower's forecast disposals of fleet assets in the 2016–20 regulatory control period.[231]

In response to our information request, CitiPower advised that it expected proceeds from the sale of fleet assets over the 2016–20 regulatory control period of $1.3 million ($2015).[232] We have accounted for these disposals in modelling CitiPower's required revenue for the 2016–20 regulatory control period.

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231 AER, *Information request to CitiPower IR# 005*, 23 June 2015.

232 CitiPower, *Response to AER information request IR# CitiPower 005*, 30 June 2015.

C Maximum demand forecasts

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure.[233] This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts. Hence accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network.

This attachment sets out our decision on CitiPower's forecast network maximum demand for the 2016–20 regulatory control period. We consider CitiPower's demand forecasts at the system level and the more local level.

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

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

In our consideration of CitiPower's demand forecasts, we have had regard to:

- CitiPower's proposal
- independent maximum demand forecasts from the Australian Energy Market Operator (AEMO)[234]
- a report by our internal economic consultant, Dr Darryl Biggar, on the forecasting methodologies underlying each Victorian electricity distributor's demand forecasts for 2016–20 (this report will be published alongside this preliminary decision)[235]
- long-term demand trends and changes in the electricity market, and
- stakeholder submissions in response to CitiPower's proposal (as well as submissions made in relation to the Victorian electricity distribution determinations more generally).[236]

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[233] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).

[234] AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014.

[235] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015.

[236] See AER, http://www.aer.gov.au/node/24446.

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

C.1 AER determination

We are not satisfied that CitiPower’s demand forecasts reflect a realistic expectation of demand over the 2016–20 regulatory control period. In determining a realistic expectation of demand over the 2016–20 period, we have had regard to the following factors:

- Observed changes in the electricity market and the way energy is consumed in recent years (e.g. strong uptake of solar PV, changing customer behaviours and energy efficiency measures) suggests that the strong positive demand growth seen in CitiPower's network prior to 2009 is unlikely to return in the short to medium term. This is discussed in section C.3.
- CitiPower's forecasting methodology effectively assumes that there is a fixed underlying relationship between demand and certain identified demand-drivers (e.g. weather) and that this relationship has been correctly estimated in their model, using the past ten years of historic data, and that this relationship will continue to hold into the future. We are not satisfied that this reflects a realistic expectation of future demand over the 2016–20 period since we are not confident that the drivers used in CitiPower's model are able to fully capture the changes in demand in recent years. This is discussed in section C.2 and C.4.
- Independent forecasts from AEMO better explain the actual demand pattern seen on all distributors’ networks. This is because it does not assume a fixed structural relationship between demand and demand-drivers over a long period and, instead, places greater reliance on industry knowledge and judgement. While not without its limitations, we consider that AEMO's forecasts better reflect recent changes in the electricity market. This is also discussed in section C.4.

We understand that CitiPower (and the Victorian electricity businesses) are in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR). We also note that AEMO will publish updated connection point demand forecasts for Victoria. We are open to CitiPower submitting an updated demand forecast that accounts for the factors listed above, including the most recent demand data and AEMO’s updated forecasts.

We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will also consider updated demand forecasts and other information (such as AEMO's revised connection point forecasts) in the final decision to reflect the most up to date data.

We have also received a number of consumer submissions that raise concerns with CitiPower's and the other Victorian distributors maximum demand forecasts. The CCP submitted that we should pay particular attention to the distributors’ maximum demand forecasts and whether they have been over estimated, given the following considerations:

- forecasts of maximum demand are key drivers of revenue requirements

- distributors' forecasts exceed and contrast with AEMO's forecasts, and
- distributors have consistently over forecast maximum demands in the past.[237]

The Ethnic Communities Council of Victoria (ECCV) also supported us further examining the Victorian distributors' forecasts that exceed forecasts by AEMO.[238]

The VECUA also submitted that the Victorian distributors have consistently over estimated their peak demand and energy delivered projections. VECUA put forward that network distributors are insulated from volume risk through revenue cap regulation, which allows them to pass that risk on to customers. Therefore if the actual energy delivered is lower than forecast by networks' then networks will increase their prices to recover their guaranteed revenues. VECUA also considered it important to note:[239]

> …that the Victoria distributors were rewarded with windfall profits for their forecasting errors, as their revenue allowances included returns and depreciation on load-driven capex which they did not incur.

As set out in this appendix, we have closely examined CitiPower's maximum demand forecasts and drawn similar observations to these submissions. A key part of our work has been to analyse CitiPower (and the other Victorian distributors) demand forecasts with reference to AEMO's independent maximum demand forecasts. However, the VECUA submitted that AEMO has consistently over estimated its energy forecasts in recent years and has not fully considered the influence of future factors in reducing demand (such as energy efficiency schemes, automotive closures, cost reflective price structures and battery storage technology).[240] We do not agree with the VECUA and consider that AEMO's explanation of its forecasting methodology reveals that it has considered a wide variety of information in its forecast, including predictions for energy efficiency and automotive closures in Victoria and this represents an enhancement and improvement to its previous forecast approach.[241]

Further, the CCP and VECUA referred to AusNet Services demand forecasts as the only Victorian distributor to forecast lower energy consumption in the future compared to the past.[242] VECUA has submitted that AusNet Services demand forecasting

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237 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 32–37.

238 Ethnic Community Council of Victoria, *Submission to the Australian Energy Regulator Victoria Electricity Pricing Review*, 15 July 2015, p. 4.

239 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 14–16.

240 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 17.

241 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 11.

242 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 35-37; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 15–16.

methodology incorporates actual interval metering data, which it considers may account for the differences between AusNet Services forecast growth and other Victorian distributors.[243] The CCP considered that the AusNet Services approach to developing its forecast demand is a significant enhancement in forecasting future demand and is a direct outcome from the decision to mandate the roll out of the AMI program in Victoria.[244] We consider there is merit to these views (and will be useful as distributors develop their information capacity). However we have not directly taken this into account for our assessment of CitiPower's maximum demand forecasts because it has not been necessary due our assessment approach which is based substantially on comparison with AEMO's demand forecasts.

C.2 CitiPower's proposal

CitiPower provided historical and forecast demand figures in their proposal and in the reset Regulatory Information Notice (RIN).[245] CitiPower proposes approximately 2.38 per cent annual growth in maximum demand across the 2016–20 period. In its proposal, CitiPower forecast an increase in peak demand in specific areas of its network to be driven by:[246]

- increases in the frequency and duration of heatwaves that will increase the use of air-conditioners by commercial businesses and residential households
- population expansion, particularly along established and proposed transport corridors driven by changes in zoning
- block load additions from specific projects such as high density residential developments.

CitiPower submitted that its forecast of peak demand growth is based on public information from the Victorian Government and the City of Melbourne.[247]

CitiPower's engaged the Centre for International Economics (CIE) to develop its demand forecasts.[248] CitiPower's proposal also included a brief summary of CIE's demand forecasting method, including approaches to:

- demand drivers
- accounting for economic conditions such as incomes and electricity prices
- projections of customer numbers by tariff class, and
- post model-adjustments for block loads and embedded generation.[249]

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[243] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 16.

[244] CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 35–37 and p. 44.

[245] CitiPower, CitiPower reset RIN; CitiPower, *Regulatory Proposal 2016–20,* April 2015, pp. 83–92.

[246] CitiPower, *Regulatory Proposal 2016–20,* April 2015, p. 84.

[247] CitiPower, *Regulatory Proposal 2016–20,* April 2015, pp. 84–85.

[248] CitiPower, *Regulatory Proposal 2016–20,* April 2015, p. 86.

CitiPower's forecasting methodology is described in detail in Dr Biggar's report.[250]

C.3 Demand trends

Our first step in examining CitiPower's forecast of maximum demand is to look at whether the forecast is consistent with, or explained by, long-term demand trends and changes in the electricity markets.

Figure 6.21 shows that over the last few years, the path of electricity demand seems to be changing. From 2006 to 2009, actual maximum demand on CitiPower's network was growing steadily. Then from 2009 to 2012, demand flattened and declined. The decline in 2009 from historical demand growth has also been recorded for Victoria (as shown in Figure 6.22) and for the NEM. While there was some demand growth between 2013 and 2014, this does not necessarily indicate a return to longer-term growth.

As shown further in Figure 6.21 CitiPower's demand forecasts for the 2015–20 period are considerably higher than the actual demand observed for its network during 2006–14 (substantially so for its 10 PoE forecasts). CitiPower forecasts a return to demand growth on the network similar to that experienced prior to 2009. This contrasts with AEMO's Connection Point Forecasts, published in September 2014, which forecasts little or no growth in connection point demand on CitiPower's network for this period.[251]

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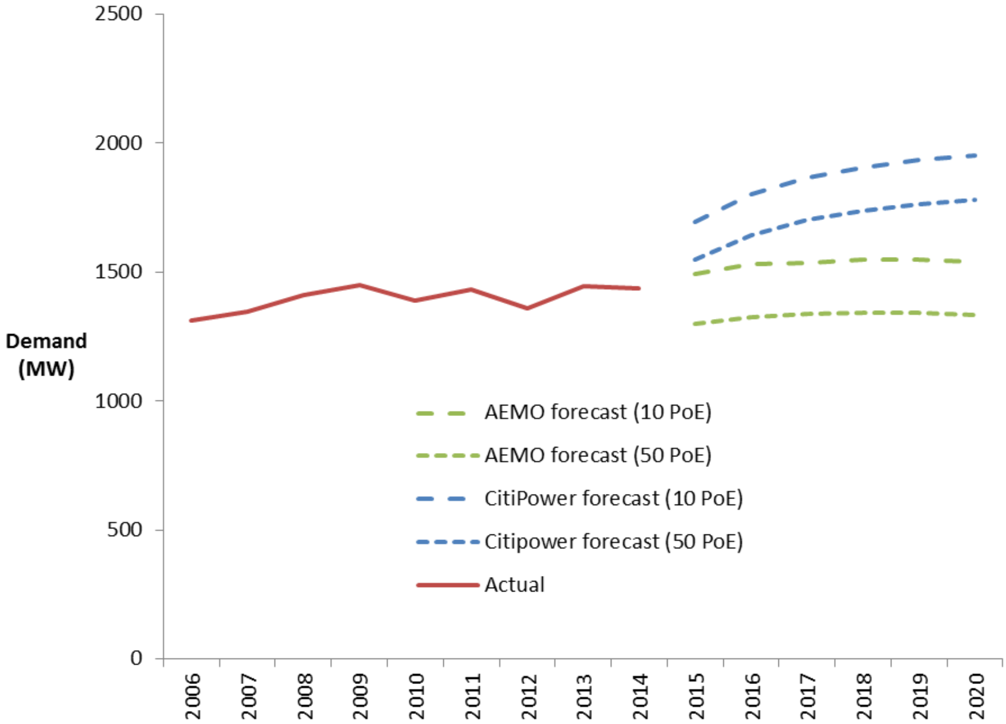
[249] CitiPower, *Regulatory Proposal 2016–20,* April 2015, p. 86.

[250] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 25–27.

[251] AEMO, *Transmission Connection Point Forecasting Report for Victoria*, September 2014, pp. 12–13.

Figure 6.21 Comparison of peak demand forecasts of CitiPower and AEMO (MW, non-coincident, summated connection point forecasts)

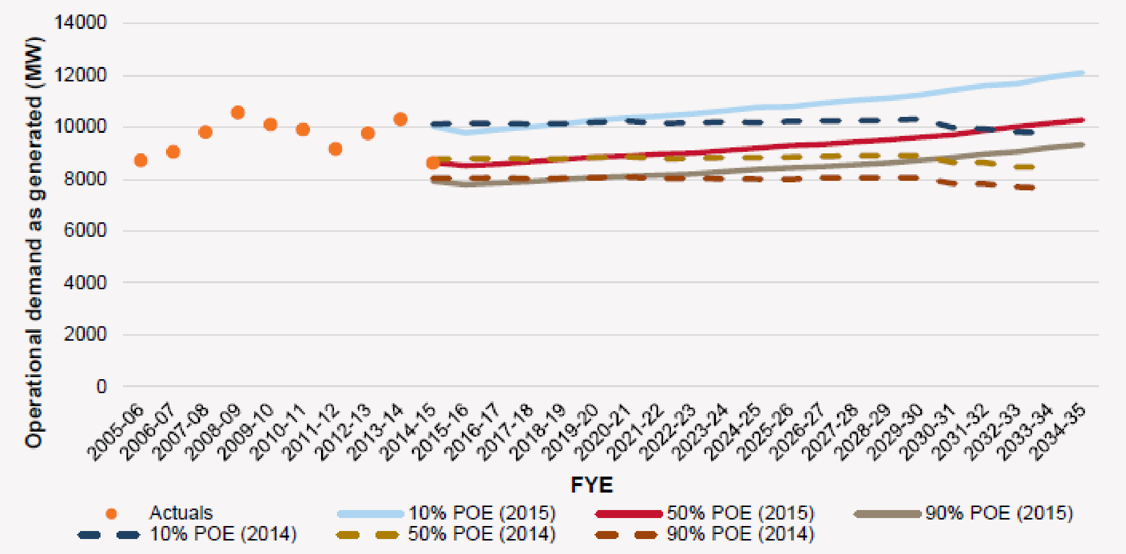


Source: CitiPower regulatory proposal, AER analysis using AEMO data on transmission connection point forecasts; reset RIN; economic benchmarking RIN 2006-14.

Note: Actual demand over the 2006 to 2014 period reflects CitiPower's actual maximum demand over this period (as reported in CitiPower's economic benchmarking RIN data from 2006 to 2014). This is opposed to weather normalised historical maximum demand data.

Figure 6.22 shows AEMO's forecasts of maximum demand across Victoria. In its 2015 national electricity forecasting report, AEMO forecast a flattening of maximum demand for Victoria for 2015–2020. However, AEMO has forecast some growth in maximum demand over the next twenty years, which is a change from its 2014 national electricity forecasting report.

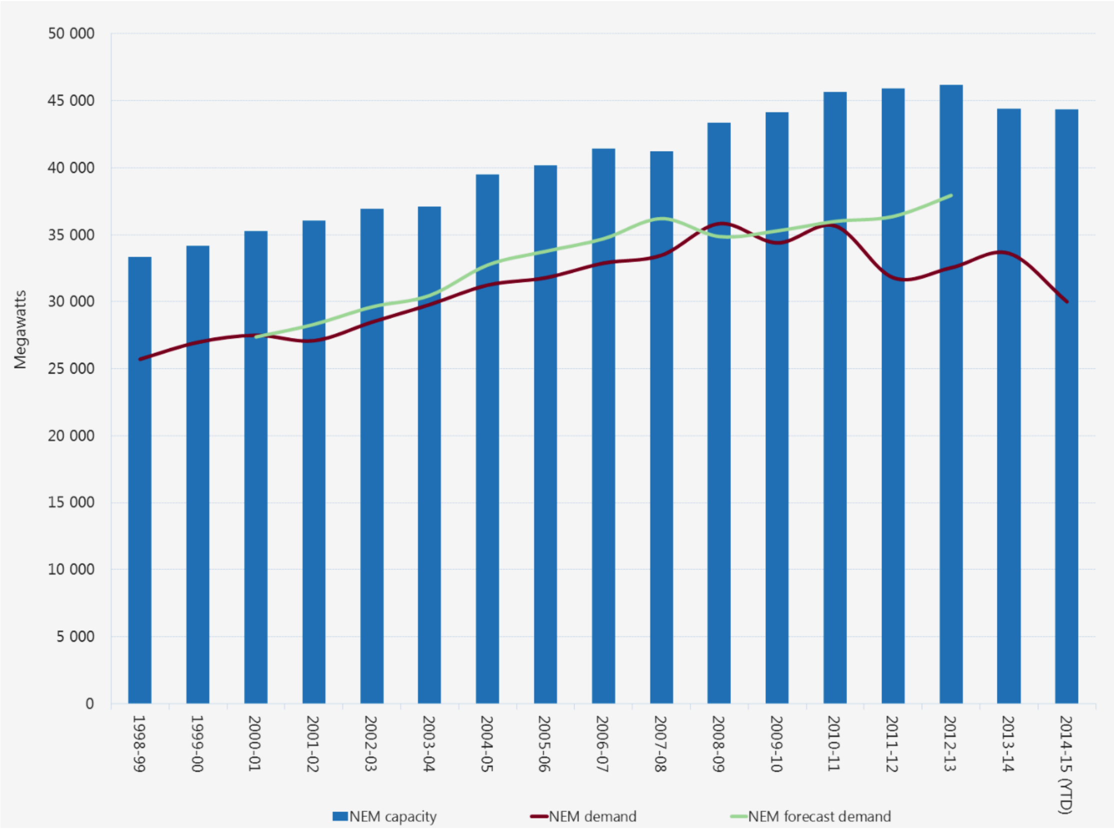
Figure 6.22 AEMO's maximum demand forecasts for Victoria



Source: AEMO, *2015 National Electricity Forecasting Report,* June 2015.

We see a similar change in peak demand patterns across the NEM. Figure 6.23 compares NEM peak demand together with the forecast peak demand two years ahead and total generation capacity, since the NEM began. It shows actual demand has been declining generally since 2008–09 across the NEM.

Figure 6.23 Comparison of historical generation capacity and peak demand across the NEM



Source: AER, accessed on 18 August 2015 at: https://www.aer.gov.au/node/9772.

Note: The step up in maximum demand in 2004-05 is as a result of Tasmania's entry to the NEM.

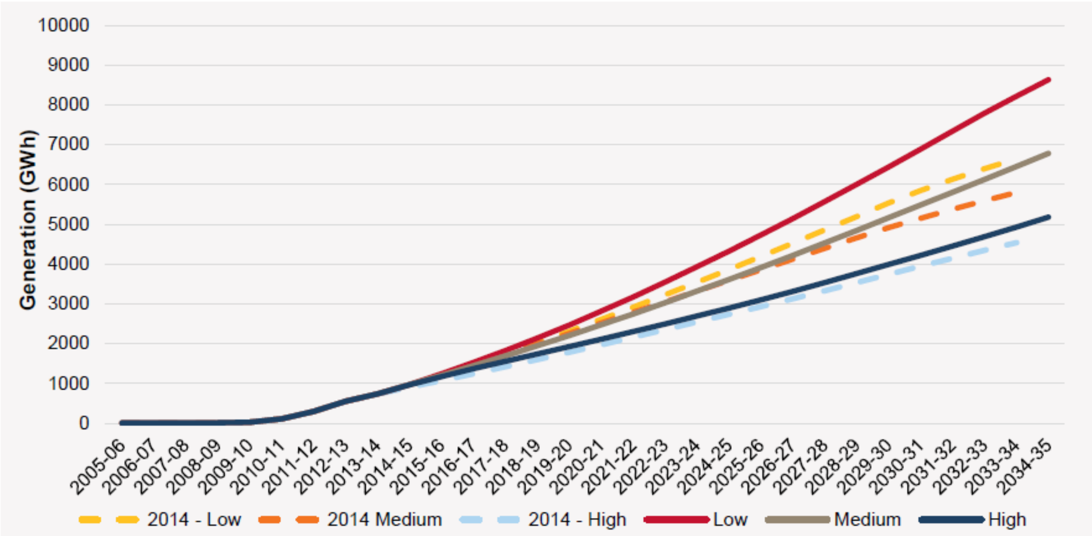
CitiPower forecasts strong demand growth for 2015–20, whereas other independent forecasts from AEMO predict low or no growth over this period. While actual connection point demand increased on CitiPower's network in 2013 and 2014 (see Figure 6.21), the observed changes in demand patterns within the span of nine years raises whether the recent flattening of demand is an aberration (and demand will return to growth) or a realistic expectation of demand over the 2016–20 period.

There have been some fundamental developments in the Australian and Victorian electricity markets over recent years that have influenced energy consumption and maximum demand patterns:

First, across the NEM, growth in rooftop solar generation (photovoltaics, or PV) and energy efficiency (through the uptake of energy efficient appliances and building efficiency) has reduced electricity drawn from the grid. Rooftop PV generation has had the long-term effect of reducing maximum demand and shifting the daily peak to later in the evening. Energy efficiency reduced overall energy consumption and has a downward impact on maximum demand.

In Victoria, AEMO reported that in the five years to 2014–15, consumption in the residential and commercial sectors decreased due to rising prices and the uptake of rooftop PV.[252] AEMO forecasts continued uptake of rooftop PV in the residential and commercial sectors, as shown in Figure 6.24. From this figure we observe a projected substantial increase in the volume of installed rooftop solar PV capacity can be observed from 2010 to 2015, with capacity expected to continue to grow strongly to 2020 and beyond.[253]

Figure 6.24 Projected capacity of solar PV systems in Victoria



Source: AEMO, *2015 National Electricity Forecasting Report*, June 2015.

However, we note that the impact of rooftop PV will likely have diminishing impacts on maximum demand over the longer-term as peak daily demand shifts to the evening. This is recognised in AEMO's forecasting report.[254] We note that electricity storage (e.g. batteries) has the potential to significantly enhance the impact of solar generation on maximum demand on the distribution network. However, wide-spread uptake of battery storage will probably not be significant over the 2016–20 period.

Second, energy efficiency also contributed to decreased consumption and AEMO forecasts that energy efficiency measures will continue.[255] Ongoing energy efficiency measures such as mandatory energy efficiency building requirements[256] and other

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[252] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 68.

[253] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 73.

[254] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 77.

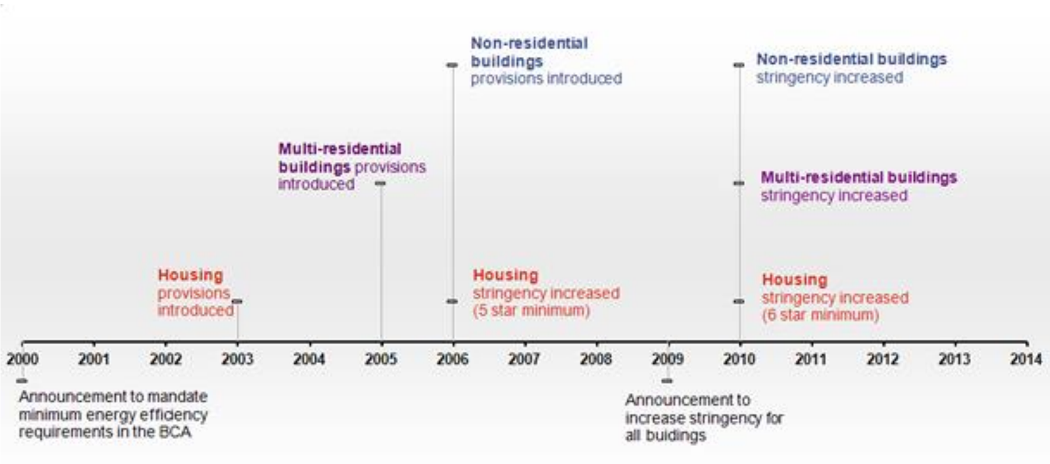
[255] AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

[256] Australian Building Codes Board (ABCB), *National Construction Code energy efficiency requirements*, http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx , accessed on 27 August 2015.

government incentives[257] have created an accumulative effect in slowing down demand growth over time. In addition, greater customer awareness of energy usage, improving appliance efficiencies and replacement of aging appliances will likely continue to put downwards pressure on consumption and maximum demand.[258]

Figure 6.25 gives an overview of government energy efficiency requirements in building provisions. From this timeline it can be inferred that the increasing energy efficiency requirements in building regulation are likely to have a cumulative effect on demand in the future.

Figure 6.25 Timeline of Energy Efficiency Requirements in Building Regulation



Source: Australian Building Codes Board (ABCB), accessed on 27 August 2015 at: http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx.

Finally, AEMO also forecast that Victoria is not expected to recover to its historical high level of operational consumption (in 2008–09) until 2030–31, when population is projected to be 1.7 million higher than in 2014–15.[259]

We consider that the combination of these factors support forecast reductions or softening of maximum demand even in the presence of economic and population growth. In particular, based on our assessment of independent forecasts from AEMO, we consider the continuing presence of energy efficiency measures, improving appliance efficiencies and continued growth in rooftop PV will likely put downward

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257 Department of Industry and Science, *Your energy savings: Rebates*, http://yourenergysavings.gov.au/rebates?live_in%5B%5D=64&interested%5B%5D=82&=Search, accessed on 27 August 2015.

258 AEMO, *2015 National Electricity Forecasting Report: Overview*, June 2015, pp. 8–11.

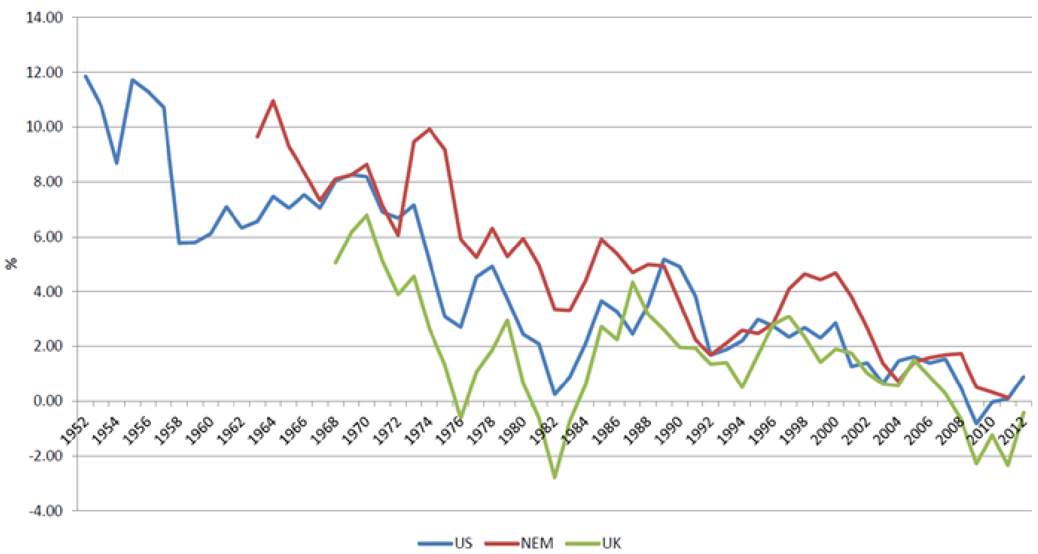
259 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

pressure on demand, which may counteract any demand growth due to economic and population growth. Solar PV and energy efficiency are not transient or temporary phenomena, but rather fundamental changes in the way electricity is consumed.

As set out in section C.4 below, we consider that CitiPower's forecasting methodology does not adequately capture the changes we are observing for the electricity market in Victoria and recent declines in demand. This is because CitiPower's methodology assumes that the structural model they have estimated using 2004–2015 data accurately and completely captures the key drivers of demand in Victoria and that the same relationships between demand and demand-drivers will continue to hold over the 2016–20 period. We are not satisfied that this reflects a realistic expectation of future demand over the 2016–20 period since we are not confident that the drivers used in CitiPower's model are able to fully capture the changes in demand in recent years.

This is consistent with international trends. Figure 6.26 highlights the fact that growth in electricity demand is currently low or zero in the USA and UK despite the existence of continued population growth and economic growth. This chart suggests that the impact of economic population growth on electricity demand is being offset by other factors (e.g. improving energy efficiency). On this basis, it is reasonable to argue that high growth is unlikely to return over 2016–20.[260]

Figure 6.26 Long-term trends in electricity growth rates



Source: Energy Supply Association of Australia (ESAA).[261]

[260] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 11.

[261] Economic and Social Outlook Conference 2014, ESAA, 3 July 2014, p. 7, accessed on 18 August 2015 at: http://www.melbourneinstitute.com/downloads/conferences/Outlook2014/Outlook2014_slides/6_Warren,%20Matthew.pdf.

C.4 CitiPower's forecasting methodology and assumptions

Our next step in examining CitiPower's forecasts of maximum demand is to look at CitiPower's methodology and whether it is likely to result in a demand forecast that reflects a realistic expectation of demand.

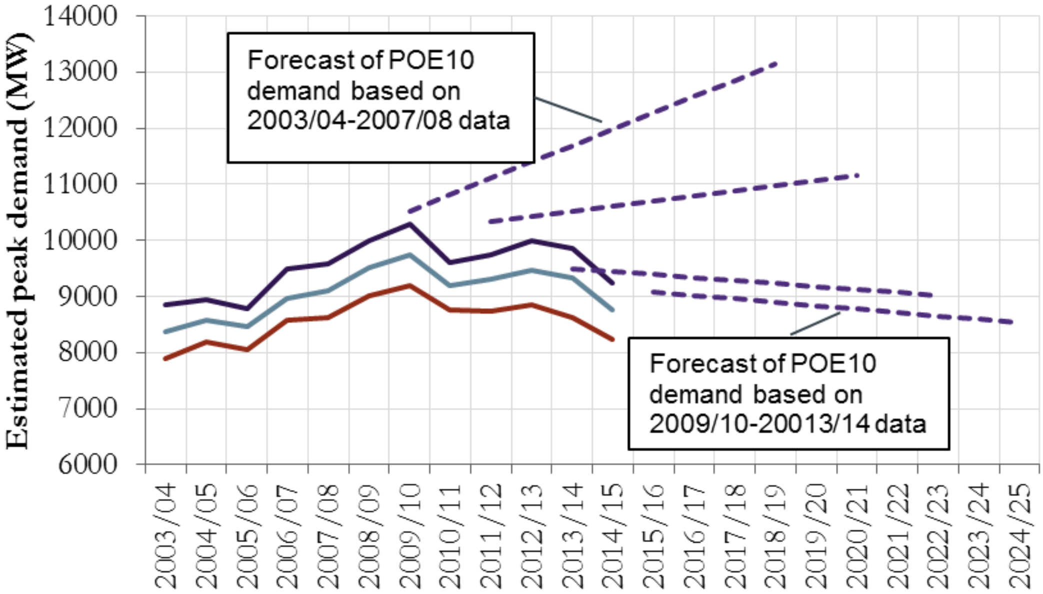
CitiPower's forecasting methodology (from CIE), like most forecasting models, assumes that there is a fixed and unchanging underlying relationship between demand and key demand drivers. It assumes that this relationship can be accurately estimated using historic data and that these relationships that have been observed in the past will continue into the future. However, if there are changes in the market which are not captured in the forecasting model, the model will not provide a reliable guide to future outcomes.

This is shown in Dr Biggar's 2015 report on the Victorian electricity distributors' demand forecasting methodologies.[262] Dr Biggar's analysis, replicated in Figure 6.27, provides a simple illustration which shows what can happen when the assumed drivers of demand do not capture a fixed and unchanging relationship between demand and the key drivers. In this example it is assumed that the primary driver of demand is time (a simple time trend). But as Figure 6.27 shows, there appears to be no fixed relationship between peak demand and time. In the first half of the last decade, peak demand growth was increasing rapidly. Since around 2009 it appears that peak demand has been declining. This illustrates that a model, which assumes a simple fixed relationship between peak demand and time would likely give unreliable forecasts of future peak demand.[263]

[262] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

[263] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

Figure 6.27 Illustration of future forecasts of POE10 levels based on the most recent five years of data



Source: Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 10.

Similarly, Dr Biggar observed that CIE's modelling enforces a single relationship between maximum demand and weather and other key drivers across the entire ten year period which is assumed to continue to hold in the future. [264]

Dr Biggar stated that CIE’s methodology is econometrically sophisticated, and has been prepared in good faith using tools which have proven robust and effective in the past.[265] However, CIE's models implicitly forecast a return to long-term growth through the assumption that the longer-term structural relationships will continue to hold in the future.[266] Dr Biggar's 2015 report noted that this approach is acceptable provided that the model has accurately and fully captured all of the key drivers of peak demand. However, after examining the drivers used by CIE, Dr Biggar expressed concern that these drivers may not be able to capture the recent apparent change in demand drivers noted above (such as investment in solar PV and increasing energy efficiency). As a consequence Dr Biggar expressed concern that CIE's models do not allow for the potential changes that we may be observing for the electricity market in Victoria and

[264] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 25–27.

[265] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 1 and 25–27.

[266] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 1.

recent declines in demand.[267] The evidence presented in section C.3 above suggests that average demand growth is likely to be low, zero or negative in the near future.

We have used AEMO's connection point demand forecasts as an independent comparison to CitiPower's forecasts. In September 2014, AEMO published its report on connection point demand forecasts for each of the Victorian electricity distributors for the 2014–2023 period. As noted previously, AEMO forecasts low or zero demand growth over the 2016–20 period.

AEMO's connection point demand forecasts are based on a methodology developed by ACIL Allen, which was developed after consultation during 2012–13 with all distribution businesses.[268] This methodology does not assume a particular long-term structural relationship for demand over time. AEMO has decided to adopt a ‘cubic’ relationship with historical demand and adopts an “off-the-point approach” (which means that the demand forecast begins at the most recent point of actual demand).[269]

ACIL Allen's "off-the-point" approach is not without its criticisms. In particular, it relies on industry knowledge and judgement to adopt an alternative to a historical linear trend and to start the forecast at the most recent point, which can be arbitrary if not based on first principles or underlying economic phenomena.[270] However, we consider it is a better model for forecasting demand for CitiPower's network for 2015–20 than CIE's models. This is because ACIL Allen's models do not assume a fixed structural relationship between long-term drivers of demand and certain economic factors across the entire period. In using the "off-the-point" approach ACIL Allen extrapolates the relationship between demand and the long-term underlying drivers based on the most recent actual demand value. Because of this, we consider that AEMO's forecast is more likely to reflect a realistic expectation of demand over the 2016–20 period.

CitiPower submitted that CIE's demand forecasting methodology is consistent with ACIL Allen's.[271] We found that while CIE broadly undertook the same forecasting stages as ACIL Allen, the key input assumptions were different. This led to different results. Some of the differences observed by CitiPower are:[272]

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267 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 26.

268 In December 2012, the Council of Australian Governments (COAG) released its energy market reform implementation plan. In this plan, AEMO will develop independent demand forecasts in 2013-14 to inform the AER's assessment of infrastructure investment plans submitted by Network Service Providers . Further detail is provided at http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

269 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 55–56.

270 This was a source of criticism in Frontier Economics’ peer review of AEMO’s demand forecasts. See Frontier, “High level review of transmission connection point forecasts: Victoria”, A report prepared for the Australian Energy Market Operator, September 2014.

271 CitiPower, *Regulatory Proposal 2016–20,* April 2015, p. 90.

272 CitiPower*, Presentation to the AER*, *Spatial demand forecasts CitiPower and CitiPower*, 15 July 2015.

- CIE produced maximum demand econometric models for each terminal station and at the total network level, whereas AEMO only undertook economic modelling at the state level.
- CIE did not observe any integration of maximum demand and energy forecast models, whereas AEMO's forecasts had energy growing faster than maximum demand.
- CitiPower disagrees with AEMO's post modelling adjustments for:
    - Contribution of solar PV to maximum demand
    - Assumptions and application of forecast energy efficiency.
- Difference in observation for Probability of Exceedance (PoE) weather normalisation and terminal station forecasts starting point.
- CitiPower raised concern with reconciliation of National Electricity Forecasting Report (NEFR) forecasts with transmission connection point forecasts.

We took these into account. On balance, we are of the view that the key difference between the results from CitiPower's and AEMO's forecasts is whether the relationship adopted between demand and temperature accurately reflects fundamental long term trends. In forming our view, we have recognised that each model has strengths and limitations. These are highlighted in our analysis above and Dr Biggar's report.[273] We do not consider CitiPower's model appropriately reflects the changes we have observed in the electricity market. As stated previously, we are open to CitiPower submitting an alternative forecast that captures the changes that we are observing for the electricity market in Victoria and recent declines in demand.

[273] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 25–27.

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 National Gas Rules.[274] 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.[275]

The expenditure forecast assessment Guideline (Guideline) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[276] It lists predictive modelling as one of the assessment techniques we may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009–10 review of the Victorian electricity distributors' 2011–15 regulatory proposals and have also used it subsequently.[277]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[278] 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

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

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

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

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

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

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).

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 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 distributors in the NEM.

The two types of RIN requested the same historical asset data for use in our repex modelling. The Reset RIN also collected data corresponding to the distributors proposed forecast repex over the 2016–20 regulatory control 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 (e.g. 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.[279]

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.[280]

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

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279 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.

280 NER, cl. 6.5.7(e)(6).

with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.[281]

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 we require to deploy our assessment techniques. 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 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.[282]

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.

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

282 NER, cl. 6.9.1.

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,[283] 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:[284]

- benchmark unit costs
- 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:

[283] Vic, SA and QLD distribution network service providers—AusNet Services, United Energy, Jemena, Powercor, CitiPower, SA Power Networks, Energex and Ergon Energy.

[284] 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.

- 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 using the CPI index.[285] We then calculated a single unit cost. We did this by first weighting the 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, the lives are 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. In this way, they can be said to derive from the distributors observed replacement practices. 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. To differentiate the two sets of benchmarked replacement lives, we refer to the benchmarks based on the calibration process as 'benchmarked calibrated replacement lives' and those based on replacement lives reported by the NEM distributors as 'benchmarked uncalibrated replacement lives'. 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:[286]

- calculating the average of all values for an asset category
- determining the standard deviation of all values for an asset category

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

286 For the benchmarked calibrated 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 led 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 replacement lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years reportable in the asset age profile.

- 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:
  - 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 (below the mean)
  - benchmark third quartile uncalibrated mean replacement life (above the mean)
  - benchmark third quartile calibrated mean replacement life (above the mean).
- 'Best' value:
  - benchmark best (lowest) unit cost
  - benchmark best (highest) uncalibrated mean replacement life
  - benchmark best (highest) calibrated mean replacement life.[287]

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.[288] 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

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287 We did not determine quartile or best values for the uncalibrated 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.

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

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.[289] They are:

(1) The Base scenario – the base scenario uses inputs provided by the distributor in their RIN response. Each distributor provided average replacement life data as part of this response. As the distributors did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years and the forecast unit cost from the upcoming regulatory control period in the base scenario.

(2) The Calibrated scenario – the process of "calibrating" the expected replacement lives in the repex model is described in the AER's replacement expenditure handbook.[290] The calibration involves deriving a replacement life and standard deviation that matches the distributor's recent historical replacement practices (in this case, the five years from 2011 to 2015). The calibrated scenario benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked scenarios – the benchmarked scenarios use 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 or third quartile" and "best performer" for each repex category, so there is no single "benchmarked" scenario, but a series of scenarios giving a range of different outputs.

The model can also take into account different wooden pole staking/stobie pole plating rate assumptions (see section D.3 for more information on this process). For the Victorian distributors, who exhibit high wooden pole staking rates relative to the rest of the NEM, we have not chosen to test different staking scenarios. A full list of the scenario outcomes is provided in Figure 6.28 and Figure 6.29 below.

Figure 6.28 Repex model outputs – replacement lives

Replacement lives	
Base case (RIN)	$681 million
Calibrated lives	$130 million
Benchmarked calibrated average	$406 million

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

290 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013, pp. 20–21.

Benchmarked calibrated third quartile	$301 million
Benchmarked calibrated best	$231 million

Source: AER analysis, using historic unit costs.

Figure 6.29 Repex model outputs − unit costs

Unit cost	
Benchmarked average	$77 million
Benchmarked first quartile	$42 million
Benchmarked best	$26 million

Source: AER analysis, using calibrated replacement lives.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the distributor did not incur any expenditure on an asset category in the 2011–15 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2016–20 regulatory control 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 distributor did not replace any assets during the 2011−15 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 calibrated replacement life of the broad asset group to which the asset subcategory belonged. Where this was not available, we used the benchmarked calibrated replacement life or the base case replacement life from the distributor.

While the majority of the data was provided in a form suitable for modelling, limited adjustments needed to be made for some of the data. For CitiPower we converted their forecast replacement volumes for service lines from kilometres to spans using the assumptions provided in its basis of preparation for the 2014 category analysis RIN.

Un-modelled 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 (or asset categories) from the modelling process, and did not use predictive modelling to directly assess these categories. However, where suitable data was available, we used predictive modelling to test our other findings on these categories. We decided to exclude SCADA repex from the model for this reason. Expenditure on pole top structures was also excluded, as it is related to expenditure on overall pole replacement and modelling may result in double counting of replacement volumes. Other excluded categories are detailed in appendix D.3 of this preliminary decision.[291]

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.[292] The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for like basis. To understand why this requires special treatment, we have described below 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

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291 For AusNet Services, we ran a limited set of modelling scenarios on SCADA and other repex, as suitable data was available. This was used to test the findings from our other techniques. For Powercor, we ran limited scenarios on pole top structures to test the findings from our other techniques. For each of these, we relied more on other assessment techniques, as detailed in Appendix A.

292 The equivalent practice for stobie poles is known as "plating", which similarly provides a low cost life extension. SA Power Networks carries out this process. We applied the same process for modelling SA Power Networks' stobie pole plating data as we have for staked wooden poles. However, for simplicity, this section only refers to the staking process.

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 to 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.[293] 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.

For the Victorian distributors, we adopted their own observed staking ratio.

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

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

replaced to approximate the volume of each new asset going forward.[294] 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 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when determining calibrated 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. Since the replacement of staked poles is not on a like-for-like basis, we make an adjustment for the calibration process to function correctly. That is, we need to know the number of staked poles that reach the end of their economic life so we can calibrate the model for when these assets are replaced. The category analysis RIN currently only provides us with information on how many new stakings have taken place, rather than how many were actually replaced. We sought, and were provided with this information directly from the distributors.

[294] 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.