CitiPower
Regulatory Proposal
2016–2020

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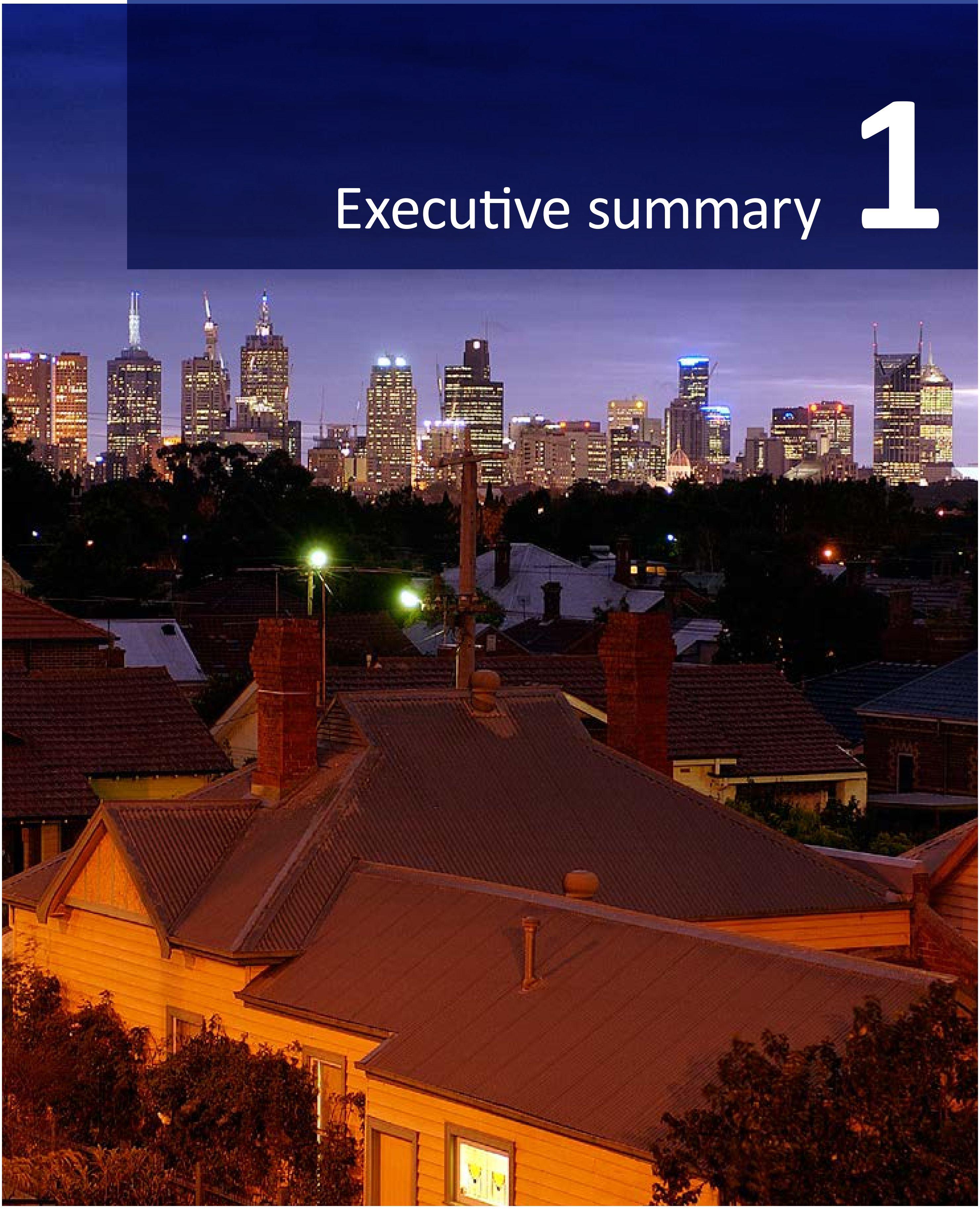
Executive summary 1



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1. Executive summary

We are seeking to invest in priorities that strike the right balance between safety, reliability, growth and affordability so that we meet the expectations of our customers today and into the future.

As a result of our efficient approach to investment, our customers will see a $28 reduction in the average residential customer's annual electricity bill in 2016, adjusted for inflation. Network charges will remain stable for the remainder of the five-year period.

Our forecast expenditure over the next regulatory control period is predominantly driven by:

- protecting our customers and our network;
- ensuring a resilient network for inner Melbourne (maintain cost-effective reliability);
- network growth (growing with Melbourne);
- building the network for the future; and
- making it easier for our customers.

1.1 Our business

We are the most efficient and reliable electricity network in Australia. We are one of Victoria's five privately owned electricity distributors and own and manage assets that deliver electricity to 325,917 homes and businesses across Melbourne's central business district and inner suburbs, including the city's world-class cultural and sporting facilities such as the Melbourne Cricket Ground, Melbourne Park Tennis Centre, Federation Square and the Victorian Arts Centre.

We have the highest customer density network in Australia by some margin yet, despite our size, we have the second highest average annual energy delivered per customer in the National Electricity Market (**NEM**). Overall around 42 per cent of the network is underground.

We responsibly manage our network, efficiently maintaining our existing assets and investing in emerging technologies that ensure our communities can meet tomorrow's challenges.

1.2 A changing energy future

Our regulatory proposal has been prepared in an environment where customers are rapidly changing how and when they use energy.

The changing energy landscape presents both challenges and opportunities for us. Our customers expect us to better enable their energy choices such as connecting solar panels and giving them greater access to information about their electricity use.

These customer choices require us to design and build our electricity network to meet changing energy usage patterns, as more customers become more proactive in managing their energy needs.

1.3 Our track record

We are proud of our strong performance and reputation for safety, efficient operations and reliability that has provided our customers with outstanding value for money.

Never compromising safety

Safety is our number one priority. We are committed to achieving the highest standards of safety for our customers, employees, contractors and the community. The overall health and condition of our assets is an important contributor and we have robust preventative maintenance and replacement policies to minimise risks arising from operation of our assets. We will continue to work collaboratively with the Victorian Government and Energy Safe Victoria (**ESV**) to minimise safety risks.

Reliability

Consistent with customer expectations, we have maintained our commitment to reliability over the current regulatory control period which is particularly important, given the contribution of Melbourne's central business district and surrounding suburbs to economic development. This is the result of a robust and disciplined approach to asset management.

Our customers enjoy the best network availability of all Australian distributors at 99.99 per cent.

Efficient network management

Our safety and reliability performance has been achieved without compromising our record as being the most cost efficient distributor of electricity in the NEM. This has been demonstrated by the Australian Energy Regulator's (**AER**) own independent benchmarking analysis.

Affordable pricing outcomes

We aim to ensure value for money. Research conducted by Oakley Greenwood[1] found that between 1995 and 2014 our average residential distribution charges decreased by $164 in real terms.

Our customers pay the lowest distribution network costs in Australia and will continue to do so.

1.4 Engaging better with our customers

To ensure we had a robust foundation for our detailed plans and submissions for the 2016-2020 regulatory control period, we undertook a comprehensive stakeholder engagement program which started more than 18 months ago to better understand what was important to our customers.

Through our engagement program, customers and stakeholders told us what they want from us over the next regulatory control period. This feedback has informed our plans and, as a result, we are confident that our regulatory proposal delivers on the expectations of our customers.

1.5 Highlights of our regulatory proposal

Protecting our customers and our network

Our top priority continues to be the safety of our customers, employees, contractors and the community.

Since 2010 we have been delivering a program of work, in conjunction with ESV, to maintain the required clearances between our powerlines and vegetation across our network. We will continue to work closely with local councils on our planning and programs and will continue to consult with them and the community on the requirements we must meet. We will also continue to work with local communities to balance our safety requirements with local visual amenity.

Ensuring a resilient network for inner Melbourne

We are the most reliable urban electricity distributor in the NEM demonstrating our commitment to best practice asset management strategies to ensure the safe and reliable operation of our network.

We monitor assets and take a risk based approach when assessing their condition, only replacing them when it is needed to maintain reliability and security of supply. Our monitoring program has found that we will need to

[1] Oakley Greenwood, CitiPower pricing comparisons, 1995 to 2014, p.4.

replace a number of assets over the next regulatory control period to ensure network reliability and safety is not compromised.

In particular, much of Melbourne's 22kV network, developed in the 1940s, is still in use today and continues to supply some of the city's inner suburbs. During the upcoming regulatory control period, we plan to decommission some of our oldest zone substations and connect customers to our more modern 66kV sub-transmission network. This works program will start by targeting ageing zone substations in Prahran, Central Business District and North Melbourne.

In addition, we will continue targeted upgrades to the 66kV network as part of the Central Business District Security of Supply project initiated by us in 2004 in conjunction with the Victorian Government. Works have included the development of several 66kV switching hubs that will interconnect to the redeveloped Brunswick Terminal Station, as well as the associated redevelopment of the zone substation in Waratah Place located in the Chinatown district of the Central Business District.

Augmenting the network to power growth

With Melbourne's population forecast to surpass Sydney's by the middle of this century, we need to deliver targeted investment where it is needed most to ensure we can support growth, including urban renewal projects, across inner Melbourne.

During the upcoming regulatory control period, we are supporting growth arising from urban renewal and redevelopment projects including:

- **redevelopment of the Batman's Hill precinct**: Lend Lease will redevelop the 2.5 hectare site opposite Southern Cross station in its 'Melbourne Quarter' which will include in excess of 100,000 square metres of commercial space, approximately 600 residential apartments and 4,000 square metres of retail space;
- **E Gate precinct**: located at gate 'E' in the rail yard area near North Melbourne rail station, Major Projects Victoria is proposing to develop housing for up to 10,000 residents and 50,000 square metres of commercial and associated retail space; and
- **Fishermans Bend precinct**: Places Victoria has released its draft vision for the redevelopment of this area to provide homes for more than 80,000 residents and new workplaces for up to 40,000 people. This urban renewal will involve a variety of residential developments ranging from warehouse lofts, to townhouses and high rise towers, while continuing to encourage the operation of businesses.

Building the network for the future

The emergence of customers wishing to both consume and produce energy requires us to address new challenges, particularly as energy flows and quality of supply issues become more complex. As a result, we need to design more sophisticated network control and protection systems to ensure a safe and reliable delivery of power. For example, a number of city businesses have installed embedded generation such as gas fired generators which feed electricity into the network. This extra energy injected into the network can magnify the impact of network faults that occur. That is why we will be installing new equipment at the North Richmond and Albert Park zone substations to manage fault current levels that are approaching the allowable limits. If we go over these limits, when a network fault occurs it could cause extensive damage to equipment and a threat to public safety.

Making it easier for our customers

Access to usage data from smart meters was a common theme in customer and stakeholder feedback throughout our stakeholder engagement activities. One of the key things that we are planning to address is to implement systems to better engage with our customers, understand their individual preferences and provide access to their data through an automated customer portal. Coupled with investment in a customer relationship management system, we will be better able to respond to customer requests, work with them and their electricity retailers to reduce power bills further, as well as give easier access to new tariffs that incentivise customers to help us minimise overloads on high demand days.

Table 1.1 Distribution charge impact for typical customer (including smart metering charges) (per cent)

Typical annual bill	2016	2017	2018	2019	2020	Average % p.a.
Residential	-7.3	-0.6	-0.1	0.2	0.4	-1.5
Small commercial	-7.4	-2.9	-2.6	-2.6	-2.8	-3.7
Large	-1.4	2.7	3.0	3.3	3.3	2.2

Source: CitiPower

Table 1.2 Revenue requirement for standard control and metering services ($m real)

	2016	2017	2018	2019	2020	Total
Annual revenue requirement	324	328	348	352	366	1,719

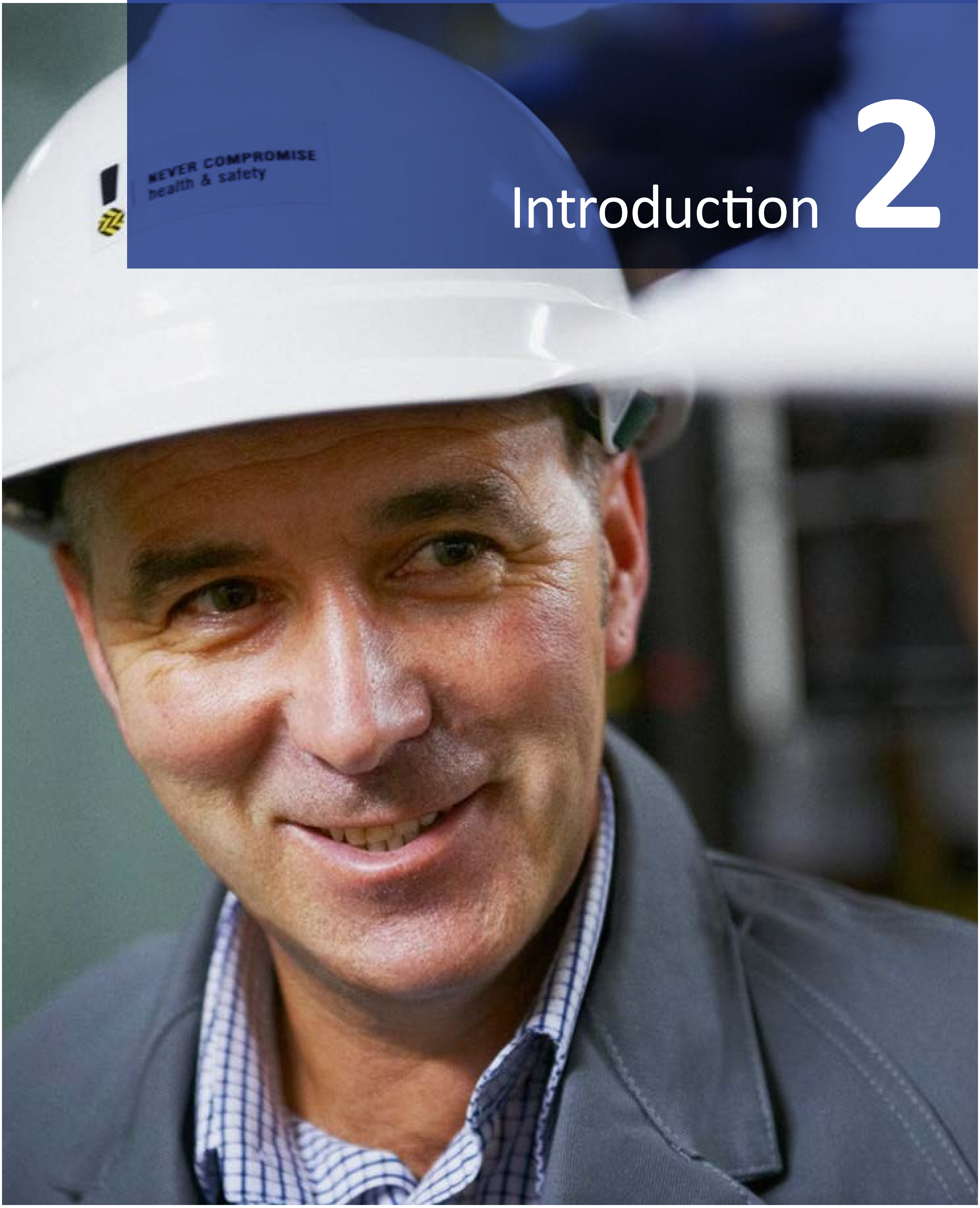
Source: CitiPower

Table 1.3 Proposed forecast expenditure for standard control and metering services ($m, real)

	2016	2017	2018	2019	2020	Total
Forecast net capital expenditure	177.0	201.9	188.0	162.9	130.9	860.1
Forecast operating expenditure	101.0	101.9	109.9	112.6	112.6	538.0

Source: CitiPower

Introduction 2



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2. Introduction

This document, appendices and attachments comprise our regulatory proposal to the Australian Energy Regulator (**AER**) for the regulatory control period 2016–2020. It sets out the revenue we believe is necessary to manage the network in a safe, reliable and efficient manner for our customers and the community in general.

The Regulatory Proposal is supported by the following accompanying documents:

- an Overview Paper that has been prepared in line with clause 6.2.2(C1) of the *National Electricity Rules* (**Rules**);[2] and
- copies of our documentation supporting the Regulatory Proposal and appendices and attachments (including the information required by the Expenditure Forecast Assessment Guideline and the *Price Reset Regulatory Information Notice* (**Reset RIN**)).

This Regulatory Proposal and its appendices and attachments were prepared in accordance with the Rules and Reset RIN requirements, as set out in the attached, *NER Cross Reference Matrix* and *Reset RIN Cross Reference Matrix*.

2.1 Our vision and values

Our vision is connecting for a bright future. To realise this vision, we are focused on:

- continually improving how we engage with customers and key stakeholders on what matters to them to ensure we meet the energy needs of Victorians today and into the future;
- providing customers with outstanding value for money by maximising the efficiency of the Business operations, with a focus on safety and reliability;
- maintaining appropriate levels of investment in the network to support growth in Victoria, including industrial and infrastructure developments; and
- emerging technologies and alternative sources of energy, and changing consumer patterns to ensure effective and cost efficient reinforcement of our network.

Our values underpin everything we do, every day. Together they give us greater focus on understanding and supporting customers, doing what is right and helping employees and our business strive for excellence in everything we do:

- live safely;
- make it easy for your customer;
- succeed together;
- be community minded;
- be the best you can be; and
- drive and embrace change.

2 Clause 11.60.3(a) relevantly provides that 'current Chapter 6' applies in respect of the making of a distribution determination for an 'affected DNSP' for the next regulatory control period (being the regulatory control period that immediately follows the period ending 31 December 2015). Clause 11.65.2 relevantly provides that references in rule 11.60 to 'current Chapter 6' are to be read as Chapter 6 of the Rules as in force immediately after the National Electricity Amendment (Network Service Provider Expenditure Objectives Rule 2013) came into force. That rule came into force on 26 September 2013 contemporaneously with version 58 of the Rules. Furthermore, clause 11.65.2 states that references to 'current Chapter 6' in clause 11.60 are to be read in this way despite clause 11.60.2. Accordingly, except where otherwise stated, references to Chapter 6 of the Rules in this document are to Chapter 6 in version 58 of the Rules.

2.2 Regulatory context

As a monopoly service provider, we are subject to a comprehensive set of regulatory obligations designed to ensure appropriate outcomes for customers, the community and investors. We require a fair commercial return to enable us to deliver an appropriate level of network reliability, safety and customer service in an efficient and sustainable manner.

The economic regulation of our business is performed by the AER. In undertaking this economic regulation role, the AER is required to do so in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (**NEO**) as stated in section 7 of the *National Electricity Law* (**NEL**).

The objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The Victorian Government retains responsibility for setting service levels, while Energy Safe Victoria (**ESV**) is responsible for safety and technical regulation in Victoria.

The AER has decided to apply a revenue cap form of control to our standard control services in the 2016–2020 regulatory control period and has put in place incentive arrangements to encourage us to pursue efficiency gains, further investigate demand management opportunities, and improve service performance to customers over the regulatory control period.

The AER is required to ensure that pricing outcomes, and the revenues on which they are predicated, are sufficient to enable us to undertake the capital and operating work programs required to deliver the service levels as defined by the *Victorian Electricity Distribution Code* (**Code**), comply with all applicable regulatory obligations and requirements and maintain the safety of the distribution system. The allowed pricing outcomes must also provide for a fair commercial return to our shareholders. We have developed our capital expenditure program and forecasts taking into account the requirements of the Code and consider that the proposed capital expenditure programs are sufficient to ensure that we comply with that Code.

Since the 2011-2015 regulatory determination, there has been significant regulatory change. This is discussed further in chapter 4.

In addition, at the time of preparing this regulatory proposal, a number of important consultations or decisions remain in progress, including Rule changes aimed at expanding competition in metering and related services and whether Victoria joins the National Energy Customer Framework (**NECF**). This regulatory proposal reflects our best assessment of the impact of open Rule change processes and other deliberations. However, changes to regulatory arrangements that are determined subsequent to the submission of this regulatory proposal may require further consideration during the AER's determination process.

In October 2014, the AER released its *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**).[3] The F&A Paper, amongst other things, defines the revenue control mechanism to apply in the 2016–2020 regulatory control period, the AER's proposed approach to the classification of distribution services and the specific application of regulatory incentive schemes in the 2016–2020 regulatory control period.

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[3] AER, *Final Framework and approach for the Victorian Electricity Distributors*, Regulatory control period commencing 1 January 2016, 24 October 2014.

We accept the conclusions advanced in the F&A Paper. As a consequence, this regulatory proposal is based on the application of a revenue control mechanism and the service classification outlined in the F&A Paper.

For the purposes of sections 6.3.2(4) and S6.1.3(13) of the Rules, we are proposing our next regulatory control period commence on 1 January 2016 and operate for a period of five years concluding on 31 December 2020.

Further information on the F&A Paper can be found at **aer.gov.au**.

2.3 Structure of this regulatory proposal

In addition to this regulatory proposal, we have prepared a plain English overview document which provides a summary of this regulatory proposal. It is available on our website **talkingelectricity.com.au**.

Table 2.1 Chapters of the regulatory proposal

Chapter	Title	Description
1	Executive summary	An overview of the regulatory proposal, its objectives and conclusions.
2	Introduction	Contextual information.
3	Our track record	A description of our business in terms of its role, the network, our customers and a summary of our achievements in terms of safety, reliability, affordability and service.
4	Our operating environment	Current operating challenges and new operating challenges emerging.
5	Benchmarking	Assessment of our efficiency performance.
6	Our customer engagement	An overview of our engagement with customers and our findings.
7	Real price growth	Provides our forecast of labour, material and contract escalation in the 2016–2020 regulatory control period.
8	Demand, energy and customer forecasts	Presents our demand, energy and customer number forecasts for the 2016–2020 regulatory control period.
9	Capital expenditure	Details the capital expenditure forecast for the 2016–2020 regulatory control period.
10	Operating expenditure	Details the operating expenditure forecast for the 2016–2020 regulatory control period.
11	Incentive schemes	An explanation of the incentive schemes that will apply in the 2016–2020 regulatory control period.
12	Rate of return	Sets out the rate of return we consider should be applied to our determination.
13	Revenue and pricing	Summarises the total revenues that will be recovered through our tariffs.
14	Managing uncertainty	An explanation of proposed pass through events and triggers.

Chapter	Title	Description
15	Metering	The total revenues that will be recovered for metering services in the 2016–2020 regulatory control period.
16	Non-standard control	Our proposed charges and terms for alternative control, public lighting and negotiated services for the 2016–2020 regulatory control period.
17	Glossary	A description of the defined terms within the regulatory proposal.
18	Appendices	A list of appendices to this regulatory proposal.
19	Attachments	A list of attachments to this regulatory proposal.
20	Models	A list of models attached to this regulatory proposal.
21	Regulatory information notices	A list of attachments to the reset RIN.

2.4 Determination timeframes and feedback opportunities

This regulatory proposal presents our proposed expenditure, regulatory arrangements, rate of return and distribution revenue for the 2016–2020 regulatory control period.

Following an assessment of this regulatory proposal and submissions received from interested parties, the AER will make a preliminary distribution determination by 31 October 2015.

Transitional arrangements are currently in place as a consequence of Rule changes in 2012 which extend the usual determination timeframes. Thus, although our next regulatory control period will still commence on 1 January 2016, the AER will continue its determination process into 2016 as required by clause 11.60.4 of the Rules.

Interested parties will have the opportunity to make further submissions on the AER's preliminary distribution determination until 45 business days post the determination. Subsequently the AER will publish a substitute distribution determination on 30 April 2016 that will take effect from 1 January 2017.

Any differences between the preliminary distribution determination and the substitute distribution determination that impact allowed revenues in the 2016 regulatory year will be addressed by means of a revenue 'true up' at 1 January 2017.

Further information on our determination process can be found at the AER website: **http://www.aer.gov.au/node/27890**.

Our track record 3

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3. Our track record

Over the current, and previous, regulatory control periods, we have properly and determinedly responded to the incentives under the regulatory framework to maintain downward pressure on costs and innovate to the benefit of all our customers. At the same time, we have operated our network in a reliable and safe manner that has delivered strong service improvements for our customers.

Today our distribution charges represent less than 21[4] per cent of the average residential electricity bill whilst our distribution charges are the lowest in the National Electricity Market (**NEM**). Further, based on the Australian Energy Regulator's (**AER**) rankings, we are the most reliable distributor in Australia.

3.1 Purpose

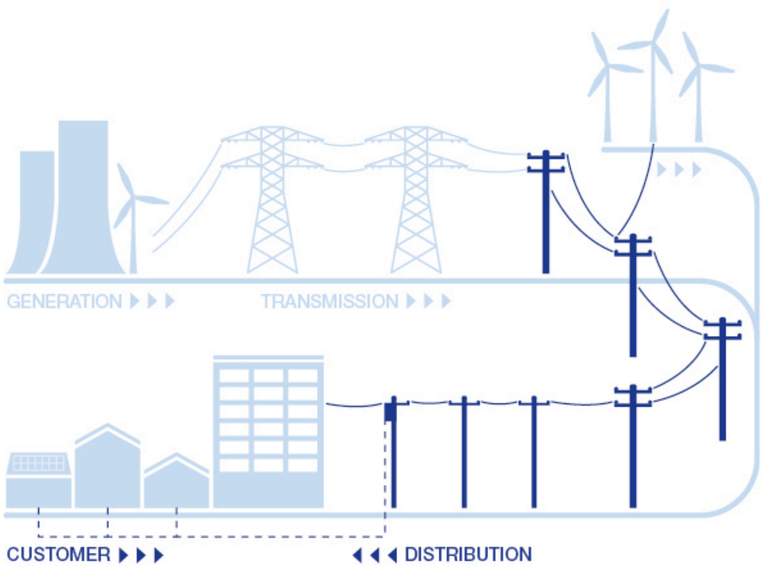
The purpose of this chapter is to provide an overview of our role, ownership, organisation and our performance over the current regulatory control period.

3.2 Our role

In the NEM, generators (either fossil fuelled or renewable) produce electricity, which is transported at extra high voltage across the transmission network (operated by AusNet Services in Victoria), to transmission network 'exit points' in or near urban centres.

We then deliver electricity from the transmission system exit points to customers across inner Melbourne. Retailers sell electricity to customers, having purchased it from the NEM wholesale market. They pay us for use of the networks that deliver electricity to customers.

Figure 3.1 Distribution in the electricity supply chain



Source: CitiPower

[4] Oakley Greenwood, CitiPower pricing comparison, 1995 to 2014, 29 December 2014, p. 5

We own and operate an electricity distribution network serving 325,917 customers in a network of 157 square kilometres. This network includes the central business district (**CBD**) and inner suburbs including North Melbourne, Brunswick, Northcote, Carlton, Fitzroy, Collingwood, Richmond, Kew, Balwyn, Camberwell, Hawthorn, Armadale, St Kilda, South Melbourne and Port Melbourne.

We are a key component of Victoria's economy and community. The composition of our customers with an emphasis on business, government and important social infrastructure has particular implications for our business and its network. In particular, our customers depend heavily on receiving a reliable supply of electricity. The cost of disruption of electricity supply to our customers is very high. We understand the premium placed on supply reliability and security and this is reflected in business planning processes to ensure customers' expectations are met.

As the local distribution network service provider servicing the commercial centre of Victoria, our primary responsibility is planning, building, operating and maintaining the 'poles and wires' — a strategic community asset and core component of Victoria's and Melbourne's energy infrastructure. We seek to do this in a safe, reliable, efficient and prudent manner.

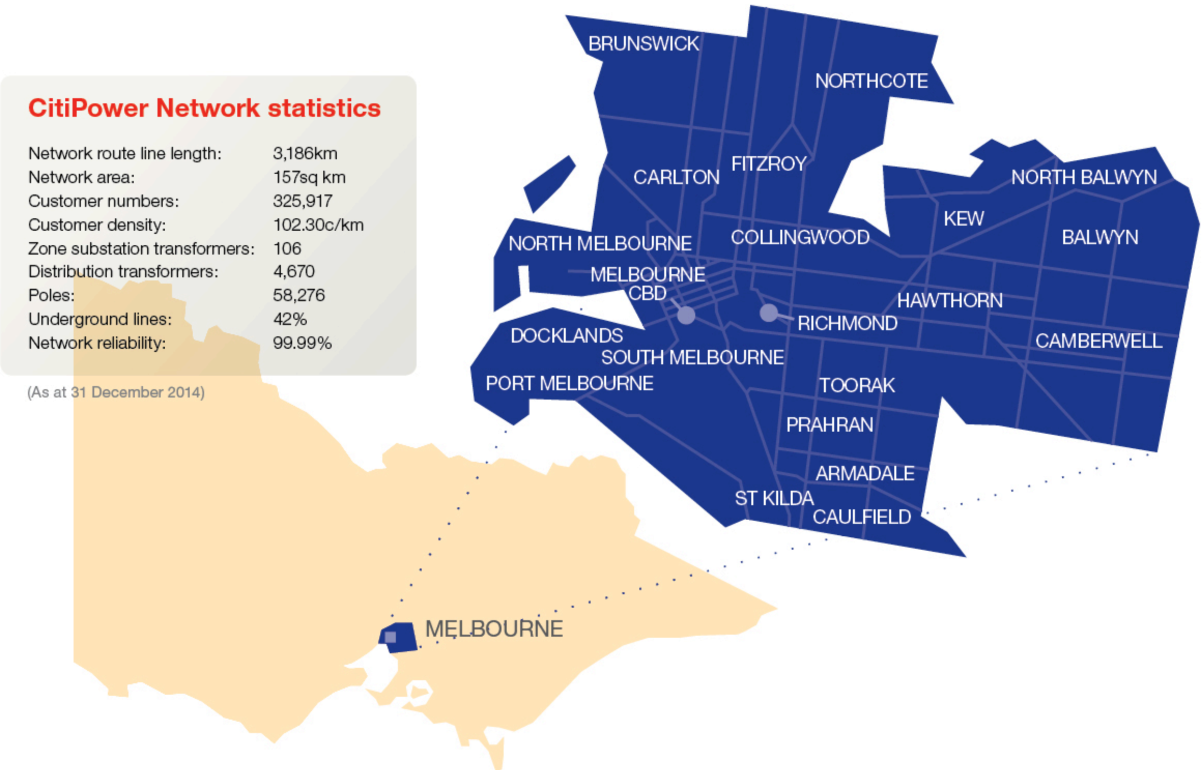
We connect residential and commercial customers to a safe and reliable electricity supply. Our key distribution activities include:

- maintaining network safety and reliability to meet the current power supply needs of our customers;
- extending and upgrading the network so that the future power supply needs of customers are met when required;
- operating the network on a day to day basis;
- connecting new customers to the network;
- maintaining the public lighting system;
- reading electricity meters; and
- providing meter data to retailers.

The foundation of the Australian energy market place is changing with multiple global trends reshaping the sector, transforming our business from electricity distributor to energy enabler. These changes are driven by growth in distributed generation and disconnections from the grid via self-generation, influence of new technologies such as solar photovoltaics (**PV**), electric vehicles, battery storage, energy efficiency, demand side management and smart grid technology and changing preferences of customers in terms of supply control, usage, service standards and costs. Rapid change will require us and our network to adapt rapidly to ensure we are able to continue to meet the needs of our customers.

Our network is the densest in Australia, with more 102 customers per kilometre of line. It also has the highest proportion of CBD customers and portion of underground assets in Australia (around 42 per cent).

Figure 3.2 CitiPower's network



Source: CitiPower

Prior to 2004, our network was designed and operated on the basis that no loads would be interrupted in the event of the single failure of a major component of the network. This security criterion, known as 'N-1' for the networks ability to withstand one contingent failure without loss of load, has been reviewed in the light of an assessment of the impact such a failure would have in Melbourne and security criteria adopted in similar CBD networks around the world. The resultant review was subject to a regulatory test[5] and resulted in an amendment to the *Victorian Electricity Distribution Code* (**Code**)[6] in 2008.

Security of supply in inner Melbourne and its CBD is of paramount importance given the high concentration of people, commerce and cultural activities that depend on electricity supply each day. Catastrophic CBD network failures in Auckland, New York, London and Birmingham demonstrate that such failures can occur, and when they do, impose significant costs on the community and businesses.

3.3 Our ownership, organisational structure and governance

We are operated by CitiPower Pty and our assets owned by the CitiPower Trust. CitiPower Pty is the trustee of the CitiPower Trust and together CitiPower Trust and CitiPower Pty are collectively referred to as 'CitiPower'. CitiPower is owned by Victoria Power Networks (**VPN**). VPN is ultimately 51 per cent owned by Cheung Kong

[5] See NERA, Melbourne CBD Enhancement: Regulatory Test Analysis CitiPower, April 2007.

[6] See ESCV, Final Decision CBD Security of Supply, February 2008.

Infrastructure Holdings Limited and Power Assets Holdings Limited, which form part of the Cheung Kong Group of companies based in Hong Kong. The remaining 49 per cent of the company is ultimately owned by Spark Infrastructure Group, a publicly listed Australian infrastructure fund.

VPN is the principal entity and owner of investments in Powercor, CitiPower, CHED Services and Powercor Network Services (**PNS**) and has responsibility for the overall direction of these companies. The corporate functions of CitiPower and Powercor (another Victorian DNSP) have been integrated and are supplied by CHED Services. Our field services are provided by PNS.

The Board has overall responsibility for our corporate governance including the critical responsibilities of strategy setting, policy definition and compliance and monitoring of business performance. The Board has established the following committees to assist in the execution of its duties: Audit; Risk Management and Compliance; and, Remuneration. In addition, all investment decisions above $1.5 million are subject to the Capital Investment Committee (**CIC**) which includes the Chief Executive Officer and the Chief Financial Officer.

All investment cases prepared within our Business must provide adequate information about how the investment contributes towards our longer term strategic direction. Secondly, business cases require approvals from the Network Planning Committee (**NPC**) or the IT Project Governance Committee (**IT PGC**) and the CIC. This ensures that our network planning and management objectives align with our corporate strategic objectives. During 2014 we also began trialling a new portfolio and project control framework which is designed to result in more efficient investments through a stronger investment framework and stronger capital controls. It is anticipated the new framework will be fully introduced in 2015.

All of our proposed capital investments are appraised and approved through a single process. This ensures that a consistent investment appraisal criterion is applied to all investment decisions. The approval process delegates approval responsibility appropriately to the NPC (>$300k), the CIC (>$1.5 million), Chief Executive Officer (<$5 million), Chief Executive Officer and Chairman jointly (<$10 million) and the Board (>$10 million). Further, the capital investment process is subject to periodic review and audit.

It is a fundamental requirement that all capital investments must either enhance or protect existing customer and shareholder value or is incurred to satisfy a non-financial requirement such as customer service, regulatory, quality, legal, environmental or health and safety compliance obligation.

Attached to this regulatory proposal are copies of the Expenditure Approval Manual[7], Post Implementation Review Policy[8] and Purchasing and Procurement Policy Manual[9] that outline the investment governance framework and evaluation process.

3.4 Never compromising safety

Keeping our customers, communities and employees safe has always been, and remains, our number one priority. We will never compromise safety. It is embedded in our culture and values.

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7 CitiPower and Powercor, *Expenditure Approval Manual*, 7 August 2013.

8 CitiPower and Powercor, *Post Implementation Review Policy*, 7 August 2013.

9 CitiPower and Powercor, *Purchasing and Procurement Policy Manual*, 9 March 2012.

Electrical safety in Victoria

In Victoria, responsibility for electricity safety rests with the independent technical regulator Energy Safe Victoria (**ESV**). ESV is a Victorian Government statutory authority.

Victoria's safety regulatory regime requires us to provide ESV with documentation for review that details the safety systems that we have in place to reduce the risk of our network starting fires or posing other safety risks to the community and our employees. An Electricity Safety Management Scheme (**ESMS**) and a Bushfire Mitigation Plan (**BMP**) must be submitted to ESV each year, whilst we are also required to submit an Electric Line Clearance Management Plan (**ELCMP**) annually.

As part of its role, ESV also annually reviews our safety performance. Their reviews focus on the key safety indicators, as well as the operation of the ESMS, which became a mandatory requirement on our business following the 2009 Victorian Bushfires Royal Commission (**VBRC**).

The primary responsibility for ensuring network safety rests with us and ESV holds us accountable by requiring us to participate in targeted annual audits to confirm compliance with our safety systems.

ESV also provides comments on and input to our safety programs included in our regulatory proposal, both to us and the AER.

The reliability and safety performance of electricity networks, including their potential to start fires, is ultimately a function of environmental factors as well as how well the networks are planned, designed, maintained and operated. This is in turn a reflection on the design and effectiveness of both economic and safety regulatory regimes.

We have well established network development, replacement and maintenance programs in place to reduce the probability of network assets creating a safety hazard or starting a fire. These programs amongst other things address:

- overhead conductor failure, complete or partial separation of electric wires;
- pole failure; and
- cross arm failure.

Workplace safety

Victoria's Occupational Health & Safety Act 2004 (**Act**) provides a broad framework for achieving health and safety standards in the workplace. It consists of objectives and general duties that apply to all businesses including us. The objectives of the Act are to:

- secure the health, safety and welfare of employees and other persons at work;
- eliminate at the source, risk to health, safety or welfare of employees and other persons at work;
- ensure the health and safety of members of the public is not placed at risk by the conduct of employees and self-employed persons; and
- provide for the involvement of employees, employers and organisations representing those persons in the formulation and implementation of health, safety and welfare standards.

Our experience from our non-regulated presence in other state jurisdictions has found work health and safety acts to have similar objectives and duties.

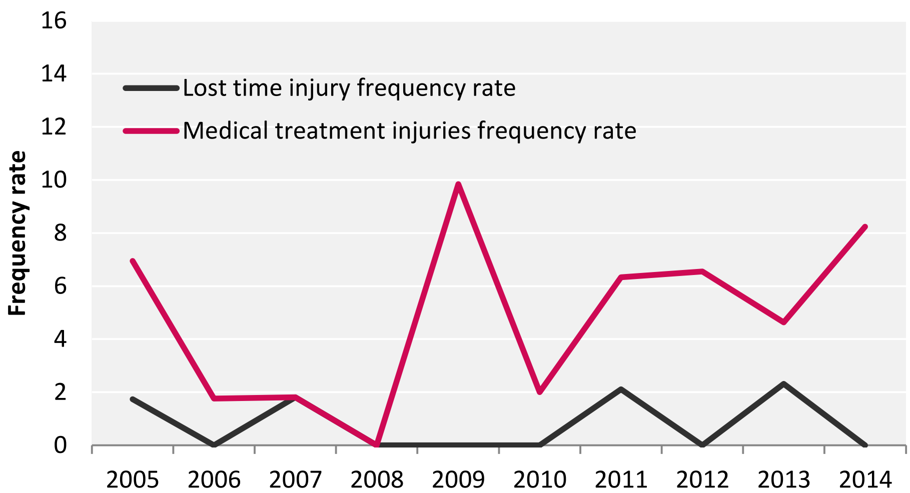
Complying with the Act is an essential aspect of doing business in Victoria and as a business, we are fully committed to ensuring compliance.

In 2014 we achieved a 60 per cent reduction in significant incidents, which are incidents that have the potential for a fatality or permanent disability. Also over 2014, we have improved our identification of hazards through emphasising the importance of reporting risks.

In the spirit of promoting our safety culture, we have for 2015 tightened our internal safety targets further, placing us in the best position to realise zero significant incidents in the future. Also in 2015, we are introducing a safety leadership and engagement program for our senior management to ensure that everyone in our business has safety top of mind every day.

Our employee safety performance continues to lead the industry and is reflected in figure 3.3, which demonstrates excellent and improving outcomes in terms of the Lost Time Injury Frequency Rate (**LTIFR**) and Medical Treatment Injuries Frequency Rate (**MTIFR**).

Figure 3.3 **Lost time injury frequency rate and medical treatment injuries frequency rate**



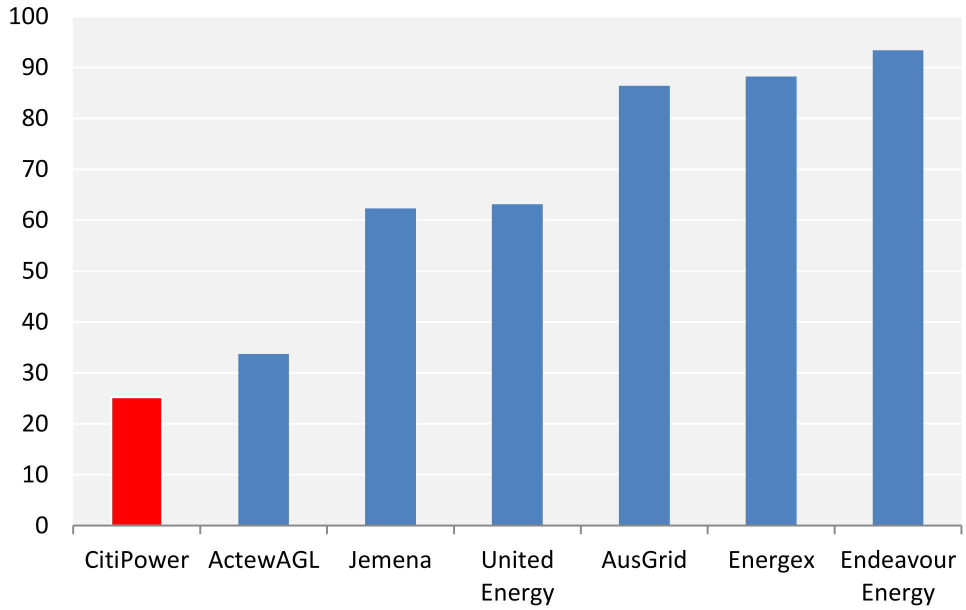
Source: CitiPower

3.5 Australia's most reliable urban network

We understand our customers place considerable importance on a reliable and secure supply. This is particularly important given the importance of Melbourne CBD and its surrounds to the welfare of the Victorian and Australian economies. That is why we are the most reliable urban distributor in Australia.

We have continued to perform strongly against other Australian distributors over the current regulatory control period. Over the current regulatory control period our customers experienced the lowest number of planned and unplanned minutes off supply in Australia. They also experienced the lowest frequency of planned and unplanned outages in Australia. The reliability performance is testament to the robust asset management programs in place across the network.

Figure 3.4 Average number of minutes off supply per customer (2006-2013)[10]



Source: AER Economic Benchmarking RINs

Over the current regulatory control period, we have continued to ensure current service performance is sustainable. This has included:

- continuation of existing asset management programs to maintain system average unplanned/planned reliability performance;
- investment in areas where localised reliability issues exist;
- improved identification and rectification of supply quality issues; and
- improved ability to detect outages through automated fault indicators.

The developments related to the bottom two points have been greatly enhanced by the completion of the smart meter program and its integration into network management systems.

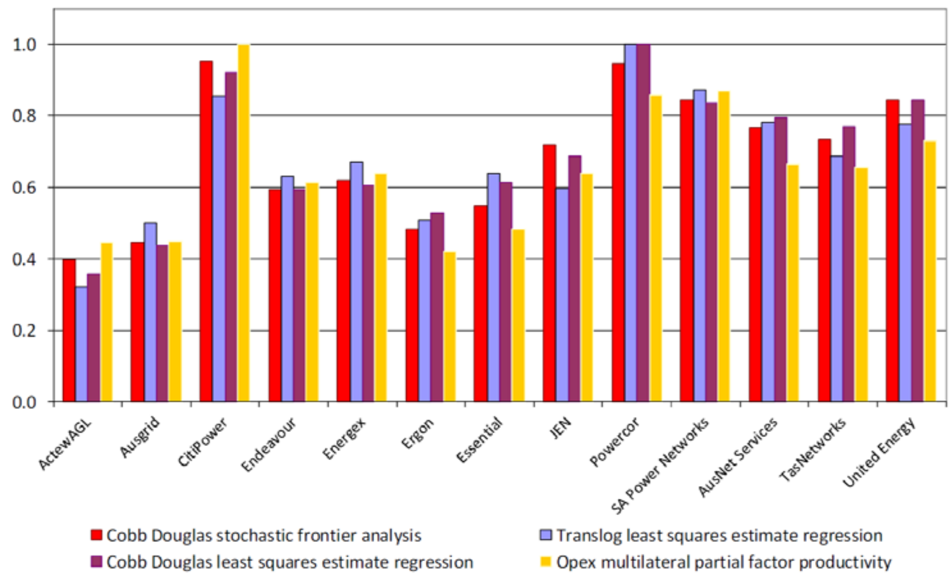
[10] The effects of major events have been excluded from the minutes off supply reported in this figure consistent with the AER's Service Traget Performance Incentive Scheme Guideline

3.6 Affordability of distribution services

We take pride in our strong efficiency performance that has allowed us to deliver balanced outcomes in terms of price and quality of our service for our customers. Based on the AER's own analysis, we have consistently featured in the top 25th percentile of performers over the period 2006–2013 and been the most efficient distributor in Australia.

Whilst the AER's own analysis demonstrates we are performing strongly, it should be noted this performance has been achieved despite a number of new regulatory obligations imposing additional costs and declining energy sales throughout most of the regulatory control period.

Figure 3.5 Operating expenditure efficiency



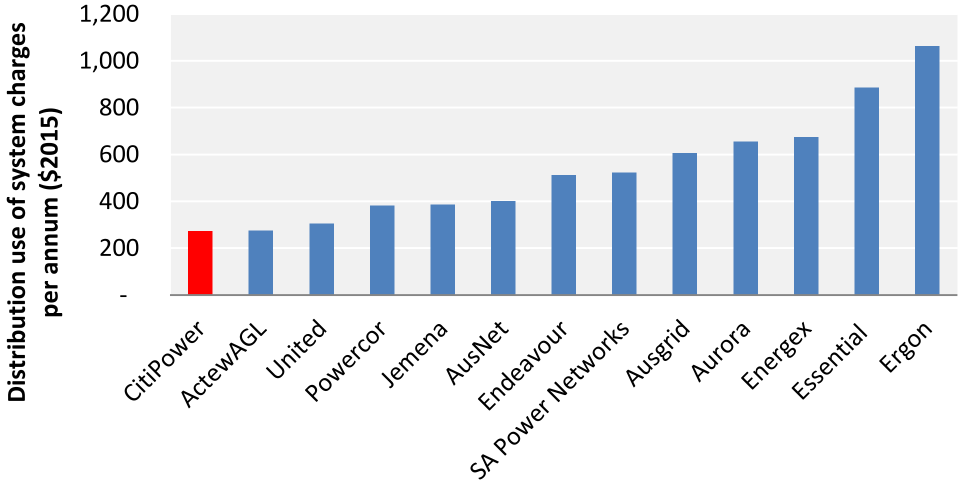
Source: AER, *Benchmarking Fact Sheet*, published 27 November 2014, p. 2.
Note a high score represents greater operating expenditure efficiency.

Our strong efficiency performance has enabled our customers to benefit from some of the lowest network charges in the NEM. Independent research[11] concluded that for our average residential customer, distribution use of system charges comprise less than 21 per cent of the average electricity bill, compared to a range of 45–50 per cent in other states and territories.

Our customers also enjoy the lowest distribution use of system (**DUoS**) tariffs in Australia. Based on our published DUoS tariffs (ex GST), and assuming an annual consumption of 4,300 kWh, our average residential customers on a single rate tariff pay $271 per annum compared to significantly greater DUoS charges in other states.

[11] Oakley Greenwood, CitiPower pricing comparisons, 1995 to 2014, 29 December 2014.

Figure 3.6 Distribution use of system charges per annum ($, real)[12]



Source: CitiPower

3.7 Putting customers first

Excellence in customer service and making it easy for customers is an integral component of our vision. We are committed to providing outstanding service to our customers at all times. This commitment was reflected in the Customer Service Institute of Australia presenting us the Australian Service Excellence Awards Best of the Best award in 2012.

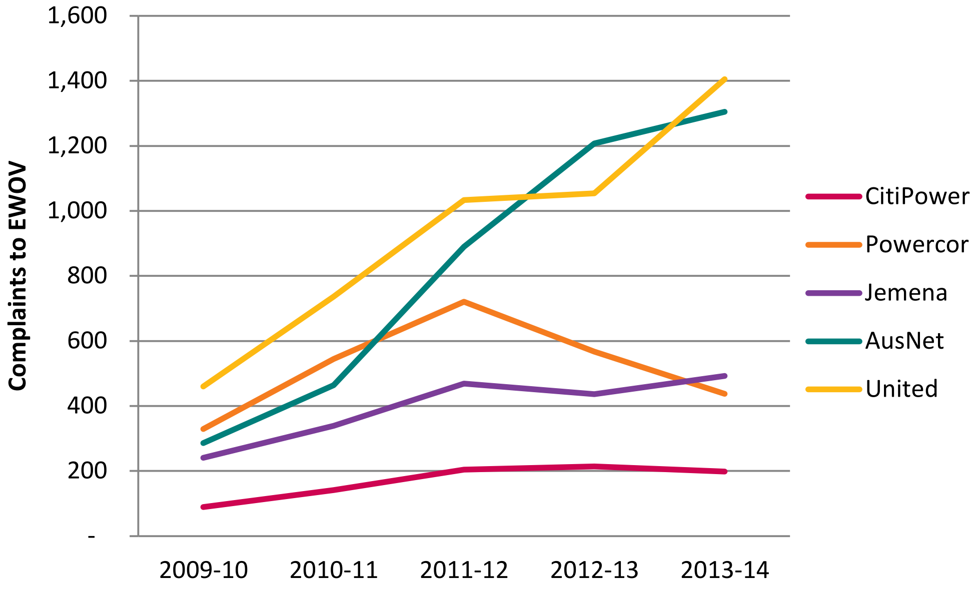
Our 'Powerful Customer Service' program, in place since 2011, is focused on listening to our customers and taking responsibility for their satisfaction by meeting commitments and ensuring our people follow through on the resolution of customer complaints. The success of the program over the regulatory control period 2011-2015 is reflected by our business having:

- average complaints per 1,000 customers below 0.40 for the past ten years;
- the lowest level of Ombudsman complaints over the past five years (see figure 3.7); and
- consistently high satisfaction ratings across residential customers (82 per cent) and major customers (84 per cent).

We do however recognise there remain areas for improvement. Of the complaints received, most related to meter exchanges, unplanned outages, voltage variations, connections and disconnections for safety reasons. In preparing this regulatory proposal we have closely examined the reasons underlying these complaints and, where possible, sought to implement improvements.

[12] All bills are ex GST and based on published 2014/15 prices. Assumes annual consumption of 4,000kWh. Assumes a flat profile and the most basic residential tariff (no electric hot water).

Figure 3.7 Complaints received by Energy Water Ombudsman of Victoria



Source: EWOV, EWOV Annual Report 2014, p. 43.

We have also consistently delivered very high levels of appointments and connections by the agreed date with the customer. Over the current regulatory control period less than 0.05 per cent of connections have not been met by the agreed date.

We have also continued to meet our obligations with respect to repair of faulty street lights, repairing the overwhelming majority within five business days of the fault being reported. Over the current regulatory control period on average less than 0.5 per cent of faulty street lights were not repaired within five business days.

At the forefront of mind in developing this regulatory proposal, we have sought to deliver outcomes that are consistent with the long term interests of customers.

To understand customers' long term interests, we have undertaken a comprehensive customer engagement program entitled 'Talking Electricity', which aligns with the requirements of the AER's Consumer Engagement Guideline[13]. The 'Talking Electricity' program is described in greater detail in chapter 6.

In summary what we have heard from customers is that they want us to:

- run a safe electricity distribution network;
- focus on cost effective management of our assets and investments to maintain reliability levels, manage risk and support growth;
- get more from emerging technologies to build a more resilient network that can meet customer needs in the future;
- help facilitate customers' energy choices, educating them about new technologies and industry changes to help increase their satisfaction;
- provide improved access to data and information about energy consumption; and

[13] AER, Consumer Engagement Guideline for Network Service Providers, November 2013.

- maximise opportunities to improve the service experience.

3.8 A culture of continuous improvement

Over the current regulatory control period, we have continued to find new and exciting ways to innovate and drive business and service improvement. The completion of the smart meter program in 2013 within budget and on time is already delivering significant benefits for our customers including:

- remote reading 30 minute interval data of virtually all meters across the network eliminating the costs associated with manual quarterly meter visits and special meter reads;
- remote reconnect and disconnect of a customer's premise (depending on the customer's retailer) to avoid costly and untimely truck calls when customers move in or move out;
- implementation of the meter outage notification system which brings benefits to our customers through early identification of localised faults, pinpoints their exact location, identifies the exact time of restoration and reduces the need for field crews to undertake outage investigations. The MON system was the winner of the Innovation award at the prestigious Australian Business Awards 2014;
- accessing of voltage data to support investigation of voltage complaints in lieu of dispatching specialist crews and voltage recording equipment;
- supply status test which enables us to verify on contact from a customer whether a supply complaint is on the customer or network side of meter avoiding a potentially costly service truck visit; and
- improved monitoring and reporting of short duration momentary outages in rural areas.

Combined these initiatives delivered more than $3.2 million in benefits for our customers in 2014.

We are also further developing the network 'smarts' that will enable enhanced load performance management (allows more efficient operation of the network), demand management technology to interface with in-home appliances (can allow more efficient capital expenditure decisions), supply capacity control (to manage and reduce the impacts of severe customer load shedding during large scale emergencies on Victorian electricity grid) and tamper alarms (reducing theft and network losses).

In the field we have also sought to actively innovate over the current regulatory control period including revision of design and construction standards, purchase of new fleet, introduction of revised line practices and the rollout of workforce mobility devices to improve efficiency in the field.

We have also sought to adapt our service to meet changing customer needs, particularly in relation to transparency and more information and education. While the preferred method of contact remains the telephone, we have greatly enhanced the use of internet, SMS alerts, email and other advancing digital technologies such as our release of Australia's first outage application, meaning customers can increasingly connect with us using the channel of their choice. Over the last two years we have invested more than $9 million in new telephony systems, and responded to requests for better access to information – we are one of only two distributors in Australia able to provide customers with specific information via an automated service about their property, rather than suburb, when they are calling about a power outage.

Over the 2016–2020 regulatory control period we will look to further advance many of these initiatives and develop new ones to the ultimate benefit of our customers. These are discussed more fully in chapter 9 of this regulatory proposal and the following provides a window into some of our planned innovation initiatives.

Innovative expenditure

With peak demand forecast to continue to increase in specific areas of the network, together with our ageing assets, we are committed to undertaking a range of innovative investments to address these factors, rather than rely on traditional 'network solutions' to add new capacity or replace assets.

These innovative investments draw upon recent technological advancements to enable us to better interact with and provide improved service to our customers. The innovations include:

- retiring and decommissioning the ageing 22kV zone substation network supplied from West Melbourne Terminal Station. Rather than replace the ageing 22kV network on a 'like-for-like' basis, we will take a different and lower cost approach by integrating these customers into our 66kV zone substation network;
- control schemes at select zone substations to provide capacity to control fault currents and enable connection of some medium scale embedded generation;
- sophisticated analytics to dynamically manage our network using the energy consumption data available from our smart meters;
- improved customer response to localised outages via direct communication to each smart meter; and
- managing our assets more efficiently by remote condition diagnostics and condition alerts.

Through these innovations, our network operations centre will become better informed about energy consumption enabling more efficient management of our assets. Our customers will also be better informed about how they use energy, which may lead to a change in energy consumption behaviour and thus more efficient investment decisions.

Our operating environment 4

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4. Our operating environment

4.1 Overview

In preparing our regulatory proposal, we have been cognisant of the environment in which we operate and how that may change over the next regulatory control period. Many of the unique characteristics that distinguish our operating environment from other Australian distributors remain similar over the next regulatory control period. Other elements of our operating environment are more generic to the distribution sector and will be challenges for all distributors.

The purpose of this chapter is to bring attention to the key factors in our operating environment that have influenced the preparation of this regulatory proposal, and how they have been considered. These factors include:

- changes in the energy landscape – the distribution sector is going through a period of unprecedented change driven by smart meter technology, automation of the network and rapid growth in distributed energy resources. Keeping up with these changes requires prudent investment in information technology and SCADA systems;
- customer expectations – our customers are seeking to be better informed to enable them to exercise greater choice over how their energy needs are met. They are seeking access to this information through multiple channels. At the same time our customers are increasingly exercising their choices resulting in fundamental changes in the way energy is consumed. These changes have wide ranging impacts on our business from the contact centre through to network planning;
- a changing regulatory environment – over the past five years the regulatory framework under which we operate has undergone major transformation. Regulatory changes may impact on the incentives we face and our expenditure program into the future;
- highest customer density in Australia and highly interconnected - more of our assets are underground, as a proportion of our total network, compared to other distributors across the National Electricity Market (**NEM**). The relative connectivity and density of our network impacts our planning and expenditure decisions;
- resilience – the *Victorian Electricity Distribution Code* (**Code**) requires a higher level of system resilience for the central business district of Melbourne compared to the rest of Victoria. As a result security is an important driver of future expenditure;
- ageing assets – we presently operate the second oldest network in Australia, which creates potential future reliability issues. This will impact our replacement expenditure over the next regulatory control period; and
- congestion – operating in dense and congested environments creates unique challenges in terms of planning and undertaking works across our network. The impact of congestion is observed in the unit costs we incur in undertaking works.

Combined, these features create a network requiring unique and relatively specialised expenditure solutions. Despite these challenges, we have, and will continue over the next regulatory control period, to deliver strong safety, reliability and financial performance for our customers and shareholders.

The remaining sections of this chapter describe the factors above further.

4.2 Changes in the energy landscape

The landscape in which we operate is changing at an unprecedented pace. Market forces and technology are shifting the traditional linear energy supply chain to a more contemporary model where consumers become producers ('prosumers') and distributors become enablers of energy solutions.

Smarter grids

Smart grids can mean different things to different people. We have adopted the definition outlined by the United States Department of Energy which has identified seven traits that constitute a smarter grid:

- optimise asset utilisation and operating efficiency;
- accommodate all generation and storage options;
- provide power quality for the range of needs in the digital economy;
- anticipate and respond to system disturbances in a self-healing manner;
- operate resiliently against physical and cyber-attacks and natural disasters;
- enable active participation by customers; and
- enable new products, services and markets.

Globally, the electricity sector is focusing efforts on 'smarter grids' as a way to make valuable infrastructure improvements, increase customer options and improve efficiency. This is in response to customers, regulators and governments[14] seeking networks that are safer, more reliable and environmentally cleaner.

A core foundation of the move to a smarter grid has been the completion of the smart meter rollout across our network which was importantly completed on time and on budget.

Smart meters provide a view of the network never seen before, providing the ability to better manage capacity versus demand, react to changes in the network, provide greater safety margins, faster restoration time, optimised plant life and foresee critical network events before they occur.

Already smart meters are also offering customers immediate benefits including reduced costs associated with manual meter reading and automatic fault detection.

[14] For example, see Energy Market Reform Working Group, New Products and Services in the Electricity Market, Consultation on regulatory implications, December 2014

Table 4.1 describes some of the other smart meter leveraged benefits already being realised over the current regulatory control period.

Table 4.1 Smart meter leveraged initiatives overview 2011-2015

Program	Description	Benefit
Meter outage notification	Use outage data provided by smart meters in an intelligent process to generate notifications to systems that are used to co-ordinate response to outages	Greater outage clarity on the network leading to more informed outage profiling Improved outage data to use in quality related reporting
Distribution transformer monitoring	Access to distribution transformer interval data and customer interval data linked to a specific asset to support asset management and protection against theft	Supply quality monitoring Reduced operational costs Faster response to faults
Power flow analysis	Create reports in the data warehouse that can export interval data in a format suitable for existing power flow tools	More accurate network reporting Streamlined planning Capital deferment
Proactive voltage monitoring	Voltage polling tool used to investigate voltage anomalies remotely	Avoided costs associated with operational impact of solar installations Reduction in customers' damaged electrical appliances
Smart meter safety reporting	Utilise smart meter data to identify safety concerns in the network	Improved safety outcomes for customers and employees Foundation established for additional smart meter reporting capabilities
Home area networks	Trial in 1,000 homes installing in-home display units bound to the smart meter via the establishment of an authorised home area network	Customers are more informed about their energy choices

Source: CitiPower

In addition to smart meters, we have completed over the current regulatory control period the first stage of our Distribution Management System (**DMS**) implementation. Already this has resulted in a single SCADA system and the associated reduction in support costs. Stage 2 of the DMS will unlock further benefits including faster fault detection, isolation and restoration, enhanced voltage control and integration of DMS with the outage management system enabling system controllers' real time network information spanning the sub transmission system through to the low voltage network.

Over the next regulatory control period we will continue to invest in new technologies that will reduce distribution costs and improve the quality of our services and provide customers with easily assessable information and encourage active participation in the energy value chain. These investments are grouped into three categories, network management optimisation, smart analytics and network innovation. When completed, these programs will deliver further benefits including:

- improved management of quality of supply compliance - improved service quality ensuring no impact on customer load side equipment;

- containing operational costs - improved operational efficiency translating over time to reduce the cost of distribution services;
- reliability - reduce current levels of supply interruptions from both planned and unplanned outages;
- capital deferment - deferment of capital expenditure associated with refurbishment or replacement of assets;
- customer engagement and service - improved customer engagement and participation resulting in increased customer satisfaction; and
- improved safety - avoidance of internal or community safety incidents resulting in avoided injuries.

Realisation of further network benefits necessarily requires investment over the next regulatory control period, particularly in information technology. In proposing this investment, we have been mindful that the benefits afforded must be tangible and need to be supported by a rigorous cost benefit analysis. Further discussion of the evolution to a smart grid and its benefits are discussed in chapter 9.

4.3 Customer expectations

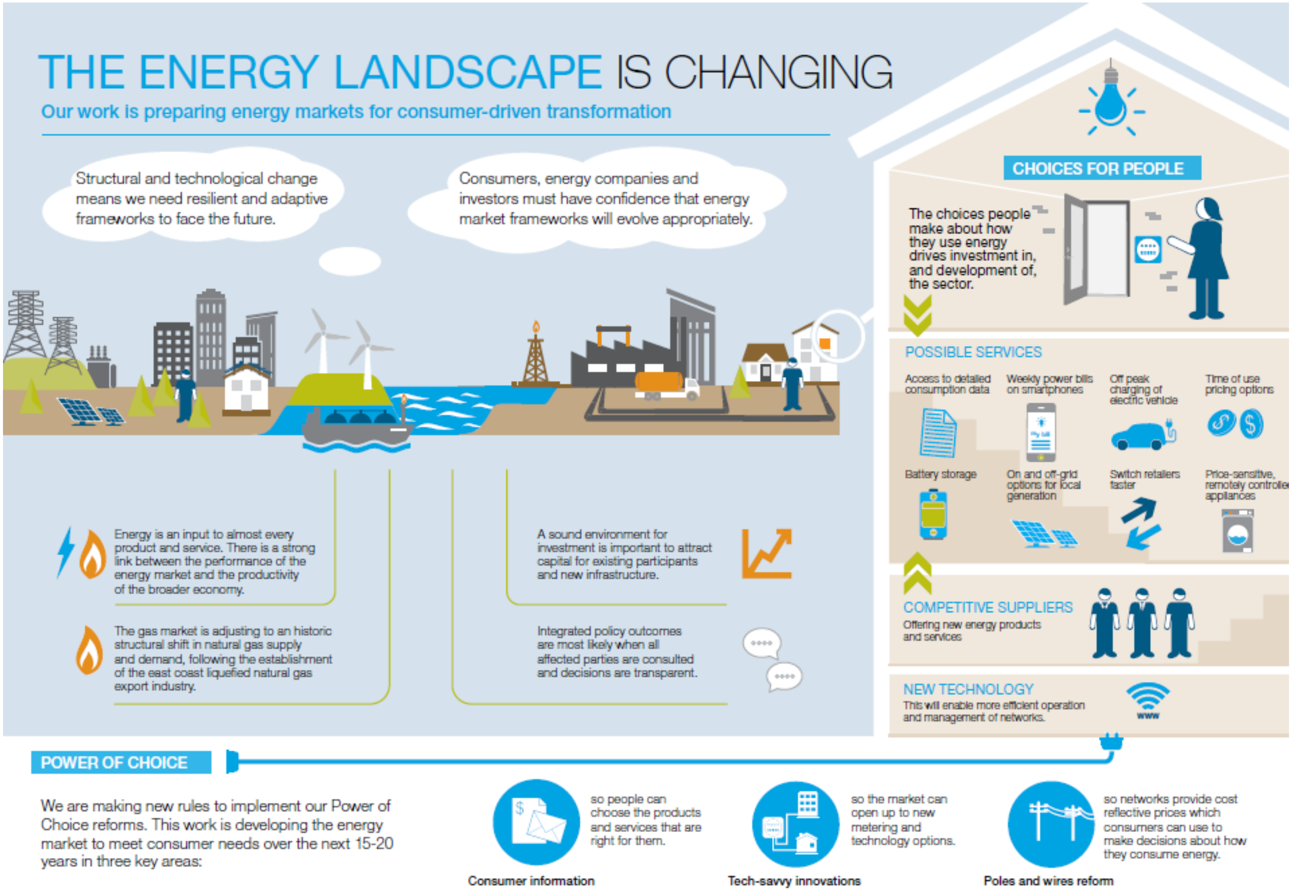
Changing customer behaviour and expectations around how they use energy and the range and levels of services they expect are changing the way we need to invest in our network over the next regulatory control period.

Due to advances in communication technology, our customers are increasingly able to access high quality information for a range of their daily needs with few limitations on location or time. This has raised expectations for accurate, timely information via a wide range of channels including smart phone applications and social networking sites.

Customers are also increasingly accustomed to controlling what information they receive and how they receive it using preferences, portals and dashboards, which they expect to be easy to configure themselves. Their rising expectations regarding availability, timeliness, accuracy and relevance of information will need to be met by us to allow us to continue to meet these expectations.

These behavioural changes are manifesting themselves in many aspects of energy markets, as noted by the Australian Energy Markets Commission (**AEMC**) in Figure 4.1. These changes include our customers seeking greater choice as to how they use energy and the services they seek to use.

Figure 4.1 The changing energy landscape



Source: AEMC

As our customers' needs evolve from simple connection and fault rectification requests to more sophisticated energy management services and support queries, we will need to be ready to address the changed circumstances. For example, the take up of distributed generation such as solar photovoltaics (**PV**) and more generally, demand side management has far reaching implications for all parts of our business from the role of our contact centre and customer facing systems right through to how we plan, build, operate and maintain our network.

Our customers' changing expectations are not limited solely to the services they require but also to how their energy needs will be met into the future. These changing expectations were noted by Oakley Greenwood and the Institute for Sustainable Futures[15] who observed:

> *The electricity supply industry is undergoing a period of significant change which has the potential for major implications on Victoria Power Network's (VPN) business model. This has arisen due to a combination of factors including:*

- *the impact of energy efficiency programs and environmental awareness and policy;*

15 Oakley Greenwood and Institute for Sustainable Futures, Scenario Development prepared for CitiPower Pty and Powercor Australia Limited, May 2014, p. 8.

- *the rapid rise of small scale distributed generation, and in particular, solar PV at a residential level, in no small measure as a result of environmental awareness and policy;*
- *the impact and role of technological changes;*
- *the impact of the GFC on energy usage; and*
- *shifting customer and usage responses to either or both price increases and changing price signals.*

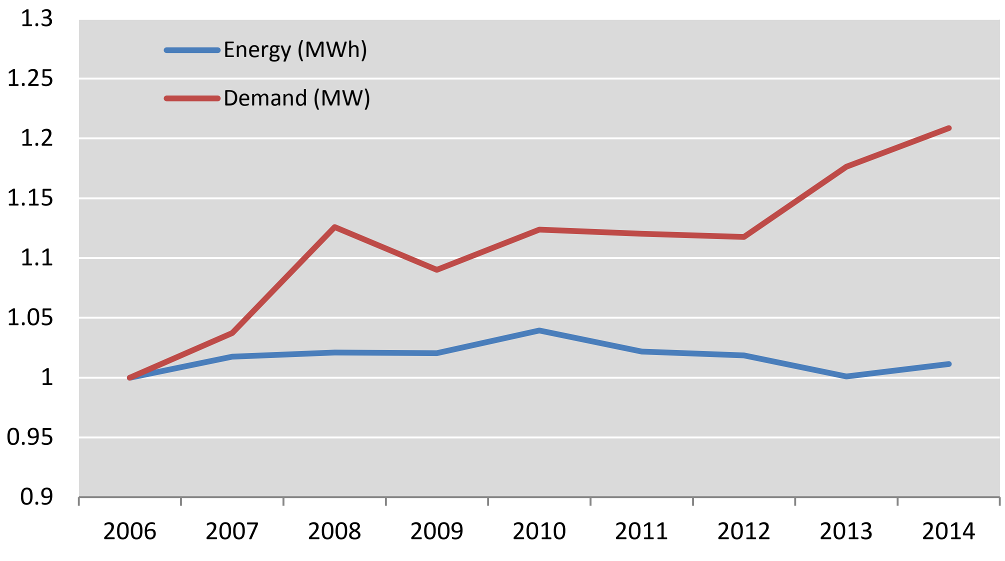
These impacts are projected to continue into the future and potentially accelerate as new technologies become competitive and consumers become more engaged and informed with respect to energy usage, and more capable through technology, of responding to price signals. Coupled with this, the business faces a changing and potentially more demanding regulatory environment.

Whilst the impact of solar PV on our network is not as great as some other distributors, we have been impacted by the growth in larger embedded generation, principally in commercial properties across the Central Business District (**CBD**), Docklands and inner suburbs. Embedded generators can impact the network through increased fault level contributions which the network was not originally designed to manage.

At the last price reset, we proposed a comprehensive strategy to manage fault levels based on work conducted by Sinclair Knight Merz (now Jacobs). At that time the Australian Energy Regulator (**AER**) rejected the strategy in favour of us opening a number of bus-tie circuits at constrained zone substations to segregate fault level contributions. Opening bus-ties is however not a sustainable solution as it creates other risks across the network. This regulatory proposal seeks to modify the open bus-tie strategy to sustainably manage the fault level issues across the network. Further details are provided in chapter 9.

More generally, promotion of government energy efficiency initiatives and incentives, combined with rising energy prices has had a strong dampening effect on energy consumption. The decline in energy consumption has not however been matched by peak demand, which despite a decline in the period 2010–2012, set new network records in 2013 and 2014.

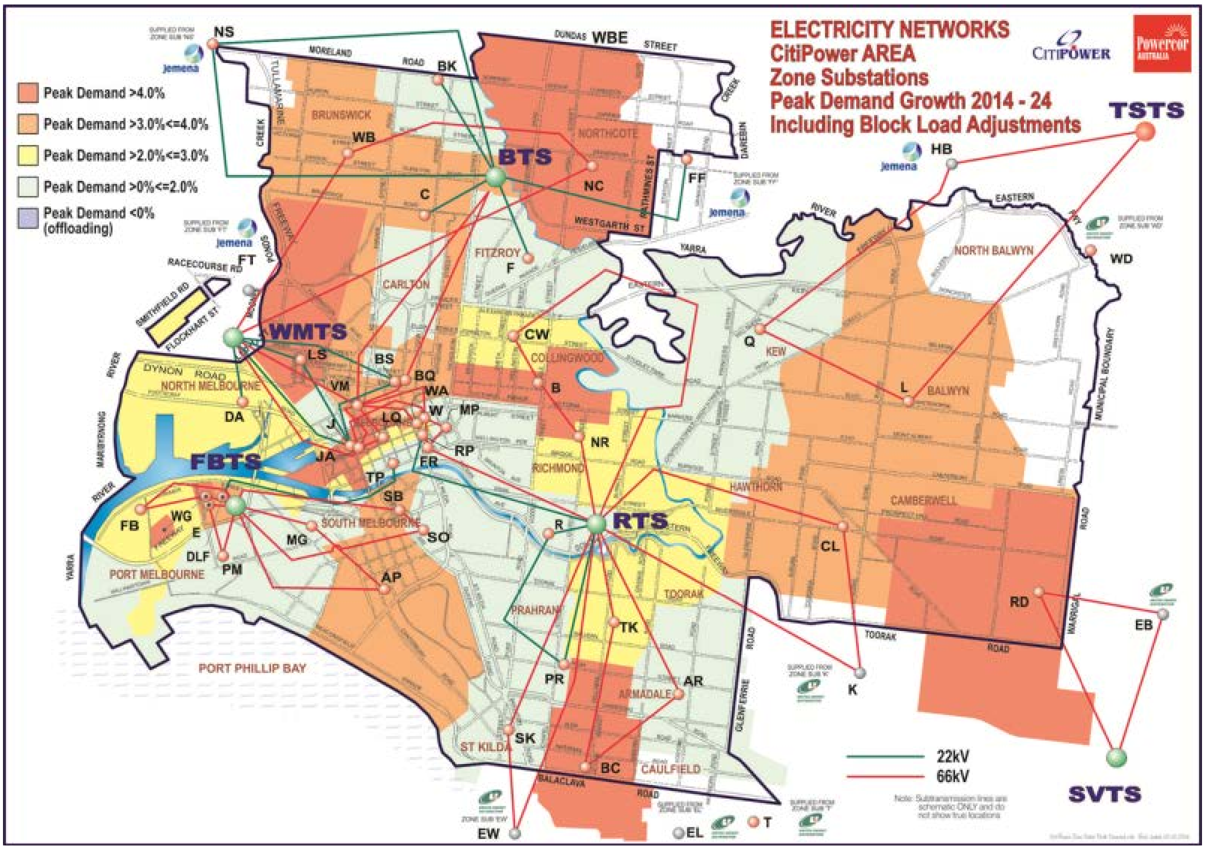
Figure 4.2 Normalised energy and peak demand consumption 2006-2014



Source: CitiPower

We have sought to innovatively manage the increasing divide between energy consumption and peak demand through load management however, over the next regulatory control period, without augmentation, customers would likely face more frequent and lengthy outages. Solar PV has only marginally impacted peak demand as it typically does not operate during network peak demand.

Figure 4.3 Zone substation spatial peak demand forecasts



Source: CitiPower

Figure 4.3 presents the growth projections for the period 2016–2020 by zone substation. It shows that demand growth in excess of 4 per cent per annum is expected across a number of zone substations including Northcote, North Melbourne, Collingwood, Balaclava, Riversdale and the north western section of the CBD. Areas around Balwyn, Camberwell, South Melbourne and Brunswick are also expecting demand growth of between 3 and 4 per cent per annum.

Finally, the Australian Energy Market Operator (**AEMO**) recently reviewed what customers, including our customers, are willing to pay for reliability. We are obliged to use the value of customer reliability (**VCR**) that AEMO determined from its review in assessing our proposed network investments. As a result of new VCR values, which are considerably lower than previous values, we have deferred some augmentation projects that were previously earmarked for the next regulatory control period. The lower VCR will also impact on reliability over the next regulatory control period.

4.4 A changing regulatory environment

There has been considerable change over the current regulatory control period in terms of economic and technical regulation that has, and will, impact how we operate our business.

In terms of economic regulation, we have seen the expansion of the Regulatory Information Notice (**RIN**) requirements. Whilst the AER has made the case that the expansion of the RIN will allow for better regulatory decision making, the incremental costs of providing the requested information is not inconsequential.

Today the majority of data provided by us is based on estimates, which are generated based on manual processes and judgements. It is understood going forward estimated data will not be acceptable to the AER beyond the 2016 reporting period. As a consequence we will require significant data, systems and most importantly, work practice changes to record and report the requisite actual data.

Other substantive economic regulatory changes have included:

- the 'Better Regulation' project which amongst the many National Electricity Rule (**Rule**) and guideline changes, requires us to demonstrate a greater focus on consumer engagement and focus on the long term interests of customers;
- 'Power of choice' initiatives which to date have included fundamental reform of network tariff setting framework. Further change is expected to include changes to facilitate demand side response by customers; and
- introduction of meter contestability from as early as July 2017.

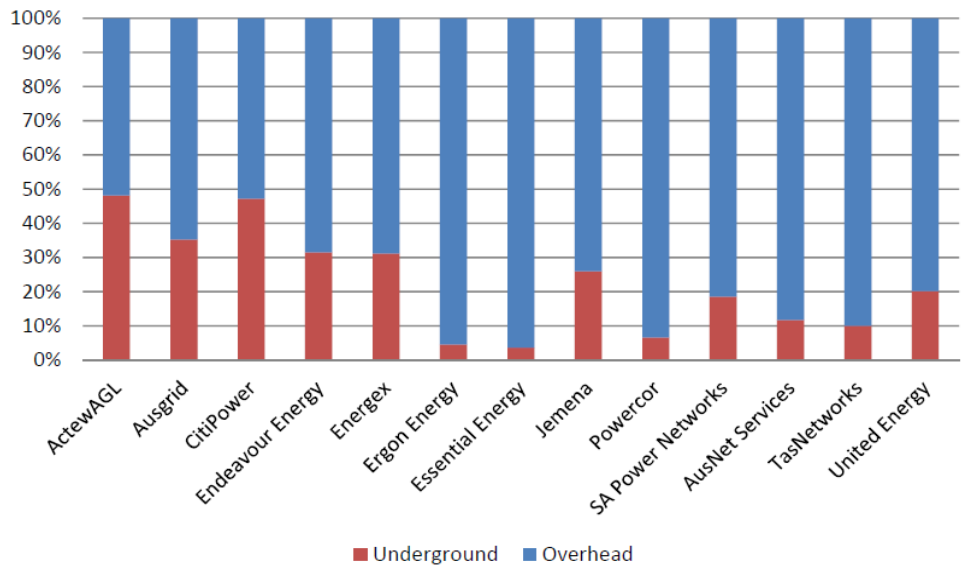
The impact of some regulatory changes are often not transparent in forecast expenditure as they are captured in larger capital expenditure projects or programs. Others however are more readily identifiable through operating expenditure step changes as identified in chapter 10.

4.5 Dense and highly interconnected

We deliver electricity to 325,917 customers in a 157 square kilometre area making it the highest customer density network in Australia by some margin (2,076 customers per square kilometre). Despite our size, we deliver more energy per annum than TasNetworks, ActewAGL and Jemena, and have the second highest average annual energy delivered per customer in the NEM.

Our network consists of underground sub-transmission assets which predominately operate at 66kV, with some 22kV. Our overhead assets generally operate at a voltage of 11 kV, with some 6.6 kV. Overall around 42 per cent of the network is underground.

Figure 4.4 **Composition of overhead and underground lines**



Source: AER, Electricity distribution network service providers, Annual benchmarking report, November 2014, p.21.

The sub-transmission network is supplied from a number of terminal stations which typically operate at a voltage of 220kV. The sub-transmission network nominally operates at 66kV or 22kV and is often configured in loops to maximise reliability. The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for the distribution to the surrounding area.

The distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment to provide effective protection and control. Whilst the majority of the high voltage distribution system nominally operates at 11kV, there are some notable exceptions.

6.6kV distribution systems can be found in areas of:

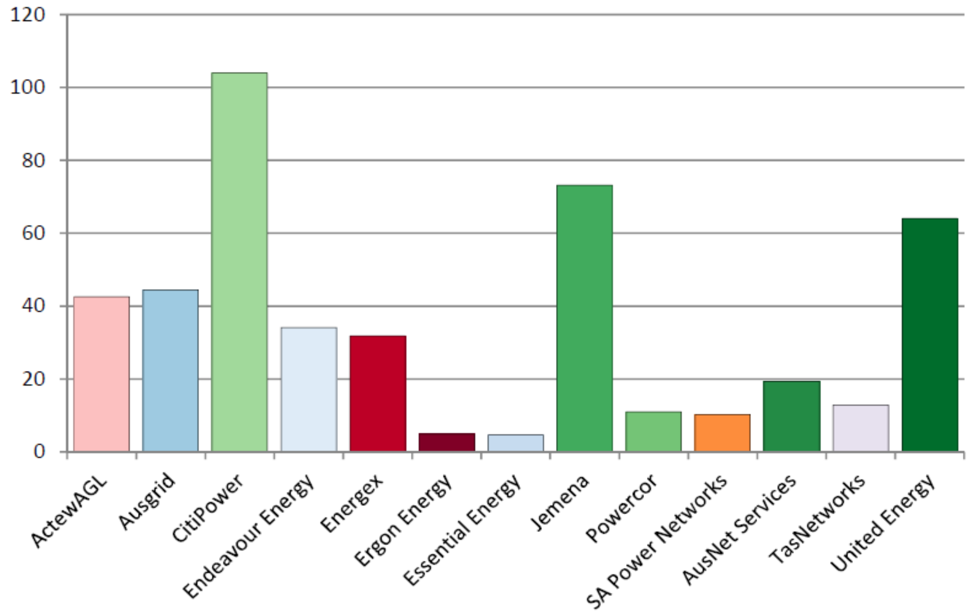
- Port Melbourne;
- the CBD;
- North Melbourne;
- Brunswick; and
- Fitzroy.

Distribution feeders are generally operated in a radial mode from their respective zone substation supply points with inter-feeder tie points which can be reconfigured to provide for load transfers and other operational contingencies.

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 or 400 volts. These voltages are derived from distribution substations which are located throughout the distribution network. Both overhead and underground low voltage reticulation, including service arrangements, complete the final connections to the low voltage consumers' points of supply.

It is notable we have the highest proportion of customers in the NEM serviced on CBD high voltage feeders. We have no long or short rural feeders.

Figure 4.5 Customer density (customers/km of route line length, average 2009–2013)



Source: AER, Electricity distribution network service providers, Annual benchmarking report, November 2014, p. 19.

4.6 Network resilience

We have an obligation under clause 3.1A of the Code to take steps to strengthen the security of supply of the Melbourne CBD. Those steps are set out in our Melbourne CBD Security Upgrade Plan[16].

The obligation under the Code was preceded by the publication of our Regulatory Test Final Report[17] that economically justified the scope of works defined to upgrade the 66kV sub-transmission network in the Melbourne CBD to an 'N-1 Secure' standard.

Works on the upgrade have been on-going during the current regulatory control period and have included:

- establishment of two new 66kV sub-transmission lines from Brunswick Terminal Station (**BTS**) to Bouverie /Queensberry (**BQ**) zone substation;
- refurbishment of the BQ zone substation including installation of nine circuit breakers and two 66/11kV transformers;
- refurbishment of the Victoria Market (**VM**) zone substation and linkage via two 66kV sub-transmission lines with BQ zone substation; and
- commencement of the refurbishment of the Waratah Place (W) zone substation including installation of circuit breakers, transformers and associated switchgear and protection. Work has also commenced on linking of W zone substation via two 66kV sub-transmission cables with BQ zone substation.

Unfortunately as a result of a number of planning disputes surrounding the BTS upgrade, progress over the current regulatory control period has not occurred as quickly as we would have liked. Following conclusion of what we expect to be the final challenge in the Victorian Civil and Administrative Tribunal, works at BTS are

16 CitiPower, Melbourne CBD Security of Supply Project Plan, 16 June 2008

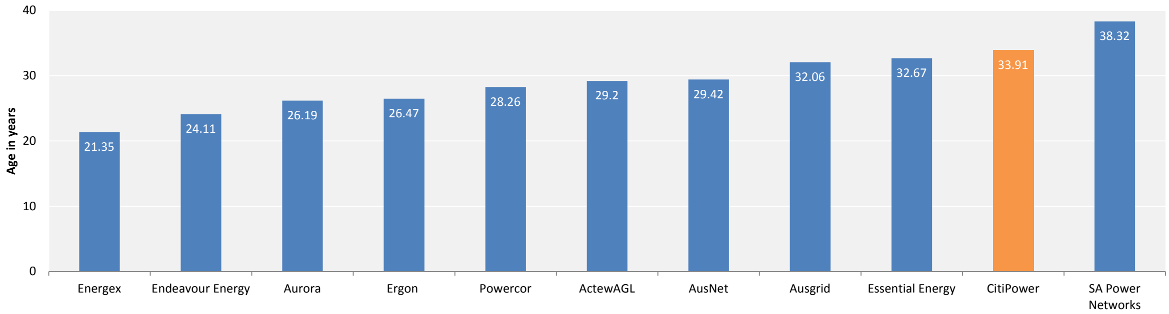
17 NERA, Melbourne CBD Enhancement: Regulatory Test Analysis, CitiPower, 5 April 2007

scheduled for completion in 2016. This will enable us to complete the distribution works over the period 2016-2017. Further discussion of the CBD security of supply project is contained in chapter 9.

4.7 An ageing network

Our network is growing older. Based on analysis of the Category Analysis Regulatory Information Notice (**CatA RIN**), we have, on average, the second oldest network in the NEM.

Figure 4.6 Average Australian network asset ages



Source: Category analysis RIN, CitiPower

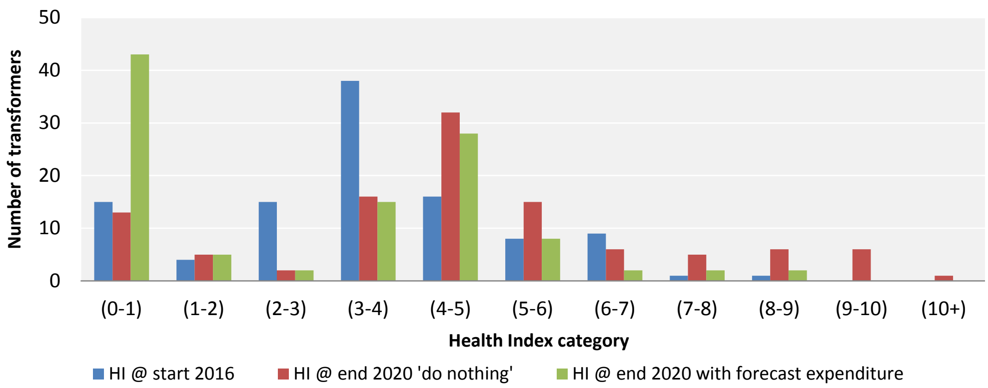
There are two key areas of ageing and potentially unreliable assets that are a priority:

- assets with a poor health index (**HI**); and
- assets in the 22kV sub-transmission network.

We use condition based risk management (**CBRM**) process to plan the replacement of major items of plant and equipment. CBRM is based on aging algorithm taking into account a range of inputs including condition, environment and other operating factors.

Figure 4.7 presents the outcome of the analysis for the sub-transmission transformers which are one of the asset classes with the highest consequence of failure. The red bar represents the HI at 2020 without intervention, showing a significant increase in the proportion of transformers with a HI of 7 or above by the end of the regulatory control period. Based on this regulatory proposal, the health index at 2020 will be represented by the green bars.

Figure 4.7 Health index forecasts 2020 – transformers



Source: CitiPower

Many of our other network assets that are ageing are located within our 22kV sub-transmission network, including transformers and indoor switchboards within existing zone substations. Some of these zone substations also have secondary voltages of 6.6kV, which is inconsistent with the present 11kV standard in the CBD and the inner suburbs. These non-standard 6.6kV secondary voltages have many technical limitations when compared with the standard 11kV secondary voltage. Having a 6.6kV distribution feeders limits system flexibility with regard to load transfers and effectively creates islands within the network.

Over the next regulatory control period we are planning to progressively replace the 22kV sub-transmission network with a 66kV sub-transmission network and replace the 6.6kV network with 11kV. Operation of the sub-transmission network at the higher voltages will also reduce the amount of distribution losses, which provides environmental and customer benefits.

4.8 Congestion

There are a number of characteristics our network in the CBD and the challenges of operating in the centre of a city that drive the need for a different approach to our operations. These characteristics and challenges include:

- drive times - traffic speeds in Melbourne are slow, and get progressively slower approaching and entering the CBD;
- restrictions on working during daytime hours - the combination of traffic management arrangements and access restrictions mean that significant amount of activity on the network has to be conducted outside of business hours i.e. overnight or during weekends; and
- network design necessitates two man teams – many of the assets in the network are located in confined spaces. This necessitates two man teams for many operational areas and compounds the response time to faults as both members of the team are required to be present before the fault can be addressed.

As noted previously, a large portion of our network is located underground. In the CBD virtually all assets are located underground. There is however very limited room available in the majority of footpaths and roads in the CBD and inner Melbourne for new circuits to be laid or repairs and upgrades to occur due to the plethora of plant and equipment that has been installed by other utilities. As a result, excavation may be required to depths of 1.5 to 2 metres to find clear passage.

Other issues particular to undertaking works in the CBD relate to removal of waste material, which is typically more expensive in CBD and inner Melbourne locations, traffic management costs, obtaining council permits which is more costly and difficult, restrictions in relation to noise pollution and site restoration.

These issues make operating a network in a CBD and surrounding suburbs an often challenging and more difficult task than operating a network in other areas. The impact of this can be observed when comparing many of our unit rates against those of other distributors servicing predominantly urban or rural territories.

5 Benchmarking

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5. Benchmarking

We are one of the most efficient distribution networks in Australia as demonstrated by a range of benchmarking analyses.

Such an outcome is not a surprise given our track record in seeking efficiency improvements and responding to the AER's incentive framework.

We have sought and achieved efficiency improvements while maintaining a strong safety and reliability record.

Our strong benchmarking performance supports the efficiency of our historical operating and capital expenditure.

We consider top-down benchmarking models provide a useful starting point for the Australian Energy Regulator (**AER**) to begin to understand differences in the relative performance of distributors.

Top-down benchmarking is more useful than bottom-up category level benchmarks due to its aggregated nature which is less prone to data inconsistencies.

5.1 Our performance

The AER published its first annual benchmarking report on 26 November 2014[18] and subsequently released on 27 November 2014 a benchmarking report it commissioned from Economic Insights.[19] These two reports demonstrate that we benchmark well across a range of expenditure categories and a range of benchmarking models.

Our strong benchmarking performance supports the efficiency of our historical operating and capital expenditure. We have sought and achieved efficiency improvements while maintaining a strong safety and reliability record.

5.1.1 Operating expenditure

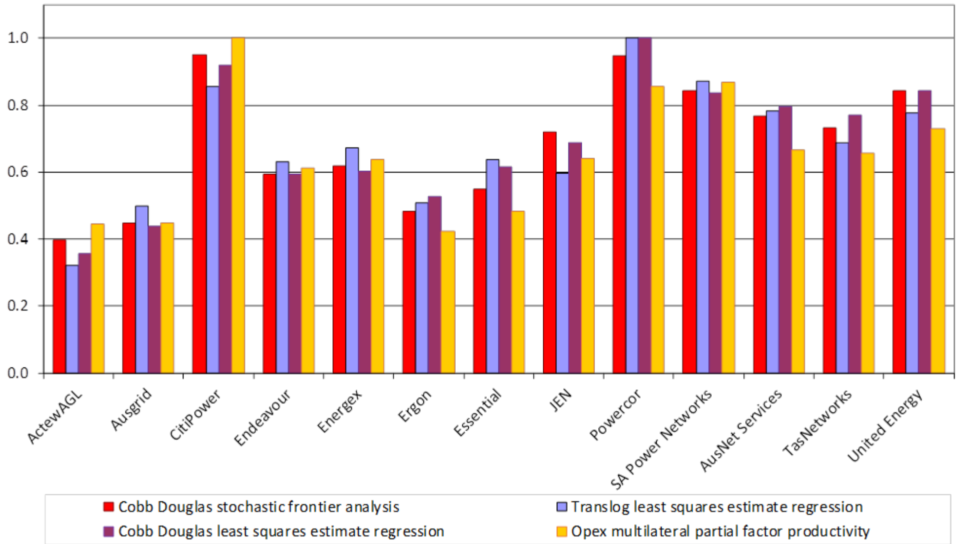
Economic Insights' analysis demonstrates our operating expenditure is efficient relative to other distributors in the National Electricity Market (**NEM**), shown in figure 5.1. This provides support to the efficiency of our historical operating expenditure for the purposes of forecasting our operating expenditure requirements for the 2016–2020 regulatory control period.

Importantly, the benchmarking analysis demonstrates that we have been responding to the Efficiency Benefit Sharing Scheme (**EBSS**) by seeking to minimise our operating expenditure continuously through the regulatory control period. Our performance under the EBSS is discussed in chapter 13.

18 AER, Annual Benchmarking Report, November 2014.

19 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, Report prepared for the Australian Energy Regulator, November 2014.

Figure 5.1 Operating expenditure efficiency scores, average 2006 to 2013



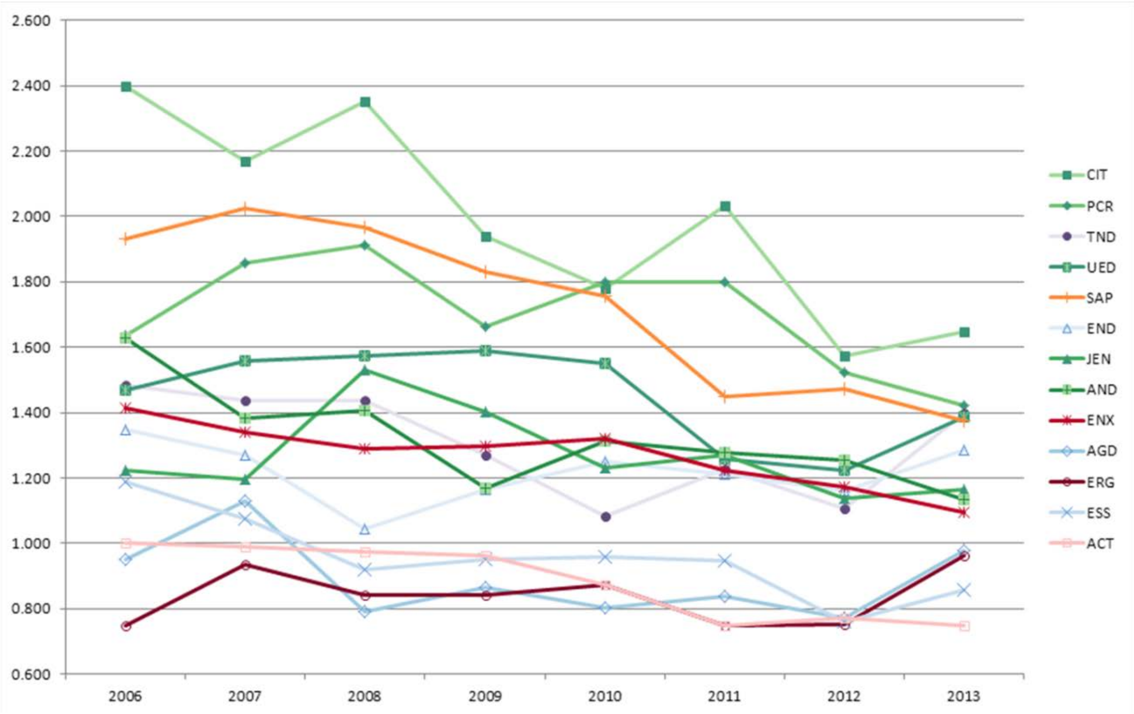
Source: AER, *Benchmarking Fact Sheet*, published 27 November 2014, p. 2.
Note a high score represents greater operating expenditure efficiency.

Figure 5.2 demonstrates that we have remained one of the most efficient distributors throughout the 2006-2013 period. While there has been a decreasing trend in operating expenditure productivity across all distributors (as shown in Figure 5.2), this is a reflection of the increasing compliance costs required to meet regulatory obligations to achieve the operating expenditure objectives in the National Electricity Rules (**Rules**), for example changes in vegetation management and bush fire mitigation activities as a result of the Victorian Bushfires Royal Commission (**VBRC**) findings.[20] The decreasing trend in operating expenditure productivity should not be misinterpreted as declining operating efficiency. It simply reflects cost drivers that are not captured in the model.

The benchmarking analysis demonstrates that our actual 2014 operating expenditure is an appropriate starting point for forecasting efficient operating expenditure required to meet the operating expenditure objectives for the 2016–2020 regulatory control period. As discussed in chapter 10, we have applied our actual 2014 recurrent operating expenditure as the base level of expenditure for forecasting our 2016–2020 operating expenditure requirements. Using an efficient base level of expenditure ensures that the 2016–2020 forecasts are also efficient.

20 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010.

Figure 5.2 Operating expenditure multilateral partial factor productivity 2006 to 2013



Source: AER, *Annual Benchmarking Report*, November 2014, figure 13.
Note: CitiPower is represented as 'CIT'. A high score represents greater operating expenditure efficiency.

5.1.2 Capital expenditure

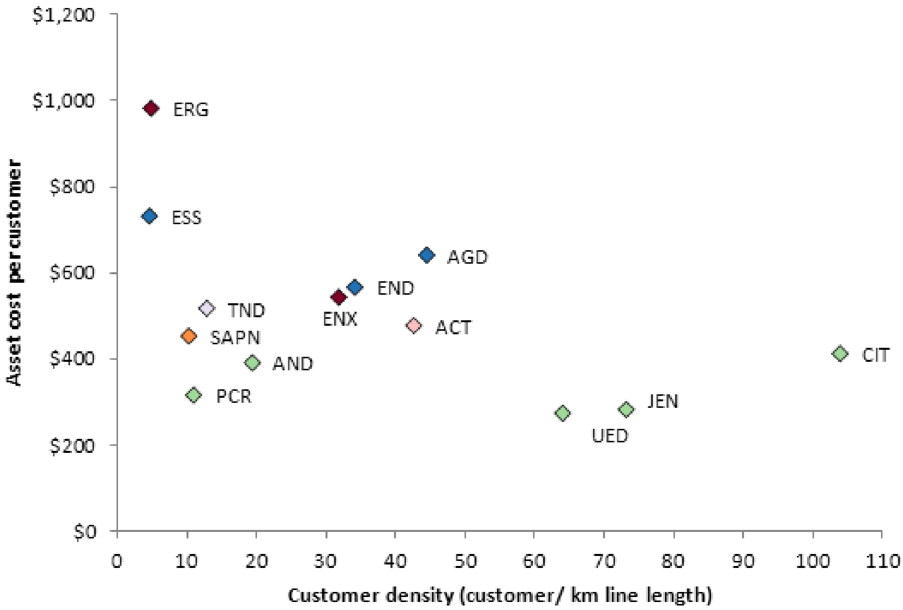
The profile of total capital expenditure is highly dependent on network conditions and customer characteristics prevailing at the time. Unlike operating expenditure, capital expenditure is not re-occurring and therefore cannot be directly compared across distributors at a point in time. For these reasons capital expenditure is more difficult to benchmark and is generally better assessed at the project level and aggregated category level.

The benchmarking analysis presented in the AER's 2014 annual benchmarking report indicates that our asset cost[21] per customer is among the lowest in the NEM, even given we have one of the highest portion of underground assets in the NEM, refer figure 5.3. This indicates that our historical capital expenditure decisions have been efficient. Our forecast capital expenditure for the 2016–2020 period also ensures that we remain one of the most cost efficient networks in Australia.

Our performance relative to the AER's capital expenditure category models for aggregated replacement and augmentation expenditure categories is discussed in chapter 9.

21 The AER calculated the annual asset cost as depreciation plus the average return on capital.

Figure 5.3 **Asset cost per customer, average 2006 to 2013**



Source: AER Annual Benchmarking Report, published 26 November 2014.
Note: CitiPower is represented as 'CIT'. A lower asset cost per customer represents is indicative of more efficient capital expenditure.

5.2 Role of benchmarking in regulatory determinations

Benchmarking analysis provides high level information which is a useful guide and starting point for assessing the efficiency of distributors' current and forecast expenditure. Notwithstanding, the potential usefulness of top-down benchmarking, a distributor's regulatory proposal should remain the starting point for the AER's assessment process and benchmarking models should not be applied as a direct substitute for a distributors forecast.

Chapter 4 discusses some of the key characteristics of our network which are important when considering our expenditure requirements and which, if not adequately taken into account, can potentially result in misleading benchmarking analysis.

The development of robust benchmarking analysis, suitable for use in regulatory assessment processes, is a long journey which requires a long term commitment from industry and the regulator to collaborate to ensure that the data is of high quality, the models are robust and uncontrollable exogenous differences between distributors are properly understood by all parties and are appropriately accounted for. The AER has only recently commenced this journey and accordingly there is still a way to go before direct reliance should be placed on the results.

At this stage, we consider top-down benchmarking models can be used as a useful starting point for the AER to begin to understand differences in the relative performance of distributors. Given current data availability and quality, top-down benchmarking is a more useful tool for assessing distributors' regulatory proposals than bottom-up category level benchmarking. This is because top-down benchmarking, due to its aggregated nature, is generally less prone to distortions resulting from data reporting inconsistencies and errors than bottom-up category level benchmarks. Top-down benchmarking models therefore could be used by the AER as one of a number of tools for assessing distributors' regulatory proposals.

In summary, we recognise that benchmarking is an important part of the regulatory framework that, when combined with other expenditure assessment methods, is a useful tool for assessing the efficiency of distributors' historical and forecast expenditure required to meet the operating expenditure and capital expenditure objectives in the Rules.

5.3 Category level unit rate benchmarking

We have reservations regarding the accuracy of the detailed level category information that is intended to be used by the AER for unit costs analysis. We also have reservations regarding whether network specific operating environment conditions impacting on unit costs can be adequately taken into consideration in category level unit costs analysis.

The following three principles should be met before comparisons of unit rates across distributors could be considered sufficiently reliable for regulatory assessment purposes:

- accurate and consistent reporting of data across distributors;
- a sufficient number of comparable projects are available to obtain a representative sample; and
- account is taken of exogenous differences in operating environment.

If the above principles are not met then differences in unit rates between distributors cannot be attributed to inefficiency with any level of certainty. This is because differences in unit rates may be a function of data inaccuracies, unrepresentative samples or exogenous differences. If these factors exist then it is impossible to isolate the difference in unit rates attributable to management inefficiency.

As discussed in the sections below, our review of the category analysis regulatory information notice (**RIN**) data and basis of preparation documents strongly indicates that, at this stage, none of the above principles are met. We therefore consider that, the category level benchmarking analysis should be used cautiously and the AER should give thorough consideration to the serious limitations of the data and the analysis. Until such time as the above principles can be met with confidence, we do not consider it appropriate for inferences to be made regarding efficient unit rates.

5.3.1 Accurate and consistent reporting

Unit rate calculations are very sensitive to the accuracy of the data reported by distributors. Unit rates are a function of both the reported expenditure and the reported activity volumes. Error in one or both of these can lead to significant misrepresentation of the true unit costs of undertaking an activity.

At the time the AER requested the category level data from distributors, internal business systems were not in place to either collect the required data in the field or to store or report the data in the form required. This is because the type of data requested has not previously been required for business operations. In our case, our business systems do not report the information required in the form requested and consequently there is a significant level of estimation and assumption in the reported data. For example, we do not capture unit costs in performing individual tasks in the field, this is because, for efficiency reasons, field crew undertake multiple tasks in one site visit. It has not previously been necessary for every task undertaken in the field to be individually itemised, costed, time confirmed and reported. We understand that this is also the case for the other Australian distributors. Consequently the data provided by distributors in the category analysis RIN responses cannot be an accurate reflection of that requested by the AER and will not be so until business systems both in the field and back-office of every distributor are implemented to enable accurate data collection and reporting.

Additionally, as a consequence of the significant level of estimation in the category level data reported by distributors to date, differences in the estimation methods and assumptions applied by distributors to populate the data requested will also lead to comparability issues.

At this stage, our observation from reviewing the category analysis RIN data and basis of preparation documents is that data inaccuracies and differences in estimation methods are very likely to account for a large majority of the differences in distributor's unit rates calculated from the category analysis RIN data.

5.3.2 Representative sample

For unit rates to be comparable across projects and across distributors it is necessary for the sample of projects to be representative of a typical project undertaken in the industry. This requires a sufficiently large sample of similar sized projects be included in the unit rate calculations. The sample should cover a sufficient number of projects for each distributor to ensure the average unit rate is reflective of the industry.

Where there is a small sample size, the unit rates are unlikely to be representative of a typical project for the industry because:

- unusual projects can receive too much weight in the unit rate calculation; and
- projects of a particular distributor may receive too much weight in the calculation, resulting in a unit rate which is overly representative of a distributor's specific network characteristics.

Our observation from reviewing the category analysis RIN data is that in many cases, there is an insufficient sample of similar projects for the derived unit rates to be representative of a typical project that could be undertaken by any distributor in the NEM.

5.3.3 Accounting for exogenous differences

Differences in unit rates between distributors may also be due to exogenous differences in network operating environments. The AER acknowledges that differences in costs can arise from network operating environments, for example differences in network density and location:

> *We consider a key driver of the cost of replacing an asset is its location on the network. We would anticipate that assets in geographically remote segments of the network would encounter extended travel costs to service its assets. Conversely a NSP with a highly dense network would have higher traffic management or other civil costs.*[22]

We are in a unique position to demonstrate the likely magnitude of the contribution that differences in network operating environments can make to differences in unit costs. The Powercor and CitiPower networks are operated under the same management team, with the same business systems and processes. Powercor's network has relatively low customer density on average and very low density in specific parts of the network, for example the Mallee and the Wimmera in north-west Victoria. Conversely, CitiPower's network is concentrated in Melbourne's Central Business District and has the highest customer density of the distributors in the NEM.

Due to the joint management of these two networks, differences between CitiPower and Powercor's unit rates are not attributable to differences in data collection or reporting. Differences in the unit rates are therefore primarily attributable to differences in external operating environment factors.

As demonstrated in chapter 5, the contribution of operating environment conditions to differences in unit rates between distributors is potentially very large. Consequently, we do not consider that, at this stage, sufficient normalisation of data is undertaken nor is there adequate data to enable inferences to be made about the extent that inefficiency is a contributing factor to the differences in unit rates between distributors.

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[22] AER, Better regulation, Explanatory statement, Final regulatory information notices to collect information for category analysis, March 2014, p.57.

6 Our customer engagement

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6. Our customer engagement

We take very seriously our responsibility to deliver electricity to all customers safely, reliably and efficiently. We also have a responsibility to work with our customers and diverse stakeholders to understand their requirements to ensure that we continue to deliver services that meet their needs now and in the future.

We have a proud history of customer engagement and for building, maintaining and enhancing effective relationships and dialogues with our customers. In addition to our customer consultative committee and our regional business managers, who are responsible for developing and maintaining relationships with our major customers throughout our distribution network, we routinely monitor customer satisfaction with our services. In addition, in recent years we have undertaken significant community engagement activities to support the successful rollout of smart meters to over 99 per cent of our customers.

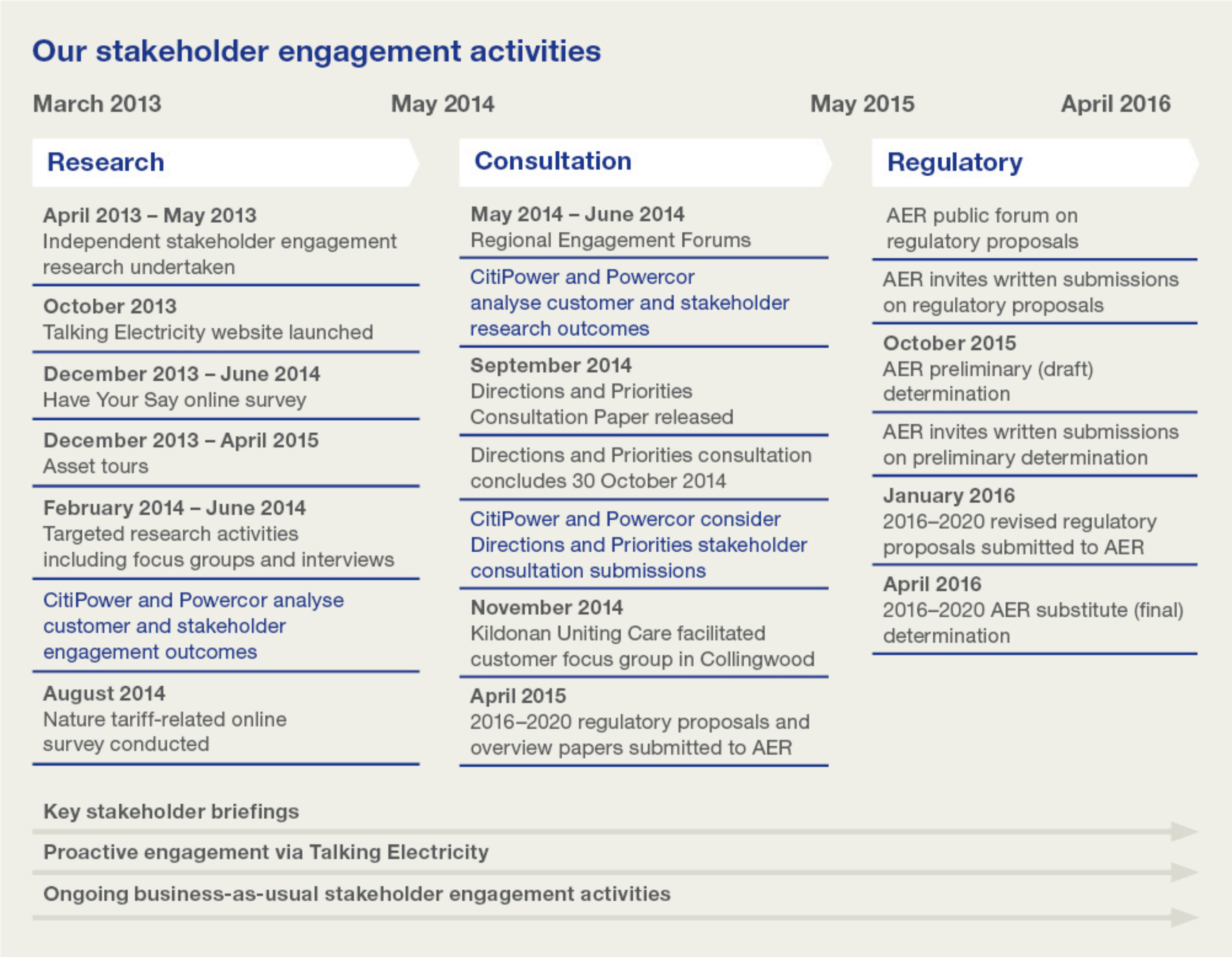
A comprehensive review of the effectiveness of our business as usual engagement activities was undertaken during early 2013 and this review, combined with recent stakeholder engagement experience from utility businesses both in the United Kingdom of Great Britain (**UK**) and in Australia, was incorporated into the development of our price reset stakeholder engagement program (**engagement program**) in mid-2013. In parallel, we provided input to the Australian Energy Regulator (**AER**) as they developed the *Consumer Engagement Guideline for Network Service Providers* (**Consumer Engagement Guideline**).

The cornerstone of our engagement program was the importance of commencing our engagement activities early enough to enable time for effective engagement as well as time to consider customer feedback and factor the feedback into the development of our regulatory proposal for the 2016–2020 regulatory control period.

6.1 Overview of our engagement program

To guide the development of our regulatory proposal, we designed and implemented our engagement program, the objective of which was to engage with our customers and stakeholders in order to understand their current and future needs, concerns and preferences. An overview of our engagement program is provided in figure 6.1.

Figure 6.1 Our price reset stakeholder engagement program



Source: CitiPower

Objectives

Our objectives for the engagement program were to:

- help our customers and stakeholders gain a better understanding of the electricity industry and raise their awareness of our role;
- successfully communicate our price reset-related plans to all customers and stakeholders via open and clear channels with a view to those customers and stakeholders becoming informed participants in the price reset (also referred to as regulatory determination) process;
- ensure we were positioned to listen early to our customers' and stakeholders' concerns;
- better understand the views and preferences of our customers and stakeholders;
- assess the concerns and issues raised and our potential to address them;
- provide prompt and clear feedback to our customers and stakeholders on our assessment and how we are planning to incorporate the feedback into our future plans;

- use the feedback we received from customers and stakeholders to help shape our regulatory proposal;
- be inclusive and clearly outline what our customers and stakeholders could expect from us via our engagement activities;
- demonstrate an evidence based process;
- implement good engagement practices and share our learnings with other distributors;
- comply with regulatory guidelines, including the AER consumer engagement guideline for network service providers; and
- provide an ongoing platform for future engagement activities.

Our engagement program was managed with the assistance of stakeholder engagement experts from within our Business, and was supported by market research organisations including Colmar Brunton.

Colmar Brunton designed and hosted our price reset online survey, designed and facilitated the residential customer focus groups and conducted interviews with our small/medium enterprise and large business customers. This ensured independence of our quantitative and qualitative market research activities, the objective of which was to provide confidence that our customer views were obtained in a robust and credible manner. The research approach and results were formally documented by Colmar Brunton and have been published on our Talking Electricity website, our dedicated engagement website.

During the second half of 2014, Nature (quantitative market researchers) were engaged to design and host an online survey to understand our customers' views on peak rebates and maximum demand tariffs, the results of which can also be found on our Talking Electricity website.

The AER's consumer engagement guideline, issued in November 2013, provides a high level framework based on best practice principles drawn from the Stakeholder Engagement Standard (AA1000SES) and the International Association of Public Participation framework (**IAP2**). Drawing on AA1000SES and IAP2, the guideline outlines four best practice principles that should guide all aspects of network service providers' customer engagement. The principles require all components of engagement to be:

- clear, accurate, relevant and timely;
- accessible and inclusive;
- transparent; and
- measurable.

Our engagement program was designed to comply with these principles and, in addition, we adopted a best practice approach to stakeholder engagement based on an adaption of the highly respected IAP2 spectrum.

The IAP2 spectrum is an internationally recognised, best practice framework designed to assist organisations select the appropriate level of engagement for different stakeholder groups. Recognising that there is no 'one right' approach to stakeholder engagement, the spectrum provides us with an adaptive framework for successful stakeholder engagement.

The spectrum provides five engagement levels – inform, consult, involve, collaborate and empower – and depending on the current involvement or activity with each stakeholder group, their level of influence on us and their level of dependency on our success, they can be organised and prioritised for different levels of engagement. Depending on the involvement stakeholders currently have with us and our goals, some stakeholders will require higher levels of engagement than others, and some will need to be taken on a journey over a longer period of time. As part of the planning of our engagement activities, an IAP2 assessment was undertaken to confirm the desired engagement level of each activity.

Our engagement program has utilised a variety of channels and engagement tools to effectively engage with our diverse stakeholders to obtain feedback about our current and future services. We have considered the feedback received in the development of this regulatory proposal. Table 6.1 summarises our assessment of our engagement program against the key performance benchmarks based on the AER's consumer engagement guideline.

Table 6.1 Our engagement program alignment with key performance benchmarks

Performance benchmarks	Alignment
AER Consumer Engagement Guideline Best practice principles:	
Clear, accurate, relevant and timely	✓
Accessible and inclusive	✓
Transparent	✓
Measurable	✓

Source: CitiPower

We are proud of our price reset engagement program which meets the requirements for effective customer engagement as outlined in the Consumer Engagement Guideline and aligns with the IAP2 framework.

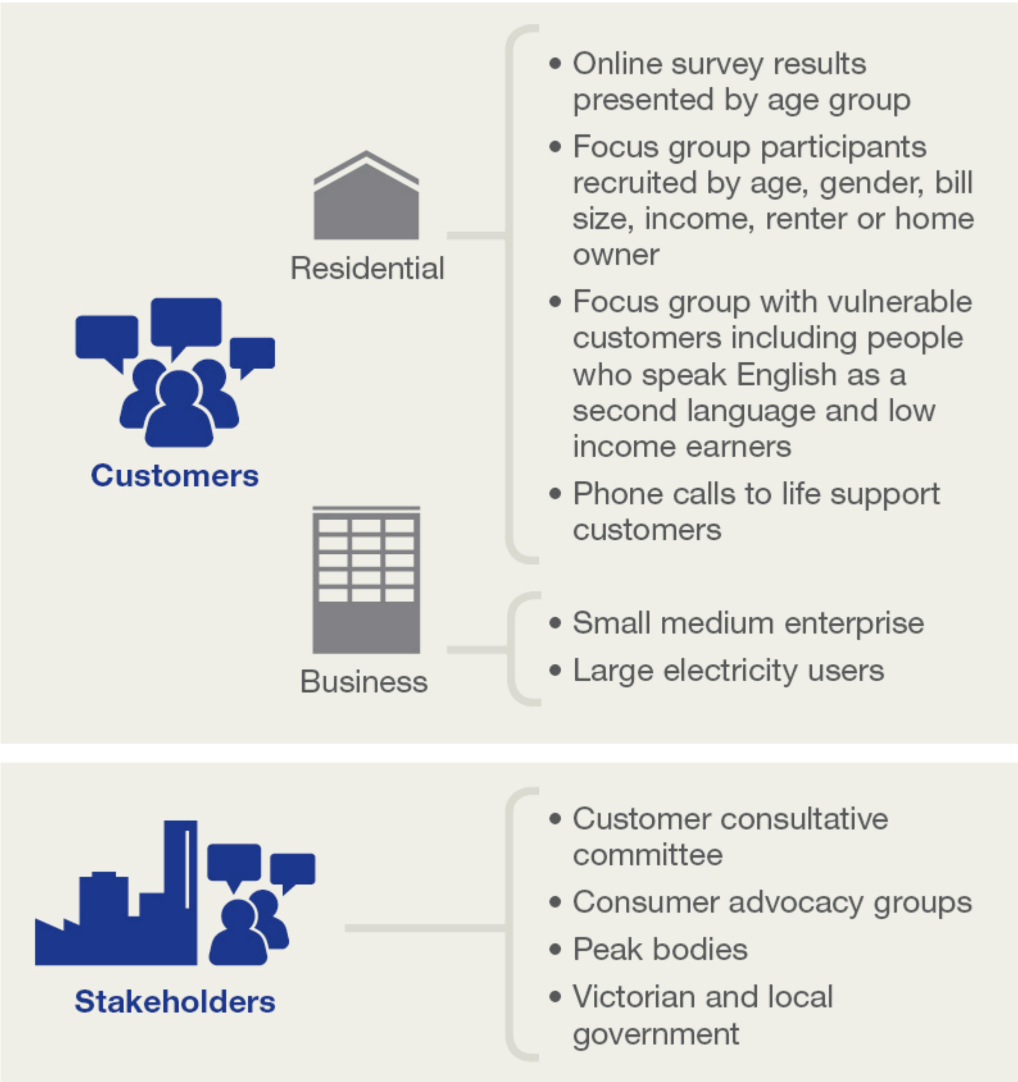
Details of our approach, background information, research findings and all outputs from our engagement program are available on our **TalkingElectricity.com.au** website and in appendix A.

6.2 Our customers and stakeholders

We have over 325,917 customers, 83 per cent of which are residential customers and 17 per cent are business customers.

As part of our engagement program planning, we identified different customers, customer cohorts and stakeholders to be engaged through a variety of engagement activities. Figure 6.2 summarises our customers and stakeholders.

Figure 6.2 Our customers and stakeholders



Source: CitiPower

6.3 Our engagement approach

6.3.1 Overview

As outlined in figure 6.1, our engagement program encompasses three phases.

Research phase

Our research phase focused primarily on informing our customers and stakeholders about who we are, our role in the supply of electricity and the services that we provide, engaging with our customers and listening to what our customers and stakeholders think about our current services, our performance and their future needs.

Market research undertaken during April 2013 as part of the review of our business as usual stakeholder engagement activities highlighted the fact that almost 80 per cent of our customers surveyed, particularly residential customers, did not know who we were, our role in the supply of electricity and the services that we provide[23]. In addition, a key stakeholder engagement learning from our UK peer, UK Power Networks, was that, unless your customers know who you are and what you do, any attempts to engage your customer about specific service-related topics and obtain their views, will deliver poor engagement outcomes.

Consultation phase

Our consultation phase focused on involving our customers and stakeholders and was designed to progress and integrate customer expectations and concerns into our planning for the 2016–2020 regulatory control period. Key elements of this phase included our regional engagement forum and our 'Directions and Priorities' consultation, together with a targeted focus group. This phase culminates with the submission of this regulatory proposal.

Regulatory phase

The regulatory phase is focused on the AER's evaluation of our regulatory proposal. This phase includes opportunities for our customers and stakeholders to provide feedback to the AER on our proposed expenditure plans and our required revenue for the 2016–2020 regulatory control period as part of the AER's consultation activities.

6.3.2 Our engagement activities

The engagement activities covered all customer segments and key stakeholder groups across our electricity distribution area. Opportunities to participate were widely promoted; we made use of independent market research experts, involved senior management and subject matter experts and aimed to reach different customer segments in a variety of ways. Refer to figures 6.3 to 6.5.

More detail is available in appendix A.

[23] UMR Research, CitiPower-Powercor Consumer survey May 2013 Final: '18% can name CitiPower as their distributor'.

Figure 6.3 Engagement activities timeline

Source: CitiPower

Figure 6.4 Research phase activities overview

Source: CitiPower

Figure 6.5 Consultation phase activities overview

Source: CitiPower

6.4 What our customers and stakeholders have told us

6.4.1 Customer expectations

Through our engagement program, our customers and stakeholders told us what they want from us during the next regulatory control period. This feedback has informed our plans and, as a result, we are confident that our regulatory proposal delivers on the expectations of our customers.

Customer expectations have been summarised into six key insights:

- customers want reliable supply for a reasonable price;
- they want efficient and targeted investment across our networks;
- customers want us to pay close attention to safety and maintenance and they support additional investment in activities that reduce risk of fire danger;
- they expect forward and proactive planning to ensure the resilience, capacity and capability of the network;
- future needs are best met by a smart grid to enable choice and flexibility, taking pressure off the existing network and facilitating the connection of renewable energy sources; and
- customers want greater access to readily understandable information about their electricity usage.

6.4.2 How we are responding

The integration of customer expectations and concerns into our planning is an important part of developing our regulatory proposal. Table 6.2 illustrates how the engagement outcomes have been factored into our regulatory proposal.

Table 6.2 Our response to your feedback

What you said	What we will do
You want a safe, reliable electricity supply at a reasonable price. Most people (82 per cent of survey participants) are satisfied with the reliability of their electricity supply and 54 per cent of them do not want to pay any more to improve it. Larger business customers expect a reliable supply of electricity, to allow business to operate with uninterrupted, continuous supply.	We will take a cost efficient approach to all our investments in the network, ensuring we deliver safe and affordable energy for all our customers in the longer term. Rather than the costly replacement of some of the oldest substations in Victoria, we will make better use of newer infrastructure close by. We will assess the condition of underground pit and pillar assets, replacing those that are deteriorating and could present a potential risk to public safety.
Take all reasonable measures to protect the safety of customers and their communities, and reduce the bushfire risk. Survey participants were happy to accept a small price increase that contributed to reduced risk of fire danger and undergrounding or relocating of assets in areas of natural beauty.	Safety is our number one priority. We will take all reasonable steps to ensure ongoing community safety including ongoing maintenance of our electricity assets.
A clear preference for the development of a wider safety campaign targeted at all of those that come into contact with the electricity network (as opposed to specific messages targeted at specific groups).	We will work with Energy Safe Victoria to promote community safety.
Targeted investment to support growing areas of Melbourne – businesses want us to either maintain, or slightly improve, current reliability levels and focus on investing in the development of additional substations, particularly to service the inner city and inner west Melbourne.	We are investing to provide capability to support high-density residential and commercial development in the central business district (**CBD**) and inner suburbs.
Some customers would like to see power lines put underground to improve visual amenity or to reduce the potential for car accidents. However survey participants were, overall, not willing to pay a small increase for this undergrounding.	Developers of new subdivisions are generally required to underground electricity cables. Undergrounding existing power lines is expensive and would impact on customers' bills. Some undergrounding can take place if customers directly benefiting from the work are prepared to pay or work with their local council to secure funding. We will continue to work with local authorities and customers who commission projects to put lines underground.
Many people are happy with our current vegetation management practices but some would like to see more frequent pruning or other risk management strategies introduced. There is a strong dislike of 'V' or 'U' shaped heavy cutting of trees, with general preference for more regular light trimming in residential areas. However over half of survey participants (52%) were not willing to pay a small increase in return for trimming vegetation more frequently and less severely.	We are committed to vegetation management practices that balance safety with affordability.
Residential customers are generally happy with connection processes but business customers expect us to be transparent, work to exact timelines, be flexible, supportive, reliable and	We will automate our standard connections processes to make it easier, faster and cheaper for customers. We will continuously explore ways to improve timeliness and

What you said	What we will do
dependable.	quality of service to connect large customers. We will effectively communicate the time needed to develop the right solutions for complex connections.
Enable the connection of more renewable energy and embedded generation in the CBD. Our customers want us to be a leader, not a follower, when it comes to investment in the network, particularly renewable energy sources such as solar and wind.	We are further investing in technology to better control fault levels which will enable us to connect more embedded generation, in particular at North Richmond and Albert Park.
Install more energy efficient street lighting.	We will continue to work with the City of Melbourne and other municipalities to keep the lights on and introduce new types of energy-efficient units that contribute to safe liveable cities and communities.
Greater access to smart meter data, via an online portal, would give you greater ability to manage electricity use and power bills. You wanted easy-to-access, easy to understand information. Some customers would like us to advocate on their behalf and provide information on usage and the most appropriate retail offerings.	We are planning to invest in a customer relationship management system and online customer portal so customers can access their electricity usage data and manage their electricity bills. We are unable to provide advice on the most appropriate retail offering but we can provide the information to inform your decision.
A smart grid is a necessary initiative worthy of investment. It was generally felt that future needs would be best met with a smart grid to enable choices and flexibility, and would take pressure off the existing network and traditional sources of power.	Invest in the development of a smarter network by using advanced technologies that create efficiencies and improve reliability and safety. We will investigate demand-side solutions to meet localised energy requirements during peak periods, and the application of new technologies such as batteries and cold storage.
A fast response is expected to issues that our customers raise.	Our call centre and website provide channels for our customers to contact us. In addition, we currently provide outage information through our website and apps, and SMS notifications straight to customers' phones. We will continue to look at ways of improving our communications on an ongoing basis.
Engage with us more effectively – you welcomed the opportunity to participate but want more information about issues.	We will consult on our future tariff structures as well as issues affecting customers' electricity supply and energy choices, reflecting that the way customers use electricity is changing.
You want flexibility and do not want to be disadvantaged by any changes to tariff structures. Different types of tariffs are confusing.	We are extending our engagement program by consulting on our future tariff structures. We are currently considering a number of options, including rebates for lower energy use as well as tariffs for peak demand periods.

Source: CitiPower

6.5 Conclusion and next steps

We are proud of our price reset stakeholder engagement program and believe that it has been ‘fit for purpose’ given the nature of our business and our customers’ level of knowledge of our role and services, as well as the regulatory determination process.

Our Talking Electricity website and electronic newsletters will contain information about the AER’s consultation process and any upcoming public forums regarding our regulatory proposal.

Learnings from the price reset stakeholder engagement program will help refine the business wide stakeholder engagement approach which is being refreshed in 2015 to ensure that it remains aligned with our current and future priorities.

In early 2015, our customer consultative committee was refreshed and membership increased to capture a broader range of views. The refresh incorporated feedback obtained during consultation activities during 2013 and 2014 as well as leveraging ‘best of breed’ approaches to consultative committees from utility peers worldwide.

It takes time to develop, maintain and enhance longer term relationships with our customers, our stakeholders and their advocates. Through our price reset engagement activities, we have strengthened existing relationships and developed new relationships that we will maintain and enhance on an ongoing basis.

We are continuing to evolve our engagement approach across all our business activities to ensure that our business focus and our strategic priorities remain firmly focused on the long term interests of our customers.

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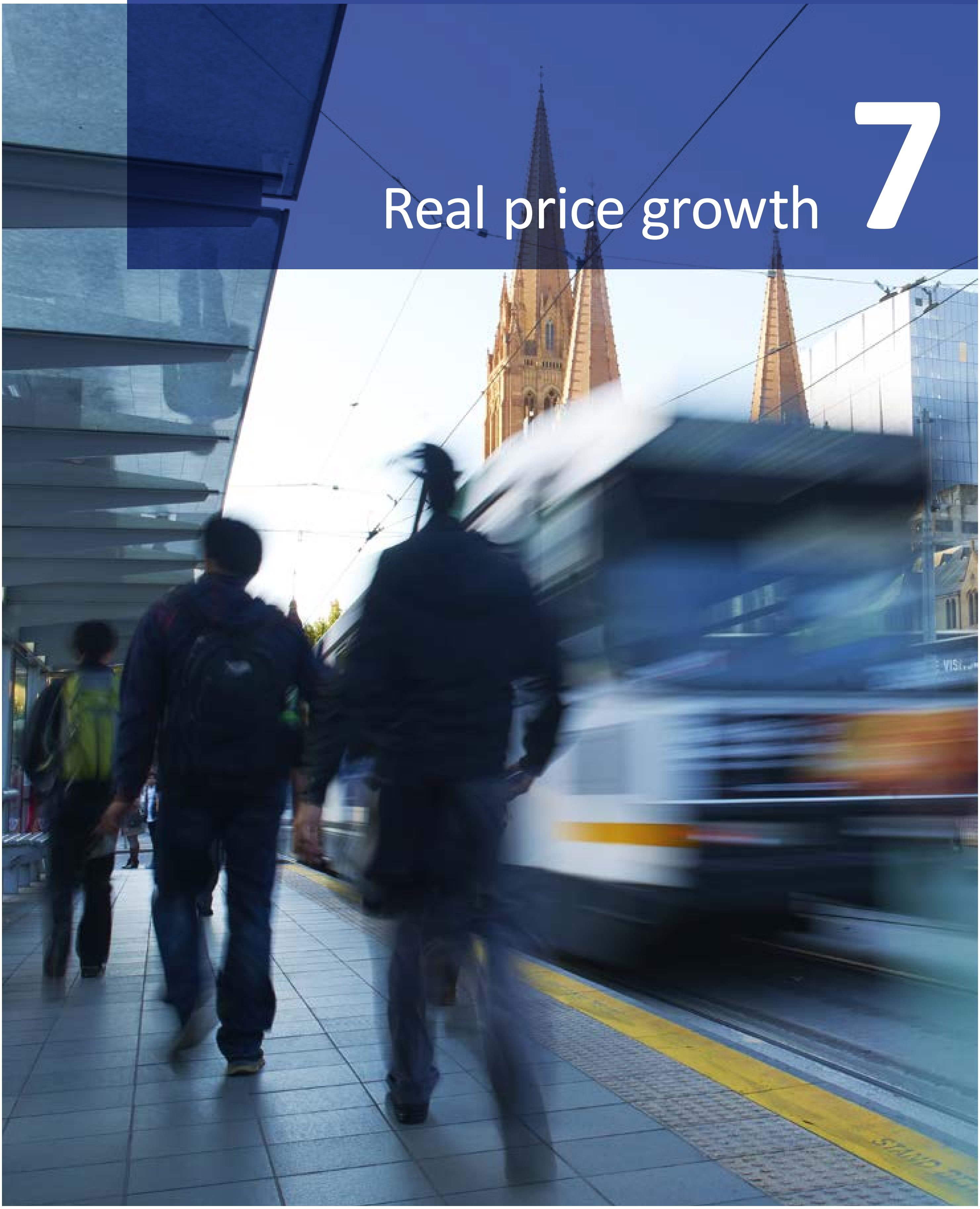
Real price growth 7



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7. Real price growth

Our Enterprise Bargaining Agreements (**EBAs**) reflect efficient market outcomes. We negotiate strongly but in good faith to ensure we attract and retain the highly-skilled labour required to operate an electricity distribution network while minimising costs.

We achieve operating efficiency by ensuring we optimise the utilisation of our labour resources. Our labour costs therefore reflect the efficient costs required to deliver a reliable electricity supply to our customers.

EBA wage growth rates directly reflect the growth in labour prices paid by electricity distributors. Wage growth rates forecast for the broader Electricity, Gas, Water and Waste services (**EGWW**) sector do not sufficiently reflect the skills required in the electricity distribution industry.

We therefore consider that EBA wage growth rates provide the most realistic forecast of our wage growth rates over the 2016-2020 regulatory control period.

We have examined the expected growth in prices over the 2016–2020 regulatory control period for key inputs we use to deliver standard control services, including prices for labour, materials and contracts.

We found that over the 2016–2020 regulatory control period input prices for labour and contracts are forecast to grow at a faster rate than the Consumer Price Index (**CPI**). We therefore include real price escalators in the labour and contracts components of our operating and capital expenditure forecasts for the 2016–2020 regulatory control period.

We use a range of electricity distribution equipment such as transformers, circuit breakers, conductors and poles. In aggregate, we expect our materials input prices to grow at approximately the same rate as the CPI. We therefore do not include real price escalation in the materials component of our operating and capital expenditure forecasts for the 2016–2020 regulatory control period.[24]

Our real price growth forecasts for labour and contracts are set out below.

7.1 Labour price growth

Our internal labour price growth is driven by the outcomes of EBAs. The electricity distribution industry, like most industrial sectors in Australia, has a highly unionised workforce and we are required to negotiate wage growth rates, and other terms and conditions of employment, with our unionised employees through EBAs in accordance with our legal obligations under the Fair Work Act 2009 (**FW Act**).

Given that EBAs are the primary means of determining labour price growth in the electricity distribution industry, we consider that applying EBA wage growth rates to forecast labour price growth provides the most realistic expectation of labour input costs required to achieve the operating and capital expenditure objectives in the National Electricity Rules (**Rules**).

In this section we:

- explain our proposed labour price growth forecasts for the 2016–2020 regulatory control period, refer section 7.1.1;
- demonstrate that our EBAs reflect efficient market outcomes, refer section 7.1.2;
- demonstrate that the EGWW Wage Price Index (**WPI**) is not representative of labour price growth rates for the electricity distribution sector, refer section 7.1.3; and

[24] Reset RIN requirement 18.2(c) requests evidence that our method for forecasting material price escalation explains the price of materials previously purchased. Our reporting systems do not capture data in the form required to provide the requested information.

- explain that it is not appropriate to make productivity adjustments to the labour price growth forecasts, refer section 7.1.4.

7.1.1 Our proposed labour price growth forecasts

Actual EBA growth rates for period up to expiry

For the period up until expiry of our EBAs, our proposed labour price escalation rates are based on our actual annualised EBA wage growth rates, weighted for the proportion of EBA employees on each EBA.[25]

We have two existing EBAs. The first covers employees that are members of the Australian Services Union (**ASU**), the Association of Professional Engineers, Scientists and Managers Australia (**APESMA**)[26] or the National Union of Workers (**NUW**) and was agreed in 2013. The second covers employees that are members of the Electrical Trades Division of the Communications Electrical Plumbing Union (**CEPU**) and was agreed in 2014. Both these EBAs are attached.

Our existing EBAs set out the wage growth rates for the period to:

- 31 December 2016 - agreement with CEPU; and
- 30 June 2017 - agreement with ASU, APESMA and NUW.

As explained in section 7.1.2, our EBA wage growth rates reflect efficient market outcomes. Using our actual EBA wage growth rates up until expiry ensures the forecasts reflect a realistic expectation of our labour costs required to achieve the operating and capital expenditure objectives.

Applying any labour price growth rate less than our actual EBA wage growth rates would result in the business systematically recovering less than the efficient costs required to achieve the operating and capital expenditure objectives. As discussed in section 7.1.3, the EGWW WPI is not representative of labour price growth rates for the electricity distribution sector and is not a suitable substitute for our actual EBA wage growth rates which reflect our actual costs. Applying the actual EBA rates up to the date of expiry is also consistent with Australian Competition Tribunal 2010 judgement on Ergon Energy's appeal[27] and the AER's approach in subsequent regulatory determinations for the SP AusNet and ElectraNet electricity transmission networks.[28]

Historical industry average EBA growth rates for period after actual EBAs expire

For the period following the expiry of each of our EBAs, we apply the five year historical average EBA growth rate for all privately owned electricity networks, calculated by Frontier Economics.[29]

EBA wage growth rates across the electricity network industry have been relatively consistent over the past ten years, as demonstrated in figure 7.1. This reflects the nature of the industry which is in a steady state, with steady network growth and consequently steady labour demand and supply conditions. The low variation in EBA wage growth rates over time is further supported by the low intra-year standard deviation in the average private

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25 Employees currently engaged under individual employment agreements and are technically covered by the terms and conditions of an EBA, are entitled to revert back to those EBA conditions at any time. Consequently, there is no systematic wage growth differential between EBA and non-EBA employees. We have therefore applied the weighted average EBA rate to all internal labour.

26 Renamed 'Professionals Australia' in 2013.

27 Australian Competition Tribunal, Application by Ergon Energy Corporation Limited (Labour Cost Escalators)(No3)[2010] ACompT 11, paragraphs 58 to 60.

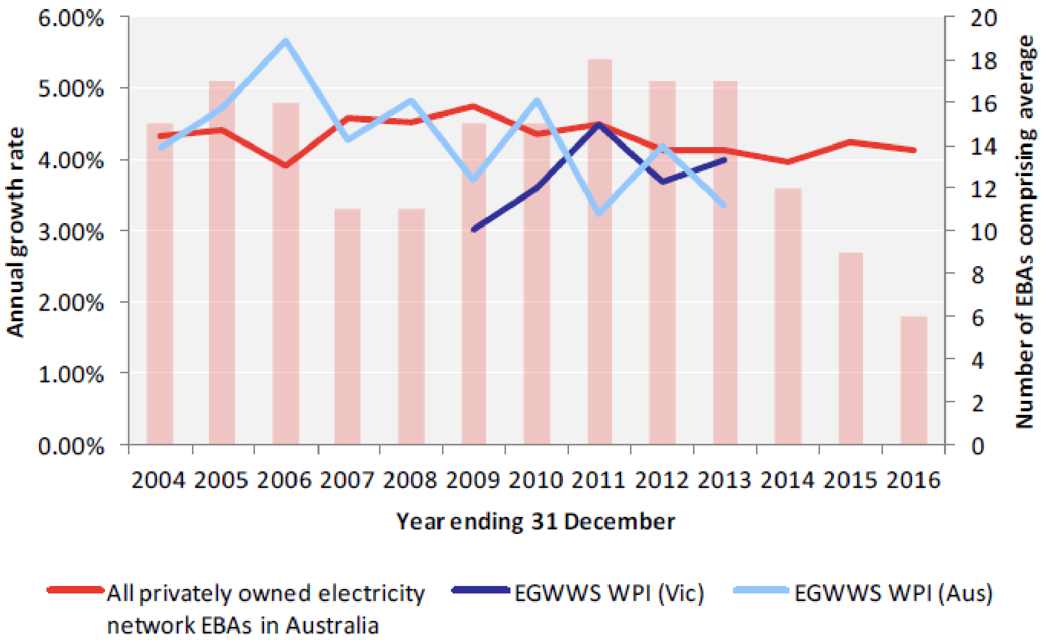
28 AER, Final Decision, SP AusNet Transmission Determination 2014-15 to 2016-17, January 2014, page 68. AER, Final decision, ElectraNet Transmission determination, 2013-14 to 2017-18, April 2013, p. 55.

29 Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, p. vi.

sector EBA wage growth rates of only 0.21 per cent around a mean of 4.40 per cent.[30] It is therefore reasonable to expect that wage growth rates over the forecast period will continue to reflect historical industry averages.

Figure 7.1 also demonstrates the difference between EGWW WPI and the average EBA wage growth rates for privately owned electricity networks over the past ten years. The data clearly shows that the EGWW WPI is not representative of actual labour price growth for the electricity distribution sector, particularly in Victoria. Section 7.1.4 explains why the EGWW WPI is not representative of the labour price growth for the electricity distribution industry.

Figure 7.1 Comparison of historical EBA rates compared to the EGWW WPI



Source: Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, p. 15.

The private sector industry average EBA wage growth rate provides a realistic forecast of our EBA wage growth rates for the 2017 to 2020 period. Our current employee weighted average EBA wage growth rate is within one standard deviation of both the private sector industry long term average (2004 to 2014) and short term average (2010 to 2014). Additionally, our long term average EBA wage growth rate (over the period 2004 to 2014) is also within one standard deviation of both the private sector industry long and short term averages.

The low variability in EBA growth rates both across time and across networks is reflective of the essential services nature of the industry with relatively constant demand and the persistent shortages in specialised electrical tradespeople. These two factors contribute to the labour market for electricity distribution labour being relatively unaffected by broader macro-economic conditions. There is no reason to expect that these conditions will materially change during the 2016–2020 regulatory control period.

For the reasons noted above, the historical private sector industry average growth rate therefore reflects the prudent and efficient costs that we require to meet the operating expenditure objectives in clause 6.5.6 of the Rules.

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[30] Calculations taken over the period 2004 to 2014.

Using an historical industry average EBA wage growth rate also provides us with strong incentives to seek to outperform the industry benchmark and retain the benefits for five years in accordance with the Efficiency Benefit Sharing Scheme (**EBSS**). Applying an industry average EBA wage growth rate is therefore consistent with the revenue and pricing principles in the National Electricity Law (**NEL**) which states that '*A regulated network service provider should be provided with effective incentives in order to promote economic efficiency…*' clause 7A(3).

Additionally, applying an industry benchmark would promote dynamic efficiency as it is reasonable to expect that the private sector industry average EBA wage rate may decline as some distributors seek to outperform the benchmark.

Our proposed labour price growth rates are presented in table 7.1. The calculation is provided in the attached model, *CP Labour Escalation*.

Table 7.1 Labour price growth forecasts (per cent)

Labour escalation	2015	2016	2017	2018	2019	2020	Average 2016-2020
Nominal	4.52	4.52	4.33	4.33	4.33	4.33	4.37
Real	2.16	1.87	1.68	1.68	1.68	1.68	1.72

Source: CitiPower

7.1.2 Our EBA negotiations reflect efficient market outcomes

Framework for negotiation

As noted above, our internal labour price growth is driven by the outcomes of EBAs. Under the FW Act, we are required to negotiate wage growth rates, and other terms and conditions of employment, with our unionised employees through EBAs. The FW Act prescribes a range of rights and obligations on parties to EBA negotiations which are intended to allow market forces to drive the negotiation outcome. Attachment, *DLA Piper*, *Legal Advice, Enterprise Bargaining Agreements*, provides more details on the rights and obligations.

With limited exceptions, the FW Act allows bargaining to continue indefinitely until an agreement is reached. During this bargaining period the employee parties (unions and their member employees) are able to utilise industrial action in pursuit of their claims. Employers have limited options to respond to any such industrial action, other than agreeing to the employee/union demands or locking out their workforce which, given that we are a provider of essential services, is not an effective or efficient outcome for any party. Prolonged industrial action or lock-outs could lead to network outages not being rectified and consequently result in electricity supply and safety impacts. Our options for engaging alternative labour in such circumstances are also very limited due to high proportion of union membership among people holding the required technical qualifications, including those in the contractor sector.

Additionally, the market for the specialised labour skills required to operate an electricity distribution network is shallow due to the specialised skills and training required. An historical shortage in training new apprentices has also affected the availability of skilled resources today. The skills required are specialised and cannot easily be sourced or transferred from other industries. Lines persons in particular require specific training to operate on network assets. Further, electrical work requires a high level of industry-specific health and safety training which is not provided in other industries. The industry therefore must continue to invest in succession planning to make up for historical shortages and to prevent future shortages. Attachment, *VESI Skills & Training Reference Committee*, provides a matrix of our minimum training requirements for all internal employees or contractors that work on the network.

The persistently tight labour market conditions for trained, highly skilled lines persons, electrical technicians and engineering experts is reflected in the consistently strong wage growth rate observed in the electricity distribution sector.

Our objectives

In negotiating our EBA wage growth rates, we balance multiple objectives, including:

- ensuring our labour prices are constrained to reflect efficient market outcomes. As a privately owned business we have strong incentives to negotiate competitive EBA wage growth rates;
- ensuring we attract and retain the necessary labour skills to continue providing a secure and reliable electricity supply. Due to the extensive level of training required and the costs associated with this training, it is important that we offer competitive labour rates to retain trained labour and avoid the risk of losing highly skilled personnel to other network services providers or other electrical or engineering trades. The time and cost of training new personnel is significant and this must be taken into consideration when negotiating wage growth rates that provide efficient outcomes over the longer term. Further, we must invest in succession planning and ensure that wage rates offered are sufficiently attractive to persons new to the labour market that may be still deciding which sectors or industries they want to pursue a career in; and
- ensuring that our operational practices can continue to evolve and new processes, methods and technologies can be adopted in a timely manner to support continual productivity improvements. We renegotiate our EBAs approximately every three years. The timeframe provides for a reasonable period of wage rate certainty while also enabling sufficient flexibility to review business processes and practices which may be captured in the next round of EBA negotiations. For example, in our most recent EBA negotiations with the CEPU we pursued a claim to change the terms of the Consultation and Introduction of Change clause. This clause required us to consult and agree with the CEPU and employees before introducing any change in production, program, organisation or technology which are likely to have effects on employees. Following extensive negotiations we were able to achieve a change in the wording of this clause including that the clause only applies where the change is a ‘major’ change and only where it has a ‘significant’ effect on employees, which allows the businesses more flexibility to introduce changes.

Importantly, while the EBA wage growth rate is an input into overall labour costs, it is not the main determinate of operational efficiency and productivity. The most significant factor for labour cost efficiency is the utilisation of labour, that is the way in which work is performed and how labour resources are planned, organised and deployed. Appendix B explains how we ensure the optimal utilisation of our labour to efficiently manage periods of increased and decreased labour requirements and minimise the risk of inefficiencies associated with stranded or underutilised labour.

Our negotiations

Notwithstanding the legislative and market constraints discussed above, our EBAs are the result of intense negotiations which are clearly undertaken at arm’s-length from the unions. For example, we are able to demonstrate in detail the process that was followed and the extent of resistance against claims being pursued by the CEPU in our most recent EBA negotiations. We committed management time attending strategy, preparation and negotiation meetings over ten months, responding to the CEPU log of 120 claims. Attachment, *CEPU Log of Claims*, provides more details on the negotiation process.

The CEPU’s initial starting point, in relation to the headline wage increase, was a minimum eight percent per annum. The final EBA wage growth rate agreed is 2.25 per cent per half year (equivalent to 4.55 per cent per annum).

The CEPU also requested numerous changes to non-wage employment terms and conditions which we did not concede, including for example:

- a reduction in weekly hours worked from 36 to 32 hours;
- an increase in annual leave from 4 to 6 weeks for all employees; and
- specification of redundancy payments to include four weeks per years of service, ex gratia payments for every five years of service and payment of accumulated sick leave. There is no specification of redundancy payments in our EBAs.

Some changes requested by the CEPU were agreed as we considered these were appropriate or beneficial over the long term, for example in relation to the provision of thermal clothing in certain circumstances.

At the same time, we pursued specific changes to EBA clauses which limited our ability to drive productivity improvements in our operations, some of which were agreed with the CEPU. For example, a revision to remove the need for extensive consultation for non-major workplace changes (as noted above) and also providing for disagreements about major changes to employment conditions that significantly affect an employee to be referred to the Fair Work Commission (**Commission**) for conciliation. This enables the Fair Work Commission to use its influence and mediation skills to facilitate the achievement of major changes. In the previous enterprise agreement consultation and introduction of change clauses, a change to an employee's employment conditions (even if it was not a major) could only occur with employee and union consent and there was no process for conciliation with the Commission.

These changes provide us with more flexibility in the management of our labour force which is the key contributing factor in ensuring efficiency in our overall labour costs. These changes are evidenced in our final EBA with the CEPU.

In reaching these outcomes, we faced a range of work bans and other forms of industrial action across our network over a period of four months, which had material impact on our commercial performance and ability to schedule and efficiently perform planned work on our network. Attached is a set of industrial action notices received from the CEPU.[31] In an attempt to challenge the work bans and progress negotiations we sought the assistance of the Fair Work Commission, which facilitated numerous negotiation meetings before a member of the Commission. We communicated extensively with our workforce during the negotiations in an effort to convey the reasonableness of the company position and demonstrate good faith bargaining. The conduct of the negotiation process and the impact of the EBA outcomes on the business were taken very seriously.

Achievement of the long term efficient outcomes through the EBA negotiation requires balancing the long term benefits of achieving future productivity changes and resisting union claims against the short term costs of industrial action and conceding on some union claims. The EBA outcome which promotes the long term benefits of consumers therefore may require accommodating, to some degree, one or more of the union claims, whether that be in relation to wage growth or other terms and conditions of employment.

Our resulting EBA rates are prudent and efficient

The above clearly demonstrates that our EBAs are negotiated at arm's-length from the unions and that we take a strong position in our negotiations, despite the consequence of prolonged industrial action. Our EBA wage growth rates therefore reflect the most prudent and efficient outcome for the business given the circumstances. Our negotiation process ensures that our resulting EBA wage growth rates represent the efficient and prudent costs required to achieve the operating expenditure objectives in the Rules. It would be inconsistent with the Rules for the AER to ignore our EBA outcomes as the EBA wage growth rates reflect the growth in the efficient costs required to deliver standard control services in accordance with the operating expenditure objectives.

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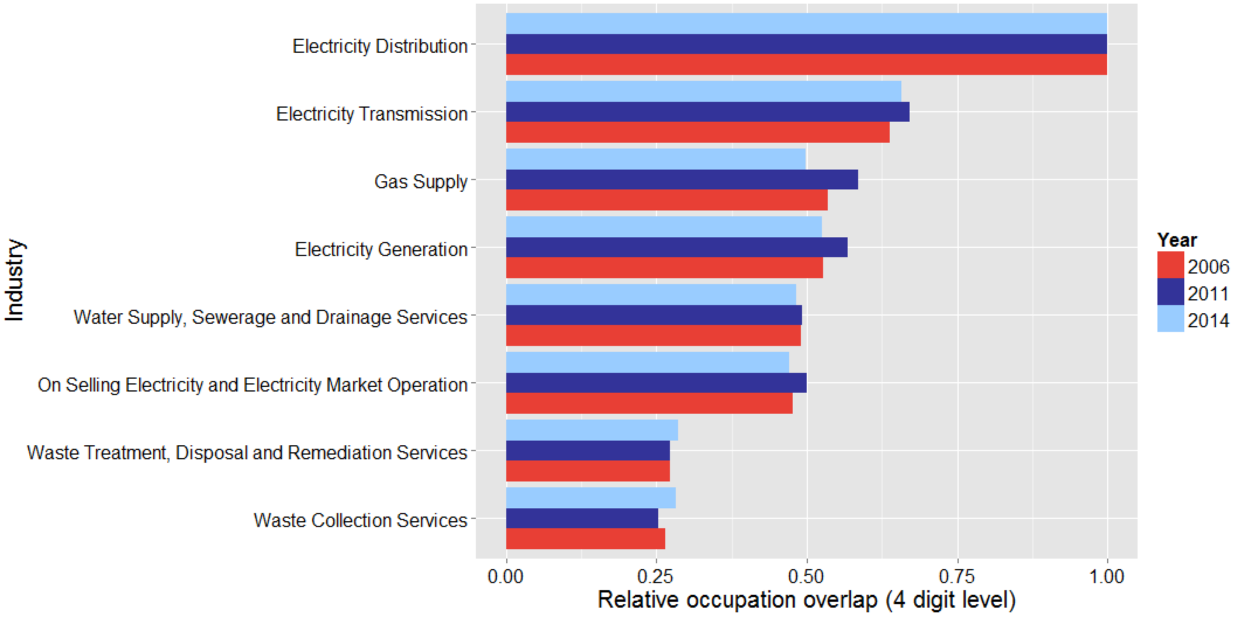
31 Fair Work Act 2009, Notice by Bargaining Representative of Employees of Intention to take Employee Claim Action (s.414)

Additionally, as noted above, our negotiations focus on promoting the long term benefits of electricity users. The resulting EBA wage growth rates are therefore consistent with the National Electricity Objective (**NEO**).

7.1.3 The EGWW WPI is not representative of electricity distributor's labour price growth

Applying EBA wage growth rates for the forecast period provides a more realistic cost forecast than a forecast of the EGWW WPI. This is primarily because the EGWW WPI is made up of sectors and sub-sectors which have materiality different labour skill requirements to electricity distribution. This is demonstrated in figure 7.2 which shows the extent of overlap in the labour skill requirements between the electricity distribution sector and other sectors captured in the EGWW WPI. Attachment, *Labour cost escalation forecasts using Enterprise Bargaining Agreements*, provides further detailed analysis of differences in labour skills requirements between sectors and sub-sectors captured in the EGWW WPI.[32]

Figure 7.2 Labour skill overlap in EGWW 2006, 2011 and 2014



Source: Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, p.12.

Further, using EBA wage growth rates as the basis for forecasting labour price growth is also more consistent with the AER's principles for the assessment of expenditure proposals than forecasts of the EGWW WPI. As discussed by Frontier Economics[33], this is primarily because:

- EBA wage growth rates are transparent and can be calculated from publicly available data. Conversely, consultants' forecasts of the EGWW WPI are not transparent due to the proprietary nature of the models;
- calculating EBA wage growth rates is a simple method for forecasting labour price growth. Conversely, consultants' methods for calculating the EGWW WPI cannot be assessed against this principle as they are not disclosed; and

[32] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.3 and appendix B.

[33] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.5.2.

- EGWW WPI forecasts have not proven accurate or reliable. Consultants' EGWW WPI forecasts have tended to be lower than the industry average EBA rates and there are large differences in forecasts between consultants.[34] This is likely because, as discussed above, the EGWW WPI is not representative of the labour skill requirements of the electricity distribution industry. Conversely, EBA rates have been relatively consistent through time and provide a direct representation of the labour growth rates in the electricity distribution industry.

In conclusion, the above analysis demonstrates that using EBA growth rates as the forecast of labour price growth provides a more realistic forecast than the EGWW WPI because it:

- is a low cost and transparent mechanism which provides a directly representative forecast of labour price growth rates paid in the electricity distribution industry; and
- provides the most realistic expectation of our labour price growth for the forecast period and is therefore consistent with clause 6.5.6(3)(c) of the Rules which requires the AER to accept a proposal that reasonably reflects a realistic expectation of cost inputs required to achieve the operating expenditure objectives.

7.1.4 Labour productivity

We have not applied productivity adjustments to the labour price escalators set out in table 7.1 because:

- we do not support the application of pre-emptive labour productivity adjustments which are inconsistent with the intent of the EBSS and are likely to lead to less than a reasonable opportunity to recover the efficient costs of providing direct control services; and
- our current quantity of labour is efficient and we do not expect net reductions in labour costs to arise due to foreseeable productivity changes over the regulatory control period. Our actual labour costs in 2014 are therefore the appropriate base for escalating for real growth in the per unit price of labour. Refer to appendix B which explains why our labour costs are efficient.

Further, we note that in its draft decision on the NSW/ACT distributors the AER rejected the use of EBAs on the basis that EBAs may contain a trade-off between wages and productivity.[35] As noted by Frontier Economics, there are two problems with the AER's position:[36]

- first, labour and productivity are not separable concepts. Economic theory implies that as labour productivity increases, all else being equal, labour prices should increase and therefore it is artificial to treat labour price and labour productivity separately; and
- second, the use of the EGWW WPI captures labour productivity of both electricity distribution and non-electricity distribution sectors of the economy, such as water services, waste services and electricity generation and retail services. As discussed in section 7.1.3 and in detail in Frontier Economics' report[37], the labour skills required for electricity distribution services are significantly different to those required in other sectors captured in the EGWW WPI. It is therefore unreasonable to assume that labour productivity in the electricity distribution sector reflects that of the broader range of sectors included in the EGWW WPI.

[34] For example refer to tables 3.9 and 3.10 of attachment, CIE, *Labour price projections*, December 2014, p. 27.

[35] AER, Draft decision, AusGrid distribution determination 2014-19, Attachment 7: Operating expenditure, November 2014, p. 7-151.

[36] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.2.

[37] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.3 and appendix B.

7.2 Contracts

We use external contractors to deliver specialised services, for example vegetation management, asset inspection, electrical construction, civil works and traffic management.

The primary nature of these contracts is for labour-based services. The Australian Bureau of Statistics' WPI for the construction sector most closely reflect the types of labour skills required to deliver these services.

We engaged the Centre for International Economics (**CIE**) to develop forecasts of the construction sector WPI for Victoria. CIE's report, *Labour price projections,* is attached.

Our contracts price escalator is based on CIE's construction sector WPI forecasts. The resulting growth rates provide a realistic expectation of our contract cost increases over the forecast period. We have therefore applied these forecasts to the contracts component of our operating and capital expenditure forecasts.[38]

Our contracts price escalators for 2016-2020 are provided in table 7.2. The calculation is provided in the attached model, *CP Contracts Escalation*.

Table 7.2 Contracts input price growth (per cent)

Contracts escalation rates	2015	2016	2017	2018	2019	2020	Average 2016-2020
Nominal	3.56	3.59	4.81	4.38	4.36	4.39	4.31
Real	1.22	0.96	2.15	1.73	1.72	1.74	1.66

Source: CIE, *Labour price forecasts*, December 2014, p. 7.

7.3 Proportion of labour, materials and contract costs

Table 7.3 demonstrates the proportion of our operating expenditure and capital expenditure attributable to each of labour, materials and contracts costs based on our actual expenditure in 2014 for standard control services.

Due to the nature of operating an electricity distribution network, there is limited opportunity to substitute labour-based services for materials or vice versa.

We acknowledge however that there is a degree of opportunity to substitute the use of internal labour relative to labour-based contractor services. The optimal mix of internal relative to contracted labour-based services at any point in time is subject to prevailing market conditions as well as legal and contractual obligations. We continuously review the optimal mix of internal labour relative to contracted labour services and seek to implement the most efficient strategy at every opportunity.

Table 7.3 Proportion of labour, materials and contracts (per cent)

Expenditure type	Labour	Materials	Contracts
Operating expenditure	47.7	3.0	49.3
Capital expenditure	32.3	21.7	45.9

Source: CitiPower

38 Reset RIN requirement 18.2(c) requests evidence that our method for forecasting input price escalation explains the price of purchased inputs. Our reporting systems do not capture data in the form required to provide the requested information for contracts.

We note that the AER's draft decision on the NSW and ACT distributors assumes that materials costs contribute to 38 per cent of operating expenditure. We have examined the category analysis RIN data reported by all distributors.[39] Based on this data, the weighted average contribution of materials costs to standard control services operating expenditure in 2013 across the industry is five per cent. The AER's assumption of 40 per cent is clearly not an appropriate benchmark for us or the industry more generally.

We have therefore applied real price escalators to our forecast expenditure based on our forecast of labour, materials and contracts costs for each of operating and capital expenditure which is based on our actual proportions in 2014.

7.4 Overall real price growth

Tables 7.4 and 7.5 show the overall value of real input price growth rates applied to each of the operating and capital expenditure forecasts.

Table 7.4 Operating expenditure real price growth ($m, real)

Operating expenditure	2015	2016	2017	2018	2019	2020
Labour	0.6	1.7	2.4	3.3	4.1	4.8
Materials	-	-	-	-	-	-
Contracts	0.4	1.0	1.9	2.9	3.8	4.5
Total value of real price growth	1.0	2.6	4.3	6.1	7.8	9.4

Source: CitiPower

Table 7.5 Capital expenditure real price growth ($m, real)

Capital expenditure	2016	2017	2018	2019	2020
Labour	0.9	1.8	2.6	3.2	3.3
Materials	-	-	-	-	-
Contracts	0.9	3.4	4.5	5.0	5.1
Total value of real price growth	1.7	5.2	7.2	8.2	8.4

Source: CitiPower

39 Jemena's data is excluded because it is not provided in either the public or confidential versions of Jemena's category analysis RIN as provided by the AER.

8 Demand, energy and customer forecasts

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8. Demand, energy and customer forecasts

Demand for electricity usually increases on hot summer days, when most of our customers turn on their air-conditioners. This drives a spike in demand.

When we forecast that the peak in demand will be greater than the capacity of our network in that area, then we must ensure that we can continue to meet the demand required by our customers by investing in the network or implementing economic demand management solutions.

Our forecasts indicate that peak demand is increasing, even though energy has been decreasing. It is peak demand, however, that drives investment.

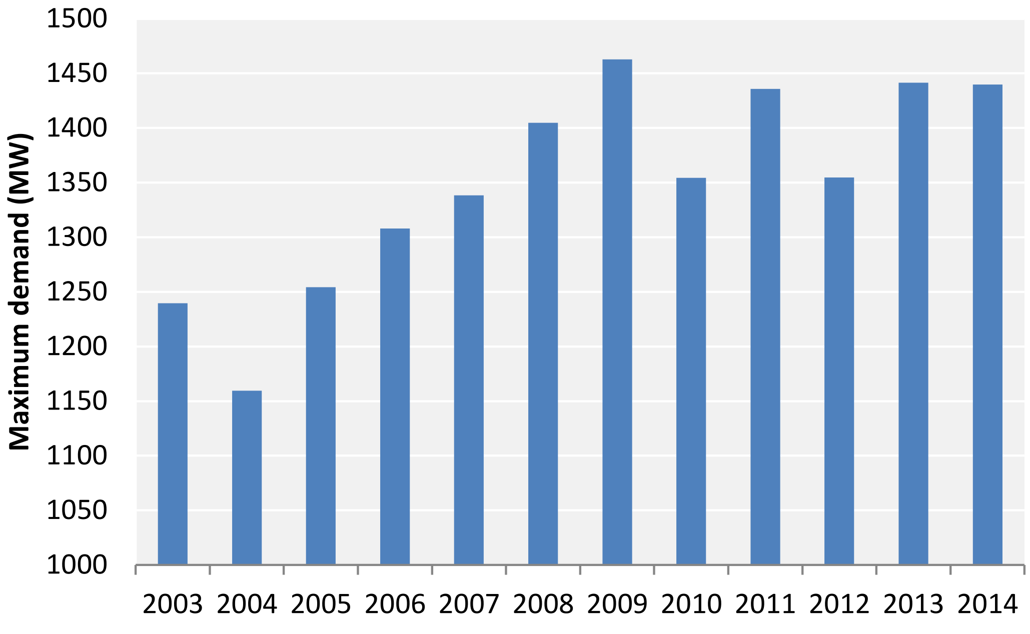
Our demand forecasts have been prepared using a robust process that combines our own detailed local knowledge with independent economic analysis.

Our peak demand, energy and customer forecasts are described in more detail in appendix C.

8.1 Peal demand forecasts

We experienced a near network peak on 12 March 2013 of 1,442MW, just shy of our highest ever peak of 1,463MW reached on 29 January 2009. The peak in 2013 was recorded at 3.30pm, reflecting the large amount of commercial demand.

Figure 8.1 Increasing 'raw' level of peak demand (coincident demand at terminal station level)



Source: CitiPower

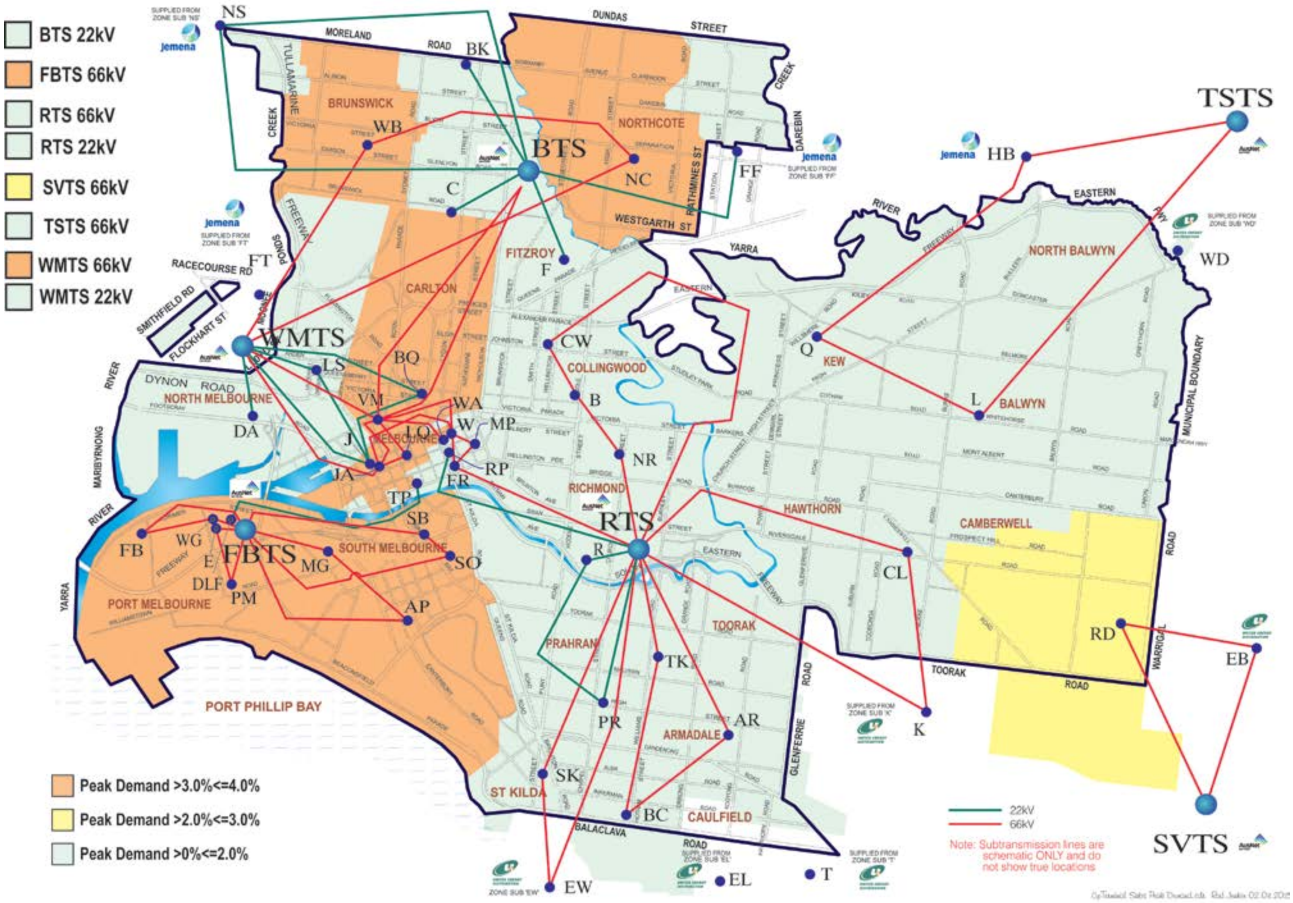
The use of air-conditioners by commercial and residential households was a key driver to the network peak, as it was during a ten day heatwave (early March 2013) in Melbourne. Increases in the frequency and duration of heatwaves[40] will be a significant contributor to a new network record peak being recorded in the future.

Over the 2016–2020 regulatory control period, we expect peak demand to increase in specific areas of our network. The increase in locational peak demand will be driven by:

- transfer of load around our network given our program to retire the 22kV sub-transmission network;
- population expansion, particularly along established and proposed transport corridors driven by changes in zoning; and
- block load additions from specific projects such as high density residential developments.

The map below highlights the areas of our network where we expect increases in demand.

Figure 8.2 Peak demand forecasts by zone substation



Source: CitiPower

The areas that we have identified for the continued growth in peak demand is supported by a range of evidence from government and sectorial information that is publicly available.

40 Climate Council, *Heatwaves: Hotter, Longer, More Often*, 2014. Available from: http://www.climatecouncil.org.au/uploads/9901f6614a2cac7b2b888f55b4dff9cc.pdf

The Victorian Government's projections for annual population growth reinforce our expectations of strong population growth in inner Melbourne.

In its response to the Directions and Priorities Consultation Paper, the City of Melbourne also noted that: [41]

> *..the electrical network will need to facilitate significant growth within the central city and surrounds. Plan Melbourne, the Victorian Government's Metropolitan Planning Strategy released in 2014, predicts there will be an additional 310,000 dwellings in the central city and surrounds. This area referred to as the Central Subregion in Plan Melbourne, is projected to grow from 485,000 residents in 2013 to 765,000 residents by 2031. This will help support Melbourne's central city as Australia's largest business centre with a growth from 435,000 jobs in 2011 to almost 900,000 jobs by 2051. As part of the Central Subregion, the City of Melbourne is growing quickly and will continue to do so. In 2013, the City of Melbourne was the fastest growing local government area in Australia with over 11,000 new residents. By 2021, the residential population of the municipality is estimated to be over 150,000 residents living in 92,000 homes, increasing to over 190,000 residents living in over 115,000 homes by 2031.*
>
> *The majority of our new housing will occur in our growth areas, which offer significant development opportunities as they transition from predominately industrial or commercial uses to a mix of uses, including high density housing. These areas include City North and Arden-Macaulay to the north of the city, the Hoddle Grid, Southbank, Fishermans Bend, Docklands and E-gate. Fishermans Bend, in both the City of Melbourne and City of Port Phillip, is the largest urban renewal area covering 250 hectares and expected to accommodate 40,000 new jobs and 80,000 new residents by 2051.*

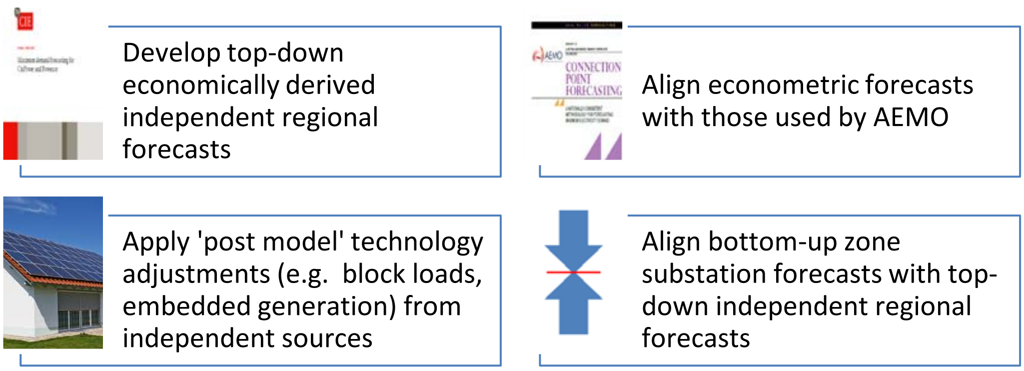
The foreshadowed growth of residential housing around Fishermans Bend is a consequence of the rezoning of the land from industrial or commercial use to high density residential housing. Block loads such as E-gate in the inner north of Melbourne are also driving the expected high demand growth around the Fishermans Bend and West Melbourne terminal station areas.

8.1.1 Forecasting demand from our customers

Our peak demand forecasts have been prepared using a robust process that draws upon independent analysis of economic and environmental factors. A key objective of our demand forecasting process was to align our econometric modelling methodology with that used by the Australian Energy Market Operator (**AEMO**).

The key elements in our process are shown in figure 8.3.

Figure 8.3 Key elements of our forecasting process



[41] City of Melbourne, Feedback to the Directions and Priorities Consultation Paper, October 2014, pp. 6-7.

We engaged the Centre for International Economics (**CIE**) to undertake a top-down forecast of maximum electricity demand at the terminal station level, underpinned by the same economic drivers that are used by AEMO.[42] The forecasts took into account average demand as well as maximum demand at each terminal station.

CIE's forecasts for average demand growth took into account the following demand drivers:

- price - electricity prices are projected using forecasts of the real electricity residential price index, including assumptions about the adoption of time of use tariffs;
- income - projections based on the growth rate in Gross State Product (**GSP**) per capita in each quarter;
- population - annual forecasts of population in local government areas; and
- weather - the effect of temperature on demand largely due to air-conditioner and heater usage.

CIE also used an econometric model to forecast summer, winter and annual maximum demand. The modelling took into account relationships between the ambient temperature effects using weather station data from the Bureau of Meteorology aligned to each terminal station, as well as calendar effects reflecting the dependency of maximum demand on the day of the week, time of summer, etc.

They then combined the results of the economic simulation with the forecasts of average quarterly electricity demand to obtain a distribution of maximum demand at each terminal station for each year of the forecast period.

The process undertaken by CIE was broadly consistent with the two step modelling approach used by AEMO to deliver its forecasts in 2013.

Post-model adjustments were made by CIE for:

- known changes in block loads, such as negative adjustments for industry shutdowns or positive adjustments for load increases such as major new connections; and
- demand from major embedded generators, notably solar photovoltaics (**PV**) based on a report from Oakley Greenwood on the impact of technology changes on terminal station demand.[43]

As energy efficiency policies and outcomes are already reflected in the historical data, post model adjustments were not included for energy efficiency. CIE forecasts assume that growth in energy efficiency policy and outcomes will continue to occur at the historical rate.

CIE's forecasts for the annual change in coincident maximum demand at the network level, in megawatts (**MW**), are shown in table 8.1.

Table 8.1 Coincident annual maximum demand at terminal stations annual growth rate (per cent)

	2016	2017	2018	2019	2020
50%PoE	5.6	3.8	2.3	1.9	0.0
10%PoE	5.5	3.9	2.9	2.5	-0.5

Source: CIE, *Maximum demand forecasting for CitiPower and Powercor*, Final report, July 2014, p. 130.

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42 CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014.

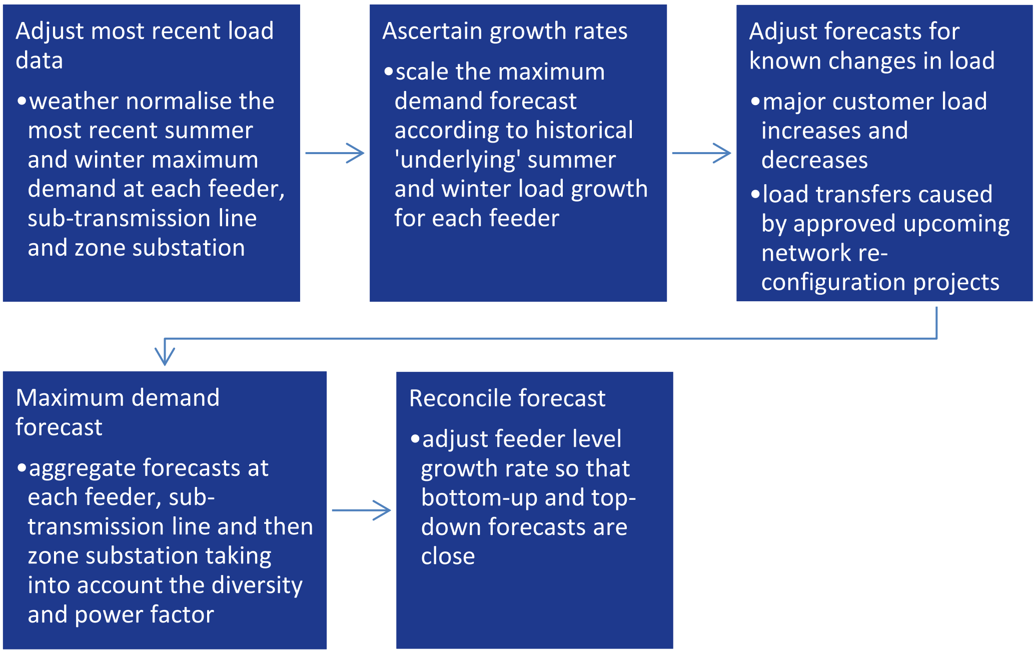
43 Oakley Greenwood, Summary and documentation of the terminal station impacts of five technology trends, May 2014.

We adjusted down the CIE top-down forecasts in cases where the baseline forecasts were inconsistent with the judgement of expert planners with strong local area knowledge. This forecasting adjustment is consistent with industry 'best practice' outlined in the ACIL Allen report for AEMO entitled *Connection Point Forecasting*.[44]

We reconciled the top-down forecasts with our own bottom-up forecasts for demand. This is because top-down forecasts generally lack local detail, which is a key strength of bottom-up forecasts as they capture the underlying characteristics of the areas serviced by local zone substations. In contrast, bottom-up forecasts cannot take account of changing economic outlook and other longer term factors.

Our bottom-up forecasts were prepared using the following process.

Figure 8.4 Bottom-up forecasting process



Source: CitiPower

Our reconciliation process was reviewed by ACIL Allen and found to be appropriate, although they identified some minor areas for improvement, mostly related to the weather corrected forecasts at the 10 per cent probability of exceedance level (10 per cent PoE) for extremely hot summer days.[45]

8.1.2 AEMO forecasts

AEMO has produced two sets of forecasts in Victoria: system level forecasts and forecasts at each transmission connection point.

We have worked with AEMO to discuss their methodology, as well as providing historical data and our demand forecasts. However, as discussed below, AEMO has assumed aggressive assumptions associated with solar PV penetration and energy efficiency that we have been unable to verify, and as a result we have been unable to align our forecasts with those of AEMO at the transmission connection point level.

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44 ACIL Allen Consulting, Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand, Report to Australian Energy Market Operator, 26 June 2013.

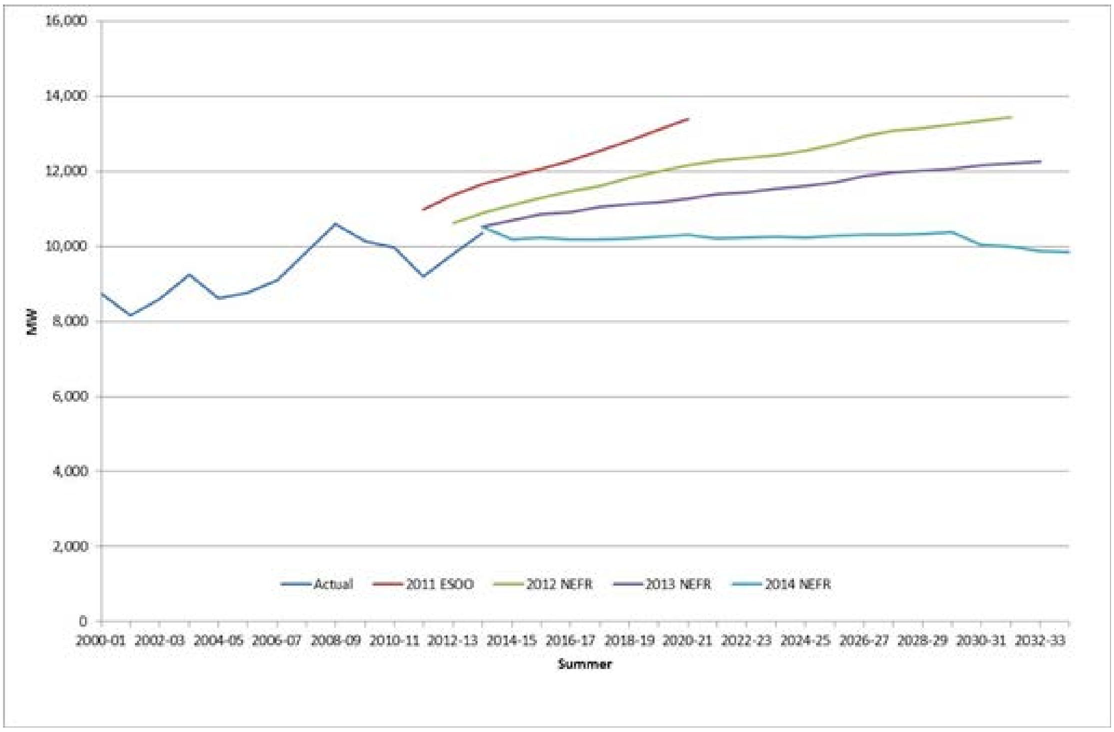
45 ACIL Allen, Demand forecasts – reconciliation review, 27 January 2015.

We will continue to work with AEMO as they continue to develop and refine their forecasts. However, given our concerns with AEMO's forecasts, we consider it appropriate that the AER relies upon our own demand forecasts rather than those of AEMO. This would be consistent with the AER's draft decision in NSW where it accepted the distributors' forecasts over those produced by AEMO.

System level forecasts

AEMO produces Victorian system level forecasts of peak demand in its National Electricity Forecast Report (**NEFR**). Since the first NEFR report in 2012, GHD has estimated that AEMO has reduced its summer 10 per cent PoE forecasts for Victoria for the period to 2018/19 by 25 per cent, with the ten year growth rate falling from 1.6 per cent to 0.1 per cent per annum.[46] The change in forecast is shown in figure 8.5.

Figure 8.5 Victorian summer 10% PoE peak demand forecasts



Source: GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 12.

According to GHD, the reductions in long term growth rates appear to reflect methodological changes to the core model, as well as other elements of the forecasts outside of the core model such as increasing estimates of future rooftop PV generation.

Transmission connection point forecasts

In September 2014, AEMO produced its first electricity demand forecasting report of maximum demand at the transmission connection point level for Victoria, i.e. each terminal station. We understand that these terminal station maximum demand forecasts consist of four different forecasts:

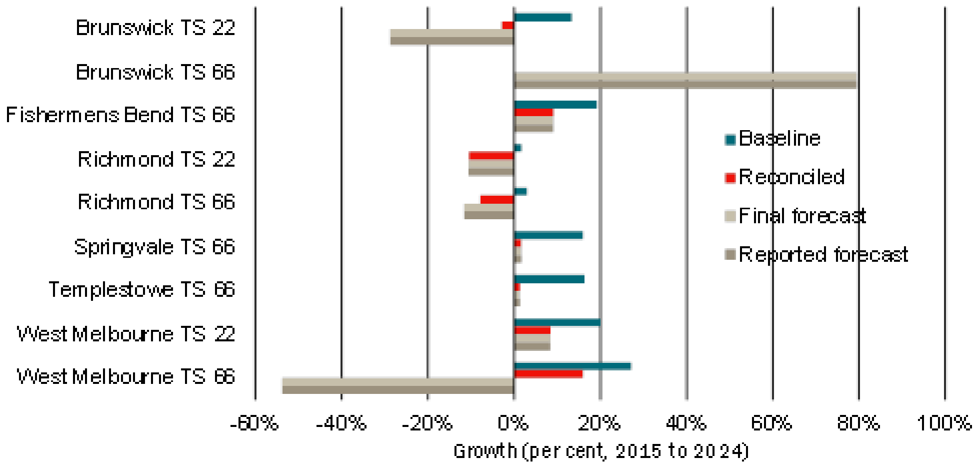
- baseline forecast which are extrapolated from historical trend;

46 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 12.

- reconciled forecasts which are the baseline forecasts adjusted for solar PV and energy efficiency to then reconciled to the state-wide forecasts;
- final forecast which is further adjusted by block loads and known transfers; and
- report forecast which is made publicly available, which largely matches the final forecasts discussed above.

There are substantial reductions in the growth rates for us as a result of moving from baseline to reconciled forecasts, as shown in figure 8.6.

Figure 8.6 AEMO changing forecasts for terminal stations



Source: CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, p. 4.

As shown above, the reconciliation process to take baseline peak demand forecasts for each terminal station and reconcile this to Victoria-wide demand has been an important component of AEMO's forecasting approach. Two key aspects of the reconciliation process are:

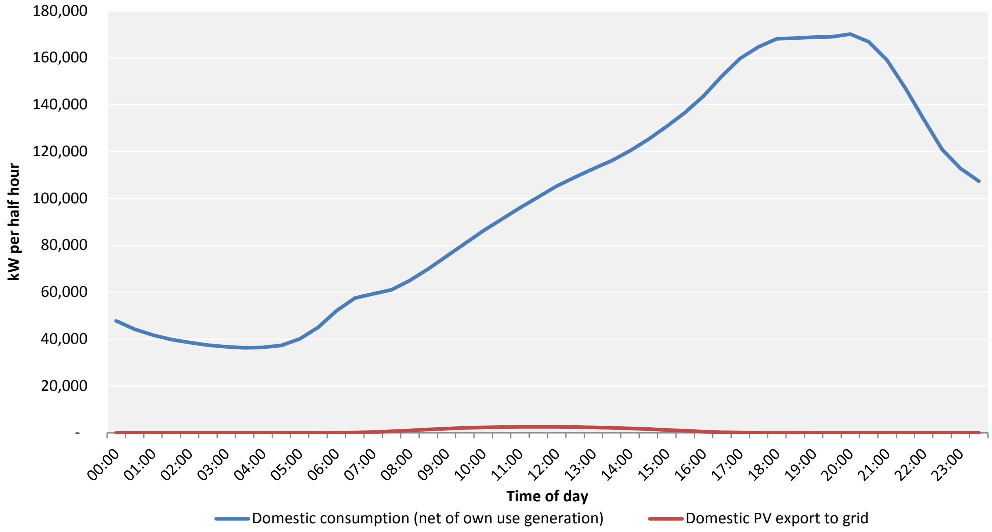
- contributions of solar PV to reductions in peak demand; and
- energy efficiency assumptions.

AEMO assumes a large contribution from rooftop solar PV to peak demand. However, AEMO has previously found that during the Victorian heatwave of January 2014 showed that at the state wide system peak recorded at 4.30pm on 16 January 2014, embedded solar generation contributed 1.04 per cent to the peak operational demand.[47]

Our own experience is that solar PV makes a very small contribution, if any, to peak demand. For example, on 14 January 2014, when our network reached its peak demand for residential customers at 8.00pm, solar PV contributed around 0.007 per cent of that peak demand. This is shown in figure 8.7.

47 AEMO, *Heatwave 13-17 January 2014*, 26 January 2014, p. 6, which is available from: http://www.aemo.com.au/News-and-Events/News/2014-Media-Releases/Heatwave-13-to-17-January-2014.

Figure 8.7 Domestic consumption of electricity on 14 January 2014



Source: CitiPower

In terms of AEMO's forecasting process relating to contributions from solar PV, CIE and Oakley Greenwood identified four material assumptions that place downward pressure on the installation forecasts:[48]

- assuming that 50 per cent of all energy that is produced will be exported is too high unless large increases in the penetration of solar PV on commercial rooftops is assumed (which it does not appear to given comments in the NEFR);
- methodology makes no allowance for the possibility that tariff structures (as opposed to tariff levels) will adjust in response to Rule changes requiring a move to cost-reflective tariffs and competitive pressure placed on distributors;
- methodology makes no allowance for the required payback period for future customers to be shorter than for those who already have installed solar PV systems given the increased maturity of the technology; and
- forecasts do not appear to have taken into account the downward risk that current incentives for purchases of solar PV will decline in the future.

Secondly, in relation to energy efficiency the CIE and Oakley Greenwood found that the forecasts were partly based on unpublished reports; were not appropriately disaggregated to take into account the energy savings of different appliances and customer classes; and that AEMO made the unreasonable assumption that energy efficiency programs will be implemented by industry irrespective of the fact that the Federal Government has scrapped the funding.

A further review of the connection point forecasting process used by the AEMO was undertaken by GHD. Separately, GHD identified similar material forecast issues as identified by the CIE/Oakley Greenwood report, including:

- solar PV generation forecasts 'could reflect over-optimistic assumptions about generation from a given installed capacity by AEMO';[49]

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48 CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, pp. 21–22.

- forecasts may have double-counted the level of energy efficiency adjustment that applies to the most recent demand observation, such that the adjustments are at the high end of a wide range of uncertainty;[50]
- concerns with the reconciliation process between the state-wide forecast and the connection point forecasts; and
- the alignment between AEMO energy and peak demand models.

AEMO has stated that as this is the first time they have undertaken Victorian connection point forecasts, they identified an improvement action plan for future connection point forecasts. We are working with AEMO in providing feedback and suggestions for improvements to their forecasting process.

Given the range of shortcomings in AEMO's forecasting process, we consider it appropriate that the Australian Energy Regulator (**AER**) relies upon our own demand forecasts which take into account independent economic analysis together with our detailed local knowledge, utilising a robust methodology that has been independently verified. This would be consistent with the AER's draft decision in NSW where it accepted the distributors' forecasts over those produced by AEMO.

8.2 Energy forecasts

We engaged CIE to develop our energy volume forecasts for the 2016–2020 regulatory control period. CIE forecast growth rates in energy volumes for residential, commercial and industrial customers, taking into consideration factors that drive demand for a particular tariff class and factors that contribute to network-wide demand growth, including:

- historical trends in energy usage;
- projections of customer numbers by tariff class;
- block-load forecasts; and
- economic conditions such as income and electricity prices.

Table 8.2 sets out our forecast growth in energy volumes for the 2016–2020 regulatory control period.

Table 8.2 Energy volume growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Energy growth rates	3.1	3.1	2.4	1.8	1.4	1.2

Source: CIE, *Tariff volume forecasts*, February 2015, p. 16.

8.3 Customer forecasts

We engaged CIE to develop our customer number forecasts for the 2016–2020 regulatory control period. CIE forecast the growth rate in customer numbers for residential, commercial and industrial customers as follows:

- residential customers – based on the forecast growth in dwelling numbers by local government area produced by the Victorian Government Department of Transport, Planning and Local Infrastructure. CIE mapped the relevant local government areas to our network areas;

49 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 20.

50 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 17.

- commercial customers – based on a time trend from the most recent data point (2013); and
- industrial customers – assumed zero growth from the most recent data point (2013).

Table 8.3 sets out our forecast growth in customer numbers for the 2016–2020 regulatory control period.

Table 8.3 Customer number growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Customer number rates	2.0	2.0	1.6	1.6	1.6	1.6

Source: CIE, *Tariff volume forecasts*, February 2015, p. 7.

9 Capital expenditure

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9. Capital expenditure

We need to invest **$850 million** of capital expenditure into our network to continue to meet expected demand and connect new customers while safely delivering over the next regulatory control period a quality and reliable electricity supply to our consumers.

As demonstrated in chapter 5, we are one of the most efficient distributors in Australia. Our rigorous cost controls and condition-based approach to maintaining and replacing assets has resulted in a reliable electricity supply at low cost, as discussed in the chapter 10.

We have asked our stakeholders their views on our business, to better understand their priorities and concerns. In terms of feedback, generally our stakeholders:

- are satisfied or very satisfied with the current level of reliability;[51]
- do not want an increase in their electricity bill except to reduce the risk of fire danger arising from our network;[52]
- are supportive of creating a smarter grid, which further utilises the information available from smart meters to enable us to better manage and react to changes in the network;
- have a strong desire for investment and upgrades to the network to support the use of renewable energies;[53] and
- seek access to their energy consumption data to enable more informed choices about usage patterns and investment options.

We have taken our stakeholder views and expectations into account in developing our expenditure forecasts for the 2016–2020 regulatory control period.

The capital expenditure has been properly allocated to standard control services in accordance with the principles and policies in the Cost Allocation Method (**CAM**).[54]

This section should be read in conjunction with appendix E to gain a full appreciation of our regulatory proposal.

9.1 Overview of capital expenditure

Table 9.1 summarises our forecast capital expenditure, by category, for the 2016–2020 regulatory control period.

51 For example, see Colmar Brunton Research, CitiPower Stakeholder engagement research – online customer survey results, 18 July 2014, p. 36.

52 Colmar Brunton Research, CitiPower Stakeholder engagement research – online customer survey results, 18 July 2014, p. 50.

53 For example, Colmar Brunton Research, CitiPower Stakeholder engagement research report, residential customer focus groups and SME customer interviews, 30 April 2014, p. 15.

54 This includes allocated costs between distribution services, allocated directly attributable costs, allocated shared costs between the relevant categories of distribution services and allocated directly attributable costs and shared costs.

Table 9.1 Total capital expenditure ($m, real)

	2016	2017	2018	2019	2020	Total
Replacement	48.9	50.0	62.5	57.3	41.3	260.0
Augmentation	38.9	62.6	42.9	24.3	11.2	179.9
Connections	71.6	71.0	63.9	62.4	63.1	332.1
VBRC	0.6	2.6	2.2	2.3	2.1	9.8
IT and communications	18.6	18.7	17.3	15.3	11.2	81.1
Non-network	6.1	11.4	7.0	6.5	5.5	36.5
Equity raising costs	2.3	-	-	-	-	2.3
Gross direct capital expenditure	**187.1**	**216.3**	**195.9**	**168.2**	**134.3**	**901.8**
Add direct overheads	17.4	18.1	18.8	19.3	19.9	93.5
Gross capital expenditure	**204.5**	**234.4**	**214.6**	**187.5**	**154.2**	**995.3**
Less customer contributions	31.5	34.1	28.0	25.8	25.4	144.9
Less disposals	-	-	-	-	-	-
Net capital expenditure	**173.0**	**200.3**	**186.6**	**161.7**	**128.8**	**850.4**

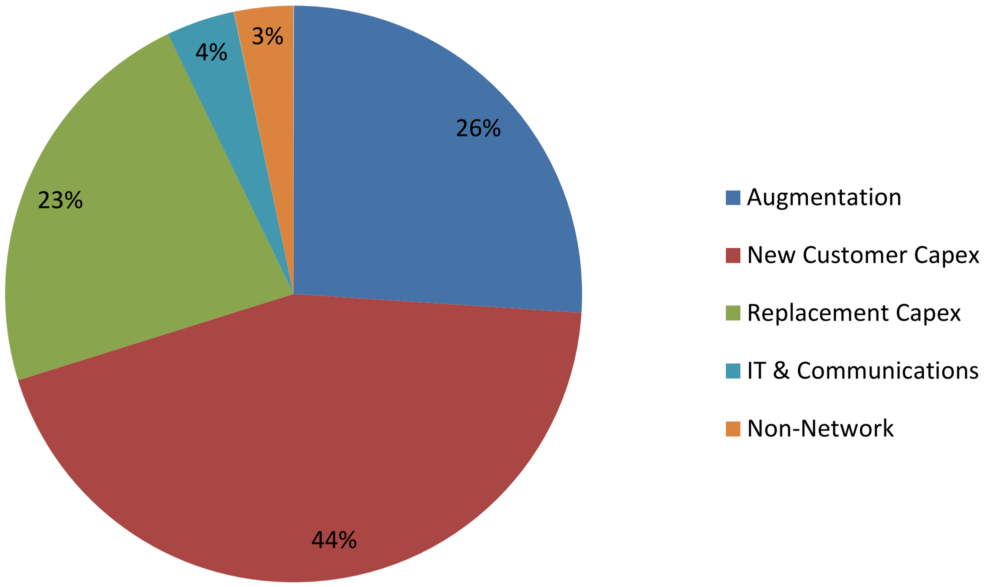
Source: CitiPower

9.1.1 What we have delivered

Our capital expenditure program during the 2011-2015 regulatory control period has delivered reliable electricity supply at an efficient cost.

The largest proportion of our gross capital expenditure was spent on new connections, as shown in figure 9.1. We had over 15,000 net additional customers connect to our network, in addition to customer driven works through relocations and redevelopments. This includes connections for new commercial and residential high-rise developments in the Docklands area, redevelopment of Melbourne Park and the Emporium shopping complex, as well as medium density housing in inner Melbourne.

Figure 9.1 Capital expenditure by category in the current regulatory control period



Source: CitiPower

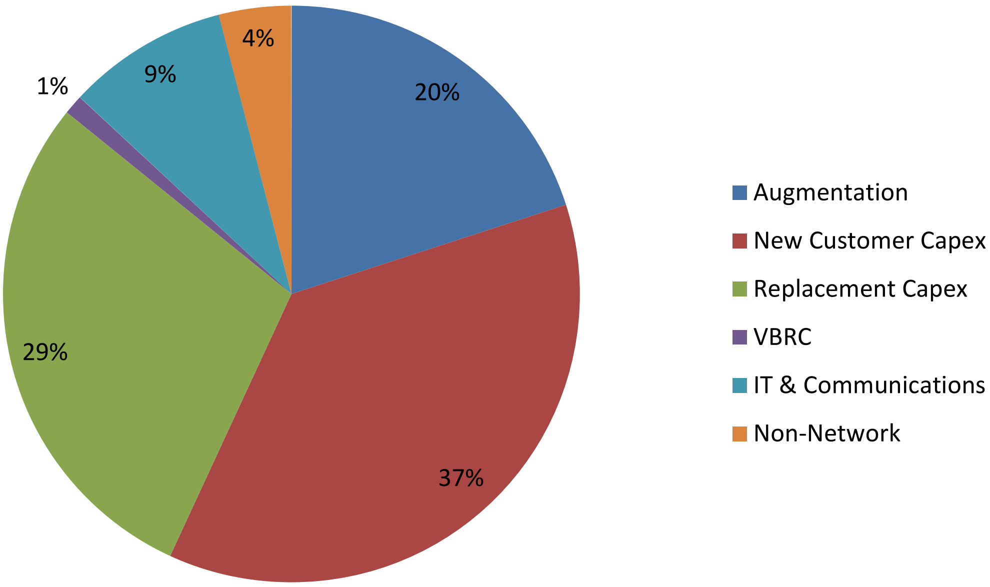
We have continued to progress the Central Business District (**CBD**) Security Upgrade and Metro projects which will provide greater resilience to our network in the Melbourne CBD and inner suburbs. These projects will be completed in the 2016–2020 regulatory control period, as a result of delays in the current period arising from community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station (**BTS**).

Replacement expenditure to maintain the reliability of the network was the third largest category of expenditure, enabling us to provide a network that is available over 99.98 per cent of the time.

9.1.2 Proposed capital expenditure

We have determined the amount of capital expenditure that we need to spend during the 2016–2020 regulatory control period to ensure that we continue to provide a safe and reliable electricity supply to our consumers, while also meeting our regulatory obligations. The breakdown by capital expenditure category is shown in figure 9.2.

Figure 9.2 Forecast capital expenditure by category (excluding equity raising costs)



Source: CitiPower

The largest category of capital expenditure is expected to continue to be related to new customer connections. Replacement expenditure will account for around 29 per cent of capital expenditure. Augmentation, VBRC, IT and non-network expenditure together are around one third of the total forecast for capital expenditure.

Our planned network capital expenditure is primarily driven by the following factors:

- rebuilding and refurbishment of zone substation buildings and equipment in co-ordination with the CBD Security Works which were delayed as a result of the BTS delay;
- completing the augmentation works related to the CBD Security Upgrade and Metro projects following the granting of the BTS planning permit;
- connections and customer-driven works associated with specific urban renewal projects; and
- IT expenditure to deliver a smarter network, as well as replacing the existing billing system to support Power of Choice initiatives and innovative tariff offers.

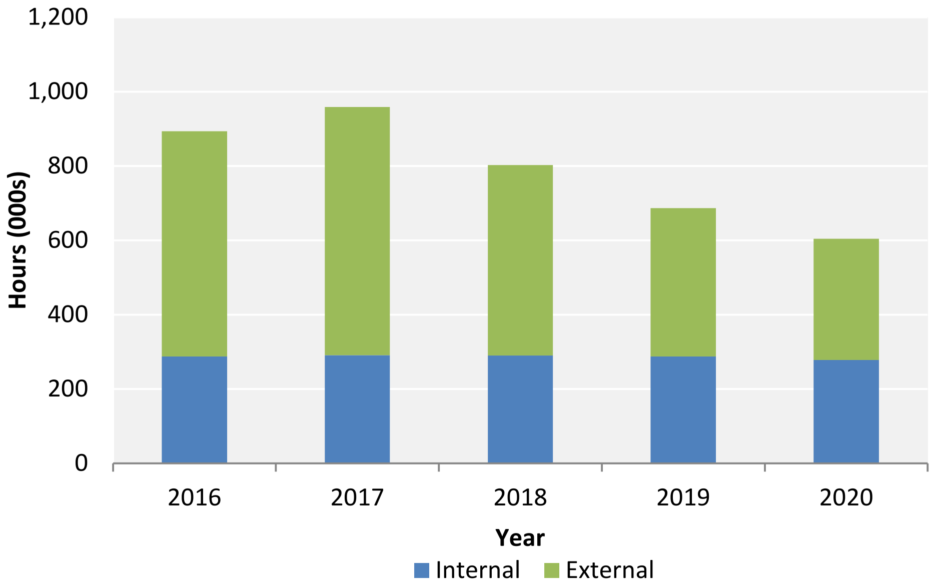
We have developed a deliverability plan to ensure that we are able to provide the necessary works over the 2016—2020 regulatory control period. Our deliverability plan will utilise internal labour resources which will be supplemented, as required, by use of external subcontractors. We have established a number of arrangements to ensure that we can access external resources as required, including:

- long term panel contractors including preferred labour electrical and civil works suppliers; and
- access to agency and limited tenure personnel.

The mix between internal and external labour resources will be determined by, amongst other things workload volumes, timing and locations; skills and competencies requirements; resource availability and peak period workloads.

Our proposed deliverability plan for network-related works, by work hours, is shown in figure 9.3.

Figure 9.3 Deliverability plan by internal and external labour capability



Source: CitiPower

Panel contractors provide us with a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable us to minimise the costs of engaging external resources to assist it in delivering services required by our customers.

9.2 Replacement expenditure

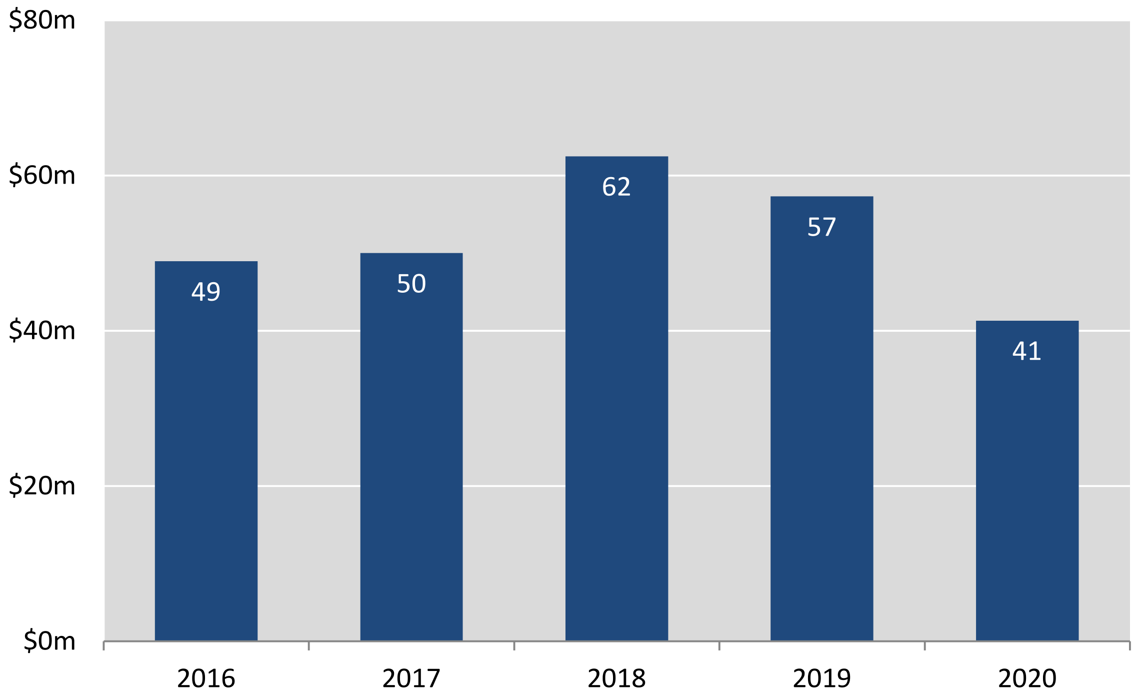
We are committed to taking a targeted and cost effective approach to the replacement and refurbishment of our assets.

Our proposed capital expenditure will enable us to continue to maintain the safety, security and reliability of the network which will minimise outages for customers. That is, the expenditure will allow us to 'keep the lights on'.

This section explains why our forecast capital expenditure for replacement is required in order to continue to deliver a safe and reliable electricity supply to our customers.

The profile of our forecast replacement expenditure is shown in figure 9.4.

Figure 9.4 **Forecast direct replacement expenditure including real escalation ($m, real)**



Source: CitiPower

Replacement capital expenditure is primarily driven by the condition of the asset. That is, the asset is replaced when its condition deteriorates to a level that triggers its replacement in accordance with the internal asset management policies.

There are times, however, when other factors trigger the need for the asset to be replaced, such as technical obsolescence, environmental considerations or proactive programs to replace assets of a certain class to address safety related matters.

9.2.1 What we have delivered

We have continued to deliver a safe and reliable electricity supply during the 2011–2015 regulatory control period.

As a result of our asset inspection regime where we review the condition of each asset, in the period from 2011 to 2013 we:

- replaced nearly 400 poles;
- replaced over 30km of underground cables, including 11km in the CBD;
- replaced 20km of overhead cables;
- replaced a transformer, switchboard and 20 associated circuit breakers at the Richmond (**R**) zone substation;
- replaced a transformer at Fitzroy (**F**) zone substation, as well as three 66kV circuit breakers and three high voltage (**HV**) circuit breakers at other zone substations; and
- replaced control and protection equipment at 16 zone substations.

'Based on the information provided, and performance to date, ESV is satisfied that all the safety programs proposed to the AER and agreed with ESV will be achieved by CitiPower by the end of 2015'

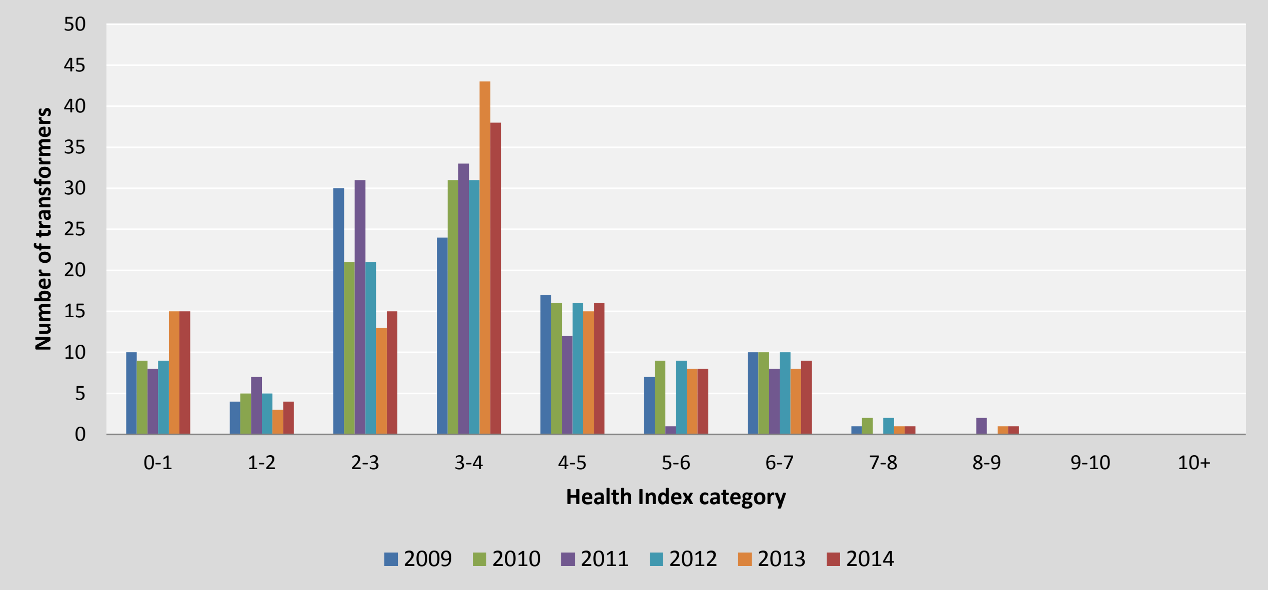
Source: ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014, p. 9.

The replacement of assets does not include those assets that we have refurbished or undertaken remedial action to correct defects to maintain and/or prolong the asset life.

Maintaining the health index (HI)

We have maintained the HI profile of our transformers in zone substations over the current regulatory period, as shown in figure 9.5.

Figure 9.5 Maintaining the Health Index over the current regulatory control period



Source: CitiPower

This demonstrates that our expenditure during the 2011–2015 regulatory control period was appropriate, with neither overinvestment nor underinvestment.

9.2.2 How we prepared our forecasts

We apply the following condition-based asset management methodologies to our network assets:

- reliability and safety based regime — this methodology is based on the principles of Reliability-Centred Maintenance (**RCM**) together with regulatory obligations that are built into our asset management procedures and is applied to routine replacement expenditure for high-volume plant and equipment such as poles, pole top-equipment, cross-arms, insulators and batteries. The approach incorporates the asset condition assessment and evaluation of operating environment; and

- Condition Based Risk Management (**CBRM**) – this methodology is applied to assess the condition, including the risk of the deterioration, of major items of plant. These major plant items such as transformers and switchgear require significant and lumpy expenditure.

These methodologies are discussed in more detail in the sections below.

'Poles and wires'

The reliability and safety based regime, based on RCM principles and regulatory obligations, is applied to high-volume plant and equipment such as poles and wires. It involves regular physical inspections of the assets, where defects are identified.

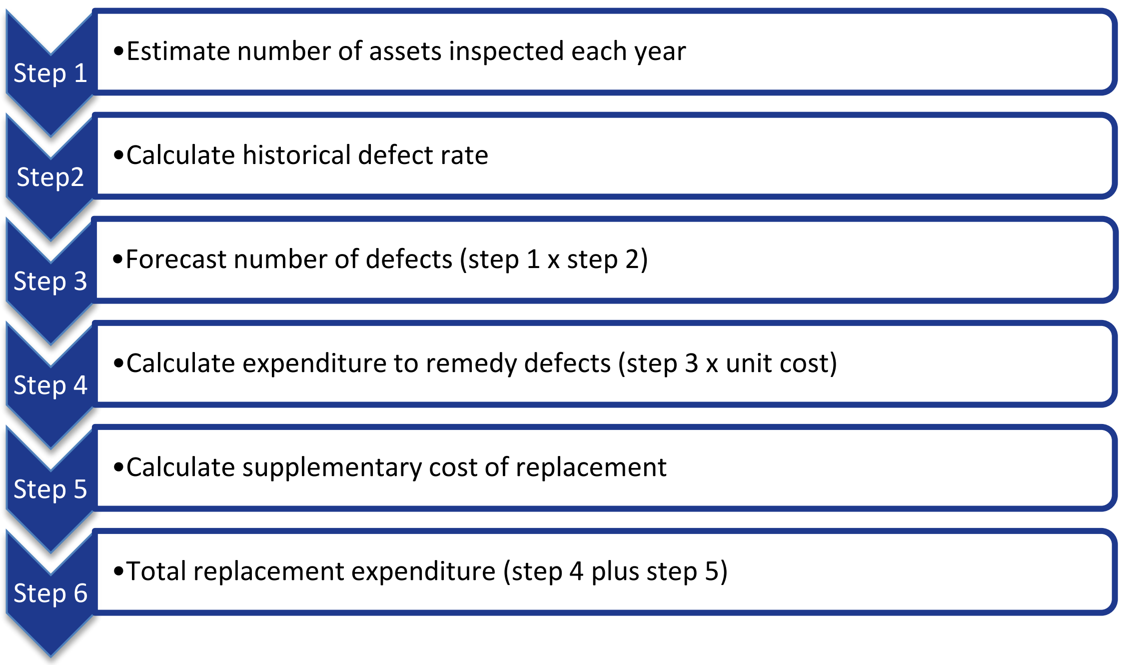
The RCM methodology identifies each possible way in which a defect may occur in an asset, and the root cause of that defect. For each different type of defect, the possible impact on the safety, operations and other equipment in the network is assessed. Consequently, a maintenance strategy for the asset is developed which considers the type of defects, the possible impacts and viable inspection and maintenance tasks.

Where a defect is identified in an asset, then the maintenance strategy to address that defect is implemented. This may involve replacement of the asset, or interim measures to prolong the life of the asset, such as pole staking.

The performance of assets is monitored to identify where the developed maintenance plan is not achieving the outcomes intended by the strategy. This provides a feedback mechanism for the routine review of each strategy, to ensure that it remains appropriate and efficient, also taking into account cost, industry developments, and changed environmental conditions. As a result, the strategies continue to evolve and improve through this rigorous process.

In forecasting the expenditure for poles and wires, we have used the following process:

Figure 9.6 Process for forecasting expenditure for poles and wires



Source: CitiPower

Our replacement costs have been based on the average rate over the period from 2011 to 2014 for each asset category. Because it is more efficient completing several jobs on multiple assets when dispatching a work crew to the field, rather than completing an individual asset job and returning to the depot, we capture total costs for a program of work then allocate the costs to asset categories. As a result, the averages accurately reflect the cost of delivering the total program of works but are less reliable at an individual asset level. The asset categories align with our internal reporting systems.

Transformers and switchgear

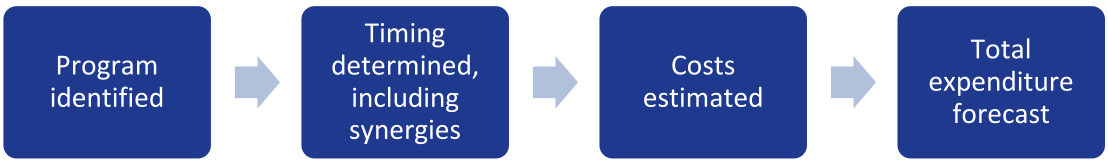
The CBRM methodology provides for a systematic framework to determine the replacement of major plant and equipment including, for example, transformers and circuit breakers. The variables include the following:

- asset condition – this is based on a HI which is a numeric representation of the condition of the asset;
- asset performance – this identifies the Probability of Failure (**PoF**) of an asset; and
- risk – this assesses the combination of PoF and the Consequence of Failure (**CoF**) for individual assets.

Under this methodology, a calculation is made for each individual item of plant and equipment in order to determine the year in which it will reach or exceed a threshold health index value. The methodology identifies a proposed year for the replacement of the asset. This is then reviewed in conjunction with other augmentation and development plans in order to identify opportunities for synergies, such that the replacement schedule can coincide with other major works.

The process to forecast assets using the CBRM methodology is set out below.

Figure 9.7 Process for forecasting expenditure for larger assets



Source: CitiPower

The programs are identified through the output of the CBRM process, together with reported maintenance defects of associated equipment, or through our safety related asset management policies.

The timing of each program is considered in relation to the condition of the asset and the risk associated with the probability of failure, or in conjunction with other asset projects such as a planned augmentation or customer connection.

We have obtained cost estimates from a supplier for each of our large replacement projects. For smaller projects, our cost estimates have been derived from historical project costs for similar projects.

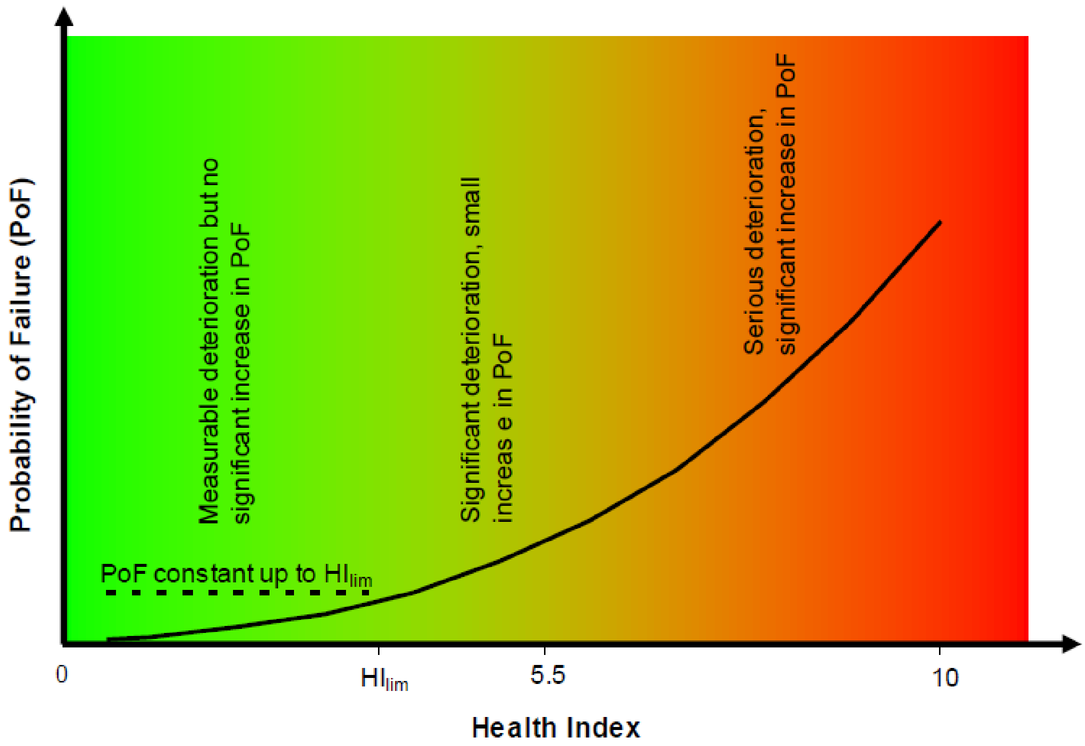
Approach to checking the reasonableness of expenditure forecasts using top-down measures

In order to check that our expenditure forecasts are reasonable, sustainable and enable us to prudently and efficiently manage our ageing and deteriorating large assets using current strategies, maintenance policies and operating practices, the CBRM models are used to generate HI profile predictions for future years.

The HI profile is used as a visual tool to understand at a high level the current condition of our major plant assets. The HI of an asset combines information relating to age, environment, duty, and specific condition and performance information. The HI is presented in a range from 0 to 10, where 0 is a new asset and 10 represents end of life.

An asset can accommodate significant degradation with very little effect on the risk of failure. However, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The relationship between the condition of the asset and hence the HI, and the risk of failure is shown in figure 9.8.

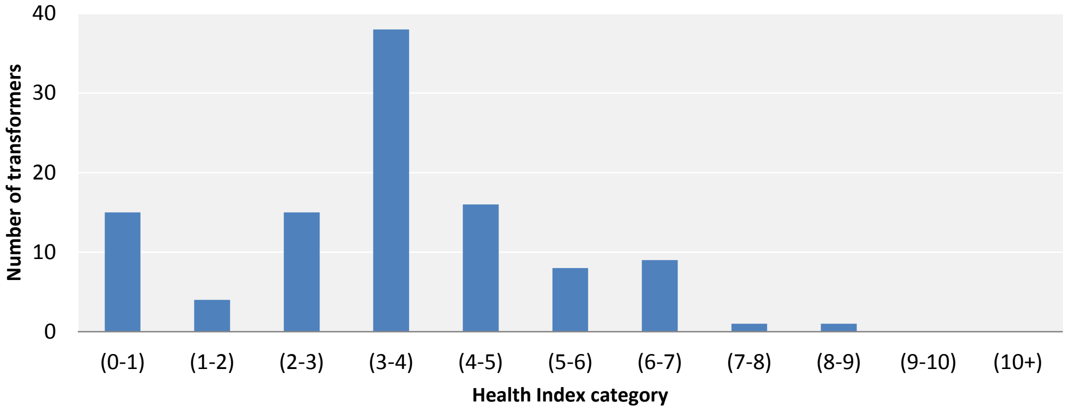
Figure 9.8 Relationship between Health Index and Probability of Failure



Source: CitiPower

We focus on those assets with a HI of seven or above. A HI of seven represents the stage where planning for replacement is required as the asset is showing signs of end of life and the probability of failure is increasing. For our transformers in our zone substations, the HI at the start of the 2016–2020 regulatory control period is shown in figure 9.9.

Figure 9.9 Health index of transformers at zone substations at the start of 2016



Source: CitiPower

We can use the CBRM models to generate HI profile predictions for future years to check the appropriateness of our expenditure forecasts. The profiles are compared using a 'do nothing' approach, against the forecast replacement (and network reconfiguration) strategies to ensure that, over the forecast period, the HI profile for the total transformer fleet is appropriately managed. This is particularly applied to that portion of the profile that is greater than or equal to seven, as from that point the rate of change of the probability of failure significantly escalates.

A HI profile similar at the end of the forecast period to the current profile infers that:

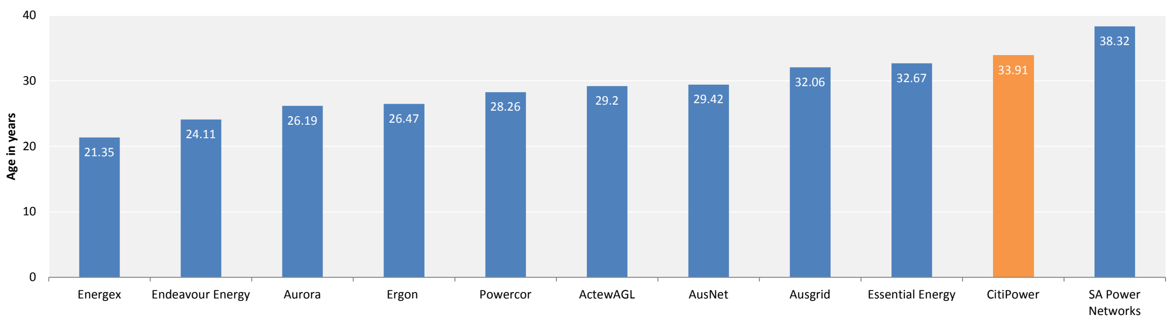
- no changes to asset management processes are required over the forecast period;
- no backlog of pending replacements at the end of the forecast period; and
- no over-replacement is forecast.

If the HI profile increases over the forecast period, then it would suggest that a step up in expenditure is required.

9.2.3 Drivers of expenditure

We have one of the oldest networks in the National Electricity Market (**NEM**). This is shown in figure 9.10 where we have calculated the average age of each network by multiplying the number of assets in service each year by the asset age.

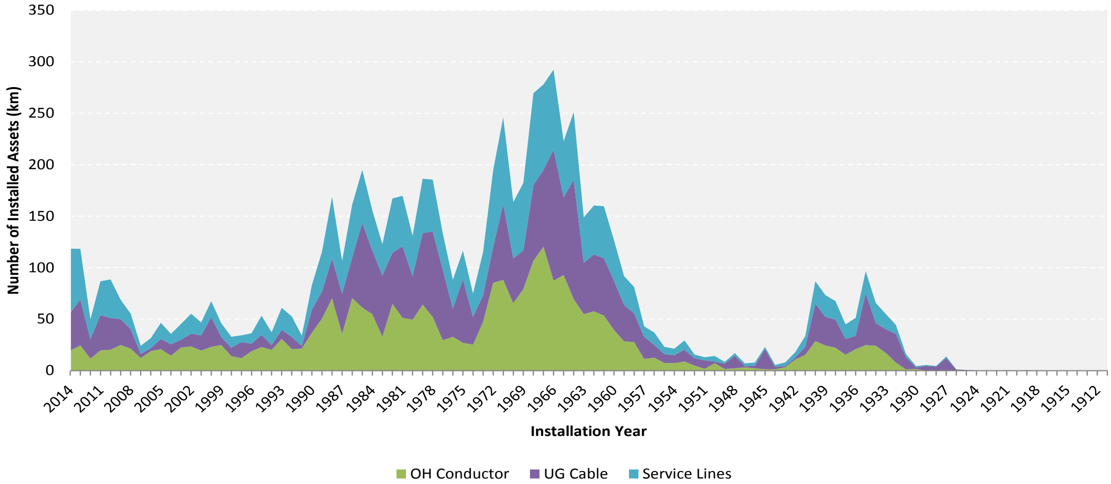
Figure 9.10 Average distribution network ages



Source: Category Analysis RIN, CitiPower

The majority of our assets were installed during the 1960s, 1970s and 1980s. This is shown in figure 9.11 containing the number of line assets installed (by kilometre) each year.

Figure 9.11 CitiPower lines asset age profile



Source: CitiPower

The graph also shows a number of assets installed in the 1930s. This is associated with the 22kV sub-transmission network in inner Melbourne that is intended to be decommissioned.

Age is not the sole determinant of the condition of our assets. Other factors that we assess such as the operational history, operating environment, and manufacturing design and performance are also important in determining their condition. That said, the age of our network will be a contributing factor to its overall condition and increase the risk of failure.

9.2.4 What we plan to deliver

Our expenditure forecast is driven by the planned delivery of:

- completion of the refurbishment works intended to take place during the current regulatory period, but which have been delayed as a result of delays to the upgrade of BTS;
- 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; and
- replacement or refurbishment of large plant and equipment based on condition.

These factors are discussed in turn below.

Deferred projects from current regulatory period

As a result of community and local government objections to the planning permit for the upgrade of BTS from 22kV supply to 66kV supply, there were delays to the CBD Security Upgrade and Metro projects. This also had knock-on impact onto related replacement projects.

The Brunswick (**C**) zone substation redevelopment is required to address the age and condition of its transformers and switchgear. For example, the three transformers have HI scores of 6.6, 8.27, and 6.6. The zone substation is served by 22kV sub-transmission lines from West Melbourne terminal station (**WMTS**) and as part of the refurbishment we intended to upgrade it to 66kV, given our long term strategy to replace the ageing 22kV sub-transmission network with the 66kV sub-transmission network. However as WMTS66 is overloaded, we need to connect the upgraded zone substation to BTS when it is upgraded to 66kV. This replacement project is now overdue.

The switching substation in Waratah Place, referred to as W, is in a deteriorating building. As the station is upgraded to a new zone substation (**WP**), we will demolish the existing building and rebuild. This is necessary for the new facility to be capable of safely and securely housing new 66kV switchgear that is part of the CBD Security of Supply project, as well as housing a zone substation. This project was delayed as a result of the delays to the upgrade of BTS, but is now underway.

The WP zone substation will take the entire load from Russell Place (**RP**) zone substation which will be decommissioned. These assets at RP are in poor condition, with two of the transformers having HI scores around a level of seven. Additionally, we need to rectify defects in the building structure above the RP zone substation to minimise public safety hazards, regardless of the zone substation decommissioning.

The timeline in figure 9.12 details the steps taken by us and AusNet Services from May 2008, up to the final decision at Victorian Civil and Administrative Tribunal (**VCAT**) in 2014, to finalise the planning permit requirements for the BTS development.

Figure 9.12 Timeline of Brunswick Terminal Station upgrade delays

2008	•May: Regulatory Test consultation paper published •August: BTS regulatory test final report
2009	•December: AusNet services lodges planning permit with Moreland Council, proposing use of outdoor air insulated switchgear
2010	•March: AusNet letter of Offer to CitiPower stated completion expected three years from signing •June: planning application rejected by Moreland City Council
2011	•March: revised regulatory test publshed, proposing use of indoor gas insulated switchgear •May: final revised regulatory test report published •July: revised planning permit lodged with Moreland City Council •November: revised planning application rejected by Moreland City Council
2012	•February: Minister for Planning approves amendment to Moreland Planning Scheme, rezoning site to Special Use Zone and establishing BTS Incorporated Document •August: AusNet signs contracts with AEMO and CitiPower
2013	•February: Demolition works commence. Community concerns raised about tree removal. Council advises AusNet that removal of existing trees and excavation below one metre requires additional planning approval
2014	•February: AusNet submits revised planning permit application to include existing tree removal and excavations below one metre •June: Moreland City Council issues notice of decision to grant a planning permit •July: Application for review of the Moreland Council decision, lodged by representatives of the Merri Creek Residents Group, with VCAT •August: VCAT mediation sessions unsuccessful in resolving issues. VCAT hearing held •September: VCAT upholds Moreland City Council's planning permit, and AusNet is issued with permit to begin construction works

Source: CitiPower

Increasing defect rate on poles and cross-arms

We have observed an increasing defect rate on our poles and cross-arms during the current regulatory period, which is consistent with the replacement (**repex**) model predictions and expectations of an ageing asset base. Many of our poles were installed in the 1960s.

We need to continue to invest to replace these assets so that the reliability of the network does not deteriorate.

Compliance with environmental regulations

The transformers in the Armadale (**AR**) and Montague (**MG**) zone substations are emitting noise that is approaching the limits permitted by the State Environment Protection Policy (Control of noise from industry, commerce and Trade) No. N-1, also known as SEPP N-1.

To ensure continuing compliance with the relevant regulations, it will be necessary over the next regulatory control period to undertake works to reduce noise emission.

Protection relays

We have an ageing protection relay population. Protection relays help isolate faults, prevent unnecessary outages and protect network assets from damage. Modern protection relays also provide significant system information and self-diagnose faults. Our older fleet of relays has no relay health monitoring, meaning that faulty relays will only be identified when they fail to operate. To prevent an increased probability of the primary protection failing at the same time as the backup protection, and to avoid the associated risk of a safety incident, network damage or a lengthy customer outage, it is necessary to increase the rate at which the older protection relays are replaced.

We propose to both increase the rate of replacement and to target the highest risk relays at the front end of the program to reduce the risk of a protection relay fault impacting the network and safety. Replacing the ageing relay fleet with modern protection relays will both reduce the safety risks associated with protection relay faults and provide operational benefits such as real time information to help manage the network, self-diagnose protection relay faults, better cater for embedded generation and be able to remotely change relay settings and protection sequences when carrying out modifications to the network.

Condition of transformers and switchgear

Many of our transformers were installed in the 1960s. These assets have high health indices and are in need of replacement. In addition to C zone substation, the transformers in the Richmond (**R**) zone substation and Dock Area (**DA**) zone substation need to be replaced, and the latter will also involve the zone substation being upgraded to be served at 66kV.

The condition of the switchboard and cooling towers at Flinders Ramsden (**FR**) zone substation drive the need for replacement, as well as the condition of several 66kV circuit breakers in our other zone substations.

It should also be noted that the buildings, transformers and switchgear associated with our 22kV sub-transmission network are also in poor condition. Rather than undertake a like-for-like replacement of these assets, we intend to decommission the network and transfer the load to the 66kV sub-transmission network and zone substations.

The main reason for the timing of a number of these projects is to achieve synergies with the asset refurbishment plans of AusNet Services at WMTS. When we carry out the decommissioning of the 22kV zone substation network supplied from WMTS, AusNet Services will no longer be required to invest considerable capital expenditure to replace its ageing 220/22kV transformers and switchgear at WMTS.

Our strategy to retire the 22kV network enables AusNet to achieve a more efficient refurbishment of WMTS by not requiring AusNet to rebuild the WMTS 22kV switchyard. However, we will need to offload the Bouverie St/Bouverie Queensberry (**BSBQ**), Spencer St **(J**), and Laurens Street (**LS**) zone substations served by WMTS22, and upgrade the DA zone substation to 66kV supply from WMTS66, in collaboration with AusNet Services completing the rebuild of WMTS.

This project is further discussed in section 9.3.

Checking the reasonableness of our forecasts

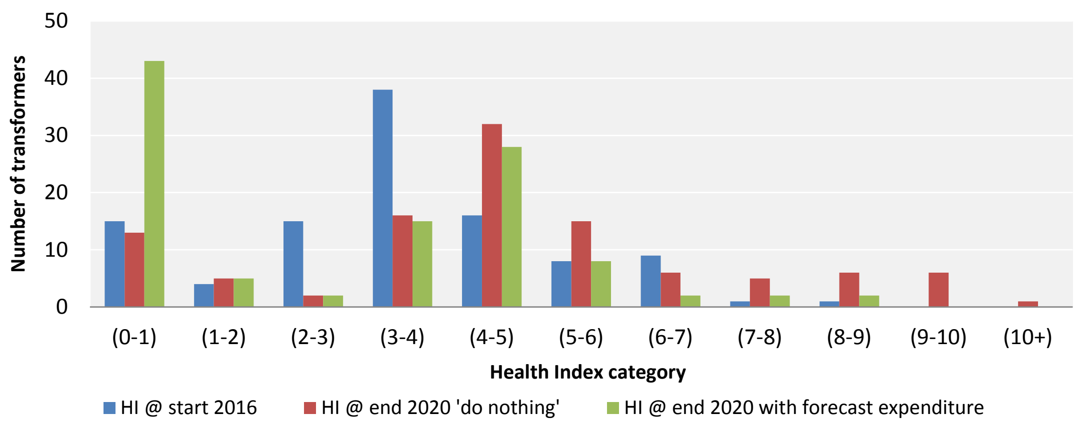
As noted above, we are able to undertake a top-down check that our expenditure forecasts are reasonable, sustainable and will enable us to prudently and efficiently manage our ageing and deteriorating large assets using current strategies, maintenance policies and operating practices by using the HI profile predictions for future years.

We have created the HI profile at the end of the current regulatory period and compared that to:

- the profile that would occur if we 'do nothing' over the 2016–2020 regulatory control period; and
- the profile that would occur if we undertake the investments set out in this Regulatory proposal.

Using transformers in zone substations as an example, figure 9.13 shows that our forecast expenditure is reasonable as we are able to appropriately maintain the number of transformers with a health index of seven or above, as well as maintain the overall HI profile. If we did not undertake any investment over the 2016–2020 regulatory control period, then the number of zone substations with transformers with HI of seven or above would rise from two to seven.

Figure 9.13 Health Index profiles of transformers in zone substations



Source: CitiPower

The HI profile forecast graphs for 66kV circuit breakers and 22/11kV circuit breakers show a similar trend.

9.2.5 Replacement (repex) model

In the Forecast Assessment Expenditure Guidelines, the AER indicated that it will use the 'repex model' as part of its assessment of the proposed replacement capital expenditure. The repex model is a high-level probability based model that forecasts replacement for various asset categories based on their condition (using age as a proxy) and unit costs.[55] The AER used this model in our 2011-2015 regulatory determination.

The AER recognises that there are a range of factors that can influence the replacement life for an asset, including the:

- operational history;
- environmental condition (e.g. damp or dry, or coastal or inland); and

[55] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, Explanatory Statement, November 2013, p. 185.

- quality of its design and installation (including early-life failures of assets).[56]

Given the complexity of predicting the replacement of individual assets, the AER considers the purpose of the repex model is to simplify the analysis but still maintain some accuracy at the aggregate level.[57] As a result, it has inherent limitations including:

- the life of assets replaced in the past is assumed to be the same as for asset replacement in the future, such that the repex projections are backward looking and may differ significantly from a truly optimal forward looking replacement program;
- assumption that recent past replacement expenditure reflects implementation of an optimal replacement strategy;
- the number of units replaced in the past is directly proportional to historical expenditure;
- use of asset age as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or environmental standards may be the primary driver for particular asset categories;
- assumption of a normal distribution profile around the mean for the replacement life of each asset category, where there is likely to be a high degree of variability around the 'mean' age that limits the accuracy of its use in predicting volumes for replacement; and
- sample sizes may be too small for some asset sub-categories to be statistically significant, and thus may lead to inaccurate results.

In light of the limitations of the model, the AER suggests that it will only use the repex model to cross-check the forecasts of a distributor where those forecasts appear to be deficient.

Repex model output

The AER's repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network by asset category.

The AER's model indicates that the largest category of replacement costs will be for poles, which is consistent with our own forecasts based on the defect rates of the assets. The repex model also forecasts a large amount of expenditure for switchgear and transformer replacement.

However, the repex model uses history to 'calibrate' the average replacement lives of assets across the business. This leads to results that are outside the normal industry expectations.

For example, in reviewing the model in 2010, Parsons Brinckerhoff found that the asset lives determined by the repex model were not reasonable, noting:[58]

> *PB considered the case of CP's underground cables which comprise 43% of the network replacement value. From our analysis we noted that the calibrated average life of 87 years for CP is 17 years longer than that applied for Jemena and United at 60 years, and 44 to 45 years longer than that applied for SP AusNet and Powercor at 42 and 43 years respectively. Given the average life of 87 years, and Nuttall's standard deviation approximation, this suggests an expectation that 20% of the cable population will remain in service for over 95 years, with 8% remaining in service for over 100 years. PB is not aware of any Australian distributor that would expect any cables to remain in service for over 100 years. Therefore we*

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56 AER, Electricity network service providers Replacement expenditure model handbook, November 2013, p. 9.

57 AER, Electricity network service providers Replacement expenditure model handbook, November 2013, p. 9.

58 Parsons Brinckerhoff, *Repex model review CitiPower – Powercor*, July 2010, p. v.

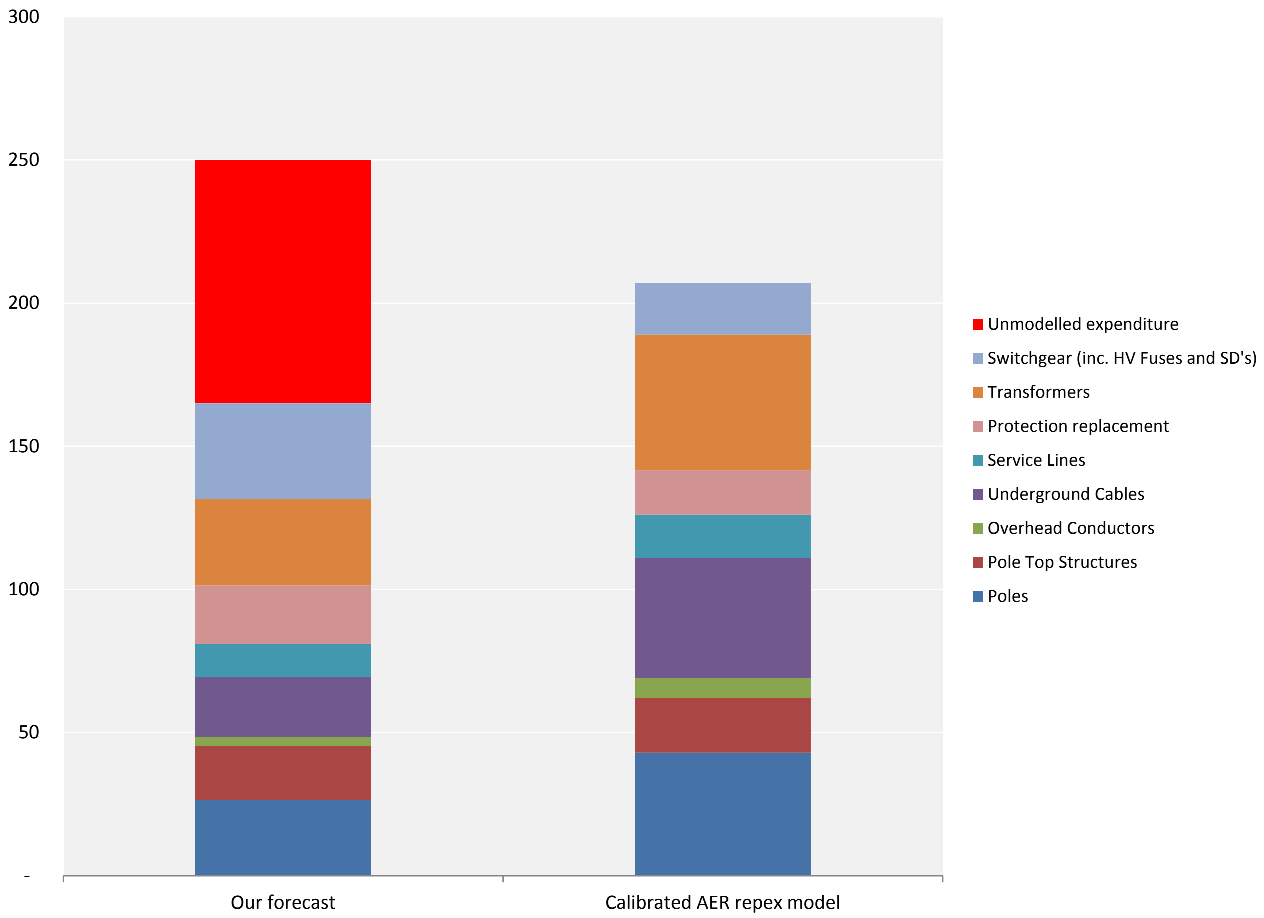
> *consider that the calibrated life input to the model does not appear to be aligned with industry expectations.*
>
> *Similarly, PB notes that in the case of CP's Secondary Systems, an average life extension of 6 years has been applied over the PAL proposed life of 49 years. In our opinion this ignores the fact that equipment of this type are typically replaced due to obsolescence, withdrawal of vendor support, or the unavailability of spares, and PB considers that the likelihood of achieving an average service life extension of this magnitude is extremely low without accepting the considerable amount of additional risk, or incurring mitigating expenditure associated with operating obsolete equipment.*

As a result, the repex model may understate the level of capital expenditure that we will require to replace some categories of assets.

Repex reconciliation

The repex model forecasts a lower level of overall expenditure for replacement related works compared to our own forecasts. For the elements of replacement expenditure where the cost drivers are covered by the repex model for standard control services, our forecasts are lower than the forecasts from the repex model. This is shown in figure 9.14.

Figure 9.14 Comparison of our forecast to repex model forecast output ($m, real)



Source: CitiPower
Note: direct costs excluding labour escalation

The repex model is not expected to reflect all of the replacement costs for assets incurred by a distributor. The AER 'expects that the chosen sub-categories should represent between 70 to 80 per cent by value of replacement expenditure'.[59] We calculate that the repex model drivers cover around 66 per cent of our replacement expenditure.

The repex model does not cover those assets that are either not replaced by age, or are not defined by a detailed asset age profile required by the repex model, including:

- property, buildings and associated facilities,
- asset refurbishments and component replacements; and
- environmental expenditure.

AER's repex model does not include costs such as property refurbishments, replacing a roof on a zone substation, replacement of fences, and general maintenance activities. These costs are essential to maintaining the distribution network, but are not associated with an age profile and thus are excluded from the repex model. For

[59] AER, Electricity network service providers Replacement expenditure model handbook, November 2013, p. 13.

example, it does not include building civil replacement costs associated with the C and RP zone substations or the Waratah Place (**WP**) switching station, nor does it cover costs associated with fire systems, lifts or cooling systems.

Costs associated with the program to remediate our highest risk underground pits in the roadways or footpaths in the Melbourne CBD are also excluded from the repex model. Some pits opened for cable works have been found to be in a deteriorated and dangerous condition. The significant hazard is the sudden collapse of the pit covers or lids under the weight of traffic or pedestrians.

The repex model also does not capture expenditure associated with management of environmental matters, for example, the reduction of noise to ensure compliance with Environmental Protection Authority standards, or the replacement of line coverings preventing bird interference.

9.3 Augmentation expenditure

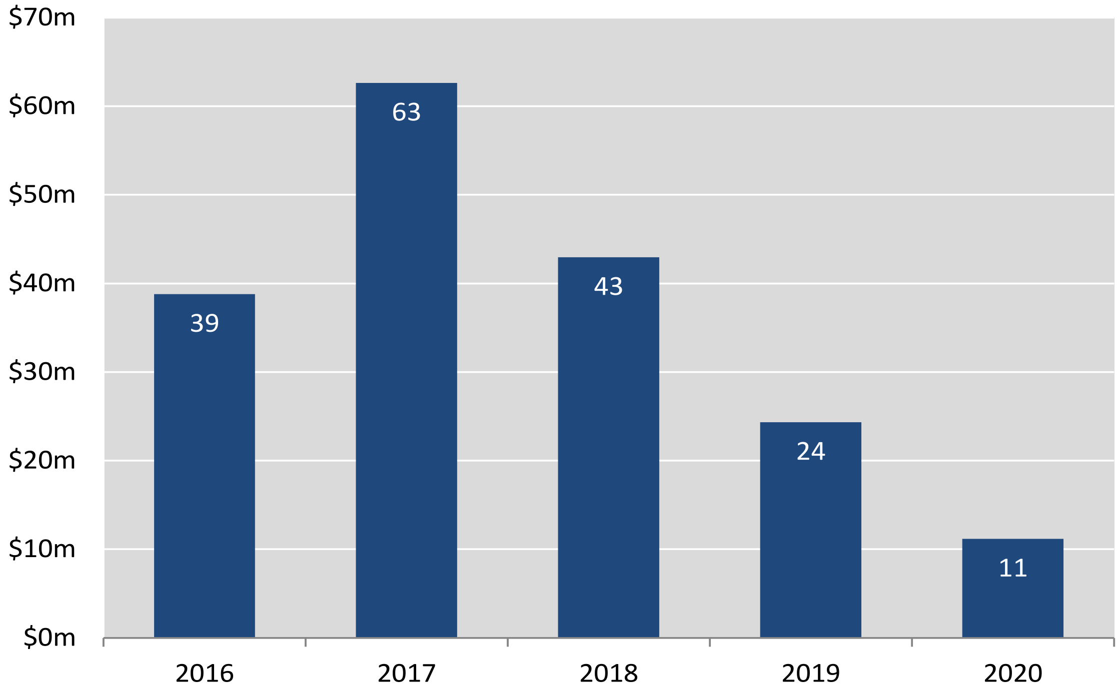
To ensure we continue to support the growth and development of our communities, we need to target our investment in high growth areas to meet future demand.

Our proposed capital expenditure will also allow us to undertake augmentation to maintain the security, reliability and quality of supply of the network, including to increase resilience into the Melbourne CBD and inner suburbs as required by the Essential Services Commission.

This section explains why our forecast expenditure for augmentation is required in order to meet or manage the expected demand over the 2016–2020 regulatory control period.

The profile of our forecast augmentation expenditure is shown in figure 9.15.

Figure 9.15 Augmentation direct capital expenditure including real escalation ($m, real)



Source: CitiPower

Augmentation capital expenditure comprises:

- demand driven expenditure to upgrade the capacity of the existing distribution network, in response to local or regional demand growth;
- non-demand expenditure required to address the security of supply of the network; and
- non-demand expenditure required to address the maintenance of reliability and quality of supply of the network.

9.3.1 What we have delivered

In the 2011–2015 regulatory control period, we have delivered a range of projects including:

- completing a significant portion of the CBD security of supply upgrade plan, which included the construction of a new switching station and three sub-transmission cables and network re-arrangement;
- progressing the Metro capacity project which included the redevelopment of a zone substation, a new sub-transmission cable and the installation of temporary capacity into the network until the upgrade of BTS from 22kV to 66kV is completed;
- construction of a new zone substation at Southbank (**SB**), which was the first part of our plan to decommission the 22kV sub-transmission network and integrate the supply into the 66kV sub-transmission network;
- commencement of works to decommission the ageing 22kV Prahran (**PR**) zone substation by installing additional capacity at an adjacent Balaclava (**BC**) zone substation and upgrading the sub-transmission loop serving BC;
- installation of auto control schemes at four zone substations, as well as a 66kV reactor at a zone substation to allow further embedded generation into our network and to manage the fault levels from existing generation; and
- construction of several new 11kV feeders, and installation of new capacity banks at two zone substations. We also uprated a sub-transmission line together with United Energy Distribution.

Use of demand management

We have used demand management initiatives in the current regulatory period to defer network augmentation. For example, we have in place a contract with a large customer to utilise their own generation rather than drawing on the network during particular times of peak demand.

9.3.2 How we prepared our forecasts

Our forecasting methodology for augmentation expenditure differs depending on whether the network constraint is demand or non-demand driven.

Demand driven

For augmentations that are driven by increasing demand on the distribution network, we have undertaken the steps outlined in figure 9.16 to forecast expenditure. This process is consistent with the methodology that is set out in the Distribution Annual Planning Report (**DAPR**).

Figure 9.16 Process to forecast augmentation capital expenditure

Source: CitiPower

The forecasts for peak demand across our network assets have been determined using the following process, which is described in more detail in chapter 8:

- top–down independent econometric forecasts at the terminal station and across our network have been undertaken by the Centre for International Economics (**CIE**), an independent economic forecaster;
- bottom-up forecasts for demand at HV feeder and each zone substation, taking into account information about customer connections and embedded generators, which has been reconciled to the top-down forecasts; and
- the reconciled zone-substation forecasts have be used to model forecasts of maximum demand on each sub-transmission line and zone substation.

The forecasts do not apply a growth rate to large industrial loads. These are only adjusted upon advice from the customer regarding an increase in load or by applying local knowledge in respect to a known closure of a plant or industrial type load.

With the demand forecast, we use the probabilistic planning approach to assess and value the amount of load and energy that would not be supplied on our network assets if an element of the network is out of service. For example, we calculate the amount of unserved energy at a zone substation if one of the transformers fails.

The energy at risk is assessed against our internal policies to determine whether it is sufficient to trigger a review of the network constraint. Where it is sufficient, we assess a range of options to address that network constraint, including non-network options.

For large augmentation projects over $5 million that are subject to a regulatory investment test (**RIT-D**), we undertake a detailed assessment process to determine the value of supply reliability from the customer's perspective, using the latest values of customer reliability as calculated by Australian Energy Market Operator (**AEMO**). This is then compared to the costs of the different options, including non-network solutions, to determine the preferred option, which is the credible option with the highest net economic benefit.

The large reduction in the AEMO value of customer reliability (**VCR**) between 2013 and 2014 resulted in the deferral of some projects that were intended to be undertaken in the 2016–2020 regulatory control period.

The change in VCRs impacts the reliability targets for the Service Performance Target Incentive Scheme (**STPIS**), and will result in lower reliability for our customers going forward.

For smaller augmentation projects, we conduct a detailed investigation into possible network and non-network solutions to address the network constraint, and the most cost effective solution is chosen as the preferred option.

We have obtained cost estimates from a supplier for each of our large augmentation projects. For smaller projects, our cost estimates have been derived from historical project costs for similar projects.

Approach to checking the reasonableness of our forecasts using top-down measures

We use load indices to provide a high level indication of demand-related network risk and performance of assets on our network. In addition, it can be used to check the appropriateness of our bottom up augmentation expenditure forecasts.

The load index measures applied in the UK have been adapted to accommodate the greater spread of load conditions on our network, reflecting the use of probabilistic planning standards rather than deterministic standards.

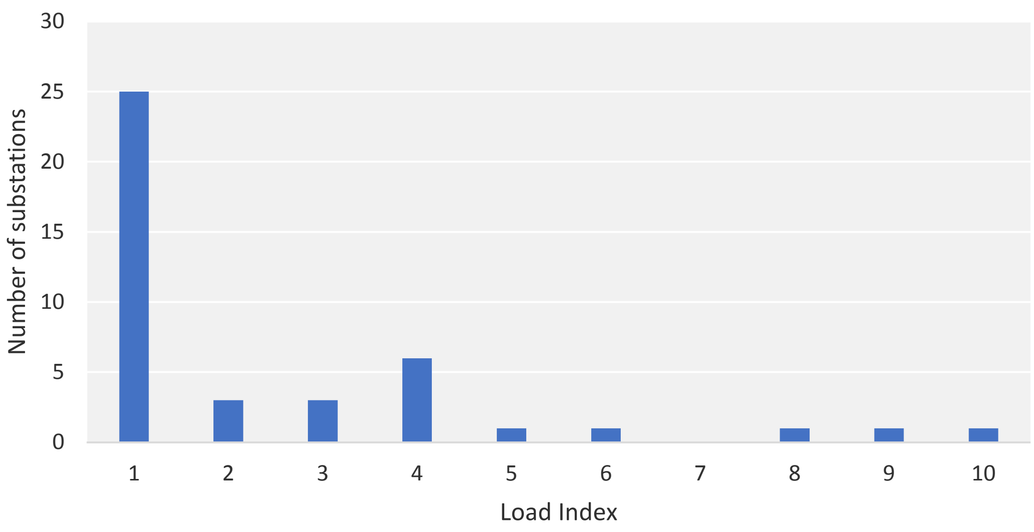
The load index is generated from two factors;

- demand driver – measure of maximum demand relative to firm capacity; and
- duration driver – measure of hours or energy at risk.

The load index is placed on scale from one to ten, with an index of one indicating that there is no load at risk under peak load conditions, and an index of ten indicating that load shedding is likely to occur, resulting in significant loss of supply and/or time required to restore supply, as the peak load is forecast to exceed the N capacity of the zone substation.

Our expected load index profile at the start of the 2016–2020 regulatory control period is shown in figure 9.17.

Figure 9.17 Load index of CitiPower zone substations in 2016



Source: CitiPower

Similar to the health index approach, as zone substations move into the seven and higher categories, plans are required to manage or alleviate the loading constraints. The profile shows that we have a zone substation with more than 750 hours at risk in the event of an outage of a transformer (represented as a load index of eight). Additionally, we have a zone substation that is approaching its normal capacity at times of peak demand (represented as load index of nine), and one that is forecast to exceed its normal capacity at times of peak demand leading to load shedding (a load index of ten). Given the load indices, we need to augment the network.

Using the demand forecasts, we generate load index profile predictions for future years to check the appropriateness of our expenditure forecasts. The profiles from the forecast augmentation projects are compared to 'do nothing' approach. This approach ensures that, over the forecast period, the load index profile for the total transformer fleet is appropriately managed. The comparisons focus on that portion of the profile that is greater than or equal to seven.

A load index profile similar at the end of the forecast period to the current profile infers that:

- no changes to network planning processes are required over the forecast period;
- no backlog of pending augmentations at the end of the forecast period; and
- no significant reduction in utilisation is forecast.

If the load index profile deteriorates over the forecast period, then it would suggest that a step up in expenditure is required.

Non network alternatives

There are a range of non-network solutions that are evaluated for use to defer demand-driven network augmentations, including:

- automated, contracted or voluntary demand management;
- shifting appliance or equipment use from peak periods to non-peak periods (eg: controlled load (off-peak) water heating);
- operating appliances at lower power demand for short periods (eg: air conditioner load control);
- converting the appliance energy source from electricity to an alternative (eg: switching from electric to gas heating);
- use of energy efficiency programs;
- use of pricing structures, such as Time of Use tariffs, to change consumer consumption patterns;
- voluntary load curtailment by customers, such as in response to a request to reduce electricity usage;
- voluntary load shedding and disconnection of non-critical loads by customers;
- power factor correction of customer equipment;
- operation of embedded generators using conventional and renewable fuel sources;
- use of stand-by generators to enable load transfer; and
- installation of storage devices such as batteries that can store energy in times of reduced demand and convert back to electricity at times of peak demand.

Non-demand driven

As noted previously, augmentation expenditure may also be driven by non-demand factors such as ensuring the security, reliability and quality of supply of the network.

Security of supply is often considered alongside a demand-driven augmentation project. For example, this includes obligations that we face under the *Victorian Electricity Distribution Code* to strengthen the security of supply in the Melbourne CBD.

Reliability of supply issues are often linked to replacement needs on the network. However, replacement projects can result in load being temporarily or permanently shifted around the network, leading to a need to augment the network. For example, the decommissioning of the 22kV sub-transmission network will result in load being permanently shifted, and will drive the need to increase capacity on the areas of the network taking up this load shift.

Quality of supply issues in the network are identified during the process to identify possible demand-driven constraints. That is, we consider whether the forecast changes in demand, both changes in load growth and embedded generation (e.g. solar PV growth), may result in the prospective fault current or voltage levels being outside the allowable limits.

If no demand-driven augmentation is planned to address network constraint, then we will consider options to address the issue.

9.3.3 What we plan to deliver

Our expenditure forecast is underpinned by the following key drivers:

- localised demand growth in established residential and commercial areas, driven by customer connection activity;
- need to increase capacity to alleviate the need for like-for-like replacement of the ageing 22kV sub-transmission network in a co-ordinated manner with AusNet’s upgrades of the relevant terminal stations; and
- completion of the CBD Security of Supply and Metro projects.
- Demand driven expenditure comprises around 33 per cent of the augmentation forecast. The drivers are discussed below.

Demand driven

A large number of small projects to increase capacity in the feeder network are driven by expected growth in peak demand.

Projects to install a third transformer at the BQ zone substation, and the upgrade of the Dock Area (**DA**) zone substation from 22kV to 66kV supply out of West Melbourne termination station (**WMTS**) were intended to be undertaken in the 2011–2015 regulatory control period, but were efficiently deferred. These will now be undertaken in the 2016–2020 regulatory control period. The latter project is also required as a result of the decommissioning of the 22kV sub-transmission network from WMTS.

Impact of falling energy consumption

Debate around falling energy consumption leading to an expected decline in network expenditure is not that relevant to our business.

Augmentation expenditure is not a large part of our overall capital expenditure. In the current regulatory period, 26 per cent of total capital expenditure related to augmentation works. The majority of augmentation expenditure was driven by the obligation to increase resilience of the network in the inner areas of Melbourne including the CBD.

For the 2016-2020 regulatory control period, we expect to spend only 20 per cent of capital expenditure on augmentation works, where only a third of that expenditure will be driven by a need to address peak demand constraints on the network.

Checking the reasonableness of our expenditure forecasts

As noted above, we are able to undertake a top-down check that our expenditure forecasts are reasonable, sustainable and will enable us to prudently and efficiently manage our network constraints by using the load index (**LI**) to generate profile predictions for future years.

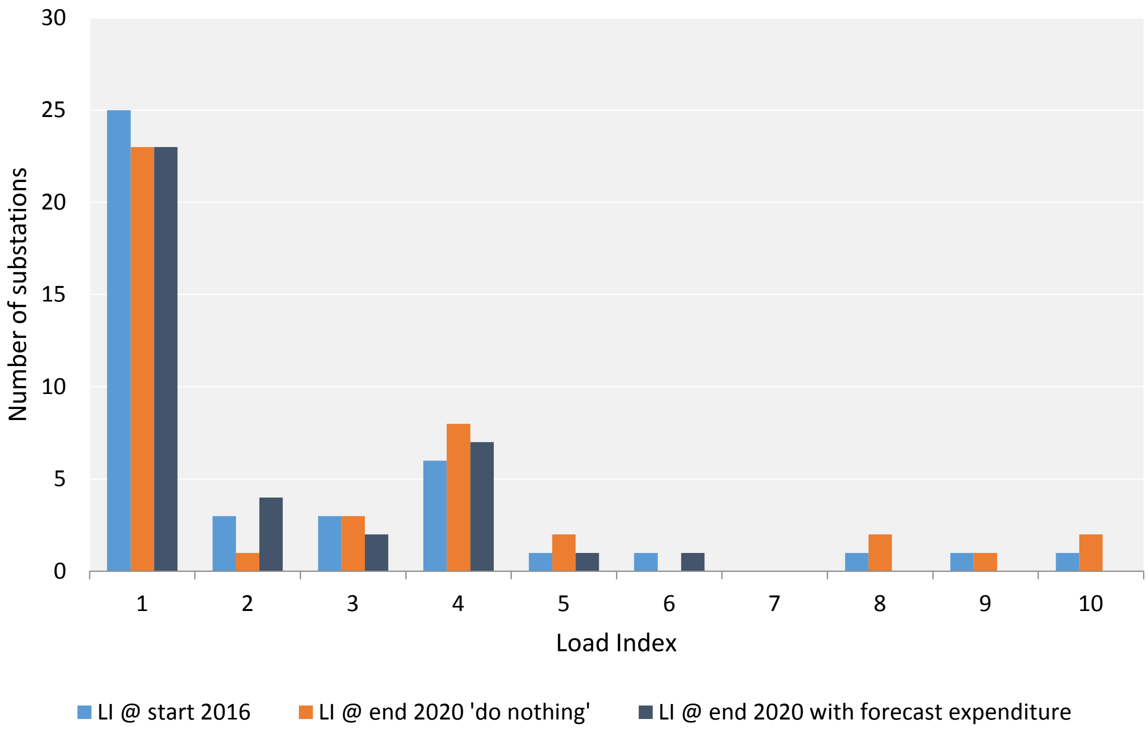
We have created the load index profile at the end of the current regulatory period and compared that to:

- the profile that would occur if we 'do nothing' over the 2016 – 2020 regulatory control period; and
- the profile that would occur if we undertake the investments set out in this regulatory proposal.

The comparison of these profiles allows us to ensure at a top-down level that the network constraints at zone substations and on sub-transmission lines are being appropriately managed. This comparison focuses in on that portion of the profile that is greater than or equal to seven.

Figure 9.18 shows that our forecast expenditure is reasonable as we are able to appropriately maintain the number of zone substations with a load index of seven or above, as well as maintain the overall load index profile. If we did not undertake any investment over the 2016–2020 regulatory control period, then the risk on our network will increase substantially.

Figure 9.18 Load index profile of transformers in zone substations



Source: CitiPower

Zone substations will have load indices of seven or above if the proposed augmentation works are not carried out. In contrast, no zone substations will have high load indices if the required works are undertaken.

Non-demand driven

<u>Addressing fault levels to allow further embedded generation</u>

To manage the fault levels from existing embedded generation, we are currently undertaking works at North Richmond (**NR**) zone substation which will be completed during 2016. We also plan to install a 'Normally Open Auto Close' scheme at Albert Park (**AP**) zone substation to ensure we operate within equipment fault level constraints, and maintain the safe operation of our network.

<u>CBD security upgrade</u>

The Melbourne CBD security upgrade is an obligation under clause 3.1A of the *Victorian Electricity Distribution Code*. This obligation followed the publication of a Regulatory Test that economically justified the scope of the works defined to upgrade the 66kV sub-transmission network in the Melbourne CBD to an 'N-1 Secure' standard.

The CBD Security of Supply and Metro projects were intended to be completed during the 2011–2015 regulatory control period. However, as a result of community and local government objections to the planning permit for the BTS upgrade the works were delayed. Consequently, the following distribution works were delayed and are now proceeding to revised targets:

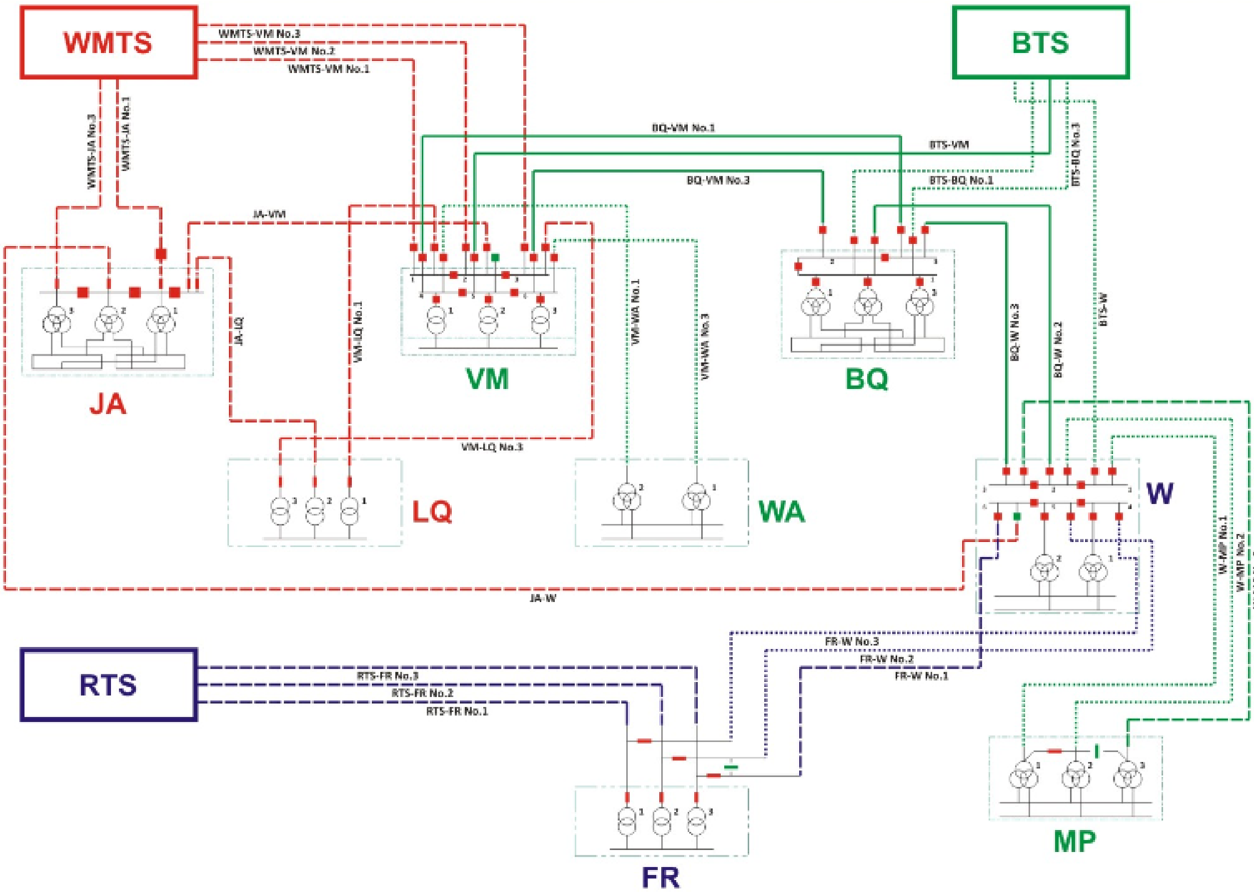
- establishment of sub-transmission cables from BTS to Bouverie/ Queensberry (**BQ**) zone substation and to Victoria Market (**VM**) zone substation;
- installation of two transformers, sixteen 66kV circuit breakers and associated high voltage switchgear and protection equipment at the rebuilt Waratah Place (WP) zone substation; and

- establishment of two sub-transmission cables from BQ to WP zone substation and associated protection equipment.

Related works to establish additional 11kV feeder transfer capacity and distribution remote switching at four zone substations in the Melbourne CBD were also impacted by the BTS delay.

The works will now be completed by the end of 2017. The expected schematic for the network following the completion of these works is shown in figure 9.19.

Figure 9.19 Expected schematic of the 66kV sub-transmission network following completion of the security works



<u>Replacement of the 22kV sub-transmission network</u>

We have commenced a program to replace the 22 kV sub-transmission network by reconnecting these customers onto zone substations supplied by the 66 kV sub-transmission network. The program will involve augmentation of the network as it will result in a need to replace this capacity through the construction of feeders and new transformers to allow for the decommissioning-related works to take place.

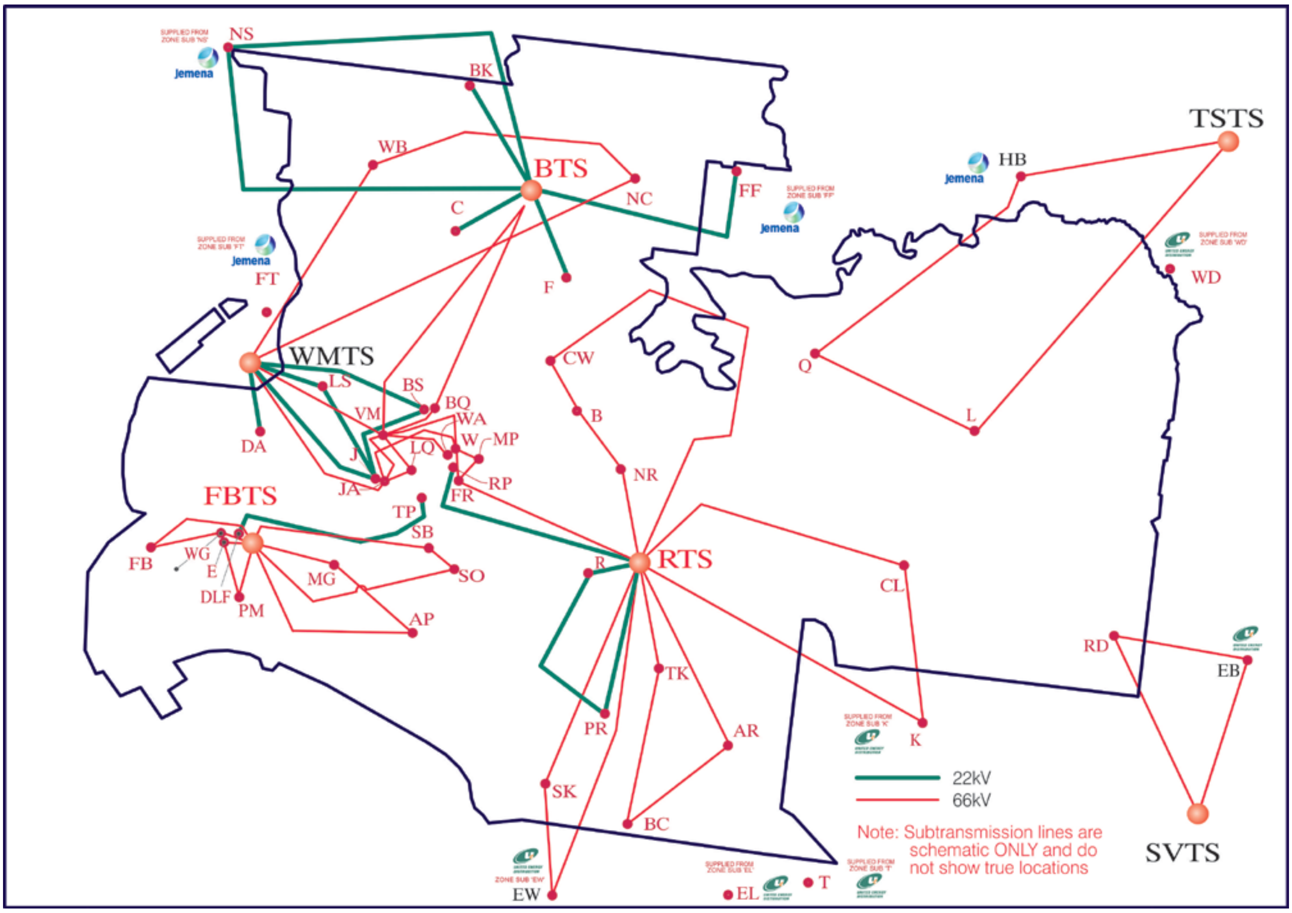
The replacement program is necessary as many of our ageing assets are in poor condition within the 22 kV sub-transmission network, including transformers and indoor switchboards within existing zone substations.

Some of these zone substations have secondary voltages of 6.6 kV, which is inconsistent with the present 11 kV standard in the CBD and inner suburbs. These non-standard 6.6 kV secondary voltages have many technical limitations when compared with the standard 11 kV secondary voltage. Having 6.6 kV distribution feeders limits system flexibility with regard to load transfers and effectively creates islands within the network. We intend to upgrade the associated 6.6 kV distribution network to 1 1kV as part of the replacement program.

Operation of the sub-transmission network at the higher voltage of 66 kV also reduces the amount of distribution losses from the network.

A schematic of our sub-transmission network is set out in figure 9.20.

Figure 9.20 Schematic of the sub-transmission network



During the 2016–2020 regulatory control period, we intend to:

- decommission the Bouverie Street (**BS**), Laurens St (**LS**), and Spencer St (**J**) zone substations served from West Melbourne terminal station (**WMTS**) after transferring the load to nearby zone substations through newly constructed 11kV feeders;
- upgrade the Dock Area (**DA**) zone substation from 22kV to 66kV, connected to WMTS66;
- decommission the Tavistock Place (**TP**) zone substation after transferring the load to the Southbank (**SB**) zone substation following the construction of new feeders across the Yarra River. For operational purposes TP must be decommissioned at the same time as the J zone substation;
- decommission the Russell Place (**RP**) zone substation after constructing new 11kV feeders to transfer the load to the new Waratah Place (**WP**) zone substation, which is associated with the CBD security of supply project; and

- decommission the Prahran (**PR**) zone substation after transferring the load to Balaclava (**BC**) zone substation through feeders that are currently being constructed.

Many of the zone substations targeted for decommissioning are served by WMTS. AusNet Services is undertaking works to rebuild the WMTS due to the condition and age of the plant and equipment.[60]

Given our strategy to retire the 22kV sub-transmission network, it would be inefficient for AusNet Services to rebuild the 22kV switchyard at WMTS. AusNet Services has advised us that they will avoid costs of around $41 million of not proceeding with the replacement of the WMTS22 switchyard and transformers.[61] The replacement of our assets served from WMTS22 must therefore be co-ordinated with the timing of the AusNet Services rebuild of WMTS.

9.3.4 Augmentation (augex) model

In assessing augmentation expenditure forecasts, the AER indicates in its *Expenditure Forecast Assessment Guidelines* that the 'augex model' will be one of several tools used to review our forecasts.[62]

The augex model only models demand-driven network capital expenditure. The model determines whether an asset needs augmentation based on the utilisation of the asset together with the forecast demand growth. When the peak demand of the asset reaches a certain proportion of its capacity, then it triggers augmentation.

Distributors usually use a complex range of forecasting methods to predict augmentation expenditure. However, the augex model attempts to simplify this process by essentially assuming a distribution network with rigid, deterministic planning criteria, and predicable augmentation methods. This results in the following model limitations:

- the model is very sensitive to small changes in parameters;
- sub-categories of assets may have small sample sizes, which can impact the accuracy of parameters;
- larger projects for some asset classes can have significant variability in scope, project costs and amount of capacity added to the network, resulting in historical data that is not appropriate for forecasting purposes; and
- history may not be a good predictor for the future.

The simplifications in the augex model necessarily lead to a reduction in accuracy of the planning outcomes that would be expected from a distributor.

It is noted that the augex model is a new tool that Nuttall Consulting has developed for the AER, and it has not yet been applied in regulatory determinations.

The AER has previously attempted to assess augmentation using modelling, where Nuttall Consulting determined an average weighted probability of forecast augmentation and applied that to the distributor's forecast in the 2010 draft determination.[63] However, the AER decided not to rely upon that tool in the 2010 final determination on the basis that the model required further testing to ensure that the model could reliably forecast the augmentation capital expenditure that would reasonably reflect the capital expenditure criteria over the 2016-2020 regulatory control period.

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60 AER, *SP AusNet Transmission Determination 2014–15 to 2016–17*, Final Decision, January 2014, pp. 73-74.

61 AusNet Services, *Letter to CitiPower re: West Melbourne Terminal Station 22kV Asset Replacement Avoided Cost*, 4 March 2015.

62 AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, Explanatory Statement, November 2013, pp. 167-168.

63 AER, Victorian electricity distribution network service providers distribution determination 2011-2015, draft decision, June 2010, p. 316.

The AER's concerns about the ability of the forecasting tool to provide forecasts that achieve the capital expenditure criteria remain valid and must be demonstrated if it is to rely upon the augex model. This is because:

- the consultant who developed the augex model noted that it is a regulatory tool, and not a planning/management tool;[64]and
- the capital expenditure criteria in clause 6.5.7 of the Rules requires the AER to accept the forecast of required capital expenditure if it reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives. This includes the requirement to meet or manage the expected demand, and well as the quality, reliability or security of supply for standard control services.

We are therefore concerned about the juxtaposition of the uses of the augex model to forecast the capital expenditure necessary to meet expected demand but not being appropriate to be used as a planning tool to address expected demand.

Furthermore, we note that the AER did not rely on the augex model in its draft decision in NSW, rather it only took into account trends in utilisation rates in a qualitative sense.[65]

Augex model output

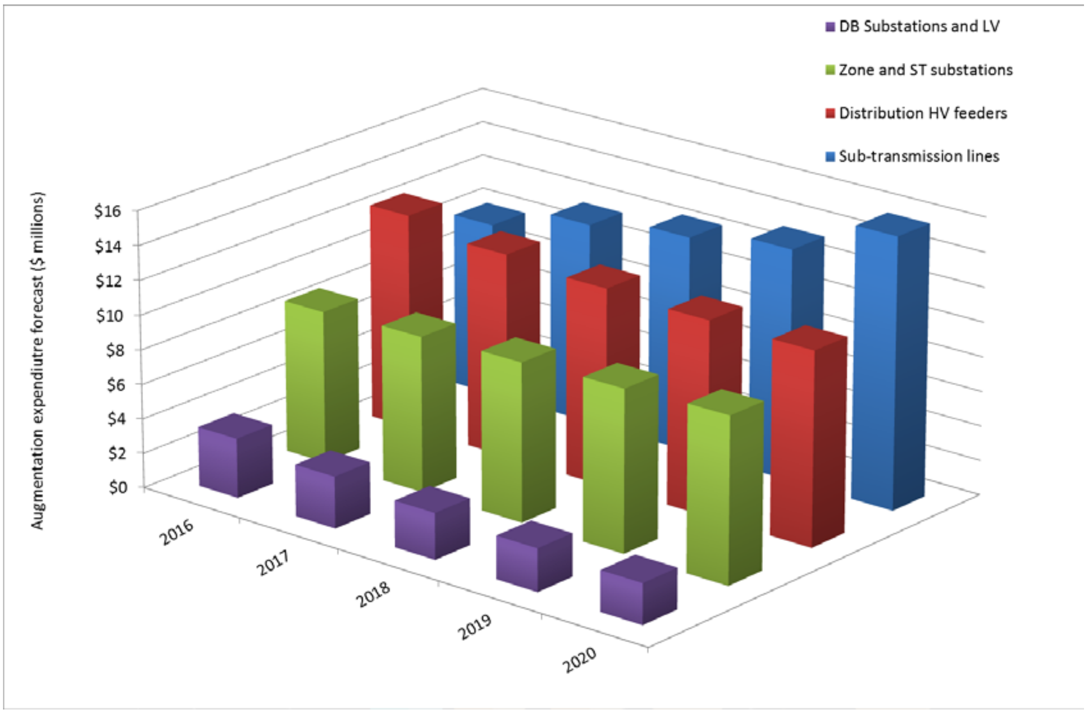
We used a consultant, Jacobs, to assist us in populating the augex model. Jacobs have prepared a report which outlines the steps that were undertaken in the model population, including how it determined the input parameters.[66] The model is sensitive to small changes in the input parameters. The outputs of the model are shown in figure 9.21.

64 AER, AER expenditure workshop no.4 slides – DNSP replacement and augmentation capex – 8 March 2013, available from https://www.aer.gov.au/node/19508.

65 For example, see AER, Draft decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure, November 2014, p. 6-35.

66 Jacobs, CitiPower AER augex modelling assistance, 25 November 2014.

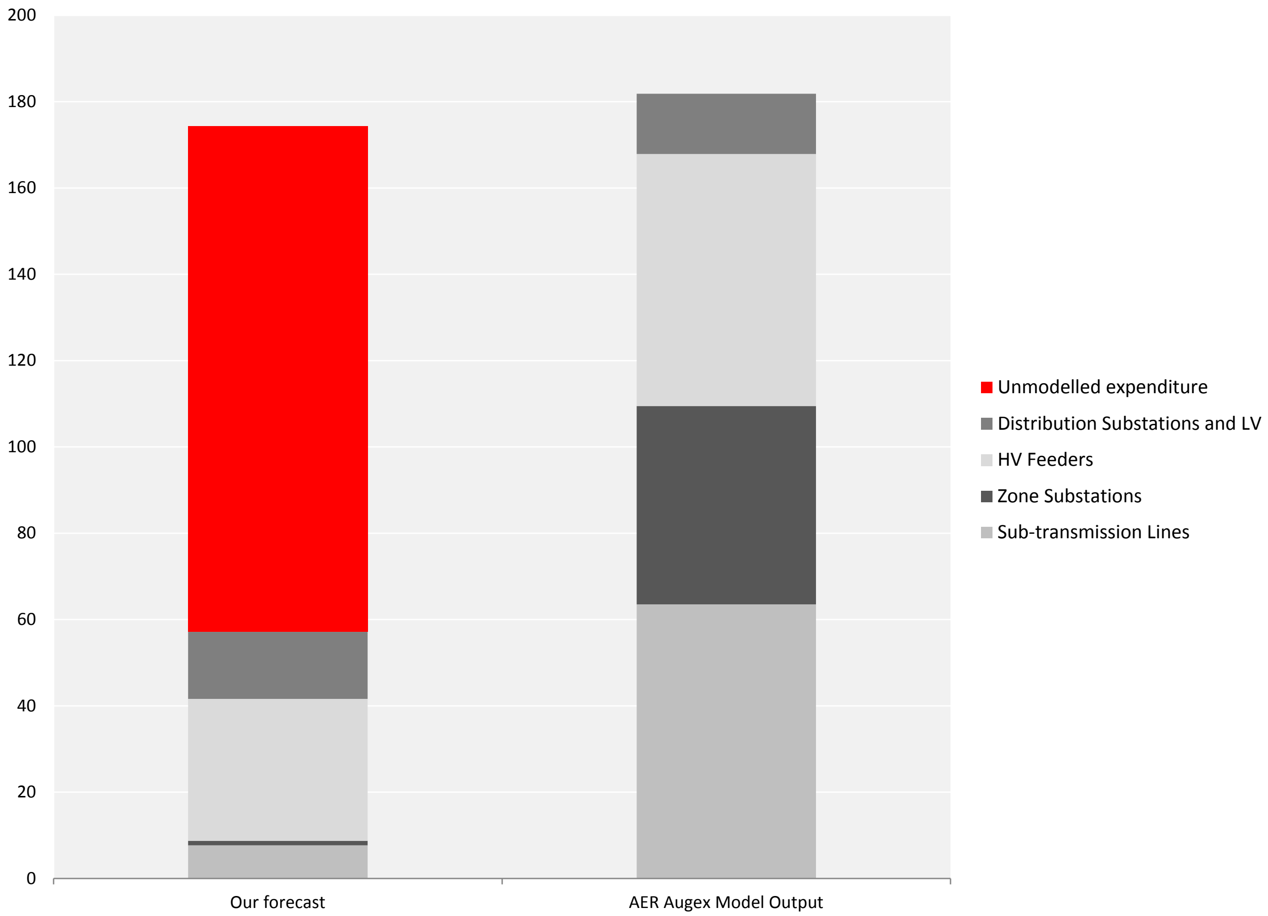
Figure 9.21 Augex model forecast output summary – annual expenditure



Source: Jacobs

The augex model forecasts a higher level of expenditure required for augmentation related works compared to our own forecasts, as shown in figure 9.22.

Figure 9.22 Comparison of our forecast to augex model forecast output ($m, real)



Source: CitiPower
Note: excludes labour escalation

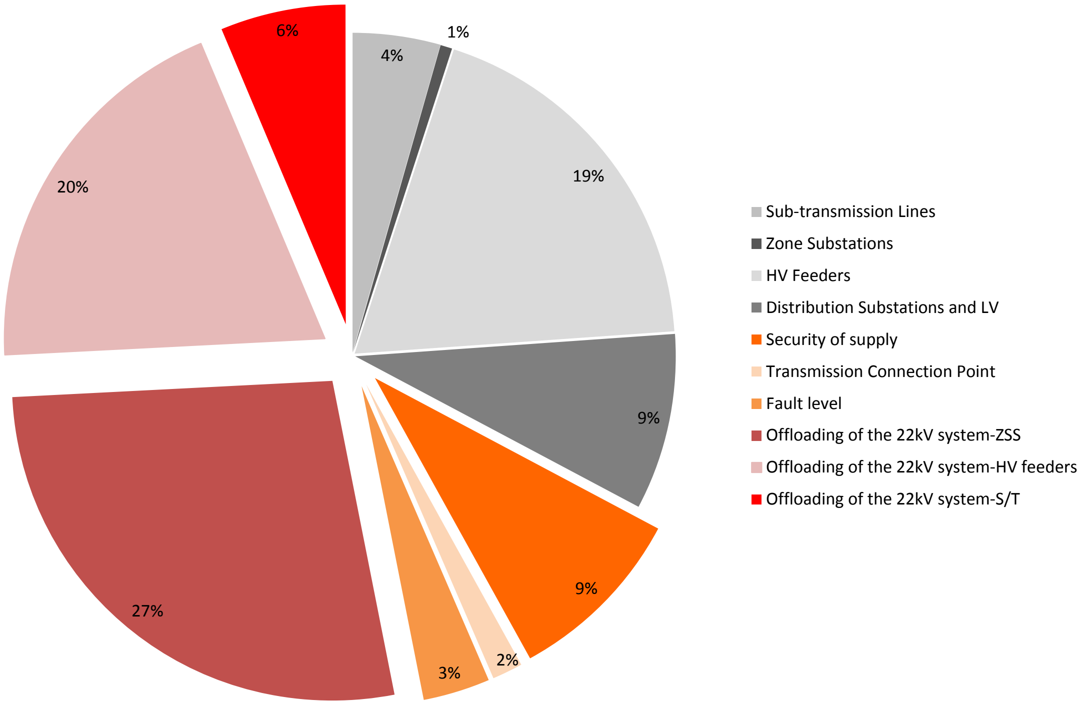
We estimate that the drivers of 33 per cent of our augmentation expenditure is covered by the AER's augex model.

The remaining 67 per cent of augmentation expenditure that is not covered by the augex model relates to:

- non-demand related augmentation works related to the decommissioning of the 22kV sub-transmission network;
- security of supply related works, including the CBD Security and Metro upgrades;
- fault level mitigation works; and
- distribution works resulting from the need to address transmission connection point constraints at Richmond and West Melbourne terminal stations, as well as Fishermens Bend terminal station.

This is shown in figure 9.23.

Figure 9.23 Our augmentation expenditure not captured by augex model



Source: Source: CitiPower

The replacement-driven works that will result in augmentation of the network have been discussed earlier in this chapter.

The augex model also does not capture the costs of works to provide new 66kV cables to connect to the upgraded 66kV connection point at BTS as the installation of these cables removes the demand constraints at the terminal station level. The augex model does not capture utilisation and demand at the terminal station level.

Additionally, the security of supply works relating to the CBD Security of Supply Upgrade Plan are not captured by the augex model.

Finally, fault level mitigation works are excluded from the augex model, as the model is not designed to cover current and forecast fault levels, only current and forecast peak demand utilisation. We will be installing new reactors at the North Richmond (**NR**) zone substation and installing a circuit breaker 'normal open – auto close' control scheme at Albert Park (**AP**) zone substation, to manage fault current levels that are approaching the allowable limits as a result of increasing levels of embedded generation

9.3.5 Synergies between augmentation and replacement

We are able to use both the Load Indices and Health Indices at zone substations to obtain an overall picture of the current load and condition of the zone substation transformers, and how this is expected to change overtime.

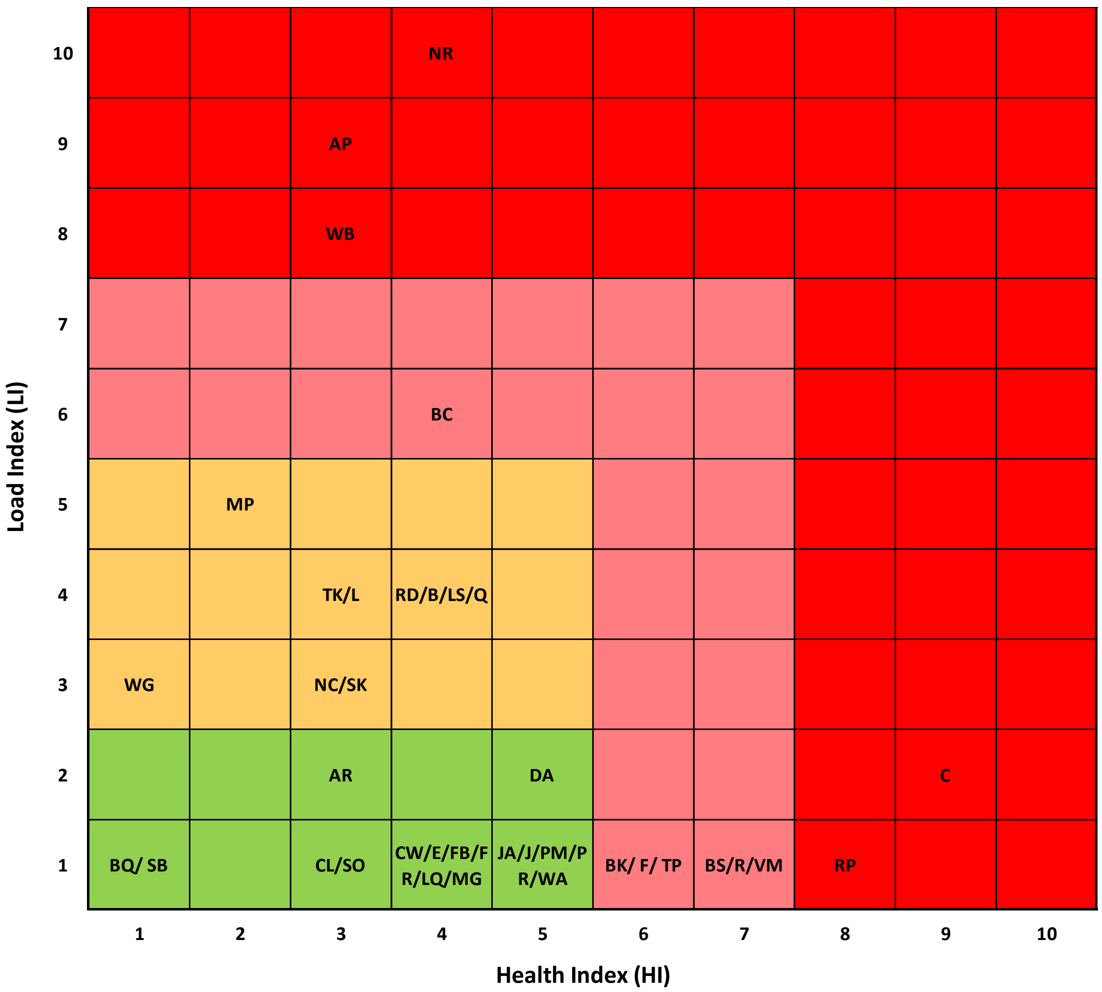
A matrix can show which zone substations have transformers that:

- have large amounts of energy at risk in peak times, and may require augmentation, with a high load index;

- are in poor health and in need of replacement, with a high health index; and
- have large amounts of energy at risk at peak times and are in poor health, with high load and health indices, where the transformers are in need of replacement with a higher capacity transformers.

The matrix in figure 9.24 shows the Load and Health Indices for each zone substation that we expect at the start of the 2016–2020 regulatory control period. This takes into account expected works during the 2015 calendar year.

Figure 9.24 Load and health indices at zone substations at start of 2016

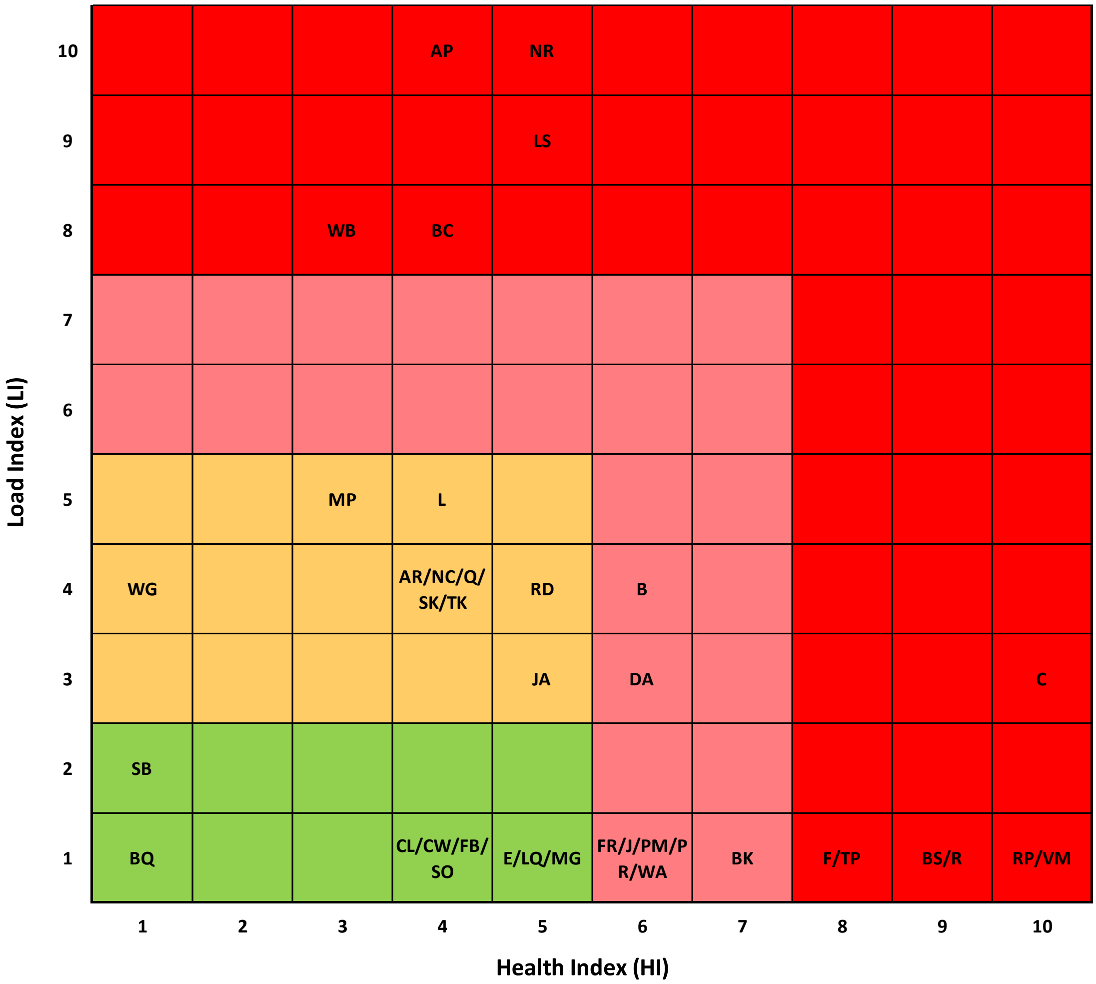


Source: CitiPower

As can be seen, we have high load index at North Richmond (**NR**), Albert Park (**AP**) and West Brunswick (**WB**) zone substations. We also have high Health Indices at the Brunswick (**C**), Russell Place (**RP**), Bouverie Street (**BS**), Richmond (**R**), and Victoria Market (**VM**) zone substations.

If we do not invest in augmentation and replacement works over the 2016–2020 regulatory control period, i.e. 'do nothing', then an increasing number of zone substations will have Load and Health Indices as shown in the matrix in figure 9.25.

Figure 9.25 Load and health indices at zone substations at the end of 2020 in the 'do nothing' scenario

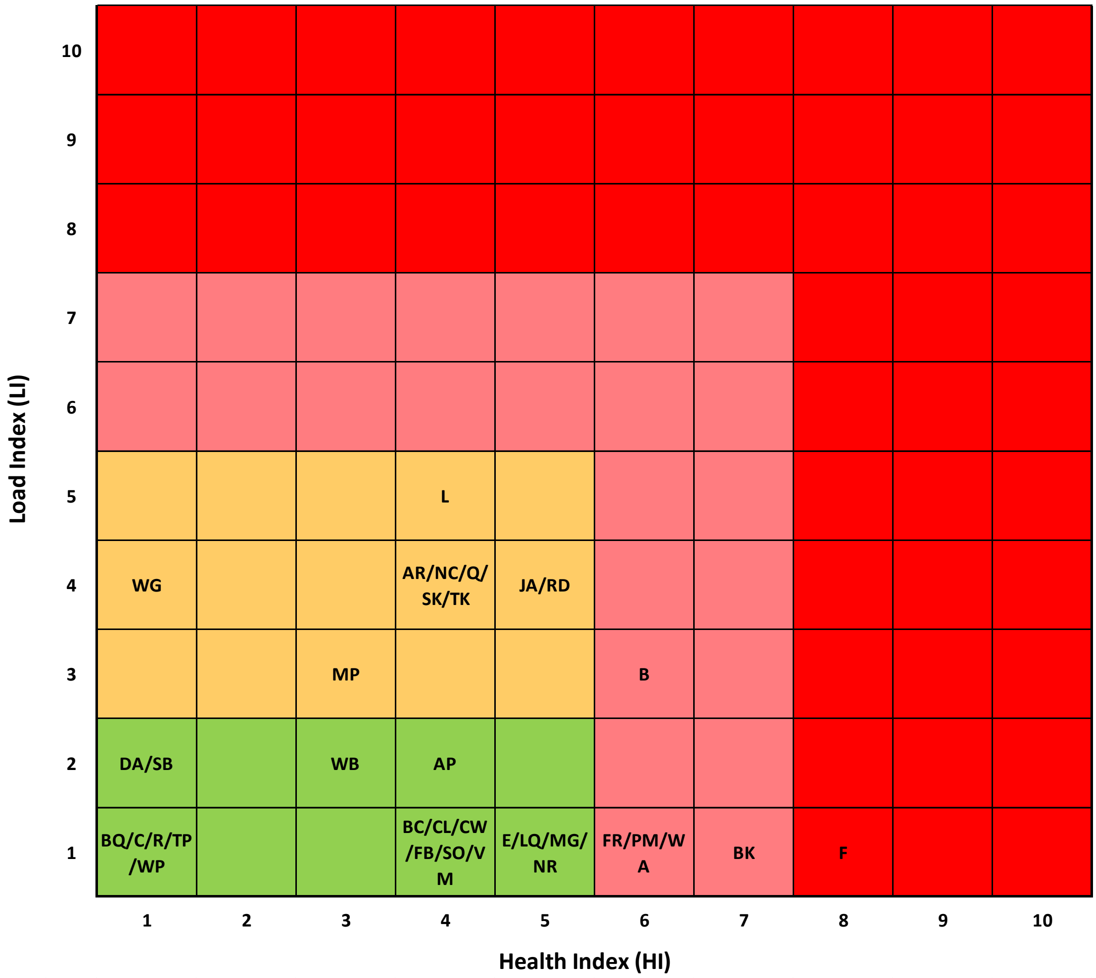


Source: CitiPower

If we do nothing, then five zone substations will have high load indices and eight zone substations will have high health indices including Brunswick (**C**), Bouverie St (**BS**), Richmond (**R**), Fitzroy (**F**), Tavistock Place (**TP**) and Brunswick (**BK**) which are all connected to our 22kV sub-transmission network. It is clear that if we do not invest, then our customers would experience a vast increase in the number of outages as our assets become overloaded and/or fail due to poor condition.

The matrix in figure 9.26 shows the Load and Health Indices for the zone substations given the expenditure contained with this regulatory proposal.

Figure 9.26 Load and health indices at zone substations at the end of 2020 with proposed expenditure



Source: CitiPower

This matrix demonstrates that our proposed expenditure will address zone substations with high health and load Indices. For example, the completion of the BTS upgrade and associated works will address the concerns at the BS, C and RP zone substations.

9.4 Connection expenditure

When customers seek to connect to our network, or change their existing connection, then we need to meet our customer's requirements.

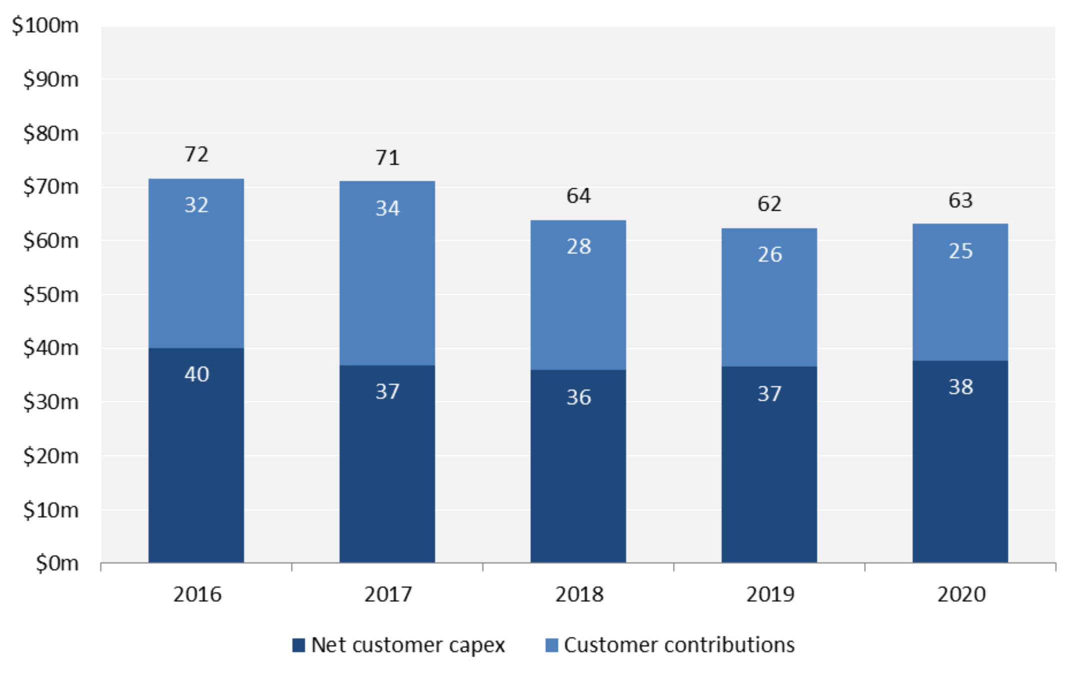
Our forecast expenditure will enable us to connect customers to our network, including to supply new residential customers, assist industrial customers in expanding their operations, and to support connection of renewable energy generators.

A significant portion of this expenditure will be directly recovered from the connecting customer via a customer contribution.

This section explains why our forecast capital expenditure for connections and customer-driven works is necessary to connect residential, commercial and industrial customers to the distribution network, as well as connections for embedded generators and customer requested relocations (i.e. recoverable works).

The profile of our forecast gross and net customer connection expenditure is shown in figure 9.27. The forecast for 2016 and 2017 is driven by specific customer connection projects.

Figure 9.27 Forecast customer connection expenditure including real escalation ($m, real)



Source: CitiPower

The difference between the gross and net customer contribution figures is as a result of customer contributions. We will receive funding directly from some customers toward their connection.

This category of expenditure is driven by customers, rather than being initiated by us. It is influenced by economic conditions and development demographics, including major projects arising from government initiatives, generation and embedded generation, changes in industrial and agricultural sectors and housing developments.

9.4.1 What we have delivered

We connected over 15,000 net additional customers to our network in the 2011-2015 regulatory control period. The majority of these connections were smaller residential connections.

We also completed some large customer connection projects and customer-driven works during that time including:

- connection for new commercial and retail precinct in Batman's Hill;
- connection for new commercial and residential high –rise developments in the Docklands area, Southbank, and Melbourne CBD;
- redevelopment of Melbourne and Olympic Parks sporting and events precinct; and

- connection for The Emporium shopping complex on Lonsdale St, Melbourne.

9.4.2 How we prepared our forecasts

We have used two different methodologies for forecasting customer connections into the AER's specified categories, depending on whether the category of connection has a high or low volume of activity.

Low volume activity

We have undertaken a bottom-up build of the expenditure for the following categories of connections where there are typically low volumes, namely:

- commercial/ industrial connections connected at high voltage (**HV**);
- embedded generation; and
- recoverable works (reported as quoted services)

For projects that cost $2.5 million or more, we have identified projects where the customer has made initial enquiries with us, or requested options for connections or a connection offer. Based upon correspondence with the customer, we have assessed that the project is highly likely to proceed and have included the connection in the forecast. The expenditure is based upon cost estimates from a supplier.

For the large number of smaller projects that cost less than $2.5 million, we have forecast the amount of expenditure for connections based on the average expenditure for non-major projects for the 2011 to 2014 period.

Customer contributions

Our process for connecting customers is set out in CitiPower's *Customer Connections Guideline*.

The majority of residential connections are routine connections where we can remotely connect the customer at the request of a retailer. However, where an overhead line, underground cable, substation, or embedded generator needs to be extended or upgraded to service new or upgraded customers, then the customer must submit an application to us, which sets out the location of the premises and an estimate of the amount of electricity required.

In response, we will provide a budget estimate or firm offer to the customer, where the customer may also have the option to select other approved contractors to complete works for contestable services.

The customer may be liable to pay a customer contribution towards the connection, where the contribution is calculated in accordance with *Electricity Industry Guidelines 14 – Provision of Services by Electricity Distributors* (**Guideline 14**).

Calculation of customer contributions

Under the *Electricity Industry Guideline No. 14,* customer contributions are calculated according to the following calculation:

CC=[IC – IR] + SF

Where:

CC is the maximum amount of the customer's capital contribution:

IC is the amount of incremental cost in relation to the connection offer;

IR is the amount of incremental revenue in relation to the connection offer;

SF is the amount of any security fee

Incremental cost (IC) is the cost of the project works including new incremental capital, operating maintenance and the costs of any works that we will incur in making the supply available to the nominated point of supply. The Incremental Cost excludes the Connection Service Fees and transmission costs.

If the applicant chooses to run their own tender and use another Recognised Contractor to complete any Contestable Services, the applicant is required to provide us with evidence detailing the total cost of these tasks. We will compare those costs against the average cost for equivalent work completed on our lines, when calculating any Incremental Cost.

Incremental revenue (IR) is the revenue that we will receive from the new connection via the distribution tariffs. Revenue is allowed at 15 years for a business connection and 30 years for a domestic connection, in accordance with the guidelines.

The value of the Customer Contribution also depends on the amount of electricity that the customer agrees to use. The amount of electricity consumption that the customer requires is used to calculate your Incremental Revenue.

Security fee (SF) is like a bond. It is the amount held by us and returned with interest, should the applicant achieve the agreed electrical revenue consumption targets.

If the customer seeking to connect an embedded generator to the grid, we have two different processes for connections:

- where the connection is in accordance with Australian Standard 4777, then the customer must seek pre-approval for the connection;
- all other connections are in accordance with the Guideline 14 or Electricity Industry Guideline 15- *Connection of Embedded Generators* (**Guideline 15**)*,* or chapter 5.3A of the Rules if the customer elects to follow the process.

We are supportive of small solar generation that can be connected with our network. However, the pre-approval process allows us to identify concentrations of solar photovoltaic (**PV**) systems on the low voltage network which can lead to power quality issues such as overvoltage and voltage unbalance.

The customer may be liable to pay a customer contribution towards the connection involving embedded generation, where the contribution is calculated in accordance with Guideline 15. Under the guidelines, embedded generators do not make any contributions for 'deep' augmentation but may contribute to 'shallow' augmentation, i.e. extension assets between generating plant and point of connection to the distribution network, and relevant connection assets required by the distributor.[67]

Our customer contribution forecasts were calculated by multiplying a calculated contribution rate by the gross connection capital expenditure for each of our internal reporting categories for connections. The contribution rates were calculated by first selecting a representative sample of 2013 customer projects for each connection category, and then updating the contribution rate to reflect changes in input parameters, such as our proposed Weighted Average Cost of Capital and X factors, as well as changes in cost.

It is noted that while customer contributions have been calculated in accordance with Guidelines 14 and 15, the forecasts would change in the event that Chapter 5A of the Rules is implemented in Victoria. The introduction of Chapter 5A would involve the transfer of Victorian responsibilities to a new national regulatory regime.

High volume activity

We have used economic forecasts for the following categories of connections which typically are associated with high volumes of activity:

- residential complex connection at LV;
- residential complex HV works connected at LV;
- commercial/ industrial HV works connected at LV; and
- subdivision.

We engaged the CIE to prepare forecasts of customer project connections for the 2015 to 2020 period. CIE established historical relationships between the historical data and economic and demographic variables for the connection categories. Using correlations and econometric modelling, CIE identified that population growth, dwelling growth and economic activity are statistically significant in explaining the number of customer connection projects.

Once the drivers were identified, CIE forecast the number of connection jobs using independent forecast data, in particular: [68]

- for gross state product (**GSP**), CIE used the forecast by the Australian Energy Market Operator (**AEMO**) that predicts that GSP will accelerate over the next few years before easing back towards more normal growth rate by the end of the 2016–2020 regulatory control period; and
- for the number of dwelling approvals, forecasts from the Victorian Department of Transport, Planning and Local Infrastructure which suggest that that the rate of development over the 2010 to 2013 period will continue in 2015 and 2016, before returning to levels more in line with the long term average.

The connection job forecasts produced by CIE were mapped to our internal reporting categories, known as function codes. These volumes were then multiplied by the unit rate in each function code to prepare the connection expenditure forecasts. The unit rate was calculated by dividing the total expenditure by the total number of jobs in each function code for the period 2011 to 2014.

Customer contributions

Customer contributions may also arise for connections in the high volume categories. The process for calculating the contributions is the same as that set out above for low volume connections.

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67 Essential Services Commission, Electricity Industry Guideline No. 15 – Connection of Embedded Generation, August 2004, clause 3.3.2(b)(1)(B).

68 CIE, Forecasting connection projects for CitiPower and Powercor, November 2014.

<u>Gifted assets</u>

Guideline 14 currently regulates connection services. In particular, it makes connection and augmentation works contestable in accordance with our licence conditions – we are required to call for tenders to construct the works from at least two other persons who otherwise compete for such works, unless the customer agrees with us that a tender is not required.[69] This means that customers can elect to use a third party Approved Contractor,[70] to undertake the connection work on 'greenfield assets'.

Where a third party provider completes the construction of a greenfield asset that it has funded, then we may acquire the asset as a 'gifted asset' once it is connected to the distribution network. We may then pay a rebate to the customer or developer for the asset, applying the principle that our contribution to the project is the same that we would have made if we had constructed the connection. This ensures competitive neutrality between us and third party providers.

The costs of the rebate are included within the proposed capital expenditure for this category. The forecasts for rebates have been calculated as the average of the actual rebates in the 2011 to 2014 period, by function code.

The gifted asset is included in the Regulatory Asset Base (**RAB**) at zero value. The asset is then maintained in accordance with our asset management policies.

9.4.3 What we plan to deliver

In addition to relocation works at the West Melbourne and Richmond terminal stations in response to redevelopment works being undertaken by the terminal station owner, AusNet Services, our expenditure forecast is driven by new developments and redevelopments in our distribution area, including:

- redevelopment of the E Gate precinct: located at gate 'E' in the rail yard area near North Melbourne railway station, Major Projects Victoria is planning a development to provide housing for up to 10,000 residents and 50,000 square metres of commercial and associated retail space;
- construction of multiple towers for mixed use residential apartments, retail and hotel development located on the former site of The Age newspaper on Spencer Street in the Melbourne CBD;
- further construction of a residential multi-storey building at the former site of CUB site in Carlton;
- redevelopment of the Batman's Hill precinct: Lend Lease will redevelop the 2.5 hectare site opposite Southern Cross station in its 'Melbourne Quarter' which will include in excess of 100,000 square meters of commercial space, approximately 600 residential apartments and 4,000 square metres of retail space;[71]
- redevelopment of the Webb Dock port to provide additional opportunities for capacity expansion of the existing terminals and create a third container facility. These works are underway and are expected to be completed in 2016;[72]
- redevelopment of the area to the east of Federation Square East: Major Projects Victoria has sought expressions of interest to redevelop 3.3 hectares of land, including land above the rail lines, as an urban renewal project;[73]

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69 Powercor also provides the customer the option of conducting the tender process themselves.

70 Eligible Approved Contracts are accredited by Powercor. Customers are required to select an accredited Approved Contractor.

71 Refer: http://www.lendlease.com/australia/projects/batmans-hill

72 Refer http://portcapacity.portofmelbourne.com/pages/past-present-future.asp

73 Refer http://www.majorprojects.vic.gov.au/project/federation-square-east/

- redevelopment of the Fishermans Bend precinct: Places Victoria has released its draft vision for the redevelopment of this area to provide homes for more than 80,000 residents and a new workplace for up to 40,000 people. This urban renewal will involve a variety of residential developments ranging from warehouse lofts, to townhouses and high rise towers, while continuing to encourage the operation of businesses;74
- redevelopment of the Montague precinct: the City Of Port Phillip is considering redeveloping the precinct to accommodate 25,000 residents, 13,000 dwellings and 14,000 workers;75 and
- redevelopment of the Arden Macaulay area: the City of Melbourne has identified the 147 hectare precinct in parts of Kensington and North Melbourne as an urban renewal area that will accommodate significantly more residents and employment growth over the next 30 years.[76]

9.5 Victorian Bushfires Royal Commission (VBRC)

The catastrophic 'Black Saturday' bushfires on 7 February 2009 were one of Australia's worst ever natural disasters.

The Victorian Bushfires Royal Commission (**VBRC**) was established to conduct an extensive investigation into the causes of, the preparation for, the response to and the impact of 15 of the most damaging, or potentially damaging, fires that burned.

The VBRC made 67 recommendations to the Victorian Government about changes needed to reduce the risk, and the consequences, of similar disasters in the future. The VBRC considered that failed electricity assets caused five of the 11 major fires that began that day, and in response eight of the recommendations proposed major changes to the State's electricity distribution infrastructure and operation management.[77]

Our proposed expenditure is to implement the recommendations of the VBRC, in accordance with obligations imposed on us by the safety regulator, Energy Safe Victoria (**ESV**). Whilst we are not located in a hazardous bushfire risk area, our network is still subject to bushfire mitigation actions mandated for low bushfire risk areas.

This section explains our forecast capital expenditure for obligations imposed on us arising from the VBRC.

The VBRC was established on 16 February 2009 to investigate the causes and responses to the bushfires which swept through parts of Victoria in late January and February 2009. The VBRC delivered its Final Report on 31 July 2010 which recommended a number of bushfire mitigation initiatives.

Our stakeholders strongly support our expenditure to minimise any potential fire or safety related risk. This view has been expressed by all of stakeholders, whether residential, small to medium enterprises or large industrial customers through a range of interfaces, including online surveys, one-on-one interviews and attendees at our public forums.

We have not had any obligations arising from the VBRC in respect to Low Bushfire Risk Areas (**LBRA**) in the current regulatory period, however we have LBRA obligations in the 2016–2020 regulatory control period. Our profile of forecast VBRC expenditure over time the period is shown in figure 9.28.

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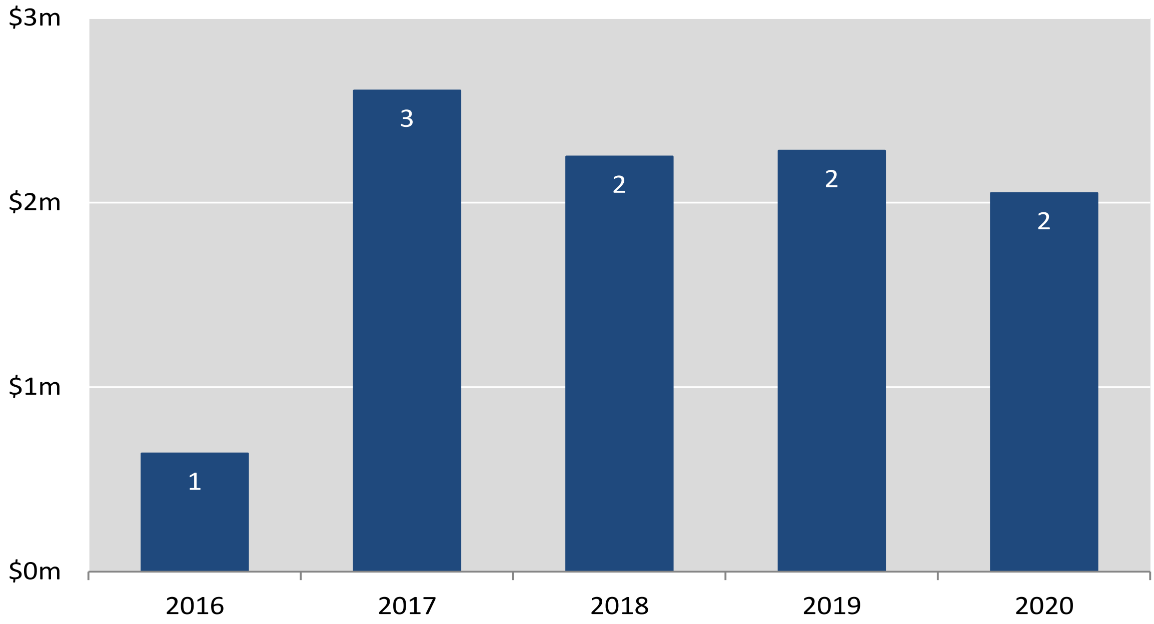
74 Refer: http://www.portphillip.vic.gov.au/Draft_Vision.pdf

75 Refer: http://www.portphillip.vic.gov.au/montague-precinct-structure-plan.htm

76 Refer http://www.melbourne.vic.gov.au/BuildingandPlanning/FutureGrowth/StructurePlans/ArdenMacaulay/Pages/Information.aspx

77 2009 Victorian Bushfires Royal Commission, *Final Report, Volume 2, Electricity-Caused Fires*, 31 July 2010, p 148. available from: http://www.royalcommission.vic.gov.au/Commission-Reports/Final-Report/Volume-2/Chapters/Electricity-Caused-Fire.html

Figure 9.28 Forecast direct VBRC expenditure including real escalation ($m, real)



Source: CitiPower

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.

9.5.1 How we prepared our forecasts

The VBRC expenditure forecast is project-based, using a bottom-up build. Based on the experiences of our sister company (Powercor) in hazardous bushfire risk areas (**HBRA**) in the current regulatory control period, we have used the cost and/or volume information from those projects in the forecasts for those same projects in LBRA.

Table 9.2 sets out the forecasting methodology for each VBRC project.

Table 9.2 VBRC forecasting methodology

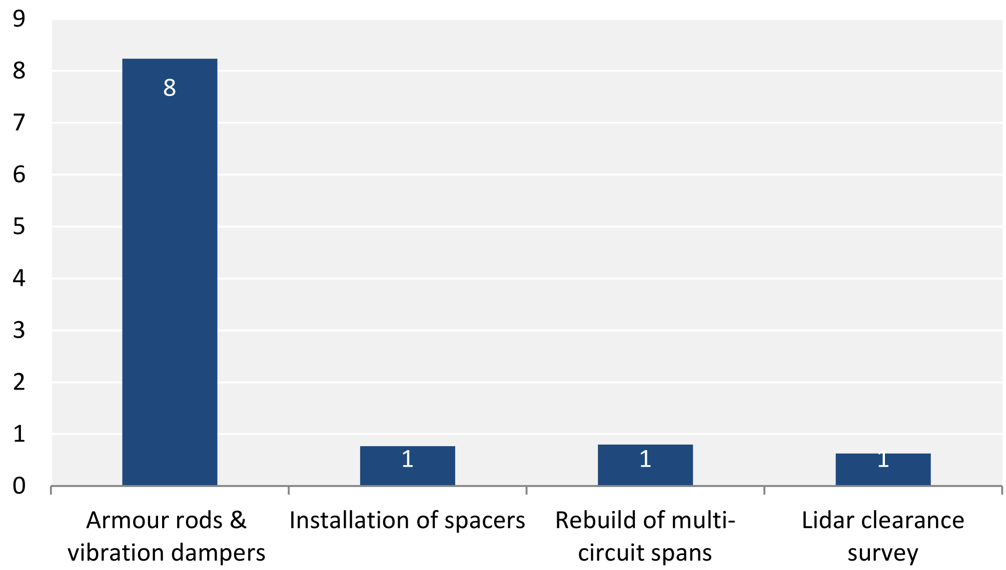
Project	Volume estimates	Cost estimates
Armour rods and vibration dampers	Based on detailed assessment of each span using our Geographic Information System (GIS)	Based upon HBRA project cost information for 22kV lines, and bottom-up build for 66kV sub-transmission lines
Survey of multi-circuit lines	GIS data	Based upon HBRA project cost information
Installation of spacers	Based on outcomes from HBRA survey	Based upon HBRA project cost information
Multi circuit re-builds	Based on outcomes from HBRA survey	Bottom-up build based on historical cost for similar projects

9.5.2 What we plan to deliver

Our forecast expenditure for VBRC relates to specific projects that we are obligated to undertake during the 2016–2020 regulatory control period.

An overview of the expenditure, by project, is shown in figure 9.29.

Figure 9.29 VBRC direct capital expenditure by program ($m, real)



Source: CitiPower

These projects are discussed below.

Armour rods and vibration dampers

We are required to install armour rods and vibration dampers in low bushfire risk areas by 1 November 2020.

Armour rods are protective devices designed to reduce wear on conductors at the contact points with insulations and conductor ties, vibration dampers are intended to reduce conductor vibration and therefore the impact of this vibration on conductors and ties.

Recommendation 33 of the VBRC which proposed that:[78]

> *The State (through Energy Safe Victoria) require distribution businesses to do the following:*
>
> - *fit spreaders to any lines with a history of clashing or the potential to do so*
> - *fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable.*

The obligation arises from subsequently issued direction by ESV issued to us on 4 January 2011 under the *Electricity Safety Act 1998*, which required us to update our Electricity Safety Management Scheme (**ESMS**) to include a program to fit armour rods and vibration dampers to certain conductors, and that the program be completed by:[79]

- in hazardous bushfire risk areas — before 1 November 2015; and
- in all other areas — before 1 November 2020.

We subsequently updated our ESMS to include the requirements of the Direction. We must comply with the revised scheme or plan as compliance is enforceable by ESV.

There are approximately 17,230 of spans in LBRA where armour rods and vibration dampers are required to be installed during the 2016–2020 regulatory control period. The figure is based on a detailed analysis of the characteristics of each span in the network using our GIS system.

The cost to install each armour rod and vibration damper is based on our sister company's (Powercor) historic average cost of installing armour rods and vibration dampers per span in HBRA, plus design and project related costs.

Survey of aerial lines and installation of spacers

We are required to survey our lines to assess whether the conductor clearances meet the minimum separation requirements set out in industry guidelines, and where they are found not to meet that level, to either reconstruct the line or install aerial spacers into the line.

The obligation arises from Recommendation 33 of the VBRC which proposed that we fit spreaders to any lines with a history of clashing or the potential to do so.

ESV issued a Direction to us on 4 January 2011 under the *Electricity Safety Act 1998* which required us to update our ESMS to:

- develop a program to identify all spans that do not comply with the minimum separation requirements set out in industry guidelines; and
- for all spans that do not comply with the minimum separation requirements, construct the spans so that they do comply or fit an aerial spacer by 1 November 2015 in HBRA and in all other areas by 1 November 2020.

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.

78 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

79 ESV, Direction under section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers, 4 January 2011.

We estimate that 330km of lines will need to be surveyed in 2016. The length of line has been assessed using the GIS system. The cost of the survey has been based on Powercor's contract rates from the HBRA survey undertaken in the current regulatory period, plus our design costs.

Additionally, we estimate that 353 spans will not comply with the minimum separation requirements in LBRA. This is based on the experience of our sister company's (Powercor) HBRA surveys assessing the compliance of the spans. The costs to install spacers on 22kV feeders have been based on our sister company's (Powercor) average costs per span incurred in the current regulatory period in HBRA.

Spans involving a 66kV sub-transmission line that do not comply with the minimum separation requirements must be rebuilt, as there is currently no spacer that can be used on such lines. The cost of rebuilding spans has been conservatively based upon the historical unit cost of replacing the cross-arm associated with the 66kV sub-transmission lines on a multi-circuit span, plus design costs. The assumption is considered conservative as a more costly pole replacement may be required.

9.6 Information technology and communications

As we move towards embracing a network of the future, information technology (**IT**) provides critical support to enable integrated digitalisation across all aspects of our operations and network.

By prudently and efficiently investing in, and managing our IT systems and infrastructure we are able to provide safe and reliable services that meets the energy needs of our customers.

IT provides critical business direction across our company, focusing on providing solutions that deliver innovative customer services through the pragmatic use of technology.

We recognise customers' need for access to energy consumption information that allows them to self- determine their energy usage practices and demand. Our aim is to provide customer services that make it easier for our customers to make informed choices through access to real time information.

Our expenditure forecasts for IT and communications support the directions and strategies of our business. We provide critical energy, metering and information services that enable the efficient and reliable delivery of energy services for our customers. Underpinning these services are Network, Asset Management, Works Management, Metering and Corporate IT services that provide the essential information to successfully operate our network.

Supporting these service levels requires a continuous investment in IT infrastructure and devices that must be proactively, prudently and efficiently managed throughout their lifecycle.

A key focus is on facilitating customer choices in an innovative and competitive energy market. This emerging market need will drive requirements for new systems, processes and capabilities over the next five years.

Long term IT planning is inherently challenging due the rapid changes in available technological solutions – hence planning in infrastructure, currency and capacity, compliance, device replacement, smarter networks, customer engagement and security have been undertaken to break the planning process into smaller streams.

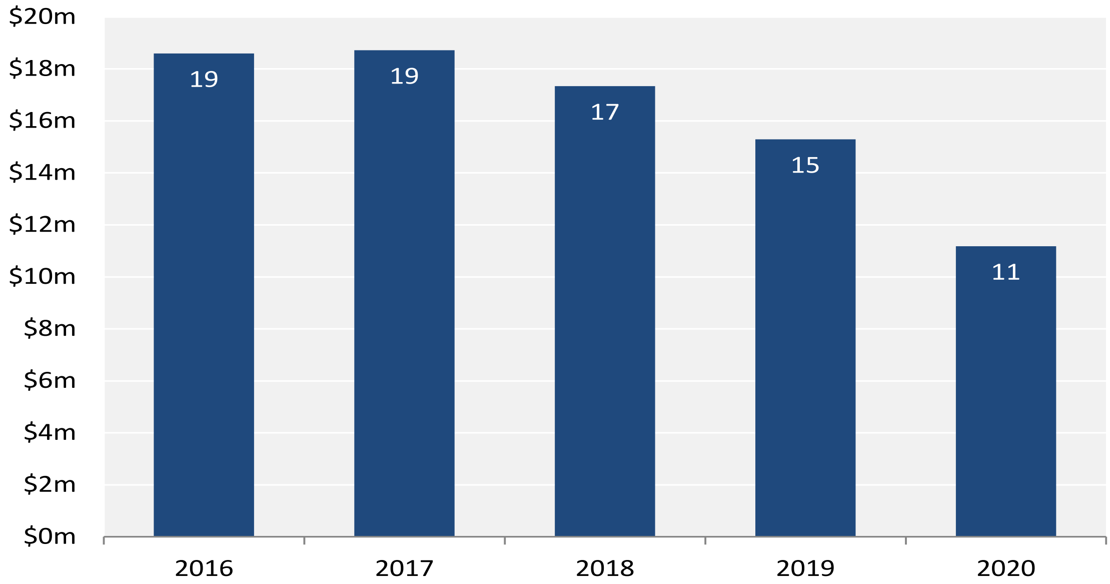
Our expenditure forecasts are driven by:

- maintaining the increasing number of IT systems to the levels required by the vendor and/or industry to ensure continued operation, support and compatibility;
- continuing the development of a smarter network by using new and existing technologies enabling more innovative and integrated self-healing network, where by notifications are automatically generated and work dispatched when a fault is detected;

- introduction of a customer relationship management (**CRM**) system and replacement of the ageing billing platform to enable the implementation of the Power of Choice reforms focused on distributors empowering customers; and
- improved security of the IT systems that support the network due to the ever increasing complexity of the converging Information and Operational Technologies required to support our distribution network.

The profile of our forecast IT and communications expenditure is shown in figure 9.30.

Figure 9.30 Forecast IT and communications expenditure including real escalation ($m, real)



Source: CitiPower

A feature of our successful IT and communications program has been a strong focus on innovation that enhances the operation of our business by empowering users and customers through seamlessly integrating digital tools, content and technology into all aspects of their day-to-day work.

The alignment between business objectives and customer engagement is required to ensure that innovative digital solutions focused on delivering value to the customer and organisation, and by working in partnership with the user community we deliver technological solutions that meet the intended need.

A key strategic focus of our IT program is to take advantage of new technologies to improve customer service, further improve network safety, innovate and optimise the use of the increasingly complex network.

We have delivered a range of innovative IT projects that have built upon the foundation of smart meter technology over the current regulatory period, and we intend to continue innovative responses to customer and business needs. An overview of our past and planned innovation is shown in figure 9.31.

Figure 9.31 Past and future IT innovation

Past innovation

- Meter outage notification (**MON**): an automated system process to make intelligent use of the outage data provided by smart meters to notify our systems used to coordinate our network response to the identified outages.
- Distribution Transformer Monitoring: providing access to Distribution Transformer interval data and customer interval data linked to a specific asset to support asset management and protection against theft.
- Remote Energisation: automated system capability that utilises the remote functionality inherent ino our smart meters to schedule and action remote energisation and de-energisation requests.

Future innovation

- Customer relationship management: capability to manage the increasing complexity of customer information provision and enable new market participants.
- Digital enablement: delivering mobile apps solutions to our user community that deliver real time information, using rapid pace design and delivery methods to meet 'here and now' consumer requirements.
- Network management optimisation: bringing together the multiple existing IT and Operating Technology (OT) systems into an integrated Smart Grid solution that will deliver flexible energy choices to our customer.

Source: CitiPower

9.6.1 What we have delivered

During the 2011 - 2015 regulatory control period we have placed a strong focus on developing the inherent capabilities of smart meters and continued a prudent investment approach into existing IT systems, applications and infrastructure. This program includes:

- data warehouse and analytics: providing a technical platform that handles high volumes of data, such as the mandated interval read volumes, in an efficient way that supports business data analysis and reporting functions.
- meter outage notification: allows for identification of customers off supply in real time, allowing us to proactively dispatch field crews to affected customers, leading to earlier outage rectification times.
- proactive voltage complaint analysis: utilises the smart meters' quality of supply (**QoS**) recording to allow improved analysis, network management and customer service. By better understanding QoS data we are able to target key areas for QoS improvement, increase the effectiveness of voltage complaint response processes and identify customers whose usage patterns affect the quality of service of their neighbourhood.
- REConnect: delivering a web-based platform to increase the efficiency of planned works, such as new connection and meter additions and alterations. The REConnect portal provides Registered Electrical contractors (**RECs**) and Retailers with the functionality to lodge requests within our network, and the ability

to upload the appropriate associated documentation (i.e. Certificate of Electrical Safety or Solar Photovoltaic forms and any other associated documentation). The platform also allows for automation of backend support processes and provides 24 hour visibility to users on the associated jobs status and provides notifications via SMS and/or email at defined process milestones.

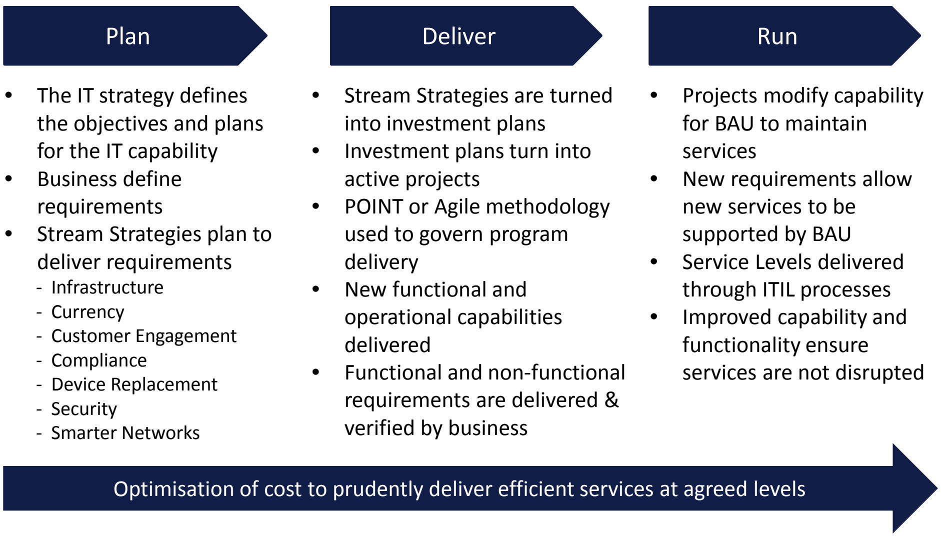
- remote energisation: automated functionality that provides remote energisation and de-energisation services to customers by leveraging smart meter infrastructure to deliver remote capability to Retailers and their customers. Automated system functionality was developed to schedule and action remote requests in line with regulatory timeframes and customer expectations, as well as ensuring work is completed within industry and business safety standards.
- home area networks/ in home displays: delivered trial smart meter capabilities that allow customers to bind an in-home display unit to our smart meters via the establishment of an authorised home area network (**HAN**).

9.6.2 How we prepared our forecasts

To maintain service levels and deliver future business requirements, a disciplined investment prioritisation process was used to identify core planning streams to ensure all aspects of our service composition were considered.

The IT Service Delivery Model turns strategies and plans to programs of work to prudently ensure business-as - usual (**BAU**) service levels can be maintained in the future at an efficient cost. These IT services are directly related to delivering energy, meeting regulatory compliance obligations and performance service levels expected by our customers.

Figure 9.32 IT Strategic Planning Framework



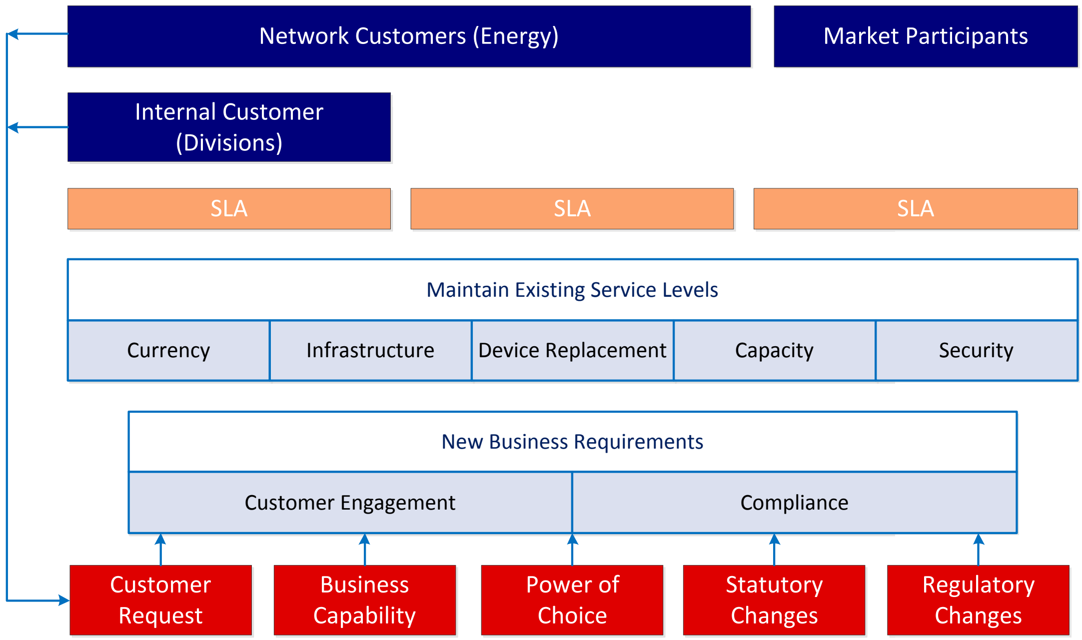
Source: CitiPower

In this planning process, new business requirements are requested as a result of external or internal needs, and adjustments are made to the investment plan to cater for new requirements whilst ensuring the BAU service levels can be maintained.

The strategic planning process identified a number of requirements that drive increased IT capital expenditure in the next regulatory period including:

- currency and capacity requirements to cater for the increased storage of interval meter data and subsequent back-up requirements;
- security requirements to monitor, manage and mitigate cyber-security threats for critical infrastructure in an increasingly hostile cyber-security environment;
- improved technology and enabling systems to enable smarter network innovative solutions to maintain customer reliability and service standards;
- compliance requirements related systems changes required to meet regulatory, legal and market compliance and the provision of actual data in response to the Request for Information Notices (**RIN**) obligations;
- customer relationship management and billing requirements driven by Power of Choice Rule changes and the implementation of time of use tariffs; and
- increasing complexity of the operating environment including multiple Financially Responsible Market Participants (**FRMPS**), Power of Choice, metering contestability and the entry of new market participants requiring the exchange of customer and network data for provision of services.

Figure 9.33 Investment stream planning supports internal and external customers



Source: CitiPower

We have undertaken a robust bottom-up build of all forecast IT costs based on individual projects or programs. The projects/programs have been identified through an iterative process which involved:

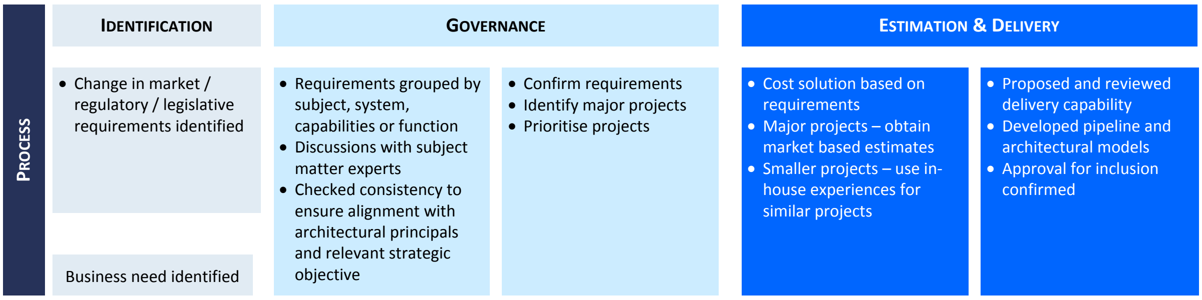
- gathering information on 2016–2020 directions and strategies from within the business, identifying projects that address these needs and requirements;
- analysing IT and energy industry trends and forecasts to assist with identifying possible business needs, this includes varying internal and external support models, cloud and purchase models;
- understanding and prospective Regulatory and Legislative changes;
- evaluating proposals and ideas to ensure they:

- align with business and IT strategic directions;
- are prudent and efficient ;
- the business and IT have the capability and delivery models in place to effectively resource the delivery and implementation of the required project/program; and
- align to a high level assessment of technology/product maturity/market readiness.

Robust cost estimates have been sourced from:

- market based outcomes from competitive tender processes;
- historical tender processes or similar projects;
- estimated data obtained from contractors or vendors; or
- actual historical costs for similar projects.

Figure 9.34 Requirements identification and costing process



Source: CitiPower

9.6.3 What we plan to deliver

Through our review of the strategic planning process, we identified a number of requirements that we must undertake during the 2016–2020 regulatory control period. Each of these requirements is discussed below.

Currency and capacity

The currency and capacity stream objective is to ensure agreed service levels are maintained via contractual support agreements, current software versions and proactive capacity planning. The programs in this stream aim to have solutions and core software within vendor support and within acceptable and consistent versions whilst maintaining adequate capacity to meet current and future business requirements.

The capacity management process proactively ensures that business needs and service definitions are fulfilled using a minimum of computing resources. To determine the capacity plan, planning activities relating to resource utilisation, demand management, infrastructure performance, application sizing and storage capacity were undertaken. From these planning processes, significant infrastructure capacity projects were allocated to the infrastructure steam with remaining projects allocated to this stream to progress.

The currency program reviewed software assets to ensure fully supported systems deliver agreed service levels and new business requirements for the investment period. To develop the currency program, activities were undertaken including a software asset register review, vendor roadmap review, options analysis, business scan of future requirements. A prioritisation process was then undertaken to determine the timing and priority of currency programs and costs estimated.

The currency and capacity program includes the following investment drivers:

- upgrade: upgrade software to current version via manufacturers recommended upgrade path.
- refresh: re-implement solution with identical, upgrades or alternative software to provide continuing business functionality.
- enhance: provide enhancement to solution software to ensure existing systems meet current business requirements.
- replace: replace solution software with alternative solution to provide business functionality on current platform.
- growth: provide additional capacity to ensure service levels are not jeopardised.

Program timing is then allocated to ensure no service interruption is incurred outside of agreed service levels.

Compliance

The compliance stream objective is to ensure financial, regulatory, statutory, market and legal compliance are maintained via implementation of new capability in a timely manner. The ability to meet compliance obligations is directly impacted by the capability of our systems, processes and analytics to deliver services and information when required by the relevant law or regulation change.

The scope of this stream includes meeting compliance obligations in a timely manner taking into consideration development and implementation timelines for each of the obligations. The core components of the compliance stream include:

- financial compliance: updates to the financial system, cost models and finance modules to ensure statutory compliance with taxation and accounting standards;
- regulatory compliance: updates to systems, data models, reporting and analytics to ensure compliance with regulatory reporting obligations and Rule requirements;
- statutory compliance: changes to systems and processes to ensure compliance with all current and future legal obligations;
- supporting system compliance: updates to supporting systems such as safety, human resources, payroll to ensure compliance with National, State and local obligations; and
- regulatory information notice (**RIN**): preparation and maintenance of information for provision to the AER relating to all RINs. Fundamental system and business process changes are required to meet the AER requirement of providing actual information for the RINs, and to improve and automate the reporting for all RINs.

  This undertaking will take time and require manual transitional solutions in the interim. In addition to annual performance and F factor reporting and price reset data provision, a change in compliance requirements in this period is the annual Economic Benchmarking and Category Analysis RIN reporting requirement. This obligation focuses on relative efficiency in providing service for previous 12 months and assesses benchmark operating and capital expenditure that would be incurred by an efficient distributor. A challenge being worked though is the provision of actuals data rather than estimates within all RIN reporting, company-wide.

Based on historical experience, the legal and statutory changes that occur in the external environment require an ongoing compliance readiness investment to ensure changes are in place when legally required. This ongoing program of work is required to ensure best endeavour attempt is made to implement solutions to meet compliance obligations or implement workarounds in the interim.

Device replacement

The device replacement stream's goal is to optimise the investment in end user devices to enable workforce productivity whilst optimising cost and performance. Investment in refreshing the end user devices maintains employee and workforce productivity and performance as the gateway to all corporate systems.

The scope of the device replacement stream includes all end user devices (**EUDs**) and human machine interfaces (**HMIs**), incorporating workstations, desktops, notebooks, printers and plotters as follows:

- desktops: optimising the replacement cycle of desktops and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of desktops to move the user to device ratio closer to 1:1, as well as using bulk purchasing procurement processes to lower costs;
- notebooks: optimising the replacement cycle of notebooks and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of laptops as a result of the increased use of mobility devices, as well as the use of bulk purchasing procurement processes to lower costs;
- printers: optimising the replacement cycle of printers to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point;
- plotters: optimising the replacement cycle of plotters to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point.
- workstations: optimising the replacement cycle of occupation specific workstations such as Control Room Operators to balance performance, reliability and cost. Replacement of specialist occupation specific workstations will be undertaken in accordance with the replacement cycle with individual business requirements defining the specification and performance levels required to be achieved (e.g. control room workstations running the Distribution Management System (**DMS**)/ Outage Management Systems (**OMS**) and SCADA).

Principles used to guide investment decisions in this stream include:

- replacement decisions will be made on the long term business needs of the organisation rather than individual needs;
- overall business considerations will be considered alongside technology considerations;
- enterprise purchasing will be leveraged to maximise bulk purchasing discounts; and
- best practice will be adopted such as standard image, standard device, support and maintenance.

Smarter networks

The smarter networks stream will continue to enable 'Networks for the Future' through targeted investment in technologies that maintain and improve customer service standards and enable new services.

Capgemini has prepared a roadmap to help us move to a smarter grid to integrate and control every aspect of the network.[80] The roadmap sets out the required investment in energy network related systems to enable improved network management and delivery of new services to customers. This leverages from the investments that we have made to-date and builds smart network capabilities in three areas:

[80] Capgemini, Networks for the future – ICT roadmap, December 2014.

- network management optimisation: the aim of this initiative is to optimise the current multiple existing IT/OT systems that need to be integrated into the smart grid solution. This initiative will deliver efficiencies and benefits by converging business resources, processes and IT systems across our network;
- smart analytics: this initiative is focused on managing the 'explosion of data', which is a consequence of the smart meter implementation. In order to make the grid smarter, this stream will undertake a number of programs to collect, process, store and exploit this data; and
- network innovation: the network innovation initiative is focused in the technology innovation that can help deliver benefits to customers by enhancing efficiency in network operations.

Building a 'Networks for the Future' is a key strategic business objective in empowering customer choice. The smarter grid will change the way that the business generates data, presents information, makes decisions, executes work and relates to customers. Amongst a number of factors continuing to impact the energy sector shifting energy production and consumption, one of the strongest drivers is customer choice. The smarter grid transformation is a long journey from the traditional (analogue world) to a smart grid (an intelligent and responsive network) where information and data flows enable service providers to support the choices that customers make.

Customer engagement

The customer engagement stream will implement a new CRM capability and flexible billing system through a program of work that will replace the current CIS OV Billing System and provide customers greater access to their energy information allowing them to make informed choices.

A CRM and a flexible billing system are required to manage the increasing complexity of the direct customer relationship and emerging customer billing requirements. The scope of this stream includes system integration, reporting capability and data migration.

Anticipated industry and regulatory change will have significant implications for billing and customer management functions[81].

Market forces are shifting the traditional linear energy supply chain to a contemporary model where consumers become producers (i.e. prosumers) and distributors become enablers of energy solutions. In response to these industry forces, energy market and industry changes are being progressed by regulators to increase innovative participation by customers in the market. The current billing system cannot meet emerging market requirements and will require significant modification on a high risk outdated platform.

The primary drivers of the customer engagement are:

- effective response to the changing energy market requiring customer intelligence capability to more effectively engage and influence customer behaviour;
- enable the implementation of flexible, innovative and dynamic tariffs which require a modern billing system that can evolve with the industry;
- enable customer access to energy data and encourage informed consumer choice and participation;
- customer enablement initiatives: develop a suite of customer enablement capabilities that leverage the information and functionality that are provided through the implementation of a CRM and flexible billing solution.

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81 Deloitte Access Economics, CitiPower and Powercor- Investing in a new billing and customer relationship management system, December 2014, p. 10.

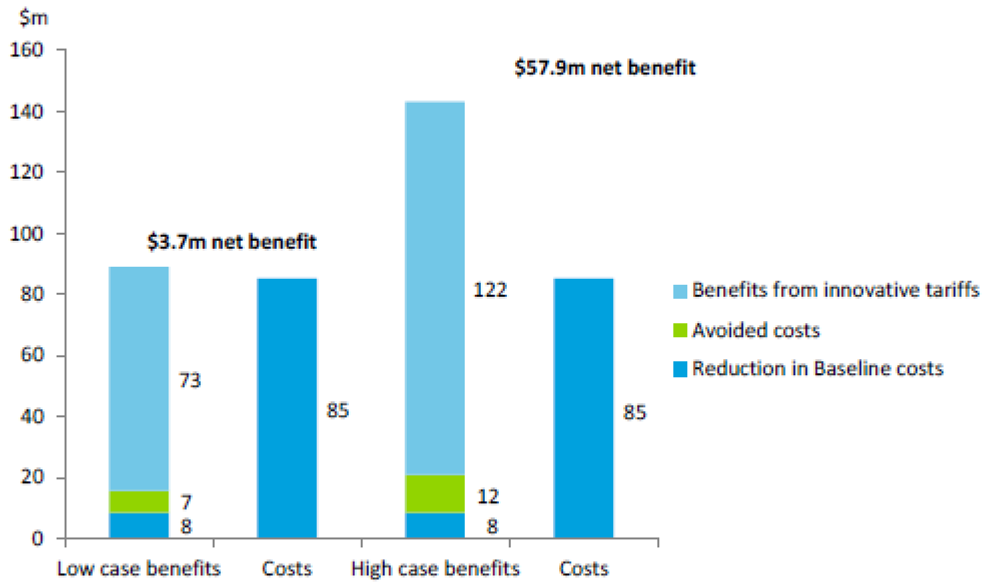
- the complexity of customer interactions as the market evolves will become increasingly challenging, driving the need to move from National Meter Identifier (**NMI**) centric engagement to full understanding of who our customer is; and
- the business is carrying a significant obsolescence risk in the current billing system solution that is increasing over time as the changing market demands more of it.

We engaged Capgemini to undertake a scan of the CRM and billing systems in the market that would meet our current customer requirements, as well as the prospective future regulatory and market changes.[82]

In addition, Deloitte Access Economics (**DAE**) has identified and calculated the benefits to customers of a new billing and CRM system and compared it to the Capgemini costs. Customers will benefit from our investment in a new system as a result of:

- the ability for us to implement new tariff options that help lower peak demand and thus reduce network investment;
- costs that we would avoid from upgrading the existing system; and
- reducing the costs to operate the existing system.

Figure 9.35 Net economic benefit from investing in a new customer relationship management and billing system



Source: DAE, Investing in a new billing and customer relationship management system, 16 December 2014, p. 4.

Overall, DAE found the there is a net benefit to customers of between $3.7 million and $57.9 million if we invest in a new CRM and billing system.

Security

Energy distribution is critical infrastructure that is potentially subject to a high risk of attack. Therefore, prudent investment in security measures is considered essential. To ensure that the availability of our distribution

82 Capgemini, CRM and Billing Market Scan – Final Report, 27 June 2014.

network is assured and that our customers continue to receive a reliable distribution of controlled power, cyber-security threats need to be monitored, managed and mitigated.[83]

Ernst & Young undertook an audit to examine the adequacy of key policies, procedures and processes governing the SCADA IT operations. Weaknesses in our security were identified and an action plan established to address the findings.

In addition, CSC were engaged to conduct an Enterprise Security Roadmap assessment of our information security practices using the ISO standard. They identified a significant number of security improvement projects across all of our IT systems.

Key decisions in the security stream have been based on robust analysis and independent opinion on areas of focus in each of the security work stream areas to address:

- increased focus on external threats based on international trends;
- heightened alert based on increasing cyber terrorism to critical infrastructure over the past decade;
- continued focus on financial fraud attempts to maintain diligence;
- focus on developing internal capability on security to minimise risk;
- cover all security domains as a part of investment spread; and
- up front focus on ‘Protect’ and ‘Detect’ within the period.

Deloitte has, on our behalf, developed a program of IT security initiatives consisting of five work streams based on best practice which aim to extend and maintain today’s IT security capability: identify, detect, monitor, protect and govern.

[83] CitiPower and Powercor, Information Security Business Case, January 2015, p. 4.

Figure 9.36 IT Security Capability Lifecycle

Source: Information Security Business Case, January 2015.

Investment in ensuring unauthorised access is prevented and the capability to detect cyber security threats in a timely manner is prudent and critical to ensuring energy network protection. Monitoring threats to determine the actions required and deploying protection capabilities to contain the impact of identified threats are fundamental capabilities required to protect our energy networks. Investment in the toolsets and processes to effectively govern information security ensures robust and best practice processes are in place.

Infrastructure

The infrastructure stream objective is to prudently optimise asset lifecycles of physical infrastructure assets to ensure agreed service levels are maintained at the lowest cost. The scope of the stream includes servers, storage, data centre infrastructure, Local and Wide Area Network infrastructure (**LAN/WAN**) and backup facilities as follows:

- servers: manage the lifecycle of both SCADA and Corporate servers including both Windows and UNIX, including hardware and associated server software;
- storage: manage the lifecycle of Storage Area Network infrastructure, including switch, array and associated infrastructure. This component also includes storage capacity for growth;
- data centre infrastructure: manage to the lifecycle of data centre infrastructure, including data warehouse hardware and associated equipment;
- LAN/WAN: manage the lifecycle of LAN/WAN infrastructure including switch, router and associated equipment; and
- backup: manage the lifecycle of backup infrastructure including replacement, refresh and growth.

9.7 Non-network expenditure

Non-network expenditure is necessary to support our network operations, such as having the Elevated Work Platforms or 'cherry-pickers' available and in good working order so that our crews are able to use them to help restore service to our customers quickly in the event of an outage.

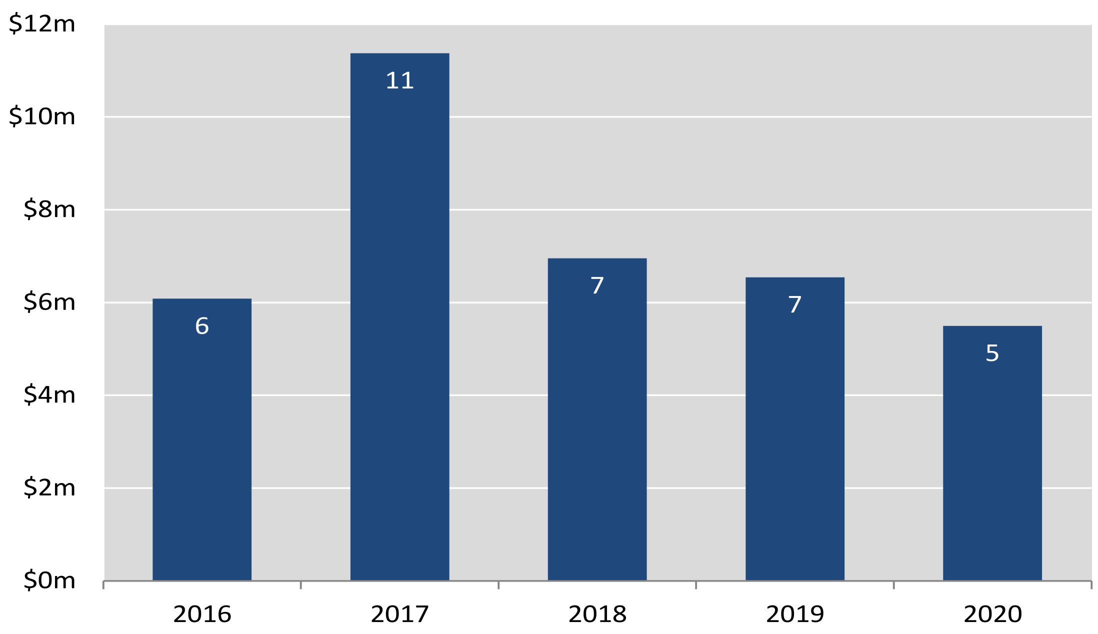
This section explains our forecasts for non-network capital expenditure, which is required to support our network operations.

Non-network capital expenditure includes the following cost categories:

- motor vehicles: relates to the purchase, replacement or rebuild costs associated with our light and heavy fleet of vehicles;
- property: relates to the provision of office and depot accommodation and buildings;
- supervisory control and data acquisition (**SCADA**): relates to the costs for SCADA and associated network communication and control equipment that are used to monitor and control the distribution network assets, including zone substations and feeders;
- other: includes equity raising costs, general equipment such as miscellaneous tools and equipment.

The profile of our forecast non-network expenditure is shown in figure 9.37.

Figure 9.37 Non-network forecast capital expenditure including real escalation, excluding equity raising costs ($m, real)



Source: CitiPower

9.7.1 What we have delivered

In the 2011–2015 regulatory control period, we have undertaken a range of activities including:

- deployment of Ethernet technology into 26 zone substations as part of our strategy to replace unsupported communications technologies in our SCADA network;

- further deployment of fibre infrastructure across our network, as well as sharing fibre infrastructure with other Victorian distributors or entering shared use agreements with fibre optic cable owners in particular cases;
- replacement of motor vehicles in accordance with our replacement cycle as well as the purchase of new fleet where necessary to support our operational requirements; and
- upgrade of our fleet to address changes in safety and compliance as required by Australian Standards or Australian Design Rules.

9.7.2 How we prepared our forecasts

This section explains the drivers and forecasting methodology for each non-network expenditure category.

SCADA

To continue to maintain the protection and control of the network, further investment in SCADA is required to deploy communication infrastructure and up to date technology to:

- address technical obsolescence;
- address new requirements; and
- ensure compliance with relevant standards.

The SCADA category captures field devices such as remote control switches and Ethernet communications devices, as well as the fibre optic cable to connect these devices with the control room.

SCADA expenditure has been forecast using a bottom-up build of requirements. This forecasting methodology is consistent with other categories of network-related expenditure, and takes into account the changing communication technologies and equipment, and the capability required by the network now and for the future.

The costs for SCADA related projects have been based on actual historical costs for similar projects.

Motor vehicles

The fleet comprises light or passenger fleet such as cars and utility vehicles, as well as heavy or commercial fleet, for example, cranes, elevated working platforms, trailers, crane borer and fork lifts. Our fleet expenditure is driven by:

- replacement cycle and condition of existing motor vehicles;
- new fleet associated with employee growth or network-related programs of work; and
- compliance with legislation and standards as they apply to varying categories of fleet.

We have used the average expenditure from 2011 to 2014 to forecast our requirements for fleet in the 2016–2020 regulatory control period.

We consider this to be an appropriate methodology for forecasting this expenditure category. While there can be year-on-year variability, taking the average over a period of four years smooths out the impact of the peaks and troughs.

Property

Property costs are driven by the need to maintain, refurbish or build new office and depot accommodation, buildings and property.

This expenditure category excludes zone substations, distribution substations and easement costs, where capital costs for those assets is captured in the augmentation or replacement categories.

For this category. we have undertaken a bottom-up build of the expenditure requirements at our only depot.

Other

These costs relate to the costs of raising equity financing, and other non-network capital expenditure such as general equipment. We have used the average expenditure from 2011 to 2014 to forecast our requirements in the 2016–2020 regulatory control period with the exception of equity raising costs, which have been forecast using the methodology set out in the AER’s Post Tax Revenue Model (**PTRM**).

9.7.3 What we plan to deliver

Our forecasts for SCADA, motor vehicles and property are discussed below.

SCADA

We forecast SCADA costs to be the largest category of non-network expenditure. Our forecasts have been informed by our strategy to develop our network communications over the longer term, and therefore an increase in expenditure is required compared to our expenditure during the 2011–2015 regulatory control period

UXC Consulting undertook a review of the methods and processes that we used in 2012 and developed a strategy for the best way forward to develop the communications network over the longer term. The review found, among other things, that we currently use a significant amount of older communications technology, and that some elements within the communications network will need to be upgraded to enable support of SCADA Distributed Network Protocol (Level 3) (**DNP3.0**).[84]

As a result, our expenditure forecast for SCADA is based on the ongoing move to Ethernet technology and replacing the unsupported technologies such as analogue radio networks and analogue supervisory cable systems over the 2016–2020 regulatory control period.

This will also assist in our move towards a ‘smarter grid’ with two-way, real-time communications to optimise the management of the increasingly complex network mix of consumption/ generation, to improve our service to customers.

Motor vehicles

We purchase, rather than lease, motor vehicles. We have determined this to be most efficient method of sourcing vehicles following an internal review of our procurement strategy.

Motor vehicle expenditure is forecast to be our second largest category of non-network expenditure. Our forecast for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. This expenditure will allow us to acquire, replace or rebuild our light and heavy fleet of vehicles and comply with the changes in safety and compliance obligations.

Property

Our property forecast for the 2016–2020 regulatory control period reflects a bottom-up build of the expenditure requirements at our sole depot in Rooney St, Richmond. The ageing buildings at the depot require modernisation to ensure occupational health and safety requirements are maintained, and to provide a safe and productive work environment for staff.

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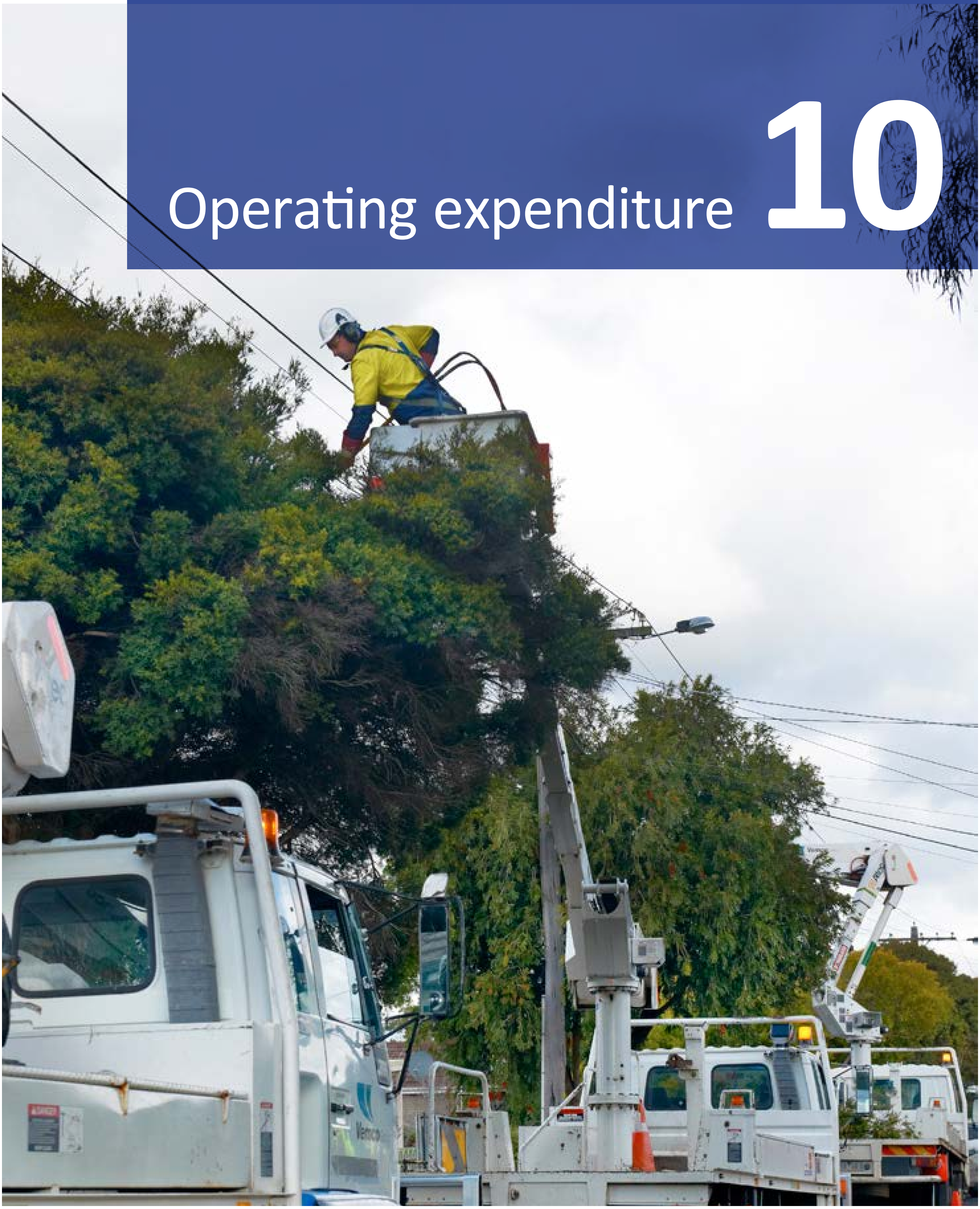
[84] UXC Consulting, Distribution Network Communications Strategy CitiPower– Powercor, December 2012.

Prior to the building being used by for electricity purposes, the site was used as a tannery and then to manufacturer industrial chemicals and water purification equipment, which has left an ongoing soil and groundwater contamination legacy that we have been actively managing. However, as the refurbishment will require disturbance of the soil, the latent environmental matters must be addressed.

Operating expenditure 10



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10. Operating expenditure

This chapter outlines our operating expenditure forecast for standard control services for the 2016–2020 regulatory control period.

Our operating expenditure forecast reflects the amount we require to meet the operating expenditure objectives, as set out in the National Electricity Rules (**Rules**).[85] This includes expenditure to meet and manage the expected demand for standard control services over the 2016–2020 regulatory control period, comply with all applicable regulatory obligations and ensure our distribution system, and network, connection and metering services, meet relevant quality, reliability, safety and security of supply standards.

The key points of our proposed operating expenditure forecast are set out below.

We are one of the most efficient distributors in Australia

Benchmarking studies show we are one of the most efficient distribution networks in Australia. This includes benchmarking at a total operating expenditure level, as well as in disaggregated categories such as vegetation management and non-network services.

Our performance relative to other Australian electricity distribution networks is discussed in chapter 5.

We continually aim to deliver efficiency improvements both to our shareholders and customers

The regulatory framework, including the range of incentive schemes applied by the AER, provides continuous incentives to seek efficiency improvements while maintaining service standards. We also have obligations as a private company to deliver efficiency improvements to our shareholders. As one of the lowest cost distributors in Australia, we have demonstrated a positive response to these incentives.

We operate in an ever changing environment

The economic and network conditions in the 2016–2020 regulatory control period are expected to differ from the economic and network conditions experienced in the 2011–2015 regulatory control period. Our operating expenditure forecast, therefore, reflects expected changes in input prices, as well as the impact of our evolving network.

We need to keep our network safe and reliable, and comply with our obligations

Safety and reliability are critical to the operation of our network. Our operating expenditure forecast reflects the need to comply with our regulatory and legislative obligations in a prudent and efficient manner. This includes responding to changes in our operating environment that are beyond our control.

We are responsive to customer needs through our ongoing customer engagement program

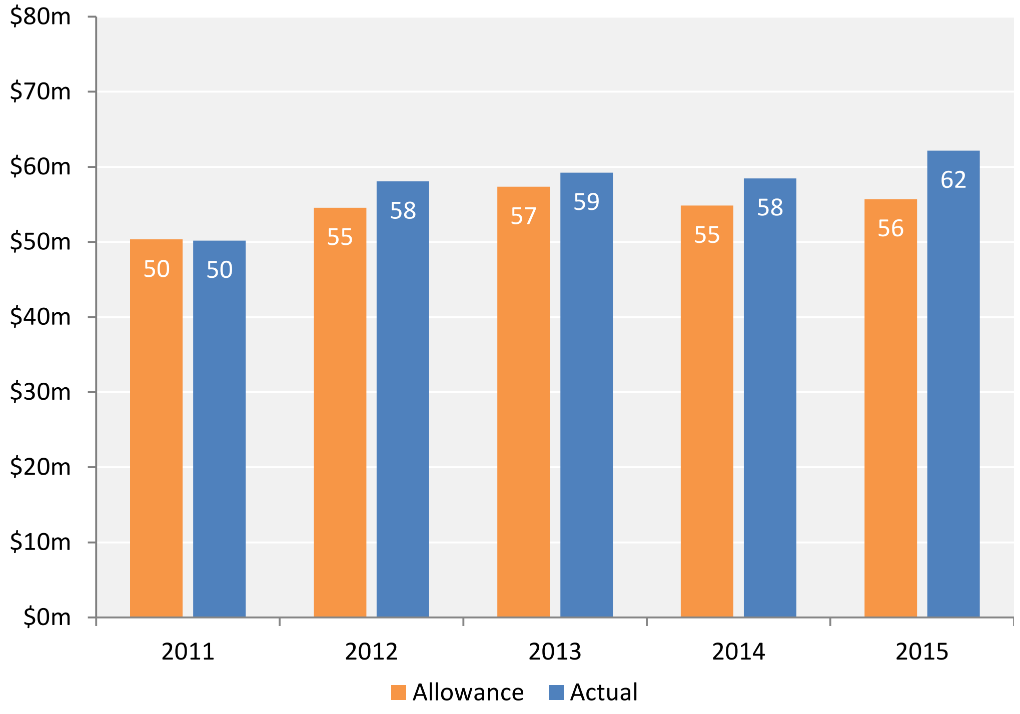
Ongoing stakeholder engagement allows our network to more effectively service the diverse needs of our customer base. The feedback received through our customer engagement programs has been important in the development of our operating expenditure forecasts. This includes, for example, enabling better access to customer data through our proposed billing and customer relationship management system.

[85] NER, cl. 6.5.6(c).

10.1 Our current operating expenditure

Our actual operating expenditure in the current regulatory control period is $288.1 million.[86] As shown in figure 10.1, this represents a forecast overspend of $15.4 million on our operating expenditure allowance.

Figure 10.1 Actual operating expenditure versus allowance for 2011–2015 ($m, real)



Source: CitiPower
Notes: 2015 'actual' spend is a forecast.

As discussed in section 10.3, our operating expenditure demonstrates a positive response to the incentives in the regulatory framework. This reflects our commitment to continually deliver efficiency improvements to our customers and shareholders, while maintaining service standards.

10.2 Our forecast operating expenditure

Our forecast operating expenditure for the 2016–2020 regulatory control period is $502.0 million ($2015). The profile of this expenditure is shown in table 10.1.

[86] This expenditure includes a forecast for 2015, as actual data is not currently available. Further, included in the attached model, *CP Opex Consolidation*, is our operating expenditure for each of the 2006–2015 regulatory years, and the operating expenditure for 2015, categorised in the same way as our operating expenditure forecast for the 2016–2020 regulatory control period.

Table 10.1 Forecast annual operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020	Total
Actual operating expenditure (2014)	58.5	58.5	58.5	58.5	58.5	292.4
Net base year adjustments	2.0	2.0	2.4	2.6	2.5	11.5
Change in capitalisation policy	19.0	19.0	19.0	19.0	19.0	94.8
Service reclassification	3.9	3.9	3.9	3.9	3.9	19.5
Step changes	3.6	1.5	5.5	5.1	2.6	18.3
Rate of change	6.6	10.0	13.5	16.5	19.0	65.5
Total	**93.5**	**94.9**	**102.8**	**105.5**	**105.4**	**502.0**

Source: CitiPower

We have developed our operating expenditure forecast for the 2016–2020 regulatory control period using a 'base–step–trend' approach. This approach is consistent with the AER's preferred model, as set out in its *Expenditure Forecast Assessment Guideline*.[87]

Specifically, we have developed our operating expenditure forecasts for the 2016–2020 regulatory control period as follows:

- nominated 2014 as the efficient revealed base year;
- adjusted our base year expenditure to include an efficient forecast for activities for which the base year expenditure did not reflect expenditure going forward (including a review for any non-recurrent costs);
- adjusted the base year to present the forecast operating expenditure consistent with the approved cost allocation methodology (**CAM**);
- adjusted the base year to include an efficient forecast for services reclassified as standard control services;
- added to the base year the efficient level of forecast step changes for the 2016–2020 regulatory control period; and
- added to the base year the efficient level of operating expenditure determined by applying a rate of change formula, including the rate of change in real prices, output growth and productivity.

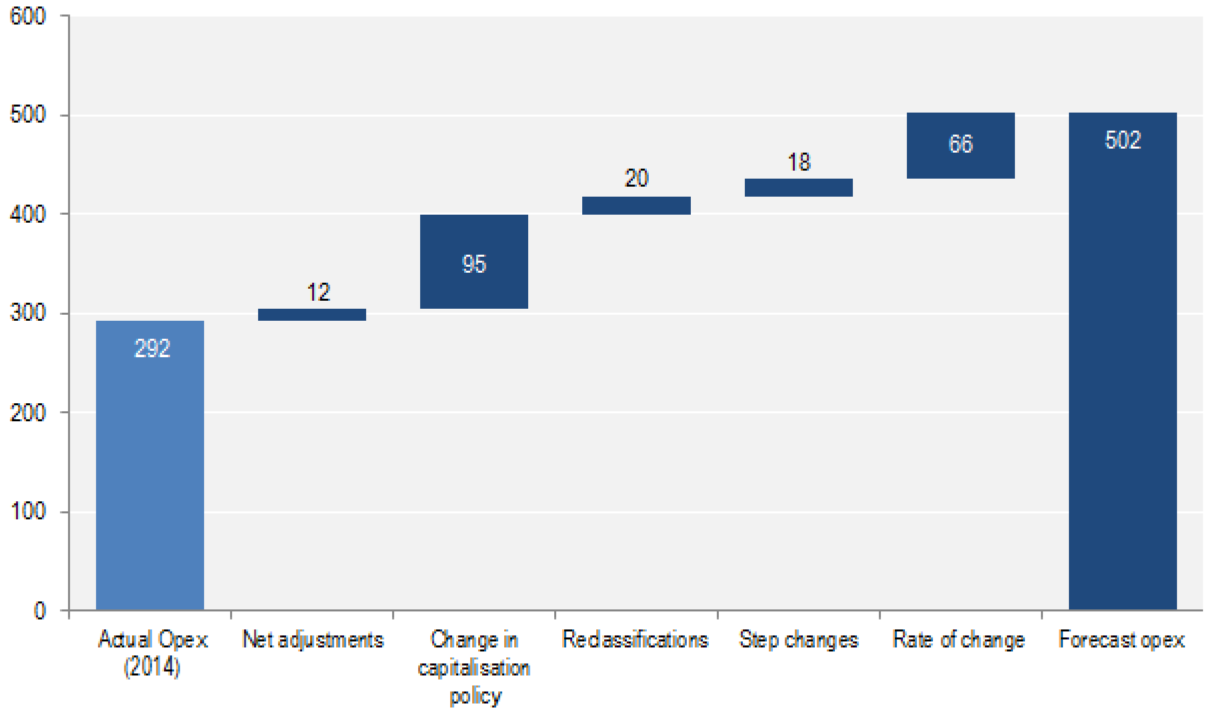
A build-up of our forecast operating expenditure for the 2016–2020 regulatory control period, using the base–step–trend approach, is set out in figure 10.2. A split of our operating expenditure forecast into different expenditure categories is also provided in regulatory templates 2.16 and 3.2.

Figure 10.2 Operating expenditure forecasting approach 2016–2020 ($m, real)

Source: CitiPower

[87] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 32.

10.3 Efficiency of the base year



Source: CitiPower

We nominate the fourth year of the 2011-2015 regulatory control period, being 2014, as the efficient year on which we have based our operating expenditure forecast for the 2016–2020 regulatory control period. We consider our base year expenditure is efficient for the following reasons:

- our base year data is current and robust;
- we are subject to an incentive framework, and have responded to these incentives;
- our ownership structure promotes efficient expenditure; and
- benchmarking analysis supports the efficiency of our operating expenditure.

These reasons are discussed in detail below. The AER, therefore, should accept our base year expenditure (subject only to the adjustments set out in section 10.3.6) when reviewing our total forecast operating expenditure.

10.3.1 Current and robust base year data

We have used 2014 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision. The currency of this data (relative to earlier years) ensures our forecasts are based on up-to-date data. That the data is audited ensures the starting point for our forecasts is robust.

10.3.2 Incentive framework

The regulatory framework in which we operate is an incentive based regime. This is embedded in the *National Electricity Law* (**NEL**), which requires a regulated network service provider be provided with effective incentives in order to promote economic efficiency with respect to the direct control network services the operator provides.[88]

This incentive framework is predicated on profit being a motivating factor, and therefore a driver for a business to seek efficiencies by reducing costs. In its inquiry into the regulatory framework for electricity networks, the Productivity Commission stated the following:[89]

> *Incentive regulations are built on a simple premise. Where the regulatory rewards to the business are (at least significantly) separated from their actual costs, profit-motivated businesses face strong incentives to cost minimise in any given period.*

To ensure the incentive to minimise costs exists throughout a given period, such as a regulatory control period, the Australian Energy Regulator (**AER**) employs an Efficiency Benefit Sharing Scheme (**EBSS**). As discussed in chapter 11, the EBSS allows distributors to retain an incremental efficiency gain or loss for five years, regardless of the year in which the gain or loss is made. The EBSS is also applied symmetrically—that is, equally to efficiency gains and losses—such that the penalty for an overspend is the same as an equivalent benefits from underspend.

In previous price reviews the AER has noted that, because of the incentive regime, it is able to rely on revealed costs to set the efficient base year:[90]

> *The AER considers that given the incentives to minimise costs in the regulatory regime, the revealed costs of a DNSP are likely to be a reasonable approximation of efficient costs in the circumstances of that DNSP for the scope of work undertaken.*

Our total operating expenditure has been subject to an EBSS throughout the 2011–2015 regulatory control period. Consistent with the reasons previously set out by the Productivity Commission and the AER, therefore, our actual operating expenditure in our base year should be considered efficient.

10.3.3 Ownership structure

In addition to the incentive framework, our ownership structure provides further reason to accept our base year total operating expenditure, without adjustment, as being efficient. That is, as a privately owned business we have an obligation to maximise returns to shareholders. This contrasts with publicly owned utilities that may face competing, non-commercial incentives that limit their responsiveness to profit based incentives.[91]

As a privately owned business, we also face scrutiny on our financial performance, beyond that of the regulator. For example, we raise financing from multiple parties (as opposed to a single Treasury). These multiple parties each continually monitor our performance, and the consequences of poor management can impact the capacity of the business to raise further capital. This provides additional discipline on us to maintain an efficient expenditure profile.

Our corporate governance framework further supports the efficiency of our actual total operating expenditure. This framework is discussed in section 3.3. In particular, our internal governance measures include structured and rigorous cost controls over all expenditure. It also includes policies that establish principles and practices that govern purchasing and procurement activities for all goods, materials, services and intellectual property assets.

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88 NEL, cl. 7A(3).

89 Productivity Commission, *Inquiry report volume 1, Electricity network regulatory frameworks*, 9 April 2013, p. 267.

90 AER, *Final decision, Victorian electricity distribution network providers, Distribution determination 2011–2015*, October 2010, p. 316.

91 See, for example: Productivity Commission, *Inquiry report volume 1, Electricity network regulatory frameworks*, 9 April 2013, pp. 270–279.

10.3.4 Benchmarking analysis

Our responsiveness to the incentive framework, and the effectiveness of our ownership and governance structures, are further supported by the performance of our business relative to other, comparable networks. Notably, the AER's *Annual Benchmarking Report* shows that we have performed well on most metrics, including at a total operating expenditure level.[92]

We provide a more detailed discussion on benchmarking in chapter 5. In summary, we consider benchmarking is an important part of the regulatory framework. When combined with other expenditure assessment methods, it is a useful tool for assessing the efficiency of a distributor's historical and forecast expenditure required to meet the operating expenditure objectives in the Rules.

10.3.5 The impact of transitioning to a new cost allocation methodology

On 3 October 2014, the AER approved our CAM.[93] Our operating expenditure forecast for the 2016–2020 regulatory control period has been properly allocated to standard control services in accordance with the principles and policies of the approved CAM.[94] In allocating our directly attributable costs or shared costs, we have ensured that no costs have been double counted. We have engaged an independent external auditor to assure us that our historic costs have been properly allocated in accordance with our approved CAM.

The transition to the approved CAM accounts for $94.8 million of our total forecast increase in operating expenditure. The primary difference in our approved CAM, relative to the previously approved CAM, is that indirect corporate overheads will now be expensed. This represents a reallocation of costs (rather than any new costs)—that is, the implementation of our approved CAM has not changed the combined total of our capital and operating expenditure forecasts for standard control services.

10.3.6 Expenditure removed from base year and base year adjustments

We have reviewed our base year operating expenditure for any non-recurrent expenditure. Although no non-recurrent operating expenditure was discovered, we identified several activities for which the 2014 base year does not reflect the expenditure for these activities going forward. A summary of these activities, and the net adjustments to our 2014 base year operating expenditure, are set out in table 10.2.

[92] AER, *Annual Benchmarking Report*, November 2014.

[93] See our approved CAM, attached: *Cost Allocation Method*.

[94] This includes allocated costs between distribution services, allocated directly attributable costs, allocated shared costs between the relevant categories of distribution services and allocated directly attributable costs and shared costs.

Table 10.2 Net base year adjustments ($m, real)

Expenditure removed from base year	2016	2017	2018	2019	2020	Total
Less: base year regulatory reset costs	-0.5	-0.5	-0.5	-0.5	-0.5	-2.4
Add: forecast regulatory reset costs	-	-	0.4	0.6	0.6	1.6
Less: base year GSL payments	-0.1	-0.1	-0.1	-0.1	-0.1	-0.4
Add: forecast GSL payments	0.0	0.0	0.0	0.0	0.0	0.2
Less: base year superannuation (defined benefit contributions)	-1.1	-1.1	-1.1	-1.1	-1.1	-5.4
Add: forecast superannuation (defined benefit contributions)	1.7	1.6	1.5	1.4	1.3	7.7
Less: base year DMIA	-0.4	-0.4	-0.4	-0.4	-0.4	-2.1
Add: forecast DMIA	0.2	0.2	0.2	0.2	0.2	1.0
Less: base year debt raising costs	-	-	-	-	-	-
Add: forecast debt raising costs	2.1	2.2	2.3	2.4	2.5	11.5
Total	**2.0**	**2.0**	**2.4**	**2.6**	**2.5**	**11.5**

Source: CitiPower

Appendix F provides additional information on these adjustments to our base year operating expenditure, as well as our approach for forecasting this expenditure for the 2016–2020 regulatory control period. This includes an outline of our approach to forecasting debt raising costs, which differs from that previously adopted by the AER.

10.3.7 Service reclassification

In addition to discussing the adjustments to our base year operating expenditure, appendix G also outlines expenditure related to the reclassification of services (for which the impact on customers is net present value neutral). A summary of these adjustments is set out in table 10.3.

Table 10.3 Service reclassification ($m, real)

Base year adjustments	2016	2017	2018	2019	2020	Total
Supply abolishment	0.8	0.8	0.8	0.8	0.8	3.9
Category RIN alignment	0.2	0.2	0.2	0.2	0.2	1.0
Reclassification of IT metering expenditure	2.9	2.9	2.9	2.9	2.9	14.6
Total	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**19.5**

Source: CitiPower

10.4 Rate of change

Actual operating expenditure in the base year reflects the economic and network conditions that prevailed during the 2014 year. Over the 2016–2020 regulatory control period it is reasonable to expect that these economic and network conditions will change and therefore the operating expenditure forecasts must take these changes into account.

The AER's *Expenditure Assessment Forecast Guideline* sets out the following reasons why efficient operating expenditure in the forecast period may differ from the base level of expenditure:[95]

- real price growth—this is changes in the prices that we pay for key inputs used in our operations including, labour, materials and contractors. Real price growth is the growth rate in prices relative to growth in the Consumer Price index. As real input prices change our efficient level of expenditure will change;
- output growth—this is the change in the scale of the network that reflects changes in demand for network services. It is reasonable that as the scale of operations increases our efficient costs will increase; and
- productivity growth—this is changes in the level of expenditure required to deliver the same level of services to customers. Productivity growth may arise during the regulatory control period as a result of economies of scale, technical changes or efficiency improvements.

We have developed forecasts of each of the above components and applied these to develop our operating expenditure forecasts. Our approach to real price growth is discussed in chapter 7. Therefore only our approaches to forecasting output growth and productivity growth are explained in this chapter.

10.4.1 Output growth escalation

Output growth escalation is required to capture increases in operating expenditure which are driven by changes in the size of the network and the quantity of services we will supply over the 2016–2020 regulatory control period.

Key categories of operating expenditure and the extent to which these vary with changes in network size are set out in table 10.4.

95 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 34.

Table 10.4 Extent of variable expenditure by key operating expenditure category

Category	Distribution services	Extent variable costs
Direct maintenance	Includes costs relating to, for example, maintenance (routine and condition based), vegetation management, emergency response and Supervisory Control and Data Acquisition (**SCADA**).	Highly variable with physical size of network. As network scale increases the scale of maintenance activity increases.
Operating	Includes cost relating to network and corporate overheads. For example, network control room, network planning, network management, GSL payments, network licence fees, levies, fleet and property overheads, land taxes, billing and revenue collection, customer services, advertising and marketing, insurance and debt raising costs, back-office and IT support.	Network operating costs that relate to network planning and management vary with workloads, which generally vary with network size. Land taxes, fleet and property vary to a degree with network size. There are some components of network operating costs that are relatively fixed (e.g. licence fees). Customer related costs vary with number of customers. Insurance and debt raising costs vary with the value of the network which is related to the size of the network. Back-office support costs vary with workload which varies to a degree with network size

Source: CitiPower

As noted in section 10.2, we have prepared our operating expenditure forecasts at the aggregate level using a revealed cost approach. We have therefore undertaken the quantitative analysis of the variation in operating expenditure resulting from changes in network size at the aggregate level, rather than by operating expenditure category.

We have used econometric models to quantify the relationship between growth in operating expenditure and growth in key cost drivers that affect the size of the network. Three of the econometric models were developed by expert econometricians, Frontier Economics, and the fourth model was developed by Economic Insights and applied by the AER's in its draft decision for NSW and ACT distributors.[96] To develop our output growth escalator we have combined the results of the four econometric models.

We consider that taking an average of the results of multiple econometric models:

- enables the impact of a broader range of operating expenditure cost drivers to be captured in the output growth escalator;
- addresses the statistical limitations associated with a small sample size and high correlations between cost drivers; and
- will likely produce a more accurate forecast than using a single model.

96 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 33.

Frontier Economics note that:[97]

> *It has long been recognised in the statistics literature that when multiple forecasts of the same variable are available, combining the forecasts from different sources generally results in more accurate forecasts than if a single source were used. In order for this to be effective, each source, even if not completely free from error, must contribute some useful information.*

Frontier Economics developed its econometric models using eight years of data for the 13 National Electricity Market (**NEM**) distributors over the 2006–2013 period. This data was sourced from the distributors' responses to the AER's Economic Benchmarking RIN. Frontier Economics' report is provided in attachment, *Opex scale escalation econometric model*. Frontier Economics econometric model results are presented in table 10.5.

Table 10.5 Frontier Economics output growth econometric models

Log operating expenditure	Model 1	Model 2	Model 3
Log Customer numbers	0.380*		
Log Total zone substation transformer capacity	0.345***		
Log Ratcheted maximum demand		0.737***	
Log Composite Scale Variable			0.665***
Log Service area	0.116***		0.170***
Log Customer per route length		-0.596***	
Urban dummy		0.813*	1.077***
2007.year	-0.003	0.010	0.013
2008.year	0.079	0.084	0.100*
2009.year	0.058	0.052	0.081
2010.year	0.113*	0.110*	0.143**
2011.year	0.156***	0.173***	0.198***
2012.year	0.246***	0.272***	0.295***
2013.year	0.217**	0.261***	0.275***
Constant	2.725	7.599***	2.645***
Number of observations	104	104	104
Within R2	0.648	0.606	0.648
Between R2	0.957	0.923	0.974
Overall R2	0.946	0.911	0.962
σu	0.177	0.264	0.149

[97] Frontier Economics, *Operating expenditure scale escalation econometric model*, January 2015, p. 27.

Log operating expenditure	Model 1	Model 2	Model 3
σe	0.096	0.098	0.098

Source: Frontier Economics, *Operating Expenditure Scale Escalation Model*, January 2015.

Notes: 1. The dependent variable is log(opex). All driver variables, except the year and urban dummy variables, are in logarithms

2. Estimated coefficients for each variable are shown on the first row; p-values are indicated by the number of stars next to each coefficient: *** for p-value < 0.001, ** for p-value < 0.01, * for p-value < 0.05

3. The composite scale variable includes the following output variables and weightings, route line length – 50%, customer numbers – 25% and maximum demand – 25%.

4. The urban dummy takes the value 1 if the distributor is considered urban and 0 if the distributor is considered rural.

We note that there are other cost drivers that are not captured in the econometric models due to data limitations and statistical constraints. Notwithstanding, we consider that using an average of multiple models adequately captures the impact of growth in the core cost drivers on operating expenditure.

Output variable forecasts

To populate the econometric models and develop our output growth escalator, we require forecasts of the growth in the output variables. We forecast the growth in the output variables as set out in table 10.6.

Table 10.6 Method for forecasting output variables

Output	Forecast method	Reset RIN location	Applicable models
Customer numbers	Sourced from independent experts the Centre for International Economics (**CIE**), refer to chapter 8.	Reset RIN and 2014 Benchmarking RIN, Template 3.4 Operational data	AER model Frontier model 1 Frontier model 3
Zone substation transformer capacity	Developed using a bottom up forecasting methodology taking into account current, committed and planned projects for completion during the 2016–2020 regulatory control period. The combination of forecasting methods ensures the forecasts are reasonable given our capital expenditure program.	Reset RIN and 2014 Benchmarking RIN, Template 3.5 Physical Assets	Frontier model 1
Ratcheted maximum demand	Based on aggregate maximum demand forecasts at terminal station, 50% POE. Forecasts are developed by CIE at the terminal station using a top down econometric approach. The top down forecasts are then reconciled to the bottom up forecasts. The forecasting process is discussed in detail in chapter 8.	Reset RIN and 2014 Benchmarking RIN, Template 3.4 Operational data	AER model Frontier model 2 Frontier model 3
Route line length	Developed based on historical trends over the period 2009 to 2014.	Reset RIN and 2014 Benchmarking RIN, and Template 3.7 Operating environment	Frontier model 3

Output	Forecast method	Reset RIN location	Applicable models
Circuit length	Developed by voltage level for each of overhead and underground circuits. Our forecasting method is a combination of historical trends which is applied primarily for lower voltage categories and bottom up analysis for higher voltage lines (66kv) based on known projects. Forecasting at voltage level and taking account of historical trends and known projects ensures our forecasts are reasonable. Total circuit length is the sum of the length of circuit for each voltage category, including overhead and underground circuits.	Reset RIN and 2014 Benchmarking RIN, Template 3.5 Physical Assets	AER model

Source: Attached *CitiPower 2016 – 2020 Reset RIN* and *2014 Benchmarking RIN*

Table 10.7 provides our forecast growth rates for each of the output variables.

Table 10.7 Forecast growth rates in output variables (per cent)

Annual growth rate	2015	2016	2017	2018	2019	2020
Customer numbers	1.98	1.97	1.60	1.60	1.59	1.58
Zone substation transformer capacity	-0.35	0.00	0.34	0.94	0.47	0.00
Ratcheted maximum demand	5.05	3.40	3.41	2.77	1.63	0.83
Route line length	1.76	1.76	1.76	1.76	1.76	1.75
Circuit length	0.63	0.49	0.88	-0.33	-0.11	0.62

Source: CitiPower

Combined output growth escalator

We have removed economies of scale from the output growth component of the rate of change. Removing economies of scale from the output growth component is consistent with the AER's rate of change formula set out in the *Expenditure Forecast Assessment Guideline* and the AER's draft decision for the NSW and ACT distributors.[98] This approach means that economies of scale are considered as part of the assessment of total productivity change and avoids the potential for double counting the impact of economies of scale.

For each of the four models we have removed the economies of scale by scaling the coefficients to add to one. For each model, we then multiply the scaled coefficients by the forecast growth in the respective output variables. This provides an output growth rate for each of the four models. We then take a simple average of the implied output growth rates from the four models. This process is demonstrated in attached model, *CP Output Growth*.

Our combined output growth escalators are provided in table 10.8.

[98] AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 34; AER, *Draft Decision, Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, November 2014, p. 205.

Table 10.8 Combined output growth escalator (per cent)

	2015	2016	2017	2018	2019	2020
Model 1—Frontier Economics	0.87	1.03	1.00	1.28	1.06	0.83
Model 2—Frontier Economics	5.05	3.40	3.41	2.77	1.63	0.83
Model 3—Frontier Economics	2.64	2.22	2.13	1.97	1.68	1.48
Model 4—AER	2.50	2.12	1.92	1.64	1.42	1.32
Combined	**2.76**	**2.19**	**2.12**	**1.91**	**1.45**	**1.12**

Source: CitiPower

Importantly, our proposed output growth escalators do not capture the forecast increase in operating expenditure associated with our proposed step changes. This is because our proposed operating expenditure step changes are not driven by increases in the size of the network.

10.4.2 Productivity change

Productivity change can result from technical change, efficiency improvements and economies of scale. The AER's *Expenditure Forecast Assessment Guideline* and its recent approach to assessing productivity in its draft decision for NSW and ACT distributors indicates its preference to consider productivity as a whole.[99]

In principle, we do not consider it appropriate to pre-emptively reduce operating expenditure forecasts for potential productivity benefits that may or may not occur in future due to technical change or efficiency improvements. Applying pre-emptive productivity adjustments to expenditure forecasts is not appropriate because:

- it is inconsistent with the EBSS and incentive-based regulation. The EBSS is designed to provide incentives for distributors to seek and implement opportunities to make productivity and efficiency savings in a timely manner. The benefits of which are shared between distributors and customers. Further, reducing future operating expenditure allowances to reflect historical productivity change could inadvertently reduce incentives to seek productivity gains between regulatory control periods;
- there is no basis upon which the AER can derive a realistic expectation of future productivity change with any level of accuracy. Historical productivity changes provide little information on the likely benefits of future productivity change as future innovations are unknown and there are likely diminishing returns over time from technical changes that have already occurred; and
- it is inconsistent with the Rules because there is a very high likelihood of forecasting error and consequently a high likelihood that distributors would have an ex ante expectation of recovering less than efficient costs of operating the network to achieve the operating expenditure objectives.

Notwithstanding the above, the AER's benchmarking analysis does not provide any evidence of productivity growth in the distribution industry, or for our business, over the past eight years. The AER's benchmarking analysis instead suggests that the distribution industry has exhibited declining operating expenditure productivity over the last eight years.[100] This trend is consistent with the Productivity Commission's analysis of

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99 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 34-35. AER, *Draft Decision Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, pp. 206-207.

100 AER, *Electricity distribution network service providers, Annual Benchmarking Report*, November 2014, p. 34. Economic Insights, *Economic benchmarking of Operating Expenditure for NSW and ACT Electricity DNSPs*, p. 33.

productivity trends in the electricity, gas, water and waste sector, and is also consistent with trends observed in other jurisdictions, for example New Zealand.[101] As noted by Economic Insights 2014:[102]

> *…the civil construction–oriented nature of distribution capital means the industry has gained less from computerisation cost savings than have industries which use a higher proportion of machinery and equipment instead of structures.*

Factors contributing to declining productivity include:

- increases in operating costs that are driven by factors independent of the quantity of outputs produced or services provided, for example changes in regulatory obligations such as increased compliance reporting, increased requirements relating to vegetation management as a result of increased clearance requirements from Energy Safe Victoria and increased asset inspection as a result of the Victorian Bushfires Royal Commission findings. Due to data limitations it is extremely difficult to isolate the exact impact of each regulatory change on operating expenditure productivity;
- slow output growth which is being observed universally in advanced western economies and is beyond the control of distributors. In particular, energy throughput has been declining for the industry in aggregate since 2010. Reductions in system-wide energy throughput do not lead to reductions in distributor's costs. Distributors must provide and maintain the necessary capacity to meet peak demand location by location on the network rather than average demand; and
- changes in asset health and condition over time can require increased maintenance expenditure with no change in the physical measure of the capital stock and no change in the quantity of measured outputs.

Importantly, declining productivity trends do not necessarily provide evidence of declining industry efficiency. Observing declining productivity can be a reflection of a number of factors as indicated above.

In conclusion, we do not consider it appropriate to apply pre-emptive productivity adjustments to our operating expenditure forecasts. Further, there is no evidence to justify making pre-emptive productivity adjustments to our operating expenditure forecasts.

We have therefore applied a zero productivity adjustment in our rate of change forecasts. We will however continue to respond to the EBSS incentives during the 2016–2020 regulatory control period and seek to implement opportunities to make productivity improvements and efficiency savings, the benefits of which will be shared with customers through the EBSS arrangements.

10.4.3 Relationship between productivity growth and step changes

The AER's *Expenditure Forecast Assessment Guideline* states that the increased costs of step changes occurring in the 2016-2020 regulatory control period may be accounted for in the productivity adjustment in the rate of change formula.

As noted above, we do not consider it appropriate to apply pre-emptive productivity adjustments and have therefore applied a zero productivity adjustment. Consequently, the negative impact on measured operating expenditure productivity resulting either from past or future step changes is not captured in the productivity component of our rate of change forecasts.

To ensure that our operating expenditure forecasts are sufficient to achieve the operating expenditure objectives in the Rules, the impact of future step changes must be added to our operating expenditure forecasts as a separate item. Our step change proposals are discussed in section 10.5.

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101 Productivity Commission, *Productivity Update*, April 2014.

102 Economic Insights, *Electricity Distribution Industry Analysis*, 1996-2013, June 2014, p. v.

10.4.4 Overall rate of change

Table 10.9 shows the overall rate of change applied to our operating expenditure forecasts. The rate of change is one of two factors that explain the significant variation in forecast operating expenditure from our historical operating expenditure.

Table 10.9 Rate of change in operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020	Total
Real price growth	2.6	4.3	6.1	7.8	9.3	30.2
Output growth	4.0	5.7	7.4	8.6	9.6	35.3
Productivity	-	-	-	-	-	-
Total value of rate of change	**6.6**	**10.0**	**13.5**	**16.5**	**18.9**	**65.6**

Source: CitiPower

10.5 Step changes

This section discusses the framework and role of step changes in our total operating expenditure forecasts, as well as our approach to identifying and justifying individual step changes. The step changes are one of two factors that explain the significant variation in forecast operating expenditure from our historical operating expenditure. A summary of our proposed step changes is included, with further detail on the individual step changes provided in appendix G.

10.5.1 Rules framework

The Rules state that our total forecast operating expenditure for the 2016–2020 regulatory control period must include the amount required to achieve each of the operating expenditure objectives. The operating expenditure objectives, as set out in clause 6.5.6(a) of the Rules, are to:

(1) meet or manage the expected demand for standard control services over the regulatory control period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

  (i) the quality, reliability or security of supply of standard control services; or

  (ii) the reliability or security of the distribution system through the supply of standard control services,

  to the relevant extent:

  (iii) maintain the quality, reliability and security of supply of standard control services; and

  (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

The Rules further state that the AER must accept our forecast operating expenditure where it is satisfied the forecast operating expenditure for the regulatory control period reasonably reflects the operating expenditure criteria. The operating expenditure criteria in clause 6.5.6(c) of the Rules are:

(1) the efficient costs of achieving the operating expenditure objectives in clause 6.5.6(a) of the Rules;

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

As discussed in section 10.3, our total operating expenditure in 2014 reflects the efficient costs a prudent operator in our circumstances would require to meet the operating expenditure objectives. This is based on our current operating environment, and having regard to our current service targets, regulatory obligations and other prevailing environmental circumstances. To meet the operating expenditure objectives in the 2016–2020 regulatory control period a prudent operator in our circumstances will be required to undertake new or increased activities, and to incur new or increased costs associated with the following:

- a change in a regulatory obligation or requirement;
- a change in the expected demand for standard control services which is not otherwise provided for in the rate of change;
- where base year operating expenditure is not sufficient to maintain:
  - the quality, reliability and security of supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); or
  - the safety, reliability and security of the distribution system through the supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); and
- a change in expenditure that is in the long term interests of consumers, but is of limited benefit to the business.

Our operating expenditure forecasts therefore include the impact of step changes over the 2016–2020 regulatory control period for new or increased activities and new or increased costs. These step changes reflect the changing environment in which we operate.

Our approach to forecasting step changes is largely consistent with that proposed by the AER in its *Forecast Expenditure Assessment Guideline* and its draft decision for the NSW and ACT electricity distribution businesses. In particular, the AER stated that step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control.[103]

As set out above we have also included step changes for where base year operating expenditure is not sufficient to maintain the quality, reliability and security of supply of standard control services, or the safety, reliability and security of the distribution system. Similarly, we have included step changes where the additional operating expenditure will result in cost savings to consumers, but are of limited benefit to our business. Our reasons for including these step changes are set out below:

[103] AER, *Draft decision, Ausgrid distribution determination 2014–19*, November 2014, p. 7-161.

- the scope of operating expenditure step changes must be determined by reference to the statutory test for the AER's acceptance of our proposed operating expenditure forecast. That is, the nature of forecast changes to our operating expenditure (relative to base year operating expenditure) that may constitute a step change depends upon the content of the operating expenditure objectives in clause 6.5.6(a) of the Rules. For example the Rules do not confine step changes to operating expenditure changes arising from changes in regulatory obligations and requirements, or operating and capital expenditure trade-offs;
- in its draft decision for the NSW and ACT electricity distributors, the AER stated that separately forecasting operating expenditure for activities that may change at a different rate to operating expenditure (more generally) may lead to forecasting bias.[104] In effect, the AER is concerned that distributors will separately forecast activities that increase at a higher rate than total operating expenditure, but fail to separately forecast activities that increase at a lower rate.

  The AER's position may be appropriate in regard to small changes in costs, such that the impact of variations would not limit or overstate the capacity for our forecast operating expenditure to achieve the operating expenditure objectives. Our forecast step changes, however, represent material changes to our expenditure. That is, without these changes our forecast operating expenditure may not be sufficient to maintain the quality, reliability and security of supply of standard control services, or the safety, reliability and security of the distribution system.[105] This is supported by our current level of efficiency—as shown in the AER's benchmarking analysis—and this efficiency has been achieved using an approach that included material step changes (for the circumstances outlined previously).

  Moreover, we have separately forecast activities that increase at a lower rate, or may otherwise lead to an operating expenditure forecast that does not meet the operating expenditure criteria. For example, we have removed from our operating expenditure forecasts the impact of higher regulatory reset costs in our base year. The removal of our actual DMIA expenditure from the base year, and replacing it with a forecast based on the expected allowance follows a similar premise. We also remove actual GSL payments, to ensure our forecast operating expenditure is not overstated due to anomalous GSL payments in our base year.
- similarly, the AER should not assume that base year expenditure is sufficient to provide all forecast costs necessary to maintain network security, in particular for IT security expenditure. Environmental changes in the IT security space are rapid and continual. The advance of technology means that what may have been prudent in 2014 is not necessarily sufficient to manage risk in 2016 and beyond.

The regulatory framework is also important in the timing of IT security expenditure. IT security expenditure is not self-financing. That is, it is typically driven by avoiding the potential for future costs, as opposed to productivity or efficiency gains that our business will benefit from. As a commercial entity, we would not undertake this expenditure unless it was explicitly included in our operating expenditure allowance, notwithstanding it being in the long term interests of consumers. The AER acknowledged these circumstances in its Final Decision for Envestra's gas network in Victoria:[106]

> *In some limited circumstances the benefits of a discretionary project may not be productivity gains, but the project is expected to lead to lower prices to customers. If there are few benefits to the gas service provider, the benefits of undertaking the project to the gas service provider may not outweigh the cost of the project. Therefore it may not undertake the project without an increase in opex. A step change in opex may be necessary so that customers benefit in the long term.*

[104] See, for example: AER, Draft decision, *Ausgrid distribution determination 2014–19*, November 2014, p. 7-173.

[105] See, for example: NER, cl. 6.5.6(a).

[106] AER, *Access arrangement final decision, Envestra Ltd 2013–17, Part 2: Attachments*, March 2013, p. 171.

It is also notable that IT security requirements may not be linked to specific regulatory obligations. This does not mean, however, that IT security expenditure is not prudent and efficient. Instead, prescriptive regulations that require particular IT security solutions would almost certainly become redundant as technology evolves.

10.5.2 Identifying and justifying step changes

Based on the above, we undertook a series of internal workshops. These workshops identified events that are foreseeable, and forecast their impact by relying on the best information available. For an identified step change to be proposed, it was required to demonstrate:

- there is an uncontrollable change in the environment that affects our efficient forecast expenditure;
- when this change event occurs and when it is efficient to incur expenditure to address the change in the environment;
- the options considered to meet the change and the selected efficient option—that is, we took appropriate steps to minimise its cost from the time the event was foreseeable;
- when we expect to make the changes to meet the changed environmental event;
- the efficient costs associated with making the step change; and
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.

In regard to the latter—that costs cannot be met from our existing regulatory allowance—careful attention has been taken to ensure no output growth is incorporated into the step changes in scope. For example, only the incremental costs above our base year and output growth have been included for step changes where an existing level of costs is reflected in our base year. Our scope changes, therefore, reflect new requirements or activities and do not in any way constitute ‘more of the same’.

Similarly, our proposed step changes are not accounted for in forecast productivity growth. As discussed in section 10.4, we have not applied a productivity growth adjustment in developing our operating expenditure forecasts. This reflects our concerns as to the robustness of any such adjustments. In any event, our analysis indicates that applying a productivity adjustment would result in an increase to our forecast operating expenditure for the 2016–2020 regulatory control period. Instead, we have applied a zero productivity growth rate and included forecast step changes.

To the extent that further unforeseen or uncontrollable events occur, we propose to rely on the uncertainty provisions discussed in chapter 14. However, unless relevant materiality thresholds are met, such events may result in expenditure being incurred that is not provided for through our regulatory allowance. That is, the proposed step changes are required to allow us a reasonable opportunity to recover our prudent and efficient costs.[107]

10.5.3 Forecast step changes

Our proposed list of step changes, consistent with the framework above, is shown in table 10.10.

[107] NER, cl. 6.5.6(c).

Table 10.10 Operating expenditure step changes for 2016–2020 ($m, real)

Step change	Total
Customer charter	0.2
Superannuation (accumulation members)	1.6
Monitoring IT security	2.0
Lease renewal	3.7
Mobile devices	1.8
Customer Information System (**CIS**) and Customer Relationship Management (**CRM**)	2.2
Decommissioning zone substations	6.7
Total	**18.3**

Source: CitiPower
Notes: Total does not add due to rounding.

A summary of these step changes is provided below. The full justification for each step change is set out in appendix G.

Customer charter

Under clause 9.1.2(b) of the *Victorian Electricity Distribution Code*, we are required to provide a customer charter to each customer at least once every five years. The charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:[108]

- the identity of the distributor;
- the distributor's guaranteed service levels; and
- other aspects of the customer's relationship under the *Victorian Electricity Distribution Code* and other applicable laws and codes.

We last provided a customer charter to all our customers in 2011. Therefore, we will next need to provide a customer charter in 2016. This step change reflects the costs of developing, producing and circulating our customer charter.

The forecast impact of this change is set out in table 10.11. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[109]

Table 10.11 Customer charter ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Customer charter	0.2	–	–	–	–	0.2

Source: CitiPower

108 Clause 9.1.3 of the Victorian Electricity Distribution Code.
109 NER, cl. 6.5.6(a)(2).

Superannuation (accumulation members)

Our proposed superannuation (accumulation members) step change comprises two separate components—an increase in our accumulation member superannuation contributions for replacement staff; and an increase due to the superannuation guarantee levy.

Superannuation payments for 'replacement' employees

On an annual basis, we engage the actuary of our superannuation fund, Mercer, to calculate the defined benefit superannuation scheme costs we recognise in our statutory accounts. For the purpose of developing our regulatory proposal, Mercer also forecast these defined benefit costs for each year of the 2016–2020 regulatory control period.

Mercer's forecast of our defined benefit superannuation scheme costs factors in an expected decline in the number of defined benefit superannuation scheme members within our organisation over the 2016–2020 regulatory control period. This decline in defined benefit superannuation members will be offset by 'replacement' employees who must be members of an accumulation fund. However, as we use Mercer's forecast to adjust our base year operating expenditure (as set out in appendix F), the superannuation contribution for these 'replacement' employees is not reflected in our base year. As these 'replacement' employees are not due to additional scale, our contributions for these replacement employees will also not be captured elsewhere in the rate of change formula.

Superannuation guarantee levy

Our superannuation expenditure will increase due to the 25 basis point increment to the superannuation guarantee levy.[110] We have forecast this expenditure based on a half year contribution, as this increase became effective from 1 July 2014.

The forecast total impact of our superannuation step change is set out in table 10.12. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services, and to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[111]

Table 10.12 Superannuation ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Superannuation (accumulation members)	0.2	0.3	0.3	0.4	0.5	1.6

Source: CitiPower
Notes: Total does not add due to rounding

Monitoring IT security

The IT security environment is constantly evolving, and system breaches have become a growing threat. These threats have become particularly pronounced as our operating and IT landscapes continue to converge. For example, we now access our SCADA system through our general IT framework, whereas it was previously accessible only through a direct, isolated network.

Our current IT systems raise alerts for various security threats. These alerts require human intervention to determine the appropriate response, including escalating the alert where appropriate. Active monitoring of

110 See section 19 of the Superannuation Guarantee (Administration) Act 1992, No. 111.

111 NER, cl. 6.5.6(a).

these alerts, however, only occurs during business hours. As technology has matured, and the risk and our exposure to IT breaches have increased, this approach is no longer sustainable.

Given the above, we are in the process of engaging an external service provider to monitor our IT security systems on a 24 hour basis.[112] An external service provider is a lower cost option, and is expected to be more effective at identifying and responding to threats (compared to increasing our internal capacity). This service is expected to commence by June 2015.

Consistent with the Rules, this expenditure will form part of a total operating expenditure forecast required to maintain the quality, reliability and security of supply of standard control services, and the safety of the safety, reliability and security of the distribution system.[113]

Table 10.13 Monitoring IT security ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Monitoring IT security	0.4	0.4	0.4	0.4	0.4	2.0

Source: CitiPower

Lease renewal

In our network, there are five zone substation sites that are leased under 50 year agreements. The lease agreements for a number of these sites are due to expire (for the first time) in the 2016–2020 regulatory control period.

These lease agreements were initially entered into by the State Electricity Commission, and are unique and select in nature—that is, the leases are long-term, limited in number, and have not previously been renewed. Their renewal, therefore, is not a business-as-usual activity. This contrasts to other general lease arrangements (e.g. for general property, and/or motor vehicles), for which incremental lease renewals are common place and are reflected in our base year and rate of change calculations.

This step change reflects the total incremental costs associated with the renewal of these lease agreements. As these lease negotiations are ongoing, the details of the individual lease arrangements are set out in the confidential *Lease renewal* attachment. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[114]

Table 10.14 Lease renewal ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Lease renewal	0.7	0.7	0.7	0.7	0.7	3.7

Source: CitiPower

Mobile devices

Mobile devices have become an essential component of our business. For example, these devices facilitate in-situ real time data capture and access, as well as accurate and timely hazard and incident reporting. These benefits have led to productivity and efficiency gains that are reflected in our 2014 base year.

112 Dimension Data, *Monitoring IT security price estimate*, 2014.

113 NER, cl. 6.5.6(a).

114 NER, cl. 6.5.6(a).

Our existing approach for accounting for these devices is a mixture of capital and operating expenditure. However, an internal review has indicated that moving to an operating expenditure only model will be more efficient. This is shown in the modelling provided in the attached, *Office and field force mobility model*. This step change, therefore, reflects the efficient substitution of capital expenditure for an operating expenditure solution.

The forecast impact of this change is set out in table 10.15. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[115]

Table 10.15 Mobile devices ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Mobile devices	0.4	0.2	0.5	0.2	0.5	1.8

Source: CitiPower

Customer relationship management

Our capital expenditure forecast for the 2016–2020 regulatory control period includes a material project to develop a CRM system and to replace the existing billing system. The justification for this project is set out in chapter 9.

The business case for the CIS and CRM project incorporates an operating expenditure component of $2.2 million over the 2016–2020 regulatory control period. Specifically, the operating expenditure component comprises the incremental costs for maintaining software licences and support for the new billing system (above the costs of our existing system), and cloud based subscription fees for the CRM system.

The forecast impact of this change is set out in table 10.16. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[116]

Table 10.16 Customer relationship management ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Customer relationship management	–	–	0.7	0.7	0.7	2.2

Source: CitiPower
Notes: Total does not add due to rounding.

Decommissioning of zone substation sites

Our operating expenditure forecasts for the 2016–2020 regulatory control period include the costs associated with decommissioning five zone substations—Spencer Street, Russell Place, Laurens Street, Tavistock Place and Prahran. These operating expenditure forecasts are driven by three separate capital expenditure projects:

- decommission of the West Melbourne Terminal Station 22kV sub transmission network;
- Prahran zone substation offload; and
- Waratah Place zone substation development.

115 NER, cl. 6.5.6(a).

116 NER, cl. 6.5.6(a).

The operating expenditure associated with decommissioning the five zone substations includes the one off costs of removing and disposing of plant and equipment (including oil and asbestos), and remediating the sites. We do not consider it prudent to sell the land given that at a future stage we may require it. The operating expenditure has been incorporated into the business cases for the three capital expenditure business cases. As such, the justification of this expenditure is set out in chapter 9.

The forecast impact of this change is set out in table 10.17. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to maintain the quality, reliability and security of supply of standard control services, and the safety of the safety, reliability and security of the distribution system.[117]

Table 10.17 Decommissioning zone substations ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Decommissioning zone substation sites	1.6	-0.1	2.8	2.6	-0.3	6.7

Source: CitiPower
Notes: Total does not add due to rounding.

117 NER, cl. 6.5.6(a).

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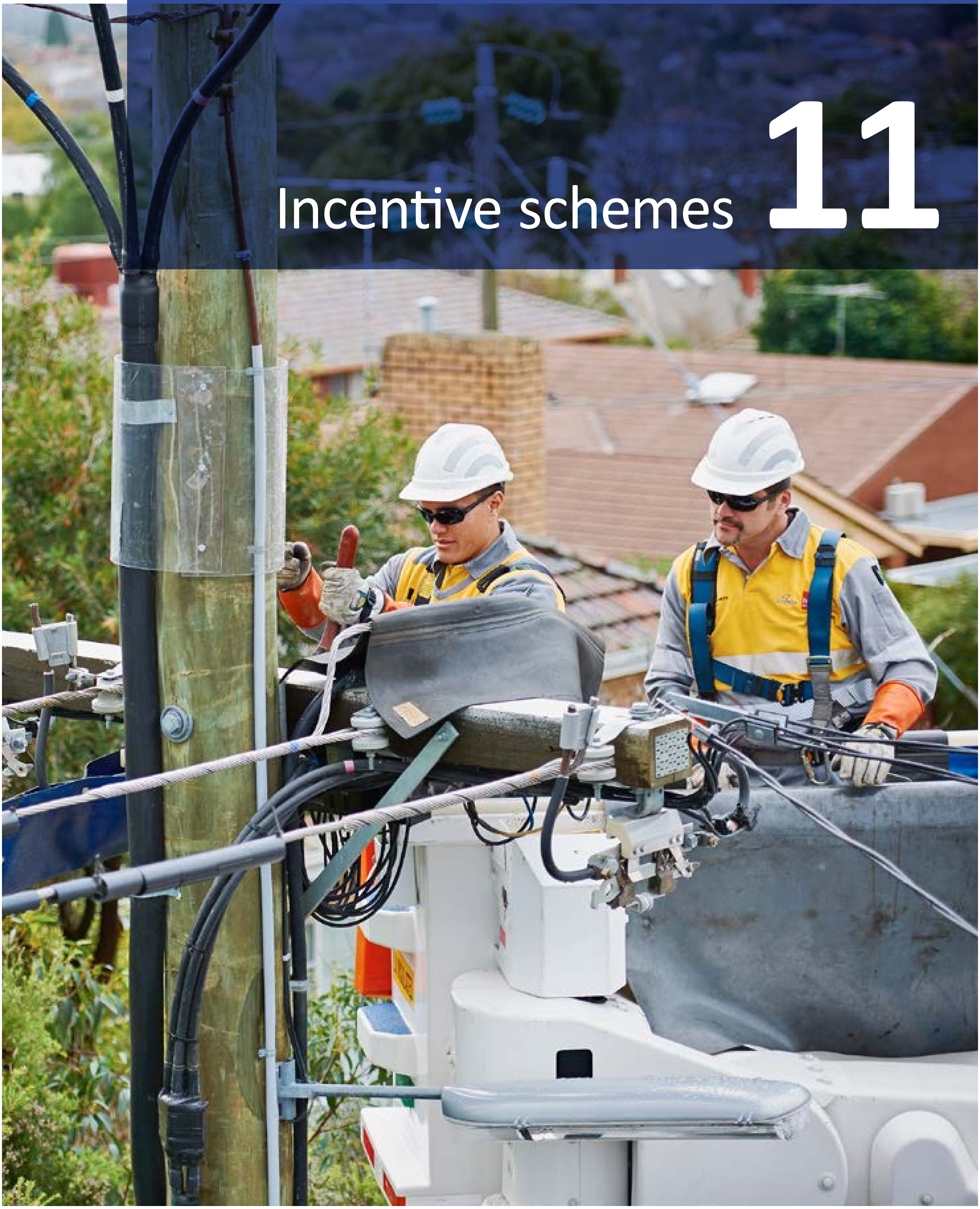
Incentive schemes 11



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11. Incentive schemes

We have a strong history of responding to incentive schemes and we are a firm believer of the incentive framework.

For the 2016-2020 regulatory control period:

- we support the application of the Capital Expenditure Sharing Scheme (**CESS**) and Efficiency Benefit Sharing Scheme (**EBSS**);
- we propose amendments to the Service Target Performance Incentive Scheme to incorporate the updated Value of Customer Reliability (**VCR**) published by Australian Energy Market Operator (**AEMO**) in 2014 and maintain the 2.5 percent annual revenue at risk cap;
- we propose an amendment to the Demand Management Incentive Scheme (**DMIS**) whereby we can seek further funding above the cap; and
- we accept the application of the f-factor scheme.

The AER has published guidelines for a number of incentives schemes and is required to set out its proposed approach in its *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**) as to how it intends to apply these schemes to us in the upcoming regulatory control period.

The Rules require us to set out in our building block proposal a description, including relevant explanatory material, of how we propose the incentive schemes should apply in the 2016-2020 distribution determination.[118]

The sections below set out our proposals in relation to the application of the incentive schemes.

11.1 Capital expenditure sharing scheme and proposed approach to depreciation

The capital expenditure sharing scheme (**CESS**) provides ex ante incentives for distributors to undertake efficient capital expenditure during a regulatory control period. The CESS provides for a sharing of the benefits between distributors and customers.

In November 2013, the AER published the Capital Expenditure Incentive Guideline for Electricity Network Service Providers (**CESS Guideline**).

A key element of the overall capital expenditure incentive framework is the depreciation approach to use when a distributor's regulated asset base (**RAB**) is updated at the beginning of the next regulatory control period. The AER can decide to use either actual or forecast depreciation. The choice of depreciation affects the power of incentives that apply to capital expenditure.

The F&A Paper proposes to use forecast depreciation to establish the value of the RAB as at 1 January 2021 for Victorian distributors. The AER considers this approach, in combination with the CESS, will provide sufficient incentive for us to achieve capital expenditure efficiency gains over the 2016–2020 regulatory control period.

We propose to apply the CESS Guideline for the 2016–2020 regulatory control period, with no amendments. We also support the use of forecast depreciation to establish the opening RAB value as at 1 January 2021 and to apply the CESS on a net basis, because this is the cost borne by customers.

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[118] NER, clauses S6.1.3(3),(3A) and (5A).

Given the CESS did not apply for the 2011-2015 regulatory control period, no carry over will apply for the 2016–2020 regulatory control period. Accordingly, we propose no revenue increments or decrements arising from the CESS in our 2016–2020 proposed revenue requirement.

11.2 Efficiency benefits sharing scheme

The efficiency benefit sharing scheme (**EBSS**) provides a continuous incentive for distributors to pursue efficiency improvements in operating expenditure. The EBSS provides for a sharing of the benefits between distributors and customers.

In November 2013, the AER published *the Efficiency Benefit Sharing Scheme for Electricity Network Service Providers* (**EBSS Guideline**).

We propose to apply the EBSS for the 2016–2020 regulatory control period. We propose that the EBSS exclude a number of categories of operating expenditure, including the following:

- debt raising costs;
- self-insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- the Demand Management Incentive Scheme (**DMIS**);
- Guaranteed Service Level (**GSL**) payments; and
- approved pass throughs.

Further, there should be an adjustment for provisions and any changes in capitalisation policy from the final determination.

We consider the requirements of clause 6.5.8 of the Rules are better achieved by excluding these cost categories of operating expenditure which cannot be forecast using a single year revealed cost approach for the next regulatory control period.

In respect to the benchmark allowance, adjustments should be made for costs for new obligations introduced after the final determination.

We note that in its draft decision for the NSW/ACT networks, the AER did not apply the EBSS on the basis that it made efficiency adjustments to the operating expenditure base year.[119] As discussed in chapter 5, our historical operating expenditure is efficient and provides an appropriate base for forecasting operating expenditure in 2016–2020 regulatory control period. It is therefore not necessary or appropriate to make efficiency adjustments to our base year operating expenditure. There is no reason for not continuing to apply the EBSS to our business for the 2016–2020 regulatory control period.

In respect to the carry over amounts that arise from applying the EBSS for the 2011-2015 regulatory control period refer to chapter 13.

11.3 Service target performance incentive scheme

In November 2009, the AER published the *Electricity distribution network service providers, Service target performance incentive scheme* (**STPIS Guideline**).

[119] AER, Draft Decision, Ausgrid distribution determination 2015–16 to 2018–19, Attachment 9: Efficiency benefit sharing scheme, November 2014, pp.10-12.

The F&A Paper proposes to continue to apply the STPIS Guideline to the Victorian distributors in the 2016–2020 regulatory control period. The AER does not propose to apply the GSL component as the Victorian distributors are subject to a jurisdictional GSL scheme.[120] Should the Victorian Government move to amend this before the next regulatory control commences, the AER intends to adopt the changed requirements.

The AER's draft decision on the NSW/ACT distributors deviated from the STPIS Guideline by calculating the reliability incentive rates based on the value of customer reliability (**VCR**) contained in AEMO's 2014 report[121] rather than the values contained in the STPIS Guideline.

We propose to apply the STPIS for the 2016–2020 regulatory control period. We propose to apply the STPIS in accordance with the STPIS Guideline, subject to the following exceptions:

- the incentive rates for the reliability parameters are calculated based on the relevant VCR values from AEMO's 2014 report;
- the reliability targets for unplanned System Average Interruption Duration Index (**SAIDI**), unplanned System Average Interruption Frequency Index (**SAIFI**), for each network segment, are calculated based on the historical five year average performance over the period 2010 to 2014 plus an adjustment to account for the deterioration in network performance that will occur as a result of the significant reduction in the VCR used for network planning purposes and the STPIS incentive rates;
- the Momentary Average Interruption Frequency Index (**MAIFI**) is not included; and
- capping total revenue at risk for all s-factor parameters to +/- 2.5 per cent, including +/- 2 per cent for reliability parameters and +/- 0.5 per cent for customer service parameters.

We propose no variations from the STPIS Guideline in relation to calculating the telephone answering target or incentive rates. We propose no additional customer service parameters.

Details on how we propose to apply the STPIS Guideline and reasons for our proposed deviations from the STPIS Guideline are set out in appendix I.

Our proposed STPIS targets and incentive rates are set out in tables 11.1 and 11.2 respectively. The calculations are provided in the attached models, *CP STPIS targets* and *CP STPIS incentive rates*.

We propose no revenue increments and decrements for the STPIS as this is dealt with in the price control formula.

For the 2016–2020 regulatory control period we do not propose any expenditure associated with improving the performance of the network for the purposes of the STPIS.

Table 11.1 STPIS targets

Parameter	Segment	2016-2020
Unplanned SAIDI	CBD	10.02
Unplanned SAIDI	Urban	34.01
Unplanned SAIFI	CBD	0.14
Unplanned SAIFI	Urban	0.50

120 Victorian Electricity Distribution Code (Victoria).

121 AEMO, Value of Customer Reliability Review, September 2014.

Parameter	Segment	2016-2020
Telephone answering %	Network	75.31

Source: CitiPower

Table 11.2 STPIS incentive rates

Parameter %	Segment	2016–2020
Unplanned SAIDI	CBD	0.05
Unplanned SAIDI	Urban	0.05
Unplanned SAIFI	CBD	2.85
Unplanned SAIFI	Urban	3.23
Telephone answering	Network	-0.04

Source: CitiPower

11.4 Demand management incentive scheme

The DMIS that applies to our business for the 2011-2015 regulatory control period comprises two components:[122]

- Part A is a demand management innovation allowance (**DMIA**) which is provided on a 'use-it-or-lose it' basis. The approved amount of the DMIA takes the form of an annual ex-ante allowance provided as additional fixed revenue for each year of the regulatory control period. For the purposes of the 2011-2015 regulatory control period the total amount for our business was capped at $1 million over the regulatory control period; and
- Part B is a foregone revenue component. A foregone revenue component allows a distributor to recover foregone revenue as a result of successful, approved demand management initiatives under the DMIA, where these result in lower energy throughput (and hence, lost revenue) for the distributor. This component was designed to interact with certain forms of control under which revenue may vary with energy volumes (for example a weighted average price cap).

For the 2011-2015 regulatory control period, we have fully utilised our DMIA of $1 million under Part A of the DMIS and we did not make any application for recovery of foregone revenue under Part B of the DMIS. Accordingly, we propose no revenue increments or decrements arising from the DMIS in our 2016–2020 proposed revenue requirement.

The F&A Paper proposes that Part A of the DMIA will continue to apply for the 2016–2020 regulatory control period and the total amount for our business will be capped at $1 million over the regulatory control period.

We propose the ex-ante capped allowance, Part A of the scheme, continues to be provided as additional fixed revenue for each year of the regulatory control period.

However, we propose an amendment to the scheme whereby we can seek further funding above the capped amount, on the proviso the AER pre-approves all proposed DMIS initiatives in excess of the capped amount. We consider a capped DMIS constrains the ability of distributors to invest in innovation. Given the rapid rate of

122 AER, Victorian electricity distribution network service providers distribution determination 2011-2015, Final Decision, October 2010.

technological change, a well-functioning DMIS should facilitate our ability to respond and realise greater benefits for consumers.

Enabling further funding to be provided, following pre approval by the AER, facilitates exploration of demand management innovations in a timely manner and ensures potential efficiency enhancing innovations are not unduly constrained or deferred due to an arbitrary cap. Innovations in demand management have the potential to replace or defer network augmentation and therefore promote efficient investment in electricity services for the long term interests of customers. Our proposal to provide an opportunity for further funding above the ex-ante cap is therefore consistent with the National Electricity Objective.

The F&A Paper also proposes that Part B will not apply because it has determined a revenue cap as the form of control. We agree that Part B of the scheme is not necessary under a revenue cap form of control.

11.5 F-factor scheme

In the 2011-2015 regulatory control period the F-factor scheme has been administered as a separate charge under Victorian legislation.

On 24 June 2010, the Victorian Parliament passed the *Energy and Resources Legislation Amendment Act 2010.* The Act amended the *National Electricity (Victoria) Act 2005* (**NEVA**) to introduce an ‘f-factor scheme’. This scheme is intended to provide incentives for distributors to reduce the risk of fire starts and reduce the risk of loss or damage caused by fire starts.

Under section 16C of the NEVA, the Victorian Government may confer functions and powers, or impose duties, on the AER to make a determination for the purpose of providing incentives for distributors to reduce the risk of fire starts and reduce the risk of loss or damage caused by fire starts.

Subsequent to passing the *Energy and Resources Legislation Amendment Act 2010*, the Victorian Government published an *f-factor scheme order 2011* (**Order**) on 23 June 2011.

The F&A Paper proposes the f-factor scheme continue to be incorporated in the control formula in the next regulatory control period. The AER proposes that it will apply any amendments made to the f-factor scheme by the Victorian Government.

We accept the AER’s position to apply the f-factor scheme for the 2016–2020 regulatory control period.

We propose no f-factor revenue increments or decrements as it is included as a pass through item under the price control formula.

11.6 Small-scale incentive scheme

We do not propose that a small-scale incentive scheme apply for the 2016–2020 regulatory control period.

We were not subject to a small-scale incentive scheme for the 2011-2015 regulatory control period. Accordingly, we propose no revenue increments or decrements arising from small-scale incentives schemes in our 2016–2020 proposed revenue requirement.

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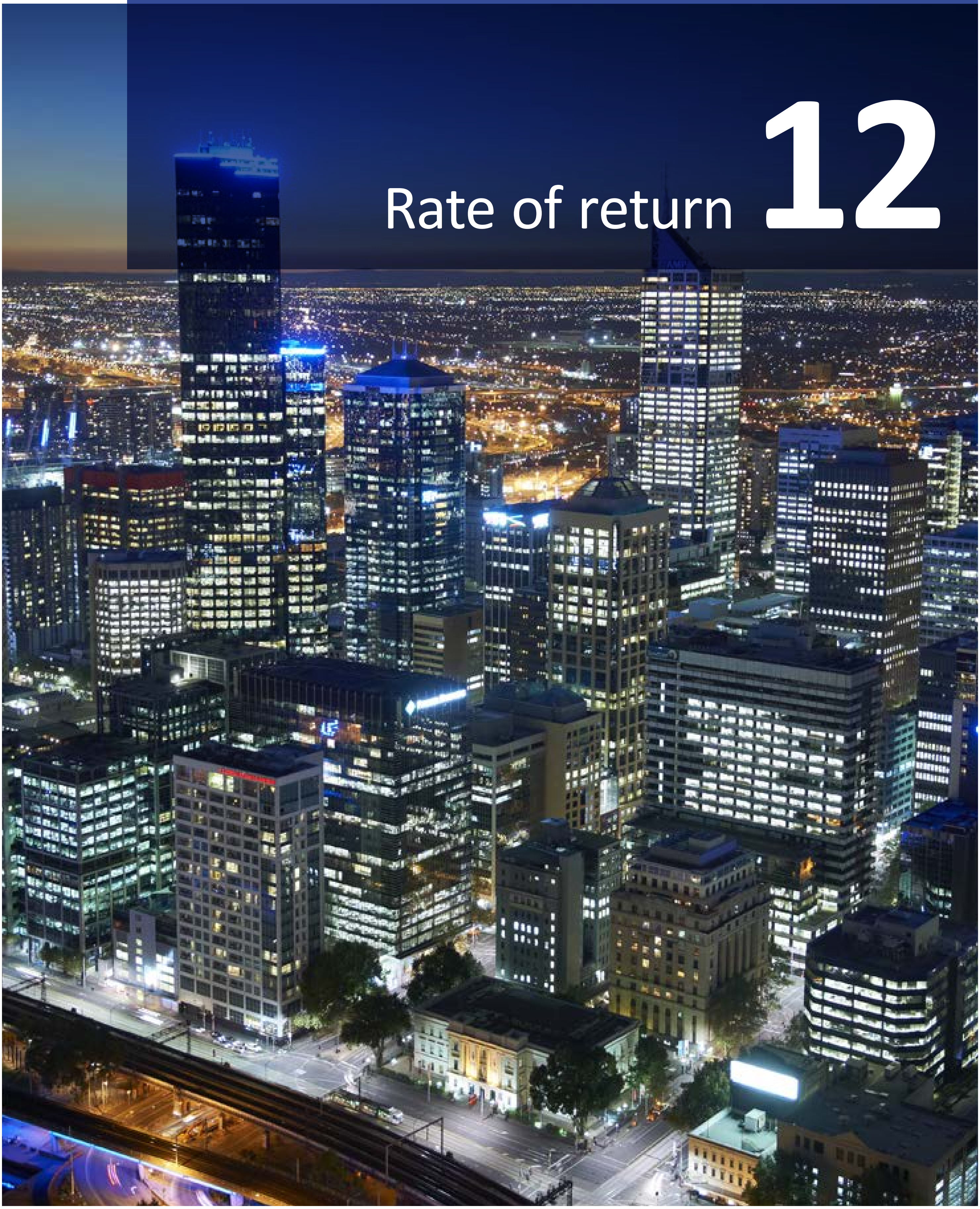
12 Rate of return



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12. Rate of return

12.1 Introduction

The National Electricity Rules (**Rules**) require the return on capital be estimated by applying a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity and should be estimated as a weighted average of the return on equity and the return on debt. An efficient rate of return is important because if the rate of return is inflated, network charges will be higher than necessary. Equally, if the rate of return is below a fair market return, the investment capital necessary to keep our network financially healthy and enable us to deliver the service customers expect will be directed elsewhere.

Our proposed approach to estimating the rate of return has regard to a broad range of information. In particular, to estimate the return on equity we take into account the output of all relevant models—the SL-CAPM, the Black CAPM, the Fama French Model, and the Dividend Discount Model. In contrast, the AER's approach set out in its Rate of Return Guideline, and in its recent draft determinations for the NSW and ACT electricity distribution businesses, effectively relies on an incorrect application of only a single SL-CAPM model to estimate the return on equity. Our approach is supported by an extensive range of evidence and expert reports. To estimate the return on debt, we adopt a ten year trailing average using a hybrid transition approach. This transition approach is applied only to the risk free rate component (and not the debt risk premium, as this component cannot be hedged). We do not agree that the Guideline transition approach reflects the efficient financing costs of a benchmark efficient entity as required by the Rules.

Combining the return on debt and the return on equity, the AER's approach provides a rate of return that falls considerably short of the rate of return that an efficient benchmark entity would require to attract sufficient capital to sustain our network into the future. This chapter seeks to explain how such a fundamental difference arises and our proposed approach to the allowed rate of return.

In 2012, the Australian Energy Markets Commission (**AEMC**) commenced a process to change how revenues are set for electricity and gas network businesses under the Rules. The new Rules include the requirement for the AER's determination to meet the rate of return objective:

> *The allowed rate of return objective is that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services (the allowed rate of return objective).*

The main change to the Rules was removal of the prescriptive provisions concerning how the return on capital should be established, and instead requiring that the AER adopt a broader consideration of all the relevant inputs it employs when undertaking its network economic regulatory functions. The Rules provide for the publication of a Rate of Return Guideline (**Guideline**) in which the AER states its intentions with respect to how it will exercise its powers. The Guideline was published in 2014.

We agree with many parts of the Guideline. However, there are also aspects of the Guideline we consider are inconsistent with the allowed rate of return objective, do not promote the National Electricity Objective (**NEO**), nor enable the recovery of the efficient costs of capital as required by the revenue and pricing principles. For example:

- there is agreement concerning the optimal debt to equity ratio employed by such a benchmark firm;
- with respect to equity, there is agreement over which leading finance models could be used to estimate the cost of equity. However, there are important differences of view concerning which of the models should be employed in the regulatory determination, what role each model should play, the manner in which the models should be implemented, and the values ascribed to key parameters used in the models;

- with respect to debt, there is agreement on the use of a ten year trailing average and that the return on debt should be automatically updated annually. However, there are important differences of view concerning:
  - the relevant benchmark credit rating;
  - the transition applied in the estimation of the return on debt;
  - the nomination of averaging periods for use in the estimation of the return on debt;
  - whether an adjustment should be made to reflect the hedging costs and the new issue premium;
- with respect to gamma, there is a fundamental difference of view concerning how to establish the relevant value.

Since the Guideline was published, the AER has published draft determinations for a number of electricity businesses (New South Wales (**NSW**) electricity distribution, NSW electricity transmission, Tasmanian electricity transmission and NSW gas distribution). These draft determinations are relevant in that the determinations:

- clarify how the AER would use financial models other than the Sharpe-Lintner Capital Asset Pricing Model (**SL-CAPM**), and the other material the AER considers to be relevant, which was not fully explained in the Guideline;
- clarify the AER's understanding of the efficient debt management strategy under the previous Rules, and its requirement for all debt averaging periods to be nominated and agreed prior to the commencement of a regulatory control period;
- provide that the benchmark debt costs will be determined using a simple average of the values published by the two currently available service providers (the Reserve Bank of Australia and Bloomberg) and how the data from the Reserve Bank of Australia and Bloomberg would be extrapolated to reflect a ten year benchmark tenor;
- use updated data to produce a gamma of 0.4 instead of the 0.5 value that appears in the Guideline (although the methodology remains as it was in the Guideline);

This chapter is structured as follows:

- an outline of the changing risk profiles for electricity distribution businesses;
- establishing the allowance for the return on equity;
- establishing the allowance for the return on debt;
- an illustrative calculation establishing a return on debt using data from the 20 day period to 30 January 2015;
- establishing the inflation rate;
- calculation of the return on capital; and
- setting the value for gamma.

12.2 The changing risk profile for electricity distribution businesses

The allowed rate of return objective highlights that risk is an important consideration in setting the allowed rate of return for equity and debt. Electricity network operators compete with other businesses to attract investment capital and investors will only provide investment capital if a competitive return is provided that adequately rewards for the risks of that investment. For consumers, it is important that regulatory decisions do not over-reward businesses for risk (because prices would be higher than they need to be) and equally that these decisions do not under-compensate businesses for risk (because under-capitalised businesses cannot make required investments or meet required service standards to consumers, and they carry excessive risk of financial failure).

For at least a century, the principal characteristics of the distribution system have not changed: the most cost effective way to manage load reliably has been to connect almost everyone to the interconnected network that provides access to centralised thermal generation. Throughout the 20 years that the economic regulation has applied through the NEM, demand has been consistently growing in a way that is less volatile than many other industries and technological change has been slow.[123]

However, the risk faced by distributors has changed dramatically in the recent past. Essentially we are now confronted with two possible future scenarios, one in which we evolve and survive and the other in which we become progressively redundant. The risks we face have changed:

- solar PV have been available since the 1970s but they played almost no part in supplying electricity to the grid-connected mass market in the ensuing 30 years because the technologies used to manufacture them were price prohibitive. In recent times, prices of solar PV units have fallen rapidly. The effect of dramatically lower global solar installation prices is that global businesses are aggressively marketing solar PV in Australia.[124]
- the second development is the introduction of 'smart' technology (smart grids and smart meters) that enable better management and control by the consumer of when and how they consume electricity. To date this has been conceived of as being a technology to improve the performance of the traditional grid connected power industry but many of the same technologies will be able to be used with or without grid connection. Some smart grid projects have been launched in Australia already, and we can only anticipate that more projects will be undertaken in the future.[125] Smart meters have been rolled out comprehensively in Victoria, and consumers can elect to be billed on a 'flexible pricing' basis, which allows consumers to better manage their energy usage and thereby reduce their energy bill.[126]
- the third factor to consider concerns power storage, most notably batteries and super capacitors. Similar to the solar PV market, price reductions of power storage systems are resulting from a race between global manufacturers to improve production technology and scale economies in manufacturing to win large-scale new business opportunities in industrialised countries.

Taken separately, each of the above developments (reduced costs for distributed generation, reduced costs for energy storage and the improved ability for consumers to manage their consumption) pose their own risks for network operators. Further, when these three factors combine it calls into question whether customer disconnections from the grid might be significant enough to risk the viability of the whole regulated price recovery system.

Customers connect to the grid and stay connected for two main reasons—to gain access to cost competitive generation and to have access to a reliable supply of electricity as and when they need electricity. The risk that now looms within the relevant 50 year investment horizon is that a significant number of customers may disconnect from the grid. The NEM's Consumer Advocacy Panel funded the preparation of a report *What Happens When We Un-Plug* that studied whether it might be cost effective for customers in Bendigo, Werribee

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123 For example, in order to facilitate investments required to achieve high reliability expectations, the Rules expressly provide that there are not asset write-offs or write-downs (also known as 'optimisation').

124 Mr T. Werner, CEO of global solar power conglomerate, SunPower recently stated that 'the economics of solar work better in Australia than in most places in America', per 'SunPower says Australia could be global leader in local generation' REneweconomy, April 2014.

125 See Smart Grid Smart City project, < http://www.smartgridsmartcity.com.au/>

126 See State Government of Victoria, Flexible Pricing, <http://www.smartmeters.vic.gov.au/flexible-pricing>

and Melbourne to disconnect individually or in clusters. It was found that it was already economic for some customers to disconnect and for most others it will become economic to do so before 2020.

Investment analysts are already downgrading electricity utility bonds in other countries on this basis:[127]

> *Electric utilities ... are seen by many investors as a sturdy and defensive subset of the investment grade universe. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. Based on our analysis, the cost of solar + storage for residential consumers of electricity is already competitive with the price of utility grid power in Hawaii. Of the other major markets, California could follow in 2017, New York and Arizona in 2018, and many other states soon after...*
>
> *In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar+ storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.*

Electricity industry commentators often refer to a 'tipping point' or a 'point of inflection' or even a 'death spiral', where the regulated pricing system becomes unsustainable and an endless spiral of disconnections commences. The 'death spiral' theory posits that if a significant number of customers find distributed generation and power storage more cost effective than staying connected, the prices for those who remain connected would rise to recover the costs of the infrastructure no longer used for the customers who had disconnected. As the prices are raised, it creates the incentive for another group of customers to disconnect and so on until there is not a sufficient customer base to be able to cover the costs of the whole system.

A particular risk in Victoria arises from the high levels of gas penetration which, at more than 90 per cent, eclipse the rates of every other State or Territory.[128] When a household has gas heating, hot water and cooking, a smaller number of solar PV panels will satisfy the smaller electricity demand compared with a household in which all its major appliances are electrical, and a smaller battery storage capacity would enable disconnection from the grid altogether. Similarly, if there are disconnections from the grid, the regulatory arrangements would seek to recover the stranded cost from the remaining customers and, because most of them have gas connected too, would be asked to carry a high per kW cost, in turn creating inequity and further incentives to disconnect.

There is no doubt that power storage, solar power and smart technology are game-changing technologies that will modify the ways in which households and businesses consume energy. However it is important to read the 'death spiral' thesis with some caution. This is because 'death spiral' type arguments fixate heavily on the potential impacts of solar power and power storage technologies and give too little credit to the capacity of conventional electricity distributors to update their business model by harnessing new technologies. The rollout of smart meters for example, will enable energy distributors to modify the manner in which energy consumption is charged (delivering more accurate, real-time pricing for consumers, which enables consumers to use energy in more cost-effective ways).[129] Having rolled out smart meters en masse, we are in a strong position to do so. Moreover, the 'death spiral' theory is predicated on so many intersecting factors that it is difficult to gauge a time at which these three factors might come together in such a way that a flight from the grid could occur. As Paul Graham, chief economist of the CSIRO Energy Flagship has commented, it is unclear how long it will be before power storage systems can be said to be affordable, and thus game-changing.[130]

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[127] Barclays credit strategy team per Barron's Income Investing, 2014.

[128] AER 2014, State of the Energy Market, page 110.

[129] Grattan Institute, Fair pricing for power, July 2014.

[130] CSIRO, Change and Choice: The Future Grid Forum's Analysis of Australia's potential electricity pathways to 2050, December 2013, p. 30.

What is clear, however, is that the manner in which the AER considers risk in estimating the rate of return is inadequate to account for risks faced by the network service providers under the prevailing market conditions. Specifically, the AER's draft determinations for the NSW electricity distribution businesses proceed on the basis that a gearing ratio, a 'beta' value within an SL-CAPM model, and a benchmark credit rating can adequately recompense a distributor for the returns required on risky investments.[131] These draft determinations, and the Guideline they apply, are largely based on consideration of an analysis of risk by the AER itself, and a report from Frontier Economics (both undertaken at the time of the Guideline development process).[132] It is simply not the case that an adequate compensation for risk can be provided that way. That is:

- restrictions on asset optimisation and the application of a revenue cap—additional measures the AER suggest insulate the business from risk—may not be effective, particularly if the number of disconnections changes the willingness or ability of the remaining consumers to pay for common and potentially stranded assets that were built solely to service customers who have now disconnected; and
- the analysis undertaken by Frontier Economics fails to acknowledge the new risks arising from the scenarios outlined previously (i.e. risks posed by solar penetration, battery storage and smart meters).

It is incumbent upon the AER to engage with the above material and identify how these risks are accommodated in the overall allowed return on capital.

12.3 Return on equity

According to the new Rules, in determining the allowed rate of return regard must be had to relevant estimation methods, financial models, market data and other evidence. Our proposed approach to estimating the return on equity component of the allowed rate of return contributes to this by:

- identifying the relevant rate of return models, being the SL-CAPM, the Black CAPM, the Fama French Model, and the Dividend Discount Model (which are, in fact, the same as those identified by the AER);
- identifying the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise modelling results as a weighted average of the individual estimates with the weights that avoid double-weighting any of the key conceptual elements of the models.

In contrast, the AER's proposed approach effectively estimates the return on equity using a single model—the SL-CAPM. The AER has always used the SL-CAPM for setting rates of return for electricity distribution businesses, even though a vast array of evidence now shows the significant shortcomings of the SL-CAPM and the superior usefulness of other models. Further, the particular implementation of the SL-CAPM applied by the AER estimates returns on equity that move perfectly in parallel with movements in the risk free rate. The effect is that returns on equity have plummeted as observed yields on Commonwealth Government Securities have fallen.

This section explores these issues in detail as follows:

- section 12.2.1 introduces the models that are relevant in estimating the return on equity;

[131] AER, Ausgrid draft determination, November 2014; AER, Essential draft determination, November 2014; Endeavour draft determination, November 2014; AER, ActewAGL draft determination, November 2014.

[132] Frontier Economics, Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia, July 2013.

- section 12.2.2 identifies the key reasons why the approach in the Guideline is delivering an unacceptably low return on equity and does not comply with the requirements of the Rules;
- section 12.2.3 sets out our proposed approach to the return on equity; and
- section 12.2.4 provides an illustrative calculation using current market data.

12.3.1 Identify and compare the relevant models and any other relevant evidence

In developing the new Rules for estimating the rate of return, the AEMC stated that no single return on equity model is preferable as being free of weaknesses or captures all the strengths of others.[133] Accordingly, the AER's Guideline sets out that the relevant financial models for estimating the return on equity are:

- Sharpe Lintner CAPM (SL-CAPM);
- Black-CAPM;
- Fama French Model;[134] and
- Dividend Discount Model.

The AER also proposed to use other information, such as expert reports prepared in the context of assessing whether corporate takeover offers are 'fair', and surveys of practitioners. To the extent these other sources are of any use, they tend to be useful in illustrating how the above models should be implemented and combined in practice to deliver timely estimates of value or return.

We agree with the 'relevant' set of models outlined in the AER's Guideline. In particular, in a report prepared on behalf of a number of energy network business, Professor Gray considered all four of the return on equity models provide evidence that is relevant for estimating the return on equity because:[135]

- all four models have a sound theoretical basis;
- all four models have the purpose of estimating the required return on equity as part of the estimation of the cost of capital;
- all four models can be implemented in practice; and
- all four models are commonly used in practice.

Along with a number of other energy network businesses, we also commissioned a series of detailed reports from leading experts to explore the strong and weak characteristics of each model. The first set of relevant reports was provided by the Energy Networks Association as part of the consultation process on the Guideline.[136]

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[133] AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 48.

[134] Although the AER found the Fama French Model to be relevant, its Guideline proposes to give it no role, page 13 the Guideline.

[135] SFG, The required return on equity for regulated gas and electricity network businesses, June 2014, [9]

[136] NERA Economic Consulting, Review of cost of equity models, June 2013, NERA Economic Consulting, Estimates of the [Black CAPM] zero beta premium, June 2013, SFG Consulting, Dividend discount model estimates of the cost of equity, June 2013, SFG Consulting, Evidence on the required return on equity from independent expert reports, June 2013, CEG Consulting, Estimating the return on the market, June 2013, CEG Consulting, Estimating E[Rm] [expected return on the market] in the context of regulatory debate, June 2013, SFG Consulting, Regression-based estimates of risk parameters for the benchmark firm, June 2013, SFG Consulting, The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model, June 2013, CEG Consulting, Information on equity beta from US companies, June 2013, SFG Consulting and Monash University, Comparison of OLS and LAD regression techniques for estimating beta, June 2013, SFG Consulting and Monash University, Assessing the reliability of regression-based estimates of risk', June 2013, Incenta Economic Consulting, Term of the risk free rate for the cost of equity, June 2013, NERA Economic Consulting, The market, size and value premiums, June 2013, NERA Economic Consulting, The Fama-French three-factor model, October 2013, SFG Consulting, Reconciliation of dividend discount model estimates with those

Since the publication of the Guideline, SFG Consulting has prepared a suite of reports, which explore in detail a series of issues raised in the Explanatory Statement that accompanied the Guideline. A report dated 12 May 2014 addresses the issues raised in connection with the equity beta in the context of the SL-CAPM.[137] The next three reports focus on the issues raised in relation to each of the other financial models and a fifth report addresses how to set a single allowed return on equity figure using the above inputs.[138] In February 2015 SFG Consulting has written further reports on each of the above topics in response to the suite of draft determinations that the AER issued in late 2014.[139]

NERA has also prepared reports that provide important insights into the empirical performance of the SL-CAPM, the AER's variation on the SL-CAPM and the Black CAPM and into historical estimates of the market risk premium.[140]

Incenta has provided two reports, one prepared for submission to the AER as part of the first group of decisions to be made under the new Rules released in late 2014 and another in response to those draft decisions.

Grant Samuel has extensive experience undertaking valuations in the context of stock market acquisitions and it has provided its views on the AER's approach.[141]

A summary of the strong and weak characteristics of each model, as set out in these reports, includes:

- empirical studies of the SL CAPM have consistently found the performance of this model to be poor.[142]
- the SL-CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. The extent to which the SL-CAPM underestimates returns to low-beta portfolios is both statistically significant and economically significant.[143]
- further estimation problem arise with the SL CAPM during periods of high or low official interest rates, when this model is implemented in the way the AER has for many years (by using a current Commonwealth Government Bond yield to estimate the risk free rate, in combination with a very long run average of historical excess returns to estimate the MRP). The AER's approach, which is inspired by Ibbotson, behaves as

compiled by the AER, October 2013, CEG Consulting, AER equity beta issues paper: International comparators, October 2013, SFG Consulting, Letter: Water utility beta estimation, October 2013, SFG Consulting and Monash University, Comparison of OLS and LAD regression techniques for estimating beta, June 2013, SFG Consulting and Monash University, Assessing the reliability of regression-based estimates of risk, June 2013, Incenta Economic Consulting, Term of the risk free rate for the cost of equity, June 2013, NERA Economic Consulting, The market, size and value premiums, June 2013, NERA Economic Consulting, The Fama-French three-factor model, October 2013, SFG Consulting, Reconciliation of dividend discount model estimates with those compiled by the AER, October 2013, CEG Consulting, AER equity beta issues paper: International comparators, October 2013, SFG Consulting, Letter: 'Water utility beta estimation', October 2013.

137 SFG Consulting, Equity beta, May 2014.

138 SFG Consulting, Cost of equity in the Black Capital Asset Pricing Model, May 2014; SFG Consulting, The Fama-French model, May 2014; SFG Consulting, Alternative versions of the dividend discount model and the implied cost of equity, May 2014; SFG Consulting, The required return on equity for the benchmark efficient entity, February 2015.

139 SFG Consulting, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, February 2015; SFG Consulting, Using the Fama-French model to estimate the required return on equity, February 2015; SFG Consulting, Beta and the Black Capital Asset Pricing Model, February 2015.

140 NERA, Empirical Performance of the Sharpe-Lintner and Black CAPM, February 2015; NERA, Historical Estimates of the Market Risk Premium, February 2015;NERA, Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama French Three Factor Model, March 2015.

141 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015

142 SFG, Cost of Equity in the Black Capital Asset Pricing Model, May 2014, page 2; see also SFG Consulting: Equity Beta, May 2014, page 6–7; SFG, The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, March 2015; NERA, Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama French Three Factor Model, March 2015.

143 NERA, Empirical Performance of the Sharpe-Lintner and Black CAPMs, February 2015, page 54.

if investors' expectations move in perfect parallel with yields on the Commonwealth Government Bonds. There is no solid basis for this assumption.

- alternatives to the Ibbotson inspired approach adopted by the AER for establishing the market risk premium (for use in the SL-CAPM)—such as the Wright approach, which assumes that the real return on equity is more stable over different market conditions—are not a panacea for all the flaws in the Ibbotson approach.
- the Black CAPM is a more general application of the SL CAPM, and does not rely on the assumption that all investors can borrow at the risk-free rate of interest. It has been demonstrated to provide a significantly better empirical fit to the data than the SL-CAPM.[144] However, the Guideline has identified that the Black CAPM model's use is limited to informing the foundation model (SL-CAPM) parameter estimates.
- despite the AER's assertions that the Black CAPM is unusable because a zero beta portfolio is allegedly hard to estimate, the Black CAPM (also referred to as 'empirical' or the 'Zero Beta' CAPM) has been used extensively in US regulation cases, particularly when estimating a beta value less than one. For example, as set out table 12.1:

Table 12.1 Application of the Black CAPM in regulatory proceedings

Regulator	Citation
New York Public Service Commission (2009)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers 2009 N.Y. PUC LEXIS 507
New York Public Service Commission (2007)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service 2007 N.Y. PUC LEXIS 449; 262 P.U.R.4th 233
New York Public Service Commission (2009)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service 2006 N.Y. PUC LEXIS 227; 251 P.U.R.4th 20
Oregon Public Utility Commission (2001)	In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149. 2001 Ore. PUC LEXIS 418; 212 P.U.R.4th 379

Source: CitiPower.

- while empirical studies have consistently found that the Black CAPM performs better than the SL-CAPM, the Black CAPM is known to have a downward bias for value stocks.[145] The same problem, however, arises with the SL-CAPM when current returns on central bank debt are used to estimate of the risk-free rate and this is added to a long run average estimate of MRP.

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[144] NERA, Empirical Performance of the Sharpe-Lintner and Black CAPM, February 2015, page [56-57]..

[145] SFG, Cost of Equity in the Black Capital Asset Pricing Model, May 2014, page 38.

- the Fama French Model provides separately for an additional return on value stocks, and empirical studies in the US and Australia have confirmed that it provides an unambiguously better fit to the data than the SL CAPM.[146]
- the Fama French Model is newer than the other two CAPM models, but one of the authors of the model has received a Nobel Prize for the body of work for which this model is a part.[147] The Fama French Three Factor model has also appeared in a number of state regulatory proceedings in the United States.[148]
- the Guideline takes the approach that although the Fama French Model is 'relevant', it should play no part whatsoever in the establishment of the allowed rate of return. In our view this is wholly unacceptable. In particular, if the Fama French model is wholly excluded from the analysis, there is no other model that specifically addresses the downward bias for value stocks.
- the Dividend Discount Model (or Dividend Growth Models) approaches the task of estimating the required rate of return in a different way to the CAPM and Fama French Model. It has the advantage of not requiring any assumptions about what factors drive required returns—it simply equates the present value of future dividends to the current stock price.[149]
- the Dividend Discount Model is commonly used in industry and regulatory practice. For example, as the Federal Energy Regulatory Commission of the United States (**FERC**) notes, the model has become the most popular technique of establishing the cost of equity, and it is generally accepted by most commissions. Virtually all cost of capital witnesses used this method, and most of them consider it their primary technique.[150]
- whereas the Guideline materials identify some concerns with the dividend discount approach, the specification adopted by SFG Consulting addresses most of those concerns.[151] This model performs well provided a robust method is used for forecasting future dividends. SFG Consulting has reviewed a range of ways that this model can be implemented, both those generated by or for the AER during the Guideline consultation process and in other publications. The principal issues include how quickly it is assumed that the actual level of dividends reverts to the long run assumed dividend rate of growth, whether that progression is linear or otherwise and how long term dividend growth is assumed to be related to assumptions about over-all economic growth.

12.3.2 Flaws with the AER's approach to estimating the allowed return on equity

The AER's approach to estimating the allowed return on equity has a number of flaws including:

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146 SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 9.

147 Eugene Fama is the 2013 recipient of the Sveriges Riksbank Prize in Economic Science in memory of Alfred Nobel (the Nobel Prize in Economics).

148 Direct testimony of Paul R. Moul, Managing Consultant – P.Moul & Associates, Commonwealth of Massachusetts Department of Telecommunications and Energy, October 17, 2005;Application of Pacific Gas and Electric Company for Authority to establish its Authorized Rate of Return on Common Equity for Electric Utility Generation and Distribution Operations and Gas Distribution for Test Year 2006; Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Nevada Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto 2007 WL 2171450 (Nev.P.U.C.); Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008.

149 SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, 6 June 2014, page 9.

150 United States of America Federal Energy Regulatory Commission, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

151 SFG, Dividend Discount model estimates of cost of equity, June 2013; SFG, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, Feb 2015; SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 9.

- the AER brings a skewed perspective to the evaluation of the strengths and weaknesses of the models;
- the AER's extra-legislative criteria distort the evaluation of the merits of the available inputs;
- the Guideline does not give real weight to all the relevant inputs as required;
- the AER has laboured over an improper search for a preeminent model and improper constraints inherent in using a 'foundation' model instead of devoting its efforts to specifying all the available models and giving them the weight they merit;
- even when implementing the foundation model approach, the AER has made a flawed selection of the Ibbotson inspired approach to implementing the SL-CAPM as the foundation model;
- the AER's incorrect selection of parameter values for the AER's Ibbotson inspired SL-CAPM; and
- the AER's flawed use of expert reports.

These flaws are discussed separately below.

A skewed perspective on the strengths and weaknesses of the available models

We are concerned that the assessment by the AER is not being undertaken on an 'even handed basis' and that this could explain how the other flaws discussed below have come about.

Despite the superior empirical performance of the Black CAPM discussed above, the AER relegates this model to a secondary status on the following basis:[152]

> *the model is not empirically reliable;*

and

> *the model is not widely used to estimate the return on equity by equity investors, academics or regulators.*

The AER elaborates on the first criticism, stating that the return on the zero beta asset is unobservable and the methods for estimating it are unreliable. Both the AER and McKenzie & Partington appear to reach that conclusion by observing differences between the reports lodged by the businesses on this question. However, the AER at least concedes that:[153]

> *While we consider SFG's latest estimate of the zero beta premium appears more plausible, we believe that the large range of zero beta estimates by consultants for the NSPs indicates the model is unsuitable to use to estimate the RoE of our benchmark efficient entity.*

This is no different from the estimation of beta and the MRP for use in the SL-CAPM's primary model which can be specified in a broad range of plausible and implausible ways. For example, the AER's own consultants produce beta results that range from 0.3 to 0.8 and for the MRP that are a full percentage point apart. With the NSP's studies included, the ranges are considerably wider again yet the yard-stick used to exclude the Black-CAPM is not a basis upon which the SL-CAPM is excluded.

Similarly, with respect to the (arguably irrelevant) consideration of whether the model is widely used, SFG notes that:[154]

> *[I]t is common for U.S. regulatory cases to use what is known as 'the empirical CAPM.' This is an implementation of the CAPM formula with an intercept above the contemporaneous risk free rate – to be*

152 SFG Consulting, Beta and the Black Capital Asset Pricing Model, Feb 2015, p18.

153 AER, Ausgrid draft determination, November 2014 [3-182].

154 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, p21.

> *consistent with the Black CAPM and the empirical evidence that supports it. The AER's contention that the Black CAPM is not widely used in practice relies only on the label of the model, and not on its substance.*

In its letter, Grant Samuel shares its views more broadly concerning the AER's model selection choices:[155]

> *In this case, it seems that the AER's approach has been to avoid changing its existing (single) formula 'foundation model' and proceed on the basis that as long as it can show that the model is widely used and the individual inputs can be justified, there is no need to concern itself with whether or not the final output is commercially realistic.*

Despite conceding that the model is useful indirectly, the AER decided not to use the Dividend Discount Model directly in estimating the allowed return on equity because it considers that its results are too sensitive to its input assumptions, but the AER does not give equal handed acknowledgement to the same criticisms concerning the CAPM. In Grant Samuel's words:[156]

> *The DGM, in its simplest form, has only two components to estimate – current dividend yield and the long term growth rate for dividends. The current yield is a parameter that can be estimated with a reasonably high level of accuracy, particularly in industries such as infrastructure and utilities. We accept that the question of the long term dividend growth rate becomes the central issue and is subject to a much higher level of uncertainty (including potential bias from sources such as analysts) and we do not dispute the comments by Handley on page 3-61.*
>
> *However, there is no way in which the issues, uncertainties and sensitivity of outcome are any greater for the DGM than they are with the CAPM which involves two variables subject to significant measurement issues (beta and MRP). The uncertainties attached to MRP estimates in particular are widely known yet are glossed over in the AER's analysis of the relative merits. Section D of Attachment 3 of the Draft Decision contains almost 40 pages discussing the most esoteric aspects of methodologies for calculating beta but in the end the AER's choice of 0.7 is, in reality, an arbitrary selection rather than a direct outcome of the evidence. Moreover:*

- *the plausible beta range nominated by the AER (0.4-0.7) creates a 2 percentage point swing factor for the CAPM-based cost of equity. Its own expert nominated an even wider range (0.3-0.8);*
  - *the 40 pages contain little meaningful discussion of issues such as standard errors or stability over time (as opposed to different time periods). Data on these aspects would be important to properly evaluate the overall reliability of the statistics; and*
  - *the publication of only averages for individual companies and not the range hides the underlying level of variability in these measures.*

> *In short, the claim of superiority for the CAPM is unfounded.*

The Grant Samuel letter adds:

> *It is also difficult to fathom why the AER states that the DGM is highly sensitive to interest rates but makes no mention of the sensitivity of CAPM to interest rates.*

The AER's treatment of the Fama French model is the most concrete illustration of the double-standards applied in excluding its results from consideration altogether. SFG Consulting's rejection of the AER's criticisms also illustrate that criticisms (a) and (b) apply equally to the SL-CAPM while criticisms (c) and (d) are incorrect—yet the Fama French model not the SL-CAPM model is excluded on this basis:

[155] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, p. 2.

[156] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, p. 3.

In our view, the reasons that the AER provides for dismissing the Fama-French model are without basis:[157]

a. *Sensitivity to different estimation periods and methodologies.*
The AER states that the estimates from the Fama-French model can vary across different estimation periods and techniques. In response, we note that this applies to all models that require the estimation of parameters. For instance the AER's own estimates for beta vary materially over time and across estimation methods. Moreover, the fact that some estimates of the Fama-French model might produce inconsistent results is not a basis for dismissing all estimates. A better approach would be to consider the relative quality and reliability of estimates.

b. *Estimation of ex ante required returns.*
The purpose of the Fama-French model is the same as the purpose of the Sharpe-Lintner CAPM – to explain the cross-section of stock returns. That is, the purpose of these models is to identify the features of stocks that can be used to predict what average returns they are likely to generate in the future. The key difference is that the predictions from the Fama-French model have been shown to be more closely associated with stock returns. It is theoretically possible that the superior empirical performance of recent decades might not continue into the future, but that should not be the basis for dismissing the Fama-French model.

c. *Lack of a theoretical foundation.*
We note that the Fama-French model was originally motivated by the poor empirical performance of the Sharpe-Lintner CAPM. Fama and French identified that the Sharpe-Lintner CAPM did not work and set about developing a model that did. Since that time, theoretical justifications for the Fama-French factors have been developed, in a way that is quite standard for scientific progression. In our view it would be illogical to reject the Fama-French model in favour of the Sharpe-Lintner CAPM on the basis that its original motivation was the poor performance of the very model that is to be adopted in its stead.

d. *Complex to implement.*
The Fama-French model is not complex to implement. It requires the estimation of factor returns and factor sensitivities (betas). There are simply three factors instead of one. In any event, a superior model should not be rejected in favour of an inferior one on the grounds of simplicity.

The inconsistent treatment that the AER applies to the different models betrays its affection for the SL-CAPM and this explains how the other flaws below may have arisen.

Extra-legislative criteria distort the evaluation of the merits of the available inputs

Instead of directly applying the rate of return objective, the National Electricity Objective (**NEO**) and the Revenue and Pricing Principles (**RPP**), the Guideline applies a set of extra-legislative criteria that do not appear in the NER or the NEL.[158] These criteria are expressed in such abstract terms that they invite irrelevant matters to be considered causing the decision-making process to be directed away from the matters referred to in the NER and the NEL.

The AER's application of these criteria has incorporated irrelevant considerations, contrary to the requirements of the Rules. For example estimation methods and financial models are required to be consistent with 'well accepted economic and finance principles' and promote 'simple over complex approaches'.[159]

157 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, p. 2.

158 AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 24.

159 AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 24-28.

As a consequence there is a strong preference for conservatism that has resulted in the decision being based on the SL-CAPM as the foundation model, with secondary weight being given to the DDM, the Black-CAPM only in the limited role of informing certain parameter estimates used within the SL-CAPM, and no weight at all being given to the Fama-French Model which is of a substantially younger vintage than the SL-CAPM. This conservatism runs directly counter to the intention of the AEMC that the new Rules do away with the incumbency of the SL-CAPM and open the decision making to the inclusion of all the relevant models and other inputs.[160] Models chosen on the basis of being simple can easily fall into error by excluding a proper consideration of the full range of factors affecting the prevailing cost of equity.

In fact there is overwhelming evidence that the SL-CAPM's dominant role should cease. The model has a poor empirical performance and it is demonstrably producing downwardly biased results. The Black CAPM avoids the bias but further empirical improvements are possible by using the Fama French three factor model. The DGM has been used for many years in the US and it provides an independent, wholly alternative basis to setting a rate of return that is also free of the flaws in the SL-CAPM but the AER rejects all these other models from playing a material role in the AER's estimation process.

The criterion that the choice of inputs should 'promote the simple over the complex where appropriate' has been instrumental in the selection of the SL-CAPM as the 'foundation model'; even though there is a requirement to consider all the relevant estimation methods regardless of the degree of complexity that could emerge. The models show that some of the additional detail (which the AER refers to as complexity) is required to avoid downward biases for stocks with betas of less than one (i.e. Black CAPM) or which are 'value stocks' (i.e. Fama French).

The 'fit for purpose' criterion imports the notion that each relevant model should be employed in a manner that is 'consistent with the original purpose for which it was compiled'. There is no logical basis to apply this constraint upon the use of the models.

The AER has also adopted the criterion for consideration: 'where applicable, reflective of economic and finance principles and market information'. In discussing what the AER has in mind, it appears that the theoretical pedigree of the model is one of the key considerations as to whether the criterion is met or not:[161]

> *We consider economic and finance theory provides important insights into the conditions for achieving economic efficiency, including for the setting of revenue and prices for natural monopoly service providers. Economic theory also suggests economically efficient outcomes are in the long-term interests of consumers. This criterion is intended to draw on these theoretical insights to maximise the likelihood that regulatory outcomes would promote economic efficiency, and thus would achieve the allowed rate of return objective and the (national electricity and gas) objectives.*

Expressed in that way, the criterion appears unobjectionable but the AER has in fact used it as a criterion of inclusion and exclusion – as well as 'ruling in' a model the AER considers has a strong theoretical foundation despite its dubious empirical credentials (i.e. the SL-CAPM), the AER also 'rules out' the Fama French model in large part because it is perceived as lacking a theoretical pedigree even though its empirical credentials are strong.

Excluding models on this basis is likely to frustrate the achievement of the rate of return objective. We reject the notion that the lack of a theoretical foundation is criteria that can further the attainment of the rate of return objective.

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[160] AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 49.

[161] AER, Rate of Return, Guideline Explanatory Statement, page 27.

A final concern with the criteria is that they are inconsistently applied. For instance, the AER's own foundation model concept is a good deal more complex than any of the SL-CAPM, Black CAPM and DGM taken individually and the aggregate result is clearly more complex than simply estimating the Fama French model. It is also a good deal more complicated than simply estimating all the models and taking a (weighted) average of the results.

The Guideline does not give real weight to all the relevant inputs as required

The approach to establishing the return on equity set out in the Guideline is not consistent with the NER and is not the best possible estimate of the required rate of return for equity that progresses the NEO. In particular, the Guideline does not meet the requirements of the new Rules that regard must be had to 'relevant estimation methods, financial models, market data and other evidence'. It is recognised that 'an expression such as 'have regard to' is capable of conveying different meanings depending on its statutory context'.[162] And in the absence of a definition of relevant, it is to be given its ordinary meaning in the context.[163] In this regard, it was noted by the AEMC in its draft rule determination and final rule determination:[164]

> *The final rule provides the regulator with sufficient discretion on the methodology for estimating the required return on equity and debt components but also* ***requires the consideration of a range of estimation methods, financial models, market data and other information so that the best estimate of the rate of return can be obtained overall that achieves the allowed rate of return objective****.*

Nor can it be adequate to elevate a single model as the foundation model and limit the role of all other models to the secondary status of estimating parameters within that foundation model unless there is a proper basis for concluding that they are unsuitable for contributing directly to the return on equity or that the return on equity cannot lie outside those constraints and that the 'right answer' must fall within the range of outputs that the foundation model could deliver.

Further, it is relevant to consider the context of the overall regulatory structure into which this new Rule has been inserted. The same language requiring 'regard' to be had to the full range of relevant inputs now appears in both the new Rules and National Gas Rules and should be similarly applied. In understanding the meaning of these words, they need to be understood as both a reform to previous regulatory practice in electricity and to previous regulatory practice in gas. In this regard, two points from the gas industry are important:

- the AER was permitted under the previous National Gas Rules to depart from solely using the SL-CAPM and it could have chosen to use alternatives for setting the return on equity. Network providers had previously proposed other methodologies that the AER had given consideration to but either rejected outright or consigned to a secondary role as a 'cross check'. The AEMC recognised that this approach needed reform to remove consequent constraints that concepts such as 'well accepted' had placed on the AER of accommodating broader range of inputs and the AEMC considered that the new rules would achieve their stated aim; and

- the National Gas Rules are the successor to the Gas Code and much of the language is inherited from that document. The use of the term 'have regard' in the Gas Code has been the subject of extensive litigation and the courts construed the term within the context of that document as imposing a requirement on the regulator to give 'real weight' to the material and that it was inadequate to consider and give no weight to

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162 Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, para 55; Project Blue Sky v Australian Broadcasting Authority (1998) 194 CLR 355.

163 Project Blue Sky v Australian Broadcasting Authority (1998) 194 CLR 355.

164 AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 9-10; AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, page 8.

relevant information.[165] Given the prominence of that litigation in the history of the development of the current National Gas Rules, it is difficult to accept that the AEMC envisaged that it would be sufficient for the AER to consider all the relevant inputs and then give certain of those inputs no probative weight or only a constrained or secondary form of weighting.

The Guideline does not adhere to the requirement to give real weight:

- to the Fama French Model because it is not used at all (specifically given no role) in the establishment of the return on equity; and
- although some limited role may be given to the other two relevant models (the Black CAPM and DGM), these other models are each only used to inform one single parameter of the SL-CAPM. Even when used to inform a parameter of the SL-CAPM, they are used as secondary evidence that is disregarded to the extent that it is inconsistent with the primary range that is established using a different subset of the available evidence. Limiting their use this way severely constrains their ability to improve the quality of the return on equity estimate.

The Guideline Explanatory Statement describes the foundation model as follows:

> *Use one primary model with reasonableness checks. Generally, it would be expected that the output from the primary model would be adopted as our estimate of the expected return on equity (as per option one). However, where the reasonableness checks suggested the output from the primary model was not reasonable, the expected return on equity would be* ***determined based on regulatory judgement*** *(informative use of primary model).*

The more detailed specification of the foundation model, and the NSW draft decisions, give examples of the 'cross check' and 'regulatory judgement' – each of which have been problematic concepts in energy regulation. With respect to 'cross-checking' it is easy to decide what to do when all the evidence is mutually corroborative. However, there is a problem when the secondary 'cross check' material contradicts the primary material (and usually there is no concrete explanation by the regulator of what would happen). Where there is a conflict, either the initial estimate is to be preferred regardless of what the 'cross check' suggests or the secondary material is used to displace the initial estimate. In either case, one piece of information is in effect being given determinative weight and the other information is being given no weight.

The only 'circuit breaker' is to suggest that in the event of a conflict 'regulatory judgement' will prevail. The problem with this concept is that it is generally the term used when a regulator selects a value within a list of conflicting factors without providing the reasoning as to how the particular value was chosen. In other words, this term is usually used when there is no reasoning provided, and in that sense the decision is unreasonable. In this circumstance, it is impossible to know whether real weight was given to all the relevant material. This is not consistent with the Rules which require reasons to be given at both the draft determination stage and the final determination stage.[166]

For example, the AER uses 'regulatory judgement' in selecting a beta at the high end of its depressed range of 0.4 to 0.7 but there is no positive rationale expressed about why the 0.7 figure and this means that if (as we contend) the range is incorrect, it is not possible to discern whether the 0.7 number is then also incorrect if, say, the AER considers that unencumbered by the depressed range the number would be higher or whether there is a rationale for choosing that number.

[165] RE Dr Ken Michael AM; ExParte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at [54–6].

[166] NER, r. 6.10.2(3) and 6.11.2(3).

The NSW draft determinations identify a number of matters that have not been the basis of selecting the 0.7 number but the closest the NSW draft decision come to an articulation of why the 0.7 number has been chosen is to repeat that the AER has read all the materials submitted to it and reached a 'balanced outcome' by using 'regulatory judgement' that the result in it being 'satisfied' as to the furtherance of the rate of return objective:[167]

> *After taking these considerations into account, we adopt an equity beta point estimate of 0.7 for this draft decision, consistent with the Guideline. We consider this approach is reflective of the available evidence, and has the advantage of providing a certain and predictable outcome for investors and other stakeholders. We recognise the other information we consider does not specifically indicate an equity beta at the very top of our range. However, a point estimate of 0.7 is consistent with these sources of information and is a modest step down from our previous regulatory determinations. It also recognises the uncertainty inherent in estimating unobservable parameters, such as the equity beta for a benchmark efficient entity.*
>
> *We consider an equity beta of 0.7 for the benchmark efficient entity is **reflective of the systematic risk** a benchmark efficient entity is exposed to in providing regulated services. In determining this point estimate, we applied our regulatory judgement while having regard to all sources of relevant material. **We do not rely** solely on empirical evidence and we do not make a specific adjustment to equity beta to correct for any perceived biases in the SLCAPM. **We also do not rely** on empirical evidence from the Black CAPM, FFM or SFG's construction of the DGM (see appendix A and C). **We do not consider** our use of the SLCAPM as the foundation model will result in a downward biased estimate of the return on equity for a benchmark efficient entity (see appendix A.2.1).*
>
> *Our equity beta point estimate provides a balanced outcome, given the submissions by stakeholders and services providers. Figure 3-6 shows our equity beta point estimate and range in comparison with other reports and submissions. **We are satisfied** this outcome is likely to contribute to a rate of return estimate that achieves the allowed rate of return objective, and is consistent with the NEO and RPP.*

And finally,

> *We note McKenzie and Partington have now indicated the Black CAPM (of itself) does not justify any uplift to the estimated equity beta to be used in the SLCAPM. Nevertheless, we consider the model does theoretically demonstrate that market imperfections **could lead to the SLCAPM generating RoE estimates that are too high or too low. We have taken this into account in exercising our regulatory judgment** in choosing to use an equity beta of 0.7 in the SLCAPM. This is the equity beta we indicated we would use at the time we published the Guideline.*
>
> *We also acknowledge an equity beta of 0.7 is well above the fixed weight portfolio and average of individual firm equity beta estimates in Henry's 2014 report. However, in using an equity beta of 0.7 in applying the SLCAPM, we have exercised our regulatory judgment taking into account a range of information beyond the empirical beta estimates. We have selected an equity beta point estimate of 0.7 because we consider will this lead to a RoR that meets the RoR objective and best advances the RoR objective. We consider this is appropriate in all the circumstances. (Emphasis added).*

While the NSW draft decision discloses a series of matters that were not the reason for the 0.7 figure, from what has been written, it is not possible to understand how the figure of 0.7 was reached, and in the absence of disclosed rationale, it is not possible to hold the NSW draft decision to account.

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[167] AER, Ausgrid Draft Determination, November 2014 [3-83, 3-171].

Related to the lack of rationalisation for the adoption of a value of 0.7 is the lack of any reasoning that explains why this figure has been significantly reduced since the AER's 2009 NSW final determination when essentially the same information was considered (other than information which now points to a higher beta). SFG Consulting explains this in more detail in paragraphs 89 to 92 of its 13 February 2015 report titled ‘The required return on equity for the benchmark efficient entity’.

Both of these problems are illustrated in the AER’s NSW draft determinations. For example, when selecting a beta range of 0.4 to 0.7 the AER relies on a small set of partly dated data for domestic firms which is rapidly dwindling. It purports to apply a ‘cross-check’ comparison with international data from the United Kingdom and US but the US material, and the average of the combined material deliver results above the 0.7 level. To resolve the inconsistency, the AER adheres to the initial range, effectively rendering the international ‘cross check’ material of no value.

The same problem arises in relation to the ‘cross checking’ that is said to occur of the Ibbotson inspired AER approach to specifying the SL-CAPM using the Wright approach. SFG Consulting states:

> *This highlights the problem of using one subset of relevant evidence when estimating the original MRP parameter while relegating another subset of the relevant evidence to the role of ‘cross checks.’ Having determined that the Wright approach for estimating the MRP is relevant evidence, and having obtained a Wright estimate of the return on equity that is materially inconsistent with the AER’s proposed estimate, there are two possible courses of action. Either:*
>
> *(1) The AER would retain its original estimate – in which case the cross check has no effect and there seems to be no point performing it; or*
>
> *(2) The AER would revise its original estimate to make it consistent with the cross-check estimate – in which case the original evidence has effectively been discarded in favour of the cross check evidence.*

The improper search for a pre-eminent model and improper constraints inherent in using a ‘foundation’ model

The concept of a foundation model does not appear in the Rules or the NEL. Indeed, when amending the Rules, the AEMC notes:[168]

> *Ultimately it is important to keep in mind that all these financial models are based on certain theoretical assumptions and **no one model can be said to provide the <u>right</u> answer**.*

The Guideline proceeds on the basis that it is possible to select a foundation model, which will effectively provide outer limits to the range of possible values for the return on equity. As discussed in the next section, there are strong reasons why the SL-CAPM is not the best of the available models. However, even if it were the best of the available models, using it in the way that the AER has done constrains, and in some cases prevents, insights from the other models from being employed.

Elevating any one model to the ‘foundation’ status necessarily gives that model primary weight and all the other models less weight. Given the significant downward bias of this model for low beta stocks and the over-all empirical shortcomings of the SL-CAPM, the AER’s approach gives undue primary weight to the foundation model and, contrary to the requirement to take into account all the available information, the AER’s framework improperly constrains the regard the AER can effectively give to those other models.

There is substantial evidence that the SL-CAPM produces a downwardly biased estimate of the return on equity for low beta firms and value stocks – both characteristics apply to the benchmark efficient entity.[169] Further,

168 AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 48.

using current data, SFG calculates returns using the various models, which illustrates that the SL-CAPM delivers a lower result than any other model.

In fact, recently NERA, with respect to its in-sample tests of the SL-CAPM, concluded:

> *the data indicate that there is a negative rather than a positive relation between returns and estimates of beta. As a result, the evidence indicates that the SL CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL CAPM underestimates the returns to low-beta portfolios is both statistically and economically significant.*

An important basis for the AER's exclusion of the Fama-French Model was that the AER considered there to be no clear theoretical foundation to identify risk factors. This is an improper basis upon which to exclude a model that in fact performs well empirically in explaining stock market returns. Indeed, there is a lot to be said for giving primacy to empirical performance over theories as, until they are tested robustly, theories are simply one idea as to reality.

There is no reason to suppose that selecting from the upper range of possible outcomes for SL-CAPM parameters will correct for these biases. Indeed by selecting from ranges set using a downwardly biased model there is logically a significant risk that the true or unbiased return on equity will lay outside that range.

The AER has acknowledged that the DDM, Black-CAPM and survey evidence can also be informative in addressing some of these limitations but those inputs are only taken into account within an upper limit selected from an application of the SL-CAPM that has not corrected for those biases and there is, therefore, every reason to suppose that the results do not accord with prevailing (unbiased) equity returns.

Moreover this is contrary to the AER's own 'fit for purpose' criterion that regard should be had to the limitations of the model's original purpose.[170] The SL-CAPM was not originally implemented by drawing parameter estimates from competing models nor was the competing models developed for the purpose of estimating parameters of the SL-CAPM.

Flawed selection of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model

Even if the Rules did allow a foundation model to constrain the ways in which other relevant data can contribute to the allowed rate of return, there is no basis to conclude that the SL-CAPM is the 'superior model in terms of estimating expected equity returns'.

SFG Consulting states that:[171]

> *The AER adopts a model that does not fully account for factors that are associated with stock returns. The AER's use of the Sharpe-Lintner CAPM, without giving consideration to the Fama-French model, means that is places sole reliance on a model that has been shown to have less ability to explain stock returns.*

Maine Public Utilities Commission states that:[172]

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[169] SFG Consulting, referring to the extensive empirical research in this respect, such as the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973) in SFG Consulting, Cost of Equity in the Black Capital Asset Pricing Model, May 2014, page 6-10.

[170] As noted above, we consider this criterion to be a distraction that is likely to lead the AER away from the attainment of the rate of return objective. However, even it were a relevant criterion, there is a failure to apply the criterion properly.

[171] SFG Consulting, The required return on equity for the benchmark efficient entity, Feb 2015, 10.

[172] PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1998 Me. PUC LEXIS 603 at [42]. (see also PUBLIC UTILITIES COMMISSION; Investigation of Central

The theoretical weaknesses of the CAPM spelled out in the Bench Analysis causes us to rely more heavily on the DCF analysis in our decision making. In this particular case, the lack of a true forward looking beta is a large obstacle given that a pure T&D-utility industry does not exist at this point in time.

With models that do not suffer from the flaws of the SL-CAPM, any of them would be preferable to select as a foundation model (if the Rules required or permitted such a foundation model).

It is not surprising, therefore that all the other models provide mutually corroborating cluster of benchmark returns on equity for benchmark energy network businesses in the vicinity of 9.93 to 10.32 per cent while the SL-CAPM falls well below that cluster at 9.3 per cent when estimated by SFG Consulting, and orders of magnitude lower when estimated using the AER's Ibbotson inspired implementation at approximately 8.1 per cent.[173]

These figures also highlight the significance of choosing between different approaches to implementing the SL-CAPM when using it as a foundation model.

Having chosen to adopt the SL-CAPM as the foundation model, the AER is confronted with two approaches to implementing the model at opposite ends of a spectrum: the Ibbotson and Wright approaches. The AER elects to adopt the 'status quo' and by primarily relying on the 'Ibbotson Approach', to measuring the historical MRP. The AER combines its estimate of historical MRP with an 'on the day' risk free rate. The AER, has quite elaborately chosen to constrict itself to the Ibbotson approach, paying no regard to the notion of the Wright approach by adopting 'cross checking' of the sort described above that gives the secondary material no weight.

In the current economic conditions, the AER's approach of combining a contemporaneous measure of the risk free rate with an essentially constant MRP delivers values that are necessarily materially lower than prevailing market conditions.

Experts explain that there is no one-to-one relationship between movements in the risk free rate and the risk adjusted returns that investors require. In fact the MRP tends to fluctuate in the reverse direction from risk free rates.[174]

Although the expert work is informative at an aggregate level, there are also occasions when this concept is readily apparent to any intelligent observer. For example, shortly after the collapse of Lehman Brothers, two key propositions were inescapably prominent to finance market practitioners and the general business community alike – at the same time that investors became nervous and were demanding significantly increased returns, central banks were significantly reducing wholesale interest rates to try and stimulate the economy. This is a stark example of what the expert evidence shows is generally the case: the MRP and risk free rates tend to move in opposite directions.

This means that adding a long run average MRP to an immediately observed risk free rate will deliver downwardly biased results when risk free rates are low and upwardly biased results when risk free rates are high. In the current environment of record low risk free rates, a simple addition of a very long term MRP with a current risk free rate is almost bound to significantly under compensate equity investors.

Indeed, the approach in the NSW draft determinations delivers a nominal post tax return on equity of just 8.1 per cent which is substantially lower than five years previously which provided for a return on equity of, in Ausgrid's

Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1999 Me. PUC LEXIS 259 at [41]). Note: these cases predate decisions in which an equal weighting between the Black CAPM and the SL CAPM models have been adopted.

173 SFG Consulting, The required return on equity for the benchmark efficient entity, Feb 2015 page 35; AER, Ausgrid draft determination, November 2014, [3-45].

174 Incenta, Further update on the required return on equity from Independent Expert Reports, Feb 2015.

case 11.82 per cent. More than two percentage points of that drop can be attributed to the fall in the underlying risk free rate. While the risk free rate has dropped in this way, there is simply no evidence available from which to conclude that equity investors' required rates have fallen in proportion to the fall in the risk free rate.

Exactly the same question confronted the AER's US counterpart in its 28 January 2014 decision concerning the New York Independent system Operator. In that case FERC decided as follows:[175]

> *'We find NYISO's proposed ROE value of 12.5 per cent is adequately supported by substantial evidence. NYISO argues that current conditions in financial markets created a downward bias in the CAPM results, necessitating a calibration adjustment of 1.21 per cent to calculated return on equity of 11.29 per cent. Specifically, NYISO argues that the result yielded by the CAPM analysis 'appeared potentially too low relative to regulated rates of return and as the CAPM is subject to bias at times during the interest rate cycle' because of the potential impact on the historic relationship between the market returns for government debt and common equities. Given the recent trends of historic low yields for long-term U.S. Treasury bond rates, the CAPM's input for the 'risk free' rate, we find that it is a reasonable assumption that the current equity risk premium (which is added to the risk-free rate to calculate the cost of equity data point that determines the slope of the CAPM curve) exceeds the 86-year historical average used as the consultants' CAPM input. The current low treasury bond rate environment creates a need to adjust the CAPM results, consistent with the financial theory that the equity premium exceeds the long-term average when long-term U.S. Treasury bond rates are lower than average, and vice-versa.'*

It might be tempting to jump to the conclusion that under-compensating investors at this time is of little concern if, once the economic cycle turns, the current under-compensation could be offset by future over-compensation but this is not the case. If there is a mismatch in either direction between prevailing rates and regulatory allowances, inefficiencies will arise. Firstly, there are costs for a business of absorbing inter-temporal fluctuations in returns through explicitly or implicitly carrying a balance sheet provision for such a mismatch. Secondly, at times of under-compensation timely investments are discouraged or delayed and at times of over-compensation the opposite effect applies and there is an incentive to invest earlier than required. Neither is efficient. Note also that these effects are pro-cyclical which means that the direction of the mismatch encourages a business to reduce capital expenditures at times when input costs are likely to be low and to increase capital expenditures at times when input costs are likely to be high.

It is appropriate, therefore, that the Rules require (as they do) that each determination provides for a regulatory allowance that is commensurate with the prevailing efficient costs for a benchmark firm at the time. In the AEMC's words:

> *If the allowed rate of return is not determined with regard to the prevailing market conditions, it will either be above or below the return that is required by capital market investors at the time of the determination. The Commission was of the view that neither of these outcomes is efficient nor in the long term interest of energy consumers.*

In other words, unless the AER has a proper basis to conclude that the investors' expectations move in parallel with the risk free rate, placing effectively sole reliance on the Ibbotson inspired implementation of the SL-CAPM as it does, prevents its MRP estimate from adjusting to produce an allowed rate of return that can accommodate the prevailing expectations of equity investors.

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[175] Federal Energy Regulatory Commission (28 January 2014): 'Order accepting tariff filing subject to condition and denying waiver'. Docket No. ER14-500-000, page 35-36.

The flaws in AER's selection of beta

Equity beta is the key input into the SL-CAPM representing the AER's view as to the risks associated with the operation of an energy network business relative to benchmark efficient businesses. The AER has indicated that it intends to adopt an 'equity beta' to its lowest level ever in its regulatory decision making. The equity beta has progressively been down-graded from 1.0 for most of the period since the NEM began to 0.8 and now proposed to be 0.7 (including in NSW).[176]

The AER's decision to significantly downgrade the beta value is based on two principal inputs. Work by Frontier Economics sets the scene in a broad qualitative sense, suggesting that electricity businesses are comparatively safe – even with high levels of leverage. In our view, that report fails to properly assess the risks facing the business as noted by SFG.[177] Specifically, the Frontier Economics report only deals with operational risks and does not make any recommendation about whether the equity beta is likely to be above or below 1.

Further, it proceeds in the face of firm evidence that electricity network businesses are becoming more risky over time compared with a balanced market portfolio. By contrast, as discussed in detail in section 12.2, there is significant evidence to conclude that electricity network businesses are experiencing significant increases in risk. Debates can be had as to whether these risks are best included in the beta or elsewhere but presently these increases are accommodated neither in the equity beta nor in any other part of the regulatory framework.

When it comes to making a quantitative estimate, it would be surprising if all parties did not agree with the following proposition:[178]

> *In an ideal world there would be a very large number of domestic comparators and there may be no need to consider international comparators at all.*

Unfortunately the current situation could not be further from the ideal world because the number of domestic firms has dwindled to an unworkably small number with current data available of just four. When the US Federal Energy Regulatory Commission was confronted with the same problem (i.e. a comparator set that shrank below ten or so) in relation to interstate gas pipeline businesses, it broadened the sample:[179]

> *[S]tructural changes have strained the Commission's prior approach towards proxy group composition to breaking point. As a result of mergers, acquisitions, and other changes in the natural gas industry, fewer and fewer interstate natural gas companies have satisfied our prior requirements for proxy group composition.*
>
> *Our policy change was born out of a practical recognition that the size of the proxy group used under our prior approach had shrunk dramatically.*

However, the AER clings to an ever narrowing set of current data supplemented by ever more out of date observations. As SFG Consulting explains:[180]

> *The AER adopts a set of nine domestic comparator firms, only four of which remain listed. Two of the firms have not been listed since 2006 and one has not been listed since 2007. The AER's approach is to maintain the beta estimates for these firms in its sample, even though those estimates become progressively more dated with the passage of time. That is, the beta estimate at the time a firm delists becomes a permanently determinative observation in the AER's sample. By the time the current Guideline expires,*

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[176] Note that in South Australia the figure was 0.9.

[177] SFG Consulting, Equity beta, 12 May 2014, page 20-22.

[178] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 12 [38].

[179] Federal Energy Regulatory Commission, Statement of Chairman Joseph T. Kelliher, April 2008.

[180] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 10 [28]-[29].

three of the nine beta estimates will be more than 10 years out of date. These estimates will, by definition, not reflect anything that has transpired in financial markets for over a decade.

In the Guideline process, the AER picked over this scarce dataset generating several results that appear to be mutually corroborative but which are in fact averages drawn from substantially over-lapping datasets or the same data-sets reworked using two different statistical techniques. This delivered a range of 0.4 to 0.7. The principal analysis that was intended to inform the estimate was a report by Professor Henry which was not delivered until five months after the Guideline was issued.[181]

In this report, the AER's brief tightly specified the data he was to use ('nine specified Australia gas/electricity firm', 'short term Australian Government debt' and the 'ASX 300 Accum') and precisely what work was to be done. There were specific instructions on use of Australian data, weekly returns, no Blume or Vasicek adjustment etc. In other words, Professor Henry's work does not set out his expert opinion as to the level of beta at large and instead he has undertaken a highly constrained process of employing inputs provided by the AER in a manner specified by the AER and the results are product of the AER's views concerning each of the relevant inputs.

Even using the AER's tightly constrained set of instructions, Professor Henry states that the range for equity beta is 0.3 to 0.8, not 0.4 to 0.7 as published in the AER's Guideline.

The AER sought to bolster the domestic data with one set of international comparators for the Guideline and another in the NSW draft determinations. SFG Consulting has examined all that material and concluded that in relation to the first set of data relied upon, all the contemporaneous estimates are above 0.7.

In relation to the latter data, the analysis is of very poor quality. For example, the AER has relied upon the following:[182]

Alberta Utilities Commission (2013). This report documents submissions to the regulator in relation to equity beta – it does not present any estimates of beta. Unsurprisingly, user groups such as the Canadian Association of Petroleum Producers (CAPP) submitted that a low equity beta should be used. The report provides no information at all about the basis for the equity beta submissions. There is no information about how many, or which comparator firms were used. There is no information about what statistical techniques were employed or how the range of resulting estimates was distilled into a point estimate or range.

It is also important to note that the beta used in Alberta is the starting point for the analysis and after which an assessment is made of whether 'adders' are required to increase the returns to meet the required returns.

SFG Consulting has identified significant flaws in the use of the following report:[183]

PWC (2013) In its recent draft decisions the AER summarises the evidence from the PWC report for the NZCC as follows:

'PwC's June 2014 report presents the following raw equity beta estimates for New Zealand energy network firms as at 31 December 2013: 0.6 for the average of the individual firm estimates.'

The AER implies that this estimate of 0.6 can be compared with its allowed equity beta of 0.7. However, such a comparison would be an error for the reasons set out below. First, the 0.6 estimate does not appear anywhere in the PWC report. The beta estimates set out in the 'Utilities' section of the report are set out in the table below.

181 Henry O., University of Liverpool Management School*; Estimating Beta: An update*, April 2014.

182 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 15 [56(c)].

183 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 16 [50(d)].

Table 12.2. PwC beta estimates for the NZCC

Company	Raw beta	Leverage	Regeared beta (to 60% debt)
Contact	0.9	0.27	1.64
Horizon	0.5	0.31	0.86
NZ Windfarms	0.5	0.33	0.84
NZ Refining	0.8	0.17	1.66
TrustPower	0.5	0.36	0.80
Vector	**0.7**	**0.50**	**0.88**

The AER's estimate of 0.6 is the average of the raw beta estimates for Horizon and Vector, which are considered to be the firms most comparable to the benchmark efficient entity. The average of the regeared estimates for these two firms is 0.87.

In summary, the AER's range for beta of 0.4 to 0.7 is erroneous and inconsistent with the evidence before it. Although Appendix C of the Rate of Return Guideline Explanatory Statement is replete with criticisms and rejections of the point estimates proposed by user groups and businesses alike, exactly how the AER choses to adopt the upper 0.7 value from its (excessively) constrained range of 0.4 to 0.7 is unclear. The closest that Appendix C comes to an explicit statement is as follows:

[Our] proposed point estimate of 0.7 is not inconsistent with our consultants' advice.[184]

Adopting a point estimate around the mid-point would be more reasonable if our intention was to base the allowed return on equity on the Sharpe-Linter CAPM and empirical estimates alone. However, the rules require us to have regard to relevant estimation method, financial models, market data and other evidence when determining the allowed rate of return. When this information is taken into account, we consider it reasonable to select a point estimate form the upper end of the range of empirical equity beta estimates.[185]

The best inference from the totality of the AER's document appears to be that the selection is primarily chosen as an apology for the downward biases of the SL-CAPM. However, there is no basis to support the conclusions that selecting the upper bound of the AER's assessment of the range supported by the sample of four current and five former domestic comparators will be exactly sufficient to redress all the known biases in the SL-CAPM. A better and more transparent approach would be to allow for a wider sample and to simply estimate the models that have been developed to redress the well-documented problems with the SL-CAPM and then use the available evidence at hand.

The flaws in the AER's implementation of the Ibbotson approach to measuring the historical MRP for use in the SL-CAPM

The AER sets a MRP of 6.5 per cent on the basis of its long run estimates but again it has not explicitly explained how its 6.5 point estimate is drawn from a range of 5.1 per cent (which is 20 basis points above the geometric means of various cuts of the data going back to 1883) to 7.8 per cent (which is drawn from the high-point of the AER's DGM):

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184 AER, Rate of Return guideline, Appendix B, December 2013, page 76.

185 AER, Rate of Return guideline, Appendix B, December 2013, page 76-77.

We propose to estimate the MRP point estimate based on our regulatory judgement taking into account estimates from each of those sources of evidence and considering their strengths and limitations.

NERA has undertaken analysis of the historical MRP estimates relied upon by the AER and identified a number of issues.[186]

NERA's first concern is that the AER insists on using geometric means on the basis of advice from McKenzie & Partington in 2011 and 2012 to the effect that an arithmetic mean would be upwardly biased where WACC estimates are compounded. However, both the AER's own consultant, Lally, and NERA have more than once pointed out that the regulatory arrangements do not provide for compounding. Since the regulatory arrangements do not involve compounding, the reverse is true and the use of a geometric mean is downwardly biased as has been noted by the Maine Public Utilities Commission: *'….[W]we agree with the Company that it is improper to use a geometric mean in the CAPM model…'*.[187]

NERA's second concern is that the AER continues to adopt a paper authored by Brailsford, Handley and Maheswaran, first published in 2008 and updated in 2011 and again in 2012 reaching a value for the MRP (for identifying a value for the MRP used in the SL-CAPM).[188] The AER continues to take this approach despite that the reliability of the data underlying the article has been brought into question repeatedly.

The original source of the adjusted data is identified in the footnote 13 and 16 in Brailsford et al 2013 as emails received from the ASX on 11 April 2003 and 26 May 2004.[189] Within one full page of those footnotes, the authors had already described these emails, asserting that '*staff carefully considered the issue and ultimately decided on an adjustment factor of 0.75'.*[190]

The AER has effectively (falsely) invested the adjustment with the ASX corporate endorsement and created the impression that the adjustment carries the ASX's corporate approval. In this way, the AER is creating an apparently indisputable ground for its position.

Further, the AER has given weight to the notion that the Brailsford et al article has been published in a 'peer reviewed academic review' without making inquiries to understand what that peer review entailed.191 Certainly, the review did not require the source and context of the email correspondence to be set out in the published paper. By contrast, the NERA work was prepared according to the Federal Court's Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia – Practice Note CM7 including disclosing all sources upon which they rely. Accordingly, NERA's adjustment factor must be preferred.

The AER's flawed use of expert reports

The AER performs a 'cross check' for its beta estimates against expert reports (reports prepared for the purpose of stock market valuations in the context of takeovers). It is relevant to note that the question posed to these

186 NERA, Historical Estimates of the Market risk Premium, February 2015

187 PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1998 Me. PUC LEXIS 603 at [41] and PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1999 Me. PUC LEXIS 259 at [42].

188 AER, Draft determination for Ausgrid 2015-2019.

189 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008.

190 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008, page 80.

191 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008.

experts is whether a specific takeover offer is 'fair' (i.e. sufficient to be fair). This is not the same question that the AER is required to answer.

Incenta has examined the AER's reasoning and found it to be wanting.

The first issue concerns whether the Ibbotson inspired approach reflects current equity market expectations. In this regard Incenta reports the following:[192]

> *The AER has compared the risk premium over the 'spot' risk free rate that independent experts have applied to the risk premium over the spot risk free rate that it applies, and so implicitly assumed the risk premium that experts apply has remained (and will remain) constant in the face of large changes in the risk free rate. However, this masks the actual behaviour of independent experts, with almost 90 per cent having adjusted the risk free rate and / or the market risk premium in response to changes in the risk free rate.*

The AER gives particular attention to the Grant Samuel report concerning APA's unsuccessful takeover of Envestra. Grant Samuel itself has expressed serious reservations about how its report has been interpreted and used by the AER, both in relation to the MRP and other issues such as the beta adopted, and whether in fact experts use the SL-CAPM.

In essence, the AER sought to gain support from the report for the use of the CAPM to the exclusion of other approaches. Grant Samuel states:[193]

> *[O]ur approach … is to form an overall judgement as to a reasonable discount rate rather than mechanistically applying a formula. The fact is that, particularly in some market circumstances, the CAPM produces a result that is not commercially realistic. When this occurs it is necessary and appropriate to step away from the methodology and use alternative sources of information to provide insight as to what is, after all, an unobservable number that can only be inferred. In our view, Envestra was clearly a case in point.*
>
> *In using the Envestra report, the AER seems to be to trying to co-opt the parameters that we used for calculating the initial CAPM based rate to bolster its own case while trying to find ways to justify not having to recognise the fact that for the valuation of Envestra Limited's assets, we actually selected a different rate (i.e. 6.5-7.0% or, more correctly 6.5-8.0%, rather than 5.9-6.5%).*

The AER expresses concerns about the transparency of Grant Samuel's methodology but Grant Samuel responds as follows:[194]

> *In view of the apparent importance of the Envestra Report in supporting the AER's findings we are surprised that, if there were such transparency issues, the AER did not approach us for clarification. To our knowledge, we have never been approached to discuss any aspects of our discount rate or other valuation approaches.*

The AER asserts that:[195]

> *[T]he return on equity and equity risk premium estimates contained in Table 3- 20 are the final values used in the independent valuation report and reflect any uplifts applied.*

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192 Incenta Economic Consulting, Further update on the required return on equity from Independent expert reports, Feb 2015.

193 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 4-5.

194 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 6.

195 AER, Ausgrid Draft Determination, November 2014 [3-140].

As Grant Samuel disavows that assertion:[196]

> *This statement is simply not true as the table, at least in the case of Grant Samuel's reports for Envestra Limited, DUET Group and Hastings Diversified Utilities Fund, only reflects the calculated post tax WACCs ignoring the uplifts and adopts midpoints for post tax WACC and return on equity, an approach which Grant Samuel considers inappropriate.*

And in a similar vein:[197]

> *the AER claims that the implied adjusted equity risk premium range in three of the four uplift scenarios referred to by Grant Samuel in Appendix 3 of the Envestra Report justifying its uplift is consistent with its foundation model premium of 4.55%. We do not know how the AER determined this but our calculations indicate that in fact the 4.55% is well in the range in only one of the scenarios, is right at the bottom of the range in one other scenario and is outside the range in the other two.*

In summary it is not surprising that Incenta reaches the following conclusions with respect to the AER's whole approach to expert reports:

> *Taken together, our findings indicate strongly that were the AER to continue to apply the same mechanistic SL-CAPM approach that was applied in its draft decision, with JGN's current averaging period risk free rate at 2.64 per cent, the resulting estimated rate of return on equity will fall materially short of the required rate of return in the market that is implied by a consideration of independent expert reports, and not be commensurate with the efficient financing costs a benchmark entity will face over the access arrangement period.*

Inconsistent treatment of the imputation adjustment

In the section on Gamma, we discuss our approach to the valuation of imputation credits. However, it is important to recognise that there is an inter-relationship between the regulatory estimates of the required return on equity and gamma. This relationship is most apparent in the AER's post-tax revenue model (**PTRM**).

The PTRM requires the regulator's assumed value of the with-imputation required return on equity. It then removes the regulator's assumed value of imputation credits, leaving an estimate of the ex-imputation required return on equity. Allowed revenues are then based on this ex-imputation required return. The idea is that the firm requires sufficient revenue to provide investors with their ex-imputation required return, which is supplemented by imputation credits to provide them with their total required return.

The first step in this process requires an estimate of the with-imputation required return on equity. The AER's approach to this task is to 'gross up' its estimates of MRP to include the AER's assumed value of imputation credits. For example, when implementing its DGM approach for estimating MRP, the AER grossed-up forecast future dividends to include its estimate of the value of the imputation credits that will be attached to those dividends.

The adjustments for imputation credits are made in two places in the AER's estimation process:

1. The assumed value of imputation credits is **added** to produce an estimate of the with-imputation required return on equity; and then

[196] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 6-7.

[197] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 7.

2. The assumed value of imputation credits is **subtracted** to produce an estimate of the ex-imputation required on equity.

Internal consistency problems arise when the assumed value that is added in step 1 above is different from the assumed value that subtracted in step 2 above. In the AER's recent NSW draft determinations, the value that is added in step 1 is materially lower than the value that is subtracted in step 2, creating a downward bias to the allowed return on equity. On this point we consider that AER should ensure the same adjustment for imputation credits should be applied in both the steps of the AER's estimation approach.

Summary

As demonstrated above, the AER's approach to establishing an allowed return on equity is ill conceived. AER does not take into account important pieces of empirical evidences.[198] Consequently we have chosen to depart from the Guideline in all respects other than the identification of the relevant models. Our approach is described in the next section.

12.3.3 Rate of return allowance proposed in place of the AER Guideline

For all the above reasons, we consider that the approach in the Guideline cannot appropriately be remedied through adjustments correcting isolated errors and instead a new ground-up assessment of each of the inputs and how they are combined needs to be undertaken. SFG has conducted such an evaluation including with the assistance of work undertaken by other experts. Our proposal, described in the next section, is based on that work.

Instead of the approach adopted in the Guideline, we propose to establish a rate of return giving real weight to all the relevant models and inputs by:

- identifying the relevant rate of return models (which are, in fact, the same as those identified by the AER);
- identifying the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise modelling results as a weighted average of the individual estimates with the weights that avoid double-weighting any of the key conceptual elements of the models.

12.3.4 Estimate the parameters for use within each of the four models

Between them, the four models require estimates of the following parameters:

- a risk free rate of return;
- a required rate of return on the market portfolio (or an MRP to combine with the risk free rate);
- an equity beta (for the two CAPM models);
- a zero-beta return (for the Black-CAPM), or zero-beta risk premium;
- market exposure, size and book to market factors (Fama-French Model only); and

198 SFG, The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, March 2015; NERA, Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama French Three Factor Model, March 2015.

- a risk premium for comparable firms (for use with the DDM only).

The proposed source of each of these parameters is discussed below.

Risk free rate averaging period

We accept the approach to setting the risk free rate proposed in the Guideline which is to adopt a 20 consecutive business days that is as close a practicably possible to the commencement of the regulatory control period. For illustrative purposes, the figures presented in this regulatory proposal are calculated using a 20 business day period ending on 30 January 2015. We propose the averaging period for return on equity in the letter attached to our regulatory proposal.[199]

Required return on the market portfolio (or its corollary, the market risk premium)

A number of the four models include a MRP which is simply the required return on the market portfolio less the risk free rate. In the past the AER has adopted the approach of using long run average excess returns (i.e. the returns of a representative portfolio above the risk free rate) as Ibbotson calculates an MRP. It is noted that there are other ways to estimate an MRP including historical data using an approach championed by Wright, the estimates derived from a dividend growth model, and estimates from independent experts and surveys. Wright did not develop an alternative implementation of the SL-CAPM. Wright simply proposed an alternative method of estimating the MRP for use in the SL-CAPM—as the difference between the historic average market return and the current risk free rate—on the basis that market returns may be more stable over time than excess returns.

SFG note that the Ibbotson approach involves adding an effectively constant MRP to the contemporaneous risk-free rate to produce an estimate of the required return on equity that varies one-for-one with changes in the risk-free rate:[200]

> *[T]he Ibbotson approach implies that equity is more expensive than average during economic expansions and bull markets (the late 1990s and mid 2000s) and cheaper than average during financial crises (the pronounced reduction in 2008).*

It is counter-intuitive that the required return on equity should be lower during financial crises than during periods of economic expansion. This should be taken into account when the AER considers how to best employ historical data to inform estimates of MRP. In the Guideline, the AER uses historical data only via the Ibbotson approach (which leads to these counter-intuitive results) and places no weight on the Wright method for processing the historical data. By contrast, SFG recommend that both methods provide relevant evidence in which case both should be given regard.

The Guideline proposes that the AER would consider all this material and determine an MRP using ‘regulatory judgement’. The Guideline provides a worked example as at December 2013 but the AER would not necessarily exercise judgment in the same way in our regulatory proposal. We consider that there are a number of flaws in the worked example as detailed by SFG Consulting. The detailed analysis is summarised as follows:[201]

> *[I]n some places the Guideline relies on dated evidence that has now been updated, in other places it relies on inaccurate data that has since been corrected, and in other places it makes improper comparisons (e.g., where estimates that include the benefit of imputation credits and estimates that exclude the benefit are compared as equals).*

[199] CitiPower, Letter proposing return on debt averaging periods (confidential version), 29 April 2016.

[200] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 56.

[201] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 44.

Our proposal adopts SFG Consulting's view as to the appropriate manner in which the AER should exercise judgement establishing MRP. To a significant extent it relies on similar information, although certain information (such as inherently unreliable surveys) were not used. There are, however, other important differences in the details of how the other sources would be used to address flaws that SFG Consulting have identified above. SFG Consulting notes:[202]

> *[SFG Consulting would] have regard to the following evidence:*
>
> *First, we note that historical returns can be processed in two ways – by assuming that MRP is constant in all market conditions (Ibbotson approach) or by assuming that real required returns are constant in all market conditions (Wright approach). We apply equal weight to each of these approaches, producing an estimate of MRP from historical returns of 7.11%;*
>
> *a. The estimate of MRP from dividend discount models of 7.31%; and*
>
> *b. The estimate of MRP from independent expert reports of 7.08%.*

The same report illustrates why the outcome is not sensitive to the weightings given to the three sources. The relevant evidence is discussed in detail in the report. A summary is provided in table 12.3 (each grossed up for a theta estimate of 0.35) of updated SFG analysis.[203]

Table 12.3 Summary of SFG findings

Approach	Value (%)
A historical average market return using the Ibbotson approach (%)	9.20
A historical average market return using the Wright approach (%)	11.64
A DDM estimate	11.37
Independent expert evaluation reports	9.57

Source: SFG Consulting

SFG Consulting synthesises this information to provide a single point estimate of 10.81 per cent.

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Equity beta

We consider the reduction of the equity beta from 0.8 to 0.7 proposed by the Guideline to be incorrect on the basis of the following considerations emerging from work undertaken by SFG Consulting:[204]

> *a. The estimate of 0.7 is the outcome of a convoluted multi-stage approach whereby:*
>
> *i) a sub-set of the relevant evidence … is used to constrain the range of possible estimates to 0.4 to 0.7;*
>
> *ii) the other relevant evidence that is considered in the Guideline … all supports an estimate above 0.7, but the first stage of the process constrains the maximum estimate to be 0.7; and*
>
> *iii) there is relevant evidence that is not considered in the Guideline …;*

[202] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 6.

[203] SFG Consulting, The Required Return on Equity for Benchmark Efficient Entity, Feb 2015

[204] SFG Consulting, Equity Beta, May 2014, page 3-4.

b. The subset of evidence that is used to produce the constraining range of 0.4 to 0.7 is not sufficiently reliable to be used for that purpose because: the beta estimates vary wildly … across firms;… over time; … depending on which sampling frequency is used;… depending on which regression specification is used; and …depending on the day of the week and month on which they are computed;

c. The evidence from international comparable firms suggests an equity beta materially above 0.7;

d. To the extent that the 0.7 estimate has been influenced by the AER's conceptual analysis, it is wrong. The AER concludes that the conceptual analysis supports an equity beta materially below 1, but it does not. In this regard:

i) The Frontier Economics (2013) report does not support an equity beta below 1 … ; and

ii) The McKenzie and Partington (2012) report sets out two pieces of empirical evidence. One suggests that energy networks have equity betas materially above one, and the other suggests that finance risk is the primary component of beta for utilities;

e. To the extent that the 0.7 estimate has been set to match the equity beta that the ACCC uses for water utilities, it is wrong. Regulatory estimates of beta for water utilities are based on regulatory estimates of beta for energy networks (which introduces circularity) and on international water utilities … .

Additionally, the modeling of the equity beta is flawed in that the sample is too small and the estimate too variable in response to the choice of statistical method. Further, irrelevant water utility data is included instead of relevant international data on the energy network sector.

We submit, based on SFG Consulting's expert opinion, that the most appropriate estimate for the equity beta is 0.82 on the following basis:[205]

One way of having regard to the range of relevant models and evidenced is to estimate the required return on equity under each of the relevant approaches and then to determine an allowed return on equity after having regard to the relative strengths and weaknesses of each approach. Under such a multi-model approach, we would adopt a Sharpe-Lintner CAPM beta of 0.82 – the raw estimate of beta that does not reflect any evidence other than the historical statistical relationship between stock returns and market returns for the relevant set of comparable firms.

The AER's own consultant, concludes:[206]

In the opinion of the consultant, the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate for β lies in the range 0.3 to 0.8.'

Adopting 0.7 is not supported by any empirical evidence.

Black CAPM return on a zero beta asset

SFG Consulting have estimated the return on a zero beta asset by adding a zero beta premium 3.34 per cent to the risk free rate of 2.64 per cent to give an estimated return of 5.98 per cent return on a zero beta asset.

This is within the reasonable range in the Guideline and for that reason this issue does not warrant a detailed treatment in this identified document.

[205] SFG Consulting, Equity beta, May 2014, page 4 & 42.

[206] Henry O., University of Liverpool Management School*; Estimating Beta: An update*, April 2014, page 63.

Fama-French model market exposure, SMB and HML factors

Because the Guideline does not use the Fama-French model, there is no relevant departure from the Guideline in relation to these factors.

Recent regressions conducted by SFG Consulting have concluded that the best estimates for the three relevant Fama-French model factors are as follows:

Table 12.4 SFG estimates for Fama French model factors

Fama French factor	Value
Market exposure (%)	6.33
Size exposure (%)	-0.19
Book to market exposure (%)	1.15

Source: SFG Consulting

The attached report fully substantiates these figures.[207]

Risk premium for use in the DDM

SFG Consulting has estimated the risk premium for relevant comparable firms at 94 per cent of the overall market returns.

12.3.5 Our proposal to separately estimate the required return on equity using each of the relevant models

Using the above parameter estimates, SFG Consulting estimates for the four models using an indicative averaging period spanning the 20 days to 30 January 2015 are detailed in table 12.5.[208]

Table 12.5 SFG Consulting return on equity model estimates

Model	Return on equity (%)	Weight (%)
SL-CAPM	9.32	12.5
Black-CAPM	9.93	25.0
Fama French model	9.93	37.5
DDM	10.32	25.0
Proposed cost of equity	**9.95**	**100.0**

Source: SFG Consulting

On the basis of the above, our proposed return on equity is 9.95 per cent. In the PTRM this is rounded to 9.90 per cent.

[207] SFG Consulting, Using the Fama-French model to estimate the required return on equity, February 2015, page 29.

[208] SFG Consulting, The Required Return on Equity for Benchmark Efficient Entity, Feb 2015, page 35.

12.3.6 If our weighted average of all four models is rejected

It is our position that the approach to establishing the return on equity set out in the Guideline is not consistent with the Rules and is not the best possible estimate of the required rate of return for equity. In particular, we are concerned that the approach set out in the Guideline does not meet the requirements of the new Rules that regard must be had to 'relevant estimation methods, financial models, market data and other evidence'.

Accordingly, we do not agree with the approach in the Guideline that an estimate for the return on equity in compliance with the Rules can be generated using the SL-CAPM as a 'foundation model'. Nonetheless, SFG Consulting has considered what approach could be made to improve the performance of the SL-CAPM. The attached report sets out those amendments and the key ones are summarised here.

SFG Consulting identified, two significant flaws in the SL-CAPM being that it is downwardly biased for both low beta assets and value assets. SFG Consulting has separately estimated three CAPM equity betas using each of the other models to correct for these biases. The Black-CAPM in particular addresses the issue of the bias for low beta assets, the Fama French Model addresses the issue of the bias for value assets and the DGM uses contemporaneous evidence.

We believe that if the employment of the SL-CAPM as a foundation model is pursued, the correct parameters as identified by SFG are as follows.

Table12.6 SFG Consulting return on equity estimate for SL-CAPM

Parameter	Return on equity
Beta	0.82
Risk free rate (%)	2.64
Market risk premium (%)	8.17
Return on equity (%)	**9.32**

Source: SFG Consulting

12.3.7 Departure from Guidelines: Equity

The Rules require that our proposal identify where we propose departures from Guideline. The following table summarises these:

Table 12.7 Identified departures from Guideline (Equity)

Description	Guideline	Regulatory Proposal	Rationale
Relevant models to consider	SL-CAPM, Black CAPM, Fama French Three Factor model and the Dividend Growth Model.	Adopts the use of these models.	These are relevant models for estimating the required return on equity. (For detailed explanation see section 12.3.1)
Models to be used in setting allowance	SL-CAPM, Black CAPM and the Dividend Growth Model. Fama French model not to be used.	Diverges such that all four models are used.	The Fama French Three Factor Model provides valuable insights and corrects for well-documents biases that the other models do not. (For detailed explanation see section 12.3.1 and 12.3.2)

Description	Guideline	Regulatory Proposal	Rationale
Regard to financial models	SL-CAPM is used as central foundation model and any other model, information and evidence is restricted to a secondary role, at most being used to inform the estimates of SL-CAPM.	All four models should contribute directly to the allowed rate of return for equity as they provide valuable mechanism to correct for the short fallings of using a mechanistic approach that relies only on a particular implementation of SL-CAPM estimates.	There is no correct basis for relying only the AER's Ibbotson inspired implementation of SL-CAPM and for it to constrain the extent to which other evidence and information can be used to affect the computation of the allowed rate of return for equity. (For detailed explanation see under section 12.3.2 – *'The Guideline does not give real weight to all the relevant inputs as required'* and *'The improper search for a pre-eminent model and improper constraints inherent in using foundation model'*)
Implementing the SL-CAPM : beta	The SL-CAPM should be implemented using a beta of 0.7.	The beta should be at least 0.82 using a broader sample of domestic and international firms.	Network businesses face greater systematic risk than the AER assumes. (For detailed explanation see section 12.2) SL-CAPM is downwardly biased for low beta stocks and for sticks with a high book-to-market ratio. The sample of firms used by AER is too small to provide a reliable estimate and the upper end of the range (0.7) is below the upper end of the range (0.8) produced by its own consultant. (For detailed explanation see under section 12.3.2 – *'The flaws in AER's selection of beta'*)

Description	Guideline	Regulatory Proposal	Rationale
Implementing the SL-CAPM : MRP	Estimate a range for the MRP, and then select a point estimate from within that range. Range estimated with regard to theoretical and empirical evidence – including historical excess returns, dividend growth model estimates, survey evidence and conditioning variables. Point estimate to be based on regulatory judgement, taking into account the strengths and weaknesses of the evidence.	The MRP should be estimated using both Ibbotson and Wright approaches. When implementing the Ibbotson approach, the MRP should be the arithmetic average for the longest available series. The appropriate role for the DGM is as a model to be employed directly in delivering an estimate for the return on equity rather than as an input to estimating the MRP for the SL-CAPM.	The Ibbotson and Wright approaches for estimating MRP are based on the same historical data but different methodologies return different results and as such regard should be given to both. When seeking to employ the Ibbotson approach, the AER identifies a historic MRP range of 5.1% to 6.5%. The low end of this range is flawed as it relies on an incorrectly adjusted yield series and irrelevant geometric averages. (For detailed explanation see under section 12.3.2 – *'Flawed selection of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model'* and *'The flaws in AER's implementation of Ibbotson approach to measuring the historical MRP for use in the SL-CAPM'*)

Source: CitiPower

12.4 Return on debt

The relevant aspects of establishing an allowed rate of return for debt are as follows:

- establish the tenor of the benchmark debt;
- establish a credit rating for the benchmark business;
- establish whether it is ultimately preferable to set the benchmark on the basis of the 'on the day' method, the trailing average method or a combination;
- decide whether to undertake annual updating or set a single benchmark each regulatory determination with a 'look back' if a trailing average is to be used;
- determine whether and what transition should apply;
- identify a data source;
- select averaging periods; and
- assess debt transaction costs and the cost of the new issue premium.

Each of these aspects is discussed below.

12.4.1 Tenor of the benchmark debt instrument

The Guideline adopts a term to maturity of ten years for the debt portfolio of the benchmark efficient firm based on a review by the AER of actual debt portfolios of comparable businesses. The AER has concluded that the benchmark entity's debt portfolio minimises refinancing risk by comprising long dated bonds to match the long run nature of network capital investments.

We support the position in the Guideline.

12.4.2 Benchmark credit rating

The Guideline considers that the benchmark credit rating should be BBB+. Further, the AER has rejected CEG's position with respect to the appropriate credit rating for a benchmark efficient firm it its NSW gas and electricity distribution decisions.[209] CEG found that each year from 2009 to 2013, the median credit rating of energy network service providers was BBB, amid a clear trend of downgrades in the industry.

However, the AER contends that in 2013, the median was actually BBB+ and based on only a partial 2014 data set, predicted the median in the projected full year to be BBB+. The information before the AER clearly provides sufficient weight to warrant a departure from the Guideline and a reduction in the median credit rating relied on.

In relation to the comparator group used to determine the median credit rating, while the AER has deleted Ergon Energy Corp Ltd from its comparator group on the basis that its credit rating is obviously influenced by government ownership, the AER has taken the view that its comparator set should include both AusNet Services and SGSP Australia Assets Pty Ltd, even though clear evidence exists that Singaporean Government ownership in these businesses has significant effect on the consideration of their credit ratings by credit rating agencies. For example both companies were placed on negative watch when the Singapore Government diluted its ownership in 2013.

The AER has also taken the view that even if it were to consider Singapore Government ownership in AusNet Service and SGSP, some time has passed since the dilution of Singapore Government ownership (which is evidence of the effect of the ownership on the rating), and it therefore considers that credit rating agencies have had time to revise their credit ratings.[210] This statement seems to misunderstand the issue that the continuing effect of Singapore Government ownership is to provide greater comfort to credit rating agencies as to key issues relevant to their consideration of the appropriate credit rating, such that the credit rating applied to these companies is not one that would be applied to a pure play, regulated energy network business operating within Australia (which is defined as the benchmark efficient entity in the Guideline). Evidence of dilution of government ownership having a negative effect on a credit rating agency's views of the risk of a downgrade in a credit rating supports this proposition.

Further the AER appears to take comfort in the fact that the credit rating of SGSP has changed since the dilution to assert that government ownership has not been sufficient to maintain an A- credit rating.[211] The issue however is that government ownership has maintained the credit rating at a higher level that it would otherwise been over this period, and therefore the credit rating of this business is not reflective of the credit rating of an efficient private service provider which is the standard that informs the definition of a benchmark efficient firm.

We consider that the AER should review the appropriate criteria for businesses to be included in its comparator set and remove those businesses who do not reflect the risk profile of a benchmark efficient firm due to

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[209] AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296]; and AER, Attachment 3 Rate of Return – Essential Energy 2014-19, [3-315].

[210] AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296].

[211] AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296].

government ownership (full or partial) or other relevant factors such as implicit support from parent companies which improves subsidiary individual credit ratings.

12.4.3 Trailing average portfolio approach

The trailing average portfolio approach recognises that in practice a firm's actual cost of debt will be determined by historical rates. In addition, it recognises that energy networks do not raise all their capital at one time and instead have staggered debt maturities. In practice, network businesses need to balance a number of considerations when determining how much debt to refinance at what times, including:

- diversification of debt instruments and maturities;
- liquidity management;
- changes in the aggregate capital required as new investments are made contributing to a growth in the Regulatory Asset Base and as aging assets are depreciated;
- credit metrics; and
- market conditions, including access to foreign and domestic markets and the ability to hedge interest rate movements.

For this reason, firms will have different amounts of debt maturing at different points in time. It is not the case as the AER, has asserted in NSW draft decision, that a benchmark efficient entity would hold an evenly staggered portfolio of long-term (ten year) debt where exactly 10 per cent of the debt is refinanced each year.[212] Due to the considerations set out above, a benchmark efficient entity would make decisions as to the amount of debt to be refinanced in any given year to minimise its debt financing costs and these amounts may vary each year.

Nevertheless, the trailing average portfolio approach is likely to more closely align with the staggered approach to refinancing a debt portfolio than the 'on the day' method, noting that the trailing average method is a substantial simplification of what actually occurs. The trailing average portfolio approach significantly reduces the risk that prices for customers on a given network might be higher or lower than the average interest rate over time simply because the 'on the day' rate for their particular service provider occurred at a high or low point in interest rate movements.

We therefore accept the ten year trailing average portfolio approach set out in the Guideline.

12.4.4 Annual updating

At one stage during the Guideline consultation process, the possibility of a 'true up' at the conclusion of the regulatory control period was canvassed as a possibility rather than annual updating. We consider that annual updating is an important feature of moving to a trailing average approach because otherwise the two principle advantages of the trailing average would not be fully obtained (i.e. more closely matching the regulatory allowance to a portfolio of progressively refinanced debt and delivering customer prices that more closely track the evolution of market interest rates).

12.4.5 Transitional arrangements

The Guideline proposes to apply transitional arrangements in respect of the return on debt based on the QTC method. We do not consider the transition in the Guidelines complies with the Rules. The rationale for a transition articulated in the AER's Guideline was that it would reflect the 'transition' in the regulated benchmark efficient entity's efficient debt management strategies from those adopted under the 'on the day' approach to

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212 AER, Draft Decision, Essential Energy 2015-19 - Overview, page 43.

those adopted under the trailing average approach and, thus, eliminate the mismatch between the actual and allowed return on debt. As the AER now concedes, this rationale does not apply to the debt risk premium component of the return on debt because the benchmark efficient entity could not have entered into hedging arrangements for the debt risk premium under the previous 'on the day' approach to estimating the return on debt.

To the contrary, in circumstances where the AER has determined that the benchmark efficient entity would hold a debt portfolio with staggered maturity dates (a trailing average debt risk premium), there is no legal basis for applying a transition to the debt risk premium component of the return on debt. On the AER's own statutory construction of the allowed rate of return objective, the requirement in Rule 6.5.2(h) to determine a return on debt commensurate with the efficient debt financing costs of the benchmark efficient entity renders it legally impermissible to the transition the debt risk premium component of the return on debt.

Further, the reasons now advanced by the AER in support of its transition on the debt risk premium component of the return on debt do not justify its approach and similarly involve errors of law.

Rather than adopting the transition proposed in the Guideline, we consider that there should be:

- a ten year transition to the trailing average estimation of the risk free rate component of the return on debt; but
- no transition for the debt margin (or debt risk premium) component of the return on debt. That is, the AER should immediately move to a trailing average estimation of the debt risk premium component.

Rule Requirement

We consider that under the new Rules, estimating a return on debt that contributes to the allowed rate of return objective is paramount and the primacy of the allowed rate of return objective extends to the AER's decision as to whether to apply a transitional arrangement in estimating the return on debt. This was expressly acknowledged by the AER in the course of developing its Guideline. The AER stated: [213]

> *We consider that the key objective of the transitional arrangements is to estimate the return on debt so that it contributes to the achievement of the allowed rate of return objective.*

While the factors in Rule 6.5.2(k) provides guidance to the AER in estimating the return on debt, it does not override or alter the requirement under the Rules to the estimate a return on debt such that it contributes to the allowed rate of return objective. As noted by the AEMC in discussing the relationship between objectives and factors in introducing the current Rules:[214]

> *The objective, where one exists, should indicate to the regulator how the factors should influence its decision. The regulator should not assume that it may consider the factors (or other relevant provisions) and that this will of itself mean that the objective has been achieved. The overriding consideration for the regulator is the objective.*

AER's rationale for its proposed transition

In the context of the return on debt, the AER construes (expressly or implicitly) the allowed rate of return objective as follows:

- first, it ascribes to the 'benchmark efficient entity' referred to in the allowed rate of return objective the characteristic of being regulated; and

[213] AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 124.

[214] AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, page 19.

- secondly, as the benchmark efficient entity is a regulated energy business, it concludes that it follows that the debt financing practices of relevance to the allowed rate of return objective are those of a regulated energy business and thus, fall to be considered against the background of the regulatory regime and, in particular, the AER's adopted approach to the estimation of the return on debt.[215]

On the basis of this approach to the statutory construction of the allowed rate of return objective the AER concludes that 'the efficient financing costs of a benchmark efficient entity' are the financing costs resulting from the benchmark efficient entity minimising the expected present value of its financing costs over the life of its assets, taking into account the regulatory framework and the associated financial risks it faces and expects to face in the future.[216] These risks are identified by the AER to be:[217]

- refinancing risk (i.e. the risk that a firm would not be able to efficiently finance its debt at a given point in time); and
- the interest rate risk of a regulated entity, that is the risk of a mismatch between the regulatory return on debt allowance and its actual return on debt.

Put another way, the AER construes the term 'efficient financing costs' in the allowed rate of return objective to mean the financing costs incurred by the benchmark efficient entity, which it has defined to be a regulated entity, as a result of debt financing practices adopted in response to the regulatory method of estimating the regulated return on debt, so as to minimise the expected present value of its financing costs over the life of its assets while managing refinancing risk and interest rate risk.

It is on this basis the AER's statutory construction of the allowed rate of return objective outlined above that the AER determines that the establishment of a transitional arrangement in respect of the move from the 'on the day' approach to the trailing average portfolio approach is required if the return on debt is to contribute to the achievement of the allowed rate of return objective.[218]

The AER considers that:[219]

- under the 'on the day' approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates and use swaps to hedge interest rate exposure for the duration of a regulatory control period;
- under the trailing average approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt; and thus
- in moving from the 'on the day' to the trailing average approach to estimating the return on debt, a transition is necessary as the benchmark efficient entity would need to unwind its hedging contracts entered into under the 'on the day' approach.

In this manner, the AER statutory construction of the allowed rate of return objective as requiring a consideration of the debt financing practices adopted, and resultant costs incurred, by a regulated entity in response to the regulatory method of estimating the return on debt, provides the legal foundation for the establishment of transitional arrangements for the return on debt.

In support of its decision to include transitional arrangements for the return on debt allowance in the Guideline, the AER cited the mismatch between the expected return on debt of the benchmark efficient entity and the

[215] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 102-103.

[216] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 103; AER, Ausgrid Draft Determination [3-105].

[217] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 104; AER, Ausgrid Draft Determination [3-105].

[218] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121-122; AER, Ausgrid Draft Determination [3-112] and [3-113].

[219] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121

regulatory return on debt set according to the trailing average portfolio approach that would otherwise arise in the absence of transition.[220] The AER also cited the disruptive effect of unexpected and immediate changes in approach to setting regulatory allowances for businesses and consumers, issues with availability of historical data and the potential for opportunistic switching between approaches to the return on debt calculation.[221]

Subsequent to finalising its Guideline, however, the AER changed its reasoning for a transition on the debt risk premium component of the return on debt. The AER indicates in recent NSW draft determinations that the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt is relevant only in respect of a transition on the risk free rate component of the return on debt (and not the debt risk premium component as this could not have been hedged).[222]

The AER maintained that a transition arrangement was nonetheless desirable for debt risk premium component of the return on debt because a transition:[223]

- avoids potential windfall gains and losses to service providers or consumers from changing the regulatory regime;
- avoids practical problems with the use of historical data;
- maintains the same average price level while decreasing price volatility over time; and
- reduces the potential for opportunistic behaviour from stakeholders.

The reasons why the AER's proposed transition does not meet the requirements of the Rules, and why the reasoning of the AER in applying its proposed transition is otherwise flawed, are discussed below.

AER's proposed transition does not comply with the Rules requirements

As a consequence of its construction of the allowed rate of return objective, as discussed above, the AER considers the transition required for the return on debt by comparing the efficient debt management practices of the benchmark entity subject to regulation by the AER under the previous Rules and the efficient debt management practices of the benchmark entity subject to regulation under the new Rules.[224] As noted, the AER considers that:

- under the 'on the day' approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to hedge interest rate exposure for the duration of a regulatory control period; and
- under the trailing average approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt.

This construction may not be necessarily correct.[225] However, if it is accepted that the AER's construction of the allowed rate of return objective is correct, in applying a transition, the AER is required by Rule 6.5.2(h) to estimate the costs (efficiently incurred) of an entity moving from the first financing strategy identified above to the second in the 2016-2020 regulatory control period.

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220 AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121-122

221 AER, Explanatory Statement Rate of Return Guideline, December 2013, page 122-123

222 AER, Ausgrid Draft Determination [3-112], [3-113]. The issue was highlighted by AER's own consultant Associate Professor Lally, Capital Fiancial Consultants Ltd., Transitional Arrangements for the Cost of Debt, November 2014 (Lally Transition Report), Page 7.

223 AER, Ausgrid Draft Determination [3-115], [3-118]

224 The AER highlights, for example, that its 'benchmark approach to transitional arrangements' is consistent with the definition of a single benchmark entity for the purposes of estimating the cost of debt: AER, Ausgrid Draft Determination [3-124].

225 AEMC Rule Change, Final Position Paper, November 2012, Page 57 states that 'In its draft rule determination, the Commission considered that the long-term interests of consumers would be best served by ensuring that the methodology used to estimate the return on debt reflects, to the extent possible, the efficient financing and risk management practices that might be expected **in the absence of regulation**'.

The AER's objective at the time the Guideline was published was to address the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt allowance. The AER has correctly identified that its reasoning by reference to the allowed rate of return objective offers a potential justification only in respect of the risk free rate component of the return on debt and not debt risk premium. As the debt risk premium could not have been hedged, the efficient debt management strategy of the benchmark efficient entity under the 'on the day' approach involved only hedging of the interest rate exposure for the duration of the regulatory control period.

Rather than addressing a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance, applying a transition to the debt risk premium (as the AER's proposed transition does) creates a mismatch. This is contrary to AER's own objective at the time of Guideline, the AEMC's intention in amending the cost of debt provisions and the allowed rate of return objective.

In circumstances where the AER has determined that the benchmark efficient entity would hold a debt portfolio with staggered maturity dates (a trailing average debt risk premium), there is no legal basis for applying a transition to the debt risk premium component of the cost of debt. To the contrary, on the AER's own statutory construction of the allowed rate of return objective, the requirement in Rule 6.5.2(h) to determine a return on debt commensurate with the efficient debt financing costs of the benchmark efficient entity renders it legally impermissible to transition the debt risk premium component of the return on debt.

The AER also considers that a transition regime to bring to account differences between the return on debt allowance and the actual return on debt mitigates the potential windfall gains or losses to service providers or consumers with respect to the debt risk premium. The AER relies on a report by Associate Professor Lally wherein he raises the mitigation of windfall gains as an argument in support of transitional arrangements. We believe that AER's reasoning (and that of Associate Professor Lally) involves a fundamental misunderstanding of the allowed rate of return objective.

The rate of return objective necessarily requires a forward looking approach.[226] It is concerned with the required rate of return for the 2016-2020 regulatory control period. The proposed transition is intended to, and in fact would, result in a rate of return that is less than the efficient financing costs of a benchmark efficient entity for the 2016-2020 regulatory control period. This is patently contrary to the rate of return objective and the NEO (being to promote the efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers of electricity).

Both CEG and SFG Consulting similarly understand the rate of return objective as being prospective in nature.[227] CEG observes that, on the AER's own terms, its transition creates a prospective mismatch between the allowed and actual debt risk premium of a benchmark efficient entity. SFG Consulting also describes the problems with the AER's approach of setting inefficient prices for individual regulatory periods on the basis they might average out over the life of the asset.

It follows that the AER's approach is contrary to the revenue and pricing principles in Section 7A of NEL. Those principles include (among other things) that their service provider must be provided with a reasonable opportunity to recover at least its efficient costs, that a price or charge for the provision of services should allow for a return commensurate with the regulatory and commercial risks involved in providing the services and that regard should be had to the economic costs and risks of providing the services and that regard should be had to

[226] Under the building block approach, the only circumstances in which matters arising in prior regulatory control periods are relevant is if those matters affect three specified inputs to the building blocks: the value of the regulatory asset base (clause 6.5.1(e)); revenue increments and decrements arising from the application of relevant incentive schemes (clause 6.4.3(a)); and revenue increments or decrements arising from the application of a control mechanism in the previous period (clause 6.4.3(a)(6)).

[227] CEG, Critique of the AER's JGN draft decision on cost of debt, April 2015; SFG Consulting, Return on debt transition arrangements under the NGR and NER, February 2015.

the economic costs and risks of the potential for under and over investment by a service provider. Further, clawing back past gains creates regulatory risk and uncertainty, resulting in investors requiring higher returns as compensation in future.[228]

It is also important to note that if it was intended that any new approach to estimating the return on debt implemented by the AER under the new Rules be delayed or staggered, the AEMC would have expressly provided for this in savings and transitional provisions in Chapter 11 of the Rules. The AEMC did not do so. Rather, the AEMC responded to concerns in relation to transition by requiring that any significant costs and practical difficulties in moving from one approach to another to be a matter to which AER has regard to in estimating the return on debt.

On the issue of practical problems with the use of historical data, CEG observes the following:

- regulators (including the ACCC/AER) have been estimating the return on debt over the entire period and all of the relevant data that was available then is available now;
- while there may be differences in the available historical data series, the same will almost certainly be true prospectively. The AER has proposed to deal with this by giving equal weight to the currently available third party estimate and the same method could be easily be applied historically; and
- any variation in data sources is likely to be exacerbated by the AER's proposed transition. Whereas the AER's transition gives 100% weight to yields estimated during the initial short, averaging period and this estimate dominates the AER return on debt estimate over the transition (it still has 60 per cent weight in the last year of the next regulatory period), estimating a trailing average return on debt over the last ten years results in less than 1 per cent weight being given to each available month.

SFG Consulting similarly maintains that the AER's concerns about the availability of historical data are overstated and observes that the availability of data should not drive regulatory practice. In circumstances where the AER has determined that the regulatory allowances under the trailing average approach to estimating the return on debt is commensurate with the efficient financing costs of the benchmark efficient entity, and there is a robust means of calculating it, complexity in the estimation of that return using historical data is not a basis for determining to apply a transition.

Finally, as CEG outlines, the AER's proposed transition does not, in any event, address any incentives for opportunistic behaviour. Rather in proposing a transition that is divorced from the benchmark efficient entity's debt management practices, the AER is creating a framework where the opportunistic behaviour it is concerned about can exist.

12.4.6 Estimation procedure

Our approach

As mentioned above, the AER has indicated in its recent NSW draft determinations that the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt is relevant only in respect of a transition on the risk free rate component of the return on debt (and not the debt risk premium component as this could not have been hedged). Given this, it would not be correct for the AER to adopt the transition approach described in the Guideline.

Applying a transition to the debt risk premium (as the AER's Guideline transition does) would create a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance. Therefore, for our regulatory proposal, we propose to adopt the transition from the hybrid approach to the

[228] SFG Consulting, Return on debt transition arrangements under the NGR and NER, February 2015.

trailing average approach which is consistent with CEG's advice.[229] Under this approach the return on debt is set equal to the sum of:

- trailing average debt risk premium (measured relative to swap rate);
- average of swaps rates utilised in the unwinding of the business's swap portfolio; and
- the cost of swap transactions required to effect the transition and any new issue premium;

Consistent with this, the return on debt for the regulatory year 2016 for our regulatory proposal is estimated as the sum of:

- the ten year trailing average of ten year debt risk premium measured relative to swap rate over the period 2006-2015;
- the average of 1-10 year swap rates over the nominated averaging period; and
- the costs of swap transactions required to effect the transition.

This reflects the fact that if the hybrid debt management strategy is the assumed starting point then it is possible to define a transition from this starting point to the trailing average debt management strategy. It also highlights that maintaining a swap portfolio will lead to transaction costs.

Source of data

The Guideline did not express a definitive proposal as to the source of the data for the benchmark return on debt and as such it is not a matter of accepting the guideline or proposing a departure. The AER has noted that the use of independent third party estimates may be less controversial where the published source is already available and not explicitly constructed for the regulatory process.

There are currently two principal options for independently published BBB yield estimates under consideration. Namely, the Bloomberg BBB BVAL curve and the RBA published aggregate measure of ten year Australian BBB corporate debt.[230]

The RBA measure of the return on debt is a month end measure. The AER's approach (as most recently seen in the NSW draft determinations) has been to interpolate the end of month results for the RBA measure of the return on debt. For our regulatory proposal we accept this approach.

Although neither curve publishes an estimate for ten year debt, the Bloomberg service produces a 7 year fair value estimate, and the RBA's publication provides a fair value estimate for a 'target tenor' of ten years but, because most bonds in its sample are less than ten years, this is generally associated with a published 'effective tenor' of less than ten years. Extrapolation can be used to arrive at a ten year figure for both published yield estimates.

In the recent NSW draft determinations, the AER proposed a new method for extrapolating the RBA and BVAL curve to ten years target tenor. CEG reviewed AER's methodology and the extrapolation methodology proposed by SAPN in the context of its regulatory proposal to the AER. Based on its analysis, CEG concluded that over the period from 2 January 2015 to 30 January 2015, the SAPN method provides a better fit to the available data. However, CEG considered that the AER draft decision extrapolation methodology provides a better fit to data over the 9 years from 2006 to 2014.

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229 CEG, Critique of the AER's JGN draft decision on the cost of debt, April 2015.

230 RBA, Aggregate Measures of Australian Corporate Bond Spreads and Yields - F3.

In light of CEG's analysis, we consider that it may not be appropriate to lock in the AER's extrapolation method for all averaging periods. Instead it may be more appropriate to perform the test for the goodness of fit for both the methodologies for each averaging period especially when the results from the two methodologies are materially different.

The SAPN extrapolation formula is as follows:

For each service provider the average slope of the DRP with respect to changes in maturity at each point on the published yield curve at or above 1 year maturity is estimated as the slope coefficient using ordinary least squares (OLS) regression on observations of fair value DRP against maturity with an intercept term. That is, the formula below:

Average slope = $\frac{\sum_{i=1}^{n}(\mathrm{DRP_i}-\overline{\mathrm{DRP}})(\mathrm{M_i}-\overline{\mathrm{M}})}{\sum_{i=1}^{n}(\mathrm{M_i}-\overline{\mathrm{M}})^2}$; where

$\mathrm{DRP_i}$ = published yield at maturity of 'i' years less the swap rate at maturity 'i' based on data published by the relevant service provider;

$\overline{\mathrm{DRP}}$ = the mean of all $\mathrm{DRP_i}$ for 'i' greater than or equal to 1;

$\mathrm{M_i}$ = is the maturity of 'i' years associated with $\mathrm{DRP_i}$ (in the context of the RBA publication this is effective maturity);

$\overline{\mathrm{M}}$ = the mean of all $\mathrm{M_i}$ for 'i' greater than or equal to 1;

n = the number of observations of fair value DRPs with maturity greater than or equal to 1.

The extrapolated DRP at ten years is given by:

$\mathrm{DRP_{10}}$ = $\mathrm{DRP_{i_{max}}}$ + (Average slope)×(10 - $\mathrm{i_{max}}$)

Where $\mathrm{i_{max}}$ is the longest maturity associated with a published yield.

The extrapolated yield at ten years is given by:

Extrapolated yield = ten year swap rate + $\mathrm{DRP_{10}}$

The RBA publishes the DRP to swap at each maturity and the yield at each maturity, so the implied swap rate at each maturity to be used for RBA data can be calculated as:

$\mathrm{Swap_i} = \mathrm{Yield_i} - \mathrm{DRP_i}$

Our regulatory proposal gives a 50 per cent weighting to each of the Bloomberg BBB BVAL and RBA published series each extrapolated out to a ten year tenor which is consistent with the AER's approach in the recent NSW draft determinations.

12.4.7 Averaging period

Accompanying this regulatory proposal and forming part of it is a confidential letter to the AER that details our proposal with respect to the averaging periods for each regulatory year of the regulatory control period. In this confidential letter we propose the averaging period nominated for the regulatory year 2016.[231]

The Guideline proposes, that for each regulatory year in the regulatory control period, the averaging period should be specified prior to the commencement of each regulatory year in a regulatory control period. The

[231] CitiPower, Letter proposing return on debt averaging periods (confidential version), 29 April 2016..

Guideline, is however, not binding on the AER or us and, accordingly, the AER is required to assess that proposal by direct reference to the requirements of the Rules, including in particular the requirement established by clause 6.5.2(h) to estimate the return on debt for a regulatory year such that it contributes to the achievement of the allowed rate of return objective specified in clause 6.5.2(c), rather than by reference to the conditions for debt averaging periods set out in the Guideline.[232]

We do not agree with the AER that the specification of debt averaging periods prior to the commencement of the regulatory control period contributes to the achievement of the rate of return objective or that this is required by the Rules. For each of the second and subsequent regulatory years of the regulatory control period we propose an approach whereby we could nominate and the AER could approve the averaging period for use in calculating the annual rate of return on debt for that regulatory year in accordance with the process set out below:

1. We would notify the AER in writing of our nominated averaging period for use in determining the annual return on debt for regulatory year ‘t’ (where regulatory year t is 2017, 2018, 2019 or 2020) by no later than 31 July in regulatory year t-2.
2. The nominated averaging period notified by us in accordance with [1] must:
   - be a period of at least ten consecutive business days;
   - fall entirely within the period 1 September in regulatory year t-2 to 31 August in regulatory year t-1; and
   - not overlap with the nominated and agreed averaging period for use in any other regulatory year.
3. If we fail to notify the AER of our nominated averaging period for use in determining the annual return on debt for regulatory year t within the time specified in [1] above, the agreed averaging period is taken to be that mentioned in the confidential letter.
4. The AER must notify us in writing within 20 business days after receiving notice from us of a nominated averaging period under [1] of its decision as to whether it agrees to the nominated averaging period.
5. The AER must not withhold agreement to the nominated averaging period unless the nominated averaging period does not comply with [2] above.
6. If the AER withholds agreement to the nominated averaging period in accordance with [4] and [5] above, the agreed averaging period is taken to be as that mentioned in the confidential letter.
7. if the AER fails to notify us of its decision within the time period specified in [4] above, the AER is taken to have agreed to the nominated averaging period.

This process implies that the averaging period used to calculate the annual return on debt for the 2017 regulatory year must be nominated by 31 July 2015 and fall entirely within the period 1 September 2015 to 31 August 2016 inclusive. That is we will nominate an averaging period for use in determining the annual return on debt for 2017 regulatory year that complies with this process by 31 July 2015. We will ensure that the averaging period for 2017 does not occur before or overlap with the averaging period for 2016.

The reason for proposing a departure from the Guideline is that the averaging period proposal in respect of the second and subsequent regulatory years will better promote efficient debt management practices without

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[232] We observe that, insofar as the AER proceeds as suggested in its letter to Jones Day dated 16 March 2015 concerning averaging periods for the regulatory control period commencing 1 January 2016, in stating at Page 2, that ‘*we will assess the averaging periods the businesses propose against the conditions for debt averaging periods the AER proposed in the rate of return guideline(Guideline*)’ the AER will fall into legal error, in that this would involve a substitution of conditions of the AER’s own devising for the statutory criteria and consideration of relevance. The AER is instead required to assess our debt averaging period proposal directly against those statutory criteria and considerations.

harming consumers. Specifically, the nomination of debt averaging period closer in time to debt raising better aligns the debt averaging period with the period over which we, or the benchmark efficient entity in our circumstances, would raise debt based on expected debt management practices in response to:

- market conditions, including changes in market sentiment and the products available for efficient debt management; and
- the debt refinancing and new issue requirements of that entity, including as a consequence of changes in capital expenditure needs or early refinancing requirements set by rating agencies such as Standard and Poor's (**S&P**)[233].

The purpose of providing service providers with an opportunity to nominate future averaging periods is to enable them to align their actual debt costs with the return on debt allowance. Whereas under the AER's previous regulatory approach to estimating the return on debt the time that elapsed between the nomination and occurrence of the debt averaging period was at most one year, a requirement to specify debt averaging periods prior to the regulatory control period where annual updating of the return on debt is to occur means this interval may now be up to five years.

There is considerable uncertainty around when refinancing will need to occur. Although the maturity of existing debt is known now, the exact timing of refinancing is subject to market conditions around the time of maturity and requirements of rating agencies. While S&P and other credit rating agencies typically require debt to be refinanced at least three months before it matures (for maintenance of an investment grade credit rating), the timing of refinancing typically occurs between three and six months prior to maturity depending on market conditions, specifically market interest in the purchase of longer term debt, that are difficult to predict.

By providing for the fixing of debt averaging periods for later years closer to the time of debt raising when these market conditions are better known, our averaging period proposal renders it more likely that those averaging periods will align with the period over which we or the benchmark efficient entity in our circumstances would raise debt. This, in turn, contributes to the estimation of a return on debt that achieves the allowed rate of return objective as required by clause 6.5.2(h) of the Rules, in that it delivers a return on debt that better reflects the efficient debt financing costs of the benchmark efficient entity.

Our averaging period proposal in respect of the second and subsequent regulatory years delivers the above benefits without giving rise to any harm for consumers of electricity. It is also important to note that by reducing the time that will elapse between the nomination and occurrence of the averaging period for use in calculating the annual return on debt for the second and subsequent regulatory years, our averaging period proposal in respect of those years reduces the risk of those averaging periods becoming known to third parties to our commercial detriment, in issuing debt and entering hedge transactions.

Our averaging period proposal therefore contributes to the achievement of the allowed rate of return objective and NEO, to a greater degree than nomination and agreement of all debt averaging periods prior to commencement of the regulatory control period. It follows that the AER is required by clause 6.5.2(h) of the Rules and section 16(1)(a) and (d) of the NEL, to accept our proposal.

12.4.8 Automatic application

Once the averaging period is nominated and approved as per the process set out above, the calculation of the annual return on debt is mechanistic and occurs in accordance with the annual debt updating process proposed in Appendix I of our regulatory proposal on annual updating process and formula and the resultant change to the

[233] Incenta, Debt raising costs, April 2015

annual revenue requirement is effected through the automatic application of the formula specified in the Appendix I.

Whereas the AER's recent draft determinations for the ACT electricity distributor ActewAGL Distribution and the NSW gas distributor JGN, contemplate the establishment of an additional annual process for the AER calculation of the updated annual rate of return, annual revenue requirement and X factor for the later years of the period, we explain in Appendix I that these calculations can be included in the annual pricing proposal for the second and subsequent regulatory years. The AER will be able to assess these for compliance with any applicable requirements embodied in the distribution determination and remedy a non-compliance in approving that pricing proposal under clause 6.18.8 of the Rules. This proposed approach renders a discrete, additional annual return on debt update process unnecessary.

12.4.9 New issue premium

The proposed sources of debt data (i.e. the RBA and Bloomberg series) are observations of the secondary debt market—that is the market in which debt issued in the past, but which has not yet reached maturity, is sold from one bond holder to another. Alternatives to the RBA and Bloomberg series were identified in the AEMC Rule change and AER Guideline processes but these sources are also derived from the secondary market.

By contrast, when network businesses raise debt, it is by issuing new bonds to bond holders. This is known as the primary market. There are a number of differences between the primary and secondary bond markets. For example, the quantum of debt that is the subject of an issue is much greater than the later secondary trade in bonds with only a small proportion (if any) re-traded each business day.

The difference between the costs facing a business issuing bonds into the primary debt market and trading in the secondary debt market is commonly referred to as the 'new issue premium'. It is accepted that this premium is, on average, positive—due to reasons identified in the literature such as market imperfections or underwriters pricing policies.

CEG has prepared a report detailing its views on the extent of the new issue premium.[234] The new issue premium is measured as the change in yields from issue relative to changes in yields of a bond market index. Both the Bloomberg BBB BVAL fair value curve and the RBA BBB fair value curve are calculated based on Bloomberg indicative yields.

CEG's report notes that economic logic suggests that compensation for the cost of debt should be based on the cost of issuing debt into primary (issuance) markets. This is because this is the market which determines the actual yield paid by an issuer on debt raised. Further, these costs are consistent with the allowed rate of return objective.

CEG finds that the best estimate of the new issue premium that is relevant to a benchmark debt management strategy of issuing ten year BBB rated debt is 27 basis points.[235] We will continue to assess whether CEG's recent quantification of the new issue premium is appropriate, but for the purposes of our regulatory proposal have set the value to zero. Our return on debt estimate is therefore conservative.

12.4.10 Transaction costs

In order to account for the efficient financing costs a benchmark efficient entity in our circumstances would incur in maintaining a swap portfolio, it is necessary to take into account the transaction costs of entering swap contracts in the return on debt estimate. CEG considered two recent expert reports (UBS and Evans and Peck) on

[234] CEG, New Issue Premium, 2014.

[235] CEG, *New Issue Premium*, 2014, page 54.

the expected cost of entering swap contracts.[236] Based on CEG's report we adopt an estimate of swap transaction costs of 23 basis points to be included in our return on debt estimate.

12.4.11 Departure from Guidelines: Debt

The Rules require that our proposal identify where we propose departures from Guideline. The following table summarises these:

Table 12.8 Identified departures from Guideline (Debt)

Description	Guideline	Regulatory Proposal	Rationale
Credit Rating	BBB+	BBB	We consider that the AER should remove those businesses who do not reflect the risk profile of a benchmark efficient firm due to government ownership (full or partial). (For further detail, see section 12.4.2).
Transition	Transition provided in the guideline includes transition on both risk free rate and debt risk premium components of return on debt.	Transition only on risk free rate component of the return on debt and no transition on debt risk premium component.	Applying a transition to the debt risk premium would create a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance. This is contrary to AER's own objective at the time of Guideline, the AEMC's intention in amending the cost of debt provisions and the allowed rate of return objective. (For detailed explanation see section 12.4.5).

236 CEG, Critique of the AER's JGN draft decision on the cost of debt, April 2015.

Description	Guideline	Regulatory Proposal	Rationale
Averaging period nomination	The averaging periods for all regulatory years with the regulatory control period must be specified prior to commencement of the regulatory control period.	We propose an approach whereby we could nominate and the AER could approve the averaging period for use in calculating the annual rate of return on debt for that regulatory year in accordance with the process set out in this regulatory proposal.	The nomination of debt averaging period closer in time to debt raising better aligns the debt averaging period with the period over which we, or the benchmark efficient entity in our circumstances, would raise debt based on expected debt management practices in response to market conditions and debt refinancing requirements. (For further detail, see section 12.4.7).
New Issue Premium and Transaction costs associated with entering swap contracts	No provision made for these costs.	23 basis points for hedging related transaction costs and existence of new issue premium (without including the cost of new issue premium in our return on debt).	These reflect the efficient costs incurred by a benchmark efficient firm raising debt in primary markets. (For detailed explanation see section 12.4.9).

Source: CitiPower

12.5 Expected inflation

At this stage, we do not oppose the AER's current approach to determining the expected rate of inflation. However, we note that very recently in Australia and globally, expectations concerning inflation appear to be volatile and it may be that the best method for estimating inflation may evolve during the period that our revenue proposal is being considered.

Using the AER's method, the relevant inflation rate, in our view, would be 2.60 per cent.

12.6 Conclusion

Using the indicative averaging period spanning the 20 days to 30 January 2015, our proposed allowed rate of return, based on the SFG Consulting approach to apply in each regulatory year of the regulatory period outlined above would be calculated as follows:

Table 12.9 Overall rate of return

Input	Rate
Overall return on equity[237] (%)	9.90
Overall return on debt (%)	5.39
Rate of return (%)	7.20

Source: CitiPower

237 Rounded in PTRM.

12.7 Gamma

The Rules require an estimate of 'the value of imputation credits' (also referred to as 'gamma') as an input to the calculation of the corporate income tax building block.[238] In order to promote the NEO, the estimate of gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate).[239] This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role in determining returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on them, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity distribution services for the long term interests of consumers.

The estimation method that we propose to adopt will result in an estimate of gamma that reflects the value equity-holders place on imputation credits. In particular, we propose to calculate gamma in the orthodox manner with the Monkhouse formula, as the product of:

- the distribution rate (i.e. the extent to which imputation credits that are created when companies pay tax, are distributed to investors) using Australian Tax Office data; and
- the value of distributed imputation credits to investors who receive them (theta) based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis).

We propose the observed distribution rate (0.7), which is consistent with the Guideline and findings of the Australian Competition Tribunal. We propose that the distribution rate be combined with the best estimate of theta from market value studies (0.35) which is a departure from the Guideline. This leads to an estimate for gamma of 0.25. This proposal is consistent with the expert advice from SFG and NERA.[240] We consider that the AER's recent approaches fail to estimate gamma reflecting the value equity-holders place on imputation credit as the AER:[241]

- proposes to revise the definition of theta to exclude the effect of certain factors on the value of imputation credits. We consider that this is conceptually incorrect and inconsistent with the requirements of the Rules;
- the AER incorrectly proposes to use equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors;
- has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with evidence;
- has erred in not recognising that the share prices the AER uses to estimate other rate of return parameters reflect the extent to which investors value (dividends, capital gains and) imputation credits and not the extent to which investors might be able to redeem imputation credits;
- uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value;

238 NER, cl. 6.5.3.

239 NEL, section 8.

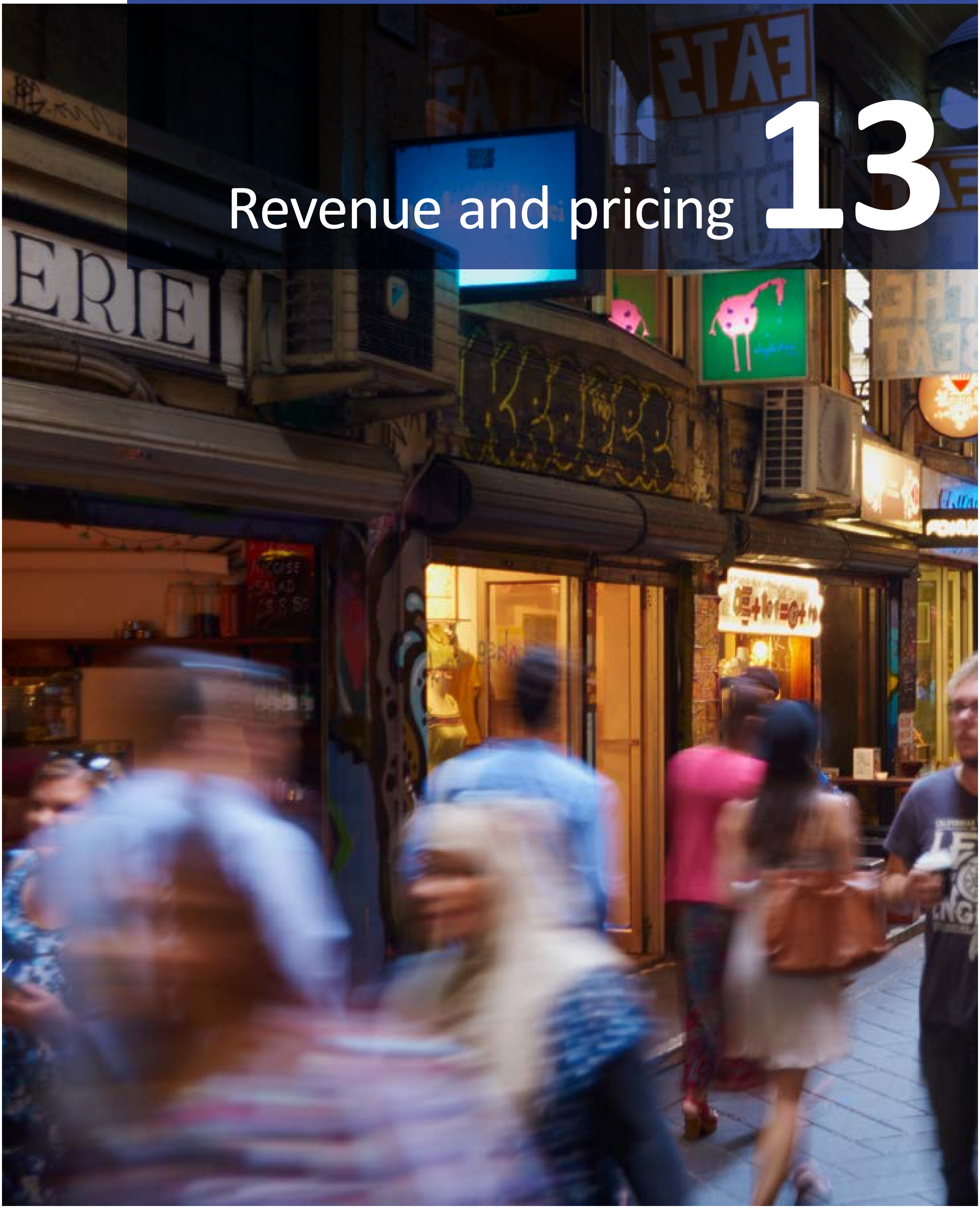
240 SFG, Estimating gamma for regulatory purposes, February 2015; NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, March 2015.

241 AER Draft Determinations of Ausgrid, Directlink, Endeavour Energy, Essential Energy, and Transgrid November 2014.

- has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors;
- the AER has erred in its interpretation of market value studies. The AER considered market value studies in a very general manner, rather than considering the merits of the particular market value estimates. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;
- has relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample; and
- reaches an ultimate conclusion as to the value for gamma is inconsistent with evidence, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER overestimated the value of imputation credits.

The issues raised in relation to gamma are discussed further in appendix J.

13 Revenue and pricing



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13. Revenue and pricing

13.1 Introduction

As shown in this regulatory proposal, our investment plan ensures the long term interests of customers and demonstrates a commitment to providing value for money.

This chapter provides a summary of our proposed 2016-2020 annual revenue requirements for standard control services which reflect the efficient costs that we reasonably expect to incur. The building block approach required by the Rules for the calculation of revenue requirements for standard control services has been applied. The AER's post tax revenue model (**PTRM**) has been used to calculate the revenue requirements. We have not departed from the AER's published PTRM. Attached is the model *CP 2016-20 PTRM*.

The following building block components have been used to calculate the annual revenue requirement for each year of the regulatory control period:

- return on capital for that year, calculated by applying the rate of return determined in chapter 12 with the opening regulatory asset base (**RAB**) value for that year;
- depreciation for that year;
- forecast operating expenditure for that year set out in chapter 10;
- the revenue increments or decrements for that year arising from the application of:
  - the efficiency benefit sharing scheme (**EBSS**) revenue;
  - the S factor true up; and
  - the shared asset revenue reduction.
- the estimated cost of corporate income tax for that year.

13.2 Regulatory asset base

13.2.1 Roll forward of the RAB to 1 January 2016

The estimated value of our RAB for standard control services as at 1 January 2016 is shown in table 13.1. The AER's Roll Forward Model (**RFM**) has been used to calculate the 1 January 2016 opening RAB. Refer to the attached model, *CP 2011-15 RFM*. The attached, *Six-month inflation correction,* sets out why and how the six-month inflation correction has been calculated. Depreciation based on actual capital expenditure has been deducted in accordance with the AER's 2011–2015 Final Determination (**final determination**). The RAB has been adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism.

Table 13.1 Roll forward of the RAB to 1 January 2016 ($m, nominal)

RAB roll forward	Total
1 January 2010 opening RAB from previous determination	1,218.2
Add: correction for six months of inflation	17.6
Add: estimated/actual net capital expenditure for 2010-2015	871.4
Add: difference between actual and estimated capital expenditure in 2010	-23.2
Add: return on difference between 2010 actual and estimated capital expenditure	-13.3
Less: actual straight line depreciation for 2011-2015	-472.0
Add: adjustment for actual inflation	206.1
1 January 2016 opening RAB	**1,804.7**

Source: CitiPower

13.2.2 Roll forward of the RAB from 2016 to 2020

The RAB has been rolled forward from 2016 to 2020 in accordance with the Rules using the AER's PTRM, refer to attached model, *CP 2016–20 PTRM*.

We have separated out one new asset class from the asset classes used in the final determination. This new asset class has been separated because it covers supervisory cables that will become redundant by December 2020, and therefore they need to be separated to ensure they receive the appropriate economic lives.

Urban supervisory networks were designed to carry protection signalling between zone substations. On top of this they also achieved low bandwidth communications for SCADA at zone substation with communication speeds of 1,200 bits per second. The typical distance between urban zone substations is 3 kilometres. Over the last 20 years with the advent of computerised relays, the communications interfaces on relays have moved to high speed fibre optic interfaces. Along with this, the standard protocols for SCADA communications have move from low speed analogue to high speed digital communications demanding Ethernet based networks.

Noise and performance problems means that existing copper supervisory network is at best usable only up to a maximum of approximately 2 kilometres. Therefore, the old urban supervisory network is inadequate for SCADA communications where we now operate gigabit ethernet ring topologies and for protection relays that also demand fibre optic interfaces. All supervisory services will be moved onto fibre over the next five years. Given the nature of the shift in technology, the urban supervisory system therefore no longer has any economic value.

The attached model, *Supervisory cables opening asset value*, sets out the calculation of the depreciated value of supervisory cable which will be replaced by 2020.

Depreciation is set out in section 13.3. Table 13.2 shows the roll forward of our RAB over 2016–2020.

There are no actual or forecast disposals for the purposes of clause S6.2.1(e)(6) and there are no forecast disposals for the purposes of clause S6.2.3(c)(3), respectively, of the Rules.

We have estimated inflation in accordance with section 12.5 of this regulatory proposal.

Table 13.2 Roll forward of the RAB over 2016-2020 ($m, nominal)

RAB roll forward	2016	2017	2018	2019	2020
Opening RAB	1,804.7	1,934.4	2,098.6	2,246.9	2,365.3
Forecast net capital expenditure	181.4	215.5	206.1	183.1	149.7
Depreciation	98.7	101.6	112.3	123.1	133.3
Inflation on opening RAB	46.9	50.3	54.6	58.4	61.5
Closing RAB	**1,934.4**	**2,098.6**	**2,246.9**	**2,365.3**	**2,443.2**

Source: CitiPower

The figures for forecast net capital expenditure for the roll forward of the RAB over the 2016-2020 regulatory control period replicate the forecasts of net capital expenditure in table 9.1 of this regulatory proposal, save for the fact that the figures in table 13.2 are in nominal terms and include half a year's weight average cost of capital, whilst the figures in table 9.1 are in real terms and do not include half a year's weighted average cost of capital.

13.3 Depreciation

The depreciation of the RAB has been calculated using the straight line depreciation method which divides the opening asset values as at 1 January 2016 by the remaining lives and new assets (i.e. forecast net capital expenditure for the 2016–2020 regulatory control period) by the standard lives.

Standard asset lives are equal to standard lives in the current regulatory control period as determined by the AER. The remaining asset lives have been calculated in the attached model, *CP 2011–15 RFM*. The 1 January 2016 asset remaining lives have been calculated so that the resulting depreciation over 2016–2020 regulatory control period is equivalent to the depreciation that would have been calculated if it had been calculated from the sum of:

- depreciation of the 1 January 2011 opening RAB value using the remaining asset lives from the last determination; and
- depreciation of each year of capital expenditure over 2011-2015 regulatory control period using the standard asset lives from the last determination.

This approach is materially preferable to the default approach set out in the electricity transmission network service provider roll forward model; refer to appendix K.

The written down value of SWER ACRs which will be replaced over 2016–2020 regulatory control period are fully depreciated in their expected year of replacement. The attached model, *PAL SWER ACRs opening asset value*, sets out the calculation of depreciated value of supervisory cables.

Table 13.3 shows our proposed standard and remaining lives.

Table 13.3 Standard and remaining asset lives (years)

Asset	Standard life	Remaining life
Sub-transmission	50.0	30.5
Distribution system assets	49.0	20.8
Standard metering	-	1.1
Public lighting	-	8.3
SCADA/Network control	13.0	7.7
Non-network general assets - IT	6.0	5.5
Non-network general assets - Other	10.0	7.4
Victorian Bushfires Royal Commission	20.8	-
Equity raising	43.0	42.6
Supervisory cables	-	5.0

Source: AER, *Final decision, Victorian Electricity Distribution Network Service Providers, Distribution Determination 2011–2015*, October 2010

Regulatory depreciation is the calculated straight-line depreciation less the inflation adjustment to the RAB. Regulatory depreciation for each year of the 2016–2020 regulatory control period is shown in table 13.4.

Table 13.4 Regulatory depreciation ($m, nominal)

	2016	2017	2018	2019	2020
Straight-line depreciation	98.7	101.6	112.3	123.1	133.3
Inflation adjustment	46.9	50.3	54.6	58.4	61.5
Regulatory depreciation	**51.8**	**51.3**	**57.8**	**64.7**	**71.8**

Source: CitiPower

We have estimated inflation in accordance with section 12.5 of this regulatory proposal and have estimated the annual inflation figures over the relevant period on the basis that inflation is constant.

13.4 Efficiency benefit sharing scheme

The EBSS provides a continuous incentive for us to achieve efficiency gains in our operating expenditure. The EBSS scheme outlined by the AER in its final determination has been applied to operating expenditure over the 2011–2015 regulatory control period to calculate the EBSS revenue increments and decrements which must be included in the 2016–2020 building blocks.

The EBSS scheme outlined in the final determination specified that the following operating expenditure categories must be excluded from the operation of the EBSS:

- debt raising costs;
- self-insurance costs;

- superannuation costs for defined benefits and retirement schemes;
- the demand management incentive allowance; and
- guaranteed service level payments.

The final determination states that, for the purpose of calculating carryover amounts, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011–2014 and a revised forecast for 2015, for the forecasts of these metrics used in the final determination using the scale escalation method described in appendix J of the final determination. Benchmark EBSS operating expenditure has been calculated in accordance with this requirement and the calculation is provided in the attached model, *CP EBSS*.

The final determination states that cost adjustments for the EBSS calculation include the adjustments set out in section 2.3.2 of the EBSS. One of the EBSS adjustments is adjustments to forecast operating expenditure for any changes in responsibilities that result from compliance with a new or amended law or licence, or other statutory or regulatory requirement. In 2014 we were required for the first time to provide an audited Economic Benchmarking Regulatory Information Notice (**RIN**) and an audited Category Analysis RIN. The incremental costs incurred for preparation of these RINs and their audit were not forecast in the final determination and have, therefore, been added to benchmark operating expenditure used to calculate EBSS carryover amounts to be applied in the 2016–2020 regulatory control period.

Table 13.5 EBSS calculation ($m, real)

	2011	2012	2013	2014	2015
Adjusted benchmark EBSS operating expenditure	47.9	52.2	55.1	53.2	53.8
Actual EBSS operating expenditure	49.4	56.5	56.8	56.8	57.4
Incremental efficiency	-1.6	-2.7	2.5	-1.8	-
Carryover year	**2016**	**2017**	**2018**	**2019**	**2020**
EBSS efficiency carryover	**-3.6**	**-2.0**	**0.7**	**-1.8**	**-**

Source: CitiPower

13.5 S factor true-up

The AER closed out the Essential Services Commission Victoria (**ESCV**) service performance scheme in 2010 and replaced it with the Service Target Performance Incentive Scheme (**STPIS**). All revenue increments and decrements that were due to arise from the ESCV scheme after 2010 were accounted for the 2011-15 revenue requirements. However, service performance in 2010 was only estimated at the time of the Final Determination. The Final Determination flagged that the final reconciliation (i.e. true up) of actual 2010 performance would be addressed in the 2016-20 distribution determination and provision for the true up was made in the Final Determination S Factor model. The calculation of the true up is provided in attached model *CP - S-factor true up - final decision*, and the S factor true amount shown in the table below.

Table 13.6 S factor true up ($m, real)

	2016	2017	2018	2019	2020
S factor	1.6	-	-	-	-

Source: CitiPower

13.6 Shared asset revenue reduction

Shared assets are those that are used to provide both regulated and unregulated services. The AER may reduce our annual revenue requirement for a regulatory year to reflect the costs of using shared assets that are being recovered from unregulated revenue. In making this decision, the AER must have regard to the shared asset principles and the *Shared Asset Guideline.*[242]

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The *Shared Asset Guideline* sets out how materiality would be tested. It defines that the use of shared asset is material when a distributor's annual unregulated revenue from shared assets is expected to be greater than 1 per cent of its total smoothed revenue requirement for a particular regulatory year. If this materiality threshold is not exceeded, no shared asset cost reduction applies.

The *Shared Asset Guideline* has been applied to calculate the materiality of our use of shared assets to earn unregulated revenue. Our shared asset revenue is primarily earned from renting poles and ducts to telecommunications companies. We understand that the National Broadband Network Company (**NBN Co**) is negotiating with Telstra and Optus regarding its new network design which is fibre to the node. It is anticipated that there will be a transfer of rental revenue from Telstra and Optus to NBN Co, but that pole and duct rental revenue will remain, in real terms, consistent with the historical trends. We have therefore assumed that shared asset revenue will remain constant in real terms at 2014 levels.

The calculation of materiality for each year of the 2016–2020 control period is shown in table 13.6. Since the materiality percentage does not exceed 1 per cent in any year, no shared asset cost reduction applies.

Table 13.7 Materiality of shared asset use ($m, nominal)

	2016	2017	2018	2019	2020
Forecast unregulated revenue from shared assets	2.9	2.9	2.9	2.9	2.9
Smoothed revenue (prior to shared asset reduction)	303.3	322.1	342.0	363.2	385.7
Materiality percentage %	0.95	0.90	0.84	0.79	0.75

Source: CitiPower

13.7 Estimated cost of corporate income tax

The Rules require that the estimated cost of corporate income tax must be for a benchmark efficient entity. The estimated cost of corporate income tax for each year of the 2016–2020 regulatory control period are shown in table 13.7 and have been calculated using the AER's PTRM which complies with clause 6.5.3 of the Rules. The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the roll

[242] AER, Shared Asset Guideline, November 2013

forward model. The standard tax asset lives are consistent with the Australian Tax Office ruling *Income tax: effective life of depreciating assets (applicable from 1 July 2014)*. The remaining tax asset lives have been calculated assuming that the proportion of assets depreciated for tax purposes is the same as that for the RAB.

We have set the PTRM to treat incentive scheme revenues as taxable income, and not as taxable expense. Incentive scheme revenue affects a distributor's actual taxable income and should therefore be taxable income in the PTRM. Incentive scheme revenue does not affect a distributor's actual tax expense and should therefore not be a taxable expense in the PTRM.

Table 13.8 Estimated cost of corporate income tax ($m, nominal)

	2016	2017	2018	2019	2020
Estimated cost of corporate income tax	25.9	25.5	25.4	25.6	28.2

Source: CitiPower

We have departed from the underlying methods in the AER's 2011-15 Roll Forward Model by using declining balance depreciation to roll forward the Tax Asset Base during the current regulatory control period. This approach was adopted in accordance with clause 11.17.2 of the Rules, which required tax allowance for the current regulatory control period to be estimated using an approach established by the ESC.

13.8 Revenue requirement

For the purposes of clause 6.4.3(a)(6) and 6.4.3(b)(6) of the Rules, there are no further revenue increments or decrements to be carried forward from the previous regulatory control period.

The previous sections set out our proposed building blocks. The building blocks are used to derive our proposed unsmoothed annual revenue requirement for standard control services which are shown in table 13.8.

We propose to adopt the revenue cap form of price control and formulae that give effect to the control mechanism as set out in the *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**). Our proposed smoothed revenue is based on revenue X factors which have been calculated so that smoothed revenue follows relatively closely the underlying building block costs (net of efficiency scheme revenue increments or decrements). Further, revenue X factors included in table 13.8, which relate to standard control services, are designed to equalise (in terms of net present value) the revenue to be earned by us from the provision of standard control services over the 2016–2020 regulatory control period with our proposed total revenue requirement for that period.

We have estimated inflation in accordance with section 12.5 of this regulatory proposal and have estimated the annual inflation figures over the relevant period on the basis that inflation is constant.

Table 13.9 Revenue requirement ($m, nominal)

	2016	2017	2018	2019	2020
Return on assets	129.9	139.2	151.0	161.7	170.2
Regulatory depreciation	51.8	51.3	57.8	64.7	71.8
Operating expenditure	95.9	99.9	111.0	116.9	119.9
EBSS efficiency carryover	-3.7	-2.1	0.8	-2.0	-
s-factor true up	1.6	-	-	-	-
Shared asset revenue reduction	-	-	-	-	-
Corporate income tax	25.9	25.5	25.4	25.6	28.2
Unsmoothed revenue requirement	301.4	313.7	345.9	366.8	390.1
Smoothed revenue requirement	303.3	322.1	342.0	363.2	385.7
Forecast CPI %	2.60	2.60	2.60	2.60	2.60
Revenue X factor[243] %	**0.12**	**-3.50**	**-3.50**	**-3.50**	**-3.50**

Source: CitiPower

13.9 Indicative charges and bill impact

For indicative impact on distribution use of system charges, refer to the table below and the attached *CP 2016-20 PTRM.*[244]

Table 13.10 Distribution bill impact for typical customer (excluding smart metering charges) (per cent)

Typical annual bill	2016	2017	2018	2019	2020
Residential	-1.4	2.5	2.5	2.6	2.6
Small commercial	-5.9	-2.2	-2.1	-2.1	-2.4
Large	-1.4	2.7	3.0	3.3	3.3

Source: CitiPower

Whilst these movements provide an early indication of our commitment to customers for the next regulatory control period, they are indicative only at this stage. The actual prices that will be charged to customers for the 2016–2020 regulatory control period are dependent on:

- the X factors that the AER will determine for us for the 2016–2020 regulatory control period;
- actual energy consumption:

[243] A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

[244] Clause 6.8.2(c)(4) of the Rules requires us to provide indicative prices. Further, please note these prices differ from those set out in the executive summary which includes both network and metering charges.

  - if energy consumption falls below our forecast, average charges would need to increase more than indicated; or
  - if energy consumption rises above our forecast, average charges would decline below the estimates indicated.
- the impacts of incentive schemes such as service target performance incentive scheme and F-Factor;
- the impacts of ‘unders and overs’ amounts adjusted for the time value of money due to variances between actual and forecast volumes;
- implementation of the new pricing objective and pricing principles. We are required to submit a proposed tariff structure statement to the AER for approval by 25 September 2015 in accordance with the pricing objective and pricing principles. Implementation of the statement must commence on 1 January 2017. As a consequence, individual customers may experience tariff changes which are more or less than the forecast average change in distribution charges; and
- we note that the percentage changes in table 13.10 are only a portion of the total network use of system charge to customers. Network use of system charges also include the cost of the services provided by the transmission network service provider and the recovery of an amount to satisfy obligations under the jurisdictional scheme requirements. These components are outside our control.

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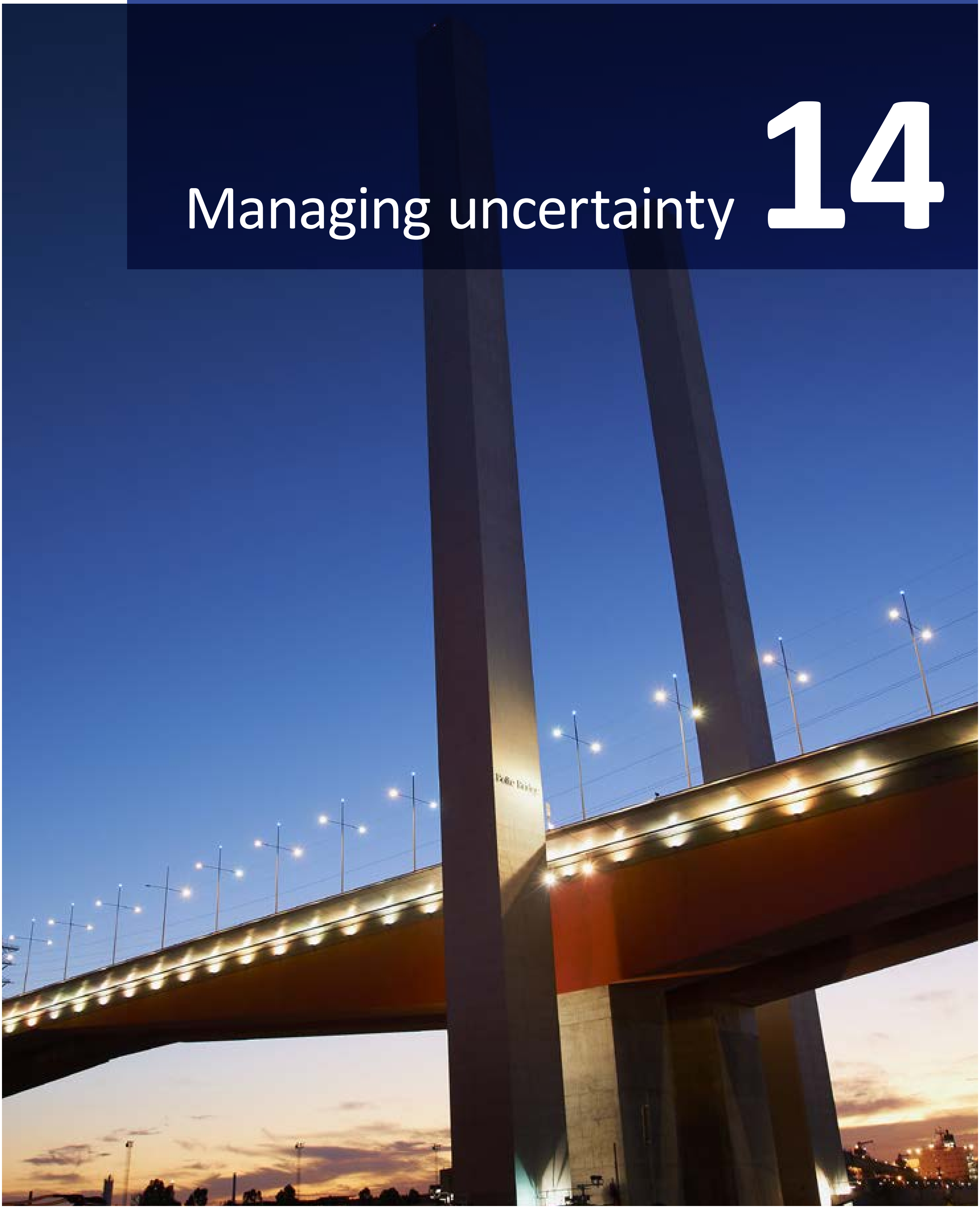
14 Managing uncertainty



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14. Managing uncertainty

While our expenditure forecasts have been prepared based on the best information currently available for what we will need to do during the 2016 –2020 regulatory control period, we are unable to predict each and every event that will occur.

Rather than building up our expenditure forecasts to cover all possible eventualities, the uncertainty regime allows us to request extra funding from the AER during the regulatory control period if a large unexpected event occurs, or if a large event occurs that we had anticipated but we had previously been unable to cost given the lack of clarity about what we would be required to do.

The exclusion of the costs of uncertain events from our regulatory proposal ensures that our customers face the lowest possible prices.

We operate in an uncertain environment. Uncontrollable external events can alter the quantity and nature of services that we are required to provide. The 'uncertainty regime' under the Rules comprises:

- pass through events;
- capital expenditure reopeners; and
- contingent projects.

These mechanisms deal with expenditure that may be required to be undertaken during a regulatory control period but which are not able to be predicted with reasonable certainty at the time of preparing or submitting a regulatory proposal to the AER.

We do not propose any contingent projects for the 2016–2020 regulatory control period. Greater description of the uncertainty regime and our proposal is contained in appendix L.

14.1 Pass through events

The pass through mechanism in the Rules recognises that a distribution network service provider (**DNSP**) can be exposed to risk of loss beyond its control, which may have a material impact on its costs. A cost pass through enables a business to seek the AER's approval to recover (or pass through) the costs of a defined unpredictable, high cost event for which the distribution determination does not provide a regulatory allowance.

A building block proposal may include a proposal as to the events that should be defined as pass through events, in addition to the events defined in the Rules, which are:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a retailer insolvency event.

We have undertaken a thorough risk assessment of our operations to ensure we have appropriate risk mitigation mechanisms in place to address those risks, in addition to reviewing the appropriate level of insurance cover. However, we have identified a number of risks which we consider would be prudently managed via a nominated pass through event rather than as an allowance in our regulatory proposal. The nominated pass through events are those which are beyond our control to prevent, are expected to have significant or catastrophic cost impacts and have a low likelihood of occurring.

We propose the following events to be approved as part of our Distribution Determination, which are to apply as nominated pass through events for the 2016–2020 regulatory control period.

Table 14.1 Nominated pass through events

Pass through event	Description
Insurer credit risk event	The insolvency of an insurer of the distributor.
Insurance event	Exposure to the risk of incurring liabilities above the insurance caps.
Natural disaster event	Occurrence of natural disasters such as floods, earthquakes, major storms and bushfires.
Terrorism event	Occurrence of act of terrorism.
End of metering derogation event	The existing metering derogation that provides exclusivity for Victorian distributors providing metering services to residential and small customers ends, leading to metering contestability.
Multiple trading relationships event	An event to capture the costs incurred should we be required to change the manner in which we interact with meters and customers.
Retailer failure event	To enable us to pass through costs (including unpaid charges for the provision of direct control services) we incur as a result of the insolvency of a retailer

These events are discussed in turn below.

In proposing these events, we have had regard to the nominated pass through event considerations outlined in chapter 10 of the Rules and we consider that each event meets the necessary requirements to be approved as a pass through event. Our proposed definition for these events and detailed assessment of how these events meet the nominated pass through event considerations is provided in appendix L.

Further, we consider that the AER's distribution determination should provide for the pass through provisions of the Rules to apply to alternative control services. The risks faced by distributors in relation to these services are the same as those faced in providing standard control services and the availability of cost pass through provisions is consistent with the basis of the control mechanism which have been developed in relation to those services.

We also propose a slight modification to the definition of 'materiality' that applies for pass through events relating to alternative control services. The current definition in the Rules relates solely to standard control services, and therefore the word 'materiality' should be taken to refer to its ordinary and nature meaning when applied to alternative control services.

Insurer credit risk event

We propose a pass through event for an 'insurer credit risk event'. This event would be triggered where an insurer becomes insolvent and we are subject to higher or lower premiums than those allowed in the distribution determination or a higher or lower claims limit or deductible than those allowed under the insurance policy will that insurer. This event is included in our regulatory determination for the 2011–2015 regulatory control period.

The proposed definition of the insurer credit risk event is:

An insurance credit risk event occurs if, as a result of the insolvency of an insurer, the distributor:

(1) incurs higher or lower costs for insurance premiums;

(2) in respect of a claim for a risk that would have been insured by the distributor's insurers, is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the relevant policy; and/or

(3) incurs additional costs associated with self funding an insurance claim, which would have otherwise been covered by the insolvent insurer.

The AER has previously recognised that the occurrence of increased insurance premiums or deductibles from external insurers is largely beyond the control of the distributors, and that the costs associated with higher insurance premiums are also beyond the control of the distributor.[245]

While we have in place a number of mitigation strategies to avoid being in a situation where one of our insurers becomes insolvent, the risk of such an event occurring is very low but not improbable. For example, HIH Insurance was placed into liquidation in 2001; similarly AIG faced a liquidity crisis during the global financial crisis but was bailed out by the US Government. It is clear that such events are infrequent. Consequently, to manage our exposure to any of our insurers becoming insolvent, we propose to continue to include an 'insurance credit risk event' in our regulatory determination.

Insurance event

We propose a pass through event for when we incur a liability above the insurance cap. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is:

An 'insurance event' occurs if:

(1) the distributor makes a claim on a relevant insurance policy; and

the distributor incurs costs beyond the relevant policy limit.

For the purposes of this insurance event:

(1) the relevant policy limit is the distributor's actual policy limit at the time of the event that gives rise to the claim; and

a relevant insurance policy is an insurance policy held during the 2016-2020 regulatory control period or a previous regulatory control period in which CitiPower was regulated.

We have an incentive to choose the most efficient mix of risk mitigation mechanisms, and consider that our level of insurance cover is appropriate, taking into account the probability of an insurance event occurring, the financial consequence of any such event occurring, and the cost and availability of insurance in the market.

The probability of an insurance event occurring that results in liability above our insurance cap is very low, however to continue to manage the risk, we propose to continue to include an 'insurance event' in our regulatory determination.

[245] AER, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, Draft decision, June 2010, page 725.

Natural disaster event

We propose a pass through event for a natural disaster. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is:

> *A natural disaster event occurs if:*
>
> *Any major fire, storm, flood, earthquake or other natural disaster beyond the reasonable control of the DNSP that occurs during the 2016-20 regulatory control period.*
>
> *The term 'major' in the above paragraph means an event that is serious and significant. It does not mean 'materially' as that term is defined in the Rules (that is 1 per cent of the distributor's annual revenue requirement for that regulatory year).*

The AER has previously stated that the occurrence of natural disasters such as floods, earthquakes, and major storms is entirely beyond the control of distributors.[246] The timing of such an event cannot be determined in advance, and the costs are variable depending on the type and magnitude of the event.

We cannot reasonably prevent a natural disaster event from occurring. That said, we have in place a number of preventive measures to manage the risks, including a Crisis and Emergency Management System which provides an effective state of readiness to prepare for, respond to and recover from, a range of credible and potential events with the aim of mitigating the effects of the event as far as practicable. In addition, we have a number of activities in relation to bushfire mitigation.

While we have obtained efficient levels of commercial insurance cover which are commensurate with our assessment of our business risk arising from natural disasters, we consider a pass through event represents a more appropriate means for managing our risk exposure to such an event given the complexity associated with developing credible self-insured risk quantifications for very low probability events.

Terrorism event

We propose a pass through event for an act of terrorism. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is:

> *An act (including, but not limited to, the use of force or violence, the threat of force or violence, attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear).*

Our ability to reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event is limited. Whilst the occurrence of a terrorism event is largely beyond our control to prevent, we continue to review and assess the level of security at our sites in addition to undertaking security surveys.

The commercial market for insurance in Australia is insufficient to cover demand. While we hold an insurance policy that covers property damage and business interruption as a result of terrorism, it may not cover all of the impacts of a terrorism event on our network and business.

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[246] AER, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, Draft decision, June 2010, pp. 725-726.

We therefore consider that a pass-through event represents the most prudent and efficient means for managing a risk of this nature during the 2016–2020 regulatory control period.

End of metering exclusivity event

We propose an ending of the metering derogation event. While the Australian Energy Market Commission (**AEMC**) has published a draft determination, this event would occur when the detail of the framework for metering contestability is determined prior to the expiration of the derogation which provides Victorian distributors with exclusive responsibility for metering services for smart meters.

Our proposed definition is:

> *An ending of the metering derogation event occurs if the impending or actual expiry of the Victorian Metering Derogation:*
>
> *(1) results in the distributor incurring costs to facilitate the introduction of metering contestability (whether prior to, or subsequent to the expiry of that Derogation) including, but not limited to:*
>
> *(a) system costs for establishing metering contestability;*
>
> *(b) meter provider of last resort costs; and*
>
> *(c) costs incurred to obtain non-metrology data from meters to enable the distributor to operate its network; and*
>
> *(2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules.*
>
> *For the purposes of this metering derogation event, the Victorian Metering Derogation is the derogation currently provided for in clause 9.9C of the Rules pursuant to the AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering infrastructure) Rule 2013, 28 November 2013 and any subsequent derogation which may be made with similar effect to that in clause 9.9C of the Rules, albeit with a different expiry date.*

At this stage, there is uncertainty regarding aspects of the framework for competition in metering and related services which may not be resolved in the final rule determination. We will be required to implement new systems and processes to facilitate the contestable metering framework, however there is uncertainty as to the detail of the framework, including:

- our roles and responsibilities;
- the IT investment required to facilitate ad operate in a contestable metering market;
- business to business (B2B) protocols; and
- the shared market protocol.

These will be determined through a range of processes, procedures and guidelines to be published by industry, government and other parties before the new rule takes effect.

We are unable to include these costs in our regulatory proposal given the uncertainty associated with the detail of the framework for metering contestability. We consider that the event may not be classified as either a regulatory change event or a service standard event as it is possible that it will be necessary for us to incur at least some of the costs prior to the expiration of the derogation. We therefore consider that a prudent approach is to nominate this as a pass through event for the 2016–2020 regulatory control period.

Multiple trading relationships event

We are proposing an event relating to the proposed introduction of multiple trading relationships at a single connection point. This follows the recommendation of the AEMC in its Power of Choice review that a customer has the ability to select more than one retailer for services connected to a National Meter Identifier (**NMI**) – for example, to purchase electricity off one retailer but sell the distributed generation electricity back into the grid via another retailer.

Our proposed definition is:

> *A multiple trading relationships event occurs if a change (including without limitation any NEM procedure or system change) occurs that:*
>
> *(1) facilitates two or more entities being able to provide services at a single connection point; and*
>
> *(2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules.*

This event would occur after the Rule change determination and/or retail market procedures have concluded.

While the rule change proposal lodged by Australian Energy Market Operator (**AEMO**) provides a high level framework in which multiple trading relationships can operate and evolve, it does not contain detailed prescriptive requirements. However, following the AEMC rule change determination, AEMO will develop retail market procedures which will contain detail of the multiple trading relationships day-to-day operation.

We are unable to include these costs in our regulatory proposal given the uncertainty as to the model of multiple trading relationships and the manner of its implementation. We are also uncertain as to whether the event falls within the definition of a service standard event. Accordingly, we propose that the event should be a nominated pass through event in order to provide certainty that the costs incurred following this event will be treated as a pass through event in the 2016–2020 regulatory control period.

Retailer failure event

We are proposing an event relating to the failure of a retailer. There is uncertainty regarding whether the retailer insolvency event specified in the Rules applies to Victorian distributors given that the pass through event was associated with the introduction of the National Energy Customer Framework (**NECF**), which has not been adopted in Victoria.

Our proposed definition is:

> *A retailer failure event occurs if a distributor incurs costs as a result of the failure of a retailer during a regulatory control period to pay a distributor an amount to which the distributor is entitled for the provision of direct control services, if:*
>
> *(a) an insolvency official has been appointed in respect of that retailer; and*
>
> *(b) the distributor is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.*
>
> *For the purposes of this definition:*
>
> *(a) The term 'costs' includes amounts which the distributor was entitled to be paid (but which are or will be unpaid as a result of a retailer failure event) for the provision of direct control services, including, but not limited to:*
>
> *(i) charges for direct control services provided by the distributor;*
>
> *(ii) charges to recover the designated pricing proposal charges incurred by that distributor, and*

these amounts must be taken to be a cost that can be passed through and not a revenue impact of the event.

(b) The term 'insolvency official' means a receiver, receiver and manager, administrator, provisional liquidator, liquidator, trustee in bankruptcy or person having a similar or analogous function.

(c) The term 'credit support' takes its ordinary and natural meaning.

(d) Other terms used in this definition that are defined in the Rules take their definition in the Rules.

The proposed definition takes into account the recent rule change request proposed by the COAG Energy Council that seeks to ensure that distributors are able to pass through foregone revenue for the provision of direct control services following the insolvency of a retailer.[247]

Similar to distributors in jurisdictions which have implemented NECF, we are unable to manage the risk of retailers defaulting on payment of their network charges. Given the uncertainty of the application of the retailer insolvency event in Victoria, we seek the AER to include this event as a nominated pass through event in our distribution determination.

[247] AEMC, National Electricity Amendment (Retailer insolvency events – costs pass through provisions) Rule 2015, Consultation, 30 October 2014.

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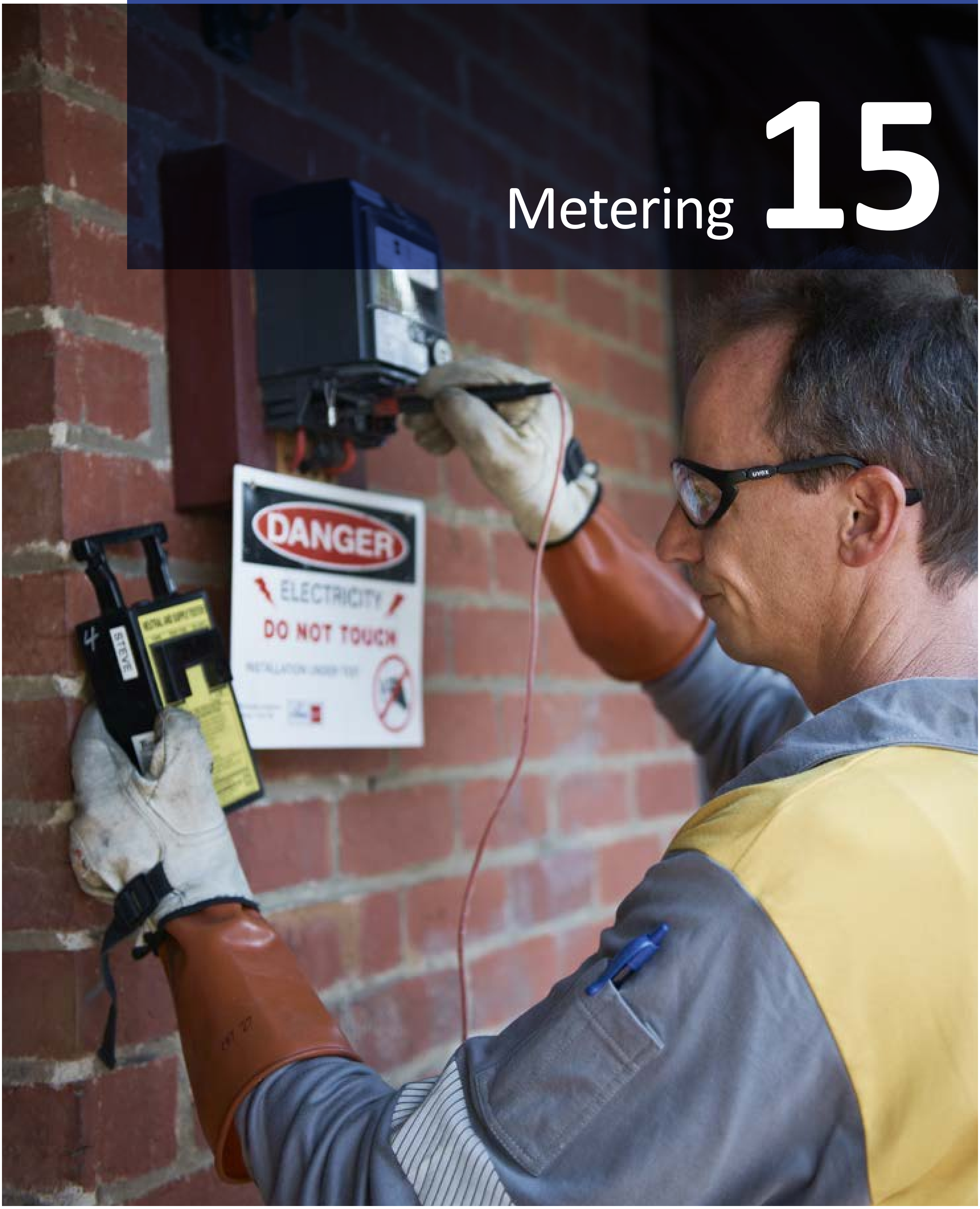
Metering 15



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15. Metering

We had a very successful metering program. Our smart meter rollout has been delivered on time and on budget.

We are already realising network benefits from our smart meter program and will continue to do so. These network benefits provide long term benefits to our customers.

The introduction of contestability in the metering market creates considerable uncertainty regarding our expenditure requirements for the 2016-2020 regulatory control period and may also affect our ability to realise network benefits.

Our regulatory proposal is based on a set of assumptions regarding the introduction of contestability from 1 January 2017. Should these assumptions prove incorrect we could incur significant additional costs that are not captured in our proposed annual revenue requirement for the 2016-2020 regulatory control period. We have therefore proposed a pass through event to manage this risk, refer chapter 14.

We are currently responsible for metering services associated with types 5, 6 and smart meters. These meters are installed in residential and small business premises consuming up to 160 megawatt hours (**MWh**) per annum. The services we provide in relation to these meters include:

- meter provision – includes purchasing meters and installing these meters at the customer's premises;
- meter maintenance – includes inspecting, testing, maintaining and repairing meters;
- meter replacement - replacement of a meter and associated equipment, at a site with existing metering infrastructure, with a modern equivalent where the meter has reached the end of its economic life;
- meter reading and data services - includes collection, processing, storage and delivery of metering data to other market participants for billing and market settlement purposes and the management of the relevant National Meter Identifier (**NMI**); and
- meter communications – includes maintaining and installing communication devices required to operate the mesh radio network and management of the day to day operation of the meter communications systems including meter data delivery, testing, fault detection, investigation and resolution.

For the 2016–2020 regulatory control period, types 5, 6 and smart meters installed up to 31 December 2016 will be regulated as alternative control services subject to a revenue cap. This chapter sets out our proposed annual revenue requirement for these meters.

It should be noted that, based on current legislative provisions, types 5, 6 and smart meters installed on or after 1 January 2017 will be subject to a contestable market and will be an unregulated service. Our proposed annual revenue requirement therefore excludes any costs for metering services associated with types 5, 6 and smart meters installed from 1 January 2017.

We are also responsible for providing customer requested auxiliary metering services and type 7 metering services relating to unmetered supply both of which are regulated services. Consistent with the *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**), these services are classified as alternative control services. Our approach to auxiliary metering services is therefore discussed in chapter 16. We do not propose a fee for providing type 7 metering services as the supply is unmetered and the cost of providing the service is immaterial.

Services relating to metering types 1-4 meters, excluding smart meters, are generally used by large customers who consume greater than 160 MWh of electricity per annum. These meters are competitively available and therefore unclassified (unregulated) services in accordance with the F&A Paper.

15.1 Smart meter rollout

The Victorian Government decided to implement a distributor-led mandated smart meter rollout for all residential and small business customers using up to 160MWh of electricity per annum. The Victorian distributors were required to replace the existing types 5 and 6 meter installations at these premises which smart meters.

The distributor-led mandated rollout of smart meters was facilitated by:

- a Victorian Government derogation in the National Electricity Rules (**Rules**) which had the effect of assigning Victorian distributors with sole responsibility for the installation of smart meters in their network area, referred to as 'the derogation';[248] and
- the Victorian Advanced Metering Infrastructure Order in Council (**AMI OIC**) which specifies how the Victorian distributors are to recover their costs of the smart meter rollout.[249]

Key differences between smart meters and the pre-existing types 5 and 6 meters are that smart meters have the capability to record the time of energy use and are read remotely rather than manually.[250]

The co-ordinated replacement of types 5 and 6 meters with smart meters throughout the network has facilitated the potential for significant savings in network related costs for customers including, but not limited to:

- reduced supply restoration times;
- remote energisation and de-energisation of connections;
- efficient load management to promote security of supply; and
- remote meter reading.

We have now moved into a 'business as usual' phase of meter management. The quantity of each type of meter currently installed by us and connected to our network as at 31 December 2014 is set out in table 15.1.

Table 15.1 Quantity of meters installed as at 31 December 2014

Meter type	Volume
AMI 1Ph 1e	221,292
AMI 1Ph 1e + contactor	7,695
AMI 1Ph 2e + contactor	33,102
AMI 3 Ph	57,594
AMI 3 Ph + contactor	1,492
AMI 3 Ph CT	2,433
Total	**323,608**

Source: CitiPower

248 The derogation is contained in clause 9.9C of the Rules.

249 Electricity Industry Act 2000, Order under section 15A and section 46D, Order in Council (Gazetted S200, 28 August 2007) and as amended.

250 Type 5 meters record time of use and are manually read. Type 6 meters are accumulation meters which report total energy consumption only and are read manually.

15.2 Meter contestability

The derogation is due to expire on the earlier of 31 December 2016 or the introduction of a national constestable market. From this time, the Victorian distributors will no longer have sole responsibility for types 5, 6 and smart metering services.

However, at the end of the derogation, we will have significant unrecovered capital costs associated with the smart meter rollout during the 2009 to 2016 period. We will also have ongoing costs associated with maintenance of meters installed during the derogation, and with maintaining the communications and information technology (**IT**) systems which support the transmission and management of data received from smart meters installed during the derogation.

There is currently considerable uncertainty however regarding the framework for metering contestability that will apply nationally and in Victoria over the 2016–2020 regulatory control period. We have therefore developed our proposed annual revenue requirement based on the current regulatory arrangements. In particular, we have assumed that:

- the smart meter derogation will expire on 31 December 2016, at which point the market will be contestable;
- we will not be required to obtain type 4 accreditation to continue to operate, maintain and replace smart meters installed during the derogation;
- we will not incur licence fees for operating the communications network within 900Mhz range;
- we will not have to upgrade our IT and back-office systems to manage the receipt of data from multiple third parties; and
- we will not be required to provide 'metering provider of last resort' services following the expiry of the derogation.

We will update our assumptions for any known changes in the metering contestability framework in our revised regulatory proposal.

However, should our revised regulatory proposal assumptions prove incorrect, we could incur significant additional costs that are not captured in the proposed annual revenue requirement for the 2016–2020 regulatory control period. To manage this risk we have proposed a pass through event to apply as discussed in chapter 14.

15.3 Revenue forecast

For the 2016–2020 regulatory control period, the AER must regulate cost recovery of smart meter services in accordance with the AMI OIC.

The F&A Paper states that types 5, 6 and smart metering services for meters installed prior to the expiry of the derogation will be subject to a revenue cap coupled with:

- an exit fee for customers choosing to remove or replace a CitiPower installed meter with a competitive sourced meter; and
- a restoration fee for when a distributor reinstates a metering installation (as a metering provider of last resort) or replaces a defective installation.

We have developed the annual revenue requirement for the 2016–2020 regulatory control period using the building blocks approach as set out below.

Our proposed exit fee is set out in section 15.4.

We do not propose a restoration fee as we have assumed that we will not be required to be a meter provider of last resort.

Importantly, our proposed annual revenue requirement is based on a number of assumptions as set out in section 15.2. Our annual revenue requirement could change significantly depending on the final framework for metering contestability.

15.3.1 Regulatory asset base (RAB)

Opening RAB

We used the Australian Energy Regulator's (**AER**) approved 2015 charges application model, updated with actual 2014 revenue and expenditure, to calculate our opening metering RAB as at 1 January 2016 which is $127.3 million ($2015), refer to the attached model, *CitiPower - AMI Charges Model (2015 Charges Application) FD 2014 act*. This is based on:

- the depreciated value of actual capital expenditure incurred up to 31 December 2014. Actual expenditure relates to the purchase and installation of smart meters, investment in the communications network and IT and other back-office systems used to support the smart metering services. Type 5 and 6 meters are fully depreciated and therefore have a value of zero in the RAB;
- forecast capital expenditure in 2015 of $6 million ($2015) based on our attached, *AMI Revised Charges Application dated August 2014*, and
- depreciation of the 2015 opening RAB and forecast capital expenditure in 2015.

The 2016 opening RAB value by asset category is set out in table 15.2

Table 15.2 Opening RAB value by asset category ($m, real)

Asset category	Closing RAB 2014	Forecast capex 2015	Forecast depreciation 2015	Opening RAB 2016
Meters	112.0	3.2	9.5	105.7
Communications	4.6	2.7	1.2	6.1
IT	23.4	0.1	8.1	15.4
Other	0.1	0.0	0.0	0.0

Source: CitiPower

RAB roll forward from 1 January 2016

We have rolled forward the metering RAB for the 2016–2020 regulatory control period using the Post Tax Revenue Model (**PTRM**). This has involved:

- adding forecast capital expenditure, refer to section 15.3.4;
- deducting forecast customer contributions. We forecast zero customer contributions;
- deducting forecast depreciation, refer to section 15.3.2;
- deducting forecast asset disposals. We forecast zero asset disposals; and
- indexing the annual closing RAB using the forecast inflation rate for each year of the regulatory control period. The forecast inflation rate is consistent with the approach for standard control services, refer to chapter 13.

The RAB roll forward calculation is provided in the attached model, *CP Metering PTRM.*

15.3.2 Depreciation

We have calculated forecast depreciation based on the following asset lives:

- smart meters have a standard asset life of 15 years. As most smart meters were installed between 2009 and 2014, on 1 January 2016 the average remaining asset life of our smart meters is 11.1 years; and
- communications and IT assets have a standard asset life of seven years. The average remaining life as at 1 January 2016 is 3.1 years.

Forecast depreciation is calculated for each year of the 2016–2020 regulatory control period for each asset category in the PTRM.

Forecast depreciation is set out in table 15.17.

15.3.3 Rate of return

To calculate the return on capital we have applied the same rate of return as that used for standard control services, provided in table 12.10. We also propose the same approach to annually proposing and updating the return on debt as for standard control services, discussed in chapter 12. Our reasons for deviating from the AER's rate of return Guideline are also set out in chapter 12.

We have applied this same rate of return as standard control services on the basis that the exit fee applied to customers removing or replacing our installed smart meters with competitively provided meters will ensure that we receive full recovery of our sunk investment costs, including the meter provision and installation costs and the back-office costs. However, if the operation of the exit fee did not provide assurance that all sunk costs would be recovered, then a premium should be added to the standard control services rate of return to reflect this added risk.

The rate of return has been applied to the RAB to calculate the return on capital set out in table 15.17.

15.3.4 Forecast capital expenditure

During the 2016–2020 regulatory control period we forecast to incur capital expenditure associated with:

- new metering connections – this relates to the purchase of new meters in 2016. We assume no new connections for the 2017 to 2020 period following the introduction of metering contestability;
- replacement of faulty meters – this relates to purchase and replacement of faulty meters that were originally installed during the derogation;
- customer initiated upgrades – this relates to upgrades to the meter installation to accommodate customer requested supply upgrades in 2016. We assume no customer initiated upgrades for the 2017 to 2020 period following the introduction of metering contestability;
- communications network – relates to the cost of augmenting the mesh metering communications network and replacing faulty communications devices. The communications network provides the delivery of metering data to the central database collection point; and
- IT system – relates to costs of the UtilityIQ system which supports the mesh communications networks.

Our capital expenditure forecasts for each of the above categories are discussed in the following section. The calculations are set out in the attached model, *CP Metering Capex & Opex*.

New metering connections

The forecast volume of total new metering connections in 2016 is based on our forecast new residential connections for standard control services which are developed by the Centre for International Economics (**CIE**), refer to attached model, *CIE Tariff volume forecasts 18 February 2015*. To estimate the volume of new meters in 2016 by meter type, we applied the proportion of new meters installed by meter type in 2014.

We have forecast no new metering installations from 1 January 2017. This is because, following the expiry of the derogation, any new meter installations are assumed to be subject to a contestable metering market and treated as an unregulated service. As noted above, we have also assumed that we will not be required to be a metering provider of last resort.

For 2016, the costs of new metering connections are recovered as follows:

- the capital cost for purchasing the new meter is part of the type 5, 6 and smart meter regulated service; and
- the labour cost for installing the new meter is charged directly to customers as an alternative control service, refer to chapter 16.

To develop our forecast capital expenditure for purchasing new meters, we sought quotes from our two main meter providers, Landis + Gry Pty Ltd and Secure Australasia Pty Ltd, on the per unit meter purchase cost for each meter type. The service provider quotes are stated in US$2015, therefore we have:

- converted these to Australian dollars based on a forecast exchange rate between Australia and US dollars derived from Bloomberg; and
- applied a real price escalator based on our contracts escalator applied to standard control services, refer to chapter 7.

To develop a unit price for each meter type we have taken a weighted average of the two service providers quotes, based on 80 per cent Landis + Gry Pty Ltd and 20 per cent Secure Australasia Pty Ltd. The weights reflect our historical purchase proportions from the two service providers.

Table 15.3 sets out our forecast new connections volumes and unit price for each meter type.

Table 15.3 Forecast capital expenditure for new metering connections in 2016

Meter type	Volume	Weighted average unit price ($, real)
AMI 1Ph 1e	4,359	209.20
AMI 1Ph 1e + contactor	7	233.57
AMI 1Ph 2e + contactor	19	257.08
AMI 3 Ph	1,633	381.00
AMI 3 Ph + contactor	4	408.26
AMI 3 Ph CT	195	487.05
Total new meter connections capex ($m, real)		1.64

Source: CitiPower

Replacement of faulty meters

Reactive replacement

For meters installed during the derogation up to 31 December 2016, we forecast capital expenditure associated with reactive replacement of defective metering equipment. Reactive replacement occurs where the meter, or communications device within the meter, fails before end of life.

Replacement of faulty metering equipment originally installed on or after 1 January 2017 is assumed to be subject to contestability and classified as an unregulated service. Therefore we forecast no capital expenditure associated with reactive replacement of meters installed from 1 January 2017.

For meters installed before 1 January 2017, our forecast fault rates are based on our fault rate in 2014. The 2014 meter fault rate reflects the current fault rate given the current age and meter mix of the existing metering fleet. The 2014 fault rate provides an appropriate base for forecasting the meter fault rate over the 2016–2020 regulatory control period because it reflects the fault rate of meters during the middle period of their 15 year economic life, and not at either the beginning or end of life. Our forecast fault rates for meters are provided in table 15.4.

Table 15.4 Meter forecast fault rates (per cent)

	2014	2015	2016	2017	2018	2019	2020
Fault rate	0.09	0.09	0.09	0.09	0.09	0.09	0.09

Source: CitiPower

The cost of reactive meter replacement includes the:

- cost of a new meter. The unit price of a new meter is sourced from quotes from our two meter providers and is dependent on the meter type, refer to table 15.3 above; and
- labour costs associated with installing the new meter. Our forecast labour costs associated with installations are forecast for each type of metering installation. Forecast labour hours are based on the average number of labour hours incurred for installing each meter type. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Table 15.5 sets out our forecast volumes and capital expenditure for reactive replacements.

Table 15.5 Reactive replacement capital expenditure ($m, real)

Reactive replacement capital expenditure	2016	2017	2018	2019	2020
Volume of meters replaced	1,015	1,026	1,020	1,015	1,009
Meter costs	0.29	0.30	0.31	0.31	0.32
Labour costs	0.52	0.54	0.54	0.55	0.55
Total reactive replacement capex	0.81	0.84	0.85	0.86	0.88

Source: CitiPower

Note: Unit cost of a replacement meter and the labour costs of installation are aggregated across all meter types. The costs vary by meter type.

Proactive replacement

We propose capital expenditure associated with proactive replacement in 2016 only. Proactive replacement relates to:

- the replacement of meters that, through company initiated testing, are identified as faulty; and
- the replacement of any remaining type 5 and 6 meters with smart meters.

The cost of proactive meter replacement includes the:

- cost of a new meter. The unit price of a new meter is sourced from quotes from our two meter providers and is dependent on the meter type, refer to table 15.3 above; and
- labour costs associated with installing the new meter. Our forecast labour costs associated with installations are forecast for each type of metering installation. Forecast labour hours are based on the average number of labour hours incurred for installing each meter type. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

We have assumed that from 1 January 2017, proactive replacement is subject to a contestable market and is classified as an unregulated service. We therefore forecast no proactive replacement for the 2017-2020 period.

Table 15.6 sets our volumes and capital expenditure for proactive replacements.

Table 15.6 Proactive replacement capital expenditure ($m, real)

Proactive replacement capex	2016	2017	2018	2019	2020
Volume of meters replaced	807	-	-	-	-
Meter costs	0.24	-	-	-	-
Labour costs	0.34	-	-	-	-
Total reactive replacement capital expenditure	0.58	-	-	-	-

Source: CitiPower
Note: Unit cost of a replacement meter and the labour costs of installation are aggregated across all meter types. The costs vary by meter type.

Customer initiated upgrades

We provide meter upgrades for existing metering customers upon request. Customer initiated meter upgrades occur when, for example, the customer requests an upgrade to the electricity supply capacity and their existing metering service can not accommodate this.

For 2016, the cost of customer initiated metering services will be recovered as follows:

- the meter cost is part of the type 5, 6 and smart meter regulated service. The per unit meter cost is sourced from quotes from meter providers and escalated to real $2015 as shown in table 15.3; and
- the labour cost is charged directly to customers as an auxiliary metering service which is an alternative control service, refer to chapter 16.

We forecast the volume of customer initiated upgrades in 2016 by meter type based on our actual 2014 volume of customer initiated upgrades. Our forecast volumes, unit costs and total cost of customer initiated metering upgrades in 2016 is provided in table 15.7.

Note that customer initiated upgrades from 2017 are assumed to be an unregulated service.

Table 15.7 Forecast capital expenditure for customer initiated upgrades in 2016

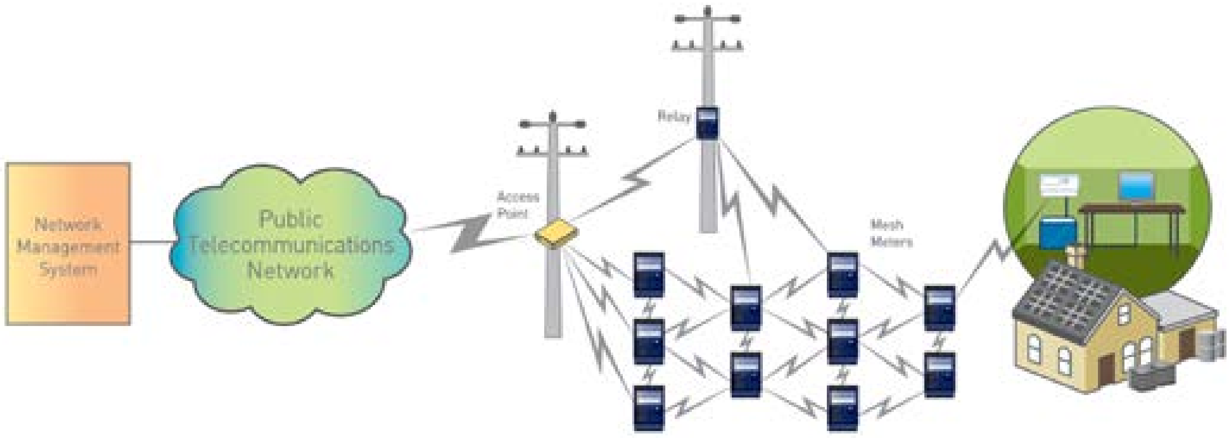
Meter type	Volume of customer initiated upgrades	Meter cost ($, real)
AMI 1Ph 1e	108	209.20
AMI 1Ph 1e + contactor	3	233.57
AMI 1Ph 2e + contactor	10	257.08
AMI 3 Ph	216	381.00
AMI 3 Ph + contactor	3	408.26
AMI 3 Ph CT	8	487.05
Total customer initiated upgrade capex ($m, real)		0.11

Source: CitiPower

Communications network

The mesh metering communications network consists of access points, relays and antennas which enable metering data to be transferred from the meter to the data collection point. Figure 15.1 demonstrates how meter data is transmitted between meters and communication devices and transported back to the central data collection point.

Figure 15.1 Data transmission between meters and communication devices



Source: CitiPower

We forecast capital expenditure in the 2016-2020 regulatory control period for:

- augmentation of the communications network;
- replacement of back-up batteries in communications devices; and
- replacement of faulty communications devices.

Augmentation of communications devices

Our forecast capital expenditure for augmentation of the communications network is based on the:

- forecast quantity of communications assets required to:
  – extend the communication network to accommodate new smart meter connections;
  – infill the communications network when smart meters are removed from the fleet due to supply abolishments; and
  – extend the communications network to achieve communication from non-communicating smart meters. As at 31 December 2014 we had 2,000 smart meters which, due to the external environment, are not communicating through the communications network and therefore are being manually read;
- forecast cost of the communications assets. Based on quotes provided from our communications network service provider Silver Spring Networks Pty Ltd. As quotes were provided in US dollars we have converted the price to Australian dollars using a forecast exchange rate sourced from Bloomberg; and
- forecast labour cost of installing the forecast quantity of communications assets. Forecast labour hours are based on the average number of labour hours incurred for installing communications assets. The hourly labour rate reflects our current labour rate for installations escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Importantly, our capital expenditure forecast for augmenting the communications network is based on the assumption that we do not need to back-fill the communications network as a result of customers choosing to replace existing smart meters with competitively sourced meters. Instead, the costs of back-filling the communications network as a result of customers exiting our metering network have been captured in our proposed exit fee.

Replacement of back-up batteries in communications devices

We forecast capital expenditure associated with the replacement of batteries in communications devices. Batteries contained in access points and relays have an expected life of five years based on manufacturer advice. We have developed our forecasts of battery replacement capital expenditure based on:

- a five year average battery life;
- on the unit price quoted by our communications service provider Silver Spring Networks Pty Ltd. As the quote was provided in $US we have converted the price to Australian dollars using a forecast exchange rate sourced from Bloomberg; and
- forecast labour cost of installing a battery. Forecast labour hours are based on the average number of labour hours historically incurred for installing new batteries. The hourly labour rate reflects our current labour rate for installations escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Replacement of faulty communications devices

We forecast capital expenditure associated with the replacement of faulty communications devices. Our forecast fault rates are based on our average fault rates in 2013 and 2014. It is appropriate to base the fault rates for the 2016–2020 regulatory control period on the average rate of 2013 and 2014 actual fault rate because the volume of communication device faults per year is very small and therefore a longer sample period is necessary to provide a representative forecast. Our forecast fault rates for communications devices are provided in table 15.8.

Table 15.8 Communications devices forecast fault rates (per cent)

	Average 2013-2014	2015	2016	2017	2018	2019	2020
Fault rate	1.63	1.63	1.63	1.63	1.63	1.63	1.63

Source: CitiPower

The cost of replacing faulty communications devices includes the:

- cost of a new communications device. The forecast unit price of new communications devices are based on a quote from our communications network service provider, Silver Spring Networks Pty Ltd; and
- labour costs associated with installing a communications device. Our forecast labour hours are based on the average number of labour hours incurred for installing communications devices. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Table 15.9 sets out our forecasts capital expenditure for the communications network.

Table 15.9 Communications network forecasts capital expenditure

$m, real	2016	2017	2018	2019	2020
Augmentation capital expenditure	0.23	0.09	0.07	0.08	0.09
Battery replacement capital expenditure	0.11	0.01	0.02	0.00	0.01
Fault replacement capital expenditure	0.00	0.01	0.01	0.01	0.01
Total communications network capital expenditure	**0.34**	**0.10**	**0.10**	**0.09**	**0.10**

Source: CitiPower
Note: Unit cost of a replacement communications device varies depending on the device.

Information technology

Our smart meter communications network is supported by the UtilityIQ information technology (**IT**) system. UtilityIQ is a web-based network management system that provides services such as device management, device health monitoring, remote firmware upgrades and outage detection.

We forecast IT capital expenditure for:

- software and hardware upgrades associated with UtilityIQ which are required by our communications network service provider, Silver Spring Networks Pty, to ensure continued operation, support and compatibility; and
- security upgrades associated with UtilityIQ and the smart meter communications network required to ensure the security of our smart meter network and associated systems.

Our proposed IT capital expenditure is set out in table 15.10.

Table 15.10 IT capital expenditure forecasts ($m, real)

	2016	2017	2018	2019	2020
Software upgrades	0.13	0.07	0.12	0.08	0.13
Hardware upgrades	-	-	-	-	0.52
Security	0.27	0.49	0.13	0.08	0.32
Total IT capital expenditure	**0.40**	**0.57**	**0.25**	**0.15**	**0.97**

Source: CitiPower

15.3.5 Operating expenditure

We incur operating expenditure in relation to types 5, 6 and smart metering for the following categories of services:

- meter data services;
- meter maintenance;
- customer service;
- backhaul communications;
- communication operations;
- direct and corporate overheads; and
- IT.

We propose a base-step-trend approach to forecast each of the above categories of operating expenditure for the 2016–2020 regulatory control period. The base-step-trend approach involves:

- identifying the appropriate base level of expenditure;
- removal of non-recurrent expenditure;
- adjusting the base year to present the forecast operating expenditure in accordance with our approved cost allocation methodology (**CAM**);
- identifying any new services to be provided in the regulatory period that are not reflected in the base year expenditure;
- escalating base level of expenditure for growth in the size of the metering service; and
- escalating for real price increases in labour, materials and contracts.

Each of these steps is discussed in the following sections. The calculations are set out in the attached model, *CP Metering Capex & Opex*.

Table 15.11 sets out our forecast operating expenditure for the 2016–2020 regulatory control period.

Table 15.11 Forecast operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020
Actual operating expenditure (2014)	9.80	9.80	9.80	9.80	9.80
Non recurrent operating expenditure	-3.00	-4.00	-4.00	-4.00	-4.00
Adjustment for capitalisation policy in accordance with the CAM	0.17	0.17	0.17	0.17	0.17
Step changes	0.18	0.20	0.20	0.20	0.21
Scale escalation	0.09	0.05	0.01	-0.02	-0.06
Real price growth	0.24	0.33	0.43	0.53	0.63
Total	**7.34**	**6.91**	**6.98**	**7.05**	**7.12**

Source: CitiPower

Base expenditure

We propose using actual 2014 operating expenditure as the base level of expenditure for each operating expenditure category. Our 2014 operating expenditure reflects business as usual (**BAU**) operating expenditure, this is because we had completed 96 per cent of the rollout of smart meters within our network area by 31 December 2013 and therefore were effectively operating in a BAU state in 2014.

We propose adjustments to the 2014 operating expenditure to remove non-recurrent operating expenditure in relation to:

- manual meter read costs that are permitted to be recovered directly from customers in accordance with the AMI OIC from 1 April 2015;
- direct overheads as the move to BAU metering activity and the introduction of contestability will require fewer overheads; and
- IT systems other than the UtiltiyIQ system. As discussed in appendix F, we have identified that, from 1 January 2016, the only IT system required primarily for metering related services, and would not be required if we did not own and operate the metering assets, is UtiltiyIQ. We have therefore applied the 2014 operating expenditure associated with UtilityIQ as the base expenditure for escalating our IT operating expenditure in the 2016-2020 regulatory control period. The remaining IT operating expenditure in 2014, which relates to other IT systems required to provide network services, has been transferred to standard control services.

We also propose to adjust the 2014 operating expenditure for our change in capitalisation policy to ensure our forecast operating expenditure is allocated in accordance with the approved CAM.

Step changes

We have identified one step change in relation to types 5, 6 and smart meters for the 2016–2020 regulatory control period.

In 2012 and 2013 we rolled out 2,547 smart meters with current transformers (**CT meters**). CT meters were rolled out toward the end of the smart rollout as they are placed in more complex sites. CT meters are three phase meters which are generally installed for small commercial customers.

In accordance with chapter 7, clause 7.6, schedule 7.3 of the Rules, CT meters are required to be tested within five years. Unlike direct current meters which are sample tested, all CT meters are required to be individually tested within five years. As we did not undertake testing of CT meters in 2014 we will incur additional operating expenditure during the 2016–2020 regulatory control period which is not included in our 2014 base year expenditure.

We therefore propose a step change for the labour costs of testing our CT meters to meet our regulatory obligations under the Rules. Our proposed labour costs are based on our current labour rate multiplied by testing time per meter of 2.5 hours.

A step change is the only mechanism for recovering the costs associated with CT meter testing. CT meter testing costs are not captured in either the scale escalation or real price growth components of our operating expenditure forecasts because they do not relate to either future growth in meter numbers or growth in the real price of labour or material inputs. Further, CT meter testing is a regulatory obligation prescribed in the Rules which must be undertaken to the standards specified by AEMO. AEMO also undertakes audits of our meter testing compliance. We therefore have no alternative option to undertaking CT meter testing.

Table 15.12 sets out our proposed step change in operating expenditure for CT meter testing.

Table 15.12 CT meter testing step change ($m, real)

	2016	2017	2018	2019	2020
Operating expenditure	0.18	0.20	0.20	0.20	0.21

Source: CitiPower

Scale escalation

For each category of operating expenditure, we have analysed the costs incurred and identified the proportion of costs that increase with the number of meters in service. This is set out in table 15.14.

We have forecast the growth rate in the volume of meters in service based on our forecast of new connections less our forecast of abolishments. New connections are only forecast for the 2016 year. From 1 January 2017, following the expiry of the derogation, we have forecasted zero growth in new metering connections. Our forecasts of abolishments are based on forecast abolishments for standard control services.

Table 15.13 sets out the growth rate in meter volumes for the 2016-2020 regulatory control period.

Table 15.13 Meter volume growth rates (per cent)

Meter connection growth rates	2016	2017	2018	2019	2020
Gross new connections	1.91	0.00	0.00	0.00	0.00
Customer abolishment rate	-0.78	-0.78	-0.78	-0.78	-0.78
Customer supply upgrade rate	0.00	-0.15	-0.15	-0.15	-0.15
Net growth rate	1.13	-0.93	-0.93	-0.93	-0.93

Source: CitiPower

We have calculated the proportion of each category of operating expenditure that varies with meter volumes as shown in table 15.14.

Table 15.14 Proportion of operating expenditure that varies with meter volumes

Operating expenditure category	Explanation	Proportion of variable costs
Meter data services	Back-office activity relating to data management and processing increases as a result of meter volume growth.	50%
Meter maintenance	Meter testing and investigation activity increases as a result of meter volume growth.	50%
Customer service	Back-office activity relating to customer services such as service order processing increases with meter volume growth.	75%
Backhaul communications	Back-haul communications costs are proportional to the volume of meter data being collected and transmitted via 3G access points.	100%
Communications operations	Back-office activity relating to monitoring meter communication activity increases as a result of meter volume growth.	75%
Direct overheads	Relatively fixed costs.	0%
Corporate overheads	Relatively fixed costs.	0%
IT	Ongoing annual licence fees for UtilityIQ increase in direct proportion to meter volume.	80%

Source: CitiPower

To calculate scale escalation rates we multiply the net growth in meter volumes from table 15.13 by the proportion of costs that vary with meter volumes from table 15.14. The resulting scale escalation rates are presented in table 15.15.

Table 15.15 Operating expenditure scale escalation rates (per cent)

Operating expenditure category	2015	2016	2017	2018	2019	2020
Meter data services	0.6	1.1	0.7	0.2	-0.3	-0.7
Meter maintenance	0.6	1.1	0.7	0.2	-0.3	-0.7
Customer services	0.8	1.7	1.0	0.3	-0.4	-1.1
Backhaul communications	1.1	2.3	1.3	0.4	-0.6	-1.5
Communications operations	0.8	1.7	1.0	0.3	-0.4	-1.1
Direct and corporate overheads	0.0	0.0	0.0	0.0	0.0	0.0
IT	0.9	1.8	1.1	0.3	-0.4	-1.2

Source: CitiPower

Real price escalation

For each operating expenditure category we have identified the costs in the 2014 base level expenditure that are associated with each of labour, materials and contracts costs. The proportion of labour, materials and contracts costs in each operating expenditure category is presented in table 15.16.

Our real price escalators for metering services operating expenditure is the same as the real price escalators developed for standard control services, refer to chapter 7.

We have applied the real price escalators to the respective labour, materials and contracts costs in the 2014 base level of expenditure for each category of metering operating expenditure.

Table 15.16 Proportion of operating expenditure (per cent)

Operating expenditure category	Proportion of operating expenditure
Labour	79
Materials	8
Contracts	13

Source: CitiPower

15.3.6 Tax allowance

The tax allowance is calculated in the PTRM. The cumulative tax loss as at 31 December 2015, opening tax assets as at 1 January 2016 and standard tax lives are sourced from the AER's approved 2015 charges application model, updated with actual 2014 revenue and expenditure, refer to the attached model, *CP Metering PTRM*. The value of imputation credits over the 2016-2020 regulatory control period is the same as that used for standard control services, refer to chapter 12.

15.3.7 Annual revenue requirement

Based on the above building block components we have derived the annual revenue requirement for the 2016–2020 regulatory control period as set out in table 15.17.

Table 15.17 Annual revenue requirement ($m, real)

	2016	2017	2018	2019	2020
Depreciation	14.01	14.68	13.64	8.21	8.39
Return on capital	8.93	8.01	6.89	5.86	5.22
Operating expenditure	7.49	7.04	7.09	7.15	7.21
Tax	-	-	-	0.10	2.45
Unsmoothed revenue requirement	30.43	29.72	27.62	21.32	23.27
X-factor (%)	20.0	9.4	9.4	9.4	9.4
Smoothed revenue requirement	31.93	28.91	26.19	23.71	21.48

Source: CitiPower

15.3.8 Control mechanism

The F&A Paper requires that a revenue cap be applied to metering alternative control services. Section 2.4.6 of the F&A Paper sets out the proposed approach to the formulae that gives effect to this control mechanism. We agree with these formulae.

15.4 Exit fee

We have implemented the smart meter rollout over the period 2009 to 2014 in accordance with the derogation and AMI OIC. In undertaking the rollout, we have incurred significant costs which we are currently recovering from customers over the life of the assets.

In accordance with the AMI OIC, we propose an exit fee apply to a customer that chooses to replace the meter we installed under the derogation with a competitively sourced meter.

We propose that the exit fee include three key components:

- recovery of the sunk investment costs;
- administrative costs to facilitate meter exit; and
- costs to ensure no other customer is made worse off. These costs are effectively the costs of lost economies of scale which should be borne by exiting customers rather than remaining customers.

A key philosophy that we have applied to develop our proposed exit fee is that no customer should be made worse off by another customer's decision to exit. As discussed in section 15.4.3, economic efficiency is best achieved when there are no cross subsidies and customers face the full economic costs of the decision whether to replace an existing metering installation.

15.4.1 Recovery of sunk investment costs

Sunk investment costs associated with the smart meter rollout which we propose should be recovered from an exiting customer include:

- the remaining RAB value associated with meter purchase and capitalised installation costs. We have divided the RAB value into meter categories to reflect the different costs of purchasing different types of metering installations. We then divide the RAB value for each category by the volume of meter installations (NMIs) in each category to calculate the share of the RAB value that is payable by an exiting customer. The relevant exit fee for a particular customer therefore depends on the meter type that the exiting customer currently has installed; and
- the customer's share of the RAB value associated with the IT system, the communications network and other shared costs relating to project deployment and project management. The exiting customer's share is based on the RAB value divided by the number of existing metering customers (NMIs) as at 31 December 2016. This component of the sunk investment cost does not vary with the type of metering installation.

The sunk investment cost to be included in the exit fee reduces over the 2017 to 2020 period. This is because the RAB value reduces over time as the average remaining life of the assets decline and the exit fee is calculated for each year of the 2017 to 2020 period based on the RAB values at the beginning of the relevant year.

The exit fee does not take into account the specific age of the exiting customer's metering installation as this would be administratively uneconomic. We also make no allowance for meters that may be reusable as the cost of recycling meters is expected to be uneconomic.

15.4.2 Administrative costs

This component of the exit fee captures the cost of facilitating exit of the customer's meter installation including:

- back-office processing costs, including data management costs; and
- costs of processing and disposal of returned meters.

The administrative fee is the same irrespective of the meter installation type or the year in which exit occurs.

We have considered whether it would be economic to recycle or scrap returned meters. We consider the handling and logistics costs of implementing either approach would exceed the potential benefits. In particular, recycling meters would also require re-testing and re-verification of the meters before deployment.

15.4.3 No customer worse off

As a result of meters exiting the network, there will be a loss of economies of scale in terms of our fixed component of operating expenditure and the efficiency of the meshed communications network.

As a result of a customer exiting the average operating expenditure per meter will increase. Thirty eight per cent of our operating expenditure costs are fixed. To ensure that remaining customers are not made worse off, we propose that exiting customers should pay the net present value of a share of the fixed operating costs incurred over the remaining years in the regulatory control period. We calculate the share of fixed operating costs based on the forecast number of customers (NMIs) as at 31 December 2016, the end of the derogation. The net present value of future operating costs is discounted based on the rate of return applied for standard control services.

Additionally, our metering communications network is a meshed network. The mesh nature of the network means that data is transmitted to the data collection point using the most efficient route, this includes transmission of data via other smart meters. To maintain effective communications when meters are removed from the network, additional communications devices are required to infill the gaps created by removed meters. We have calculated the communications infill component of the exit fee by:

- calculating the ratio of communications assets per NMI as at 31 December 2016;
- calculating the increase in communications devices required to maintain the ratio of communications assets to NMIs when a meter is removed from the network; and
- calculating the cost of the increase in communications devices required to maintain the current ratio based on the unit cost of purchasing the communications devices and the labour cost of installing these devices. The unit costs of purchasing and installing communications devices is provided in section 15.3.4.

15.4.4 Exit fee value and recovery

Table 15.18 sets out our proposed exit fee for each meter installation type for each year from 2017 to 2020 based on the above three cost components. The calculations are set out in the attached model, *CP Metering Exit Fees*.

To promote economic efficiency, we propose that the exiting customer should pay the full value of the exit fee. This is necessary to ensure that each customer makes the decision which reflects the actual economic costs to society of the decision to exit. Otherwise, if a customer faces less than the full economic costs of exit, its individual decisions may be inefficient when considered from broader society perspective. It is inappropriate for non-exiting customers to bear the burden of the costs of exiting customers.

Essentially, we consider economic efficiency is best promoted when the benefits of competition (which will flow exclusively to individual customers as a result of their individual decision to change metering co-ordinators) do not exceed the costs imposed on other participants and consumers in the electricity industry. This can only be achieved if exit fees are fully cost reflective and payable by the decision making party.

The AEMC also states that the regulatory framework should not encourage the inefficient replacement of existing Victorian AMI meters and it is therefore appropriate for customers to pay an exit fee.[251]

We note that the Draft Decision for the NSW distributors involved metering exit fee costs being recovered through standard control services revenue.[252] We consider that applying the same approach in Victoria would be inconsistent with the AMI OIC. The AMI OIC states that:

- an exit fee must be paid by the retailer to the distributor, where the retailer becomes responsible for the metering installation previously the responsibility of the distributor (clause 7.1); and
- the exit fee is to be determined in such a way that enables the distributor to recover the costs in a lump sum which is payable upon a change in the person responsible for the metering installation (clause 7.2).

Consequently, the exit fee must be payable in full upon exit and by the person that takes responsibility for the metering installation.

Further, in March 2015, the AER released a consultation paper seeking feedback on a proposal that the exit fee for NSW, ACT, Queensland and South Australian distributors only include the cost of removing the existing meter. The costs of the meter asset base would then be recovered through an annual charge on all customers, including customers that have exited. We also consider that this proposal could not be implemented in Victoria as the AMI OIC specifies that the exit fee must be a lump sum payment and must include both the costs of removing the meter installation and the unavoidable costs that a prudent distributor has incurred or would incur as a result of the metering installation being removed before the expiry of its economic life.

Table 15.18 Exit fees ($, nominal)

NMI type	2017	2018	2019	2020
AMI 1P	387.69	362.96	317.23	281.22
AMI 3P	463.41	401.48	356.21	320.30
AMI 3P CT	1,144.42	1,080.77	1,061.03	1,047.13
Non AMI NMIs	39.07	39.73	40.40	41.08

Source: CitiPower

15.5 Restoration fee

The F&A Paper proposes that a restoration fee would apply where, as a metering provider of last resort, a distributor reinstates a metering installation or a distributor replaces a defective installation.[253]

We do not propose a restoration fee as we have assumed that we will not be the meter provider of last resort upon the expiry of the derogation. As noted in section 15.2, we will update our assumptions for the revised regulatory proposal for any known changes in the metering contestability framework. We also propose a pass through event for the additional costs associated with changes in the metering contestability framework,

[251] AEMC, Draft Rule Determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015, March 2015, p.75.

[252] AER, Draft Decision Ausgrid distribution determination 2015-26 to 2018-19, Attachment 16 Alternative control services, November 2014, p. 29.

[253] AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, October 2014, p.54, footnote 117.

including the costs of providing metering of last resort services should this be a legislated requirement, refer chapter 14.

Non standard control 16

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16. Non standard control

16.1 Introduction

This chapter provides information in relation to alternative control services and addresses the requirements of the National Electricity Rules (**Rules**) and paragraphs 12, 13 and 15 of the Australian Energy Regulator (**AER's**) Regulatory Information Notice (**RIN**). Alternative control services are ancillary network services, public lighting and some metering services which are not categorised as standard control services. Ancillary network services are discussed in section 16.2 and public lighting is described in section 16.3.

Metering services, whilst also classified as alternative control services, are outlined in chapter 15.

We are proposing for the 2016-2020 regulatory control period that the methodology for setting ancillary network services remain largely the same as the methodology employed in the current regulatory control period. For public lighting we propose a bottom up build for the 2016-2020 regulatory control period consistent with the current regulatory period. The service classification for public lighting services has changed with only shared public lighting assets classified as alternative control services as per the *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**).

16.2 Ancillary network services

The F&A Paper proposes classifying alternative control services, fee based services and quoted services, as they are termed in the current regulatory period, with a single group called 'ancillary network services'. Ancillary network services are 'non-routine services provided to individual customers on an 'as needs' basis'. The charges, however, are still grouped based on whether they are a fee based service or a quoted service.

16.2.1 Fee based services

Nature of the service

Fee based services are activities that are relatively fixed in nature and are charged on a per activity basis. A description of our fee based services is provided in table 16.3.

Changes to the services

We accept the service classification as specified by the F&A Paper, however, there are a number of services we do not offer, refer to table 16.1

Table 16.1 Differences between AER's, and our proposed, fee based services classification

Service	AER's classification in F&A Paper	Proposed amendments
Temporary disconnect/reconnect services	Alternative control (fee-based)	Delete as not used
PV & small generator installation pre-approval (up to 5kW) [254]	Alternative control (fee-based)	Delete, no longer provided due to a change in obligations
PV & small generator installation pre-approval (>5kW) [255]	Alternative control (fee-based)	Delete, no longer provided due to a change in obligations

254 Changes to the 'Service Installation Rules' (2014) (SIR's) has resulted in Powercor Australia desiring to change to an audit based approach to inspecting small scale PV connections rather than charging for every site installation.

255 Changes to the 'Service Installation Rules' (2014) (SIR's) has resulted in Powercor Australia desiring to change to an audit based approach to inspecting small scale PV connections rather than charging for every site installation.

Service	AER's classification in F&A Paper	Proposed amendments
Re-test of types 5 and 6 metering installations (including smart meters) for first tier customers with annual consumption greater than 160 MWh	Alternative control (fee-based)	Delete as not used
Fault response – not DNSP fault	Alternative control (fee-based)	Delete as not used
Temporary supply services	Alternative control (fee-based)	Delete as not used
After hours field based re-energisation services	Alternative control (fee-based)	Delete as not used.
Manual meter read charge	No classification	Alternative control (fee based) – for customers that are not able to have their cyclical meter readings read remotely.[256]
Customer access to metering data	No classification	Alternate control (fee based) – for customers requesting non-standard provision of meter data.

Source: CitiPower

Methodology

Our proposed methodology for developing charges for fee based services involves applying a bottom up build of labour, materials and/or contractor costs. We have quantified the labour costs for each fee based service by:

- identifying the tasks involved in performing each fee based service;
- quantifying the time that each task will take;
- identifying the types of personnel that will be required to undertake each task, based on the skills required;
- quantifying the number of personnel that are required to undertake each task; and
- developing a labour rate, including an escalator, for each type of personnel required.

This methodology has been chosen to provide the most cost reflective assessment of these activities.

<u>Labour, contract and material rates and escalation factors</u>

We use internal and outsourced labour to provide fee based services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

Fee based services have a number of materials associated with routine connections including service cable, fuses, clamps and brackets.

The input price escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

<u>Update delivery times and personnel requirements</u>

The back office and field activity inputs in relation to time allocation and number of personnel have all been reviewed based on actual times and number of personnel that are required to complete each activity as at 2014.

[256] Advanced Metering Infrastructure Order in Council 2014, Government Gazette S263, 5 August 2014.

This involved looking through work plans and discussions with technical experts. Given that the delivery times and personnel requirements changed very little they have remained the same as the current regulatory control period.

Margins

We propose a profit margin of seven per cent in accordance with a KPMG report which has benchmarked margins earned by similar service contractors.

Charges, revenue and unit costs

Section 2.1 of the F&A Paper indicates the control mechanism to apply to ancillary network services in the 2016-2020 regulatory control period is caps on the prices of individual services.

We have developed our proposed price caps for each service based on a bottom up approach.

In accordance with the price control formula in the F&A Paper, the price caps for each fee based service increase each year from 2016-2020 by (1+CPI)(1-X), where X is different for each service and each year. This is demonstrated in the attached, *CP ACS model.*

The indicative charges and revenues for our fee based services for each year of the 2016-2020 regulatory control period is also detailed in the *CP ACS model* attachment. A description of our fee based services is provided in table 16.3.

Information about the unit cost inputs for labour and material categories used to calculate the proposed charges for fee based services in the next regulatory control period can be found in *CP ACS model* attachment.

16.2.2 Quoted services

Nature of the service

Quoted services are charges levied on a time and materials basis. These services are highly variable. A description of our quoted services is provided in table 16.4.

Methodology

Our proposed methodology for developing charges for quoted services involves recovering the costs of both labour and materials. Unlike the charges for fee based services, the charges for quoted services are developed on a case by case basis in order to meet the specific needs of the customer.

We quantify labour costs for each quoted service by:

- identifying the tasks involved in performing the quoted service;
- quantifying the time that each task will take;
- identifying the types of personnel that will be required to undertake each task, based on the skills required;
- quantifying the number of personnel that are required to undertake each task; and
- applying a labour rate for each type of personnel required.

We quantify the material costs, where applicable, for each quoted service by:

- identifying the tasks involved in performing the quoted service;
- identifying the type and number of materials that are required for each task; and
- applying a materials rate for each type of material required.

This methodology is consistent with the current regulatory control period.

Labour, contract and material rates and escalation

We use internal and outsourced labour to provide quoted services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

The labour and contract price escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

Where quoted services include materials these are passed onto customers at cost.

Charges, revenue and unit costs

Section 2.1 of the F&A Paper indicates the control mechanism to apply to ancillary network services in the 2016-2020 regulatory control period is caps on the prices of individual services.

We have developed our proposed price caps for each service based on a bottom up approach.

In accordance with the price control formula in the F&A Paper, the price caps for each quoted service increase each year from 2016-2020 by (1+CPI)(1-X), where X is different for each service and each year. This is demonstrated in the attached, *CP ACS model.*

The indicative charges and revenues for our quoted based services for each year of the next regulatory control period are also detailed in the *CP ACS model* attachment. A description of our quoted services is provided in table 16.4.

Information about the unit cost inputs for labour and material categories used to calculate the proposed charges for quoted services in the 2016-2020 regulatory control period can be found in the *CP ACS model* attachment.

16.3 Public lighting

16.3.1 Nature of the service

We provide public lighting services for thirty nine customers including local councils and Victorian government departments responsible for public lighting. The provision of public lighting, minimum standards and the obligations of distributors and public lighting customers is regulated by the *Victorian Public Lighting Code* (**Public Lighting Code**). A copy of the *Public Lighting Code* is attached.

There are a number of public lighting services, including a new category relating to dedicated public lighting assets, as detailed in table 16.2.

Table 16.2 Different public lighting services

Service	Classification of Services
Operation, maintenance, repair and replacement of shared public lighting assets	Alternative control service
Operation, maintenance, repair and replacement of dedicated public lighting assets	Negotiated service
Provision of new public lighting	Negotiated service
Alteration and relocation of DNSP public lighting assets	Negotiated service

Source: F&A Paper

For alternative control services, we propose using the AER's 2011–2015 price reset public lighting model updated for the next regulatory control period and a number of inputs including updating the light types for new and eliminated light types, traffic management costs, updates to the expected fault rates and removing operation, maintenance, repair and replacement of dedicated public lighting assets.

For avoidance of uncertainty we understand dedicated public lighting assets to be those assets which are attributed to a single customer (not cost shared assets) and which are specialised public lighting columns and the associated lighting equipment on those columns. The operation, maintenance and replacement costs associated with these assets have been removed from the attached *CP ACS model* and must be recovered through a negotiated service regime which is further discussed in section 16.4.3.

16.3.2 Treatment of services

Given that energy efficient lighting offers lower energy usage and reduced greenhouse emissions, public lighting customers have been negotiating with distributors to replace existing public lighting with more energy efficient public lighting during the current regulatory control period. We expect this movement to continue into the 2016-2020 regulatory control period and have updated the public lighting model accordingly.

The *Public Lighting Code* defines standard lighting as:

'a lamp, luminaire, mounting bracket, public lighting pole, supply cable or control equipment, normally used by or acceptable to a distributor.'

All other fittings are classed as non-standard lighting. We are obligated under clause 9.1 of our *Electricity Distribution Licence* to make an offer where a public lighting customer requests operation, maintenance, repair or replacement (**OMR**) services for public lighting with non-standard fittings. In such circumstances we charge for non-standard lighting. We propose to charge the same rate for both light fitting types.

For the 2016-2020 regulatory control period we propose to eliminate light types that are no longer in use.

16.3.3 Methodology

We have adopted the AER's 2011–2015 public lighting model for the purposes of determining the public lighting charges for the next regulatory control period.

Labour rates

We use internal and outsourced labour, determined through competitive tenders, to provide public lighting services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

Material rates

We have a number of material types associated with public lighting services including:

- lamp – a source made in order to produce an optical radiation;
- photoelectric cell – a device that uses changes in light to generate current;
- luminaire – an apparatus which distributes, filters or transforms the light transmitted from one or more lamps and which includes, other than the lamps themselves, all the parts necessary for fixing and protecting the lamps and, where necessary, circuit auxiliaries together with the means for connecting them to the distribution system; and
- miscellaneous materials – miscellaneous material required to undertake the bulk light change and fault repairs including cable, fuseholders and connectors.

Input price escalation

The input price escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

Rate of return

We have used a rate of return consistent with that applied to standard control services, refer to chapter 12.

Traffic management

In some instances traffic management is required in order to perform public lighting services. This cost is a requirement to comply with the *Roads Management Act 2004*. This is also required to comply with the *Occupational Health and Safety Act 2004* , which requires us to, amongst other general workplace health and safety obligations, ensure so far as is reasonably practicable the safety of any workplace that we manage or control. This obligation extends to any person at the workplace, including, for example, employees of any contractor engaged by a municipal council to perform public lighting maintenance services. We have reviewed historical costs to determine what this activity costs us. The costs are determined by the public lighting contract which is developed through a competitive tender process.

Proportion of luminaires that fail between bulk changes

Fault rates have been updated based on analysis of the actual fault rates experienced over the last five years with the average used to determine the rate over four years. Fault rates for T5 and P LED light types have remained unchanged due to limited actual historical data.

16.3.4 Charges, revenue and unit costs

We have provided a completed version of the AER's public lighting model refer to attachment, *CP Public Lighting ACS model.*

Section 2.1 of the F&A Paper indicates the control mechanism to apply to public lighting services in the 2016-2020 regulatory control period is caps on the prices of individual services. We have determined our charges for each public lighting service based on the outputs from the public lighting model.

Information about our charges and revenues from public lighting services for each year of the 2016-2020 regulatory control period is provided in the attached, *CP Public Lighting ACS model.*

Given that OMR of dedicated public lighting assets are no longer classified as alternative control services, this provides a considerable change in relevant alternative control services charges and total revenue from the current to the 2016-2020 regulatory control period.

The attached public lighting model contains the proposed unit cost inputs for labour and material categories used to calculate the proposed charges for public lighting services in the 2016-2020 regulatory control period. We have applied input price escalators for public lighting consistent with standard control services, refer to chapter 7.

16.4 Negotiated distribution services

16.4.1 Nature of the service

Services classed as negotiated distribution services have prices which are negotiated directly between the distributor and customers. The requirements for the negotiation are determined by the negotiated distribution service criteria and the negotiating framework. The AER has classified the following services as negotiated for the 2016–2020 regulatory control period:

- operation, maintenance and repair of dedicated public lighting assets;

- replacement of dedicated public lighting assets;
- alteration and relocation of Network Service Provider (**NSP**) public lighting assets; and
- new public lights (including greenfield sites).

16.4.2 Negotiated distribution service criteria

Clause 6.7.4 of the rules sets out the negotiated distribution service criteria (**criteria**) such as the terms and conditions of access for the negotiated distribution services and dispute resolution.

16.4.3 New negotiated service for OM&R for dedicated public lighting assets.

The AER's F&A Paper retains the classification of alternate control service for shared public lighting assets while determining to classify dedicated public lighting assets as a negotiated service.

We have understood from the F&A Paper that dedicated public lighting assets are those which are attributed to a single customer (not shared assets) and which are specialised public lighting columns and the associated lighting equipment on those columns.

The classification of dedicated public lighting as a negotiated service means that the replacement costs for dedicated public lighting columns has to be recovered through the negotiated service charge and as such the OMR for dedicated assets will be higher than the OMR charges for public lighting under the alternative control services.

While this regulatory proposal deals only with the specific prices for public lighting services classified as alternative control services, we strongly encourage the AER to take a detailed approach in setting out the criteria that will be applied by the AER in resolving any dispute about the terms and conditions of access including the price that is to be charged for the provision of a negotiated distribution service by the provider as required under clause 6.7.4 of the rules.

The following are some of the key assumptions or understandings that will inform our criteria for neogtiating terms and conditions for access including prices for the public lighting assets now classified as negotiated:

- we propose using the AER's 2011–2015 price reset public lighting model updated for the next regulatory control period and a number of inputs including updating the light types for new and eliminated light types, traffic management costs, updates to the expected fault rates and removing operation, maintenance, repair and replacement of shared public lighting assets;
- the prices determined through the above model will be the default price applied to dedicated public lights until and unless an alternate price is negotiated;
- replacement costs will be allocated across the pool of dedicated assets as they were when these assets were classified as alternate control;
- consistent with commentary in the AER's F&A Paper;
- public lighting assets which are built to the VESI standards (rather than general wiring standard) will remained owned by us; and
- access to public lighting assets owned by and directly connected to our distribution network must be in line with our processes as covered in our approved Energy Safety Management Scheme.

16.4.4 Negotiating framework

The negotiating framework sets out the procedure to follow during negotiations with any person who wishes to receive a negotiated distribution service, as to the terms and conditions for the provision of the service. The negotiating framework has been prepared to comply with the requirements of part D of chapter 6 of the Rules.

We have retained the negotiating framework approved for the 2011–2015 regulatory control period but have amended it to include additional classifications as per the F&A Paper. We will apply our negotiating framework where it is required to provide a negotiated service.

Refer to the attached, *Negotiating framework*.

Table 16.3 Description of fee based services

Fee based service	Description
Routine connections – customers below 100 amps	This charge applies when a customer with a supply point with fuses less than 100 amps moves into a new premises and requests supply. Different charges apply depending on whether we are responsible for the meter or not, whether the meter is single or multi-phase and whether the service is provided during or after business hours.
Temporary disconnect/reconnect services	This charge applies when a request is received to temporarily either disconnect or reconnect a supply point.
De-energisation of existing connections	This charge applies when a request is received to disconnect at a supply point for fuses less than 100 amps by a field visit. This charge includes Disconnection for non-payment. This service is only provided during business hours.
Re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. Three options for re-energisation are available: • reconnections (same day) business hours only; • reconnections (incl. Customer Transfer) business hours; and • reconnections (incl. Customer Transfer) after hours.
PV & small generator installation pre-approval (up to 5kW)	The PV Installation charge applies prior to connection of small scale embedded generation up to 5kW to the network. This charge specifically covers the inspection of the customer’s site to ensure safe connection to the network and includes anti-islanding testing.
PV & small generator installation pre-approval (>5 kW)	The PV Installation charge applies prior to connection of small scale embedded generation greater than 5kW to the network. This charge specifically covers the inspection of the customer’s site to ensure safe connection to the network and includes anti-islanding testing.
Meter investigation	This charge applies when a request is received to investigate the metering at a given supply point. This request may be initiated by either the retailer or a customer. Different charges apply depending on whether the service is provided during or after business hours.
Meter testing	This charge applies when a request is made to test the accuracy of a meter at a given supply point. Different charges apply depending on the type of meter being tested, if it is the first or subsequent meter and whether the meter is single or multi-phase and whether the service is provided during or after business hours.
Special meter reading	This charge applies when a request for a Special Meter Read is to be performed by a field visit outside the scheduled meter reading cycle. Where customers have multiple metering installations, such as farms and units, a separate charge applies to each meter on the property. This service is only available during business hours.
Re-test of types 5 and 6 metering	This charge applies to customers with an annual consumption greater than 160MWh who

Fee based service	Description
installations for first tier customers with annual consumption greater than 160 MWh	do not have a metering installation that has the capability of a type 1, 2, 3 or 4 installations which requires re-testing.
Fault response – not DNSP fault	This charge applies when we make a service truck visit at the request of a customer or contractor where the fault is found to be caused by the customer, rather than us. For example, the customer would be at fault: • where they are not receiving supply and they have not checked that the cause is that the main switch or safety switch is not in the 'on' position; and • where there are quality of supply issues that have been caused downstream of our distribution system. Different charges apply depending on whether the service is provided during or after business hours.
Wasted attendance – not DNSP fault	This charge applies to service truck visits requested where: • the crew arrives to find the site is not ready for the scheduled work within 15 minutes of arriving; • the truck attendance is no longer required once on site; • 24 hours notice is not provided for a cancellation; • the site is locked with a non industry lock; • asbestos removal or warning on site; • scaffolding obstructing meter position; • non adherence to VESI SIR's; or • other issues associated with safety assessment of the site. Once the site is ready for the service truck visit another appointment needs to be booked and the normal service truck visit charge applies. Business hours and after hours charges apply where appropriate.
Service truck visits	This charge applies when a service crew is requested for up to an hour in a number of circumstances including: • disconnection of complex site; • reconnection of complex site; • metering additions or alternations; and • shutdowns. While larger scale works will be charged through a Quoted Service 'After hours truck by appointment' charge, where the job unexpectedly goes above the hourly mark, additional half hourly intervals will be charged up to two hours. Different charges apply depending on whether the service is provided during or after business hours.
Temporary supply services	This charge applies when a customer requests a temporary supply. This also applies where a builder wishes to provide a temporary supply to new properties under construction.
Remote de-energisation	This charge applies when a request is received to de-energise a customer that has smart metering and related infrastructure in place which is then used to disconnect the customer from our network.
Remote re-energisation	This charge applies when a request is received to re-energise a customer that has smart

Fee based service	Description
	metering and related infrastructure in place which is then used to connect the customer to our network.
Manual meter reading	This charge applies to customers who have elected not to have their manually read meter replaced with a remotely read smart meter.
Customer access to meter data	This charge applies when a request is received from a customer more than four times in any given 12 month period; or in a different manner or form than specified in the Australian Energy Market Operator metering data provision procedures; or by a customer authorised representative as part of a request for information about more than one customer.

Table 16.4 Description of quoted services

Quoted service	Description
Routine connections - customers above 100 amps	This charge applies when customers above 100 amps request a routine connection.
Supply abolishment (>100 amps)	This charge applies when customers above 100 amps request a permanent removal of our supply assets. A separate charge applies per site.
Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 is applied. Examples include: • Vic Roads and Council requested asset relocations to allow for new road works; and • customer removal or relocation of service wire to allow work on private installation.
Auditing design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party. Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets; • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation; • any electrical distribution work completed by our approved contractor that has been engaged by a customer under Option 2 provisions; • provision of system plans and system planning scopes, for Option 2 designers; and • reviewing and/or approving plans submitted by Option 2 designers.
Specification and design enquiry fees	This charge applies when an element of detailed design is required to fairly assess the costs so that an Offer for Connection Services can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property; • the location of other utility assets;

Quoted service	Description
	• environmental considerations including tree clearing; and • obtaining necessary permits from State and Local Government bodies.
Elective undergrounding where above ground service currently exists	This charge applies when a customer with an existing overhead service requests an underground service, other than where Guideline 14 is applied.
Damage to overhead service cables caused by high load vehicles	This charge applies to an identifiable third party when overhead service cables require repairing because they have been damaged by high load vehicles pulling down cables.
High load escorts —lifting overhead lines	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads.
Covering of low voltage mains for safety reasons	This charge applies when customers request coverage of powerlines for safety reasons. The charge applied will depend on the time taken to perform the service. Differing charges can arise as a result of the type of line being covered; street mains (two wires or all wire) or service cables.
After hours truck by appointment	This charge applies when a request is received to undertake larger scale works by a Service Truck. Examples of types of works include: • disconnection of complex site; • reconnection of complex site; • metering additions or alternations; and • shutdowns (includes preparation works).
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is covered in the connection agreement. This service is not available to new customers.

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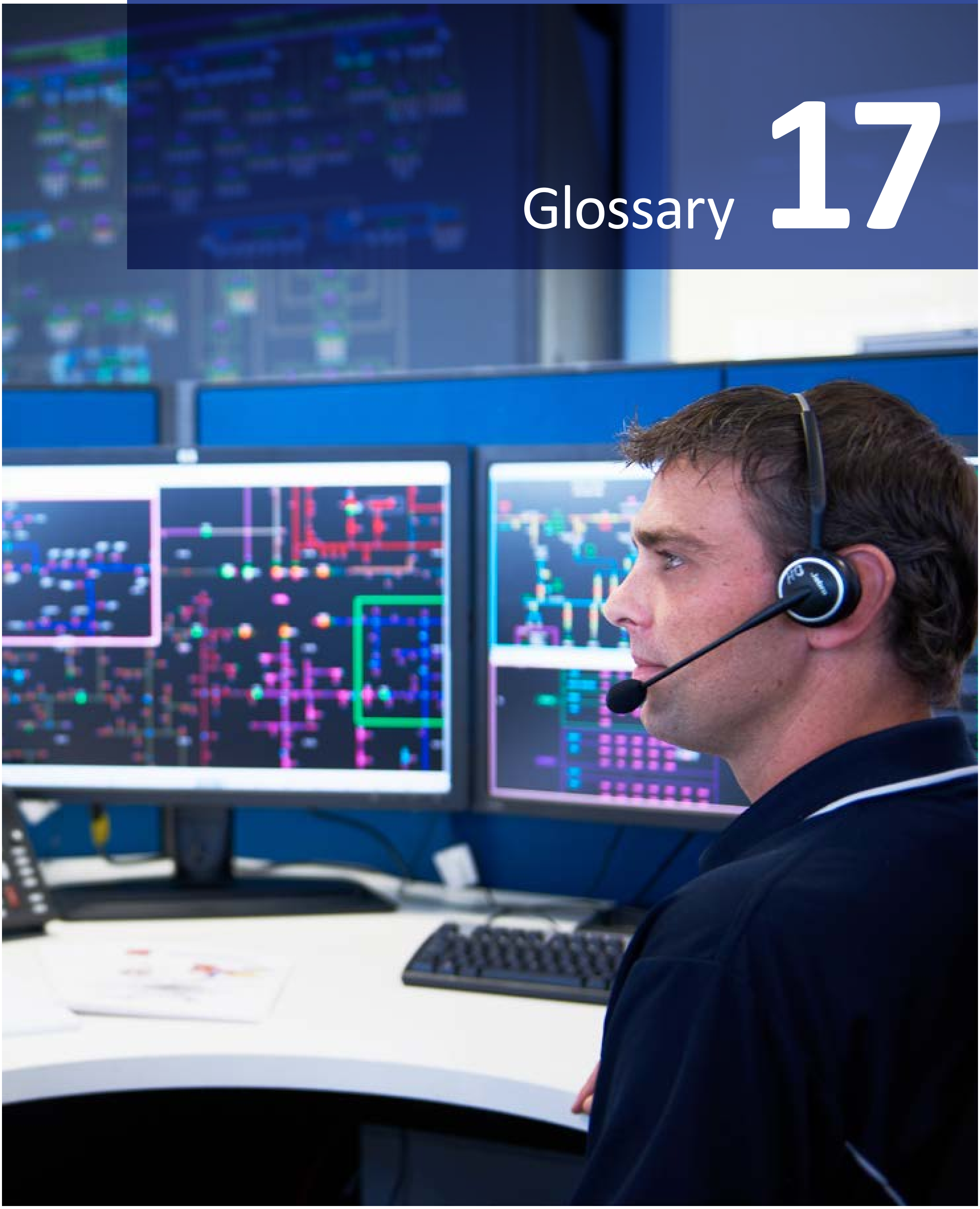
Glossary 17



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17. Glossary

Term	Definition
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
APESMA	Association of Professional Engineers, Scientists and Managers Australia
AMI OIC	Advanced Metering Infrastructure Order in Council
ASU	Australian Services Union
Augex	Augmentation expenditure model
BAU	Business-as-usual
BMP	Bushfire Mitigation Plan
BTS	Brunswick Terminal Station
CAM	Cost allocation methodology
Capex	Capital Expenditure
CatA RIN	Category Analysis Regulatory Information Notice
CBD	Central Business District
CBRM	Condition Based Risk Management
CEPU	Communications Electrical Plumbing Union
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Bond Securities
CHED Services	CHED Services Pty Ltd (ACN 112 304 622)
CIC	Capital Investment Committee
CIE	Centre for International Economics
CIS	Customer Information System
CIS OV	Customer Information System – Open Vision
CitiPower	CitiPower Pty (ACN 064 651 056)
CoAG	Council of Australian Government
Code	Victorian Electricity Distribution Code
CoF	Consequence of Failure

Term	Definition
CPI	Consumer Price Index
CRM	Customer Relationship Management
CT meters	meters with current transformers
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
Deloitte	Deloitte Touche Tohmatsu
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
DUoS	Distribution Use of System
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Reset
EGWW	Electricity Gas Water and Waste
ELCMPs	Electric Line Clearance Management Plans
EPA	Environmental Protection Authority
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EUDs	End User Devices
EWOV	Energy and Water Ombudsman (Victoria)
EWP	Elevated Work Platform
F&A	Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016
Final Determination	AER’s 2011-15 Final Determination
FRMPS	Financially Responsible Market Participants
FW Act	Fair Work Act 2009
GFC	Global Financial Crisis

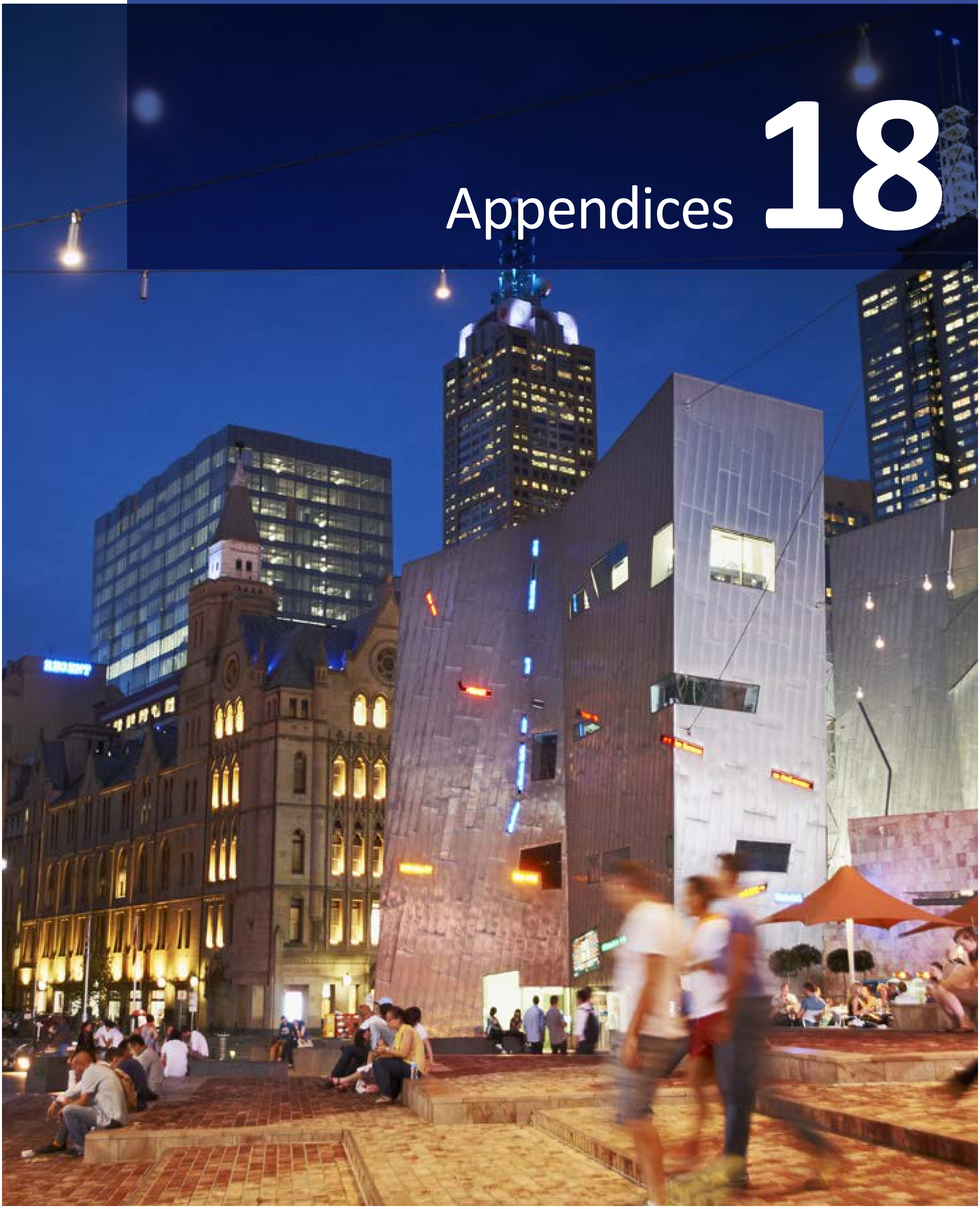
Term	Definition
GSL	Guaranteed Service Level
GSP	Gross State Product
Guideline 14	Electricity Industry Guideline No. 14 – Provision of Services by Electricity Distributors
Guideline 15	Electricity Industry Guideline No. 15- Connection of Embedded Generation
GWh	Gigawatt Hour
HAN	Home Area Network
HBRA	Hazardous Bushfire Risk Areas
HI	Health index
HMIs	Human machine interfaces
HV	High voltage
IAP2	International Association of Public Participation
IC	Incremental cost
IR	Incremental revenue
IT	Information technology
kV	Kilovolt
kVA	Kilovolt amperes
kW	kilowatt
kWh	Kilowatt hour
LAN	Local area network
LBRA	Low bushfire risk areas
LGA	Local government area
LI	Load index
LPI	Labour price index
LSA	Local service agents
LTIFR	Lost time injury frequency rate
LV	Low voltage
MAIFI	Momentary average interruption frequency index
MDC	Mildura Development Corporation
MED	Major event days

Term	Definition
MON	Meter outage notification
MRP	Market risk premium
MTIFR	Medical treatment injuries frequency rate
MVA	Megavolt ampere
MW	Megawatts
MWh	Megawatt hour
NBN	National Broadband Network
NECF	National Energy Customer Framework
NEFR	National Electricity Forecast Report
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NEVA	National Electricity (Victoria) Act 2005
NMI	National meter identifier
NPC	Network Planning Committee
NPV	Net present value
NSW	New South Wales
NUOS	Network use of system
NUW	National Union of Workers
OLS	Ordinary least squares
OMR	Operation, maintenance, repair or replacement
OMS	Outage management systems
Opex	Operating expenditure
Order	F-Factor Scheme Order 2011
PB	Parsons Brinckerhoff
PBST	Powerline Bushfire Safety Taskforce
PNS	Powercor Network Services
PoE	Probability of exceedance
POEL	Private overhead electric line

Term	Definition
PoF	Probability of failure
Powercor	Powercor Australia Ltd (ACN 064 651 109)
PTRM	Post tax revenue model
Public Lighting Code	Victorian Public Lighting Code
PV	Photovoltaic
QoS	Quality of supply
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RCM	Reliability centred maintenance
RECs	Registered electrical contractors
RECs	Renewable energy certificates
Repex	Replacement expenditure model
Reset RIN	Price Reset Regulatory Information Notice
RET	Renewable energy target
RIN	Regulatory information notice
RIT-D	Regulatory investment test – distribution
RoR	Rate of return
Rules	National Electricity Rules
SA	South Australia
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCS	Standard control services
SCER	Standing Council for Energy and Resources
SIR	Service and Installation Rules
SF	Security fee
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
STPIS	Service Target Performance Incentive Scheme
STPIS Guideline	Electricity distribution network service providers, Service target performance incentive scheme

Term	Definition
UK	United Kingdom of Great Britain
US	United States of America
VBRC	Victorian Bushfire Royal Commission
VCAT	Victorian Civil and Administrative Tribunal
VCR	Value of customer reliability
VESI	Victorian Electricity Supply Industry
VPN	Victoria Power Networks
WACC	Weighted average cost of capital
WMTS	West Melbourne terminal station

Appendices 18



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19. Attachments

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CP PUBLIC ATT 12.62	SFG Consulting, The required return on equity for regulated gas and electricity network business, June 2014	12	No
CP PUBLIC ATT 12.63	SFG Consulting, The required return on equity for the benchmark efficient equity, February 2015	12	No
CP PUBLIC ATT 12.64	SFG Consulting, The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model, June 2013	12	No
CP PUBLIC ATT 12.65	SFG Consulting, Using the Fama-French model to estimate the required return on equity, February 2015	12	No
CP PUBLIC ATT 12.66	SFG, Estimating gamma for regulatory purposes, February 2015	12	No
CP PUBLIC ATT 12.67	SFG, The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, March 2015	12	No
CP PUBLIC ATT 12.68	Smart Grid, About Smart Grid, Smart City (website)	12	No
CP PUBLIC ATT 12.69	Statement of Alastair Watson, Treasurer for SP AusNet, January 2009	12	No
CP PUBLIC ATT 12.70	Statement of Andrew Noble, Senior Treasury Analyst - CitiPower and Powercor (undated)	12	No
CP PUBLIC ATT 12.71	Statement of Gregory Damien Meredith, Treasurer for Envestra, January 2009	12	No
CP PUBLIC ATT 12.72	Statement of Sim Buck Khim, Head of Treasury - Jemena (undated)	12	No
CP PUBLIC ATT 12.73	Victorian Government, Flexible Pricing, July 2013	12	No
CP PUBLIC ATT 12.74	Werner T, SunPower says Australia could be global leader in local generation, REneweconomy, April 2014	12	No
CP PUBLIC ATT 13.1	Australian Taxation Office, Taxation Ruling, TR 2014 4, Income tax, effective life of depreciating assets (applicable from 1 July 2014)	13	No
CP PUBLIC ATT 13.2	CitiPower, Six month inflation correction, April 2015	13	No
CP PUBLIC ATT 13.3	CitiPower and Powercor, Capitalisation of Fixed Assets policy, 30 April 2015	13	No

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CP PUBLIC ATT 13.4	CitiPower, 2016-2020 Price Reset Price Control, April 2015	13	No
CP PUBLIC ATT 14.1	AEMC, Rule Change, Consultation Paper, National Electricity Amendment (Retailer insolvency events – costs pass through provisions) Rule 2015, 30 October 2014	14	No
CP PUBLIC ATT 15.1	Electricity Industry Act 2000, Order under section 15A and section 46D, Order in Council (Gazetted S200), August 2007	15	No
CP PUBLIC ATT 15.2	CitiPower, AMI revised charges application 2015, August 2014	15	No
CP PUBLIC ATT 15.3	AEMC, Draft Rule Determination**,** National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015, March 2015	15	No
CP PUBLIC ATT 15.4	AER, Draft Decision, Ausgrid distribution determination 2015-16 to 2018-19, Attachment 16 Alternative control services, November 2014	15	No
CP PUBLIC ATT 16.1	Victorian Government Gazette, No. S 263, Electricity Industry Act 2000, AMI Order in Council 2014, August 2014	16	No
CP PUBLIC ATT 16.2	Essential Services Commission, Public Lighting Code, April 2005	16	No
CP PUBLIC ATT 16.3	Essential Services Commission, Electricity Distribution Licence, CitiPower, as varied on August 2005	16	No
CP PUBLIC ATT 16.4	Legislation Victoria, Roads Management Act 2004,Version No. 029C, No. 12 of 2004	16	No
CP PUBLIC ATT 16.5	Legislation Victoria, Occupational Health and Safety Act 2004, Act No. 1072004	16	No
CP PUBLIC ATT 16.6	AER, Energy Efficient Public Lighting Charges – Victoria, Final Decision, February 2009	16	No
CP PUBLIC ATT 16.7	CitiPower, Proposed Negotiating Framework, Regulatory control period commencing 1 January 2016	16	No
CP PUBLIC ATT 16.8	KPMG, Benchmarking of Contractor Margins, April 2014	16	No
CP PUBLIC ATT 16.9	Essential Services Commission, Review Of Public Lighting Excluded Service Charges, August 2004	16	No
CP PUBLIC APP A.1	CitiPower and Powercor, Directions and Priorities Consultation Paper, September 2014	Appendix A	No
CP PUBLIC APP A.2	Colmar Brunton, Residential Customer Homework Activity Snapshot, CitiPower, 24 July 2014	Appendix A	No
CP PUBLIC APP A.3	Colmar Brunton, Top 200 Customers In-depth Interviews, CitiPower, 22 July 2014	Appendix A	No
CP PUBLIC APP A.4	Nature, CitiPower Powercor Tariff Research, 17 September 2014	Appendix A	No

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CP PUBLIC APP B.1	CitiPower, Final Distribution Category Analysis RIN, 7 March 2014	Appendix B	No
CP PUBLIC APP B.2	United Energy 2008-13, Category Analysis RIN, Basis of Preparation, 2 June 2014	Appendix B	No
CP PUBLIC APP B.3	Endeavour Energy, Basis of Preparation, Response to AER Category Analysis RIN, Submission date 31 October 2014	Appendix B	No
CP PUBLIC APP B.4	Essential Energy, Response to Category Analysis RIN, Basis of preparation, 31 October 2014	Appendix B	No
CP PUBLIC APP C.1	Department of Transport, Planning and Local Infrastructure, Victoria In Future 2014 – population and household projections to 2051, May 2014	Appendix C	No
CP PUBLIC APP C.2	AEMO, AEMO Transmission Connection Point Forecasting Report for Victoria, September 2014	Appendix C	No
CP PUBLIC APP D.1	AEMC, Rule determination: National Electricity Amendment (Economic regulation of transmission services) Rule 2006, number 18, 16 November 2006	Appendix D, Appendix K	No
CP PUBLIC APP D.2	Australian Competition Tribunal, Application by Energy Australia and others [2009] ACompT8, 12 November 2009	Appendix D	No
CP PUBLIC APP D.3	AEMC, Network Service Provider Expenditure Objectives, Rule Determination, 19 September 2013	Appendix D	No
CP PUBLIC APP D.4	AER, Final Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17, April 2012	Appendix D	No
CP PUBLIC APP E.1	ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014	Appendix E	No
CP PUBLIC APP E.2	CitiPower, Asset Management Framework 2015, 27 February 2015	Appendix E	No
CP PUBLIC APP E.3	Jacobs, CitiPower repex modelling review, 17 April 2015	Appendix E	No
CP PUBLIC APP E.4	CitiPower and Powercor, Electricity Networks, Network Augmentation Planning Policy & Guidelines, 9 December 2013	Appendix E	No
CP PUBLIC APP E.5	AEMO, Value of Customer Reliability Review – Application Guideline, Final Report, December 2014	Appendix E	No
CP PUBLIC APP E.6	CitiPower and Powercor, Demand Side Engagement Strategy, 31 August 2013	Appendix E	No
CP PUBLIC APP E.7	Ofgem, Strategy consultation for the RIIO-ED1 electricity distribution price control – reliability and safety, Supplementary annex to RIIO ED1 overview paper, 28 September 2012	Appendix E	No
CP PUBLIC APP E.8	Sinclair Knight Merz, CitiPower review of CBD security of supply and planning standards, updated final report, 22 August 2006	Appendix E	No

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CP PUBLIC APP E.9	CitiPower, Consultation Paper, Brunswick Terminal Station, Final report, May 2008	Appendix E	No
CP PUBLIC APP E.10	NERA Economic Consulting, Proposed augmentation for Melbourne inner suburbs and CBD supply – a final report prepared for CitiPower and AEMO, 31 May 2011	Appendix E	No
CP PUBLIC APP E.11	AER, AER augmentation model handbook, guidance document, November 2013	Appendix E	No
CP PUBLIC APP E.12	AER, Connection charge guidelines for electricity retail customers – under chapter 5A of the National Electricity Rules, June 2012	Appendix E	No
CP PUBLIC APP E.13	CitiPower and Powercor Australia, 2016-2020 Price Reset, Expenditure Forecasting Methodology, 30 May 2014	Appendix E	No
CP PUBLIC APP E.14	Major Projects Victoria, New suburb on doorstep of Melbourne's CBD to become a reality, news release, 27 October 2014	Appendix E	No
CP PUBLIC APP E.15	The Age, Melbourne Metrorail tunnel project revived by Daniel Andrews, 16 February 2015	Appendix E	No
CP PUBLIC APP E.16	The Age, Site of former Age building to house Melbourne's tallest skyscraper, 23 November 2013	Appendix E	No
CP PUBLIC APP E.17	CitiPower, CitiPower Customer Guideline for Making an Electricity Supply Available and Undergrounding of Existing Assets, 4 March 2010.	Appendix E	No
CP PUBLIC APP E.18	2009 Victorian Bushfires Royal Commission, Final Report, Volume 2, Electricity-Caused Fires, 31 July 2010	Appendix E	No
CP PUBLIC APP E.19	Yarra Trams, Substation to substation – Melbourne's tram power infrastructure, 27 August 2013 (website)	Appendix E	No
CP PUBLIC APP E.20	CitiPower and Powercor, Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers, 1 February 2011	Appendix E	No
CP PUBLIC APP E.21	CitiPower and Powercor, Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines, 1 February 2011.	Appendix E	No
CP PUBLIC APP E.22	ESV, Direction under Section 141(2)(d) of the Electricity Safety Act 1998, Fitting of spacers in aerial lines, 4 January 2011	Appendix E	No
CP PUBLIC APP E.23	Bill Pitt, Email submission to Directions and Priorities, 29 October 2014	Appendix E	No
CP PUBLIC APP E.24	Essential Services Commission, Compliance with AMI Regulatory Obligations as at 31 December 2013, October 2014	Appendix E	No
CP PUBLIC APP E.25	CitiPower and Powercor, Transport Policy and Procedure Manual, 14 September 2009	Appendix E	No

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CP PUBLIC APP E.26	Electricity Safety Management Scheme - CitiPower/Powercor Safety Management System Detail - Part 3, 28 October 2013	Appendix E	No
CP PUBLIC APP E.27	CitiPower, 2014 Distribution Annual Planning Report, December2014	Appendix E	No
CP PUBLIC APP E.28	Victorian Electricity Distribution Businesses, Transmission Connection Planning Report, December 2014	Appendix E	No
CP PUBLIC APP E.29	CitiPower and Powercor, Environment Manual, 1 October 2014	Appendix E	No
CP PUBLIC APP E.30	CitiPower, Asset Management Plan, Underground Cables, February 2015	Appendix E	No
CP PUBLIC APP E.31	CitiPower, Asset Management Plan for Poles, February 2015	Appendix E	No
CP PUBLIC APP E.32	CitiPower, Asset Management Plan for Pole top Structures, February 2015	Appendix E	No
CP PUBLIC APP E.33	CitiPower, Zone Substation Transformers, Asset Management Plan, February 2015	Appendix E	No
CP PUBLIC APP E.34	CitiPower, Asset Management Plan for Overhead conductors, February 2015	Appendix E	No
CP PUBLIC APP E.35	CitiPower, Distribution Substations, Asset Management Plan, February 2015	Appendix E	No
CP PUBLIC APP E.36	CitiPower, HV Circuit Breakers, Asset Management Plan, February 2015	Appendix E	No
CP PUBLIC APP E.37	CitiPower, Pits and Pillars, Asset Management Plan, February 2015	Appendix E	No
CP PUBLIC APP E.38	CitiPower, Zone Substation Major Building Property Facilities, Asset Management Plan, February 2015	Appendix E	No
CP PUBLIC APP E.39	CitiPower, Asset Management Plan for High Voltage Fuses, February 2015	Appendix E	No
CP PUBLIC APP E.40	CitiPower and Powercor, Asbestos Management Manual, 5 February 2015	Appendix E	No
CP CONFIDENTIAL APP E.41	CitiPower and Powercor, IT Security - Network Security Internal Audit Report, July 2013	Appendix E	Yes
CP PUBLIC APP E.42	CitiPower and Powercor Australia, Business Case, CRM and Billing System Replacement, February 2015	Appendix E	No
CP PUBLIC APP E.43	KPMG, Business Case for expenditure to meet RIN requirements, April 2015	Appendix E	No
CP PUBLIC APP E.44	CSC, Infrastructure requirements, October 2014	Appendix E	No
CP CONFIDENTIAL APP E.45	CitiPower and Powercor, SCADA IT Operations Internal Audit report, September 2012	Appendix E	Yes

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CP PUBLIC APP E.46	CitiPower, Material Project, AUG 11 CBD Security and Capacity Program	Appendix E	No
CP PUBLIC APP E.47	CitiPower, Material Project, AUG 10 WMTS 22kV decommissioning	Appendix E	No
CP PUBLIC APP E.48	CitiPower, Material Project, AUG 12 NR Reactors	Appendix E	No
CP PUBLIC APP E.49	CitiPower, Material Project, REPL 01 W Building replacement	Appendix E	No
CP PUBLIC APP E.50	CitiPower, Material Project, REPL 02 Replace Melbourne LV paper based lead sheath cable	Appendix E	No
CP PUBLIC APP E.51	CitiPower, Material Project, REPL 03 C Upgrade zone substation	Appendix E	No
CP PUBLIC APP E.52	CitiPower, Material Project, REPL 04 Replacement of indoor combo switches	Appendix E	No
CP PUBLIC APP E.53	CitiPower, Material Project, REPL 05 Protection relay replacement	Appendix E	No
CP PUBLIC APP E.54	CitiPower, Material Project, REPL 06 Environmental noise program - AR	Appendix E	No
CP PUBLIC APP E.55	CitiPower, Material Project, REPL 08 Replacement of underground cable pits	Appendix E	No
CP PUBLIC APP E.56	CitiPower, Material Project, REPL 09 Environmental bunding program	Appendix E	No
CP PUBLIC APP E.57	CitiPower, Material Project, REPL 07 Environmental noise program - MG	Appendix E	No
CP PUBLIC APP E.58	CitiPower, Material Project, CUST 13 E Gate development	Appendix E	No
CP CONFIDENTIAL APP E.58	CitiPower, Material Project, CUST 13 E Gate development	Appendix E	Yes
CP PUBLIC APP E.59	CitiPower, Material Project, CUST 14 Metro Rail temp construction supply	Appendix E	No
CP CONFIDENTIAL APP E.59	CitiPower, Material Project, CUST 14 Metro Rail temp construction supply	Appendix E	Yes
CP PUBLIC APP E.60	CitiPower, Material Project, CUST 15 Spencer St development (Old Age site)	Appendix E	No
CP CONFIDENTIAL APP E.60	CitiPower, Material Project, CUST 15 Spencer St development (Old Age site)	Appendix E	Yes
CP PUBLIC APP E.61	CitiPower, Material Project, CUST 16 RTS AusNet Services relocations	Appendix E	No
CP PUBLIC APP E.62	CitiPower, Material Project, CUST 17 WMTS AusNet Services relocations	Appendix E	No
CP PUBLIC APP E.63	CitiPower, Material Project, CUST 18 Yarra Trams (Dept of Transport)	Appendix E	No

Reference	Attachment	Chapter reference	Confidential
CP CONFIDENTIAL APP E.63	CitiPower, Material Project, CUST 18 Yarra Trams (Dept of Transport)	Appendix E	Yes
CP PUBLIC APP E.64	CitiPower, Material Project, PROP 19 Rooney Street remediation	Appendix E	No
CP PUBLIC APP E.65	CitiPower and Powercor Australia, IT Service Delivery, Investment Stream Strategies 2016-2020, April 2015	Appendix E	No
CP PUBLIC APP E.66	CitiPower and Powercor, Notice of Determination under clause 5.17.4(c) of the National Electricity Rules, NR zone substation 2015-2017, Dec 2014	Appendix E	No
CP PUBLIC APP E.67	CitiPower, CBD Security of Supply Upgrade Plan MP to BQ & WP 11kV Feeders, Regulatory Test Report, July 2014	Appendix E	No
CP PUBLIC APP E.68	CitiPower, Non-Network Alternatives, April 2015	Appendix E	No
CP PUBLIC APP F.1	AER, Electricity distribution network service providers, Cost allocation guidelines, June 2008	Appendix F	No
CP PUBLIC APP F.2	Incenta, Debt raising transaction costs, CitiPower, April 2015	Appendix F	No
CP PUBLIC APP F.3	Ernst and Young, CitiPower and Powercor Australia, Allocation of IT System Operating Expenditure, April 2015	Appendix F	No
CP PUBLIC APP G.1	Industrial Control Systems Cyber Emergency Response Team, ICS-CERT Monitor (Oct-Dec 2012), 2012	Appendix G	No
CP PUBLIC APP G.2	Industrial Control Systems Cyber Emergency Response Team, ICS-CERT Monitor (Jan-Apr 2014), 2014	Appendix G	No
CP PUBLIC APP G.3	Lease Renewals, April 2015	Appendix G	No
CP CONFIDENTIAL APP G.3	Lease Renewals, April 2015	Appendix G	Yes
CP PUBLIC APP G.4	Lease renewal valuations	Appendix G	No
CP CONFIDENTIAL APP G.4	Lease renewal valuations	Appendix G	Yes
CP PUBLIC APP H.1	AER, Electricity distribution network service providers, Service target performance incentive scheme, Final decision, November 2009	Appendix H	No
CP PUBLIC APP H.2	AEMC, Final Report, Review of Distribution Reliability Measures, September 2014	Appendix H	No
CP PUBLIC APP I.1	AER, Final decision, Amendment Electricity Distribution Network Service Providers Post-tax Revenue Model Handbook, January 2015	Appendix I	No
CP PUBLIC APP J.1	NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, March 2015	Appendix J	No
CP PUBLIC APP J.2	NERA, The payout ratio, June 2013	Appendix J	No

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CP PUBLIC APP J.3	AER, Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameter, May 2009	Appendix J	No
CP PUBLIC APP J.4	Lally M, Review of submissions to the QCA on the MRP, risk-free rate and gamma, March 2014	Appendix J	No
CP PUBLIC APP J.5	Handley John C, Advice on the Value of Imputation Credits, September 2014	Appendix J	No
CP PUBLIC APP J.6	Australian Trade Practices Reports, Application by Energex Limited (Gamma) (No 5) 43,857 (2011) ATPR 42-356, May 2011	Appendix J	No
CP PUBLIC APP J.7	SFG, An appropriate regulatory estimate of gamma, May 2014	Appendix J	No
CP PUBLIC APP K.1	AER, Draft decision Ausgrid distribution determination - Ausgrid 2014 - Roll forward model (distribution), November 2014	Appendix K	No
CP PUBLIC APP L.1	AEMC, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012	Appendix L	No
CP PUBLIC APP L.2	Victoria Power Networks, Insurance Management Policy Appendix C: Insurance Credit Management Policy	Appendix L	No
CP PUBLIC APP L.3	AER, Draft decision Victorian electricity distribution network service providers Distribution determination 2011-2015, June 2010	Appendix L	No
CP PUBLIC APP L.4	AER, Draft Distribution Determination – Aurora Energy Pty Ltd 2012-13 to 2016-17, November 2011	Appendix L	No
CP PUBLIC APP L.5	AER, Final Distribution Determination – Aurora Energy Pty Ltd 2012-13 to 2016-17, April 2012.	Appendix L	No
CP PUBLIC APP L.6	Cagle J. and Harrington S, Insurance supply with capacity constraints and endogenous insolvency risk, Journal of Risk and Uncertainty, Vol. 11 Issue 3, December 1995	Appendix L	No
CP PUBLIC APP L.7	AER, SPI Electricity Pty Ltd, Distribution Determination 2011-1, August 2013	Appendix L	No
CP PUBLIC APP L.8	SPI Electricity Pty Ltd, 2011–15 Distribution Determination, Insurance Pass Through Event Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited [2012] ACompT 8, April 2013	Appendix L	No
CP PUBLIC APP L.9	CitiPower, Bushfire Mitigation Strategy Plan 2014-2019, 2014	Appendix L	No
CP PUBLIC APP L.10	CitiPower and Powercor, Crisis and Emergency Management System Manual, 21 January 2014	Appendix L	No
CP PUBLIC APP L.11	Australian Government, Terrorism Insurance Act Review, 2012	Appendix L	No

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CP PUBLIC APP L.12	AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering Infrastructure) Rule 2009, 29 January 2009	Appendix L	No
CP PUBLIC APP L.13	AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering Infrastructure) Rule 2013, 28 November 2013	Appendix L	No
CP PUBLIC APP L.14	SCER, Rule Change Request, Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, October 2013	Appendix L	No
CP PUBLIC APP L.15	AEMC, Expanding competition in metering and related services in the National Electricity Market, Consultation Paper, 17 April 2014	Appendix L	No
CP PUBLIC APP L.16	AEMC, Final Report Power of choice review – giving consumers options in the way they use electricity, 30 November 2012	Appendix L	No
CP PUBLIC APP L.17	AEMC, Energy market arrangements for electric and natural gas vehicles, 11 December 2012	Appendix L	No
CP PUBLIC APP L.18	AEMO, National Electricity Rule Change Request – Embedded Networks, September 2014	Appendix L	No
CP PUBLIC APP L.19	Letter from SCER to AEMO dated 24 July 2013 regarding metering arrangements to provide for multiple trading relationships at a single site and attached terms of reference	Appendix L	No
CP PUBLIC APP L.20	AEMO, Rule Change Request – Multiple Trading Relationships, 17 December 2014	Appendix L	No
CP PUBLIC APP L.21	AEMO, Multiple Trading Relationships – Market Design for High Level Impact Assessment, 28 August 2014	Appendix L	No
CP PUBLIC APP L.22	CitiPower and Powercor Australia, Response to Consultation (template) on AEMO's Multiple Trading Relationships – Market Design for High Level Impact Assessment, 16 September 2014	Appendix L	No
CP PUBLIC APP L.23	SA Minister, Making of National Electricity (National Energy Retail Law) Amendment Rule 2012, 27 June 2012	Appendix L	No
CP PUBLIC APP L.24	SCER, Definition of Retailer Insolvency Costs Rule Change Request, March 2014	Appendix L	No
CP PUBLIC APP L.25	Joint Implementation Group (Retail Policy Working Group), National Energy Customer Framework Implementation issue No. 0001 Retailer insolvency event and pass through, 8 February 2012	Appendix L	No
CP PUBLIC APP L.26	ESCV, CitiPower distribution licence, varied 31 August 2005	Appendix L	No
CP PUBLIC APP L.27	CitiPower, Default Use of System Agreement Victorian Electricity Industry, June 2011	Appendix L	No

Reference	Attachment	Chapter reference	Confidential
CP PUBLIC APP L.28	ESCV, Credit Support Arrangements, Final Decision, October 2006	Appendix L	No
CP PUBLIC APP L.29	The Allen Consulting Group, Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006.	Appendix L	No
CP PUBLIC APP L.30	AER, Draft Decision South Australian distribution determination 2010-11 to 2014-15, 25 November 2009	Appendix L	No
CP PUBLIC APP L.31	AER, Draft Decision Queensland distribution determination 2010-11 to 2014-15, 25 November 2009	Appendix L	No
CP PUBLIC APP L.32	AER, Draft Decision New South Wales distribution determination 2009-10 to 2013-14, 21 November 2008	Appendix L	No
CP PUBLIC APP L.33	AER, Draft Decision Australian Capital Territory distribution determination 2009-10 to 2013-14, 21 November 2008	Appendix L	No
CP PUBLIC ATT 0.2	GHD, CitiPower Forecast Expenditure for Vegetation Management	VEG	No
CP PUBLIC ATT 0.3	CitiPower, Vegetation Management expenditure, April 2015	VEG	No
CP PUBLIC ATT 0.4	CitiPower, 2014-2015 Electric Line Clearance (Vegetation) Management Plan	VEG	No
CP PUBLIC ATT 0.5	Deed of Variation Supply of Vegetation Management Services, 16 December 2009	VEG	No
CP CONFIDENTIAL ATT 0.5	Deed of Variation Supply of Vegetation Management Services, 16 December 2009	VEG	Yes
CP PUBLIC ATT 0.6	Supply of Vegetation Management Services Modification No. 1	VEG	No
CP CONFIDENTIAL ATT 0.6	Supply of Vegetation Management Services Modification No. 1	VEG	Yes
CP PUBLIC ATT 0.7	Supply of Vegetation Management Services Modification No. 2	VEG	No
CP CONFIDENTIAL ATT 0.7	Supply of Vegetation Management Services Modification No. 2	VEG	Yes
CP PUBLIC ATT 0.8	Supply of Vegetation Management Services Modification No. 3	VEG	No
CP CONFIDENTIAL ATT 0.8	Supply of Vegetation Management Services Modification No. 3	VEG	Yes
CP PUBLIC ATT 0.9	Deed of Variation Supply of Vegetation Management Services, 1 March 2011	VEG	No
CP CONFIDENTIAL ATT 0.9	Deed of Variation Supply of Vegetation Management Services, 1 March 2011	VEG	Yes
CP PUBLIC ATT 0.10	Supply of Vegetation Management Services Modification No. 4	VEG	No

Reference	Attachment	Chapter reference	Confidential
CP CONFIDENTIAL ATT 0.10	Supply of Vegetation Management Services Modification No. 4	VEG	Yes
CP PUBLIC ATT 0.11	2012 Deed of Variation Supply of Vegetation Management Services, 1 January 2012	VEG	No
CP CONFIDENTIAL ATT 0.11	2012 Deed of Variation Supply of Vegetation Management Services, 1 January 2012	VEG	Yes
CP PUBLIC ATT 0.12	Supply of Vegetation Management Services Modification No. 5	VEG	No
CP CONFIDENTIAL ATT 0.12	Supply of Vegetation Management Services Modification No. 5	VEG	Yes
CP PUBLIC ATT 0.13	2013, 2014, 2015 Deed of Variation Supply of Vegetation Management Services	VEG	No
CP CONFIDENTIAL ATT 0.13	2013, 2014, 2015 Deed of Variation Supply of Vegetation Management Services	VEG	Yes
CP PUBLIC ATT 0.14	2014 and 2015 Deed of Variation, Supply of Vegetation Management Services between Powercor and Vemco	VEG	No
CP CONFIDENTIAL ATT 0.14	2014 and 2015 Deed of Variation, Supply of Vegetation Management Services between Powercor and Vemco	VEG	Yes
CP PUBLIC ATT 0.15	Letter from ESV to CitiPower regarding approval of Electric Line Clearance Management Plan 2014-15	VEG	No
CP PUBLIC ATT 0.16	Vemco supply of services - conditions of contract (2008)	VEG	No
CP CONFIDENTIAL ATT 0.16	Vemco supply of services - conditions of contract (2008)	VEG	Yes

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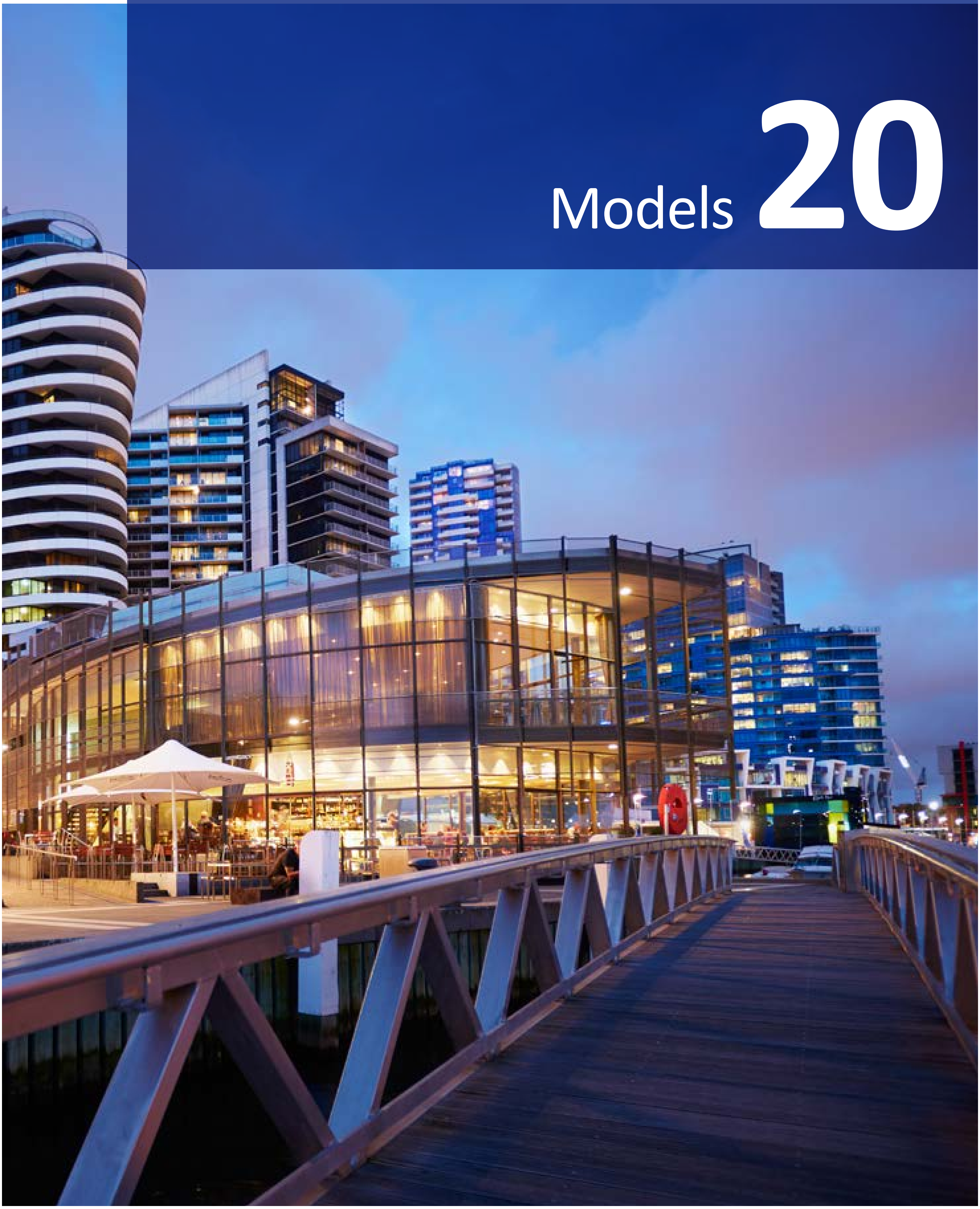

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20. Models

Reference	Topic	Model	Confidential
CP PUBLIC MOD 1.1	Other alternate control	CP ACS Model.xlsx	No
CP PUBLIC MOD 1.2	Metering	CP Metering Capex & Opex.xlsx	No
CP CONFIDENTIAL MOD 1.2	Metering	CP Metering Capex & Opex.xlsx	Yes
CP PUBLIC MOD 1.3	Metering	CP Metering Exit Fees.xlsx	No
CP PUBLIC MOD 1.4	Metering	CP Metering PTRM.xlsm	No
CP PUBLIC MOD 1.5	Metering	CP Metering Volumes.xlsx	No
CP PUBLIC MOD 1.6	Metering	CitiPower – AMI Charges Model (2015 Charges Application) FD 2014 act.xlsx	No
CP PUBLIC MOD 1.7	Public lighting	CP Public Lighting ACS Model.xlsx	No
CP PUBLIC MOD 1.8	Public lighting	CP Public Lighting Inputs.xlsx	No
CP PUBLIC MOD 1.9	Standard control	CP 2011-15 RFM.xlsx	No
CP PUBLIC MOD 1.10	Standard control	CP 2016-20 PTRM.xlsm	No
CP PUBLIC MOD 1.11	2011-2015 determination	CP 2006-10 RFM.xls	No
CP PUBLIC MOD 1.12	2011-2015 determination	CP 2011-15 PTRM.xlsm	No
CP PUBLIC MOD 1.13	Capital expenditure	CP AER augex model forecast.xlsx	No
CP PUBLIC MOD 1.14	Capital expenditure	CP AER calibrated repex model.xls	No
CP PUBLIC MOD 1.15	Capital expenditure	Contribution rates.xlsb	No
CP CONFIDENTIAL MOD 1.16	Capital expenditure	CP augmentation capex.xlsx	Yes
CP PUBLIC MOD 1.17	Capital expenditure	CP capex consolidation.xlsx	No
CP CONFIDENTIAL MOD 1.18	Capital expenditure	CP connections capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.19	Capital expenditure	CP environmental capex.xlsx	Yes
CP PUBLIC MOD 1.20	Capital expenditure	CP IT capex.xlsx	No
CP CONFIDENTIAL MOD 1.21	Capital expenditure	CP lines replacement capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.22	Capital expenditure	CP protection replacement capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.23	Capital expenditure	CP faults capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.24	Capital expenditure	CP network SCADA capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.25	Capital expenditure	CP plant & stations capex.xlsx	Yes
CP CONFIDENTIAL MOD 1.26	Capital expenditure	CP VBRC capex.xlsm	Yes
CP CONFIDENTIAL MOD 1.27	Capital expenditure	CP Yarra Valley Water replacement capex.xlsx	Yes
CP PUBLIC MOD 1.28	EBSS	Final Decision Opex.xlsx	No

Reference	Topic	Model	Confidential
CP PUBLIC MOD 1.29	EBSS	CP EBSS.XLSX	No
CP PUBLIC MOD 1.30	Operating expenditure	CP CRM Step Change.xlsx	No
CP PUBLIC MOD 1.31	Operating expenditure	CP Customer Charter Step Change.xlsx	No
CP PUBLIC MOD 1.32	Operating expenditure	CP GHD Vegetation Management 24032015.xlsx	No
CP CONFIDENTIAL MOD 1.32	Operating expenditure	CP GHD Vegetation Management 24032015.xlsx	Yes
CP PUBLIC MOD 1.33	Operating expenditure	CP Decommissioning step change.xlsx	No
CP PUBLIC MOD 1.34	Operating expenditure	CP GSL Step Change.xlsx	No
CP PUBLIC MOD 1.35	Operating expenditure	CP Mobile Replacement Step Change.xlsx	No
CP PUBLIC MOD 1.36	Operating expenditure	CP Opex Consolidation.xlsx	No
CP PUBLIC MOD 1.37	Operating expenditure	CP Superannuation Step Change.xlsx	No
CP PUBLIC MOD 1.38	Rate of change	CP Contract Escalation.xlsx	No
CP PUBLIC MOD 1.39	Rate of change	CP Labour Escalation.xlsx	No
CP PUBLIC MOD 1.40	Rate of change	CP Output Growth.xlsx	No
CP PUBLIC MOD 1.41	Redundant assets	Supervisory Cables opening asset value.xlsx	No
CP PUBLIC MOD 1.42	Rate of return	Rate of return.xlsx	No
CP PUBLIC MOD 1.43	S factor	2010 Annual CP.xlsx	No
CP PUBLIC MOD 1.44	S factor	CP PC – S factor history and 2010 estimate calculations.xlsx	No
CP PUBLIC MOD 1.45	S factor	CP – S-factor true up – final decision.xlsx	No
CP PUBLIC MOD 1.46	S factor	CitiPower S Factor.xlsx	No
CP PUBLIC MOD 1.47	STPIS	CP STPIS targets.xlsx	No
CP PUBLIC MOD 1.48	STPIS	CP STPIS incentive rates.xlsx	No
CP PUBLIC MOD 1.49	Volumes	CIE tariff volume forecasts February 2015.xlsm	No
CP PUBLIC MOD 1.50	Volumes	CIE customer number forecasts February 2015.xlsm	No
CP PUBLIC MOD 1.51	Demand Forecasts	CIE Forecast results FINAL -sent to AEMO.xlsm	No

21 Regulatory information notice

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21. Regulatory information notice

Reference	Document	Confidential
CP PUBLIC RIN 1.1	CitiPower, Vic Reset RIN 2016-20 - Consolidated Information	No
CP CONFIDENTIAL RIN 1.1	CitiPower, Vic Reset RIN 2016-20 - Consolidated Information (Confidential)	Yes
CP PUBLIC RIN 1.2	CitiPower, Vic Reset RIN 2016-20 - Back casting	No
CP CONFIDENTIAL RIN 1.2	CitiPower, Vic Reset RIN 2016-20 - Back casting	Yes
CP PUBLIC RIN 1.3	CitiPower, Reset RIN CEO Statutory Declaration	No
CP PUBLIC RIN 1.4	CitiPower, Reset RIN Directors resolution	No
CP PUBLIC RIN 1.5	CitiPower, Reset RIN Cross Reference Matrix	No
CP PUBLIC RIN 1.6	CitiPower, Reset RIN Basis of Preparation	No
CP PUBLIC RIN 1.7	Deloitte Audit Report	No
CP PUBLIC RIN 1.8	Deloitte Review Report	No
CP PUBLIC RIN 1.9	Deloitte Assurance Report	No
CP PUBLIC RIN 1.10	Deloitte Board Audit Committee Regulatory Audit Report for the year ending 31 December 2014	No
CP PUBLIC RIN 1.11	CitiPower, Confidentiality Claim	No
CP PUBLIC RIN 1.12	CitiPower, Risk management framework attachment, April 2015	No
CP PUBLIC RIN 1.13	CitiPower, Reset RIN schedule 1, Section 6 - Replacement capital expenditure modelling, clause 6.1a and 6.1b	No
CP PUBLIC RIN 1.14	CitiPower, Reset RIN schedule 1, Section 7 - Augmentation Modelling, Clause 7.2b response	No
CP PUBLIC RIN 1.15	CitiPower, Reset RIN schedule 1, Section 8 - Demand and Connections Forecasts, clause 8.3r	No
CP PUBLIC RIN 1.16	CitiPower, Reset RIN schedule 1, Section 8 - Demand and Connections Forecasts, clause 8.3s	No
CP PUBLIC RIN 1.17	ESV, 2011 Safety Performance Report on Victorian Electricity Distribution and Transmission Businesses, report released 31 August 2012	No
CP PUBLIC RIN 1.18	ESV, Safety Performance Report on Victorian Electricity Distribution and Transmission Businesses 2012, June 2013	No
CP PUBLIC RIN 1.19	CitiPower, 2009-2013 Category Analysis RIN	No
CP CONFIDENTIAL RIN 1.19	CitiPower, 2009-2013 Category Analysis RIN	Yes
CP PUBLIC RIN 1.20	CitiPower, 2014 Category Analysis RIN	No
CP CONFIDENTIAL RIN 1.20	CitiPower, 2014 Category Analysis RIN	Yes
CP PUBLIC RIN 1.21	CitiPower, Other Entities, 30 April 2015	No

Reference	Document	Confidential
CP PUBLIC RIN 1.22	Corporate services agreement 2012-2014	No
CP CONFIDENTIAL RIN 1.22	Corporate services agreement 2012-2014	Yes
CP PUBLIC RIN 1.23	Corporate services agreement, deed of variation 2014	No
CP CONFIDENTIAL RIN 1.23	Corporate services agreement, deed of variation 2014	Yes
CP PUBLIC RIN 1.24	Metering services agreement 2008-2013	No
CP CONFIDENTIAL RIN 1.24	Metering services agreement 2008-2013	Yes
CP PUBLIC RIN 1.25	Metering services agreement, deed of variation 2014	No
CP CONFIDENTIAL RIN 1.25	Metering services agreement, deed of variation 2014	Yes
CP PUBLIC RIN 1.26	Metering services agreement, deed of variation 2015	No
CP CONFIDENTIAL RIN 1.26	Metering services agreement, deed of variation 2015	Yes
CP PUBLIC RIN 1.27	Network services agreement 2012-2014	No
CP CONFIDENTIAL RIN 1.27	Network services agreement 2012-2014	Yes
CP PUBLIC RIN 1.28	Network services agreement 2015	No
CP CONFIDENTIAL RIN 1.28	Network services agreement 2015	Yes
CP PUBLIC RIN 1.29	Resources agreement 2012-2014	No
CP PUBLIC RIN 1.30	DRMS: constitution	No
CP CONFIDENTIAL RIN 1.30	DRMS: constitution	Yes
CP PUBLIC RIN 1.31	CHED Services, IT Asset Management, 12 February 2015	No
CP PUBLIC RIN 1.32	CHED Services, IT Data Management Policy, 15 January 2015	No
CP PUBLIC RIN 1.33	CHED Services, IT Software Management Policy, 12 February 2015	No
CP PUBLIC RIN 1.34	CHED Services, Telecommunications and Unified Communications Management, 12 February 2015	No

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