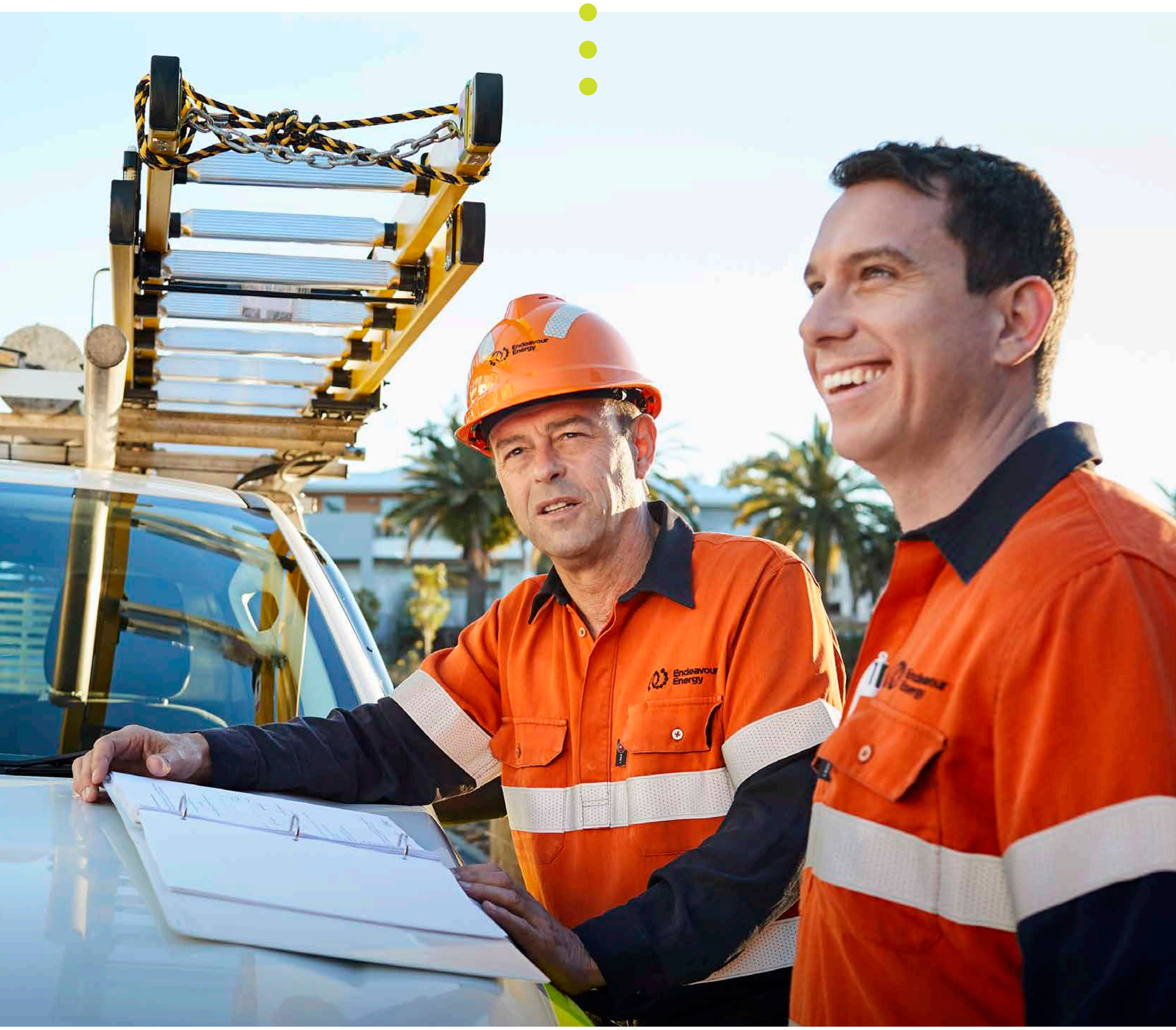
Regulatory Proposal

1 JULY 2019 TO 30 JUNE 2024



Endeavour Energy

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Foreword

Endeavour Energy connects 2.4 million people across Sydney's Greater West, the Blue Mountains, Southern Highlands, the Illawarra and South Coast to the safe and reliable electricity they need to live, work and play.

Powering the third largest economy in Australia and some of Australia's fastest growing communities means we are constantly planning for the future, so that electricity is available when and where it is needed to support new homes, new jobs, essential services and new technologies.

Every five-years, we work with customers and stakeholders to prepare investment plans to build, operate and maintain a vast electricity network. That plan is reviewed by the Australian Energy Regulator (AER), which considers feedback, and then decides the final revenue we can recover from customers to fund our operations. These costs make up about 30 percent of the average residential electricity bill, so it's vitally important that every dollar we spend aligns with our customers' priorities.

Never before has the community been so focused on the affordability, reliability and security of their electricity services as the energy industry in Australia undergoes a dramatic transformation.

Regulatory change and technological advancements are equipping customers with much greater choice and control of their energy usage. Increased customer focus and engagement with network businesses is shaping better outcomes for our customers and communities, providing new opportunities for customers to exercise control over what and when they use energy, and how much they pay.

This rapid pace of change provides both challenges and opportunities for all network businesses. For Endeavour Energy, this is coupled with the need to respond to unprecedented population growth in our region as the NSW State Government releases record areas dedicated to new housing, industrial development and employment lands.

Our focus is to service customer growth and facilitate customer choice in an efficient and prudent manner in order to serve the long-term interests of customers. In developing our plans we have also sought to address recurrent challenges such as maintaining and replacing assets in a sustainable manner, managing bushfire risk, and providing a secure and reliable supply of electricity.

In preparing our proposal we have:

- Engaged with customers and stakeholders to identify their top priorities over the next five-years and adjusted our plans where possible to reflect their feedback. After running focus groups and planning forums, and following targeted engagement with peak consumer groups and retailers, we set out our initial thinking about our plans in a Directions Paper to improve transparency and encourage more intense engagement. We also strengthened our engagement processes with a series of 'deep dives' on our capital and operating plans and tariff structures.
- Aligned our plans with the dramatic transformation taking place in our industry, which is further described in the ENA/CSIRO's Electricity Network Transformation Roadmap.
- Responded to the changes in our regulatory obligations since our last regulatory proposal, including progress on the Power of Choice reforms and amendments to our licence conditions.
- Incorporated the benefits of our new ownership structure. We are now 50.4 percent owned by an Australian-led consortium of long-term investors in the private sector with extensive experience in operating utilities. Guided by their performance culture and our previous efficiency programs we will achieve the AER's benchmark efficient level of operating expenditure and use this to forecast our future requirements.

Based on these considerations, our proposal sets out to serve the long-term interests of customers by:

1. Providing an affordable, safe and reliable electricity supply
2. Efficiently containing investment for new customer connections and economic growth
3. Enabling customers' future energy choices.

Foreword

We are genuinely committed to placing customers at the heart of all decision making.

What we've heard so far is that affordability is the number one concern for our customers, but not at the cost of reliability or safety. That's why our plans for the 2019-24 period will see network charges decrease by one percent each year in today's dollars, after we finalise our 2014-19 remittal proposal with the AER.

We will also service the population growth in our network area in a timely and efficient manner and continue to facilitate new ways for our customers to control the electricity they use and what they pay.

Now we want to share our plans with all our customers, so that as many people as possible can contribute to our plans before they are finalised. We set out a snapshot of our Regulatory Proposal below, which we explain in more detail in the remainder of this document.

I encourage you to find out more about what's planned and what this means for your future electricity bills on the pages that follow.

Then I invite you to have your say on how you want us to meet your electricity needs and operate in the future.

Tony Narvaez
Chief Executive Officer
Endeavour Energy

A snapshot of our plan

Standard Control Services ($M, Real 2018-19)	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Operating expenditure (including debt raising costs)	282.4	290.3	300.4	310.6	320.3	1,504.0
Net capital expenditure (including disposals)	457.0	430.8	423.9	411.8	417.6	2,141.1
Capital contributions	111.8	105.3	104.8	105.1	107.6	534.7
Regulatory Asset Base	6,718.9	6,883.7	7,030.8	7,157.5	7,293.6	n/a
Revenue Requirements $M, Nominal	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total (NPV)**
Return on capital (WACC 6.11%)	397.9	420.8	441.9	462.6	482.7	1,842.3
Regulatory depreciation	101.8	115.1	125.3	133.4	129.2	504.3
Revenue adjustments (incentive schemes and 2014-19 remittal)	-207.7	73.5	85.7	71.7	1.0	-1.48
Corporate tax allowance (Gamma 0.40)	40.6	40.3	47.5	51.6	50.6	192.1
Annual revenue requirement (smoothed)	877.7	902.8	926.6	953.5	988.5	3,891.6
Real price movements (%)	-1.0	-1.0	-1.0	-1.0	-1.0	n/a
Energy consumption (GWh)	16,621	16,730	16,831	16,954	17,228	n/a
Customer numbers	1,043,718	1,064,095	1,084,269	1,104,565	1,125,865	n/a
Maximum demand (MW)	3,949	4,039	4,129	4,205	4,278	n/a

A snapshot of our plan

Key Decisions	
Service classification	We propose service classifications and definitions as per the AER's 2019-24 Framework and Approach paper. This includes the AER's decision to continue to regulate our Dual Function Assets as distribution assets for pricing purposes.
Control mechanisms	We accept the AER's decision to apply a revenue cap to standard control services and a price cap to alternative control services. We propose the formulae to give effect to these control mechanisms as per the AER's 2019-24 Framework and Approach paper.
Incentive schemes	We accept the AER's decision in the 2019-24 Framework and Approach to apply the following incentive schemes to us: • The Efficiency Benefit Sharing Scheme (EBSS). • The Capital Efficiency Sharing Scheme (CESS). • The Demand Management Incentive Scheme (DMIS) including the Demand Management Innovation Allowance (DMIA. • The Service Target Performance Incentive Scheme (STPIS). In accordance with the STPIS Guideline, we have proposed an alternative approach to calculate Major Event Day thresholds. This is consistent with the methodology we applied during the current 2014-19 period.
Pass-throughs	We propose to apply the same four nominated pass-through events as approved by the AER for the 2014-19 period. We have updated the definitions to align with those contained in recent AER decisions.
Contingent projects	We nominate the Western Sydney Airport Growth Area as a contingent project for the 2019-24 period with the trigger events as defined in section 10.6 of our proposal.
Tariffs	Our tariff structure statement (TSS), Attachment TSS0.01, outlines our proposed tariff structures for the 2019-24 period. To summarise, we will: • introduce a seasonal demand tariff; • replace seasonal TOU energy charging with a flat energy rate to simplify our seasonal demand tariff structure; • give customers greater ability to respond to price signals by shortening our peak demand window from 1-8pm to 4-8pm on weekdays; • assign all new customers and existing customers who upgrade their network connection to three-phase or bi-directional flow, to the cost-reflective tariff with the option to 'opt-out' to the flat energy tariff; • make the transition as easy as possible for customers with a ten-year transition for the 'opt-out' seasonal demand tariff and introduce a voluntary seasonal demand tariff with no transition period; and • work with retailers to help educate customers on tariff choices and with the industry as a whole to facilitate uniformity of tariff design in response to retailers' feedback.

A snapshot of our plan

Alternative Control Services	
Public lighting	We have modified our pricing approach to include a differential price for LED lighting in response to customer feedback, that is 15 percent lower than traditional technology. We have made these changes while reducing our overall public lighting revenue requirements by almost eight percent.
Type 5 and 6 metering	We propose the same pricing approach as the current 2014-19 period. Our proposed metering revenue over the 2019-24 period is $90.2 million (nominal) with a metering X-factor of -25.11 in 2019-20 followed by no real price movements. This real increase (approximately $4 for residential Type 6 customers) is driven by the impacts of the transition to metering contestability.
Ancillary services	We propose the same pricing approach as the current 2014-19 period. We have developed our proposed prices for new and existing services using the benchmark labour rates determined by the AER in setting 2014-19 prices. Our proposed ancillary service revenue over the 2019-24 period is $132.4 million (nominal) with an ancillary network X-factor of -1.52 percent in 2019-20 followed by no real price movements.

1.0 Context for the Proposal

CHAPTER 1

1.1 Purpose of this document

Over the next five-years we will continue to put downward pressure on electricity bills whilst maintaining a safe and reliable electricity network, servicing population growth and facilitating customer choice and control as the industry dramatically transforms.

Every five-years, we are required to submit a plan for what needs to be spent to operate and maintain a vast electricity network. In accordance with the National Electricity Rules, the AER reviews this proposal to determine our revenue requirements and other matters relating to the provision of regulated electricity distribution services. This review includes a public consultation process which formally commences with the release of this Regulatory Proposal.

This proposal is for the period from 1 July 2019 to 30 June 2024. It details our proposed operating and investment plans developed and presented in accordance with the AER's *Better Regulation Guidelines* and includes:

- expenditure forecasts;
- rates of return;
- pricing methodology; and
- tariff structure statement.

All of this has been influenced by engagement with our customers and stakeholders to understand their expectations for the services we deliver and the network charges they pay. Accordingly, this proposal also includes a plain-English overview document to summarise and make it easier to understand the different elements that contribute to the network charges customers pay for electricity distribution.

This proposal is submitted so that the AER can ultimately determine the final revenue we can earn and how that flows through to the electricity bills of almost a million customers. We will continue to talk to customers and stakeholders to address any concerns before submitting a revised proposal (if required) in December 2018 for ultimate determination.

Structure of this Regulatory Proposal

Chapter 1 provides an introduction to our regulatory proposal including a foreword from our CEO, which provides highlights of our performance-to-date, plans for the future and how we will continue to work with our customers and stakeholders in delivering services that meet their expectations in the most efficient way.

Chapters 2-5 provide the context which has informed our proposal for the next five years. This includes: a report on our performance for the current period; the opportunities and challenges we face in providing network services to our customers; an account of how we have engaged with our customers to gather their views; and how these views have been incorporated into this proposal.

Chapters 6-13 focus on the detail of our proposal. We set out: the savings and investments we plan to make; our regulated asset base; proposed rate of return; income tax allowance; and various incentive schemes. These details inform the overall revenue required to provide distribution services and describe the implications for customer bills.

Chapter 14 focuses on alternative control services. These services are only required by a small group of customers or have the potential to be provided on a competitive basis in the future, such as public street lighting, and are subject to service-specific prices set by the AER to enable full cost recovery by those using these services.

Attachment TSS0.01 is our Tariff Structure Statement (TSS), which further expands on the billing implications by detailing our proposal to introduce a seasonal demand tariff for new customer connections and customers who upgrade their existing connection. It also explains our new alternative opt-in demand tariff, to provide customers with greater incentives to control and manage their energy usage during peak periods in order to reduce future investment needs and prices.

To complement this document, we have developed a plain-English overview of our Regulatory Proposal. This provides a summary of the key aspects of our proposed revenue requirements for 2019-24. It complies with all the requirements set out in 6.8.2(c1) of the NER.

2.0 About Endeavour Energy

CHAPTER 2

2.1 Overview

We power some of the fastest-growing regions in Australia and our focus is providing affordable, safe and reliable electricity to the 2.4 million people across our network.

Endeavour Energy plans, builds, operates and maintains the poles and wires and other distribution assets that provide an affordable, safe and reliable power supply to and from households and businesses across Sydney's Greater West, the Blue Mountains, Southern Highlands, the Illawarra and the South Coast.

The timely and efficient provision of these services is fundamental to supporting employment growth, economic development and housing affordability across one of the fastest growing metropolitan and regional economies in Australia.

Over the current regulatory period (2014-19) we have improved our performance against our three key performance indicators of affordability, safety and reliability. Over the five-year period between 2012-13 and 2017-18, Endeavour Energy's average annual network charges decreased by $75 in nominal terms (for an average residential customer). Our performance has therefore allowed our customers to continue to benefit from some of the lowest network charges in the NEM.

2.1.1 Who we are

Endeavour Energy is 50.4 percent owned by an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease. The private sector consortium comprises funds and clients managed by Australia's Macquarie Infrastructure and Real Assets, AMP Capital on behalf of REST Industry Super, Canada's British Columbia Investment Management Corporation and Qatar Investment Authority.

The remaining 49.6 percent is held by the State of NSW via a corporation constituted under the *Electricity Retained Interest Corporations Act 2015*.

This change in ownership during 2017 means we can leverage the vast infrastructure management experience of the consortium to transform our business into a world-class utility, delivering further improvements in safety, operating efficiency and customer service outcomes. The consortium has identified five priorities that will shape the future direction of the business:

- Improving safety for staff and the community.
- Developing a stronger, flexible and better skilled workforce.
- Investing to improve network resilience and customer outcomes.
- Over time, reducing customers' bills.
- Supporting future growth in Western Sydney and across our network.

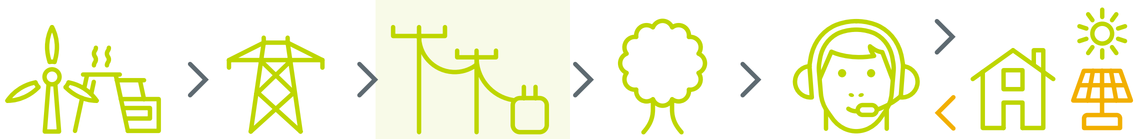
Our primary objective is to manage our assets efficiently and prudently to provide our customers with a safe and reliable service.

2.1.2 What we do

We own and operate the $6.5 billion network used to transport electricity from the high voltage NSW transmission network (which is managed by TransGrid) directly to the homes and businesses of our customers in a form they can use. Increasing numbers of solar panels mean our network is also used to transport energy from these 'distributed' sources back into the system.

We perform this role according to extensive obligations, standards, conditions and requirements, particularly in relation to customer and community safety, and the security and reliability of supply.

Figure 2.1 Electricity industry structure



Generation	Transmission	Distribution	Green Schemes	Retailer	Consumers
Generators create electricity from coal, gas, hydro, wind and solar.	Transmission networks like TransGrid carry electricity over long distances.	Distributors such as Endeavour Energy build and maintain poles, wires and substations and distribute electricity to customers.	Government green and energy efficiency schemes.	Retailers such as Origin Energy buy electricity from generators, sell it to customers and send you your bill.	

$ p.a.	Generation	Transmission	Distribution	Green schemes	Retail	Your bill
Contribution to average household bill*	41%	4%	31%	9%	15%	= 100%
Annual cost to average household	$683	$62	$508	$155	$249	= $1,657
Contribution to median small to medium business bill	43%	4%	27%	11%	15%	= 100%
Annual cost to median small to medium business bill	$1,385	$124	$862	$366	$483	= $3,220

* Based on an annual residential customer bill of 5000 kwh

The services we deliver for our customers include:

- building, maintaining and operating the distribution network including new substations, poles and wires to accommodate demand in growing suburbs;
- converting high-voltage electricity from the transmission network into safe distribution levels via our substations;
- restoring your power after emergencies such as storms, which bring down power lines and poles;
- providing new connections and infrastructure where it doesn't currently exist;
- managing bushfire risk to prevent blackouts caused by falling trees;
- trimming trees to maintain safety clearances;
- facilitating customer take-up of small-scale renewables such as solar and battery storage;
- operating a 24-hour customer contact centre;
- researching, trialling, and installing new technology (e.g. batteries) to use as alternatives to greater investment in poles and wires;
- installing and maintaining street lights, and
- undertaking various 'user pay' services such as meter testing, off-peak conversion and design certification.

As at 30 June 2017, our vast network includes:

- a 24,980 square kilometre distribution area;
- 59,300 kilometres of underground and overhead power lines to maintain;
- 31,913 pole-top, pad-mount and indoor distribution substations;
- 433,100 power poles and columns;
- 456 major power transformers;
- 164 zone substations and 24 subtransmission substations to manage;
- 20,400 protection relays;
- 42,567 high voltage circuit breakers to prevent blackouts;
- almost 1 million connections servicing 2.4 million people, including 40,000 businesses; and
- connections to 20,000 life support customers.

2.1.3 Our customers

We serve a diverse population with almost one million customers across 24,980 square kilometres. Most of our customers are households and small to medium businesses located in urban and developing rural areas. We also serve large urban areas, medical precincts and manufacturing and industrial customers who have specific needs for a safe and reliable supply; and we provide high voltage support directly to large businesses.

Our network area includes significant development zones such as Sydney's second airport, and its surrounding 'aerotropolis'. It's also home to Sydney's North West and South West Priority Growth sectors, planned as new release areas to house communities similar in size to Wollongong and Canberra. The population of Western Sydney is expected to swell by 900,000 over the next 20 years. That means that each year over the next decade, more than 20,000 new customers will require electricity services.

In addition to population growth, we face the challenge of our existing customers having the third highest energy density and second highest demand density in the NEM. This means that our customers consume a relatively high amount of energy, particularly so during peak times (4pm to 8pm). This is largely due to a combination of higher summer temperatures (often up to 10 degrees higher than the Sydney CBD) and energy-intense economic activity.

As the electricity industry undergoes rapid transformation, many customers are changing the way they interact with the network and we are seeing more small scale renewable forms of generation connecting to the network. By June 2017, over 120,000 customers had connected their own small scale renewable generation (mostly solar panels) to the network, representing a total capacity of around 330MW.

Our network plays a critical role in enabling a range of customer benefits from the increasing uptake of distributed energy resources (DER). At this stage, the network support offered by DER remains limited and our peak demand continues to grow, hitting a record high on 30 January 2017 of 4,107MW. Small scale generation is still mostly available outside of peak demand times and represents a small offset of our total energy delivered, which was 16,716GWh for the 2016-17 year.

We manage our operations over three distinct geographic regions:

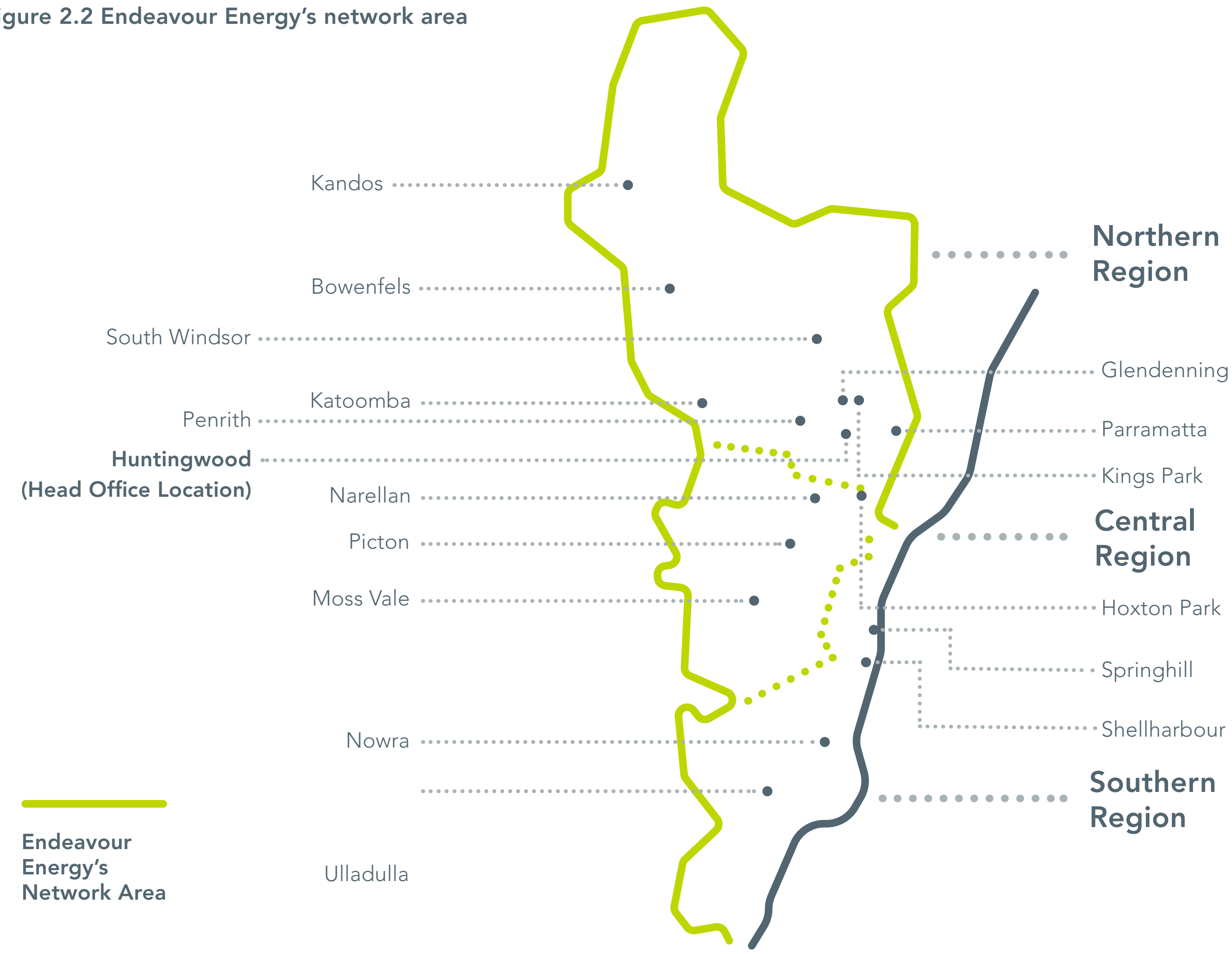
Northern region (North West Sydney and the Blue Mountains)
Most of our customers (and our network infrastructure and assets) are located in Greater Western Sydney, which includes the major cities of Parramatta, Blacktown, Penrith, along with the Hawkesbury and the Hills regions. Combined with other major centres in the Central region, they form the third largest economy in Australia.

Typical of urban expansion, greenfield development within Sydney is largely confined to regions on the city fringe. This suburban development has been primarily driven by the largest coordinated land release in the history of NSW. Development to accommodate this expansion has been concentrated in the North West and South West Sydney regions, which are entirely captured by our network area. With the population of Western Sydney expected to increase by 900,000 over the next 20 years, our investment plans for the next regulatory period support required growth in these areas.

We also supply customers throughout the Blue Mountains and beyond. This is a World Heritage Area featuring dense vegetation with challenging topography. Managing bushfire risk and reliability is a key focus for this part of our network.

Central region (South West Sydney and the Southern Highlands)
The central area of our network incorporates the major urban centres of Liverpool, Fairfield and Campbelltown. In common with the Northern region, strong greenfield growth has been experienced in areas that were previously low density rural communities. Large transport infrastructure investments underpin population and economic growth in the area.

Figure 2.2 Endeavour Energy's network area



This area will also be the home of Sydney's second airport at Badgerys Creek, featuring development of an 'aerotropolis.' It is set to open in 2026, and we are working closely with planning authorities and developers to support this and other planned development in the surrounding area.

South west of the Sydney metropolitan region, the rural townships of Picton, Bowral, Mittagong and Moss Vale form the major regional communities of the Southern Highlands.

Southern region (Illawarra and the South Coast)

Most of our resources in the Southern region are focused in Wollongong and the wider Shellharbour district. After Sydney and Newcastle, Wollongong is NSW's third largest city and is home to approximately 300,000 people. Significant growth is planned for the region led by the West Lake Illawarra area, which will ultimately accommodate an estimated 27,000 new dwellings. This region includes Port Kembla Harbour and an industrial complex, which is the largest single concentration of heavy industry in Australia.

The southernmost areas of our network are predominantly small coastal communities, popular with holiday tourists and retirees, and often subject to severe weather events. Our growth story extends to this area too, with an estimated 5,000 new homes possible in the greenfield Moss Vale Road Urban Release Area in the Shoalhaven region.

3.0 Our Performance

CHAPTER 3

3.1 Overview

Endeavour Energy's network charges are the lowest in NSW due to our long-term efficiency programs and commitment to incentive-based regulation. We have achieved this without compromising safety or reliability.

Our performance over the 2014-19 period demonstrates our commitment to:

- achieving cost reductions and productivity improvements that resulted in us:
  - spending less than the AER's approved capex allowance; and
  - reducing our opex by $64.1 million (real, 2018-19) since 2013-14 to achieve the AER's benchmark opex by year four, our forecast base year for 2019-24.
- maintaining and marginally improving our reliability and customer service performance; and
- trialling a number of innovative non-network and demand management solutions.

These results are a positive outcome for customers. By reducing our opex and capex safely and efficiently over the 2014-19 period we have reduced our opex requirements and opening Regulated Asset Base (RAB) for the 2019-24 period, which puts significant downward pressure on our portion of electricity bills.

We have made these improvements without compromising safety or the quality of customer service and reliability levels as promised in our 2014-19 proposal.

3.2 Affordability

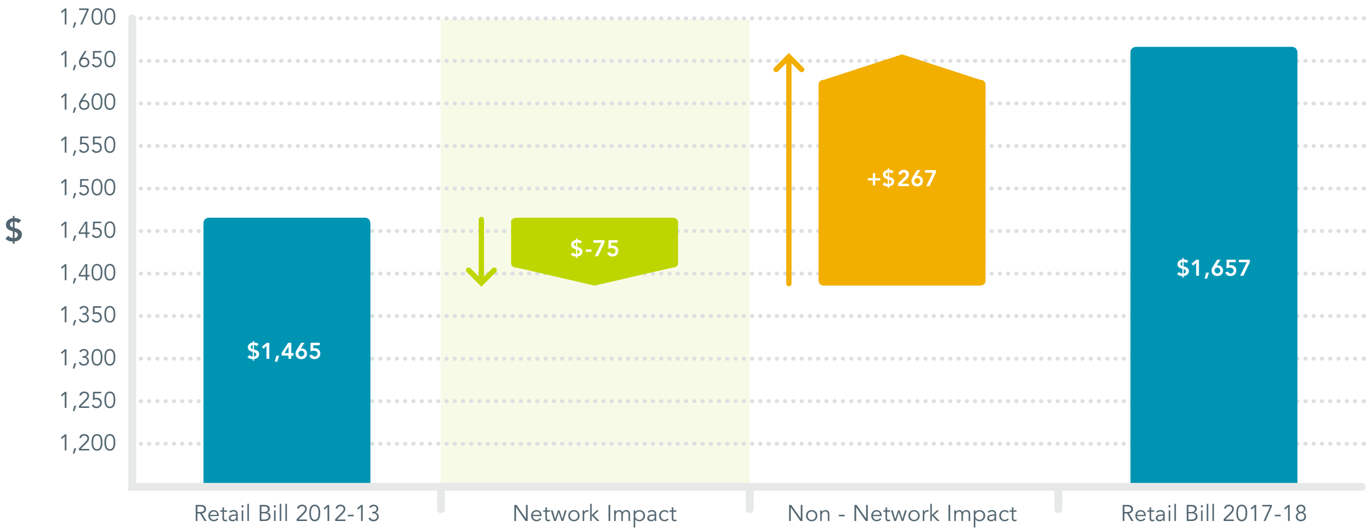
Our engagement program told us affordability is the number one concern for many of our customers, but not at the sacrifice of safety or reliability. Electricity is valued because it provides security and lifestyle benefits to residential customers and communities, and because it connects new homes and underpins prosperous businesses and regions. There's a clear expectation our plans should reflect measures to continue downward pressure on our part of electricity bills.

We're committed to improving the efficiency and productivity of our business to drive cost savings and and achieve that downward pressure on our part of customers' electricity bills.

Since the peak of our investment in 2012-13, our organisation-wide efficiency program has reduced annual total expenditure by 51 percent from $1,055.2 million (real, 2018-19) to $515.9 million (real, 2018-19) in 2016-17. We have focused on making our workforce more competitive, improving the commercial aspects of our asset management decisions, and making our business more efficient. We have achieved these reductions despite the added cost pressures from extending the network to meet significant growth in new connections, managing an ageing asset base and meeting increased compliance to vegetation management standards.

This has meant that Endeavour Energy's residential customers are paying $75 less on average for network services in 2017–18 than they were in 2012–13 as a result of meeting the targets set by the AER that significantly reduced our revenue requirements over the 2014-19 period. We have achieved these targets by reducing our cost of debt and operating costs, which will allow our customers to continue to benefit from some of the lowest network charges in the NEM.

Figure 3.1 Change in average annual residential retail bills over the past five-years



Notes:
- Calculated on the basis of Origin Energy's standing offer for residential customers in Endeavour Energy's network;
- Network Impact includes Distribution, Transmission and Climate Change Fund contributions;
- Non-Network Impact includes Generation, Government Green Schemes and Retail Services.

As a result of the reduction in our network charges, our share of an average residential customer's electricity bill has fallen to 31 percent in 2017-18, a decrease of 13 percent from 2016-17.

We also propose to return $226.7[1] million (real, 2018-19) to customers over the 2019-24 period to settle the outstanding 2014-19 determination. This, and our plans for 2019-24, will provide pricing stability for customers and continue to keep downward pressure on electricity bills.

1 As detailed in our 2014-19 remittal proposal (submitted 6 April 2018) this amount is based on our forecast revenue over-recovery for the 2014-19 period compared to the AER's 2014-19 determination updated for inflation and return on debt after retaining $110m (real, 2018-19). It is also inclusive of our unrecovered STPIS payments and calculated in accordance with the AEMC's August 2017 revenue smoothing rule change.

Tariffs

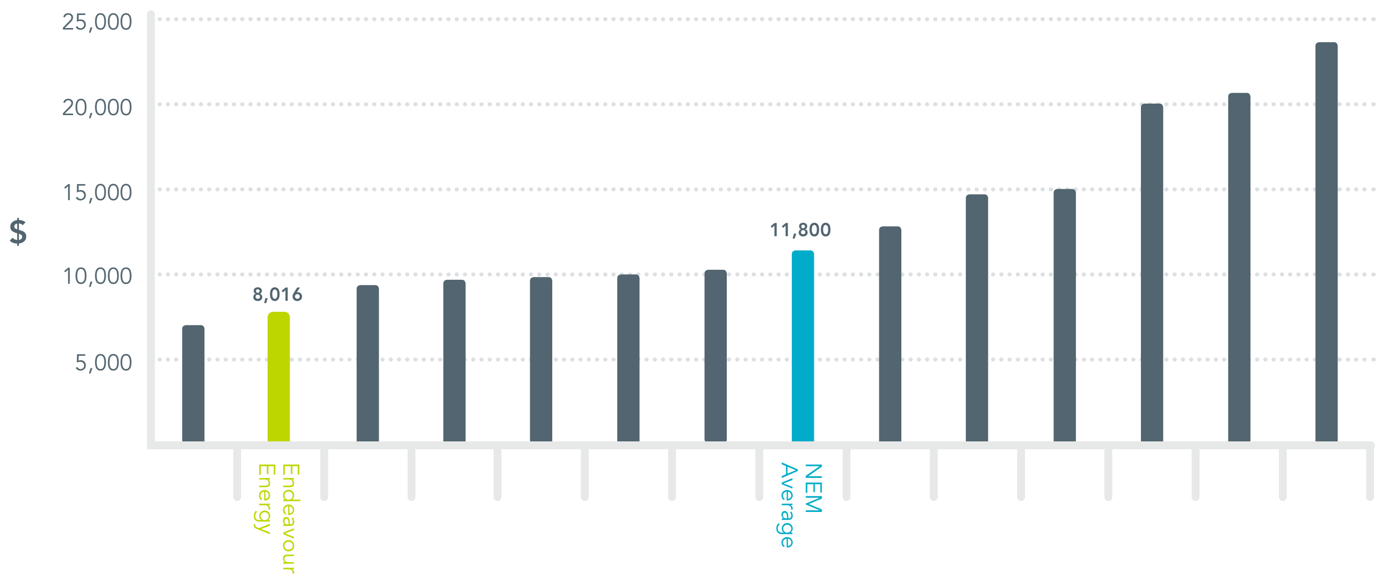
We are also working on implementing more cost-reflective tariffs to help keep downward pressure on future electricity prices. Currently, under our 'flat' tariff charges, all residential customers pay the same price per unit of energy consumed irrespective of the actual cost of supplying each customer at the time of consumption. We have more cost-reflective prices for large industrial customers and a time-of-use (TOU) tariff (i.e. the charge varies depending on the time of usage) option for residential and small business customers. This approach means there are limited incentives and opportunities for residential customers to manage their consumption during peak periods that would help reduce our future costs and prices.

In response to stakeholder feedback, we plan to introduce a tariff based on consumption during peak periods that will better signal to customers when their usage may increase their costs and our future expenditure. If these improved price signals are passed through to customers by their retailers this is likely to reduce future peak demand resulting in lower investment requirements for us and therefore reduced prices in the longer term. Our TSS, Attachment TSS0.01, outlines our tariff structure in more detail.

Efficient connection of new customers

One of our priorities over the past several years has been connecting new customers to our network in a timely and efficient manner to support jobs, economic development and housing affordability in Sydney's West and the Illawarra. We have achieved this objective and will continue to do so over the 2019-24 period. The total cost of connecting a new customer (i.e. capital contributions and connections capex per new customer) has been the second lowest in Australia over the past several years and our average connection cost per customer will continue to improve over the 2019-24 period. Despite this, some stakeholders remain concerned about the costs borne by existing customers in the longer term and we will continue to engage with them on this issue as it has potential implications across the NEM.

Figure 3.2 Endeavour Energy average connection cost per customer (FY12-FY16)



3.2.1 *Endeavour 2020*

Our *Endeavour 2020* transformation program is our business-wide efficiency program, designed to drive continuous improvement without compromising the safety or the quality of services provided to our customers. It is designed to transform our business by reducing the cost of building and maintaining our network while enabling us to efficiently deliver services to customers by focusing on the following areas:

- Optimising asset management to safely and sustainably improve work on our network.
- Improving the efficiency of works management on our network.
- Improving the efficiency of our support teams and back office functions.
- Continued enhancement of procurement practices to drive ongoing savings.

The savings associated with *Endeavour 2020* are reflected in our opex forecast for 2019-24. We expect to achieve a $64.1 million (real, 2018-19) total reduction in opex from 1 July 2014 to 1 July 2018. This reduction will also deliver ongoing savings over the 2019-24 period.

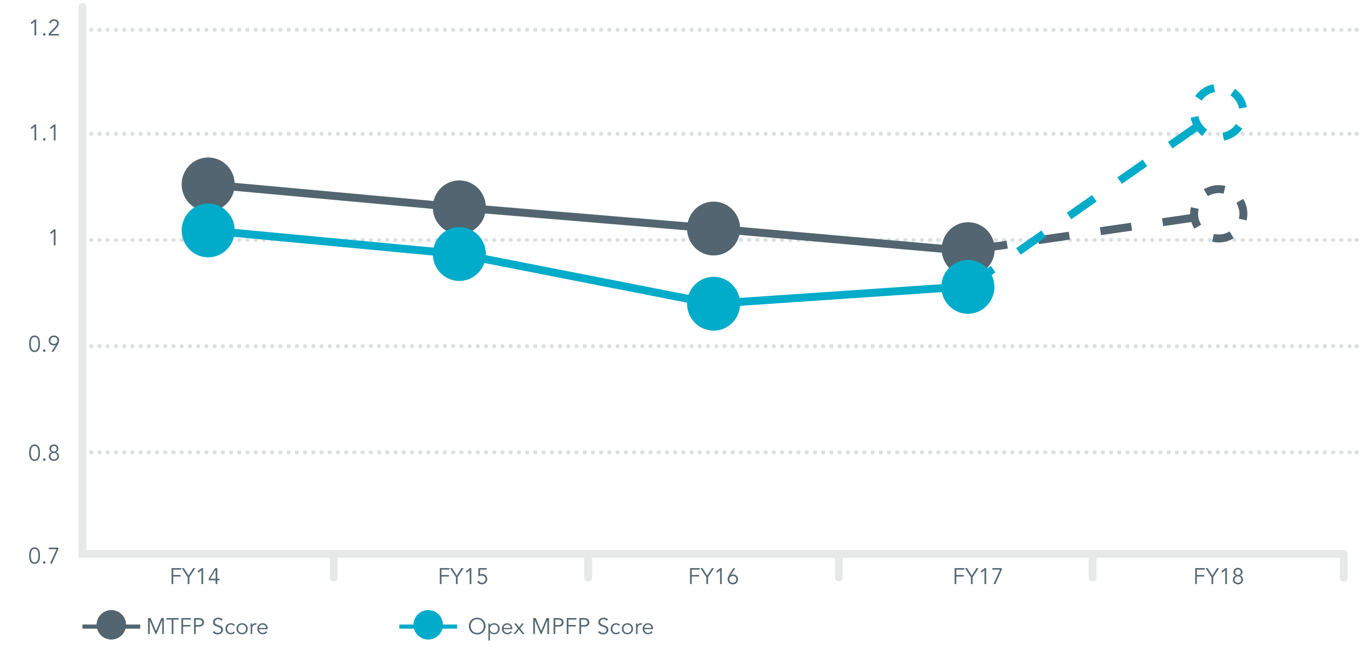
3.2.2 Benchmarking

Benchmarking techniques are increasingly being used by the AER as a tool to assess the efficiency of networks over time and against NEM peers. Despite some debate about benchmarking measures and models, Endeavour Energy supports benchmarking as it can identify potential opportunities for efficiency improvements that can improve affordability for our customers.

Endeavour Energy is currently benchmarked as the most efficient network in NSW, but we're sitting in the middle of the pack when compared to other distributors in the NEM. Our ambition is to be the best distributor in Australia and so we have set our sights on lifting our performance right across the business.

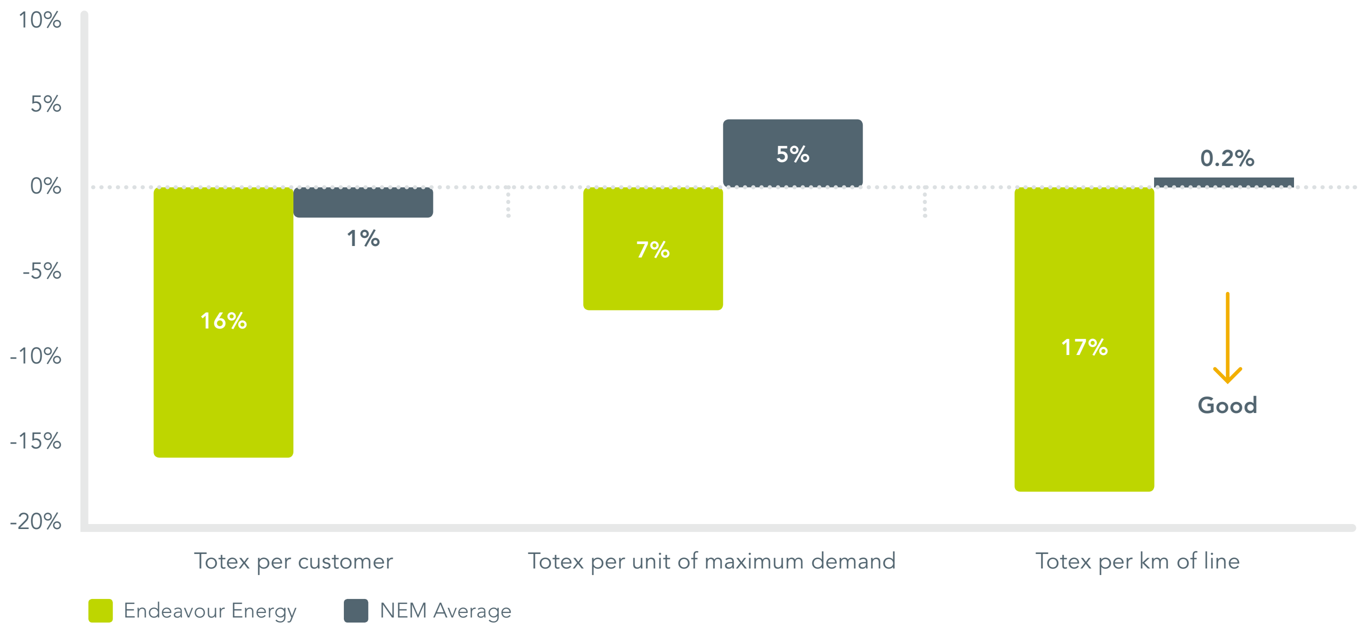
We expect our Multi-Total Factor Productivity (MTFP) and Opex Multi-Partial Factor Productivity (MPFP) benchmarking scores will improve in the 2017-18 year due to the significant cost reductions associated with the *Endeavour 2020* program and our new business priorities. We forecast achieving the AER's benchmark for opex in 2017-18. This $64.1 million (real, 2018-19) total reduction in opex since 2013-14 demonstrates that we are responding to regulatory incentives by improving our productivity and reducing our costs without compromising existing safety or service levels.

Figure 3.3 Endeavour Energy MTFP and Opex MPFP Scores FY14 to FY18[2]



The AER also uses a variety of partial performance indicators (PPI) to provide a simple visual representation of input costs relative to a specific output. We have made significant reductions in our totex per customer, unit of maximum demand and km of line compared to the flat or increasing trend in performance across the NEM in recent years.

Figure 3.4 Endeavour Energy percentage change in totex PPIs compared to NEM average (FY13-FY16)



2 This is based on our estimated RIN inputs and other assumptions for the 2017-18 year and therefore subject to change.

3.2.3 Responding to incentives

The NEM uses an incentive based regulatory framework to ensure that networks such as Endeavour Energy continually improve their efficiency without compromising the safety or reliability of their services. The incentive schemes are:

- the Efficiency Benefit Sharing Scheme (EBSS), which is designed to provide networks with a continuous incentive to pursue opex efficiency improvements;
- the Capital Efficiency Sharing Scheme (CESS), which is designed to provide networks with an incentive to spend less than the approved capex allowance during a regulatory period;
- the Service Target Performance Incentive Scheme (STPIS), which is designed to ensure networks target a level of reliability and customer service that is valued by customers; and
- the Demand Management Incentive Scheme (DMIS), including the Demand Management Innovation Allowance (DMIA), which together are designed to ensure networks trial, investigate and utilise innovative non-network solutions to address network constraints.

We have responded efficiently to these incentive schemes over 2014-19 and our customers will receive the majority of the benefits associated with our performance. We have reduced our forecast opex and RAB while maintaining reliability and investigating non-network solutions (such as our residential and grid-scale battery trials).

We plan to respond efficiently to incentives over the 2019-24 and share the benefits of doing so with our customers in accordance with the incentive based regulatory framework.

3.3 Safety

There is nothing more important to us than the safety of our workers and the community, but we also have to balance this with affordability. This does not mean we cut corners. We foster a proactive and consistent approach to hazard identification, risk assessment and the effective management of risk through the implementation of preventative controls and actions. While customers have told us that affordability is currently their primary concern, they expect us to address affordability without compromising on safety and reliability.

3.3.1 Electrical safety

Every day our people perform work that has the potential to be hazardous. The inadvertent and uncontrolled discharge of electricity from our network remains the highest consequence hazard for our network and presents a constant risk to which our employees and the public are exposed. To mitigate electrical risks, our workplace instructions and processes have been developed to preserve safety above all other considerations, and without exception.

Electrical safety awareness is embedded through a set of mandatory safety rules called the Rules We Live By. Developed with direct input from frontline workers across our business, this sets out the core rules our workers must follow and use to prevent serious injury or fatality when they perform work involving a network fatal risk. As a key component of our Network Fatal Risk Program, the Rules We Live By aims to minimise high consequence, low frequency life-changing events that have the potential to result in loss of life or permanent disabilities.

Safety is also a key consideration in our asset management decisions. We undertake inspections and monitor our assets carefully to identify signs of impending failure which may result in danger to property or people. Bushfire risk is managed through targeted asset replacements and relocations; a program of pre-summer bushfire inspections and an extensive vegetation management program.

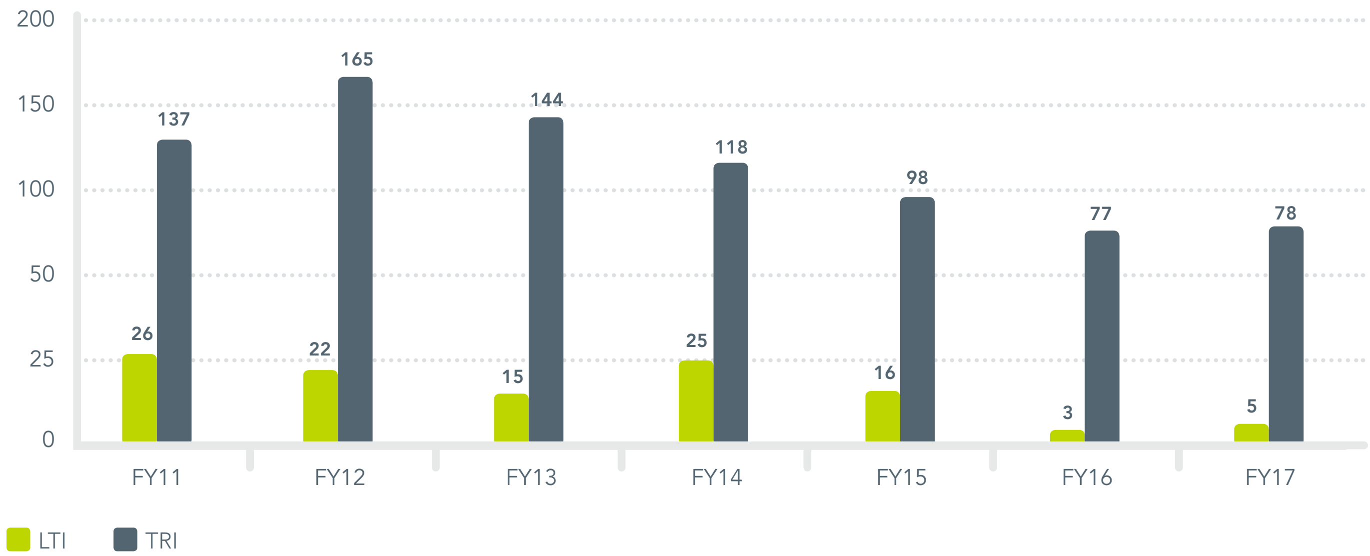
We also run electrical safety awareness programs to educate the community and our customers about the dangers associated with electricity. We design programs to create greater awareness of electrical safety based on an analysis of safety incidents involving our network and relevant data sources. Resources that highlight the dangers posed by electricity in many everyday situations and scenarios are made available to our customers, mainly through our website. We provide suggestions for preventative action and instructions on what to do during an incident.

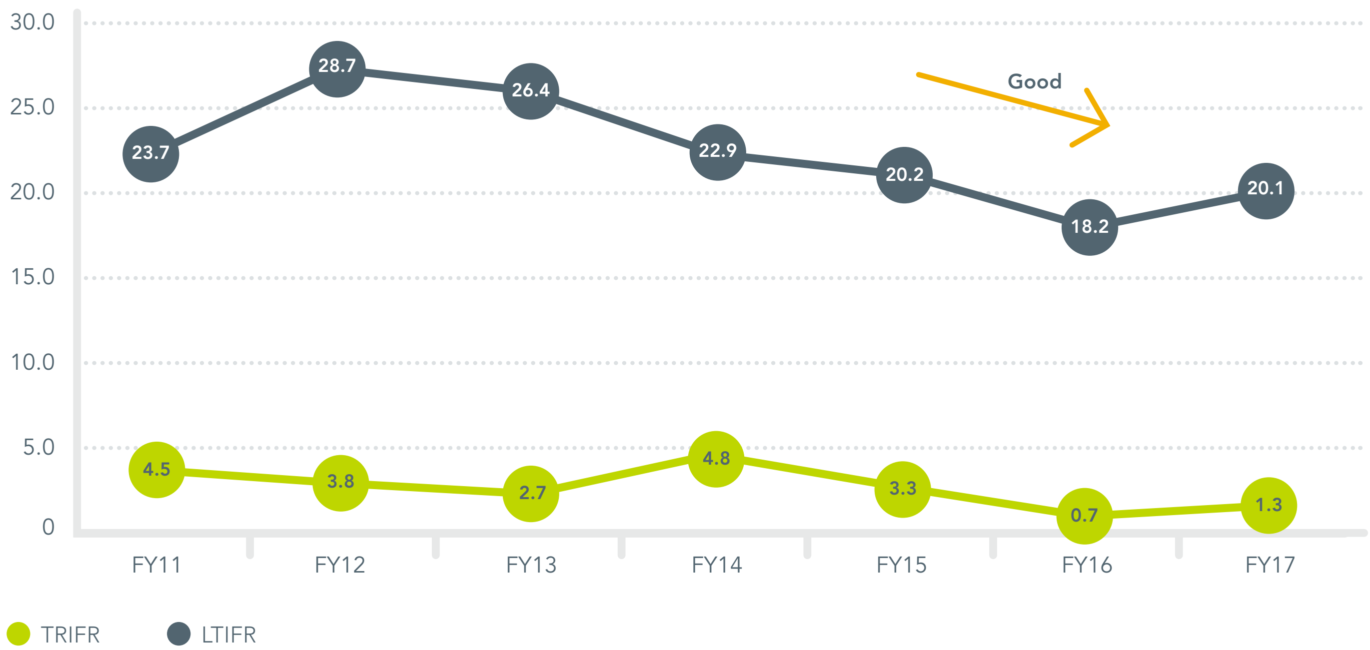
3.3.2 Workplace safety

Whilst negotiating a period of significant organisational change, we have maintained our focus on improving safety performance in the workplace and maintained a trend of improvements against the standard industry key performance indicators.

- Lost time injury (LTI): a work injury that results in the inability of the employee to work for at least one full day or shift.
- Total recordable injuries (TRI): an incident which resulted in a fatality, lost time injury, medical treatment injury and/or restricted work cases.
- Frequency rate (FR): the number of occurrences of injury or disease for each one million hour worked.

Figure 3.5 Lost time injury frequency rate and total recordable injuries FY11-FY17





Despite these improvements, we remain committed to continuously improving health and safety management towards our goal of zero incidents and injuries for workers and the public.

3.4 Reliability

Most of Endeavour Energy's customers agree that they enjoy high levels of reliability and have told us they do not want to pay more for improvements, nor do they want to pay less if it meant a poorer standard of reliability. We invest to ensure our network delivers the level of reliability our customers expect that meets minimum licence conditions in the most efficient way. For the 2019-24 period, this will mean an increase in our replacement capex in order to maintain existing reliability levels on an ageing network.

Service reliability is often impacted by a combination of internal and external events. Our inability to directly control many of these factors means that some level of unplanned interruption is likely to be experienced somewhere on our vast network during the course of a year.

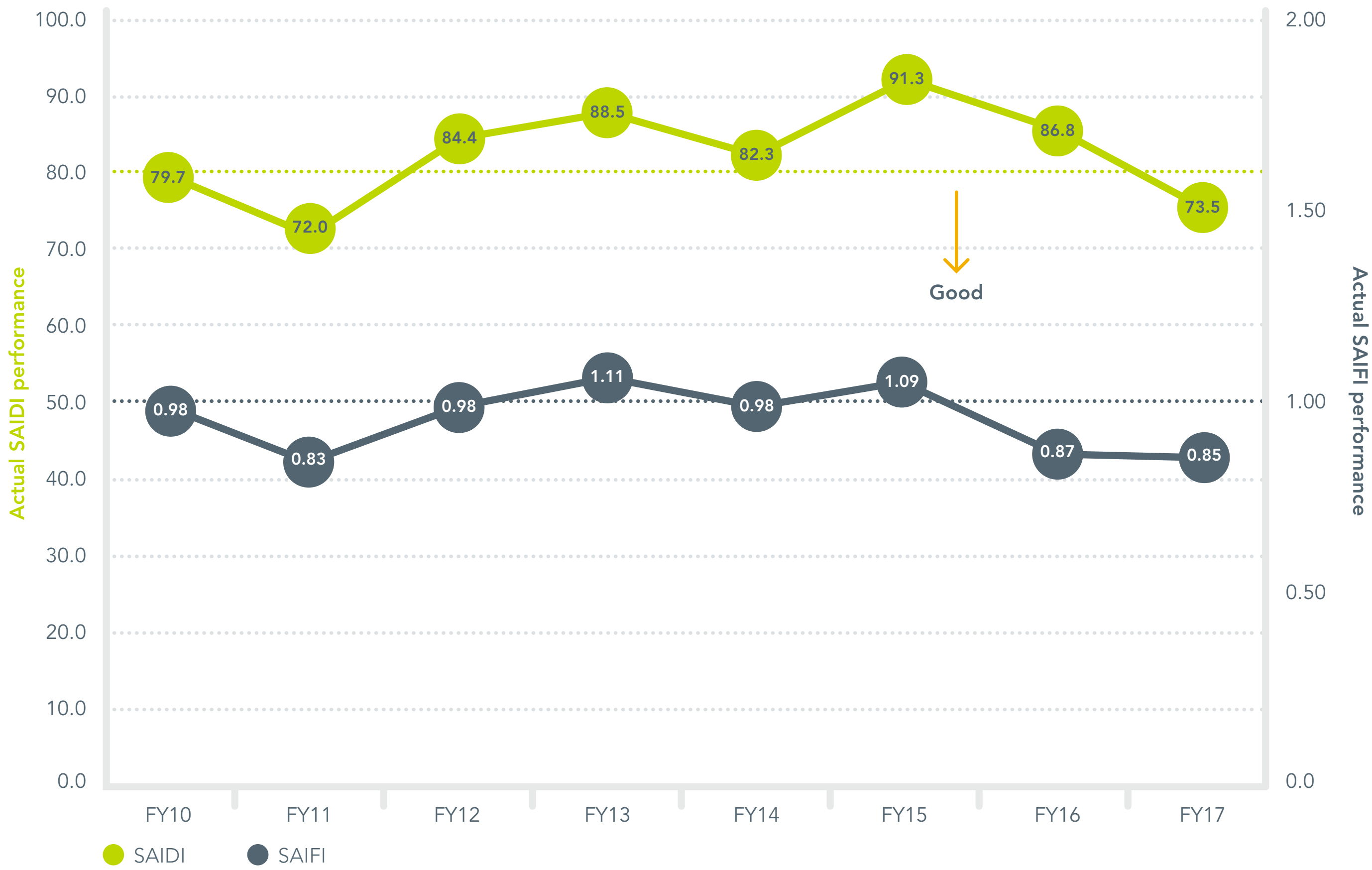
During the current regulatory period, our customers expected that reliability would be maintained at existing levels, and this has largely been achieved by providing a stable and reliable service within licence conditions that is reflective of the expectations of our customers.

Maintaining reliability has required investment to manage both the risk of failure from assets whose age and condition suggest they are at the end of their useful life, and the demands of a rapidly growing population.

This has been done in the most efficient way possible to deliver improvements in affordability while maintaining the network's reliability and resilience towards achieving the optimal service/price mix. The AER recognises that we should seek to maintain or improve reliability, but any improvements should be efficient. To support efficient reliability management, the AER has implemented the Service Target Performance Incentive Scheme (STPIS).

The STPIS ensures cost efficiencies encouraged by the EBSS and CESS are not made at the expense of supply reliability and customer service quality. The STPIS also provides capped incentive payments that are used to pay for reliability improvements. This cap ensures that we only invest in improvements that deliver actual value to customers without over investing.

Figure 3.6 Endeavour Energy reliability performance FY10-FY17



4.0 Our Operating Environment

CHAPTER 4

4.1 Overview

Never before has the community been so focused on the affordability, reliability and security of their electricity services as the energy industry in Australia undergoes a dramatic transformation. We're committed to efficient investment and giving customers more choice and control.

Regulatory change and technological advancements are equipping customers with much greater choice and control of their energy usage. Increased customer focus and engagement with network businesses is shaping better outcomes for our community, providing new opportunities for customers to exercise control over what and when they use energy, and how much they pay.

This rapid pace of change provides both challenges and opportunities for network businesses. For Endeavour Energy, this is coupled with the need to respond to unprecedented population growth in our region as the NSW State Government releases record areas dedicated to new housing and industrial development.

Our focus is to service customer growth and facilitate customer choice in an efficient and prudent manner in order to serve the long-term interests of customers. In developing our plans we have also sought to address recurrent challenges such as maintaining and replacing assets in a sustainable manner, managing bushfire risk, and providing a secure and reliable supply of electricity.

4.2 Customer growth

With the population of Western Sydney forecast to grow by 900,000 people over the next 20 years, we will service some of the fastest growing communities in Australia. Our network area includes the North West and South West Priority Growth Areas in Greater Western Sydney, which combined are projected to accommodate 500,000 new residents, the equivalent of two cities the size of Canberra or Wollongong, over the next 25 years. We expect to have almost 1.13 million customers connected to our network by the end of the next regulatory period.

Additionally, we will be expected to support the development of the Western Sydney Airport at Badgerys Creek and the large surrounding residential, commercial and industrial areas planned to support the Greater Sydney Commission's vision of a 'third city' for Sydney.

These priority growth areas and precincts are the result of the biggest coordinated land release in the state's history. Much of the forecast population growth will occur in areas where current infrastructure is limited and the network needs to be designed and built ahead of further development.

We perform a critical role in supporting this growth. Our plans and development management processes will ensure that we connect new development areas and customers to the network in an efficient and timely manner. Substantial network growth investment will be required to satisfy the spatial energy demand that is forecast from these growing pockets of our network. This investment will support a wider suite of Government plans and initiatives for promoting affordable housing, employment opportunities and economic growth in our network area. We will continue to work closely with state and local planning authorities and developers to ensure that our capital program is well targeted and sufficient to meet this expected growth.

The NSW Government's plan for growth in Sydney includes a vision for Western Sydney that will secure the city's productivity into the future – so that Western Sydney can meet its full potential, build strong centres and be an even greater place to live. Western Sydney will drive the future productivity of Sydney and NSW. This vision includes:

- growing Greater Parramatta as Sydney's second Central Business District;
- building new housing and urban renewal around strategic centres in Western Sydney;
- building on the investment and building opportunities provided by the Western Sydney Employment Area;
- bolstering economic development in strategic centres and transport gateways in Western Sydney, as well as the proposed enterprise corridors;
- connecting centres in Western Sydney to support their development; and
- building on the development of Sydney's second Airport at Badgerys Creek.

Investment in new transport infrastructure across Western Sydney, such as WestConnex, the North West Rail Link, Parramatta Light Rail and the upgrade of major roads and rail around the Badgerys Creek Airport Precinct, will provide more opportunities to foster economic development and deliver more jobs closer to where people live.

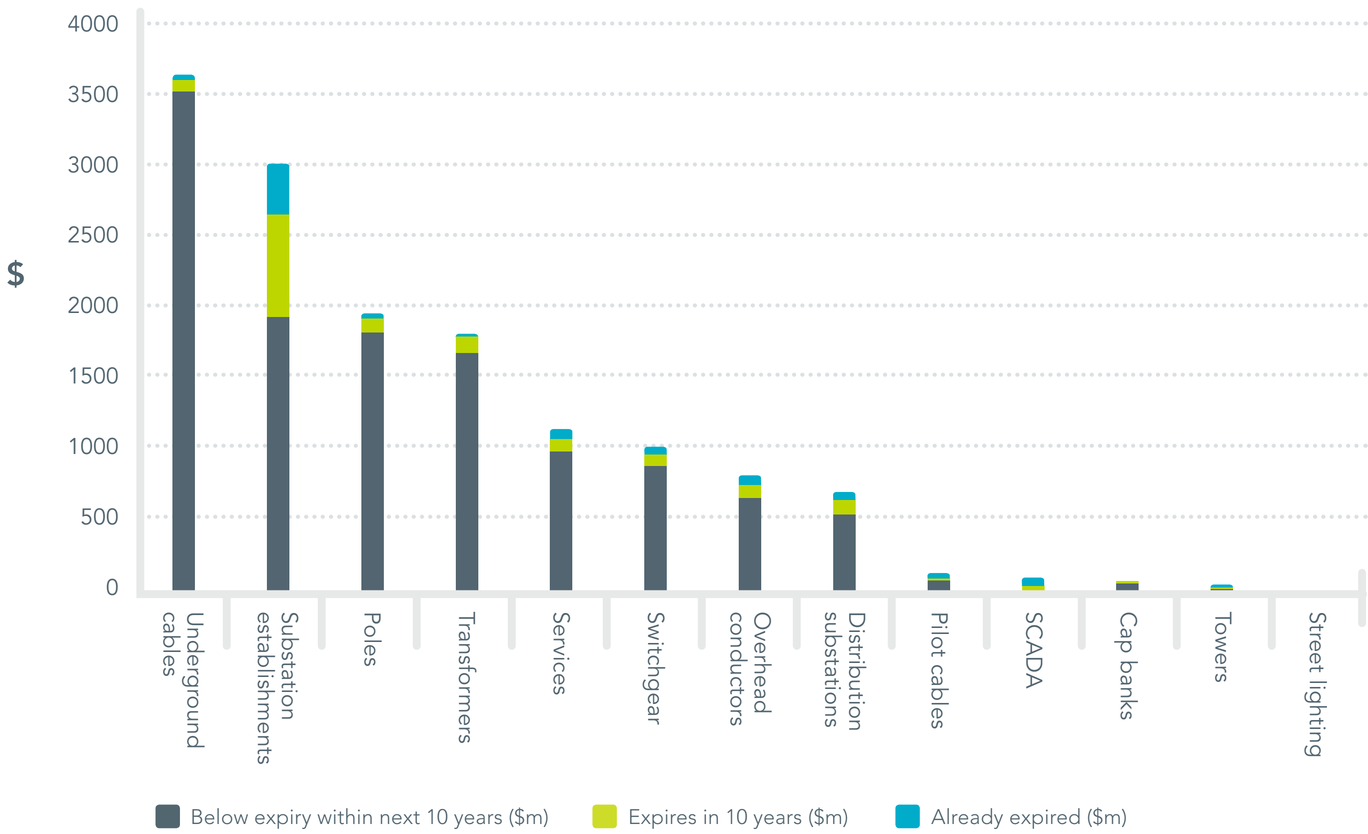
4.3 Ageing assets

The age of network assets is widely considered to be a sensible high level indicator of their general condition and ability to perform their intended function. Large parts of our network were constructed in the 1960s and 1970s primarily to support the expansion of Sydney's growing population to the west of the city. Many assets installed during this period are still in service and are rapidly approaching the end of their useful lives. This is a key driver of our replacement capex program and our reliability compliance capex.

Our top-down models, the Value Development Algorithm (VDA) model and the AER's replacement ('repex') model[3], indicate that we will need to continue to undertake asset replacement activities over the 2019-24 regulatory period. Our condition-based, risk-adjusted investment plans coupled with additional asset insight and condition data that will come with investment in new technology tools, support the intent of these models. Investment is required to address specific risks posed by the deteriorating condition of assets in critical asset classes beyond acceptable levels to ensure our network continues to deliver the safety and reliability outcomes valued by our customers.

Our probabilistic risk based asset management procedures seek to ensure we extract the maximum benefit from our assets before they require replacement. We keep assets operational past their useful life where it is efficient and safe to do so. This ensures our investment decisions are efficient and made in the long-term interests of our customers. Compliance with recent regulatory changes which require us to more transparently investigate and consider efficient non-network solutions as alternatives to network asset replacement will form a critical role in delivering services at the lowest long-term cost to our customers.

Figure 4.1 Endeavour Energy asset replacement cost value



3 Calibrated in accordance with the AER's approach in recent determinations. See Attachment 10.04 for further details.

4.4 Bushfire risk

Our network includes the World Heritage listed Blue Mountains National Park and many other National Parks along the South Coast. This means that when compared with many other networks, we have a significantly higher risk of bushfires, with the NSW Rural Fire Service estimating that more than 85 percent of our network area is bushfire prone. About 50 percent of overhead power lines and 36 percent of poles are located in these areas, along with millions of trees.

We take our safety responsibilities extremely seriously and as such we undertake a rigorous pre-summer bushfire program addressing all power lines in high bushfire risk areas. Each year, on average, we invest $40-50m to minimise bushfire risks to the community and repair identified defects to keep trees a safe distance from power lines.

The regular inspection of our network area includes three key elements:

Firstly, we complete annual routine maintenance checks ahead of the bushfire season and trim vegetation according to relevant standards and guidelines, the most significant being the ISSC3: *Guideline for managing vegetation near power lines*.

Secondly, we use helicopters fitted with high resolution imaging equipment to spot hazards from the sky and undertake capital and maintenance works to target high risk assets; and we also set firm targets to fix identified hazards ahead of summer.

Thirdly, we have rolled out the widespread use of light imaging radar technology since 2013 and as a result we check millions of trees and several thousand kilometres of network annually. In the past 6-8 months alone we've inspected 102,000 poles in bushfire prone areas and a further 47,000 poles from the ground.

This program forms one of the largest components of our operating expenditure and is essential to protecting community safety. Despite this, bushfires remain a fact of life for many Australians, and so this remains a high priority focus area for asset management.

4.5 New ownership

In mid-2017, Endeavour Energy transitioned from a wholly-owned NSW Government entity to majority new ownership by an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease. The private sector consortium comprised:

- Macquarie Infrastructure and Real Assets[4] on behalf of its managed or advised funds and clients (30.16%);
- AMP Capital on behalf of REST Industry Super (25%);
- British Columbia Investment Management Corporation (25%); and
- Qatar Investment Authority (19.84%).

The remaining 49.6% was held by the State of NSW.

Preparing for this change was a key focus of the business and the top leadership team throughout 2016-17. It also meant that the new owners of the business needed time to consider key aspects of our engagement plan and regulatory proposal against the consortium's business priorities.

This, and the desire to engage more deeply with stakeholders and customers about our plans for the next five-years, was a key factor in our request for an extension of three months in developing this proposal, which was granted by the AER in December 2017.

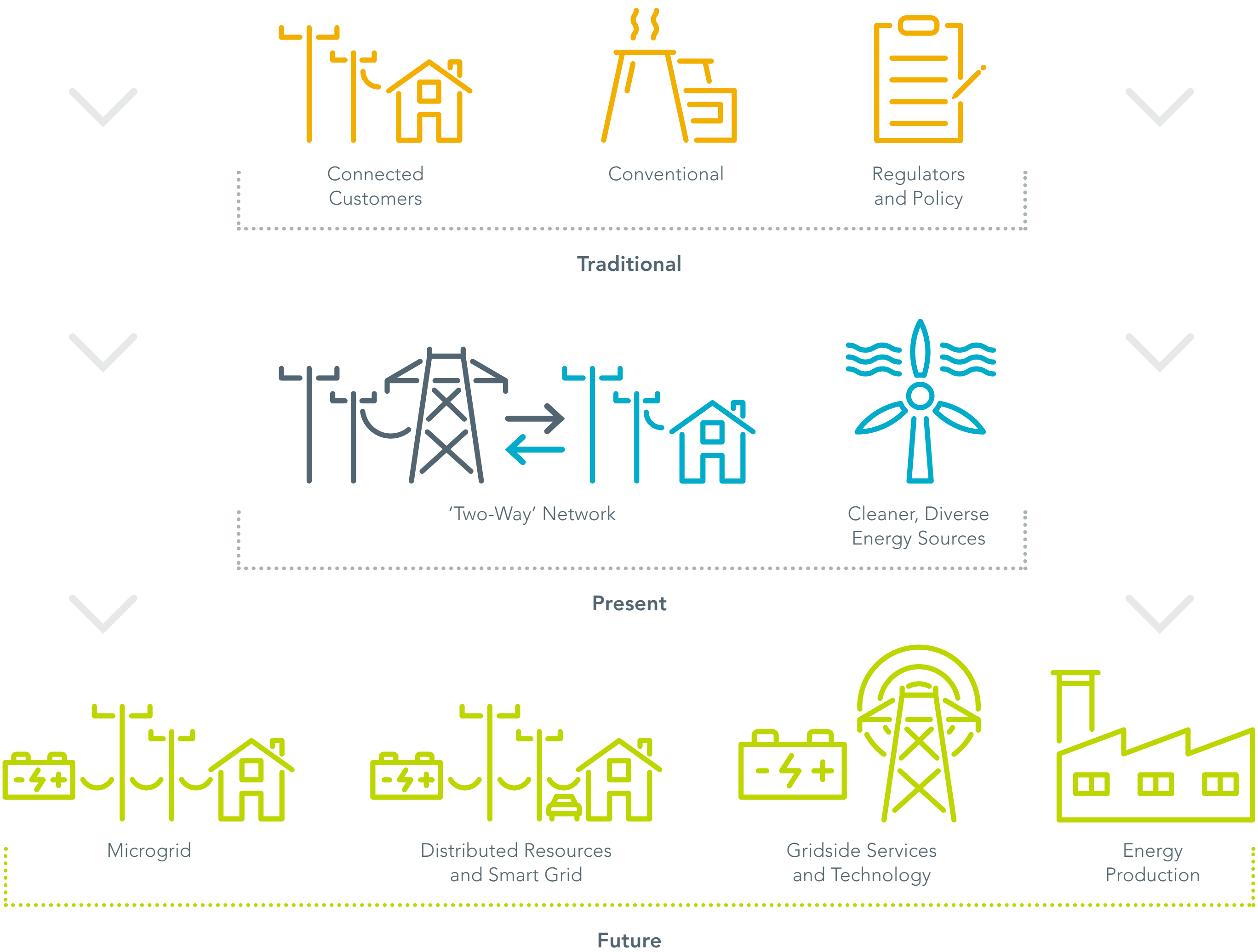
4 An operating division of Macquarie Group Limited

4.6 Market transformation

The role of a network business is changing rapidly from a centralised one-way distributor with limited customer involvement towards a model where customers decide energy investments, storage and usage patterns, as well as priorities and expectations.

How customers use, produce and value the services we provide is being impacted by the rapid uptake of solar photovoltaic (PV) panels, battery storage, access to usage data, reductions in costs for new technologies and an increasing desire to rely less on grid supply and avoid price volatility. The recent introduction of metering contestability reforms in NSW and the continued transition toward more cost-reflective tariffs further promotes this trend.

Figure 4.2 Traditional, present and future network



As a result, the conventional role of our distribution network to exclusively convey electricity downstream in a one-way energy flow is rapidly being challenged by the need to provide additional services to facilitate customer choice and control.

As customers begin to demand more choice and control over their energy usage, our network needs to evolve and become 'smarter' and more integrated to allow multi-directional energy flows which will foster successful energy transfer and trading among energy producers and consumers. This requires greater automation and control system integrity as well as innovative pricing structures.

This creates several challenges for networks such as Endeavour Energy. The existing network design and the assets employed are from an era where the energy supply model was vastly different to that which exists today, let alone tomorrow. Beyond replacing assets that have reached the end of their useful life with suitable modern equivalents, opportunities need to be taken to reshape the network design using modern technology assets, such as batteries and more sophisticated monitoring and switching devices which are more suited to changing customer end-use requirements.

To meet this challenge we are integrating these technological developments and changing customer requirements into our network investment planning considerations and evaluating opportunities presented from leveraging the current and potential future technological advances.

We are committed to exploring the tools and operational processes that will be necessary for us to meet our regulatory obligations as DER becomes an increasingly prominent feature of our network. Whilst our focus will remain on providing the services that our customers value efficiently, we plan to position our network to respond positively to meet the changing requirements of our customers.

4.6.1 Our role in a more efficient market

Network solutions

Our view of the capabilities required from our network and the investment required to meet these expectations is guided by the ENA/CSIRO's Electricity Networks Transformation Roadmap (ENTR). The Roadmap predicts growth in DER will lead to significant changes in Australia's electricity system by 2050 including greater power for customers, who will produce 45 percent of generation in the National Electricity Market, while retaining electricity supply security and reliability essential to lifestyle and employment. The Roadmap forecasts that this would save $16 billion in network infrastructure investment and a reduction in cumulative total expenditure by electricity networks of $101 billion.

Figure 4.3 ENTR balanced scorecard of customer outcomes

The Roadmap's implementation plan broadly aims to enable greater efficiency across the electricity supply chain by enabling multilateral exchanges of energy, information and value. It also aims to effectively incentivise and enable new customer choice and control whilst preserving customer protections and avoiding unfair impacts on vulnerable customers. The plan has been informed by the CSIRO's energy system analysis and wide stakeholder collaboration, and is designed to equip networks to deliver on a scorecard of five key customer outcomes.

Delivering on the Roadmap to achieve a positive energy future enabling customer choice, lower costs, high security and reliability from a cleaner electricity system by 2050 will require the ongoing renewal of our network to transform it from its traditional bulk-generation to end-use supply framework to become a neural network of interconnections of multiple distributed generation sources, peer-to-peer energy transfer solutions, and to meet the emerging requirement for bulk and distributed energy storage.

We will achieve this through integrating traditional network supply arrangements with DER, and enabling the provision of energy storage capability to assure supply security. We intend to commercially integrate supply side and demand side technology by assessing new products and finding new ways to leverage the connectivity of the network, implementing cost efficient asset monitoring systems to capture and analyse asset information, and introducing pilot network connected energy storage projects.

Non-network solutions

We recognise that non-network options are critical to providing lowest cost outcomes for our customers. We have developed a demand management and non-network options strategy with the key objective of investigating alternative options and integrating these into our network planning process. The strategy has an overarching goal of minimising peak demand drivers of network investment by incentivising customer behaviour and widespread adoption of alternative energy supply technologies and energy efficient equipment.

We have been investigating the potential of demand-side participation to alleviate network capacity constraints through multiple initiatives over the past decade, ranging from pay-to-curtail demand response agreements with major customers in constrained areas, through to broader based, end-use, load management trial programs. In 2000, we were the first DNSP in Australia to run an air conditioning cycling program as part of a trial investigating Demand Response Enabling Devices (DRED). We also trialled a Dynamic Peak Pricing product as part of the Blacktown Solar Cities (BSC) program, which sent a high price signal to customers during peak demand to encourage energy reductions. Following this, the PeakSaver program sought to financially reward customers for reducing energy consumption during peak times rather than penalising them with high prices. This program was also the first of its kind in Australia.

As our network transitions to support increased DER integration, and tariff reform and greater metering capabilities are introduced, we expect that our customers will signal a growing appetite for more active demand-side participation. We expect the role of our network in providing the aggregating capability necessary to fully leverage the capacity of DERs in a coordinated manner will become central to the success of future demand management programs.

The future focus on demand management initiatives will be centred on technology-enabled, end-use response mechanisms such as that offered by DRED-compliant appliances, as well as financial incentives focused on mechanisms such as time of use tariff arrangements.

Overcoming barriers and trialling new ideas

Despite widespread consensus on the potential for small scale renewable generation and battery storage to be used effectively to reduce peak demand from the grid, the impact of these units on curtailing network investment to date in our region has been limited. This is largely due to peak demand on our network (generally from 4pm-8pm) not aligning with periods of energy production from these units where peak production occurs early afternoon but rapidly reduces to minimal output by the early evening.

In support of the role our network will play in shaping the future electricity landscape, we are currently conducting battery energy storage trials. Through these trials we will have a better understanding of how battery storage could be used to complement grid supply during times of peak demand and avoid costly network investment. In turn, this will confirm the viability of new opportunities to use the existing network in new and exciting ways.

*Solar*Saver residential battery storage

This battery storage trial involves a number of residential customers within our North West Priority Growth area who have had a battery energy storage system installed within their premises. Known as the *Solar*Saver program, the trial aims to identify customer uptake levels and quantify network demand reduction. We are using third party suppliers to help us with the trial, with the storage system owned by the customer.

Under the trial, customers have been and will continue to be incentivised to install energy storage in a future constraint area of the network. In return, the customer allows us to remotely control the operation of the system during peak days to aid in peak demand management. Customers are able to use the battery outside of event days in a manner of their choosing. The trial will run for two summer periods commencing the past summer of 2017-18.

Grid scale battery storage – the largest in NSW

We are investigating an innovative method to provide capacity for the first stages of new release areas. This has traditionally been addressed by mobile zone substations or full substation builds. A grid scale Battery Energy Storage System (BESS) will potentially allow modular and rapid deployment of network capacity increases to defer network investment.

As a signal of our support to the burgeoning non-network service sector, we have awarded the contract to design, build and install the BESS to MPower. The BESS will be installed on a site reserved for a new zone substation at West Dapto to connect into the existing 11kV network.

With the system rated at 1MWh, it will be the largest grid support battery to be installed in NSW. The battery will charge during low load times and discharge during high load times, such as afternoons and evenings. Our network team is also investigating the potential for the battery to regulate voltage and run a small area in 'island' mode when required. If successful, the project could defer future network investment and will contribute to keeping costs down while providing reliable supply sooner to customers.

5.0 Customer-focused Decision Making

CHAPTER 5

5.1 Overview

We worked hard to improve engagement with a diverse range of customers and stakeholders and to reflect their interests in our plans. We've kept downward pressure on network charges, simplified tariffs for customers and retailers, and priced street lighting to encourage LED technology for councils.

The views of our customers and stakeholders have significantly shaped this revenue proposal.

Our goal for this proposal has been to substantially improve our engagement approach to better reflect customers' long-term interests.

We have built on the extensive customer engagement processes we undertook for our 2014-19 regulatory proposal and our first tariff structure strategy. We have also tried some new engagement techniques.

When the 2017 transaction process diverted significant resources from engagement we responded to the AER's Consumer Challenge Panel feedback that more engagement was needed to support our revenue proposal and sought an extension of time from the AER to complete further customer engagement.

We responded by leading a series of 'deep dive workshops,' designed to examine our capital and operating expenditure plans and tariff strategy in great detail with AER representatives and all stakeholder groups.

The process proved highly effective, and along with other engagement processes, helped refine and improve our proposal and customer outcomes.

5.2 Our commitment to customers

Our Customer Commitment Statement was initiated by our Board several years ago to serve as a public reminder that customers are central to our business success.

We worked with employees, our Customer Consultative Committee and external customer advocates to develop the statement below. We strive to give life to this statement in our day to day operations.

Our job as a poles and wires business is to deliver electricity safely, reliably and efficiently. Our commitment to customers is that we will:

Listen

- to understand their needs;
- to act and address their feedback; and
- to provide service that is courteous, fair and professional.

Respect

- their safety and well-being;
- their diversity and the communities in which they live; and
- their property and privacy.

Deliver

- on our promises;
- information that is clear and timely; and
- our services safely and efficiently and be easy to deal with.

5.3 A new approach

Our goal over the past two years has been to build on the extensive engagement we've undertaken since 2012 and improve our engagement to better reflect customers long-term interests.

In designing our engagement strategy, we set these objectives in conjunction with customer representatives:

- Listen, to understand customers' and stakeholders' energy priorities in order to build a credible and acceptable regulatory proposal for the five-year period 2019-24.
- Improve our relationship with key stakeholders through trusted dialogue.
- Build the capacity of customers and stakeholders to participate in the regulatory process.
- Enable customer needs for choice and control over energy decisions, given changes in technology.
- Strengthen and embed improved engagement practices at Endeavour Energy following an independent review into our engagement approach.
- Align engagement to support customer initiatives set out in the Electricity Network Transformation Roadmap April 2017, published by CSIRO and Energy Networks Australia.

After several years of relatively intense engagement, we believe we have largely achieved these objectives. More importantly, our plans deliver key customer priorities of affordability, safety and reliability.

In setting a course to improve engagement, we benchmarked our approach against international utilities, sought expert advice, broadened the involvement of our top team and increased engagement resources.

We spent more time consulting and less time informing. We listened harder, adjusted our plans in response, and were disciplined in closing feedback loops.

We adopted a principle of 'no surprises' and focused conversations on tough issues in our expenditure proposals, explaining risks and trade-offs to identify realistic alternatives where possible.

This helped to build genuine respect and understanding, and narrowed the gap where opinions differed.

We also held regular formal and informal 'engagement health checks' with key consumer groups and the AER's Consumer Challenge Panel and adjusted our approach and plans in response.

We engaged on a wide range of topics including defining customer priorities, customer communication, the role of networks versus retailers, tariff design, understanding electricity bills, reliability and affordability, price/service trade-offs, risks associated with our operations, our capital contributions policy, the type of services we provide, solar and batteries, industry transformation and plans for the future and technology to help customers manage energy usage.

Through an intense program of one-on-one meetings, interviews, teleconferences, customer forums, focus groups, online communities, facilitated deliberative planning workshops and deep dive workshops, customers and stakeholders have helped us to prioritise expenditure and shape our plans for 2019-24.

We engaged across a broad range of end-use customers, business partners and stakeholders, as illustrated in this diagram:

Figure 5.1 Endeavour Energy's customer and stakeholder segments

5.3.1 Key aspects of our new approach

You can find detailed reports of all our key engagement initiatives and research reports at www.endeavourenergy.com.au, and Attachment 5.01 to this proposal. We have provided a summary of the key initiatives below.

Deep dives

We pioneered a new engagement process as part of our extended engagement program that led to three full-day 'deep dive' sessions with multiple stakeholders. This was the first time the AER's technical teams, the AER's Consumer Challenge Panel, and key customer and stakeholder representatives came together with senior managers to review a more detailed exploration of the evidence and underlying assumptions used to justify our operating and capital expenditure plans, along with a break-down of costs allocated to specific programs.

The process centred on open, respectful conversations following presentations by our leadership team, with content focused on the underlying costs of investment. Each deep dive presentation outlined the material facts, the acceptable performance standard and risk appetite and the efficient costs to deliver the work.

The analysis focused on evidence of informed support from customers on expenditure plans and consideration of customer and stakeholder feedback. Workshop agendas were designed by participants, independently facilitated and weighted to give one third presentation time and two thirds discussion by participants. Each workshop featured strong feedback loops and interactive conversations.

This initiative helped to build shared understanding and trust across multiple stakeholder groups; developed a deeper appreciation of the risks and price/service trade-offs to manage; explored alternatives to traditional network solutions; and ultimately reduced our capital expenditure proposal by around $80m. It also kept downward pressure on network charges and led to improved tariff strategy design following feedback from retailers and customer advocates.

We achieved an average ranking of 87 percent in participant evaluations for the course structure, content and facilitation, exceeding our target of 75 percent. A number of stakeholders said they thought we needed to do more to justify aspects of our capital program and want a fairer capital contributions policy that does not burden existing customers, and we intend to continue to engage with them and set up an industry working group.

The deep dives provided Endeavour Energy with some valuable insights and challenged our thinking. Based on the strength of the process and feedback, Endeavour Energy plans to embed the 'deep dive' process into its long-term engagement strategy. A detailed report of the deep dive workshops can be found in Attachment 5.01 to this proposal.

Peak consumer group engagement

Targeted consultation helped to strengthen trust, understand priorities and refine areas for further engagement. A concerted effort was made to prioritise key stakeholders and engage with them in a more collaborative manner. We prioritised particular groups due to their willingness to be engaged, considerable industry and regulatory knowledge, and their ability to influence regulatory and consumer policy outcomes.

Feedback from the AER's Consumer Challenge Panel (CCP)

Frank, constructive and challenging feedback from the AER's CCP has directly influenced our approach to engagement and helped to generate improved customer outcomes. The objective of the CCP is to advise the AER on whether our proposal meets the long-term needs of customers; the effectiveness of engagement activities and whether customer feedback has been reflected in our proposal. The CCP encouraged Endeavour Energy to undertake more focused engagement across the building blocks of our regulatory proposal, better explain why we needed to make certain decisions, simplify customer communication, and better explain what is changing and why. We worked collaboratively with panel members and peak consumer groups to scope workshops and to then 'deep dive' into various aspects of our expenditure plans. As in the past, we also worked with our Customer Consultative Committee (CCC) on key aspects our proposal.

Independent audit of engagement

In late 2017 we completed an independent audit to assure the Board our engagement program met the *AER's Customer Engagement Guideline for Network Service Providers (Nov 2013)* and relevant sections of the National Electricity Rules. The audit found we complied with the principles set out in the *Guideline*. Furthermore, the auditor's independent discussions with key stakeholders from the PIAC, WSROC and CCP provided us with positive feedback on the overall engagement process followed by the business. The AER's CCP welcomed this new initiative and noted the significance of Board's support for the independent review.

The audit recommended further updates to our engagement strategy, and development of key performance indicators ahead of engagement initiatives being undertaken, which we have started to action.

Increased executive involvement

Our 2016 formal engagement review recommended greater involvement of our leadership team to demonstrate organisation-wide customer commitment and to provide direct access to decision makers. Following the lease transaction, Executives led bi-lateral meetings with priority stakeholders on our *Directions Paper*, chaired peak consumer group discussions, and led presentations at focus groups, deliberative forums and deep dive workshops. They were able to listen to the priorities and concerns of our customers and stakeholders first hand, and provide immediate feedback on our plans. Their knowledge was crucial in explaining key concepts and building trust with customers and stakeholders.

Focus groups

In May 2017, ten customer focus groups involving up to ten residential and small to medium business customers helped identify customer priorities and attitudes about electricity. Findings were used to shape proposed content for two larger deliberative planning forums held in August. Not surprisingly, affordability featured as the key issue across all customer groups, along with a keen interest in new technology such as solar and batteries as a means of 'regaining control' over their electricity bill. As a result of these groups we also developed 10 priority issues for further exploration.

Directions paper

In line with our commitment to 'no surprises', this new initiative was designed to increase the transparency of our proposal and engage informed stakeholders at an earlier stage in the proposal development. A detailed communications plan of one-on-one conversations was led by our Executive team to support feedback on the Directions Paper. As a result we met with major retailers, peak development groups, business chambers, state and local government and peak consumer groups.

While we received encouraging feedback on this initiative, it was constrained in its effectiveness by the significant effort required by Endeavour Energy's top team to support the transition to changed ownership.

Test focus groups and CCC engagement regarding materials for forums

These two engagement activities were conducted in the two weeks leading up to the deliberative forums. We road tested the discussion guide and the customer materials which we planned to present to customers regarding price/service trade-offs and tariff options. Feedback from the AER Consumer Challenge Panel, and Energy Consumers Australia in particular led us to sharpen communications around tariff options and price/service trade-offs, delivering our most effective communication to date on this issue. This greatly aided customer understanding of the trade-offs they could make to reduce their bills.

Online community

We responded to low levels of customer understanding about the industry ahead of the deliberative planning forums with online communities in early August 2017. The community was designed to both educate customers about the role of Endeavour Energy and attain feedback through questions ahead of the deliberative planning forums.

Deliberative planning forums

These formed the centrepiece of engagement on customers' responses to cost reflective pricing and different tariffs. We learned that customers supported cost reflective pricing but were concerned to better understand how and when different tariffs would impact their bill. They wanted to retain the choice to opt out of time of use pricing to a flat tariff. Around 100 end use customers segmented over vulnerability, solar and small to medium enterprises explored key themes of safety, reliability and affordable electricity, our plans to meet electricity demand in new growth areas, and enabling customers' future energy choices. We used the learnings from these forums as input to consultations with retailers, who asked us to simplify our proposed tariffs. Following further engagement with customer advocates in the tariff deep dive, we took steps to modify our proposed tariffs.

Targeted retailer meetings

In late August 2017 we met with our top five retailers to seek their feedback on our Directions Paper and tariff proposal. They asked us to prioritise simplicity for customers and this resulted in significant adjustments to our original tariff proposal.

Knowledge review

In late 2016 we participated in a joint knowledge review with Ausgrid and Essential Energy to take stock of the large body of existing research on electricity customers' priorities and preferences, and tariff and pricing trials. This enabled us to leverage a wide body of existing research. As a result, we decided to focus our investment on specific gaps in the research. We worked with Queensland University of Technology and Brisbane City Smart on customers' behavioural approaches to tariff strategies, learning that some family types are predisposed to taking charge of electricity use, while others will always do their own thing. This research, jointly funded by Energy Consumers' Australia will greatly help all parts of the business to understand customer decision making about energy use.

Framework and Approach Issues Paper, Stakeholder Workshop and Webcast

In September 2016 we held a stakeholder workshop to outline our initial views on changes to the Framework and Approach (F&A) for the 2019-24 regulatory determination, seek feedback on our views, and ascertain from stakeholders whether further changes were required. The engagement was attended by consumer advocacy groups, retailers, regulators and electricity distributors, and interstate participants took part through a webcast. The workshop followed publication of an issue paper which set out Endeavour Energy's thinking on the F&A, and invited responses and invited feedback.

5.3.2 The response to our new approach

The following quotes are provided to illustrate the type of feedback we received about our new techniques and approach through formal evaluations, correspondence and independent stakeholder surveys. While feedback has generally been positive about the process, several stakeholders noted they intended to reserve judgement to see how well our proposal reflected their feedback following this engagement approach.

"Very productive, well facilitated and covered good content." Deep dive feedback

"Great job! Excellent work in progressing the key conversations productively. Left me feeling positive about getting to a point of mutual understanding on big issues (and some of the small ones)." Consumer advocate in the first deep dive

"Very interested with the dedication and openness of the workshop and the support provided by senior management. A very valuable day which I believe achieved the desired effect." Customer Consultative Committee member, following the first deep dive

"I like that you are keen to involve the customers and keep us informed. Great company and more positive about who is looking after us." Customer at a deliberative forum

"Keep listening to your variety of customers and remember those who struggle to pay for electricity." Customer at a deliberative forum

"Great video that put into perspective what is involved in maintaining the electricity network and how much work is required in having a reliable electricity network." Deliberative forum participant

"Thank you for considering our opinions and ideas. Yes the vulnerable people are our responsibility." Deliberative forum participant

"We welcome the opportunity for WSROC and its councils to provide feedback, ideas, information and expertise to assist in better regulation of our energy provision through Endeavour Energy." Written submission to our directions paper, Western Sydney Regional Organisation of Councils.

"PIAC has been engaging broadly with Endeavour Energy over recent months. This engagement has covered issues including tariff design, deliberative forum content and consumer engagement strategies. PIAC considers this submission to be a further positive step in this engagement process. The submission addresses the feedback questions raised in the directions paper." Written submission to our directions paper from Public Interest Advocacy Centre

"I support your efforts to improve Endeavour Energy's engagement with customers and stakeholders, including the NSW Government." Written submission to our directions paper from Carolyn McNally, Secretary, NSW Planning and Environment.

"They are willing to engage with the industry. The CEO makes himself available to us and we have a pretty open dialogue."
Stakeholder survey – Business to Business representative

"There are various forums for the councils and we always get Endeavour to attend and they send the right calibre of person so the issues can be addressed at the forum. They send the right people to provide the right answers."
Stakeholder survey – Councils

"They're good or better than others. They're very good at maintaining a degree of professionalism as well as a reliable network. Our relationship has improved over time and our relationship with them as a retailer has been good. I don't give perfect scores but there's nothing that springs to mind that erodes that ranking." Stakeholder survey – Business to Business representative

"We approach everyone with an open mind but some people respond to us better than others. Endeavour Energy respond in a way that makes it easy to deal with them. We don't have to follow up, they're prompt and professional in their responses." Consumer and Environmental Advocates

The key phases of our engagement program are summarised below.

We have engaged extensively with a diverse group of customers and stakeholders using a variety of communication channels and engagement practices in developing our expenditure and pricing plans.

Although we have gone beyond regulatory requirements to pursue best practice in engaging with our customers and stakeholders, our approach was guided by the AER's Consumer Engagement Guidelines and IAP2 Public Participation spectrum. Broadly, this involved setting out:

- our engagement objectives, including building the capacity of customers and stakeholders to participate in the regulatory process;
- who we should engage with, and how that engagement should be best tailored to their concerns, knowledge and priorities;
- how we should engage with each 'group' within our customer and stakeholder base;
- what we should engage with them on; and
- how we would respond to the feedback received.

Because residential and small business customers tend to have a lower awareness of who we are and our role in the energy market, we provided them with comprehensive and accessible information on our role within the energy supply chain, the costs associated with our role and the nature of the regulatory framework. We also focussed on broader topics such as energy affordability, tariff structures, service levels, customer priorities and the transformation of the electricity industry due to new technologies.

Comparatively, stakeholders such as retailers, developers, peak consumer groups and local councils are more familiar with Endeavour Energy and expect deeper and more sophisticated engagement.

In light of their differing requirements, we introduced a Directions Paper which set out our early thinking on a wide range of issues specific to these groups. We received universally positive feedback for this initiative.

Establishment phase	
January – June 2016	• Reviewed our engagement. approach from our previous regulatory proposal against international utilities and decided to use more informal approaches to increase participation. • Mapped the stakeholders and consumer groups we needed to engage with. These included the AER's Consumer Challenge Panel (CCP), Public Interest Advocacy Centre (PIAC), NSW Council of Social Services, Energy Consumers Australia, Ethnic Communities Council and Total Environment Centre. These groups were prioritised due to their willingness to be engaged, considerable industry and regulatory knowledge, and their ability to achieve positive regulatory and consumer policy outcomes. • Began a strategic review of our Customer Consultative Committee • Partnered with Brisbane City Council and QLD University of Technology to better understand consumer behaviour around tariff reform.
Research phase	
June – December 2016	• Review of Australian research to understand how consumers and stakeholders wish to be engaged in the electricity sector (in partnership with Ausgrid and Essential Energy). The CCP encouraged Endeavour Energy to undertake more focused engagement across the building blocks of our regulatory proposal including working collaboratively with Panel Members and peak consumer groups to scope subject-specific reference groups and to then 'deep dive' into various aspects of our expenditure plans. • Increased executive involvement to help place customers at the centre of decision making priorities. Executives led bi-lateral meetings with priority stakeholders on our Directions Paper, chaired peak consumer group discussions, and the then Acting CEO Rod Howard being the main presenter at our test focus group and deliberative forums. Executives also attended all focus groups and deliberative planning forums. They were able to listen to the priorities and concerns of our customers and stakeholders first hand, and their knowledge was crucial in explaining key concepts and building trust with customers and stakeholders.

Engagement Phase 1 – Developing strategies and plans	
January – December 2017	**Consumers:** • Improved engagement communications (based on feedback from AER Consumer Challenge Panel), including consultation on customer materials which we planned to present to customers regarding price/service trade-offs and tariff options. Feedback from the AER Consumer Challenge Panel, and Energy Consumers Australia in particular led us to revisit communications around tariff options and price/service trade-offs presented to customers. This feedback fundamentally changed aspects of the presentation and materials for the better. • Ten focus groups to explore residential and business priorities. Findings were used to shape proposed content for two larger deliberative planning forums held in August. Test focus groups and CCC engagement regarding materials for forums. • Deliberative planning forums and an online community for residential and business customers. The deliberative planning forums were prefaced with online communities in early August 2017 in response to relatively low levels of understanding amongst customers. The participants in the online community were the same 95 customers who attended the deliberative forums that were held the following week in Wollongong and Parramatta. The community was designed to both educate customers about the role of Endeavour Energy and attain feedback through questions and activities related to their electricity usage, plans for solar and batteries, desire to adopt new technology, vehicles, reliability and future grid. At the forums, end use customers were segmented over vulnerability, solar and small to medium enterprises and explored key themes of safety, reliability and affordable electricity, our plans to meet electricity demand in new growth areas, and enabling customers' future energy choices. **Informed stakeholders:** • Forum to explore changes to the Framework and Approach for the 2019-24 regulatory determination. • Peak consumer groups and retailer roundtables. • CCC meetings and growth centre site visit. • Engagement with Regional Organisations of Councils and councils re: street lighting and tariffs. • Targeted retailer meetings with our top five energy retailers to seek feedback on our Directions Paper, with discussions focused on pricing and affordability, tariff design, metering roll outs, customer research and battery trials. • Published a Directions Paper to set out our high level plans and invited feedback on the Paper. This new initiative was designed to increase transparency of our overall approach and engage informed stakeholders at an earlier stage in the proposal development. • Board commissioned internal audit of engagement against AER Consumer Engagement Guideline. The audit recommended a further update to our engagement strategy, and development of key performance indicators ahead of engagement initiatives being undertaken.

Engagement Phase 2 – Intensive engagement with stakeholders on the details of our regulatory proposal

January – December 2018	• Sought a three month extension from the AER to undertake more intense engagement on the detail of proposed capital and operating expenditure with informed stakeholders as we did not feel we had had sufficient time to demonstrate customer support for our plans due to the large effort needed to transition to private ownership in July 2017. • Pioneered a new engagement process called 'deep dives' with the AER, the AER's consumer challenge panel, state and local government, retailers and consumer advocates to test that our plans were based on sound evidence and justified by customer feedback. • Continued one on one meetings with our regulator, retailers, councils and customer groups to listen and respond to feedback. • Our proposal will now be submitted by 30 April 2018 and we will continue to hold conservations and invite feedback.

5.3.3 What we heard from our customers and how we intend to respond

What customers and stakeholders said:	What we will do in response:
Affordability Affordability is the number one concern for many of our customers, but not at the sacrifice of safety or reliability. Electricity is valued because it provides security and lifestyle benefits to residential customers and communities, and because it connects new homes and underpins prosperous businesses and regions. There's a clear expectation that Endeavour Energy's plans should reflect measures to continue downward pressure on our part of electricity bills by containing capital investment, without compromising safety.	• Deliver a decrease in network charges of one percent each year, in today's dollars, for the period 2019-24. This figure includes our proposed remittal. • Deliver these decreases while implementing pricing reforms that will provide increased opportunities for customers to control their bills. • Lock in and maintain our real price decreases throughout the next regulatory period building on our demonstrated history of responding to incentive regulation. • Return $240m (FY19 dollars) to our customers through these reduced charges during the next regulatory period. • Continue to reduce underlying costs which will continue to reduce prices for customers. • Deliver real price decreases for our public lighting customers. • Encourage greater efficiency in the way our network is used by introducing an opt-out seasonal demand tariff for new customer connections. • Offer customers who replace their old basic meter with a smart meter the opportunity to opt-in to our seasonal demand tariff to secure the savings it can offer. • Promote programs such as SolarSaver and CoolSaver to educate customers through tangible personal experiences about what smart meters, batteries and pricing can offer them. • Facilitate the connection of distributed energy resources including solar and batteries to help consumers control their bills.
Reliability Customers were generally satisfied with current reliability with most customers, on average, having supply 99.9% of the time. Customers do not want bills to increase to fund improved reliability, nor are most willing to trade lower bills for lower reliability.	• Focus on maintaining reliability across the existing network and limiting reliability improvements to the poorest performing areas, consistent with licence conditions. • Trial new technology such as battery storage so that reliability is not compromised as we connect and utilise new generation and storage technologies in accordance with the CSIRO/ENA Electricity Network Transformation Roadmap. This industry roadmap is designed to prepare electricity distributors for a dramatically different future and save customers money.

What customers and stakeholders said:	What we will do in response:
Safety and Security Customers are concerned about the impact of extreme weather events on the network. We also have an obligation to protect customers from cyber security risks and this requires investment in new technology.	• Ensure asset management strategies are robust, but efficient, with capital and operating expenditure designed to deliver a safe, reliable and secure network. • Promote demand management technologies to delay and offset capital investment. We will continue to implement technology trials (such as our battery storage initiatives in West Dapto and Sydney's North West) and use lessons from these in our future decisions.
Fair pricing Customers understand they can benefit from new 'user pays' ways of charging for electricity. They generally support transitioning to more efficient, cost reflective pricing with an opt-out option to the existing flat tariff as it gives them choice and control. Customer groups had concerns that charging windows were too wide and included shoulder periods, which could dilute pricing signals while retailers wanted simplicity and uniformity in order to be able to develop a marketable product and pass through our tariffs to customers.	• Introduce a seasonal demand tariff. • Replace seasonal TOU energy charging with a flat energy rate to simplify our proposed seasonal demand tariff structure. • Give customers greater ability to respond to price signals by shortening our peak demand window from 1-8pm to 4-8pm on business days. • Assign all new customers and existing customers who upgrade their network connection to three-phase or bi-directional flow, to the cost-reflective tariff with the option to 'opt-out' to the flat energy tariff. • Make the transition as easy as possible for customers with a ten-year transition for the 'opt-out' seasonal demand tariff and introduce a voluntary seasonal demand tariff with no transition period. • Work with retailers to help educate customers on tariff choices and with the industry as a whole to facilitate uniformity of tariff design in response to retailers' feedback.
Growth Business groups, councils and developers want timely and affordable construction of new networks to facilitate housing, jobs and growth and have clearly advocated this as a priority. Customer advocates want a fairer capital contributions policy that does not burden existing customers. They feel it is appropriate for the beneficiaries of capital investment to pay for that investment.	• Ensure demand, energy and customer growth forecasts are robust using the latest available information, independently verified methods and expert economic advice. • Make better use of demand management programs to offset capital expenditure required for each project. • Use existing network capacity (where feasible) or temporary and mobile substations to stage new infrastructure builds. • Coordinate growth investments with asset renewal projects to achieve scope efficiencies. • Continue to minimise the costs to all customers for new connections. • Commit to supporting a 'beneficiary pays' framework for capital contributions. • Commit to developing an industry working group to further consider capital contributions policy.

What customers and stakeholders said:	What we will do in response:
Transformation, choice and control Customers are keen to know more about smart meters, solar and batteries as a means to reduce/manage their consumption and their bills, and want our network to be ready to meet their future energy needs. Local councils have shown strong support for investment in new, greener technology, such as extending battery storage trials to include council and commercial premises, and want a grid prepared for electric vehicles. Stakeholders expect Endeavour Energy to be innovative and trial new technologies, largely to keep downward pressure on capital expenditure, to prepare the grid for greater customer choice and to improve sustainability.	• Prudently invest in new technologies to improve automation, asset information, communication and monitoring systems, increasing our capacity to host distributed energy resources, including electric vehicles and utilise demand side response to manage network demand. • Align our direction with the CSIRO/ENA Electricity Networks Transformation Roadmap to provide more choice and control for customers and reduce the need for network investment in the long-term. • Partner with local councils on technology trials and initiatives to reduce urban heat. • Prepare the network so customers can connect and use new technologies to offset their own usage and feed excess back into the network for the benefit of other Endeavour Energy customers.
Vegetation management Customers generally want us to maintain the status quo with vegetation management, with safety to take priority over appearance, although councils would like to see more sensitive tree trimming in the interests of amenity and urban heat.	• Maintain our current approach on vegetation management and bushfire prevention using laser scanning technology and aerial patrols to identify trouble spots where trees may impact reliability and act on these areas as a priority. • Partner with councils to jointly promote planting of appropriate species under power lines and the relocation of assets at their cost.
Vulnerable customers Vulnerable customers want us to keep network costs as low as possible. Assisting the vulnerable is seen as the responsibility of the whole energy sector, particularly retailers. Customers have told us we should focus on assisting life support customers, as they depend on reliable power for life-sustaining medical equipment. Customer advocates encouraged us to take a broader view of vulnerability beyond life support customers.	• Propose network prices that keep bills predictable for all customers. • Minimise the risk of outages for 'life support' and other vulnerable customers, through improved technology and information. • Continue our business efficiency programs to reduce costs, which translate to savings for all customers.

What customers and stakeholders said:	What we will do in response:
Street lighting Local councils strongly support the roll out of LED street lights and would like to see earlier details of pricing, replacements, repairs; and explore future technologies to assist in their decision making. Endeavour Energy should provide a clear plan for LED replacement in its proposal.	• Propose an overall real reduction in public lighting charges in the order of 8% followed by annual CPI increases until the end of the period. This reflects the flow through of our operating cost reductions and the lower rates of return in the current market conditions. • Propose to introduce a pricing differential between LED and non-LED technology of 15% to reflect the expected maintenance savings from the increased density of LED lighting. We expect that the network pricing benefits and energy cost savings will see all councils increase their take-up of LED lighting in their areas. • Deepen future engagement with councils on issues relating to long-term planning, street lighting technologies and the future of the grid.
Education and engagement Increased education and consultation are seen as important in building trust and addressing issues such as bill impacts, reducing peak demand, consumer empowerment and ensuring that the roll out of assets is timely and meets demand. The AER is seeking a frank, respectful and open conversation on customer benefits, risks and trade-offs.	• Implement a 'no surprises' approach to our expanded engagement program with all stakeholders. • Work more closely with retailers on customer education to increase their understanding of pricing and managing consumption. • Strengthen our relationship with Regional Organisations of councils to assist them in their various local government initiatives such as reducing urban heat, street lighting and vegetation management. • Adopt a long-term approach to engagement and embed effective processes in our day-to-day operations in order to keep customers' interests at the centre of our decision making.

Key customer outcomes generated as a result of engagement

This proposal benefits customers' long-term interests through:

- **Affordability** – for the period 2019-24 network charges will decrease by 1% each year in today's dollars. This will help keep our part of the bill stable and predictable.
- **Safety** – We'll continue to design and operate our network to standards that protect the safety of all workers, our customers and the communities we serve. This includes programs to minimise bushfire risk.
- **Reliability** – We'll strive to maintain current reliability levels for customers and will only improve reliability in areas that have the worst performance.
- **Efficiency** – We'll continue to drive efficiency programs over the next five-years so that we can pass on the savings to our customers.
- **Growth** – We'll help connect homes and businesses across the NSW Government's priority growth centres, which in turn will foster economic growth, create prosperous communities and secure local jobs.
- **Choice and control** – We'll design tariffs that benefit customers who adjust their behaviour or invest in technology to better manage their own electricity use.

What we learned about engagement

Engagement over the past few years has led Endeavour Energy to recognise the following:

- Customers' long-term interests are best served where there are good relationships and early and deep dialogue that builds improved understanding amongst all parties and generates plans that are broadly supported.
- Good relationships with stakeholders require us to listen first and react second.
- We need to focus future engagement efforts on embedding consultation across our business outside of regulatory reviews, by better linking engagement plans to our corporate strategy, tariff reform strategy and network planning.
- Starting earlier will allow sufficient time to plan thoroughly and collaboratively, identify resources, enlist executive and target consumer group support.
- There is scope to make better use of the substantial investment made in educating customers to participate in deliberative planning processes by working with the same group of customers throughout the consultation period.
- Although we live in a digital era, most people prefer informal face-to-face engagement, particularly on the difficult issues.
- The principle of 'no surprises' is very effective as it allows Endeavour Energy to have difficult conversations early in the process, identify the core issues or gaps and to explore alternate options while maintaining respected and trusted relationships.
- The 'deep dive' workshops are a highly effective platform for all parties to listen first, build shared understandings and then intensify dialogue to try to reach agreement on key aspects of our proposal. They also help to explain differing perspectives in order to build common understandings about price/ trade-offs and the risks and benefits of particular choices.
- Trust and goodwill are central to producing positive outcomes for all parties, and this requires deep and regular engagement, sustained over time.

6.0 Service Regulation and Control Formulae

CHAPTER 6

6.1 Overview

We are aligned with the AER position on service classification and our proposal fully reflects the outcomes of the AER's Framework and Approach paper.

Through service classification, the AER examines which services relate to the shared distribution network, are specific to an individual customer, or can be provided by others in a contestable market. Categorising services in this way allows the AER to determine how the cost for providing these services should be recovered from customers. The classification of a service also determines the extent to which the AER's Ring-Fencing Guideline applies.

For the 2019-24 period we propose to:

- adopt the service definitions and classifications as per the framework and approach (F&A) paper;
- accept a revenue cap for standard control services and a price cap for alternative control services;
- accept the AER's proposed formulae to give effect to the control mechanisms;
- accept the AER's decision to continue to regulate our dual function assets (DFAs) as distribution assets for pricing purposes;
- submit a compliant negotiating framework document;
- apply forecast depreciation when rolling forward the RAB at the commencement of the 2024-29 period (as discussed in Chapter 8); and
- apply all incentive schemes for the 2019-24 period (as discussed in Chapter 9).

We also propose to apply the same four nominated pass-through events as approved for the 2014-19 period.

6.2 Framework and approach

The AER published the final F&A paper for the NSW DNSPs on 27 July 2017. It established the AER's approach in regards to:

- classification of distribution services;
- control mechanisms;
- pricing of dual function assets;
- incentive schemes;
- Expenditure Forecasting Assessment Guideline; and
- depreciation to apply to the RAB.

This chapter discusses service classification and the control mechanisms adopted by the AER to regulate our services. The remaining issues are discussed elsewhere in this regulatory proposal.

6.2.1 Service classification

The AER determines the most appropriate level of regulation for each of the services we expect to provide to customers. To do this, regard is given to a number of factors listed in the Rules. This helps to determine how the cost of providing particular services will be recovered from customers.

Although the current service classification has been appropriate and effective, we believe several recent developments meant that some changes to the classification were required for the new regulatory period. The AER considered these issues during the F&A process and modified the 2014-19 service listing accordingly.

2019-24 Service classification

In consideration of the changes described above, the AER has replaced the 2014-19 service classification. The AER's service classification of NSW distribution services for the regulatory period 2019-24 is outlined below.

Figure 6.1 AER service classification summary for the FY20-24 period

New South Wales Distribution Services			
Direct Control (revenue/price regulated)		Negotiated	Unclassified
Standard Control (shared network charge)	**Alternative Control** (service specific charge)		
Common distribution services (formerly 'network services')	Ancillary services		Type 1-4 metering services
Augmentation of the network	Public lighting services (including emerging pubic lighting technology		Premises connection services
Type 7 metering services	Type 5 and 6 meter provision (pre 1 July 2015)		Extension of the network
			Unregulated distribution services

The listing is largely consistent with the existing classifications with changes made to accommodate the AER's new Ring-Fencing Guideline and to improve the consistency of the classification across the NEM. For those services that have been reclassified or newly classified for the 2019-24 period we have sought waivers for ring-fencing purposes as required. We also confirm that we have not sought an exemption to include any restricted assets[5] within our proposal for standard control services capex, pass-throughs or contingent projects.

We have developed prices for both new and existing services; these prices and our approach are outlined further in Chapter 14 and Attachments 14.06, 14.09 and 14.10 to this proposal.

Dual function assets

As part of the 2019-24 F&A, the AER confirmed its decision from previous determinations that distribution pricing would continue to apply to our dual function assets. This was due to our dual function assets being an immaterial proportion of our overall regulated asset base. Further, these assets are dedicated to our distribution network meaning that separately pricing them as transmission assets would not have any material impact on our distribution prices.

Negotiating framework

We agree with the AER that none of the services we provide are suited to being classified as negotiated distribution services. Nevertheless, it is our intention to provide a compliant negotiating framework outlining the procedures we would otherwise follow in negotiating the terms and conditions of any prospective services with other parties for completeness.[6] Our negotiating framework, Attachment 0.13 to this proposal, is largely consistent with the negotiating framework we submitted for the 2014-19 period.

6.2.2 Control mechanism and formulae

Control mechanisms provide the basis of how the AER is to regulate standard control and alternative control services. That is, they determine how the prices charged and revenues raised from customers for regulated distribution services are to be controlled. The control mechanisms available to the AER are listed in clause 6.2.5 (b) of the NER.

Typically, the AER applies either a cap on the price we can charge for a particular service or a cap on the total revenue we may collect from our charges. In its F&A paper, the AER has elected to maintain the existing forms of control for standard control services and alternative control services for the 2019-24 regulatory period. We support the AER decision and propose no change at this time.

Formulae to give effect to the form of control

In addition to specifying the basis of the control mechanism for direct control services, the AER is also required to set out its proposed approach to the formulae that give effect to the controls adopted.[7] In the 2019-24 F&A paper, the AER has largely adopted the same formulae for both standard control and alternative control services with minor amendment.

We note that the AER is able to amend its formulae that give effect to the control mechanisms only if the AER considers that unforeseen circumstances justify departing from the formulae. We do not propose any changes to the formulae, and therefore we have adopted the AER's decision on classification of services.

5 A restricted asset refers to an item of equipment that is electronically connected to a retail customer's connection point on the same side as the metering point, excluding a network device.
6 NER 6.7.5 (a)(b)(c)
7 NER 6.8.1(b)(2)(ii) and 6.12.3

6.3 Maintaining our focus on risk management

There are certain events of either uncertain timing or cost for which it is not appropriate to include them within our forecast plans.

Pass-through events provide a mechanism by which a DNSP can recover costs incurred in response to the occurrence of events of a particular nature as prescribed in the Rules or nominated and approved as part of a determination. For the 2019-24 period we propose the same four nominated pass-through events that applied for the 2014-19 period. Our approach to contingent projects is contained in Chapter 10 of this proposal.

6.3.1 Pass-through events

The pass-through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through allows a business to seek the AER's approval to recover (or pass through) the costs of a defined, unpredictable, high-cost event.

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 under NER clause 6.6.1(a)(1).

We have also received feedback from PIAC that our proposed expenditure plans should only consist of costs that are reasonably required to maintain and operate our network. The principle is that customers should not have to fund any costs that are not necessary or that do not reflect a realistic expectation of what costs we will need to incur over the period. Our capex and opex forecasts should not include any events or costs that are speculative or highly uncertain in nature. Instead, we should rely on measures in the Rules such as pass-through events where appropriate.

In light of this feedback, we have undertaken a thorough risk assessment of our operations using the bow-tie risk analysis methodology[8]. We have cross-checked the results of this analysis against our historical risk register. From our analysis we have identified a number of risks which we consider should be managed via a nominated cost pass-through event rather than an allowance in our regulatory proposal. If a pass-through event occurs a proposal will be submitted to the AER who will then make a determination on the amount to be added (if any) to our revenue allowance for the 2019-24 period.

Based on this assessment, we propose the following events be approved as part of our regulatory determination, which are to apply as nominated pass-through events during the 2019-24 regulatory control period:

- Insurance cap event.
- Natural disaster event.
- Terrorism event.
- Insurer's credit risk event.

In proposing these events, we have taken into account the feedback provided by PIAC and the qualifying criteria detailed in the Rules and consider that each event meets the necessary requirements to be approved as a nominated cost pass through event. We also note that these nominated events were proposed in our 2014-19 proposal and subsequently approved by the AER.

We consider these events continue to pose a risk to our network, and our ability to manage these risks outside of the pass-through mechanism has not changed. We have assessed our practices and circumstances and consider these nominated pass-through events remain valid. Our detailed assessment of how they meet the pass-through event considerations is provided in Attachment 0.12 of our proposal.

We have also identified contingent capital projects which are discussed further in section 10.6 of our proposal.

8 The bow-tie methodology considers plausible worst case hazardous events and identifies both the preventative controls to reduce the likelihood of the risk occurring and mitigation controls to reduce the consequence of the event.

7.0 Demand, Energy and Customer Forecasts

CHAPTER 7

7.1 Overview

Customer growth, peak demand and energy consumption are forecast to grow. This means only focussing on the investment necessary to ensure safe and reliable electricity for our rapidly developing communities.

We will have over one million customers, including over 105,000 new customers, connected to our network before the end of the 2019-24 period. These customers have energy and demand requirements that we are expected to meet.

We are currently experiencing significant growth in customers, energy consumption and demand due to the population growth in our network area. We have forecast this growth to continue during and beyond the 2019-24 period:

- Peak demand[9] continues to grow; the peak demand for 2016-17 was 4,107MW – a new network record. We expect this growth to continue over the 2019-24 period to a new record peak demand of 4,278MW[10] by 2023-24 as a result of warmer weather, new connections and increased industrial activity.
- Customer numbers; we expect to connect an average of 21,000 new customers each year over the remainder of this period and over the 2019-24 period.
- Energy consumption; over the period from 2016-17 to 2023-24 we expect annual average growth in electricity consumption of 1.1 percent, largely a result of increased connections and increased commercial activity.

Our role is critical in supporting growth in demand, customer numbers and consumption. The primary driver of our augex and connections capex over the 2019-24 period is servicing spatial (i.e. location specific) demand and customer growth in greenfield development areas.

Our objective is to connect new development areas and customers to the network in an efficient and timely manner. This will support affordable housing, employment opportunities and economic growth in our network area.

To achieve this objective and ensure we can meet the expected demand for our services, our expenditure forecasts must reflect a realistic expectation of the demand forecast and cost inputs required. We have robust forecasting methods that are tested and verified by independent experts and against the expectations of the NSW Government and developers.

In developing our forecasts we have incorporated the expected impacts of energy efficiency and DER technology. We are currently investigating the use of DER and battery storage and expect the take-up of these technologies to continue over the 2019-24 period as they become more affordable and accessible to customers. In the coming period, we do not consider these technologies will have a meaningful step change impact on peak demand. However, they will continue to marginally reduce energy consumption resulting in a lower growth rate compared to peak demand growth over 2019-24.

Table 7.1 Our demand, energy and customer number forecasts

	2019-20	2020-21	2021-22	2022-23	2023-24
Maximum demand (MW) 50% PoE	3,949	4,039	4,129	4,205	4,278
Energy delivered (GWh)	16,621	16,730	16,831	16,954	17,228
Customer numbers (000's)	1,044	1,064	1,084	1,105	1,126

9 The highest amount of energy being collectively consumed across our network
10 Figure is based on a 50 percent probability of exceedance (POE) which is what is used for network planning purposes.

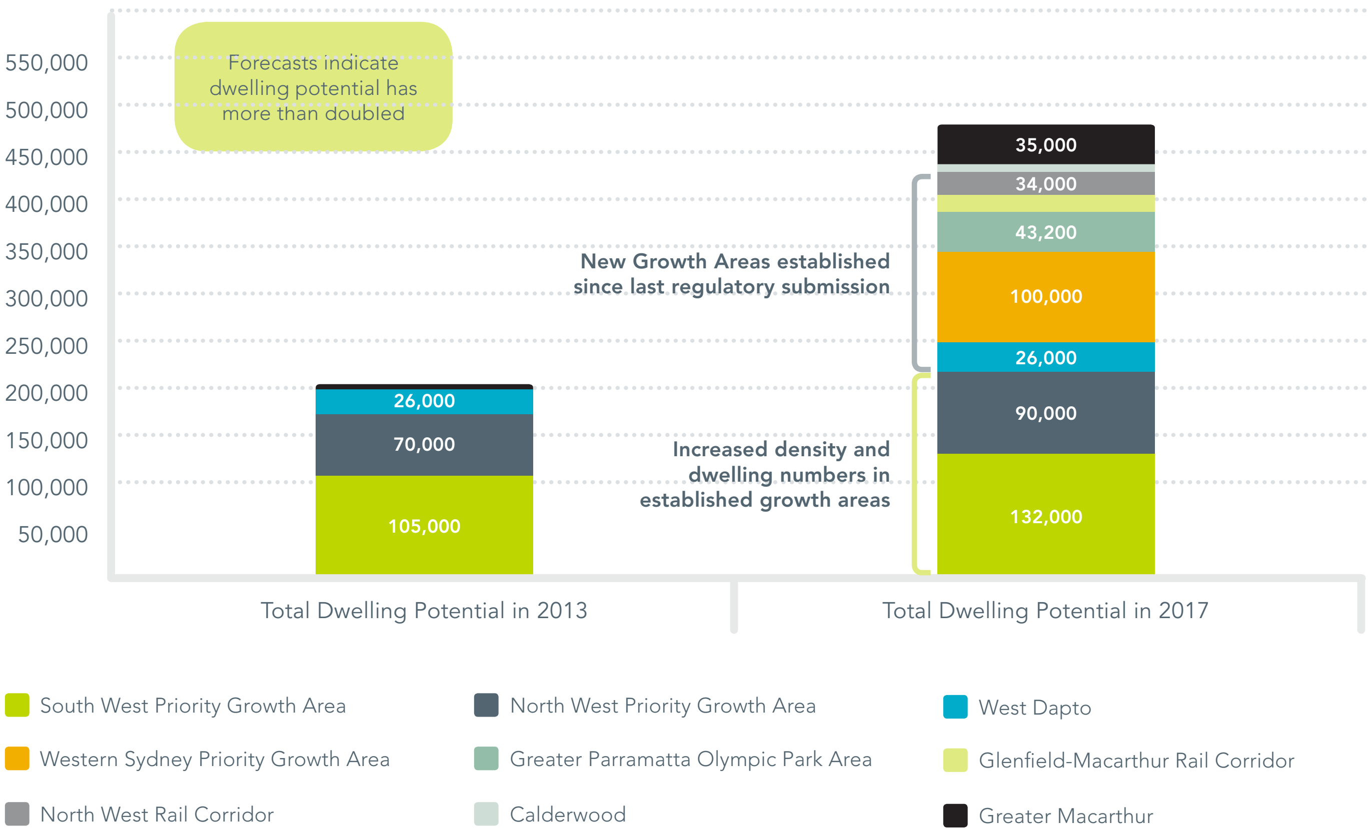
7.2 Our network

Our customer base is growing
It is projected that the population of Western Sydney will grow by 900,000 people over the next 20 years. Our network area encompasses the majority of the Priority Growth Areas and Precincts designated by the NSW Government Department of Planning and Environment. Some of the key areas driving housing and employment growth include:

- Greater Macarthur Area: Further land release to provide 35,000 new homes and create 30,000 new local jobs around the Campbelltown and Wilton areas.
- Greater Parramatta Olympic Park Area: Redevelopment and $10b infrastructure investment plans to create 72,000 new homes and 113,000 additional jobs over the next 20 years.
- North West Sydney Priority Growth Area: Significant rezoning changes of semi-rural regions and new planning controls to facilitate 33,000 new homes built by 2026 and improved transport infrastructure.
- South West Sydney Priority Growth Area: Continued staged land release and major road and rail infrastructure investment to improve economic development.
- North West Rail Corridor: Major urban renewal centred on the Northwest Metro - Australia's largest transport infrastructure project under construction.
- Western Sydney Priority Growth Area: Focuses on the development of Sydney's 'third city' around the Western Sydney Airport with plans to significantly increase home construction and work opportunities.
- West Lake Illawarra Area: Approximately 5,500 hectares of land across the Dapto and Shellharbour districts will be developed to eventually accommodate 26,000 new homes.

Since the time of our last regulatory submission in 2014 there has been a significant increase in the NSW Government's Priority Growth Areas and associated land releases. This increase has driven above NEM average growth in our customer base for the last several years and is summarised below.

Figure 7.1 Endeavour Energy – NSW Government Priority Growth and Release Areas 2013 and 2017



Development of these areas is central to the NSW Government's strategic plans to cater for the rapid future expansion of Western Sydney. A series of major transport, health and education projects are planned for these regions in 2019-24. The recent commencement of construction of a second Sydney airport at Badgerys Creek within Western Sydney will drive further demand growth in the mid-term.

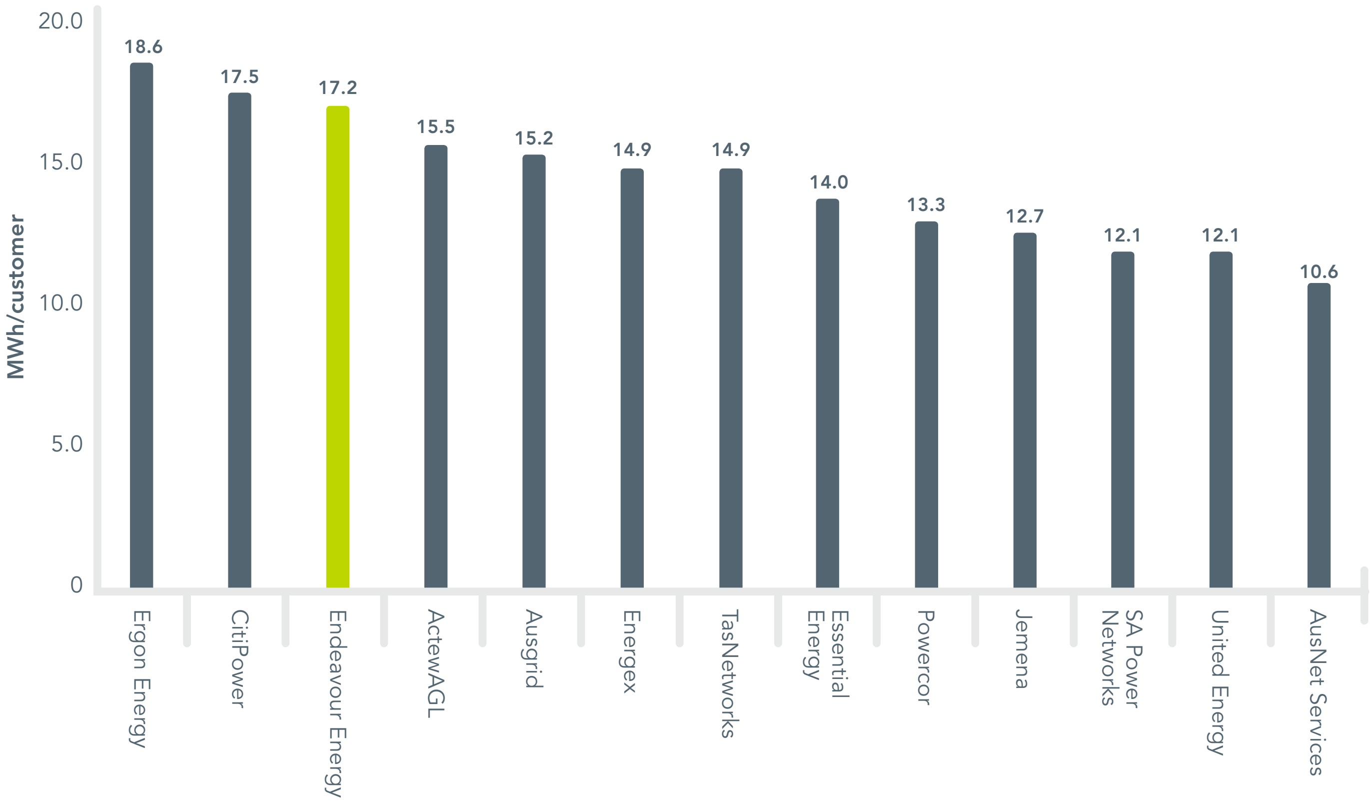
We work closely with developers, planning authorities and local councils to develop an understanding of the scope, scale and timing of developments to establish an accurate estimate of the number of new residential and commercial customer connections to our network.

As demand and usage profiles will vary across consumer types, understanding who our customers are and how their energy needs impact on the network helps us to derive accurate forecasts of demand and necessary investment on an as-needed basis. This approach is facilitated by our Growth Strategy which identifies the status of plans to service all known brownfield and greenfield developments within the network area (refer to Attachment 10.09).

Our customers require a high amount of energy at peak times

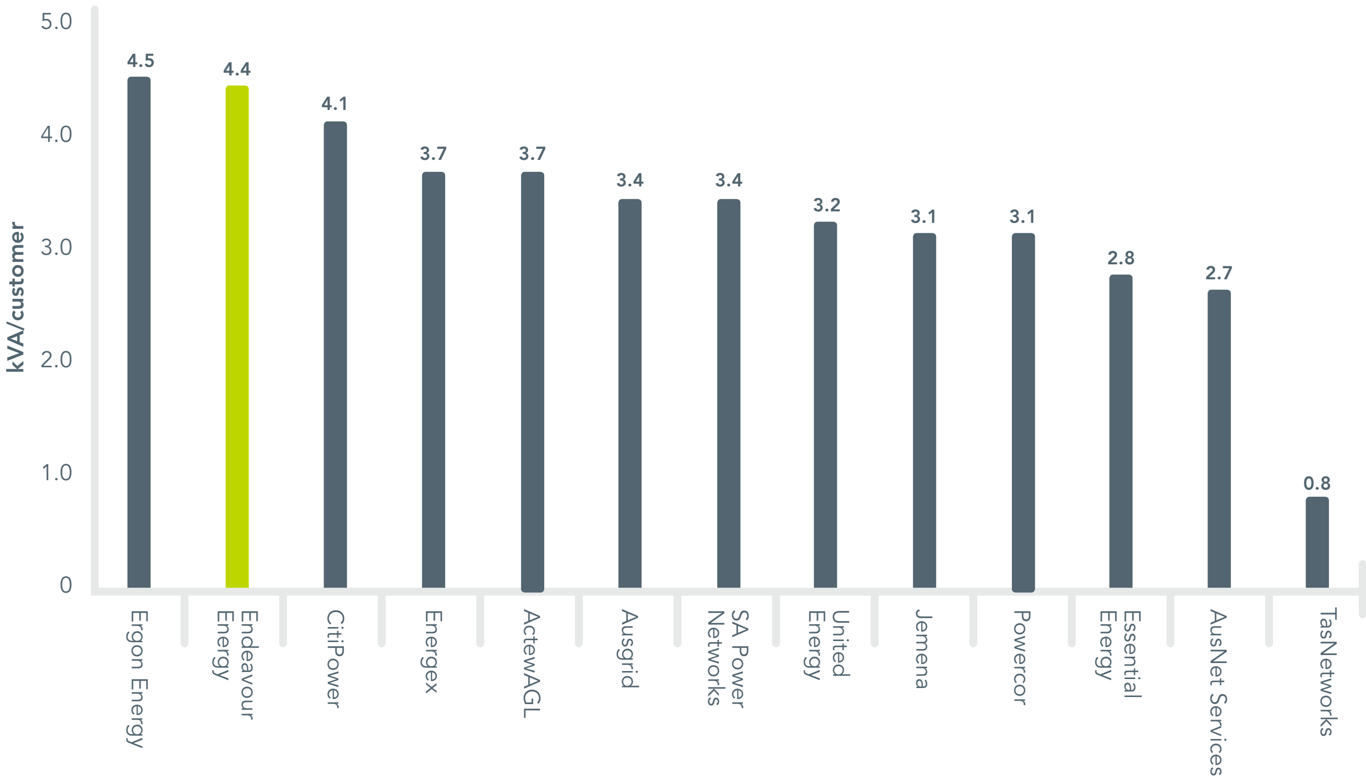
Our customers are reliant on being able to access a reliable electricity supply. On average our customers have the third highest level of energy consumption and second highest peak demand at an individual level in Australia.[11]

Figure 7.2 Energy density (FY16)



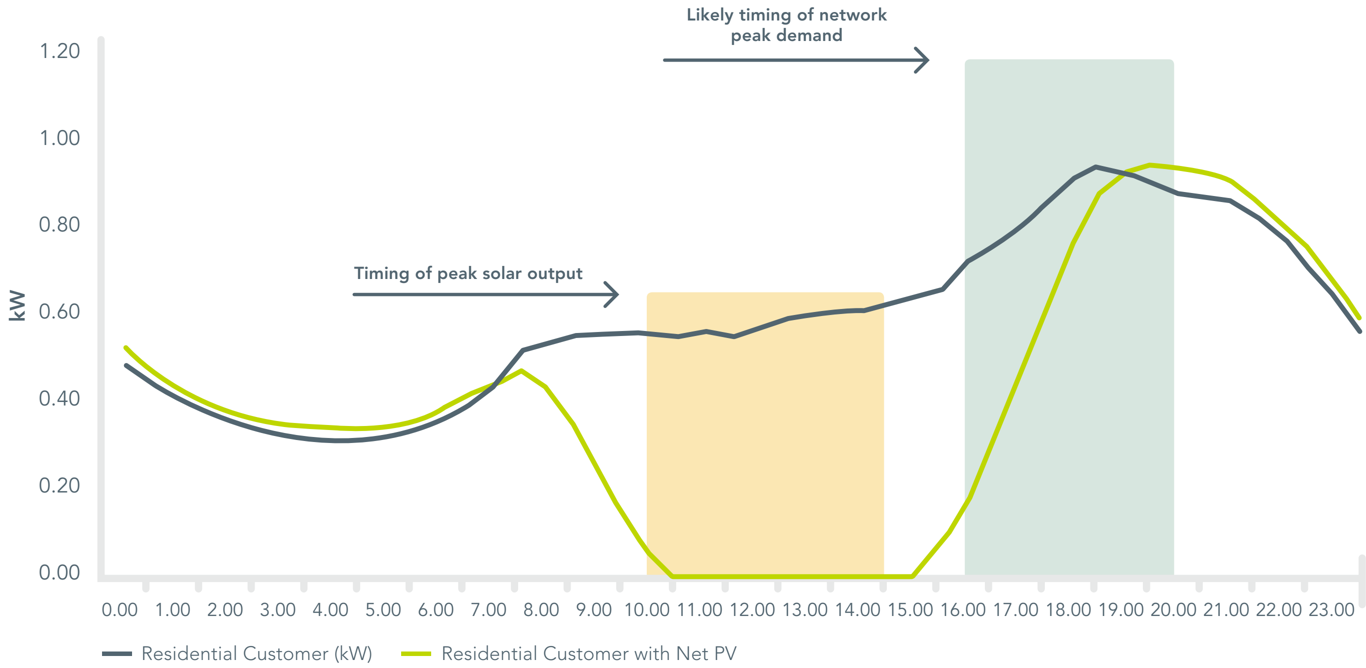
11 Source: Benchmarking RIN Data

Figure 7.3 Demand density (FY16)



The average consumption pattern of our customers is displayed below with peak demand likely to occur between 4pm and 8pm for residential customers.

Figure 7.4 Endeavour Energy - average residential customer consumption profile



Our customers require more energy at peak times due to the extreme temperatures that occur in our network area. Summer temperatures in Western Sydney can regularly exceed 40° Celsius with greater frequency than elsewhere in the Sydney metropolitan area in the absence of cooling coastal sea breezes. Conversely, during winter Western Sydney typically experiences lower average minimum temperatures than the Sydney CBD with snowfall in the upper Blue Mountains not uncommon during July and August.

As a result, air conditioners are widely relied upon by our residential and business customers to provide relief during these temperature extremes. Air conditioning penetration rates in Western Sydney are approximately 80 percent with a high proportion of installs in newly constructed dwellings continuing to drive this trend. Despite recent improvements in energy efficiency and design, ducted and split system air conditioners remain relatively high energy consuming appliances and typically contribute a significant portion of our average customer's energy bills. There is also a timing mismatch between embedded generation and peak load times. This means that energy consumption is forecast to grow at a slower rate than demand over the 2019-24 period.

Our customers are adopting renewable technologies

As of June 2017, there are over 120,000 customers with small scale renewable generation connected to our network, representing a total capacity in excess of 330MW. However, as evident in Figure 7.4 above, customers with rooftop solar generation are still reliant on our network for supply during peak periods. The relatively small contribution to peak demand supply from embedded generation has not yet provided opportunities to reduce network investment to provide a reliable supply in peak periods.

We anticipate that battery storage will provide customers with solar PV systems the ability to control their energy usage and utilise their local generation during peak times. We are currently implementing both residential and grid-scale battery trials to better understand their potential impact and benefits. However, we consider the residential take-up of battery technology will be slow and provide limited benefits during the 2019-24 period. We consider the take-up of this technology will increase as it becomes more affordable and familiar to customers over the next several years.

7.3 Maximum demand

Maximum (peak) demand is the highest combined level of demand sought by our customers from the network at a given point in time. As a summer constrained network, the highest levels of demand on our network are reached when hot weather drives simultaneous use of air-conditioning and other cooling loads (fans, evaporative coolers, pool pumps etc.). It is during these periods that the maximum demand most closely approaches the capacity of our network assets to provide a safe and reliable supply of electricity to our customers.

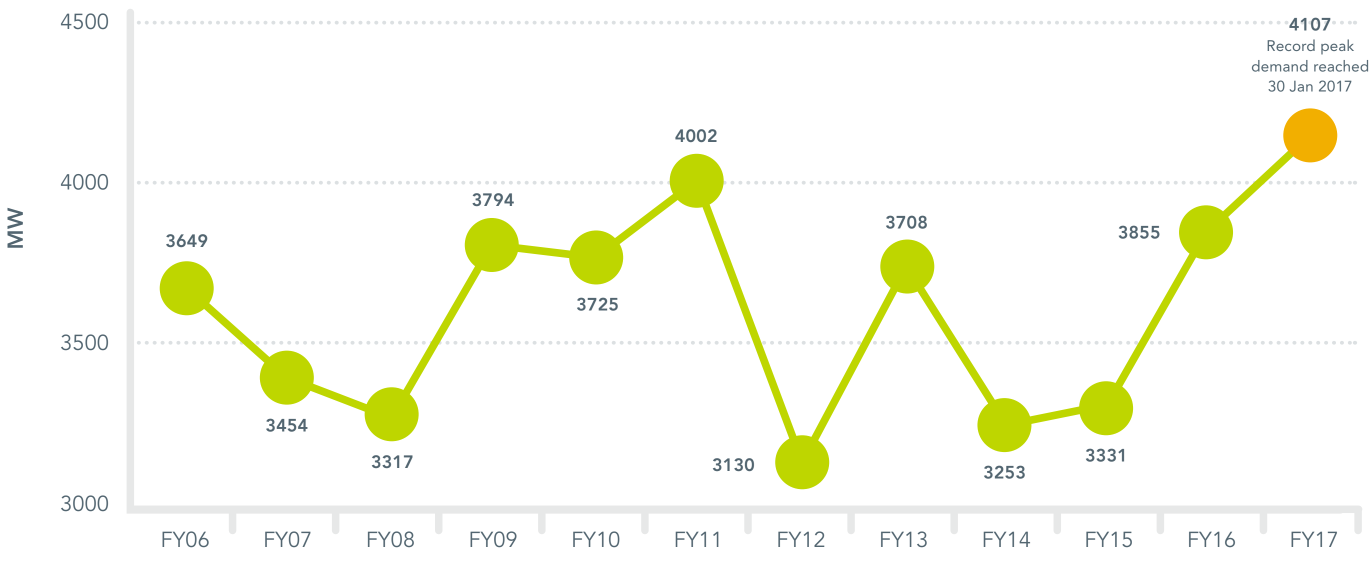
Our research clearly indicates that customers do not want to lose supply at times when they need power the most i.e. hot weather days. We have seen the inconvenience and difficulties blackouts can cause customers with widespread outages during extreme heatwaves in Victoria and South Australia during January and February this year.

To ensure our customers do not suffer from interruptions during peak periods when supply is most valued, we need to accurately forecast maximum demand in advance so we can effectively review demand management and other non-network solutions to subdue network demand at these peak times or alternatively invest in extending the capacity of the network.

7.3.1 Our demand forecast

The customer growth in our network area has been driving increased demand in recent years. On 30 January 2017, demand on our network reached a record 4,107MW.[12] This was 105MW above the previous record set in 2011 and was 252MW greater than the peak recorded in the previous year.

Figure 7.5 Summer peak demand (FY06-FY17)



12 Coincident Raw System Annual Maximum Demand at the transmission connection point.

Our forecast system predicts that maximum demand will grow from 3949MW in 2019-20 to 4278MW[13] in 2023-24, an annual compound growth rate of 2.0 percent over the 2019-24 period.

Table 7.2 Forecasts of maximum demand for the FY20-24 regulatory period

	2019-20	2020-21	2021-22	2022-23	2023-24
Maximum demand (MW) 10% PoE	4,184	4,274	4,363	4,439	4,512
% change	3.6%	2.2%	2.1%	1.7%	1.6%
Maximum demand (MW) 50% PoE	3,949	4,039	4,129	4,205	4,278
% change	3.8%	2.3%	2.2%	1.8%	1.7%

For investment planning purposes, forecasts of overall network maximum demand growth do not provide sufficient information. Network augmentation decisions are generally driven by spatial demand forecasts to ensure that customers in specific locations, particularly in the high growth pockets of our network, are not exposed to supply interruption or connection delay.

Our spatial maximum demand forecasts are provided for each of the 164 existing and 12 new zone substations on our network in the Reset RIN. There are a number of zone substations forecast to experience significant demand growth over the 2019-24 period and beyond:

- 18 zone substations are expected to experience demand growth rates of greater than 5 percent.
- 28 zone substations are expected to experience demand growth rates of between 1.5 percent and 5 percent.
- 57 zone substations are expected to experience demand growth rates of between 0 percent and 1.5 percent.

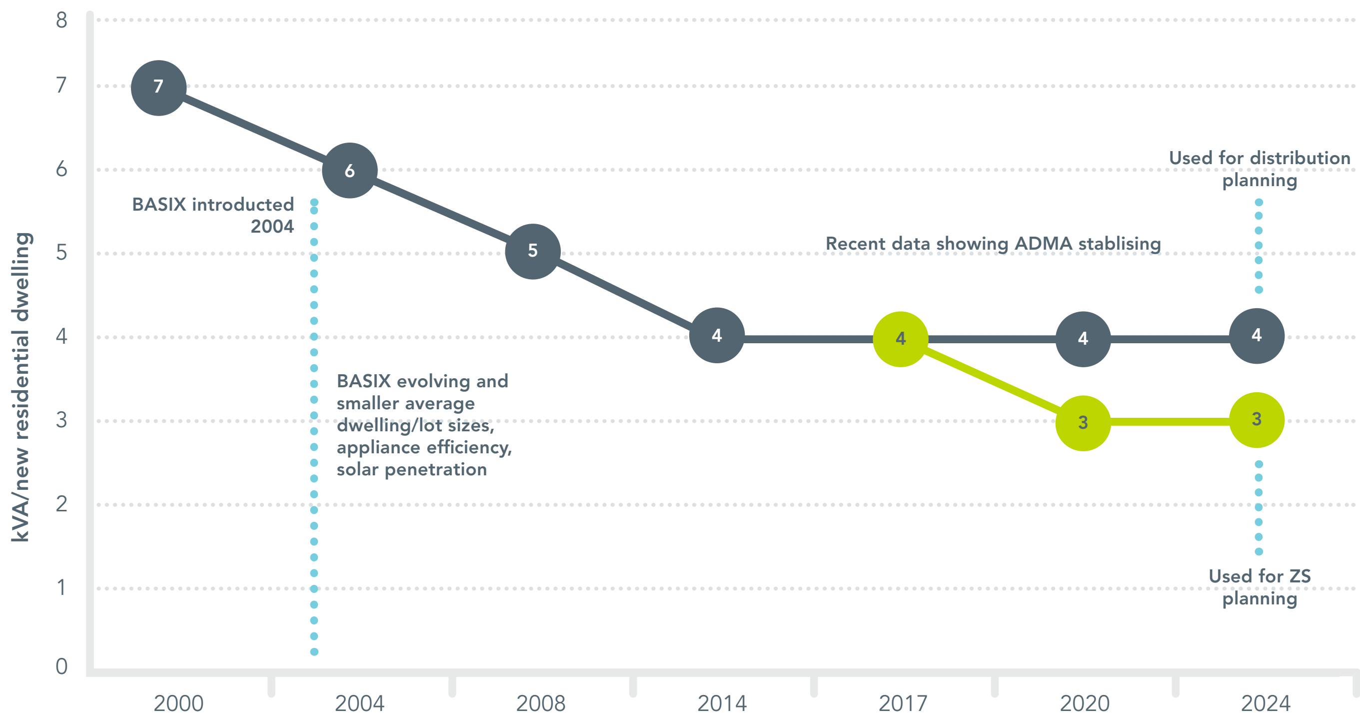
After Diversity Maximum Demand (ADMD)

As noted previously, customer growth and the associated demand growth in greenfield areas is the primary driver of our augex and connections capex forecast. A key input in our augex forecast is therefore the ADMD values we use for planning purposes.

These values provide us with an estimate of the level of demand newly constructed dwellings are likely to require from the network to ensure optimal network design and asset utilisation. As such, ADMD values are an important input into our spatial demand forecasts for our growth regions. We have recently updated our estimates of ADMD to reflect changes in consumer trends and mandated building energy ratings for new constructions.

13 Weather corrected 50% PoE.

Figure 7.6 ADMD values used for planning purposes



Some of the factors that have impacted demand include the following:

- **The Building Sustainability Index (BASIX):** Energy sustainability requirements on new developments including minimum appliance efficiency and thermal insulation standards. These appear to be contributing to reduced demand in new areas relative to established areas.
- **Solar/battery storage systems:** Our data suggests that whilst current PV cell output does not coincide with peak system demand, battery discharge during peak times can reduce premise contribution to overall demand. Also, panel orientation has changed to capture more sun during the peak periods.
- **Technological advances:** Minimum Energy Performance Standards (MEPS) have driven improvements in appliance efficiency (whitegoods, lighting, air-conditioning and home entertainment) and contributed to the general downward trend of household peak demand.
- **Lot sizes:** There is a strong correlation between energy usage and dwelling size. As lot sizes continue to be restricted, a dwelling's footprint and energy requirements tend to also be constrained.

7.3.2 Our demand forecast methodology

Each year we develop summer and winter spatial demand forecasts for the ensuing 10 years to coincide with our forward network investment planning period. As summer maximum demand consistently and comfortably exceeds winter demand levels, we most often use our summer forecasts to inform our investment planning decisions in each region within our network area. Consistent with industry practice, we present Temperature Corrected Maximum Demand (TCMD) forecasts reflecting a 10 percent and 50 percent PoE.

Our maximum demand forecasts also inform our augmentation capex forecast for the 2019-24 period, albeit to a significantly lesser extent then spatial demand growth. Our maximum demand forecast has also been used in deriving our forecast opex requirements as one of the standard output factors used by the AER in calculating the rate of change component that is part of the base-step-trend approach.

Maximum demand forecasting process

Our maximum demand forecasting model uses a bottom-up approach beginning with a forecast of peak demand at the zone substation level, then moves upwards to the sub-transmission substation level and bulk supply points. Total network level demand forecasts are determined by aggregating forecast values progressively.

Historical demands are normalised for various weather and calendar effects from which a starting point is established. From this starting point, local planning knowledge of known events such as future spot loads, lot releases and load transfers from one substation to another are accounted for in the 10-year forecast horizon. A collaborative planning approach with industry stakeholders such as the NSW Department of Planning and Environment and the Greater Sydney Commission enables us to derive accurate forecasts of expected customer connection requirements and network area growth. Regular interaction also allows us to plan for the optimal delivery and timing of augmentation works.

We then consider the growth from existing customers as well as new customer connections. Organic growth for each zone substation was taken from a report prepared for us from the National Institute of Economic and Industry Research (NIEIR), Attachment 7.02. This report informed the post model adjustments we applied to the 10 year forecast to account for other drivers that influence demand such as energy efficiency improvements, generation from photovoltaic systems and government energy policies. The forecast at each zone substation is finally aggregated to produce an overall system peak demand forecast for our network area. Our demand forecasting process is set out in further detail in Attachment 7.01.

Impacts of Distributed Energy Resources (DER)

As mentioned above, we apply post modelling adjustments (PMA), to capture future changes in maximum demand which may not be adequately considered by our forecasting model. These adjustments include impacts from different state and national energy policies and programs, such as Minimum Energy Performance Standards (MEPS), NSW Energy Savings Scheme (ESS), change of building codes (e.g. BASIX) and the impacts of DER. PMAs are applied to each year of the forecast for each zone substation based on the residential and commercial and industrial mix and its peak demand for the season as each policy and program targets different customer sectors.

An increasingly important factor in developing PMAs is the need to consider the impacts of DER. The role of the traditional grid is evolving to enable customer-driven take up of new services, such as renewable generation, battery storage, electric vehicles and home automation.

Our forecast accounts for the expected impacts of DER. We note that in the short-term (the 2019-24 period) DER technologies may reduce energy consumption per customer, but only marginally offset our forecast growth in maximum demand. This is due to the current timing mismatch between rooftop solar generation and our peak demand period and the slow take up of electric vehicles and batteries initially until they become more cost-effective and accessible to customers.

Our DER related PMAs as well as the Energy Savings Scheme are summarised below.

Table 7.3 Endeavour Energy demand forecast – post model adjustments

Category	FY24 System Wide Demand Impact (MW and % of System Demand)	Forecast units in 2020-21
Energy Savings Scheme	-25.1 (0.6%)	
Solar PV	-140.1 (3.3%)	184,529
Battery storage	-22.9 (0.6%)	13,707
Electric vehicles	+15.8 (0.4%)	20,000
Total[14]	**-172.3 (4.03%)**	

Forecasting verification

The validity of our forecasting processes has been internally assessed by comparing recent historical loads to forecast predictions using a mean absolute percentage error (MAPE) assessment. The MAPE is calculated at an aggregate level by comparing the 50 percent Probability of Exceedance (PoE) summer demand forecast and the actual 50 percent PoE weather normalised peak demand.

This has shown ongoing improvement in forecast accuracy since 2013-14, with the most recent forecast error being less than one percent for 2016-17. The forecast performance has been improved after the introduction of a new weather normalisation method based on a simulation approach.

Table 7.4 Endeavour Energy forecast performance mean absolute percentage error (MAPE) since 2009

Forecast year	2009	2010	2011	2012	2013	2014	2015	2016	2017
2010	1.7								
2011	9.0	6.2							
2012	5.6	3.7	0.7						
2013	13.4	19.0	24.8	15.9					
2014		17.1	21.6	9.9	4.2				
2015			27.4	18.8	11.1	3.9			
2016				15.6	9.2	0.6	3.7		
2017					18.1	2.8	1.4	0.9	
Average MAPE	1 year:	4.7	2 year:	8.7	3 year:	12.8	4 year:	19.6	

As evident in the Table 7.4 above, our one-year forward forecast MAPE averaged 2.3 percent over 2015 and 2016 period which compares better than the corresponding AEMO forecast MAPE of 5.9 percent.[15]

14 In future regulatory periods as customers are transitioned to more cost-reflective tariffs we expect tariff design will become a PMA factor.
15 Note: AEMO started publishing connection point forecasts in 2015

Our 50 percent PoE peak demand forecast growth shows an annual growth rate of 2.3 percent over the next 10 years between 2018 and 2027, which compares to AEMO's forecast peak demand annual growth of 1.1 percent for the same period. Our augex capex is primarily driven by spatial growth from new connections meaning a discrepancy at the system level has no material impact on our augex forecast. However, we have sought to understand the drivers of this difference.

AEMO utilises a trend method to forecast demand growth. In doing so, they subtract spot loads[16] that are above five percent of the connection point maximum demand from historical trends. This subtraction can vary from 0.2MW to over 170MW depending on the size of the connection point. This subtraction is made to avoid double counting as AEMO assumes that historical spot load growth is indicative of future spot load growth. Once the trend is developed the known future spot loads are not re-added to the forecast.

This differs from our approach that develops a forecast using weather normalised actuals as the starting point of the forecast. We then adjust these actuals using PMAs (as described above) and for known future spot loads and lot releases.
We determine likely spot load increases using load applications from developers/ customers and the latest lot release figures provided by the Department of Planning and Environment NSW. We assign a probability to the likelihood that these spot loads will eventuate, and for large customers this involves a planning review where we assess the certainty of demand and typically meet with the applicant to discuss demand management options. This generally results in reductions in demand compared to the original application. We then diversify the spot load demand when adding it to the forecast (i.e. we do not assume that the entire spot load will occur at peak times).

We consider this approach produces a more accurate forecast that better accounts for the spatial growth we must cater for in future periods. The assumption that historical spot load growth is indicative of future spot loads and lot releases is not supported by the upward trend in non-residential building approvals in our network area over several years.

Figure 7.7 Non-residential building approvals in NSW 2001-2017

Source: ABS

16 A spot load refers to a defined project which is expected to draw a defined amount of load, on a specified date (i.e. from the time of connection) at a particular point in the network, e.g. Western Sydney Airport.

Consultant review

We have engaged Cutler Merz to undertake a comprehensive review of our demand forecasting process including the methodology and assumptions that underpin our forecasts.

Overall, they consider our process to be robust and our forecasts to be realistic and based on reasonable assumptions. This report is provided in Attachment 7.04.

7.3.3 Managing peak demand

As discussed earlier in this proposal, peak demand is a key driver of future network investment. We need to ensure sufficient capacity exists on our network to meet peak demand otherwise customers will experience blackouts at the most critical times of the year. We are taking a number of steps to manage and, where possible, reduce peak demand to reduce our future investment requirements and in turn electricity prices:

- Demand management: we have a number of demand management initiatives including battery storage trials, demand response, distributed generation and programs such as *Solar*Saver and *Cool*Saver to reduce demand and/or defer investment. See section 9.5 and Attachment 10.12 for further details.
- Utilising network capacity: we efficiently stage our network development in the early phases of growth regions by making use of existing network capacity. We will continue to make use of excess capacity when doing so is technically feasible and represents the most cost-efficient outcome as revealed through our cost-benefit analysis. However, we note that these staging options will become less feasible as the development of the priority growth areas and ensuing customer connections increase.
- Cost-reflective tariffs: we are seeking to improve the cost-reflectivity of our tariffs by introducing a demand based tariff. Our proposed tariff structure will provide customers with greater incentive and control to manage their energy usage during peak periods in order to reduce future investment needs and prices. See our TSS, Attachment TSS0.01, for further details.

7.4 Customer and energy consumption forecast

As noted previously, energy consumption is expected to grow at a slower rate than peak demand. This is due to various energy efficiency schemes and standards, e.g. BASIX, which new houses are required to comply with. In the sections below we provide more detail on our customer number and energy consumption forecasting methodologies.

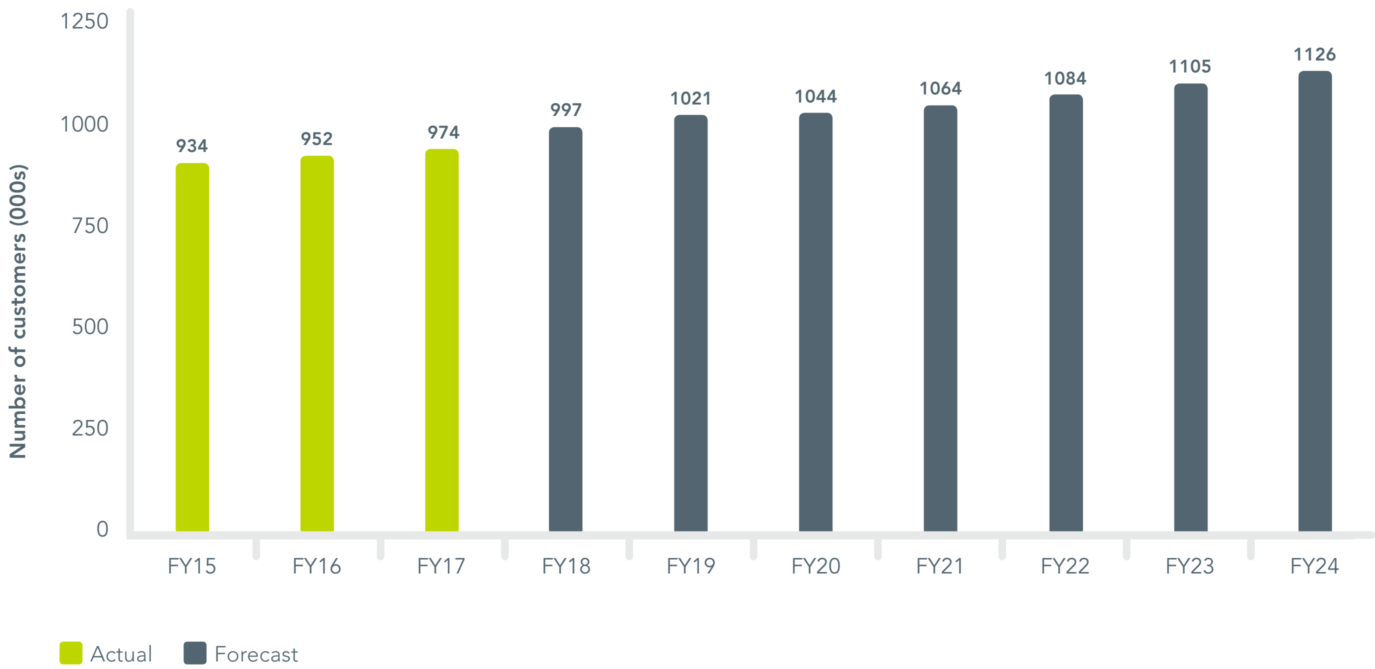
7.4.1 Our customer numbers forecast

Customer numbers for our network are forecast to grow at an average annual growth rate of two percent over the 2019-24 regulatory control period as illustrated in Table 5.7 below:

Table 7.4 Customer numbers FY20-FY24

Customer numbers	2019-20	2020-21	2021-22	2022-23	2023-24	Average
Total customers (000s)	1,044	1,064	1,084	1,105	1,126	**1,085**
Growth rate (%)	2.3%	2.0%	1.9%	1.9%	1.9%	**2.0%**

Figure 7.8 Customer number forecast (000s)



We use our customer number forecasts to inform our connection capex forecast, greenfield augex forecast and the output component of the rate of change trend factor that applies to our opex forecast. Our customer number forecasts are produced using the following methodology and assumptions.

7.4.2 Our customer forecast methodology

Domestic customers

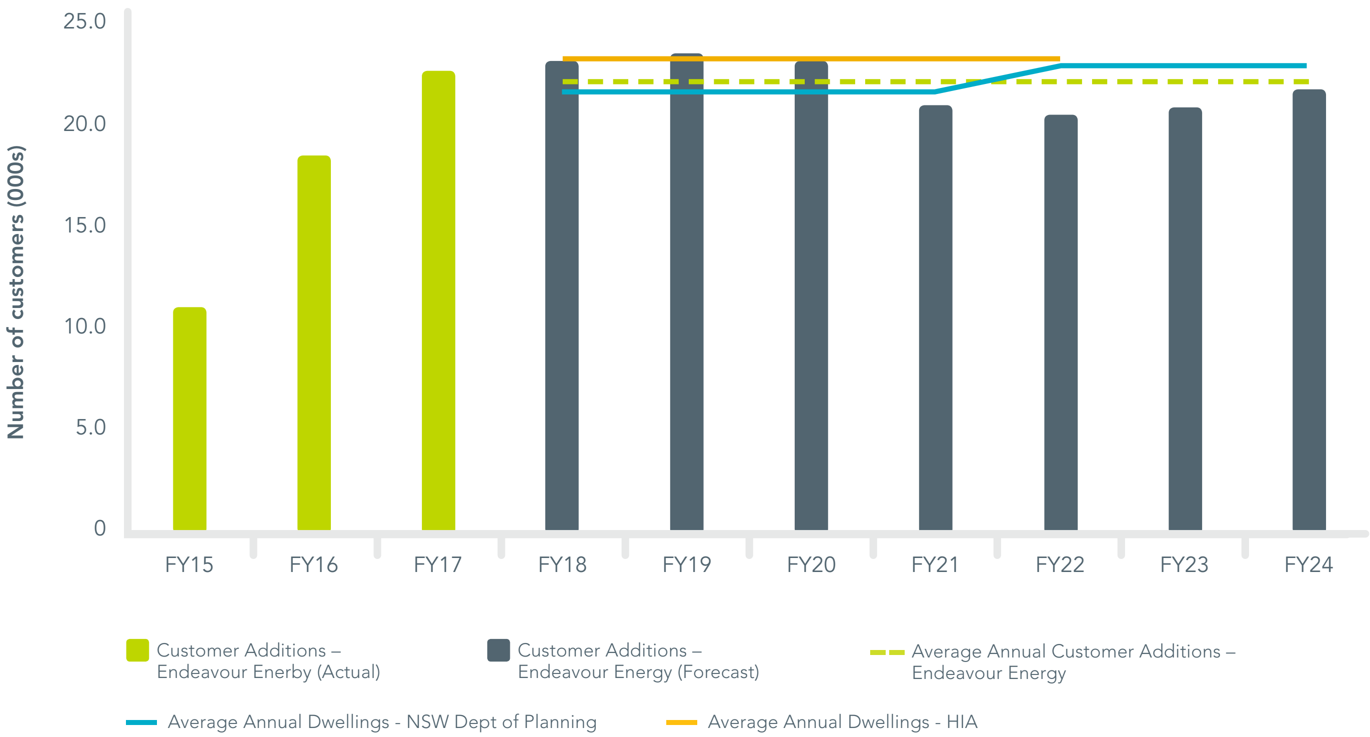
- Short-term customer numbers for the months remaining in the current financial year (FY18) and next financial year (FY19) are forecast using historical trends.
- Long-term forecasts for FY20 to FY24 are produced using a projection of household number growth for the Endeavour Energy network area. Household growth rate projections are sourced from a third-party macroeconomic forecaster, NIEIR. NIEIR provides a range of macroeconomic forecasts of which we have taken the base/medium case, see Attachment 7.03 for further details.

Commercial and industrial customers

- Short-term commercial and industrial customer numbers take account of recent monthly movements.
- Long-term forecasts increase in line with the forecast GRP growth rate as sourced from NIEIR. The exception to this is large, site-specific industrial customers and non-metered commercial customers, which are assumed to remain unchanged.

We also assess the reasonableness of our model outcomes against comparable, independent forecasts of growth activity in our network, e.g. Department of Planning and Housing Institute of Australia.

Figure 7.9 Customer number forecast compared to third party forecasts



Our forecasting approach has also been independently reviewed by Frontier Economics as part of the 2014-19 regulatory proposal. Based on its review, Frontier Economics formed the view that our customer and energy forecasting methodology is consistent with good industry practice. We continue to use this methodology to prepare our forecasts.

7.4.3 Our energy consumption forecast

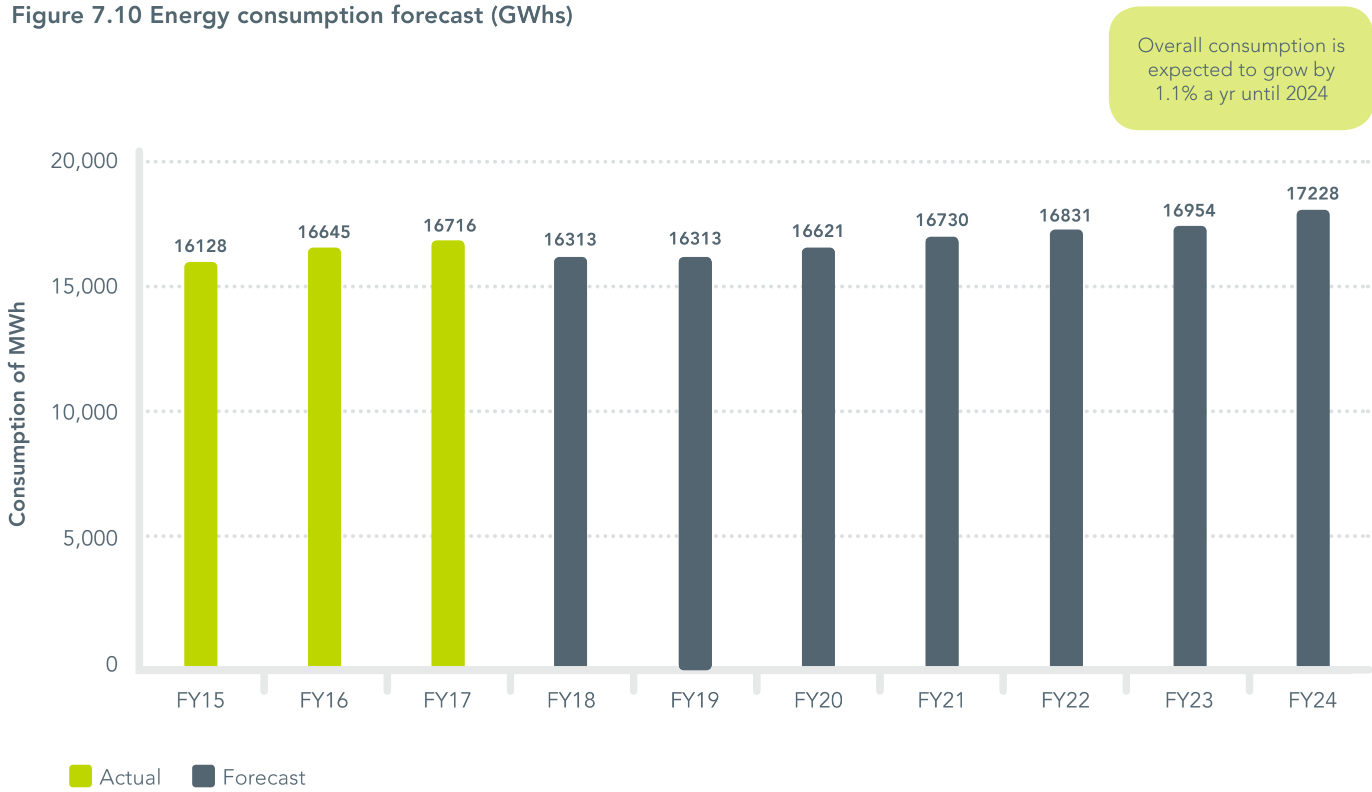
Energy consumption is the volume of electricity sold to our customers as measured in GWh over a set period. As we are subject to a revenue cap, energy consumption affects the price of electricity but not the revenue we collect. This means that if customers consume more energy than expected we will return the additional revenue we have collected in the subsequent year (and vice versa). To limit the reconciliation required each year we have robust methods in place to forecast energy consumption as accurately as possible.

We forecast consumption on our network to increase from 16,313GWh in 2018-19 to 17,228GWh in 2023-24, representing an annual growth rate of 1.1% over the 2019-24 regulatory period.

Table 7.5 Energy consumption forecast

Energy Consumption	2019-20	2020-21	2021-22	2022-23	2023-24	Average
Total energy (GWh)	16,621	16,730	16,831	16,954	17,228	**16,873**
Annual growth rate (%)	1.9%	0.7%	0.6%	0.7%	1.6%	**1.1%**

Figure 7.10 Energy consumption forecast (GWhs)



We note the decline in consumption between the actual and forecast years. This is because we forecast consumption on a weather normalised basis and the two most recent years, FY16 and FY17, were abnormally warm years. Our energy forecasting methodology, which consists of a short-term and long-term forecasting process, is described in more detail below.

7.4.4 Our energy consumption forecasting methodology

Short-term forecasts

Short-term forecasts cover the next two years. Forecasts are made on a monthly basis by applying monthly growth rates on the weather-normalised consumption values of recent months. The monthly growth rates are estimated from trend analysis of the past five-years of total system import (TSI) values for that month, after weather-normalisation of these values.

Long-term forecasts

Long-term forecasts cover the period beyond the next two years. The long-term energy forecasting methodology consists of a combination trend analysis and econometric method:

- Domestic energy forecasts are produced by applying an econometric approach. In this approach, an econometric model is estimated by fitting historical domestic consumption per customer values against disposable income per capita, retail domestic price, and temperature variables in a log-linear regression model. Standard statistical tests are performed to examine precision of the estimates and robustness of the model. The forecast produced is then adjusted for post model adjustments for the impacts that would result from PV, ESS (Energy Saving Scheme), electric vehicles, etc.
- Commercial and industrial consumer energy forecasts are based on an econometric approach. In this approach, growth rates for energy consumption are estimated by multiplying forecasts of growth rates of GSP and price and their respective elasticities (i.e., income and price elasticities). The growth rates estimated for energy are then applied to the annual consumption values for the starting year (FY19). The forecasts produced are then adjusted for post-model adjustments recommended by NIEIR, Attachment 7.02. In cases where customer specific information is available adjustments are made accordingly.
- The forecast for large industrial consumer energy is derived from trend analysis, which involves a review of recent historical trend data and adjustment for business specific information where available.

For the 2014-19 regulatory period, we engaged Frontier Economics to review our customer and energy consumption forecasting methodology. Based on its review, Frontier Economics formed the view that the forecasting methodology is consistent with good industry practice. We continue to use this methodology to prepare our forecasts.

8.0 Regulatory Asset Base and Depreciation

CHAPTER 8

8.1 Overview

We are proposing a more accurate period-by-period depreciation method to better reflect the beneficiaries of investments we make on behalf of our current and future customers.

The value of our distribution network assets used to provide standard control services is reflected in the regulatory asset base (RAB). These include system assets directly used to safely transport electricity to and from our customers, such as poles, power lines, transformers and switchgear as well as non-system assets such as ICT, land, plant and equipment.

Our RAB has increased over the 2014-19 period due to capital investment to accommodate strong customer growth in eveloping regions within our network and to replace ageing assets at risk of failure. Through our robust governance framework we have sought to limit this growth by ensuring only capital investment required to meet the capex objectives is undertaken and included in the RAB. This means we have spent 9.2 percent less capex than allowed for in the 2014-19 period.

Our opening RAB as at 1 July 2019 is forecast to be $6,512.1 million.

To further limit RAB growth in future periods, we have proposed a period-by-period asset tracking approach to depreciate the investments made during the current, and future, regulatory period.

This new approach separately depreciates assets by period over standard lives, which better reflects their economic usage and is consistent with standard accounting practice. Relative to our current averaging approach, this approach will reduce RAB growth in future periods addressing intergenerational issues.

Table 8.1 Proposed opening RAB values for standard control services for the 2019-24 period

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24
Opening RAB	6,512.1	6,886.8	7,232.2	7,571.4	7,900.5

8.2 Regulatory asset base values

8.2.1 Opening 2019-24 RAB value

The value of our RAB as at 1 July 2019 is $6,512.1 million. This value has been calculated based on clause 6.5.1 and schedule 6.2 of the Rules and derived using the AER's roll forward model (RFM). Table 8.2 below provides a reconciliation of our opening RAB value for 1 July 2019. The completed RFM is provided as Attachment 0.05.

Table 8.2 Opening RAB values for standard control services as at 1 July 2019

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19
Opening RAB	5,581.3	5,895.3	5,979.9	6,015.3	6,238.4
Add: actual and estimated net capital expenditure[17]	377.4	216.4	195.3	348.7	409.2
Less: regulatory depreciation	-63.4	-131.9	-159.8	-125.6	-130.4
Less: 2013-14 final year adjustment[18]	-	-	-	-	-5.2
Opening RAB value as at 1 July 2019					6,512.1

Capital investment over the current regulatory period has increased the value of the RAB. We have used a combination of actual and forecast capex values as detailed in Chapter 10 of this proposal to derive the opening RAB value. These capex values reconcile with those provided in annual regulatory accounts and we will update the RAB for actual 2017-18 capex in our revised regulatory proposal.

We have made adjustments to the opening RAB value in accordance with Clause 6.5.1(a). These adjustments have been made in accordance with the Rules and a described below.

2014-19 movements in provisions

We have accounted for movements in provisions attributable to capex in accordance with recent AER decisions.

Efficiency review of past capex

We note prior to making a decision on the opening RAB value for the 2019-24 period, the AER may review the efficiency of past capex under certain circumstances and exclude amounts in accordance with S6.2.2A of the Rules. This component of the capex incentive scheme is designed to ensure that only capex that is efficient and prudent should be added to the RAB.

Typically, the review period covers the final two years of the previous regulatory period (i.e. 2012-13 and 2013-14) and excludes the last two years of the current period (i.e. 2017-18 and 2018-19).[19] However, for this determination the review period is for the 2015-16 and 2016-17 years. This is because the transitional rules, clause 11.56.5, excludes capex incurred in the transitional year (2014-15) or prior to the publication of the first capex incentive guideline, which would cover 2012-13 and 2013-14 as the guideline was first published in December 2013.

17 Net of disposals and movements in provisions.
18 We note that a final year of the previous regulatory control period actual capex adjustment is not required for 2019-24 as the timing of the 2014-19 determination meant that actual 2013-14 capex was available at the time of making the determination.
19 Schedule 6.2.2A(a1)

For the 2015-16 and 2016-17 years we have assessed whether a reduction to the RAB is required in accordance with S6.2.2A of the Rules. An adjustment may be made if one of the following criteria is satisfied:

- Overspending requirement: where the sum of capex during the review period exceeds the AER allowance.
- Margin requirement: where capex that will result in an increase to the RAB includes an amount that represents a margin paid by the DNSP that does not reflect arm's length terms.
- Capitalisation requirement: where capex that will result in an increase to the RAB includes an amount that, under the DNSP's applicable capitalisation policy submitted to the AER as part of a regulatory proposal, should have been treated as opex.

We can confirm that our capex over the review period is efficient and no adjustment is required. For 2015-16 and 2016-17 collectively, our capex is $258.8 million (real, 2018-19) below the AER allowance. The reported capex was prepared in accordance with the capitalisation policy submitted at the time of our 2014-19 proposal and there have been no related party transactions.

8.2.2 RAB during the 2019-24 regulatory period

We have used the AER's RFM to roll forward our opening 1 July 2019 RAB value into each year of the 2019-24 regulatory period. Table 8.3 below provides a summary of the inputs used to derive these values. To comply with the rules, only forecast capex attributable to the provision of standard control services and in accordance with our Cost Allocation Methodology has been included in the RAB. The RFM is provided as Attachment 0.05.

Table 8.3 Roll forward of the RAB over FY20-FY24

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24
Opening RAB	6,512.1	6,886.8	7,232.2	7,571.4	7,900.5
Add: Forecast net capex[20]	476.6	460.5	464.5	462.5	480.7
Less: regulatory depreciation	-101.8	-115.1	-125.3	-133.4	-129.2
Closing RAB	6,886.8	7,232.2	7,571.4	7,900.5	8,252.0

As evident in the table above, our RAB is continuing to increase over the 2019-24 period. A key driver of this is the reduction in annual depreciation charges caused by the treatment of inflation in the PTRM. As per Table 8.4 below, the straight-line depreciation in the proposed PTRM, Attachment 0.04, is $1,507.3 million (nominal) compared with a regulatory depreciation amount of $604.8 million (nominal).

The consequence of this is that a long lived asset will accrue value over its first several years which increases the RAB value. Based on our analysis it can take up to three regulatory control periods (15 years) for a long lived asset to simply be depreciated back to its original cost. In addition to the significant investments required in the network, this is a key driver for the increases we observe in our RAB.

We have reduced our capex program for the 2019-24 period in order to limit RAB growth as far as reasonably practicable. For instance, our replacement capex program is $800.5 million (real, 2018-19) compared to straight line depreciation of $1,396.9 million (real, 2018-19). This suggests that we are not replacing the service potential of our existing assets at a rate equal to the rate that it is being consumed. However, as discussed in section 10.5.4 we intend to maintain the quality of our services through improving our delivery efficiency and asset management through improved asset condition information. Despite these efforts, there is a regulatory inertia to the RAB created by the approach to inflation that we are unable to fully offset.

20 This relates to Endeavour Energy funded capex and does not include capital contributions or gifted assets received from third parties.

8.3 Depreciation (Return of capital)

Return of capital (or regulatory depreciation) enables capital investors to recover the cost of their investment incrementally over the standard life of an asset. It is calculated as the depreciation on the value of the opening RAB value offset by the indexation on that asset base. Regulatory depreciation is based on the age profile of the assets within the RAB and the method of calculation.

We have calculated the depreciation on the RAB using the straight line depreciation method as employed by the AER's PTRM. Regulatory depreciation for each year of the 2019-24 regulatory control period is shown in Table 8.4 below.

Table 8.4 Forecast regulatory depreciation

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24
Straight-line depreciation	-264.6	-287.2	-306.1	-322.7	-326.7
RAB indexation	162.8	172.2	180.8	189.3	197.5
Regulatory depreciation	-101.8	-115.1	-125.3	-133.4	-129.2

Remaining asset life

The remaining standard lives of existing network assets is a key determinant of regulatory depreciation. Clause 6.5.5(b)(1) of the Rules requires depreciation schedules to conform to a number of requirements, one of which is that:

"The schedule must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets."

In previous regulatory proposals, we have adopted the AER's preferred Weighted Average Remaining Life (WARL) method for calculating remaining asset lives. We are concerned that this approach results in a depreciation profile that does not accurately reflect the useful lives of individual assets in practice. Our analysis of the WARL approach suggests the AER's preferred method over-weights new assets in the calculation and therefore over-estimates the remaining life of assets on our network. This results in investment cost recovery to be spread over a longer period of time than the actual economic life of assets and results in under-compensation for depreciation expenses.

Following careful consideration, we have adopted an alternative, more accurate approach to determining remaining asset life informed by the approach of other DNSPs. Our method for determining remaining asset life for the 2019-24 period separately tracks capex incurred during the 2014-19 period. We consider that this approach, by keeping track of depreciation on a period by period basis for each asset class, is preferred over the WARL method as it presents a more accurate method of estimating depreciation.

Under this approach:

- assets in existence at 1 July 2014 are depreciated by asset class using straight-line depreciation with the previously determined remaining lives;
- capex in the 2014-19 period is grouped by asset classes and separately depreciated over their standard lives; and
- capex in 2019-24 (and subsequent periods) will be grouped by asset classes and separately depreciated over their standard lives.

The separate tracking approach does not require us to group capex incurred during 2014-19 with pre-existing assets for depreciation purposes. This removes any distortion of remaining asset lives that would otherwise occur. This method produces depreciation schedules that better reflect the nature of the assets and their economic life and ensures that total depreciation (in real terms) equals the initial value of the assets. This addresses intergenerational equity issues created by the current approach, which defers the recovery of assets to future periods beyond the economic life of the asset. Overall, this is a more transparent approach that is easier for stakeholders to understand and consistent with accounting practice.

We note that the AER has accepted this approach in other determinations. We consider our proposed approach is consistent with the legislative requirements in the rules and in our experience the PTRM and RFM can be updated without undue effort. Table 8.5 below shows the standard and remaining life values (as at 1 July 2019) used to determine regulatory depreciation.

Table 8.5 Standard and remaining asset lives

Asset	**Remaining Life** (for opening RAB at 1 July 2014)	**Remaining Life** (2014-19 capex)	**Standard Lives** (2019-24 capex)
Sub-transmission lines and cables	25.4	45.1	47.4
Distribution lines and cables	33.3	49.0	50.6
Transformers	19.9	41.9	44.3
Substations	23.2	38.1	40.0
Low voltage lines and cables	22.9	49.9	52.4
Customer metering and load control	17.8	23.0	25.0
Communication	2.1	7.3	8.4
Furniture and fittings	2.8	11.4	13.0
ICT	5.0	4.2	5.0
Motor vehicles	0.6	7.3	8.0
Buildings	39.7	47.0	50.0
Equity raising costs	32.0	40.5	44.5
Emergency spares	5.8	22.7	23.6

Standard asset lives

In preparing our 2014-19 regulatory proposal we engaged Advisian to review the accuracy of our standard asset lives. This review found that we recover our RAB over a much longer period than other DNSPs as our standard asset lives for several classes were considerably longer than comparable peers.

We consider this analysis remains valid and there is sufficient evidence to support a reduction in the standard asset lives. Shortening the standard and remaining asset lives assumptions would enable us to:

- address the inconsistency between the technical lives reported in the annual RINs and the standard lives used for regulatory depreciation;
- align the standard lives with the lives used by other DNSPs; and
- protect against network bypass. Technology changes and reducing costs of off-grid supply options have the potential to create genuine competition for network business. Increasing the rate of depreciation in the period while the direct competition for network services is low and the price elasticity of demand is similarly low, as opposed to increasing prices if (or once) direct competition for network services emerges, may help guard against the risk of not being able to recover costs in the future.

However, this correction would increase our overall revenue requirement. This is because the return of capital would increase and only be partially offset by a lower return on capital in the short-term. Our priority is to improve the accuracy of the remaining life calculation which also increases our revenue requirements in the short-term.

In consideration of customers' affordability concerns we have not proposed to amend both the standard and remaining lives at the same time given the pricing impacts of this. We will confirm this decision at the time of the revised proposal. This is an issue we may also re-visit in future determinations, particularly in light of the potential for technological change.

Attachment 0.04 shows the standard and remaining life values (as at 1 July 2019) used to determine regulatory depreciation.

Tax asset lives

As previously disclosed in our 2015-16 and 2016-17 Annual RIN responses, we reviewed the tax standard asset lives considering the current weighting and composition of the underlying asset classes currently held using the most recent advice from the ATO. We have identified two asset classes for which the standard tax life materially varies (more than five percent) from the tax standard asset lives published by the Australian Taxation Office. We have updated the following tax standard asset lives:

- furniture, fittings, plant and equipment: updated from 8.6 years to 7.2 years; and
- information and communication technology: updated from 2.9 years to 4.9 years.

These changes largely offset one another from a revenue perspective.

Forecast inflation

The AER finalised its review into the treatment of inflation on 20 December 2017. The AER has decided to uphold the use of the RBA inflation target method. This method utilises a ten-year geometric annual average of the RBA's forecast headline inflation rate one and two years ahead and the midpoint of the RBA target inflation band (currently two to three percent) for three to ten years ahead.

We propose that the RBA inflation target method is used for setting forecast inflation in our final determination. For years one and two of the average we propose the AER rely on the forecast headline inflation rate from the RBA's Statement on Monetary Policy released in February 2018 and February 2019. In the absence of the latter we have adopted a forecast inflation of 2.50 percent as a placeholder to be updated in the AER's final determination. This is consistent with the forecast inflation we have used in determining our rate of return, which is discussed further in Chapter 12.

9.0 Incentive Schemes

CHAPTER 9

9.1 Overview

Our commitment to incentive based regulation has helped the business to become more efficient while keeping downward pressure on network charges.

We consider an incentive framework that a business responds to, provides the most efficient outcomes for customers. Our performance over the 2014-19 period demonstrates that our previous and new managements responded to, and continue to respond to the regulatory incentive schemes. Specifically, we will:

- achieve cost reductions and productivity improvements that result in us:
  - spending less than the AER's approved capex allowance; and
  - reducing our opex by $64.1 million (real, 2018-19) since 2013-14 to achieve the AER's benchmark opex by year four, our forecast base year for 2019-24.
- maintain and marginally improve our reliability and customer service performance; and
- trial a number of innovative non-network and demand management solutions.

These results are a positive outcome for customers. By reducing our opex and capex efficiently over the 2014-19 period we have reduced our opex requirements and opening RAB for the 2019-24 period, which puts significant downward pressure on our contribution to electricity prices.

We have made these improvements without compromising safety, the quality of our customer service or reliability levels. Instead, we have been able to maintain the quality of our services as promised in our 2014-19 proposal.

The AER has proposed that all available incentive schemes apply to Endeavour Energy for the 2019-24 period. We have asked our customers for their views. The general consensus was that incentive schemes should continue to operate and particular attention should be paid to innovative schemes in light of the industry transformations. We therefore support the AER's decision as customers support it and we have demonstrably responded positively to these incentive schemes and will continue to do so to the benefit of both our shareholders and our customers.

In addition to incentive schemes, we can also confirm for the 2019-24 period we do not expect to earn a material amount of unregulated revenue from the shared use of our distribution assets.

9.2 Efficiency Benefit Sharing Scheme (EBSS)

The EBSS is designed to provide DNSPs with a continuous incentive to pursue efficiency improvements in opex and spend less than the approved amount. The EBSS applies to us for the 2014-19 period and we have demonstrably responded efficiently to the incentive scheme. We will reduce our opex from $330.3 million (real, 2018-19) in 2013-14 to $266.3 million (real, 2018-19) in 2017-18. This will result in an EBSS carryover benefit that is included in our 2019-24 proposal.

Taking this into account, customers will receive the majority (70 percent) of the benefit as this lower opex amount will be used to set our allowance in the 2019-24 period thereby reducing network prices.

9.2.1 EBSS carryover amounts accrued during 2014-19

Our 2012-13 base year was deemed efficient by the AER and therefore it was used for setting our opex allowance for the 2014-19 period. On this basis, the EBSS has applied to us for the current period.

In applying the EBSS, the AER specified a number of cost categories, or types of costs, that would be excluded from reported opex for EBSS purposes. This is to ensure that the allowed and actual opex have been prepared on the same basis so that genuine efficiency improvements (or declines) are captured rather than reporting differences. The AER nominated several excludable costs for EBSS purposes.[21]

We have assessed our reported opex to exclude any categories or types of opex nominated by the AER. We have calculated the carryover payments in accordance with the rules and the AER's EBSS Guideline to ensure that the reported opex has been prepared on a consistent basis with the opex allowance. Based on these exclusions our forecast EBSS carryover benefit for the 2014-19 period is contained in Table 9.1 below.

Table 9.1 Forecast EBSS 2014-19 carryover benefit

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
EBSS carryover payments	23.2	69.1	78.7	64.1	-	**235.1**

Refer to the EBSS worksheet in the Reset RIN, Attachment RIN0.03, for further details.

We describe our current period performance in section 11.4 of this proposal. To summarise, our forecast EBSS carryover benefit is the result of our *Endeavour 2020* transformation program and the expected benefits of our partial privatisation. The latter of which is reflected in the significant forecast opex reduction for the 2017-18 base year.

We note that customers will receive a greater benefit from these reductions in accordance with the EBSS. The lower opex amount in 2017-18 has been used to forecast our 2019-24 opex resulting in an opex forecast that is significantly lower than it would have been if we had made no reductions to our opex over the 2014-19 period.

21 AER, Final Decision Endeavour Energy distribution determination – Attachment 9 – Efficiency benefit sharing scheme, April 2015, pp. 22-23

9.2.2 Application of the scheme in 2019-24

In the final F&A paper, the AER indicated its intention to apply the EBSS in the 2019-24 regulatory period if:[22]

"...we are satisfied the scheme will fairly share efficiency gains and losses between consumers and the distributors. We will decide if and how we will apply it in our determinations. Our determinations will take into account the information available to us at that time as to the distributors' revealed costs and the basis on which we approve their forecast opex."

We understand the EBSS is intrinsically linked to the revealed cost opex forecast approach. We have used the base-step-trend method to develop our proposed opex and have provided evidence that our 2017-18 base year represents an efficient level of opex. The base-step trend approach is the AER's preferred method for setting opex allowances.

As explained further in Chapter 11, our base year opex is forecast to be $64.1 million (real, 2018-19) less than the amount we spent in 2013-14. We have achieved this reduction through our *Endeavour 2020* transformation program and the commercial discipline and experience of our new management following the lease of 50.4 percent of Endeavour Energy to an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease.

It is noteworthy that our forecast base year opex results in a forecasting starting point for the 2019-24 period that is $2.8 million (real, 2019-19) below the opex allowance for the 2017-18 year, as determined by the AER in their 2014-19 decision. This reduction in opex will result in a significant improvement in our benchmarking performance using the AER's Opex MPFP.

This provides strong evidence that we have been responding efficiently to the EBSS over the course of the 2014-19 period, which has resulted in an efficient base year opex and reduced opex forecast for the 2019-24 period. On this basis we consider the EBSS should continue to apply to Endeavour Energy in the next regulatory period to ensure operating cost improvements continue to be sought and to provide customers with the opportunity to further benefit from reduced network prices. In particular, our new management should be provided with an opportunity to respond efficiently to the scheme over a full regulatory period.

Proposed excludable categories of opex

In accordance with the EBSS guideline, we propose to exclude costs from the EBSS that are not forecast using a single year revealed cost approach for the 2019-24 period. Consistent with the AER's 2014-19 determination and more recent decisions, we propose to exclude the following categories of operating expenditure for the purposes of calculating EBSS payments:

- Debt raising costs.
- Non-network alternatives costs (DMIA).
- Movements in provisions.

We consider excluding these costs will ensure allowed and reported opex for the 2019-24 period are prepared on a similar basis and consistent with the scope of the EBSS (i.e. costs forecast on a revealed cost basis).

22 AER, Preliminary framework and approach – Ausgrid, Endeavour Energy and Essential Energy – Regulatory control period commencing 1 July 2019, March 2017, p. 66

9.3 Capital Expenditure Sharing Scheme (CESS)

The CESS is designed to provide a strong continuous incentive to undertake efficient capex by rewarding DNSPs that outperform their capex allowance and penalise spending above the allowance. The CESS also provides a mechanism for sharing these gains and losses between DNSPs and customers that mirrors the 70:30 ratio offered through the EBSS. This provides a strong incentive to not over invest in the network.

9.3.1 CESS benefit accrued during 2015-19

For the 2014-19 period our forecast capex spend of $1,559.9 million (real, 2018-19) is 9.2 percent below the allowed amount. As discussed in section 10.4 of this proposal we underspent over the earlier years of the 2014-19 period due to a number of capital constraints. Over the remainder of the 2014-19 period we expect to correct this underspend to ensure there are no material between-period deferrals. Our preference was to spend the capex allowance in full by the end of the period, however this would have resulted in a CESS penalty so we have instead targeted a CESS neutral position.

In addition, we note that the Rules stipulate that the CESS does not apply to us in the 2014-15 transitional year.[23] Due to the four year application of the CESS and our capex profile we are forecast to earn/incur a zero CESS benefit/penalty despite our capex program for the 2014-19 period in total being 9.2 percent below the AER's allowance. This compares to a CESS reward payment of $7.7 million (real, 2018-19) if the CESS applied for the full 2014-19 period.

We do not consider this outcome is in accordance with the capex incentive objective contained in the Rules, cl 6.4A(a). However, we accept this outcome as not receiving a CESS payment will benefit customers through reducing our revenue requirements and therefore prices.

Our CESS model has been prepared in accordance with the Rules and the AER's CESS Guideline. We have used a forecast for actual capex in the final two years of the current regulatory period. Also, consistent with the EBSS, we have adjusted our reported capex for movements in provisions attributable to capex.

Table 9.2 Forecast CESS FY15-FY19 carryover benefit

$m; Real FY19	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**Total**
Allowed capex	455.0	368.5	311.4	302.4	288.9	**1,726.4**
Reported capex	390.4	225.0	195.5	347.5	401.5	**1,559.9**
Adjustments						
Movement in Provisions	6.6	-1.7	2.3	-	-	**7.3**
Adjusted capex for CESS purposes	397.0	223.3	197.9	347.5	401.5	**1,567.1**
$m; Real FY19	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**
CESS carryover payments	0.0					**0.0**

23 NER 11.56.3(a)(3)

Deferred capex adjustments

We understand the AER may elect to exclude CESS rewards in certain circumstances. One of these circumstances is when a CESS reward (or part of) has been earned by deferring capital work into the next regulatory period that fails to provide any benefits to customers. The AER will adjust CESS payments where capex has been deferred and:[24]

- the amount of deferred capex is material;
- the amount of the estimated underspend over the current period is material; and
- total approved forecast capex in the next period is materially higher than it is likely to have been if capex had not been deferred.

We have reviewed our delivered capital program over 2015-19 to determine whether any adjustment to our CESS payment is required to account for material project deferrals. Over the 2014-19 period we have responded to changing circumstances efficiently, consistent with the AER's views on how a DNSP should manage its capex allowance.[25]

We have serviced a higher amount of customer and demand growth than expected while maintaining network reliability and managing the impacts of the lease transaction process. In doing so, we have delivered the outcomes we committed to as part of our 2014-19 proposal with a capex spend that is 9.2 percent below the allowance.

This has resulted in a lower RAB for the 2019-24 period and no CESS payment to Endeavour Energy. This is a positive outcome for customers. Given this, and the immateriality of the underspend, we do not consider there is reason to adjust our CESS neutral position for between period deferrals.

9.3.2 Application of the scheme in 2019-24

The AER intends to apply the CESS to Endeavour Energy for each year of the 2019-24 regulatory period. In accordance with the feedback we have received from customers[26], we support the AER's decision and consider the CESS will contribute to the capital expenditure incentive objective.[27]

We also note that the AER has proposed to use forecast depreciation to establish the RAB at the commencement of the 2024-29 regulatory control period for NSW distributors. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capital expenditure efficiency gains over the 2019-24 period. We support this decision and consider it is consistent with the incentives provides by the CESS.

24 AER, Capital Expenditure Incentive Guideline, Explanatory Statement, Nov. 2013 p.46
25 AER, Preliminary framework and approach – Ausgrid, Endeavour Energy and Essential Energy – Regulatory control period commencing 1 July 2019, March 2017, p. 66
26 Endeavour Energy, Request to AER to update the framework and approach for the next regulatory control period – 31 October 2016 Attachment B: Tariff Structure Statement and Framework and Approach Workshop report, September 2016, p.12
27 NER 6.4A(a)

9.4 Service Target Performance Incentive Scheme (STPIS)

The STPIS provides us with a financial incentive to maintain and improve service performance (being reliability and customer service) where customers are willing to pay for these improvements. In doing so it balances the incentives to reduce expenditure with the need to maintain or improve service quality. In other words, the STPIS ensures that cost efficiencies encouraged by the EBSS and CESS are not made at the expense of supply reliability and customer service quality.

Below we set out our performance in the 2014-19 period and how we propose to apply the STPIS in the 2019-24 period, including proposed targets.

9.4.1 Our 2014-19 reliability performance

Service reliability is often impacted by a combination of internal and external events. Our inability to directly control many of these factors means that some level of unplanned interruption is likely to be experienced somewhere on our vast network during the course of a year. While it can be difficult to totally control our SAIDI and SAIFI performance we seek to build a resilient network and respond promptly to any unplanned outages that do occur.

STPIS performance

STPIS targets were set by the AER for the first time for the 2014-19 regulatory period. Our annual SAIDI, SAIFI and customer service performance against these set targets are shown in Table 9.3, Table 9.4 and Table 9.5 below.

Table 9.3 Unplanned SAIDI (average annual minutes off supply per customer)

Unplanned SAIDI (minutes)	2012-13	2013-14	2014-15	2015-16	2016-17
Urban Target	N/A	N/A	60.3	60.3	60.3
Urban Actual	65.2	63.3	66.7	65.9	54.6
Variation	-	-	6.4	5.6	-5.7
Short Rural Target	N/A	N/A	175.9	175.9	175.9
Short Rural Actual	200.5	173.3	209.3	191.0	168.5
Variation	-	-	33.4	15.1	-7.4

Table 9.4 Unplanned SAIFI (average annual number of interruptions per customer)

Unplanned SAIFI (number)	2012-13	2013-14	2014-15	2015-16	2016-17
Urban Target	N/A	N/A	0.800	0.800	0.800
Urban Actual	0.881	0.830	0.898	0.737	0.720
Variation	-	-	0.098	-0.063	-0.080
Short Rural Target	N/A	N/A	1.765	1.765	1.765
Short Rural Actual	2.230	1.710	2.019	1.560	1.522
Variation	-	-	0.254	-0.205	-0.243

Table 9.5 Telephone answering performance (% of calls answered within 30 seconds)

Telephone answering (%)	2012-13	2013-14	2014-15	2015-16	2016-17
Target	N/A	N/A	75%	75%	75%
Actual	84.2%	73.1%	75.1%	90.2%	84.7%
Variation	-	-	0.1%	15.2%	9.7%

At the time of our 2014-19 proposal we committed to maintaining reliability over the period. Our results over the past five regulatory years reveal that we have delivered on this commitment. Our year-on-year reliability performance has been broadly in line with our historical performance and our five-year average feeder category SAIDI and SAIFI reliability performance is very close to target.

In regards to customer service, we have generally outperformed the AER's telephone answering targets. We have also steadily reduced the number of inbound call centre roles over the past few years to a more sustainable level. This decision has contributed to a reduction in our operating expenditure. Our current staffing levels better balance our competing priorities of customer service quality and cost efficiency. We expect our telephone answering performance to be more moderate in the future as a result.

9.4.2 Application of the scheme in 2019-24

As detailed in the final F&A paper, the AER has proposed to continue applying the STPIS for each NSW DNSP as follows:

- Set revenue at risk for each distributor at ±5 percent.
- Segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural) as per the scheme's definitions.
- Apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and customer service (telephone answering) parameters.
- Set performance targets based on the distributor's average performance over the past five regulatory years.
- Apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets.
- Apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report.
- Not apply the GSL component in NSW provided we remain subject to a jurisdictional GSL scheme.

In accordance with the feedback we have received from customers[28], we support the AER's decision to apply the STPIS to us for the 2019-24 period and address the matters above in more detail below.

Revenue at risk

We support the AER's proposed total revenue at risk of ±5 percent which will be an increase from the ±2.5 percent revenue at risk which currently applies in NSW. We consider this increase is appropriate given the STPIS has now evolved beyond an introductory phase for Endeavour Energy. The performance of all DNSPs in the NEM is now subject to the STPIS and the merits of the scheme have been adequately demonstrated to justify this increase in total revenue at risk to align with the AER's most recent STPIS determinations.

28 Endeavour Energy, Request to AER to update the framework and approach for the next regulatory control period – 31 October 2016 Attachment B: Tariff Structure Statement and Framework and Approach Workshop report, September 2016, p.12

We consider ±5 percent revenue at risk is likely to provide a stronger counterweight to the combined influences of the EBSS and CESS on targeting cost efficiencies. The STPIS plays an important role in ensuring cost efficiencies pursued under the CESS and EBSS do not come at the expense of service standards.

Additionally, this increase is appropriate in light of the heightened customer and policy interest in the reliability and security of supply. This increase in concern is due to recent major interruptions in other networks and greater awareness of the importance of system security during a period of major market reforms and system transformation. By placing at risk an increased amount of revenue, we believe our customers are provided greater assurance that their reliability priorities are not secondary to our continued focus on achieving cost reductions and transformative change.

We propose to attribute this revenue at risk between the reliability of supply and customer service parameters as per the STPIS Guideline. For the customer service component, the maximum revenue increment or decrement will be ±0.50 percent.[29] The revenue at risk for the reliability of supply component for each year will therefore be subject to the customer service component outcomes within the constraints of the overall revenue at risk requirement of ±5 percent.

Network segmentation

We support the AER's proposal to segment our network according to the feeder categories as defined by the scheme (CBD, urban, short rural and long rural). We note that we do not have CBD or long rural feeders for STPIS purposes.

Performance targets

We support the AER's decision to set targets based on our average performance over the past five regulatory years. Based on this approach, performance parameter targets for the current and next regulatory period are displayed in Table 9.6 below. We expect to provide updated targets in our revised regulatory proposal to include our measured performance over the 2017-18 year.

Table 9.6 Proposed performance parameters for FY20-24

Performance parameter	2014-19 STPIS Target	2019-24 STPIS Target
Unplanned SAIDI (minutes)		
Urban	60.3	63.1
Short Rural	175.9	188.5
Unplanned SAIFI (number)		
Urban	0.800	0.813
Short Rural	1.765	1.808
Telephone Answering (%)		
% calls answered within 30 seconds	75%	81.5%

In accordance with feedback from customers, our proposed capex and opex plans are designed to meet these targets and maintain our existing performance.

29 Amended STPIS November 2009 clause 5.2(b)

Excluded events

The STPIS allows the impact of some major exogenous events to be excluded from measuring DNSP reliability performance. Clause 3.3(a) of the STPIS provides a list of specific events leading to a supply interruption that may be excluded when calculating a revenue adjustment under the STPIS.

Events which cause the daily unplanned SAIDI to exceed a pre-defined threshold may also be excluded from the STPIS. A statistical formula is used to identify this threshold value which when exceeded, is determined to be a major event day (MED). The STPIS currently sets this threshold at 2.5 standard deviations from the mean and is commonly referred to as the "2.5 beta method".

We propose to use an alternative approach to calculate MED thresholds using the power transformation (Box-Cox) method. In accordance with Appendix D of the STPIS, we are required to propose an alternative data transformation method which results in a more normally distributed data set. We have proposed this variation in accordance with clause 2.2 of the SPTIS and the requirements outlined in Appendix D.

This method was approved by the AER in our 2014-19 determination and it results in a more normally distributed data set compared to the natural logarithm transformation method. This is supported by a number of testing techniques we have undertaken to compare the performance of these two methods. Section 4 of our STPIS Proposal (Attachment 10.07) reveals these findings in further detail. As the Box-Cox method has applied to the 2014-19 period, our historical data and resulting 2019-24 STPIS targets would need to be updated should an alternate method be approved by the AER.

Value of customer reliability

The value of customer reliability measure (VCR) is an estimation of the value customers place on improved service reliability. A rise in the VCR indicates an increased willingness from customers to pay for a more reliable supply with a VCR reduction suggesting the opposite. We use the VCR to inform our capital investment decisions and also to calculate the reward and penalties for exceeding or failing to meet our STPIS performance targets.

The most recent analysis of the VCR was conducted by AEMO. These results were published in 2014 and have regularly been relied upon by the AER to develop STPIS incentive rates for all DNSPs including those for our 2014-19 determination. Without a more recent and robust review of the VCR, we propose to accept these values (rather than those published in the STPIS Guideline) and apply adjustments to reflect the impacts of inflation. This ensures VCR consistency that corresponds to the feedback from our customers which has not suggested an observable change in the value placed on service reliability over the current regulatory period.

As our network is divided into urban and short rural segments, the STPIS requires us to weigh each parameter attributable to each segment between unplanned SAIDI and unplanned SAIFI. We propose to attach the weights as set out in Table 1 under clause 3.2.2 of the STPIS.

Guaranteed Service Levels

The AER has stated the GSL component of the STPIS will once again not apply as it is currently provided through an equivalent scheme administered by our jurisdictional regulator IPART. We support this decision.

Banking mechanism

The STPIS allows DNSPs to propose delaying a portion of the revenue adjustments for one year. This may be requested to limit price volatility and is offered regardless of whether the s-factor adjustment is positive or negative.

In response to customer desire to limit fluctuations in electricity prices, we will diligently review the impact of our reliability performance and STPIS rewards and penalties on network charges and inform the AER of our intention to bank or defer any payments.

9.5 Demand Management Incentive Scheme (DMIS)

Effective demand management can defer, limit or eliminate the need to invest in traditional network assets, which in turn can lead to long-term savings for customers.

Demand management solutions have typically been sought to dampen or shift customer demand during peak periods. As network planning generally seeks to provide sufficient capacity during these peak periods, demand side responses (e.g. peak shaving, load shifting and broad-based load reductions) can be effective in lowering peak demand and removing the need to invest in assets to accommodate these demand levels.

The AER has indicated that demand management can offer alternatives to network investment outside of peak demand driven constraints. To reflect this view, they broadly define demand management as the act of modifying the drivers of network demand to remove a network constraint.[30]

We agree that the search for efficient non-network alternatives should not be limited to addressing peak demand issues and believe demand management may have the potential to provide an alternative to network asset replacements and power quality issues such as voltage regulation and frequency control. Recent regulatory changes such as the expansion of the Regulatory Investment Test (RIT-D) process to include replacement expenditure and the creation of a Distribution Annual Planning Report (DAPR) template will ensure that we pursue and evaluate demand management for a wider range of network constraints.

9.5.1 Demand Management Incentive Scheme (DMIS)

The AER published a new Demand Management Incentive Scheme (DMIS) which will replace the existing scheme and apply to us in the next regulatory period. The objective of the scheme is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.[31]

The new DMIS will provide a 50 percent cost uplift for undertaking efficient and eligible demand management projects. The scheme allows the value of this multiplier to vary but prohibits changes to committed projects. We believe the certainty of receiving a pre-defined and fixed return will further incentivise investigation of non-network solutions.

We note that our regulatory proposal does not need to outline an exhaustive list of eligible DMIS projects we intend to undertake for the 2019-24 period. Instead, we will identify eligible DMIS projects over the course of the period as we investigate non-network solutions through the RIT-D process, which has recently been expanded to replacement projects in addition to augmentation. A demand management compliance report will be prepared on an annual basis to allow the AER to validate the outcomes achieved and the pass through of incentive payments to be included in the annual pricing proposal process.

The new DMIS will be an important mechanism that incentivises increased adoption of efficient non-network solutions that benefit customers through a transparent process. We expect the DMIS will improve the viability of non-network solutions in the long-term as the costs of emerging technologies continue to fall and consumers become more responsive to market signals.

30 AER, Demand Management Investment Scheme (DNSP), December 2017, p.18
31 NER, Clause 6.6.3(b)

9.5.2 Demand Management Innovation Allowance (DMIA)

Our performance during the 2014-19 period

The DMIA that applied to us for the 2014-19 period was the November 2008 version rather than the current DMIA.

Pilots and trials provide an efficient way to test the potential usage and value of emerging technologies for customers. Over the previous and current regulatory periods, the allowance provided through the DMIA was used to fund a number of trials and pilot projects. Some of these include:

- power factor correction trial;
- pool pump trial;
- demand management education project;
- ripple control development project;
- residential battery storage trial; and
- grid scale battery storage.

We note that our DMIA expenditure will primarily occur in the latter years of the 2014-19 period. This is primarily due to our trialling of battery storage technology in residential and grid scale scenarios. These projects were delayed until battery devices of sufficient reliability and quality could be sourced from the market at an efficient price.

Our actual and forecast DMIA expenditure for the 2014-19 period is set out in Table 9.7 below.

Table 9.7 Actual and forecast DMIA expenditure to allowance

$m; Real FY19	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Allowance	0.65	0.65	0.65	0.65	0.65	**3.2**
Actual/Forecast	0.30	0.01	0.33	1.28	1.28	**3.2**

In accordance with the November 2008 DMIA, any unspent DMIA amounts for the 2014-19 period will be returned to customers via a single adjustment in the second year of the 2019-24 period (2020-21) once the full results for the 2014-19 period are known.

Application of the DMIA in 2019-24

As noted above, the AER has introduced a new DMIA which provides funding for research and development for innovative demand management projects that have the potential to reduce network costs in the long-term.

The new DMIA provides an annual allowance calculated as $200,000 + 0.075% of the MAR for each respective DNSP (as opposed to a specified amount as per the previous DMIA). Similar to the current DMIA, this allowance is provided ex ante and is recovered from consumers throughout the regulatory control period.

Based on this method our proposed DMIA for 2019-24 is outlined in Table 9.8 below. We note that we will bear any overspend to these amounts and any underspend will be returned to customers as per the existing DMIA.

Table 9.8 Proposed annual allowance caps

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Allowance	0.85	0.85	0.85	0.85	0.85	**4.2**

In developing pilots and trials we engage with customers, stakeholders and industry participants to identify research opportunities which may benefit customers. We are interested in any opportunities to engage in industry-wide trials and research projects that allow for collaboration and a transparent sharing of knowledge. We are particularly interested in understanding and supportive of the transformative changes envisaged by the ENA/CSIRO Electricity Network Transformation Roadmap and any initiatives related to the Roadmap.

9.6 Shared asset guideline

The AER may reduce our annual revenue requirement to reflect the costs we recover from using network assets to provide services that are not regulated. This means customers of standard control services do not unfairly pay for the entire cost of the shared asset. In making this decision, the AER must have regard to the shared asset principles and the shared asset guideline.

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 AER's shared asset guideline sets out its approach to making a reduction to a DNSP's annual revenue requirement to reflect the use of shared assets, including the definition and calculation of materiality.

The use of shared assets is material when a DNSP's annual unregulated revenue from shared assets is expected to be greater than one percent of its total smoothed revenue requirement for a particular regulatory year.[32] If this material threshold is not met, no shared asset cost reduction applies.[33]

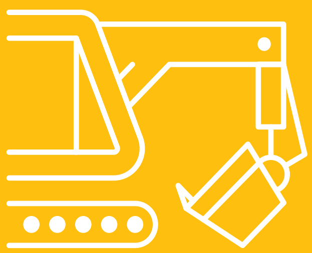
We have applied the AER's shared asset guidelines and calculated the materiality of our use of shared assets to earn unregulated revenue. The calculation of materiality for each year of the 2019-24 period is provided in the Reset RIN, Attachment RIN0.01 to this proposal. Based on these calculations, we do not expect to earn a material amount of shared asset revenue in the 2019-24 period. Consequently, no shared asset cost reduction to the proposed annual revenue requirement for any regulatory year of the 2019-24 period is necessary.

32 AER, Shared Asset Guideline, November 2013, p8.
33 AER, Shared Asset Guideline, November 2013, p6.

10.0 Capital Expenditure

CHAPTER 10

10.1 Overview



Our focus is to contain investment to that needed to ensure the supply of safe and reliable electricity to our rapidly growing region. This means replacing ageing assets while building the new infrastructure needed for 105,000 new customers.

We are proposing additional capex to replace ageing assets in order to maintain network performance and to support the significant customer growth occurring in our network area.

Our proposed capex for the 2019-24 period is $2.17 billion (real, 2018-19), which is required to support the housing and employment growth in Western Sydney and NSW's South Coast. This forecast is higher than our allowance for the 2014-19 period and is driven by:

- An increase in connections capex so that we can connect over 21,000 new customers to our network each year. We have changed how we apply our capital contribution policy following feedback we received from stakeholders. Benchmarking verified that our practices were out of step with industry practice. We reviewed our approach to ensure that connecting customers only pay for assets dedicated to their supply and existing customers only pay for assets that provide a shared benefit between the new and existing network.
- An increase in network augmentations to cater for the growth in customers and demand in multiple greenfield locations across our network. We utilised non-network, temporary supply options and existing capacity over the 2014-19 period during the early stages of development in the Priority Growth areas. These solutions will become less feasible as this growth accelerates, which means we have to invest in the network more.
- An increase in our replacement program to replace assets that have reached their end of useful life or are no longer suitable in order to manage safety and reliability risks. Our proposed replacement capex is $454 million below the amount forecast by the repex model using the AER's historical calibration method. This reduction is to account for the potential benefits our new and improved technology tools and solutions will have on our asset management practices.

We have used a combination of bottom-up condition based assessments and top-down model challenges to prepare our forecast. Our capex forecast is prioritised on a probabilistic risk basis. We have engaged with customers at a detailed level in preparing our capex forecast. We have reduced our capex forecast following feedback from customer representatives.

Table 10.1 Forecast standard control services capital expenditure (inc. equity raising costs)

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Capital Expenditure	462.3	435.8	428.8	416.5	422.2	**2,165.6**

We have challenged our overall forecast capex using the AER's models

We prepare detailed investment plans based on asset condition information prioritised on a probabilistic, risk adjusted basis to ensure our forecast is adequate to meet our obligations and maintain service quality. We tested the resulting forecast with customers and against the AER's calibrated repex and augex models and made further adjustments.

The investment projection models, and our detailed needs-based investment plans rely on several key inputs and assumptions such as customer growth, expected demand and consumption, utilisation rates and asset age and condition based information. We provide these forecasts in this proposal and the 2019-24 Reset RIN along with our forecasting methodology and expert, independent verification of several of these inputs.

We will service the significant growth in our network area and replace assets at a sustainable rate

The key focus of our capex forecast is servicing the significant growth in our network area. The NSW Government's priority growth areas are projected to accommodate 900,000 new residents over the next 20 years as part of the largest coordinated release of greenfield land for residential, commercial and industrial development in the state's history.

In addition to servicing growth, we will continue to replace assets that have reached their end of useful life or are no longer suitable in order to manage safety and reliability risks. Our forecast capex also supports the grid modernisation required to facilitate increased customer choice and participation in new and emerging energy services without adversely impacting network safety, security and reliability as detailed in the ENA/CSIRO Electricity Network Transformation Roadmap.

We have developed a forecast capex that considers the feedback we have received from our customers and stakeholders

Our overall objective is to serve the long-term interests of customers as per the NEO. We have engaged extensively with customers in preparing our regulatory proposal, including undertaking 'deep dives' with stakeholder groups. The clear message from our customer engagement program is that customers expect our capex allowance to be:

- affordable and sustainable: we have increased our forecast capex from the 2014-19 period and the initial forecast in our Directions Paper. This reflects the increased rate of growth in our network area and the change in the application of our capital contribution policy. **We have made off-setting reductions elsewhere in this proposal to ensure this increase in capex does not increase prices beyond what was consulted on in our Directions Paper;**
- no less or more than what is required: our capex forecast is based on detailed asset condition information and robust estimates of customer, demand and energy growth. We develop our capex forecast on a risk adjusted, probabilistic basis. We challenge and adjust our forecasts based on customer feedback and the results of our top-down model, the Value Development Algorithm (VDA) model, and the AER's repex and augex models. This ensures our forecast represents the efficient amount required to meet our obligations and demand for our services;
- sufficient to maintain our existing service quality, reliability and safety: we have developed our forecast capex with the objective of meeting our obligations and maintaining the safety, reliability and resilience of our network;
- reflective of a cost-effective and fair capital contribution policy: in August 2017 we amended our approach to capital contributions to move from a 'causer pays' approach to a 'beneficiary pays' based on feedback we received from stakeholders. This reduces the costs to connecting customers and DUOS prices for existing customers in the short-term.
- supportive of efficient use of non-network alternatives and initiatives associated with the ENA/CSIRO Electricity Network Transformation Roadmap: our demand and capex forecasts account for the expected impacts of embedded generation and emergent storage technologies. As part of our business as usual planning processes we routinely test our investment plans for efficient non-network alternative solutions. We will continue to transparently and efficiently trial innovative demand management solutions and investigate non-network alternatives.

10.2 Customer insights

In accordance with the NEO, our objective is to manage and invest in the network in a way that best serves the long-term interests of customers. In preparing our proposal it is therefore critical to engage with customers and test our plans and priorities with them to ensure our proposal advances their long-term interests.

As described in Chapter 5 and Attachment 5.01 of this proposal, we have consulted extensively with our customers in preparing our plans for 2019-24. This includes a series of capex specific 'deep dive' stakeholder forums we held during February and March 2018. In this section we highlight the insights of customers with respect to our capital plans and how we have sought to respond to these insights.

10.2.1 Customer feedback and our capex response

We will continue to deliver a safe, resilient and reliable network service
We sought customer feedback on whether we should maintain, reduce or improve the level of reliability for our network over the 2019-24 period. Customers' reactions were varied (see some examples below) but most supported maintaining existing service levels. On balance we have developed a capex program that seeks to maintain existing service levels.

- **Improve:**
  - Wollondilly Shire Council noted that a priority for its community was to improve network resilience to reduce the risk of failures during storm events or network failures impacting significant power reliant sectors (e.g. town centres). Wollondilly Shire Council recommended that we improve capacity and reliability in areas which experience frequent outages, increase the undergrounding of key distribution links and increase our contingency resources and planning for catastrophic failures.
  - One of the primary concerns of NSW Health is the ongoing security and sustainability of supply, which should be addressed through adequate investment in network infrastructure. We have been and will continue to engage with NSW Health on reliable supply to major hospitals on an ongoing basis.
- **Maintain:** we presented a number of options to end-use customers through our deliberative forums and focus groups. The general consensus amongst end-use customers was that we should maintain, rather than improve reliability other than where reliability was poor.
- **Reduce:** PIAC recommended that we do not use a desire to increase reliability to justify higher revenue. Rather, given the generally high standard of reliability for Endeavour Energy, PIAC suggested that slightly lower levels of reliability for reduced costs should be considered further and that our engagement on this question with end-use customers could have better addressed this issue. On this, we sought the advice of our research agency in framing the question to avoid possible bias and note this as an area for further consideration.

Our proposed capex is designed to maintain the existing safety, reliability and resilience of the network. We consider this appropriately balances the feedback we have received from stakeholders. A relatively small portion of our capex forecast, less than one percent, will be used to improve the reliability performance of our worst performing feeders in accordance with our ministerially-imposed licence conditions. Any other improvements in supply reliability are not included in this proposal and will be justified on a business-case basis in accordance with the STPIS.

34 Endeavour Energy, Attachment 5.01 - Customer and Stakeholder Engagement Activities and Findings, April 2018, p.191

We will service the growth areas of our network in a timely and efficient manner

A key driver of our capex program for the 2019-24 period is servicing the growth areas of our network. These are described in more detail in section 10.5.2 of this chapter. We have received feedback from stakeholders emphasising the importance of servicing this growth in a consultative and timely manner.[34]

> Regular consultations with relevant council officers to ensure timely provision of power related infrastructure will support balanced growth throughout the region.

It has been made clear that additional work is required for existing priority growth areas and that we must ensure our forecast accounts for non-priority growth areas and infill growth as well.[35]

> We are anticipating rapid growth in the designated Western Sydney Priority Growth Area (WSPGA) and in our City Centre coupled with the anticipated development at Western Sydney Airport (WSA) and Western Sydney Employment Area (WSEA). Despite the importance of the proposed WSA and WSEA, it is crucial to confirm that other parts of the growth area such as Austral and East Leppington are included in the overall network planning and delivery program.

> It is our opinion that Endeavour Energy should engage earlier with Western Sydney Councils' strategic planning and economic development departments to ensure timely infrastructure delivery. As mentioned in the paper, there have been capacity constraints in some locations in the South West Priority Growth Area which need to be prioritised in consultation with the relevant local councils.

And:[36]

> ...in conjunction with growth area development (Macarthur Release area) and other significant expansion areas such as Appin and Picton/Tahmoor/Thirlmere – timely expansion of network and capacity either through direct supply or augmented by on-site storage such as in West Dapto. Understanding infill growth and town/village expansion plans for Wollondilly – participate in regular coordination meetings with council.

In meeting this growth, we have also received feedback from PIAC stressing the importance that our forecast augex is efficient and prudent. Specifically, PIAC recommends:[37]

> ...that Endeavour Energy ensures it has a strong empirical basis for expenditure on expanding the network due to population growth in greenfield areas and, where appropriate, to include such expansions as contingent projects.

We explain in section 10.6 of this Chapter how we considered this feedback and have nominated a contingent project in response to PIACs recommendation.

During our capex deep dives we sought to address the concerns raised above and provided more detail on our forecasting methodology, growth servicing strategy and proposed augex projects. The main concern for stakeholders was the increase in our augex between regulatory periods and understanding why this was required. Stakeholders understood and acknowledged the robustness of our demand and customer forecasts and were supportive of our staging approach to

35 Endeavour Energy, Attachment 5.01 - Customer and Stakeholder Engagement Activities and Findings, April 2018, p.191
36 Endeavour Energy, Attachment 5.01 - Customer and Stakeholder Engagement Activities and Findings, April 2018, p.216
37 Endeavour Energy, Attachment 5.01 - Customer and Stakeholder Engagement Activities and Findings, April 2018, p.244

servicing growth. Stakeholders were of the view that the increased utilisation of non-network solutions and working more closely with developers could yield additional deferral benefits.

Based on this feedback we have updated our staging timeframes and reduced our augex forecast by $30 million. We will continue to work closely with stakeholders, including customer interest groups, state and local government and developers, to ensure our investment is both efficient and timely. Our Growth Strategy and Servicing Plan, Attachments 10.09 and 10.10, provide further detail on our intended approach while Chapter 7 provides more detail on the robustness of our demand and customer number forecasts.

We will continue the conversation regarding our approach to capital contributions

In August 2017, we changed how we applied our capital contribution policy to realign our practices with our 'beneficiary pays' intent. Under the ASP scheme and aided by the rapid escalation of developments, our capital contribution policy had drifted to a 'causer pays' approach. This meant that connecting customers paid a disproportionate amount of the connection costs, including some assets that would be shared by existing or future customers.

We received feedback from developers and councils that our approach was detrimental to customers and out-of-step with other participants in the NEM. We reviewed our approach and determined that connecting customers were paying for more than just the assets dedicated to them. Due to the tax impacts of contributed assets this resulted in a higher overall cost when considering the contribution from connecting customers and DUOS prices, so we realigned our approach with our original intent.

However, this change was an area of contention during our capex deep dive sessions. Several stakeholders expressed concerns with our 'new' approach and considered it was unfair for existing customers. While the change resulted in a short-term reduction in DUOS prices and a lasting reduction in connecting costs to new customers, some stakeholders were opposed to the long-term increase it would create in DUOS prices.

We have considered this feedback and at this stage are retaining our current practice given that the majority of our existing customers were connected on this basis (or an even more favourable basis). However, we understand our approach remains of concern to the AER's CCP and others and we are planning additional and broader industry engagement to resolve this issue.

We will manage our network in a sustainable manner

The largest driver of our capex program is the asset replacement (or repex) program, which aims to renew assets, which have reached the end of their serviceable lives or are no longer fit for purpose, at a sustainable rate over time. Our repex forecast is necessary to ensure we maintain our existing service quality and level of risk and is supported by the AER's model and calibration approach in recent determinations.

Our objective is to target a level of expenditure that is replicable and sustainable over multiple regulatory control periods. Customers are supportive of a consistent level of repex over time. To establish the efficient level of expenditure, customers said we should engage directly with the AER on their modelling results. Our initial modelling using the AER's historic approach to repex resulted in a forecast in the order of $1.3 billion (using calibration S1 discussed in Table 10.8). Reflecting on the expectations of our customers and our current network condition this model outcome was revised to approximately $850 million, which was the basis of our deep dive consultation on repex.

These discussions are not complete, however based on the information provided to date by the AER we have reduced our repex forecast from the amount presented in the capex deep dives by $50 million. We will continue to engage with the AER on the appropriate level of repex in the long-term and the efficient transition to this amount (if required).

We will trial and deploy innovative technologies where it is efficient
We note that customers expressed interest in the possibilities associated with future grid technologies. Some of the feedback we received included:[38]

PIAC supports consumers having greater choice and control in the future energy market. In order for this to be the case, it is important that Endeavour Energy and other DNSPs play a key role in facilitating these choices.

However, the decisions on how the future market develops must be based on both the long-term interests and preferences of consumers. While there are clear benefits in DNSPs providing some innovative services in the future market, there may be non-DNSP solutions that also support good, or in some cases better, consumer outcomes.

In addition, there were mixed views as to whether customers should have to fund research and innovation in these technologies at an increased cost.

During the capex deep dive consultation, stakeholders questioned the extent to which our demand forecast and proposed augex reflected the use of non-network alternatives, particularly demand management.

In developing our investment plans we routinely investigate whether non-network solutions can provide a viable and cost-efficient alternative to network investment. Our capex forecast reflects the utilisation of existing excess capacity on the network, temporary supply options, demand management options and the impacts of distributed energy resources. In addition to this, we will investigate new technologies as they emerge during the period via the AER's new DMIS and DMIA, which provide an appropriate incentive to trial and implement efficient non-network solutions. We will consider and propose innovative trials and new technologies in accordance with the planning arrangements in the Rules, in consultation with stakeholders and the DMIS and DMIA.

38 Endeavour Energy, Customer and Stakeholder Engagement Activities and Findings, April 2018, p.246

10.3 Capital governance, forecasting methodology and key inputs

Our capital plans are developed to achieve identified outcomes and objectives that align with the capex objectives and our network strategies. Our asset management approach is summarised below.

Figure 10.1 Asset management model

Our Expenditure Forecasting Methodology Statement (Attachment 0.07) provides a more detailed explanation of our investment planning and governance framework and forecasting methodology. Our Network Strategy (Attachment 10.01) outlines the overarching strategic direction and principles for asset management, which guide us in developing the right balance between costs, risks and benefits.

The Network Strategy is implemented through the plans and programs that have been guided by the framework. Individual plans in the key network investment areas have been developed that are supported by detailed analysis, which explicitly takes into account:

- externally imposed obligations and requirements including service standards, design standards, safety and environmental obligations, and specific asset performance targets;
- information about the network system including loading, condition of assets, performance variability, current capacity, age and the criticality of key assets;
- forecasts of demand growth and connections by location; and
- inputs obtained from stakeholder engagements.

These plans are integrated and optimised in the Capex Proposal (Attachment 10.03). The Capex Proposal is developed using a risk-based project prioritisation framework to integrate and prioritise these plans into an overall capex program. This prioritisation process is employed as part of the annual investment planning cycle and is supported by our Capital Allocation Selection Hierarchy (CASH) decision support tool.

All major network projects and capital programs are then required to comply with the procedures set out in the Investment Governance Framework (IGF). These procedures, described in Attachment 10.13 are summarised below:

Figure 10.2 Key stages of the network investment governance framework

10.3.1 Approach to forecasting capital expenditure

Broadly, we use needs-based plans that are tested against and aligned to both the AER's repex and augex models and our own VDA model to forecast the overall level of efficient capex. Further, with the VDA model, we are able to also use it to provide a useful reasonableness check through its ability to align with and be calibrated against the achievement of network outcomes.

Once a target level of efficient capex is established through this process, we then develop individual asset management plans for each category and asset class. The required capital works is determined based on network need, which is identified using condition based analysis. Our category level approach is summarised below:

- Augex: we use a probabilistic approach and stage investment through the use of the existing network, minor extensions, non-network alternatives, temporary or mobile supply options and network augmentations.
- Connections and capital contributions: are informed by customer growth forecasts at a category level (residential, industrial etc.) and a valuation of forecast gifted assets.
- Repex: condition based assessments to identify assets at the end of their useful life or that are not fit for purpose using criteria specified in our asset maintenance and performance standards and through individual asset condition and performance assessment regimes. Non-modelled repex categories are prepared on a business case basis.
- Non-system: are forecast in support of the level of system capex and informed by historical trends and periodically reviewed on a bottom-up basis.

10.3.2 Key inputs and assumptions

There are several key inputs and considerations that underpin our forecast capital expenditure at the time of preparing this proposal:

- Refer to Chapter 7 for our demand and customer forecasting methodologies.
- Refer to Attachment 0.09 for our proposed Connection Policy for the 2019-24 period.
- Refer to Attachment 10.08 for our NSW Distribution Licence Conditions.
- Refer to the Reset RIN, Attachment RIN0.01, for forecast utilisation, asset life, reliability performance and other expected network performance information.
- Refer to AEMO's latest published Value Customer Reliability (VCR) values for those we use for network planning purposes.

The rules also require us to identify the key assumptions that underlie the capital expenditure forecast. The section below summarises the key assumptions that underlie our forecast of required capex for the 2019-24 period, with further information on the reasonableness of each assumption provided. These are provided in Attachment 0.08 and outlined below.

- **Legal and organisational structure:** The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
- **Amendments to reliability and planning licence conditions:** The capital program has been prepared on the basis of compliance with the ministerially imposed licence conditions that came into effect on 7 June 2017.
- **Strategic management framework:** Capex programs have been developed using a strategic management framework that prioritises maintaining a safe, reliable and sustainable network.
- **Forecasts of demand:** Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.

- **Labour cost escalation:** Forecast labour cost escalation has been set consistent with the advice provided by an expert independent consultant BIS Oxford Economics and CEG.
- **Customer Engagement:** We have engaged with stakeholders in developing our regulatory proposal in accordance with the stakeholder engagement process outlined in the NER.

Our licence conditions in particular have a material impact on our asset management framework and capex requirements. As the compliance regulator, IPART conducts frequent audits to demonstrate ongoing compliance with our obligations. These include:

- distribution reliability and performance conditions: set overall reliability, individual feeder performance and customer service standards that we must comply with. This drives our proposed reliability compliance capex as detailed in section 10.5;
- critical infrastructure licence conditions: set out requirements regarding our management and operational presence in Australia and data security requirements. Our technology transformation capex addresses, amongst other things, our data security obligations; and
- management systems; our asset management system must be consistent with International Standard (ISO) 55001 and our environmental management system must be consistent with ISO 14001. Our safety management systems must also comply with Australian Standard (AS) 5577 in accordance with the NSW Electricity Supply (Safety and Network Management) Regulation 2014. AS5577 effectively prohibits us from consciously accepting a higher risk position. These management systems impact our entire capex forecast and mean that reductions are achieved through productivity and more efficient investment decisions rather than increasing risk.

In regards to real cost escalation, we have received real cost escalators based on the most recently available market data and economic analysis. We have applied the real labour escalators to our forecast capital expenditure as outlined in the table below.

Table 10.2 Real labour escalators FY20-FY24

Real cost escalators (%)	2019-20	2020-21	2021-22	2022-23	2023-24
Labour – utility	1.5%	2.0%	2.4%	2.4%	2.0%
System capex labour proportion	23.8%	23.8%	23.8%	23.8%	23.8%
System capex labour escalator	0.4%	0.5%	0.6%	0.6%	0.5%

Consistent with our approach to opex, we have not applied real escalation to the materials component of our capex forecast as we reasonably expect the costs of materials will rise largely in line with CPI over the 2019-24 period.

10.3.3 Program delivery

Following the lease transaction, our new management team identified opportunities for our business to derive further capital delivery efficiencies. Two new delivery models have been developed to implement our capital program and are in the early stages of roll-out.

- **Major Projects Unit (MPU):** contracted delivery of the major capital works program, including new zone substation construction, major plant replacements, sub-transmission feeder construction and related civil programs. A small number of contractors have been engaged under a new Collaborative Framework Agreement (CFA) for the period 2017-18 to 2023-24.
- **Alliance partnership:** a non-incorporated joint venture for delivery of low value, high volume programs. This allows our external partners to work seamlessly alongside our internal employees as a combined and flexible workforce.

We expect our new Major Projects Unit and Alliance Partnership will enable us to meet our obligations to facilitate development growth in our network area and deliver reliability outcomes from a resilient network as expected by our customers in an efficient manner. Other expected benefits from this model include:

- lower administration costs through less contracts, variations and scope creep;
- improved access to broader and different skills and capabilities;
- reduced costs through sharing of depots, equipment and skills with external contractors; and
- fast and flexible resourcing with more consistent standards of work.

10.4 Our performance in the 2014-19 period

During the 2014-19 regulatory period we expect to deliver capital investment totalling $1,559.9 million (real, 2018-19), which is 9.2 percent lower than our allowance of $1,726.4 million (real, 2018-19). Over the 2014-19 regulatory period, our capital program has focused on ensuring our customers continue to receive a reliable electricity supply from a safe and secure network.

In delivering our programs we have focused on achieving cost reductions through innovation, improved asset management processes and productivity improvements in our delivery capability. Overall, we maintained reliability while servicing higher than expected demand and customer growth and managed the within-period deferrals associated with the lease transaction process.

Table 10.3 Actual and forecast capital expenditure compared to the FY15-FY19 regulatory allowance

$m; Real FY19	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Allowance	455.0	368.5	311.4	302.4	288.9	**1,726.4**
Actual/Forecast	390.4	225.0	195.5	347.5	401.5	**1,559.9**

Our performance over the current period is useful in demonstrating:

- our delivery capability and efficiency;
- the efficiency and effectiveness of our capital governance framework; and
- the extent to which we have responded to the CESS efficiently.

In the sections below we detail the outcomes and challenges we faced during the current regulatory period and explain why we expect to spend less than our capital expenditure allowance.[39]

39 In accordance with S6.1.1(6) of the NER our capex for each year of the previous, current and forecast regulatory periods is provided in Attachment 10.19. We can confirm these capex amounts have been treated in accordance with our approved CAM, reflect arm's length terms and do not include amounts that should have been treated as opex under our previously submitted capitalisation policies.

10.4.1 2014-19 outcomes

Our expected capital expenditure for 2014-19 has allowed us to meet our core objectives and deliver on our commitment to maintain a reliable supply from a safe and secure network at an efficient and affordable cost to customers. Significantly, we are forecasting to spend less than we initially estimated was required despite needing to cater for unexpected increases in the number of customers connecting to our network. Any underspend will be passed through to customers in the 2019-24 regulatory period in the form of a lower-than-expected regulated asset base and therefore a lower contribution to network prices.

During the course of the 2014-19 period we will:

- install or replace several thousand assets, including:
  - 19 transmission/zone substations;
  - 2,800 distribution substations;
  - 2,300 transformers;
  - 22,400 poles;
  - 200 km of lines; and
  - 1,300 SCADA and communications devices;
- service NSW's largest growth areas and connect approximately 95,000 customers to our network, a record high;
- service a record peak demand of 4,107MW;
- meet our reliability objectives, specifically:
  - maintain network reliability (SAIDI and SAIFI results over period); and
  - improve the reliability of over 400 blackspot feeders in accordance with our obligations;
- deliver key investments in support of the ENA/CSIRO Electricity Network Transformation Roadmap including:
  - commencement of both residential and network grid-scale battery trials;
  - SCADA master station upgrade to support better visibility and control of the network;
  - automation of pole top devices;
  - proof of concept and rollout in selected areas of fully automated network switching to restore customers after a fault;
  - neutral integrity monitoring device trial and rollout to improve customer safety and targeting of low voltage cable replacement programs; and
  - technology transformation and cyber security improvements.

We achieved these outcomes while improving our safety performance, all within the AER's overall capex allowance. This performance was in part due to our *Endeavour 2020* efficiency initiatives, which improved our asset monitoring and performance data, and our processes to enable a more targeted replacement of assets along with delivery and procurement efficiencies.

10.4.2 Key events

Lease transaction

In 2014, the NSW Government announced that it would commence a process to lease the Government's electricity network assets. The arrangement for Endeavour Energy was to offer a 50.4% majority shareholding for a 99-year lease of assets. The purpose of the transaction was to help the NSW Government raise capital for the Sydney Metro projects, the WestConnex motorway and various school and hospital infrastructure projects.

The 2014-19 re-determination process also increased the level of investment uncertainty and led to a need to re-prioritise expenditure earlier in the period to critical activities such as vegetation management. Furthermore, the availability of capital prior to the completion of the lease transaction was also limited and therefore we did not consider it prudent to commit to long-term investments without the prior approval of the new, prospective majority shareholder.

This resulted in a number of planned capital investments being deferred until later in the period – whilst not compromising network safety and reliability in the short-term – in order to provide the new majority shareholder flexibility to review and undertake investments that aligned to their asset management practices and expectations for the business in the longer-term. Following the completion of the transaction process the Australian-led consortium, based on their vast experience in managing networks, recognised the need to increase our investment over the remaining years of the 2014-19 period to redress the short-term decisions that were made.

Our objective was to return to a sustainable level of capex to maintain the quality, reliability and safety of our services, without incurring a CESS penalty. This investment was primarily concerned with servicing growth within our network area, system asset replacements and transformation of our ICT systems.

Customer and demand growth

At the time of preparing our plans for 2014-19, significant planned expansion of our network was required to supply several large developments in the north west and south west Sydney regions, which were identified by the NSW Government as priority growth areas that would establish over 220,000 homes and 950 hectares of commercial/industrial lands. Over the course of the 2014-19 period, the NSW Government announced additional growth areas within our network area which included:

- Western Sydney Employment area: plans to commence construction of the proposed Western Sydney Airport, Sydney Science Park and Western Sydney Employment Lands;
- Greater Macarthur Priority Growth Area: the NSW Government identified approximately 7,700 hectares of land that can be developed to ultimately establish over 60,000 new homes and 700 hectares of commercial/industrial lands; and
- West Lake Illawarra Growth Area: approximately 5,000 hectares of land in the Wollongong and Shellharbour local government areas that will accommodate an estimated 26,000 homes and over 300 hectares of commercial/industrial lands.

See section 10.5.3 and Attachment 10.22 to this proposal for further details on our growth areas.

In addition to this customer-driven demand growth, peak demand has also been driven by extreme temperature events as Western Sydney experienced the hottest summer on record for both maximum and mean temperatures over 2016-17. A peak demand of 4,107MW was recorded on 30 January 2017 exceeding the previous record by 105MW, which was made on 1 February 2011. See section 7.3.2 and Attachment 7.01 for further details regarding our demand forecast and methodology.

Future grid

The emergence of new technologies and regulatory reforms have meant our customers have more choices about how they access and consume their electricity. Our objective is to enable customers to take advantage of these technological changes through efficient price signals, improved planning frameworks and targeted network investments.

Our position is aligned with the ENA/CSIRO's Electricity Network Transformation Roadmap which was released in April 2017. This Roadmap outlined a detailed and comprehensive plan for how the energy market in Australia can be transformed over the coming decades to incorporate technological advancements to the benefit of customers.

At the time of developing our plans for the 2014-19 period there was limited industry direction or consensus on long-term future network planning requirements. Since then a clear strategic vision and plan has been developed. We have responded to this by increasingly making use of new technologies to enable a safer, more reliable and efficient supply of electricity to customers where it makes good business sense. Below we provide examples of some of the changes we have implemented over the 2014-19 period to contribute to the achievement of the ENA/CSIRO Electricity Network Transformation Roadmap.

- Advanced grid architecture:
  - Our distribution feeder modernisation program which isolates faults and automatically restores supply. The devices reduce arc-flash, have greater sensitivity to earth faults and allow for improved monitoring of two-way power flows.
  - Our feeder automation program, which helps maintain reliability to customers, was extended to the Bomaderry, Wentworth Falls and West Wollongong areas.
  - Neutral integrity metering has been deployed to help detect hazardous conditions and faults on underground sections of the low voltage network for the targeted replacement of CONSAC cable, or to defer replacement where the cable remains serviceable.
- Battery trials:
  - A centralised utility scale battery system at the site of our future West Dapto Zone Substation is being trialled to determine its load management and reliability benefits. If this pilot is successful, these types of battery systems can be deployed to growth sites across our networks to defer the construction of zone substations.
  - We established a trial to determine the incentives and control issues associated with batteries installed in residential dwellings. If successful, this pilot will form part of our suite of opt-in demand management solutions which include remote air-conditioning and pool pump control during times of network peak demand.

Bushfire hazards

Over 85 percent of our network area has been identified as bushfire prone by the NSW Rural Fire Service. Consequently, we have historically focused a significant proportion of our total investments in activities and projects to mitigate the impact of bushfire events on our customers.

As explained in section 11.4.2 of this proposal, our vegetation management programs, which are predominately opex based, seek to efficiently reduce the likelihood of these risks. In addition to our vegetation management opex, we also have capital programs that play an important role in managing bushfire risk, for example:

- High voltage distribution steel mains replacement: the Victorian "Powerline Bushfire Safety Taskforce Final Report" published in September 2011 highlighted the risk presented by steel mains and the need to progressively replace these assets with a suitable alternative to reduce bushfire risk. We have implemented a program in response to this, prioritising steel high voltage distribution mains in bushfire prone areas which exhibit rust, pitting or corrosion. Over the 2014-19 period, we expect to replace 405 km of high voltage distribution steel mains.

- Corroded earthwire replacement: At the start of the 2014-19 period we had approximately 815km of lines fitted with galvanised steel overhead earthwires. Corroded earthwires represent a bushfire and safety hazard. Over the 2014-19 period, we expect to have replaced 370km of the highest risk earthwires.
- Protection modernisation program: At the start of the 2014-19 period we had over 500 distribution feeder protection systems (relays) that did not have the required speed and performance of modern relays to clear faults in a safe and timely manner. We have commenced replacement of these relays with high speed numerical relays with hi-set overcurrent characteristics within each zone substation 11kV feeder protection system. This program will have replaced 90 percent of the older relays by the end of the 2014-19 period and will materially reduce arc flash accidents, electric shock incidents and bushfire ignition risks.

Reliability Performance

Reliability of supply is a key driver of customer satisfaction and an important aspect of our network performance. In our 2014-19 proposal we committed to maintaining our overall reliability performance and addressing our worst performing feeders in accordance with our obligations under Schedule 3 of the NSW Reliability and Performance Licence Conditions.

To date, we have delivered on these commitments over the 2014-19 period. At an overall network level our SAIDI and SAIFI performance has been largely steady.

Figure 10.3 SAIDI performance FY10-FY17

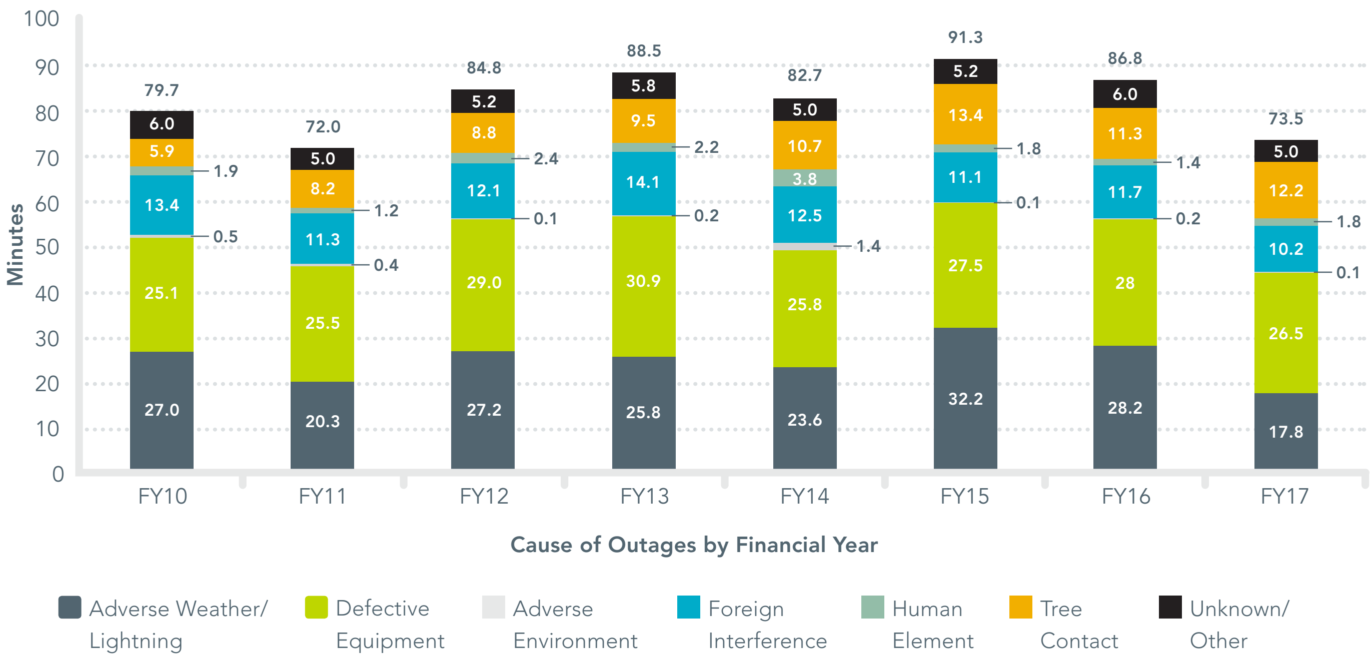
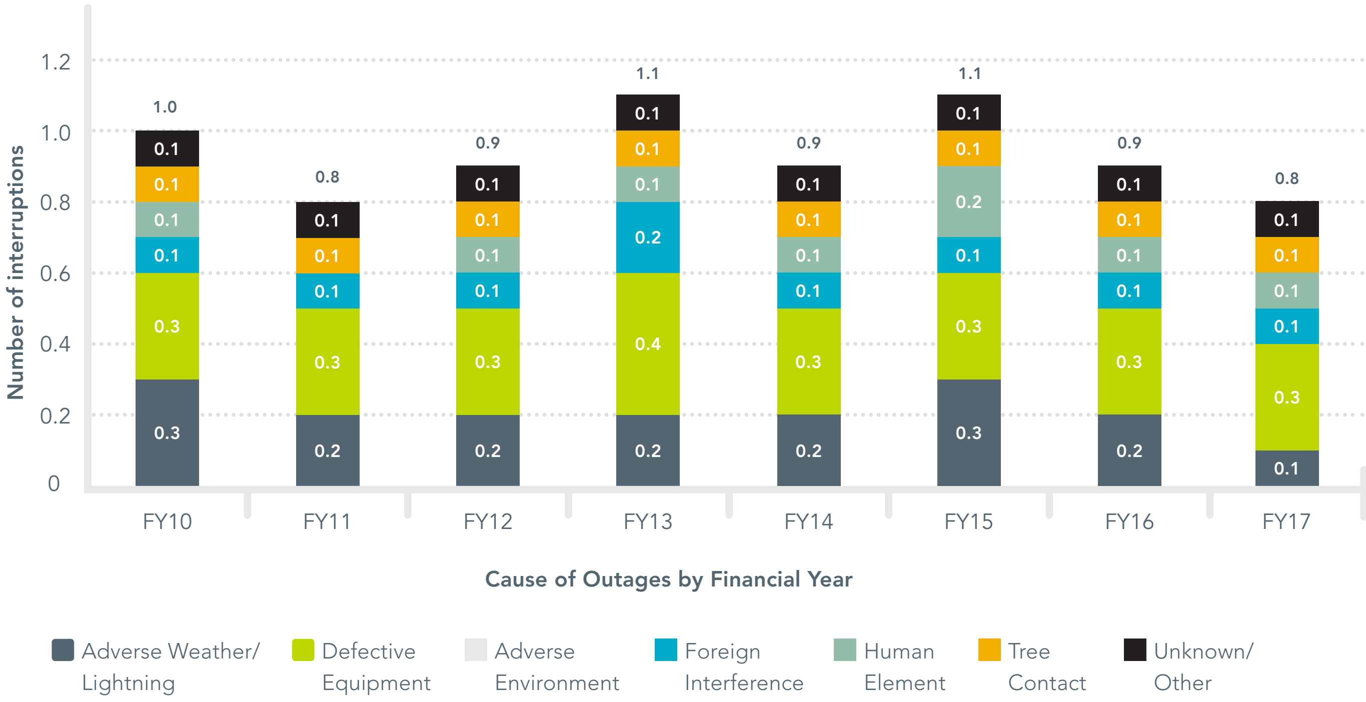


Figure 10.4 SAIFI performance FY10-FY17



It should be noted that these measures exclude extreme weather events such as major storms. There were several major storm events over the period[40], and these events are typically addressed through fault and emergency maintenance opex rather than capex.

Also, over the 2014-19 period over 400 non-compliant feeders will be addressed through a capital project in accordance with Schedule 3 of our licence conditions to maintain individual feeder performance within the minimum standards.

40 For example: April 2015 event, November 2015 event, January 2016 event, July 2016 event, October 2016 event, March 2017 event

10.5 Forecast capital expenditure program

The investment proposed over the next period will allow us to meet customer demand prudently and efficiently and ensure that our network continues to meet the statutory obligations in relation to reliability and security.

The table below summarises the capital expenditure forecasts required for our network for the 2019-24 regulatory period. These forecasts align with the objectives of our network strategy, reflect our consideration of the feedback and direction we have received from customers and stakeholders, and have been prepared in accordance with our key assumptions as outlined in section 10.3.2. Forecast capital expenditures have been allocated to standard control services in accordance with the approved CAM.

Table 10.4 Forecast capital expenditure over the FY20-FY24 regulatory period

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Connections	63.5	61.1	61.0	61.3	62.4	**309.4**
Augmentation	93.5	94.7	85.4	70.9	72.2	**416.8**
Replacement	151.0	153.0	159.7	164.0	172.7	**800.5**
Reliability	4.0	4.0	4.0	4.0	4.0	**20.0**
Other System	13.6	8.2	6.4	6.4	6.7	**41.4**
Capitalised Overheads	79.4	79.7	80.5	80.0	80.5	**400.0**
Non-System Assets	49.7	35.1	31.7	30.0	23.6	**170.1**
Equity raising costs	7.5	-	-	-	-	**7.5**
Total Capex	**462.3**	**435.8**	**428.8**	**416.5**	**422.2**	**2,165.6**

10.5.1 Connections and contributions

As discussed earlier in this proposal, we are currently experiencing significant customer growth in our network area and will continue to over the 2019-24 period. When customers seek approval to connect to our network, augmentation or extension work may be required to accommodate their connections. This work falls into one of two categories:

- **Capital contributions:**[41] for dedicated network assets a customer is required to fund these at their own cost and then 'gift' them to Endeavour Energy to maintain and operate; or
- **Connections capex:** large residential developments and new commercial and industrial sites can require augmentation and extension of the shared network which services our broader customer base. Modifications to the shared network are funded by Endeavour Energy and therefore our customers.

41 There is a contestability framework in NSW that allows customers to choose their own accredited service provider (ASP) and negotiate prices for connection services. This means capital contributions are made up of the value of assets constructed by third parties. These contributions are valued by Endeavour Energy and subtracted from total gross capex which decreases the revenue that is recovered from all customers.

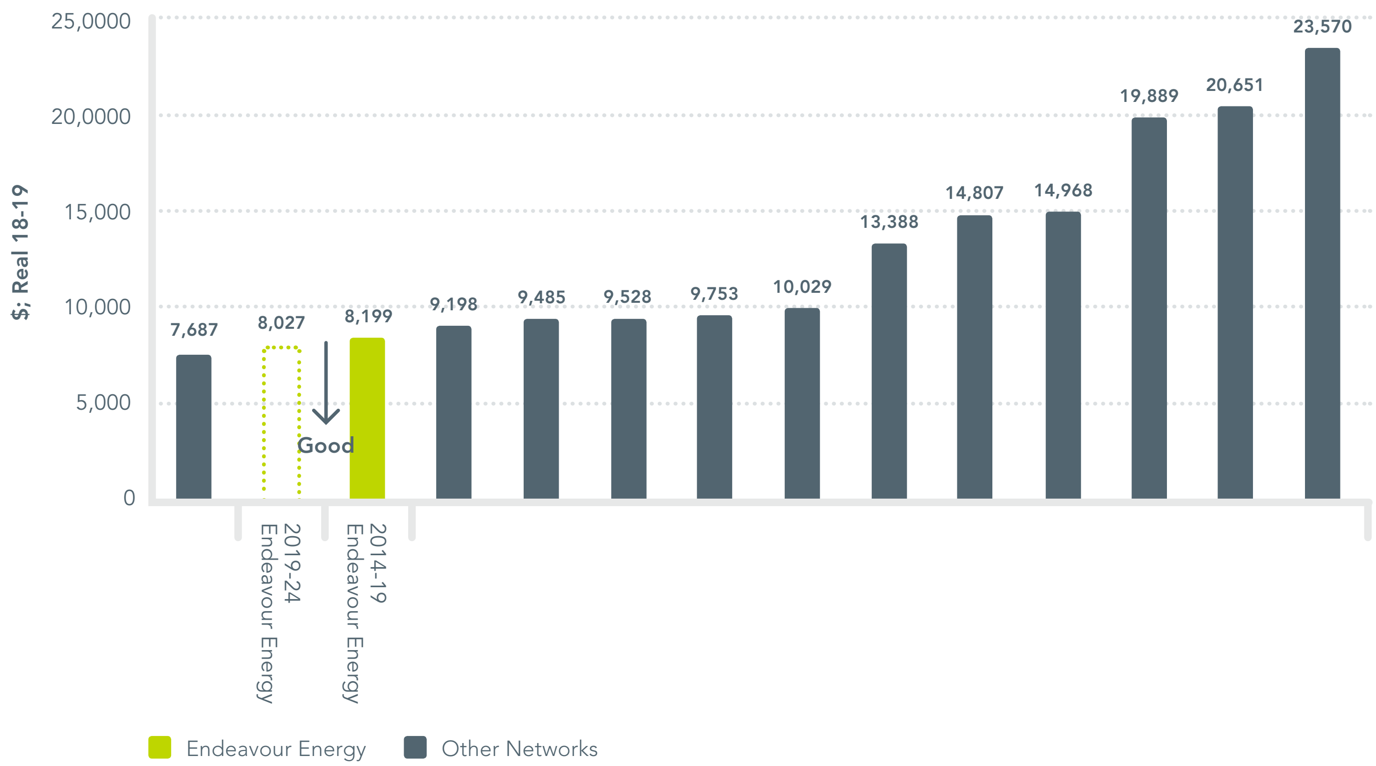
Our forecasts for both connections capex and capital contributions are provided in the table below.

Table 10.5 Proposed connections costs for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19 Actual/Forecast	2019-24 Forecast
Connections Capex	84.9	124.7	309.4
Capital Contributions	448.5	682.9	534.7
Connection Cost	533.4	807.6	844.1
Customers Connected (number)	68,025	98,503	105,158
Connection Cost per New Customer ($)	7,842	8,199	8,027

As evident above, the combined connection cost in 2019-24 is forecast to be $844.1 million (real, 2018-19) compared to $807.6 million (real, 2018-19) during the 2014-19 period. This increase is driven by an increase in the forecast number of customer connections from 98,503 to 105,158. Our unit rates are improving and remain amongst the most efficient in the NEM as evident in Figure 10.5 below.

Figure 10.5 Connections cost (connection capex plus capital contributions) per new customer[42] ($; Real FY19)



42 Source: RIN data, FY10-FY16 average performance for non-Endeavour Energy DNSPs.

As our unit rates are improving this means that the increase in our connection capex is driven by increasing volumes and our approach to capital contributions. As detailed in Chapter 7, our connection volumes are based on expected customer and dwelling growth and development activity over the period. Our customer number forecast reflects a robust estimation method informed by independent expert NIEIR and consultation with the Urban Development Institute of Australia (UDIA), councils and the state government to ensure it is reasonable.

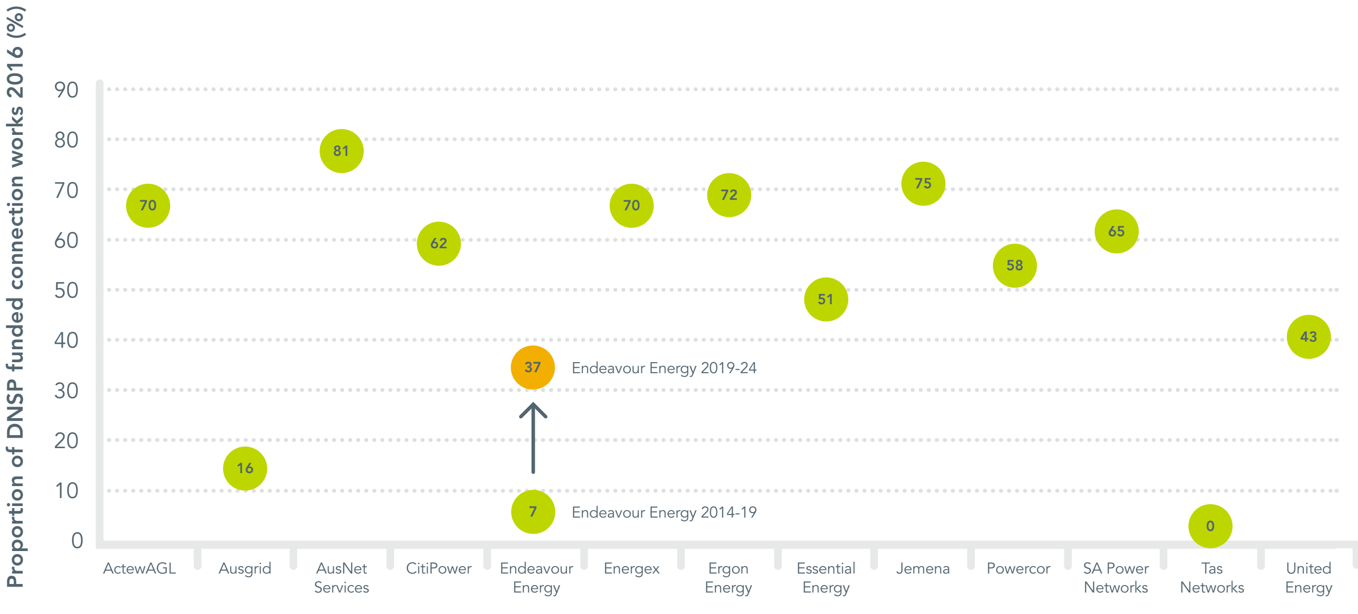
Our approach to capital contributions is discussed below. We note that the mix capital contributions and connections capex is changing following a change in the application of our capital contributions policy that was made in August 2017.

Change in the application of our capital contributions policy

Historically, Endeavour Energy funded the majority of connection costs with a contribution sought from developers for the customer service line and the low voltage cables. The ASP scheme was introduced in the late 1990s so that connecting customers had a choice of provider for the contributed portion of the works.

In recent years, the larger scale of developments has resulted in more 'upstream' shared assets being funded by connecting customers. This meant Endeavour Energy inadvertently shifted from a 'beneficiary' pays arrangement to a 'causer' pays in practice. This shift was brought to our attention by stakeholders who questioned our funding arrangements and highlighted their inconsistency with national practice.

Figure 10.6 Proposed connections capex for FY20-FY24 as a proportion of capital contributions compared to NEM FY16 actuals



Based on this feedback and analysis we reviewed our practices and determined that we were imposing shared distribution and, in limited cases, sub-transmission asset costs on developers. This created a subsidy between connecting customers and existing or future customers who may also benefit from the use of these shared assets.

To bring practices in line with our original intent and the approach of the industry more broadly, we changed how we applied our contributions policy so that:

- dedicated or customer specific assets are fully funded by the relevant customer – single end use large connections still fund almost all connection costs under this approach; and
- assets that will provide current and/or future customers with supply or improve service or resilience are funded across our customer base in common with all other common service assets.

This is a return to a 'beneficiary' pays approach that we consider is more appropriate, particularly with an increase in 'two-way' energy flow with increasing penetration of embedded generation and battery storage.

In addition to this, we considered the implications of this change on the price customers pay. At the overall level, being DUOS prices and the capital contribution cost a connecting customer bears, this change results in a lower cost. This is because we reduce the income tax associated with gifted assets by recovering more of these costs via our RAB. However, on a strictly DUOS basis this means electricity prices increase in the long-term.

In accordance with the NEO, we are required to act in the long-term interests of both existing and future customers. This means the concerns and interests of connecting customers should not be considered less important and separate to the existing grid connected customer base. Therefore, we have sought to reduce DUOS prices and capital contributions collectively.

As noted previously, the total connection cost per customer in our network area is the second lowest in Australia over the last several years. We expect this trend to continue into the next regulatory period irrespective of the change in mix between connections capex and capital contributions.

As discussed in section 10.2, during the capex deep dive sessions several stakeholders expressed concerns about the impact of this change on DUOS prices for existing customers in the long-term. We are proposing to retain our existing approach as the majority of our existing customers were connected on similar (or more favourable) terms. We will continue to engage with the AER and stakeholders on this issue. In addition, we have committed to conducting a broader industry workshop with other NSW networks to review the approach to capital contributions within the NSW context.

10.5.2 Augex

As noted in Chapter 7, we have shifted into a prolonged period of customer growth. In catering for growth we adopt a probabilistic planning approach. This means we assess the likelihood and consequence of failure, or unavailability, or one element of item of plant and use VCR to monetise this risk. We provide 'N-1' security, which means that customers can be supplied in the event of failure or unavailability of one element or item of plant, if the cost of doing so is less than the value of risk.

A key component of our investment approach for augex is servicing growth in "stages" to defer significant network investment until it is self-evidently necessary. Broadly, these stages entail utilisation of the existing network and/or minor network extensions, non-network solutions and network augmentation. We select the most efficient option and staging approach that best addresses the strategic objectives outlined in our Growth Strategy and Growth Servicing Plan (Attachments 10.09 and 10.10 respectively).

Based on this approach, our forecast augex for the 2019-24 period is outlined in the table below.

Table 10.6 Proposed augex for FY20-FY24

$m; Real FY19	2014-19 Allowance[43]	2014-19 Actual/Forecast	2019-24 Forecast
Brownfield	118.8	97.7	115.7
Greenfield	192.4	158.2	301.1
Total	**311.2**	**255.8**	**416.8**

An increase in augex is required to accommodate the customer and associated demand growth on our network over the 2019-24 period. Specifically;

- customer growth: our customer numbers are expected to grow by approximately 21,000 per annum compared to 9,000 per annum as recently as 2010-11; and
- spatial demand growth: approximately one third of our 164 zone substations are expected to experience growth rates of greater than 1.5% per annum and another third expected to experience growth rates of between 0% and 1.5%, per annum.

In the following sections we provide more detail on our proposed augex by driver.

Brownfield augex

Brownfield refers to augex on existing parts of the network generally caused by 'organic' demand growth i.e. from existing customers. As noted previously, peak demand is continuing to grow. Energy efficient and DER technology is only having an impact on energy consumption at this stage. It is important that we service demand growth from our existing customers to ensure they have a reliable supply of electricity at critical times i.e. hot weather events. The significant impact of blackouts at these times was evident during the Victoria and South Australia outage events of January and February this year.

Our proposed brownfield augex reflects improving efficiency in our unit rates and the use of available headroom capacity or limited demand growth in some existing locations. A key driver of this program is our demand forecast, detailed in Chapter 7.

The majority of our brownfield augex is driven by the impacts of connection driven demand growth in existing areas and managing fault levels, voltage and feeder constraints. Key investments include:

- High voltage development works: proposed capex of $32.8 million (real, 2018-19) to address overloaded feeders and manage 11kV feeder constraints, fault levels and voltage regulation. This amount is consistent with our 2014-19 program and reflective of our risk-based approach. We seek to minimise this capex through monitoring, load transfers, ratings studies and leveraging existing projects.
- South Penrith Zone Substation: proposed capex of $28.1 million (real, 2018-19) to cater for new residential, industrial and commercial release areas around the Penrith CBD. In the early stages of this project we are utilising existing capacity and managing load at risk through demand management, temporary load transfers and cyclic loading of assets. Ultimately, a new zone substation in the South Penrith area will be required as the existing Penrith Zone Substation has a firm capacity of 52 MVA against a forecast demand of 54.8 MVA by summer 2019 with a further 20 MVA of residential, commercial and industrial load applications received.

43 An allowance was not provided at the augex category level. For comparison we have split the total allowance in the same proportion as the 2014-19 actual/forecast augex.

- Riverstone East Zone Substation establishment: proposed capex of $20.6 million (real, 2018-19) to cater for the new residential release of 5,800 lots. We have been utilising existing capacity from Riverstone and Schofields Zone Substations. A new zone substation in Riverstone East will be required as Riverstone Zone Substation cannot sustain the expected increase in demand and existing feeders from Schofields cannot be extended further due to distance.
- Westmead Zone Substation augmentation: proposed capex of $12.8 million (real, 2018-19). This is due to the $3.0 billion expansion of Westmead Hospital and Health Precinct and the development of light rail in the area which will further increase high density residential developments.
- Feeder 214/215 constraints: proposed capex of $9.5 million (real 2018-19) to address load at risk in the Parklea, West Castle Hill and Bella Vista areas. We have sought to manage load at risk through temporary load transfers and automated switching. We will need to reinstate feeder 229 to increase contingency capacity from Sydney West via Baulkham Hills.

We have tested the reasonableness of our brownfield augex forecast against the AER's Augex model as a top-down challenge. We engaged Dr Brian Nuttall, who designed the augex model, to conduct this analysis. Dr Nuttall found that the augex model provides very strong support for our brownfield augex forecast which is well below the model's forecast. We note that the augex model is relied on less by the AER than the repex model. However, the augex model provides evidence of our improving unit rates and efficiency, Dr Nuttall notes:[44]

> ...it is also worth noting that both Endeavour and the model are forecasting that augex per unit of demand growth will reduce significantly from historic levels…….The model predicts total augex only needs to increase by a factor of 1.3 due to this increase in demand growth. Endeavour on the other hand is forecasting a much more significant reduction in augex than predicted by the model, with Endeavour's forecast of total augex reducing by 10% compared to historical levels.

See Attachment 10.03 for further details on our brownfield augex.

Greenfield augex

Our greenfield augex is forecast to be materially higher than the forecast for the 2014-19 period. This increase is due to the increasing customer growth numbers, industrial development and emerging spatial capacity constraints. During our capex deep dive sessions stakeholders understood and accepted that there is significant customer growth in our network area over the 2019-24 period that we will need to service.

Our staged approach, which defers network investments, means that over the 2014-19 period we serviced a material amount of customer connections through existing or nearby capacity and/or temporary supply options in the earlier stages of development. This is evident in the increasing utilisation of distribution feeders over the period and the reduced availability of capacity 'headroom' in zone substations neighbouring growth areas.

44 Attachment 10.25: Nuttall Consulting - Assessing the Endeavour Energy augex forecast, February 2018, p. 25

Figure 10.7 Utilisation of 11kV feeders FY13-FY17

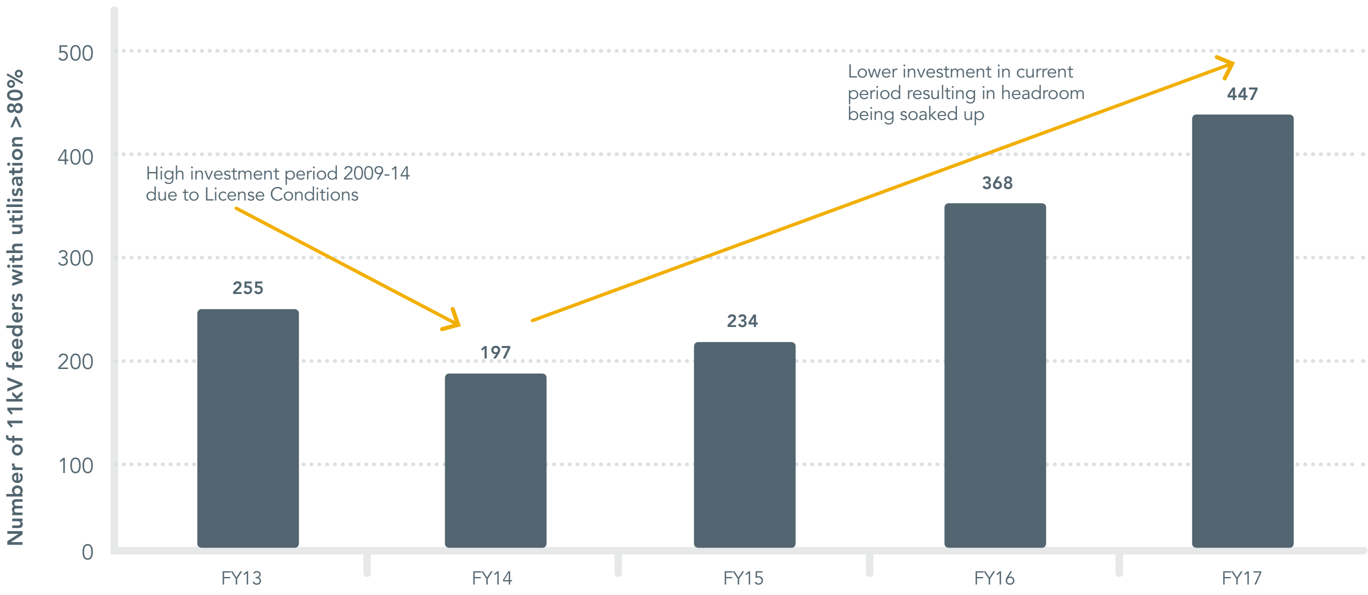
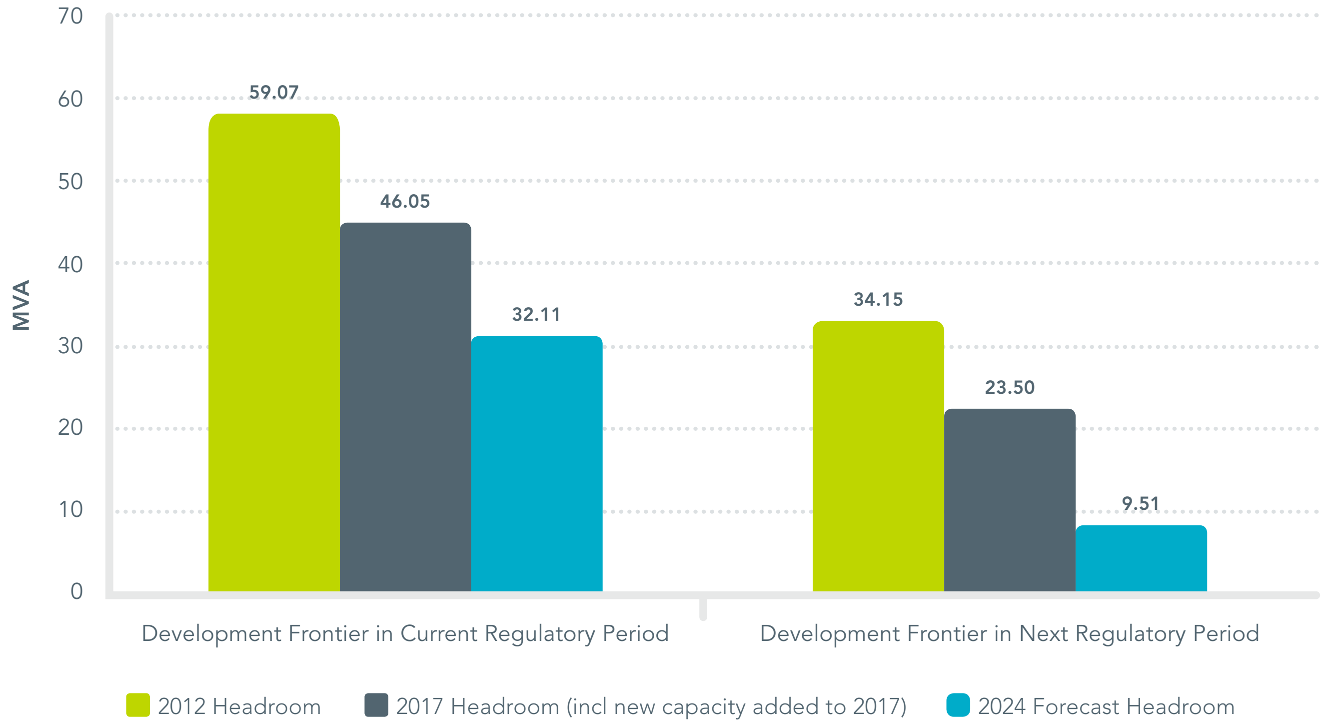


Figure 10.8 Average capacity headroom in zone substations surrounding greenfield growth areas (MVA)



This means that for the 2019-24 period several projects are moving into the latter stage solutions which involve more expensive network investments. These include HV feeder augmentations, underground circuit lines and increasing capacity through the establishment of new zone substations. This has resulted in an increase in land costs and associated civil works to construct and house new assets in new locations rather than being able to upgrade and rely on existing network assets.

The faster pace of developments and location of developments to existing network with capacity headroom limits the ability to utilise existing capacity or temporary supply options for the 2019-24 period. This means that the increase in greenfield augex is driven by volume (i.e. the number of zone substation establishments required) rather than unit prices, which are decreasing.

Table 10.7 Greenfield augex FY15-FY19 compared to FY20-FY24

	2014-19 Actuals/Forecast			2019-24 Forecast		
Greenfield Augex	**ZS Projects**	**Cost ($m; FY19)**	**Cost per ZS project ($m)**	**ZS Projects**	**Cost ($m; FY19)**	**Cost per ZS project ($m)**
Industrial	1	36	36.0	3	91	30.3
Residential	6	128	21.3	13	210	16.2
Total	**7**	**164**	**23.4**	**16**	**301**	**18.8**

Overall, the opportunities to utilise capacity headroom to address growth areas is becoming limited. This means we will need to build more network during the 2019-24 period to address greenfield growth compared to the current period. However, in doing so we are building more for less by improving our efficiency and lowering our unit rates.

We have tested this forecast using our VDA model and the AER's augex model. We note that the augex model is typically used for forecasting capex to meet growth on the existing network. We have altered the model to include greenfield growth and applied a calibration method similar to what is used in the repex model. Dr Nuttall has independently reviewed the input parameters and calibration steps we have used, see Attachment 10.25.

Based on this analysis, we consider our forecast augex is reasonable as it only 67 percent of the forecast produced by the AER's calibrated augex model and the unit rates have declined from historical levels.[45]

Managing uncertainty

We adopt a conservative and prudent approach to managing customer and demand growth to ensure that network investments are only made where it is efficient and necessary. We manage uncertainty in a number of ways:

Accuracy of our demand and customer forecasts: as discussed in Chapter 7, we use robust forecasting methods to ensure we form a realistic expectation of future growth. Our forecasts are independently verified by experts and tested against third party forecasts for reasonableness.

Our forecasts reflect the impact of demand management and non-network initiatives such as solar PV installed on the network to date. Post-modelling adjustments are then obtained from an independent expert to form a realistic expectation in the future uptake and growth in these technologies (such as batteries). This means that we build for a much lower level of demand per customer than historically. For instance, our ADMD in 2000 was 7kVA per customer and we now use 3.2kVA for zone substation planning.

45 Attachment 10.25: Nuttall Consulting - Assessing the Endeavour Energy augex forecast, February 2018, p. 24

Staging investment: as aforementioned, we defer the establishment of zone substations by staging our solutions. This allows time to observe and verify the actual growth experienced before committing to costly and permanent solutions. The stages are broadly as follows:

- Stage 1: Utilise existing capacity in the 11kV network (connection costs only).
- Stage 2: Augment/Extend 11kV feeders (typically $1-7 million in augex).
- Stage 3: Temporary/Mobile supply or single interim transformer (typically $5-20 million in augex).
- Stage 4: Full zone substation establishment (typically $20-40 million in augex).

This approach means we provide supply on an as-needed basis to growth areas. During our capex deep dive sessions customers were supportive of our staged approach to servicing growth and considered this could provide further opportunities for non-network options than currently anticipated. Based on this feedback we have made a $30 million reduction to the augex presented at the deep dives by extending the earlier stages.

An example of our staged approach at Box Hill is provided below.

Figure 10.9 Staging approach case study – Box Hill

Stage 1	Stage 2	Stage 3	Stage 4
Existing 11kV Feeders from Riverstone Zone Substation	22kV conversion and two new 22kV (7km) Feeders from Mungerie Park Zone Substation ($7m current period 2017)	Augment part of 22kV network ($1m current period connection capex 2018)	Establish 22kV Box Hill Zone Substation ($34m next period)
300 homes	3750 homes	4350 homes	14,000 homes potential 122ha industrial and town centre ($34m next period)

In stages 1 and 2 for 11kV/22kV capacity we are generally providing supply at 'N' security meaning the load on the feeder is the trigger for further investment. We will move beyond stage 3 when the risk and cost of failure, noting a single asset failure will cause an interruption at 'N', outweighs the cost of investment.

Non-network alternatives: the process above provides additional time to investigate and utilise demand management and non-network alternatives at each solution stage. We publish a DAPR and RIT-D reports in accordance with the Rules to investigate viable non-network alternatives.

We have had success historically with demand management programs such as *Solar*Saver and *Cool*Saver, distributed generation, demand response programs (typically air-conditioner and pool pump cycling) and pricing trials as detailed in Attachment 10.07.

We are currently conducting both residential and grid-scale battery trials and continue to improve the cost-reflectivity of our tariffs. These initiatives can lengthen the stages outlined above or reduce the scale/cost of network based solutions. As discussed above, we have made further reductions to our augex on the assumption that these solutions will lengthen the earlier stages.

Key augex projects

Area Plans are developed for areas that are expected to require significant investment in the future. The purpose of these area plans is to outline an overarching view of the network infrastructure that will be required to service the identified growth area.

The identification of growth focus areas covered by area plans is based on the following triggers:

- Priority Growth Areas are identified by the NSW Government and require a level of analysis, rendering these growth focus areas in need of network development area plans.
- Annual planning reviews of the capacity of the network and its ability to meet forecast demand for electricity and the growth in new customer connection.
- Our ongoing interactions with urban planning bodies and developers, which serve to identify future development needs and development areas.

The growth areas identified for which we have long-term development area plans are:

- North West Priority Growth Area;
- South West Priority Growth Area;
- Western Sydney Priority Growth Area;
- Sydney Metro North West Urban Renewal Corridor;
- Greater Macarthur Priority Growth Area;
- Glenfield to Macarthur Urban Renewal Corridor (subset of Macarthur Priority Growth Area); and
- West Lake Illawarra Growth Area.

In addition to these strategic growth areas, existing large urban centres within our supply area such as Liverpool, Parramatta and Penrith are experiencing significant brownfield re-development and increases in density, which in themselves attract special planning consideration.

Area plans for these centres are formulated as required when significant investment requirements are foreseen, driven by firm redevelopment plans or observed significant growth trends. Triggers are typically driven by situations such as changes in planning limits to increase density or building heights, increases in applications for supply connections to new higher-density developments, etc.

A listing and descriptions of our greenfield augex projects is provided in Attachment 10.22. In accordance with the Rules[46] some of our forecast capex relates to projects which have already satisfied the requirements of the RIT-D. These are:

- Stage 2 of South Marsden ($9.6 million in 2019-24) with final project assessment report issued April 2018; and
- North Leppington ($3.2 million in 2019-24) with final project assessment report issued in October 2016.

A draft project assessment report for South Leppington Stage 2 ($14 million in 2019-24) has also been recently published.

An overview of the features of our largest greenfield release areas is provided in the following sections.

46 NER Clause 6.5.7(b)(4)

North West Priority Growth Area

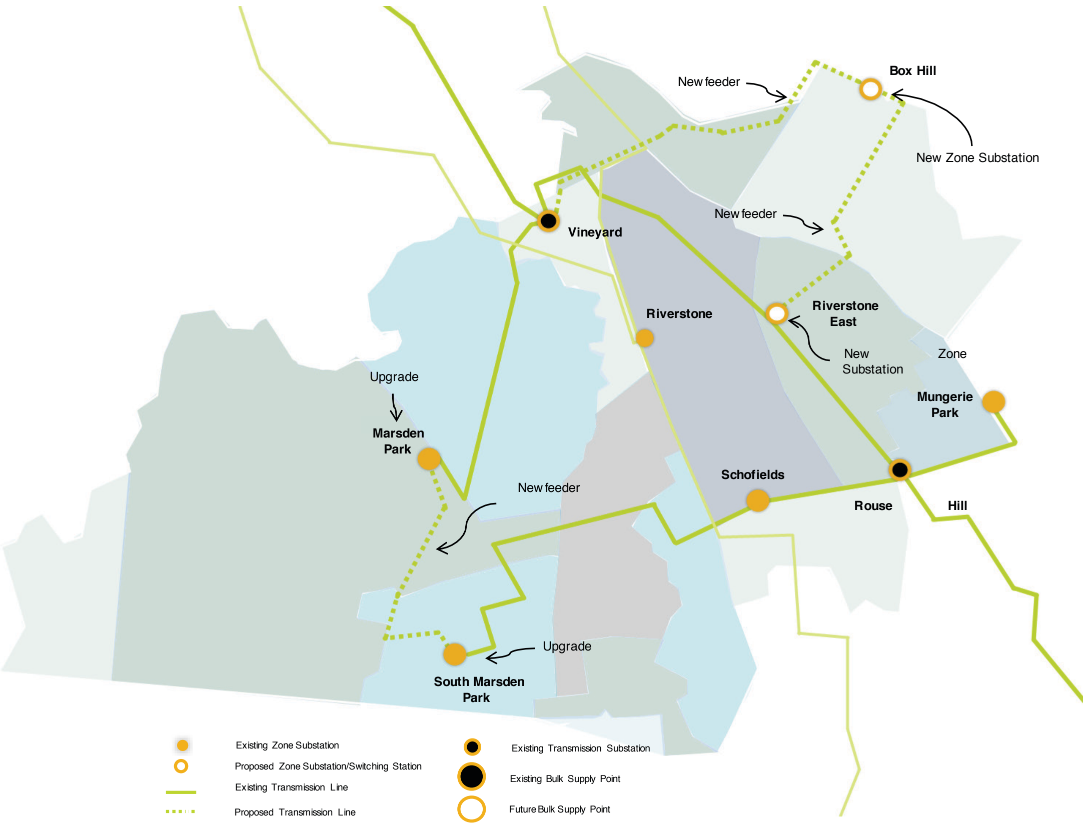
The North West Priority Growth Area is approximately 10,000 hectares of mostly rural land that is progressively being urbanised with greenfield development. It is within the boundaries of the three local government areas of The Hills, Blacktown and Hawkesbury, which will ultimately have 90,000 homes and over 500 hectares of commercial and industrial development.

The NSW Government aims to facilitate delivery of 33,000 homes by 2026 by investing in road, rail and water infrastructure to release land in this area for development, for example the Sydney Metro North West rail line due to be completed in 2019. The State Government is also actively pursuing increased housing supply to tackle housing affordability via policy changes and provision of infrastructure. In addition there has been strong growth in commercial/industrial areas such as the Sydney Business Park at Marsden Park where larger businesses have moved in. Investing in electricity capacity to connect greenfield development is necessary to supply these investments and developments.

Western Sydney has a hotter climate than coastal areas, often 10 degrees warmer than the coast, with temperatures above 40 degrees occurring during most summer periods. Demand is summer peaking driven by air-conditioning demand. Although penetration of solar PV continues to grow, the peak generation of output of solar at midday does not align with the evening peak, when air-conditioners and other household appliances are used.

We have invested prudently to support growth in the North West Priority Growth Area, however capacity constraints for greenfield development remain in specific locations. This is because new precincts are released over time, creating new development frontiers; higher densities are being encouraged; and the fact that previous investment has been efficiently staged.

During a five-year period commencing 1 July 2019 we plan to invest approximately $80 million in major growth projects to ensure continuing connection capacity is available in the North West Priority Growth Area. See Attachment 10.22 for the full area plan.



South West Priority Growth Area

The South West Priority Growth Area is approximately 10,000 hectares of mostly rural land that is progressively being urbanised with greenfield development similar to the North West Priority Growth Area.

The area is located within the boundaries of the Liverpool, Camden and Campbelltown local government areas. It will ultimately have 132,000 homes and over 450 hectares of commercial / industrial lands including the new Leppington and Edmondson Park Town Centres.

The NSW Government has delivered the South West Rail Link from Glenfield to Leppington via Edmondson Park to stimulate residential and commercial development in this priority growth area. Investment in road, rail, sewer, water, gas, telecommunication and electricity infrastructure is occurring to meet demand as each precinct is released.

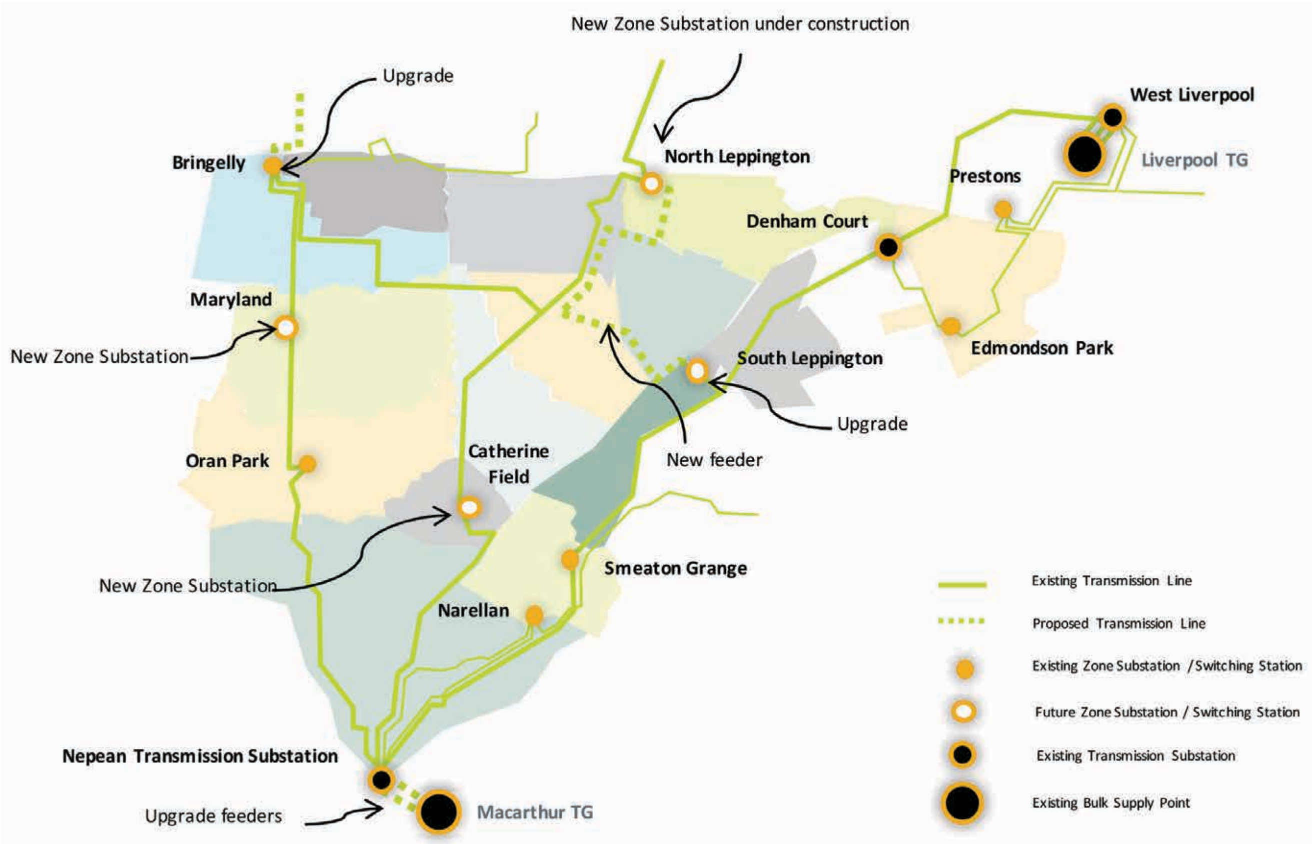
We have previously invested prudently to support growth in the South West Priority Growth Area, however capacity constraints for greenfield development remain in specific locations.

This is due to new precincts being released over time creating new development frontiers; higher densities around transport corridors and town centres; and the fact that previous investment has been staged.

During a five-year period commencing 1 July 2019 we plan to invest approximately $52 million in major growth projects to ensure continuing connection capacity is available in the South West Priority Growth Area.

The ultimate development of the South West Priority Growth Area will take place over a 30-year period and will require ongoing investment to provide a forecast electricity capacity of 600MVA.

See Attachment 10.22 for the full area plan.



Western Sydney Priority Growth Area

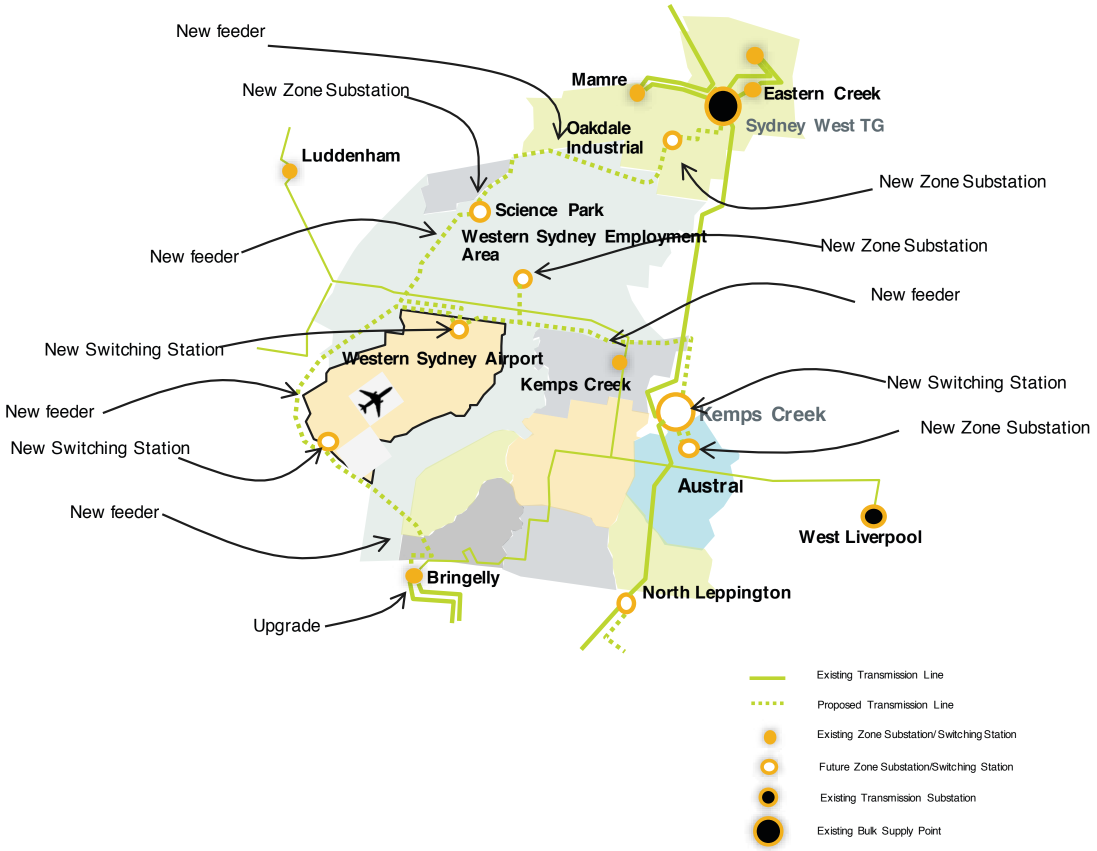
The NSW Government is working with local councils and service utilities to develop employment opportunities, residential and supporting infrastructure and services around the planned Western Sydney Airport at Badgerys Creek in Sydney's west. This forms the basis of the Greater Sydney Commission's vision of a 'third city' for Sydney, after Sydney CBD and Parramatta.

The new Western Sydney Priority Growth Area is approximately 10,300 hectares of rural land that encompasses the proposed airport, the Sydney Science Park and Western Sydney Employment Lands extending from Eastern Creek to Austral, Leppington and Bringelly.

The area is shared between Blacktown, Fairfield, Liverpool and Penrith local government areas with Liverpool and Penrith sharing the majority of the area.

Since the announcement of the construction of the airport, development interest in the surrounding lands continues to increase significantly. The airport is expected to be operational by 2026; however works to clear the site of existing electricity infrastructure will begin in 2018-19, while construction of the 132kV electricity infrastructure to support the airport and the surrounding development areas will need to begin in 2020-21.The airport developer, rather than our customers, will be required to fund the dedicated assets of this network infrastructure.

At this stage it is unclear what the connection requirements will be for the Western Sydney Airport. We have therefore included a contingent project for this component of potential investment; see section 10.6 of this chapter for further details. For the surrounding areas we plan to invest approximately $102 million in major growth projects to support development of the Western Sydney Priority Growth Area. As the 'third city' vision begins to take shape, further development of the growth area will take place over a 40-year period and will require ongoing investment to provide a forecast capacity of 850MVA.



Greater Macarthur Priority Growth Area

The Greater Macarthur Priority Growth Area is approximately 17,600 hectares of mostly rural lands across Campbelltown and Wollondilly local government areas.

Of this area, the NSW Government has identified approximately 7700 hectares of land that can be developed in the short term and will be priority growth precincts.

Developments at Menangle Park, Mount Gilead, Wilton New Town and the West Appin precincts are expected to establish over 60,000 new homes and 700 hectares of commercial / industrial lands.

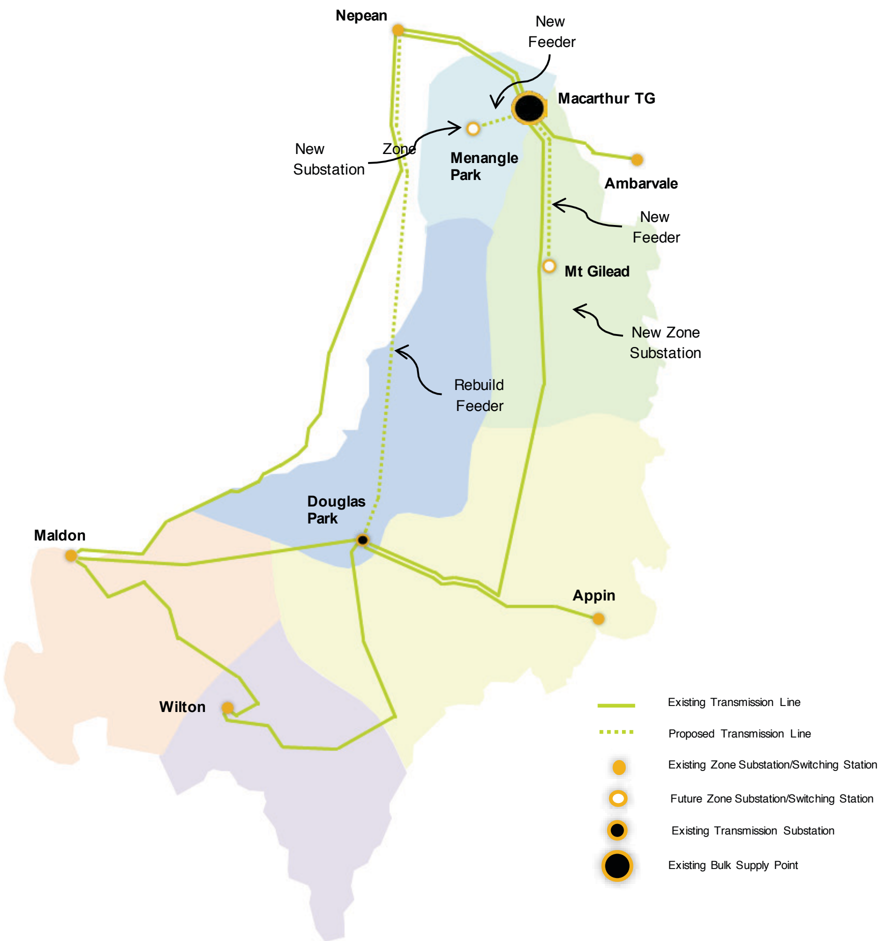
There has also been more recent interest in developing areas south of Mt Gilead and this will result in the construction of additional new homes. Collectively this will ultimately impose network demand in excess of 300MVA.

Development in the precincts listed is predominantly driven by large single developers and landowner consortiums and consequently could develop at a faster pace than fragmented precincts.

During a five-year period commencing 1 July 2019 we plan to invest approximately $33 million in major growth projects to ensure continuing connection capacity is available in the Greater Macarthur Priority Growth Area.

Further investment will be required as this new development frontier gathers pace.

See Attachment 10.22 for the full area plan.



West Lake Illawarra Growth Area

The West Lake Illawarra Growth Area is approximately 5,500 hectares of mostly rural land across Wollongong and Shellharbour local government areas. It will ultimately accommodate an estimated 26,000 residential dwellings and comprise 3.1km2 of commercial / industrial lands. Based on the total number of dwellings and commercial / industrial lands, the ultimate imposed network demand is estimated at 128MVA.

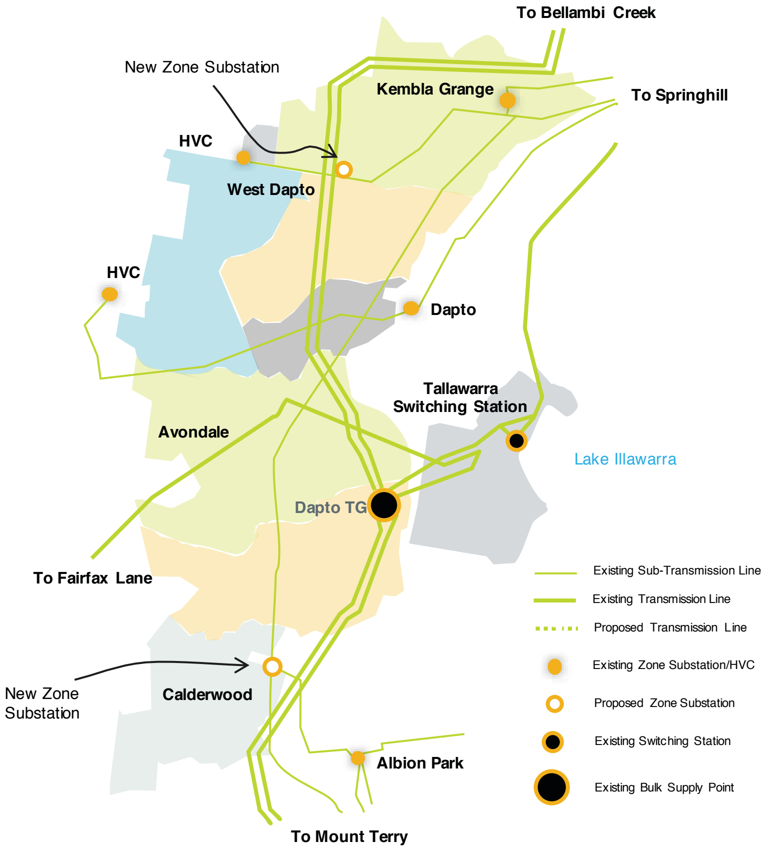
There are four main greenfield development precincts in the area. These are Calderwood, West Dapto, Tallawarra and Avondale. These precincts are located within the boundaries of the Illawarra escarpment to the west, the existing suburbs of Horsley, Dapto and Tallawarra to the east, the existing Kembla Grange employment lands to the north and Albion Park to the south.

Current developer activity within the Calderwood precinct is driven by a single large developer whereas the larger West Dapto precinct comprises fragmented land ownership with small developments. Initial development activity has commenced in the Avondale precinct, but there is presently no activity in the Tallawarra precinct.

The NSW Government through the Wollongong office co-ordinates the Illawarra Shoalhaven Development Program. It aims to manage continued land and housing supply in the Illawarra and Shoalhaven region through implementation of regional strategies.

During a five-year period commencing 1 July 2019 we plan to invest approximately $30 million in major growth projects to ensure continuing connection capacity is available in the West Lake Illawarra Growth Area. Further investment will be required as development matures.

See Attachment 10.22 for the full area plan.



10.5.3 Asset replacement

We invest in the renewal and replacement of assets when the condition of the asset indicates that the continued safe and reliable operation of the existing asset is no longer economically viable. There are a number of regulatory obligations that drive our investment including public safety, workplace safety and environmental legislation.

Our objective is to replace assets at a sustainable rate to maintain the safety and reliability of our services. We determine our replacement needs through the following steps:

- Repex modelling: this informs the size of our overall program and enables the creation of a long-term view of the appropriateness of our expenditure.
- Value Development Algorithm (VDA): this is another modelling check of the reasonableness of the repex model outcomes with a wider range of asset end-of-life and performance issues and calibration to network service outcomes considered.
- Develop asset based plans: we develop detailed asset level plans based on specific condition assessments using replacement criteria specified in our asset maintenance and performance standards, prioritising key assets which perform a critical role in the network.
- Governance: we collate and integrate these plans into the Strategic Asset Renewal Plan and coordinate its delivery amongst other investment activities through the annual Strategic Asset Management Plan development process.

Based on this, our forecast repex requirements for the 2019-24 period are outlined in the table below.

Table 10.8 Proposed repex for FY20-FY24

$m; Real FY19	2014-19 Actual/Forecast	2019-24 Repex model – Calibration S1	2019-24 Forecast
Modelled repex			
Pole replacement	88.3	156.0	159.0
Overhead conductors	101.7	271.0	89.0
Switchgear	73.6	90.0	114.0
Transformers	38.5	132.0	107.0
Services	63.2	63.0	47.0
Underground cables	45.4	77.0	66.0
Total modelled repex	**410.8**	**789.0**	**582.0**
Unmodelled repex	**206.2**	**465.0**	**218.5**
Total repex	**617.0**	**1,254.0**	**800.5**

Modelling outcomes

We have modelled repex using calibrations relied upon by the AER in previous determinations, namely:

- calibration S1: calibrated to reflect the last five-years of actual repex unit costs and volumes (FY13-FY17). This produces a 2019-24 modelled repex forecast of $789.0 million (real, 2018-19) for 2019-24;
- calibration S2: calibrated to reflect projected repex unit costs. This produces a 2019-24 forecast of $1,315.0 million (real, 2018-19) for 2019-24; and
- calibration S3: calibrated to historical benchmark unit costs across the NEM. This produces a 2019-24 forecast of $1,166.0 million (real, 2018-19) for 2019-24.

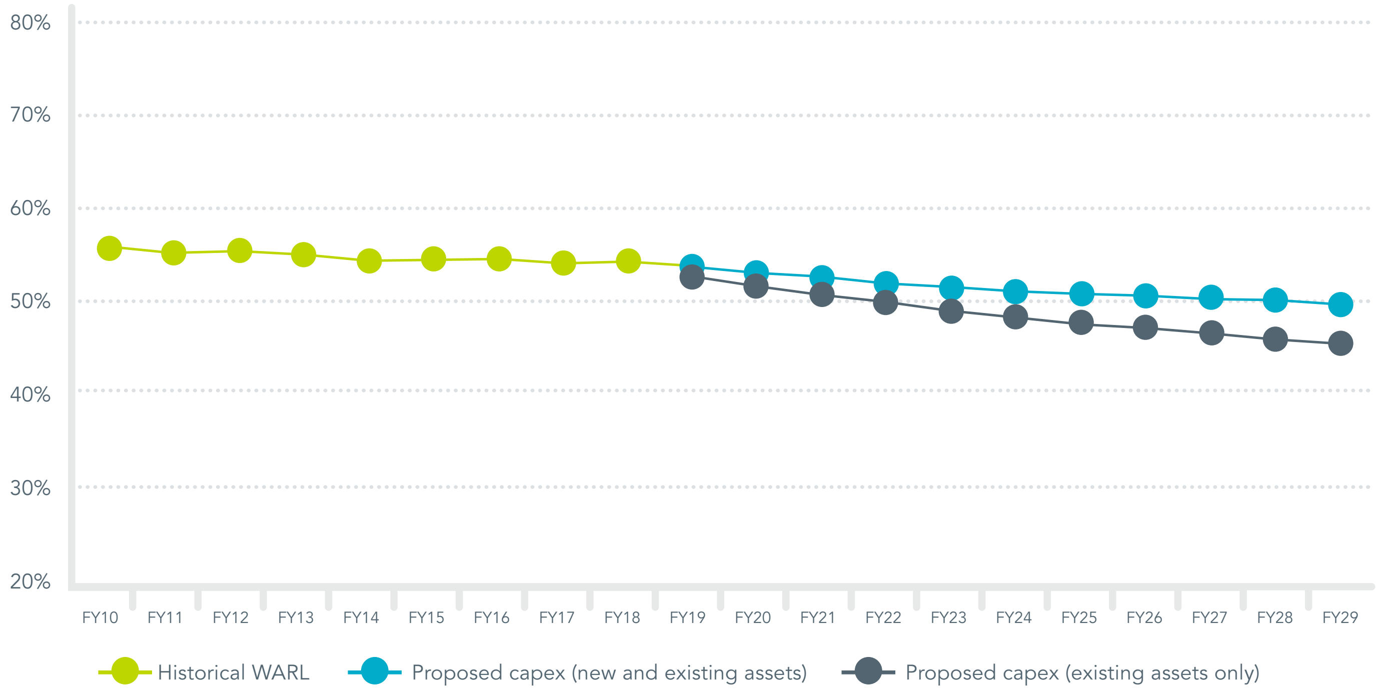
We engaged Dr Nuttall to review and validate our repex modelling. Dr Nuttall notes that the repex model supports our forecast which is below both repex modelled amounts (both AER modelled repex categories and all repex categories)[47]. See Attachment 10.21 for further details on our repex model approach and outcomes.

We have also discussed our repex modelling approach with the AER and note that the AER intends to calibrate the repex model using the most recent three years (rather than the typical five) and by calibrating unit costs and benchmarking average asset lives.

Our preference is for the continued use of a five-year calibration period to mute the impacts of one-off events such as our lease transaction process. We understand the AER's rationale for benchmarking asset lives. We are supportive of this approach provided it is done on a like-for-like basis to ensure that a reasonable target is set for DNSPs that is achievable. For instance, trade-off decisions may be made by DNSPs to achieve a low unit cost by utilising a lower quality solution that has a shorter asset life (and vice versa). In response to the AER's new approach, we have reviewed our asset lives and adjusted the lives for consac cables, service lines and earthwires resulting in a $50 million reduction to the repex we presented at our capex deep dives.

Based on this, we consider our repex forecast represents an efficient estimate of our replacement needs and costs over the 2019-24 period. Our repex forecast is lower than the repex model outcomes and condition based plans. We have sought to reduce our expenditure in response to customer and stakeholder concerns regarding affordability and RAB growth. However, this means that, all else being equal, our asset base will continue to age over the 2019-24 period as illustrated below.

Figure 10.10 WARL forecast



47 Attachment 10.25: Nuttall Consulting - Assessing the Endeavour Energy repex forecast, February 2018, p.16

This implies that the proposed level of investment will be unable to maintain current network outcomes into the long-term, and represents a strategic underinvestment in asset renewal thereby increasing risk. As noted in section 10.3.2, under the NSW Electricity Supply (Safety and Network Management) Regulation 2014 we must comply with AS 5577. This means we cannot consciously accept or target a higher risk position or a greater failure rate in an asset category.

As such, we have reduced our capex below condition based forecasts on the expectation that we can achieve the same outcomes at a lower cost rather than accept a higher level of risk. Specifically, we will seek to:

- achieve productivity gains through ongoing improvements to workforce planning and delivery efficiencies associated with the recently introduced MPU and Alliance partnership;
- refine risk identification and management processes through improved targeted asset condition information. These improvements are associated with our technology transformation program that will provide better tools to capture asset data in order to make more effective asset investment decisions; and
- mitigate risk through non-network options following the expansion of the RIT-D and the expected increase in embedded generation and storage devices in coming years.

We consider these changes will allow us to better target our replacement programs, extend asset lives and maintain the existing level of network risk at a lower repex amount.

Category level forecasts

We also note that the repex model produces estimates at the individual asset category level. Our investment plans are within the overall forecast set by the selected repex model calibration but vary at an asset category level. This is because our investment plans are developed based on asset condition information and risk based assessments as opposed to the more generic asset inputs used in the models. We consider our detailed asset renewal plans are the better way of identifying genuine network risks at a category level. Our key investments and category level programs are described in detail in our Repex Proposal, Attachment 10.04.

10.5.4 Non-modelled repex and other system capex

There are a number of un-modelled repex categories and also other system capex categories, such as reliability, that are allocated to repex for RIN purposes. Collectively, these categories of capex are typically assessed as 'non-modelled repex'. In the absence of an applicable model this assessment involves a more detailed approach. Below we provide a summary of the key categories of expenditure.

Substation civil and ancillaries

This category relates to the wholesale replacement of zone and transmission substations and switching stations. While some components of this category are captured as part of the modelled repex, the majority is un-modelled. We currently have over 200 substations and switching stations across our network of which 10 percent are over 50 years old. Replacement requirements are determined by condition and serviceability based on maintenance test results and diagnostics of individual component assets and safety impacts.

Replacement can include the like-for-like replacement of elements such as buildings, auxiliary equipment, protection systems, instrument transformers, busbars, civil works and underground cabling. This approach typically represents the lowest cost solution. However, wholesale replacement of the substation is carried out in instances where there is a confluence of component replacement needs that justify the cost. This is particularly applicable when a control building requires replacement.

Our forecast represents an increase compared to the current period and is provided in Table 10.9 below.

Table 10.9 Proposed substation civil and ancillaries capital expenditure for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19 Actual/Forecast	2019-24 Forecast
Substation civil and ancillaries	99.2	138.2	170.8

Some of the key programs driving this increase are as follows:

- Whole or partial replacement ($50 million for unmodelled component) of Marayong, Sussex Inlet, Unanderra, Greystanes and West Wollongong Zone Substations and the Carlingford Subtransmission Substation control building replacement.
- Civil works associated with the replacement of 11kV paper insulated cables and 11kV feeder circuit breakers or switchboards ($34 million); this program supports the 11kV circuit breaker replacement program which is increasing to address safety issues associated with the failure of oil circuit breakers in switchrooms.
- Protection relay replacement ($21 million); these works are required to maintain the current reliability and safety performance of the network. The increase is in part driven by the first generation of microprocessor based relays reaching the end of their useful life.

For a full listing of programs see Attachment 10.04 and Attachment 10.16 for further details.

Reliability

We invest to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, which aim to ensure that customers connected to the worst-performing parts of the network receive at least the minimum specified levels of reliability. The main driver of investment in this capital expenditure category is our performance against Licence Condition reliability targets, Attachment 10.08.

Reliability focused projects included in our expenditure forecast are considered in the context of the AER's STPIS scheme. Our reliability expenditure included in this proposal is solely for maintenance of our reliability performance and compliance with our licence obligations. Any STPIS improvements will be assessed on a case-by-case basis and funded via the STPIS. Given the target for these licence condition is poor performing feeders, and given that in the majority of cases these areas supply a very small number of customers, it is unlikely that the outcome of addressing these poor performing areas will have any appreciable impact on SAIDI/SAIFI, and thus no appreciable impact on the STPIS performance calculation.

We detail our approach and compliance obligations in Attachment 10.07 to this proposal. Our reliability forecast for the 2019-24 period is similar to the approved level of reliability capex to the 2014-19 period and is shown in Table 10.10 below.

Table 10.10 Proposed reliability capital expenditure for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19 Actual/Forecast	2019-24 Forecast
Reliability Capex	27.2	19.0	20.0

SCADA, Communications and Network Control

SCADA systems enable the remote monitoring and control of the network. This allows our control rooms at Huntingwood and Springhill to provide faster and more accurate response to incidents and outages as well as productivity improvements for planned operations. The SCADA system also has a limited amount of automatic functions to restore load after a network incident, provide alerting and alarming, and control the controlled load systems. We expect that investment in this category, along with Technology and ICT capex, will allow us to maintain existing service levels following the reductions we have made to our proposed repex program.

Investment in SCADA systems has two elements: replacing assets which have reached the end of their life and installing new or upgrade systems and equipment to provide increased performance from the network. Investment in SCADA is important in maintaining the safety and reliability performance of the network. It is also important to upgrade SCADA systems to provide enhanced security for network control elements as new cyber threats emerge. The SCADA elements within Endeavour Energy's capex proposal include:

- Substation SCADA remote terminal unit replacements at end of life;
- The SCADA masterstation upgrades in the system control rooms;
- The replacement and/or upgrade of radio communications equipment in substations, field devices and base stations throughout the network; and
- The replacement and/or upgrade of the microwave communications equipment throughout the network.

The SCADA capital works are managed through a series of ongoing replacement programs which are reassessed on an annual basis for need and efficiency of solutions through the development of a business case or a project scoping document. Each program is detailed in Attachment 10.03. Unit costs are reviewed each year taking into consideration the actual costs currently being incurred, site specific factors and changes in technology. Further, the expenditure for each program is subject to the approval governance process. The proposed SCADA renewal capex expenditure for the 2019 – 24 period is shown in Table 10.11 below.

Table 10.11 Proposed SCADA capital expenditure for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19Actual/Forecast	2019-24 Forecast
SCADA Capex Forecast	52.1	50.1	48.0

Technology

We continue to evaluate operational technology solutions for their applicability and cost effectiveness to address network management issues on our network. The focus of this work is generally on understanding how a range of technologies that have proven their effectiveness in similar situations elsewhere may be utilised within our network to add value in the future. The AER's models are not suitable for innovative based investments, so we develop our technology forecast on a business case basis. Our forecast for the 2019-24 period is provided in Table 10.12 below:

Table 10.12 Proposed technology capital expenditure for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19Actual/Forecast	2019-24 Forecast
Technology Capex Forecast	19.1	23.2	24.9

Our Future Network Strategy (Attachment 10.31) details our approach to technology investment and includes an overview of the pilots, trials and new technologies we intend to roll out (or continue to) over the course of the 2019-24 period. These proposed plans are broadly focussed on achieving better optimisation of network assets; maximising the capabilities of our internal support systems and staff; and facilitating customer choice by enabling them to take advantage of the future opportunities presented by industry change. We expect these improvements, along with ICT capex, will allow us to maintain existing service levels following the reductions we have made to our repex program.

Our initiatives are examined against our key strategic goals of safety, reliability and sustainability (cost), to determine if they are likely, in the case of a successful trial, to provide a cost justified rollout. Some examples of the technology centred initiatives proposed for 2019-24 include:

- **Grid monitoring and smart meter integration:** Data collected from increasing numbers of smart meters has the potential to deliver improved asset utilisation and asset efficiency, and to provide greater hosting capacity of DER. To realise these benefits, we are preparing to develop a B2B interface capable of handling and interpreting the new wealth of data as well as analytics to support LV asset monitoring which will result in more efficient capital investment and maintenance decisions;
- **Feeder and network automation:** These systems have the ability under certain conditions to restore supply to customers using alternative feeders. Having successfully deployed feeder automation schemes during the current regulatory period, we intend to build on our learnings from these projects and develop more schemes in areas where the availability of existing SCADA switches, suitable tie points and fault history are favourable;
- **Distribution Fault Anticipation (DFA):** DFA devices can transmit real-time line condition information to the mobile devices of operations staff to aid field maintenance activities, refurbishment and replacement decision making, and safety and bushfire risk assessment;
- **Distribution Management System (DMS):** A new, integrated system allowing real time monitoring and control of customer outages and provide significant risk management, safety and efficiency benefits;
- **Electric vehicle supporting infrastructure:** As electric vehicles continue to gain popularity, our customers may also wish to leverage the storage within the electric vehicle battery for the purposes of trading. We intend to trial vehicle to grid technology to provide us with insights into the potential impacts of this emerging trend on the network, review potential future demand management applications and develop strategies to integrate it with other initiatives to improve network operation;
- **Analytics and distribution state estimation:** Due to the complexity of our network, it is not always known what the effects of various switching configurations could have in regards to power load flows, load estimations during peak demand and network/feeder losses. To identify these network switching constraints, we plan to investigate various OT platforms for implementing analytics and distribution state estimation system; and
- **Field force automation and scheduling:** With the ongoing reductions in technology deployment costs, there will be increasing economic justification to broaden the deployment of field-force mobility solutions. Extending the mobility roll out is expected to provide benefits in asset management through improved data collection as well as improved efficiency in the field processes themselves, particularly when combined with improved work scheduling.

10.5.5 Demand Management

We consider non-network alternatives to augmentation, such as demand management and embedded generation, to be important aspects of optimising the available capacity in the network to meet the forecast demand. Non-network alternatives are generally designed to reduce or avoid the need for network capacity or the need to retire and replace assets by reducing the peak demand or by moving demand away from peak periods on a permanent or temporary nature.

The demand management strategy is focused on the use of non-network alternatives and demand management initiatives, systems and technologies to avoid network augmentation, development or replacement of the network. These strategies are implemented where they have been proven to be cost-effective. The RIT-D analysis is used to investigate all options that address a network limitation that meets the RIT-D criteria. Non-network option investigations are an integral part of this process to identify the most cost-effective solution. Non-network options are also investigated for non RIT-D projects.

The demand management strategy also includes the development of the Company's capability and understanding of demand management techniques through the use of pilots and trials of new technology and systems that have the potential to provide demand management functionality. The strategy has three components:

- **Pilots and trials:** During the current regulatory period, it is expected that the focus of the pilots and trials funded under the DMIA will increase our understanding of the ways in which demand management techniques can be applied to reduce the peak demand caused by residential customers. Historically, we have trialled peak time rebates, air-conditioning and pool pump control programs, off-peak water and power factor correction. In more recent years we have trialled the application of residential energy storage, a grid connected battery trial and residential inverter power correction.
- **Targeted constraint driven initiatives:** We have, for many years, utilised demand management techniques to defer the need to augment specific parts of the sub-transmission and distribution networks (including zone substations), where the cost of the demand management program is justified by the associated deferral of capital expenditure. Consideration of whether there is the opportunity for the use of demand management is integrated into the planning processes as part of the RIT-D process (which now includes replacement projects) and will be done in accordance with the AER's newly released DMIS guideline.
- **Broad based initiatives:** Demand management initiatives are also targeted more broadly to improve the utilisation of the network and to extend the time before growth in demand causes constraints to occur. Our demand management strategy recognises that broad-based initiatives require some degree of targeting at areas where growth is occurring, to avoid expenditure where there is unlikely to be a return in terms of immediate deferred capital expenditure. However, before a broad based program is implemented there needs to be known future capital expenditure where a cost benefit can be estimated albeit, non-firm. While this type of program is known as broad based, it is more appropriate to label it as 'targeted broad based' demand management programs. Therefore, the concept of a broad based program is now defined to have the following objectives:
  - Target areas with known growth in demand.
  - The growth in demand is forecast to approach network limitations.
  - Future capital expenditure will be required to cater for growth in demand.
  - Cost effectiveness in demand reduction expenditure can be demonstrated.

As with targeted initiatives, broad based initiatives will be considered in accordance with the RIT-D process and the AER's newly released DMIS guideline. Our demand management strategy is outlined in more detail in Attachment 10.12 to this proposal.

DMIS

As noted above, the AER has recently released a new DMIS to replace the existing scheme. The new DMIS seeks to incentivise demand management so as to reduce system capex and electricity prices in the longer term. The scheme has two components:

- DMIA: an allowance for researching, developing or implementing demand management capability or capacity that is innovative.
- DMIS: an incentive payment worth up to 50% of the expected demand management costs for a project identified through the RIT-D process (capped at the project's expected net benefit and 1% of MAR in total).

In Chapter 9 we requested that both components of the scheme apply to us for the 2019-24 period. Broadly, the new DMIS supports our existing planning processes. Our demand management projects for the 2019-24 period will be identified through the RIT-D process. This process results in the preparation of the annual Network Demand Management Plan that identifies all projects (RIT-D and Non RIT-D) that require non-network option investigations.

This information is also included in the DAPR. If the screening test identifies that a non-network option is feasible a public consultation process in the form of a Non-Network Options Report will be issued. This report will provide all the details a non-network service provider requires to make a submission for a non-network option.

We consider our pilots and trials will be eligible for funding under the DMIA component of the scheme in accordance with our established practices under the previous version of the DMIA.

10.5.6 Overheads

Table 10.13 Proposed capitalised overheads for the FY20-FY24 period

$m; Real FY19	2014-19 Allowance[48]	2014-19 Actual/Forecast	2019-24 Forecast
Direct Overheads	97.9	89.6	76.8
Network Overheads	164.4	150.5	175.7
Corporate Overheads	134.5	123.1	147.5
Total	**396.9**	**363.3**	**400.0**

CAM and capitalisation approach

We have ensured that the total forecast capex in our building block proposal only relates to standard control services that are properly allocated in accordance with the CAM approved by the AER on 8 March 2018. The CAM can be found at Attachment 0.06.

Our capitalised overheads comprise both direct overheads and indirect overheads. Direct overheads represent the costs of functions which exist only to support the capital program, such as our Project Management Office, Program Directors and Project Managers where 100 percent of these costs are capitalised. Indirect overheads represent the cost of other functions throughout the business which indirectly support both operating and capital programs, and therefore the portion of indirect overheads related to the capital program must be calculated.

48 The capitalised overheads allowance was provided at the total level. Category level figures have been developed in line with the 2014-19 actual category splits.

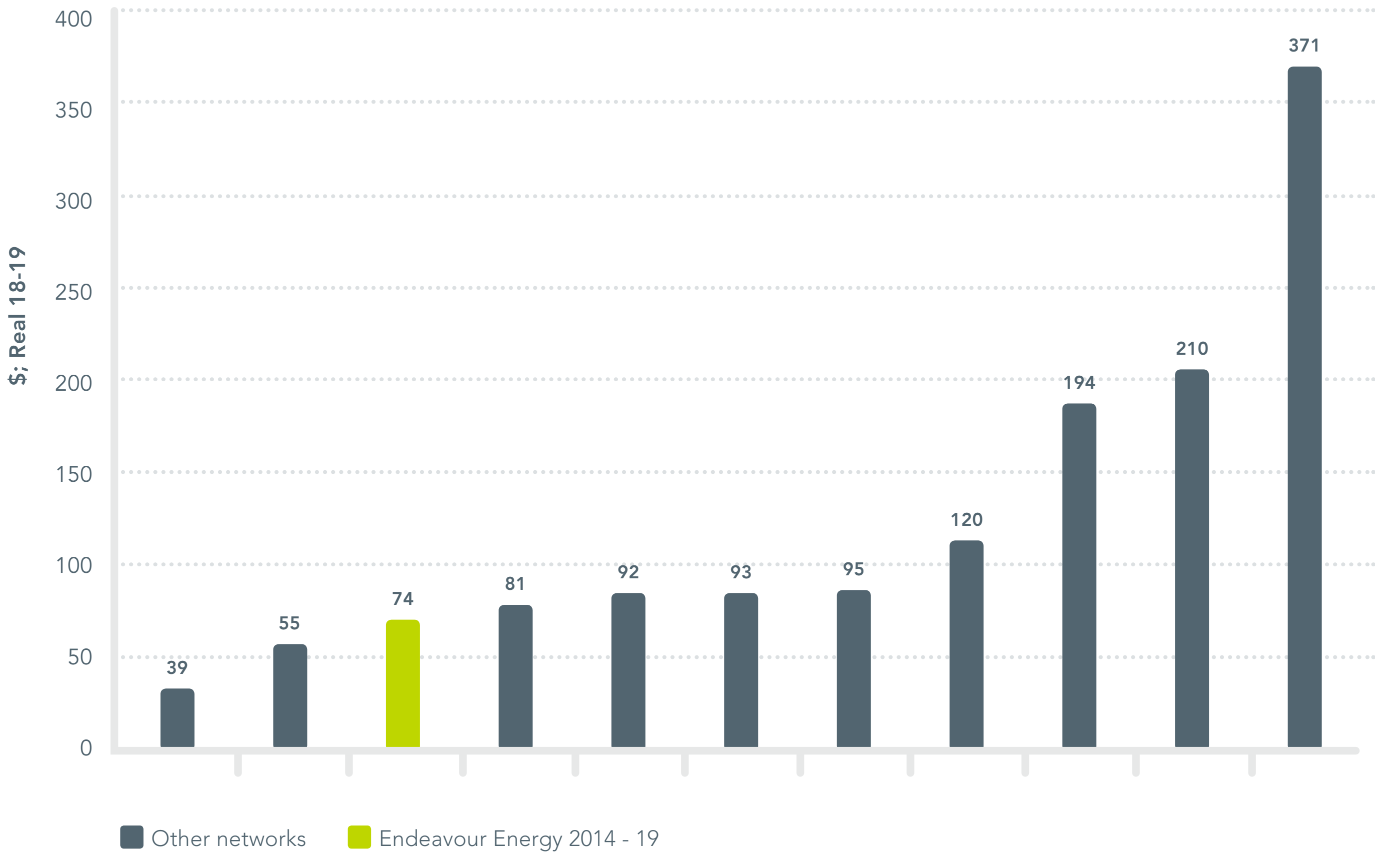
To ensure we comply with AASB 116, in relation to indirect overheads, Company Policy 6.9 Capital Expenditure Overhead Calculation (Attachment 10.15) provides a methodology for the capitalisation of indirect overhead expenditure. This Policy states that an overhead pool is determined based on an analysis of activities undertaken, and the nature of costs incurred, at a granular organisational unit (responsibility centre) level.

A capitalisation rate is then calculated by reference to the proportion of direct capital labour to total direct labour for each organisational unit. The capitalisation rate is then applied to the overhead pool to determine the amount of eligible indirect overhead expenditure to be capitalised.

Efficiency of our overheads

As overheads relate to a number of activities, it is difficult to assess or determine what the efficient level of overheads are for a business. Our capitalised overheads, based on the last five-years of actual data, are relatively low compared to other DNSPs.

Figure 10.11 Average capitalised overheads per customer ($; real 18-19, NEM Average FY12-FY16)



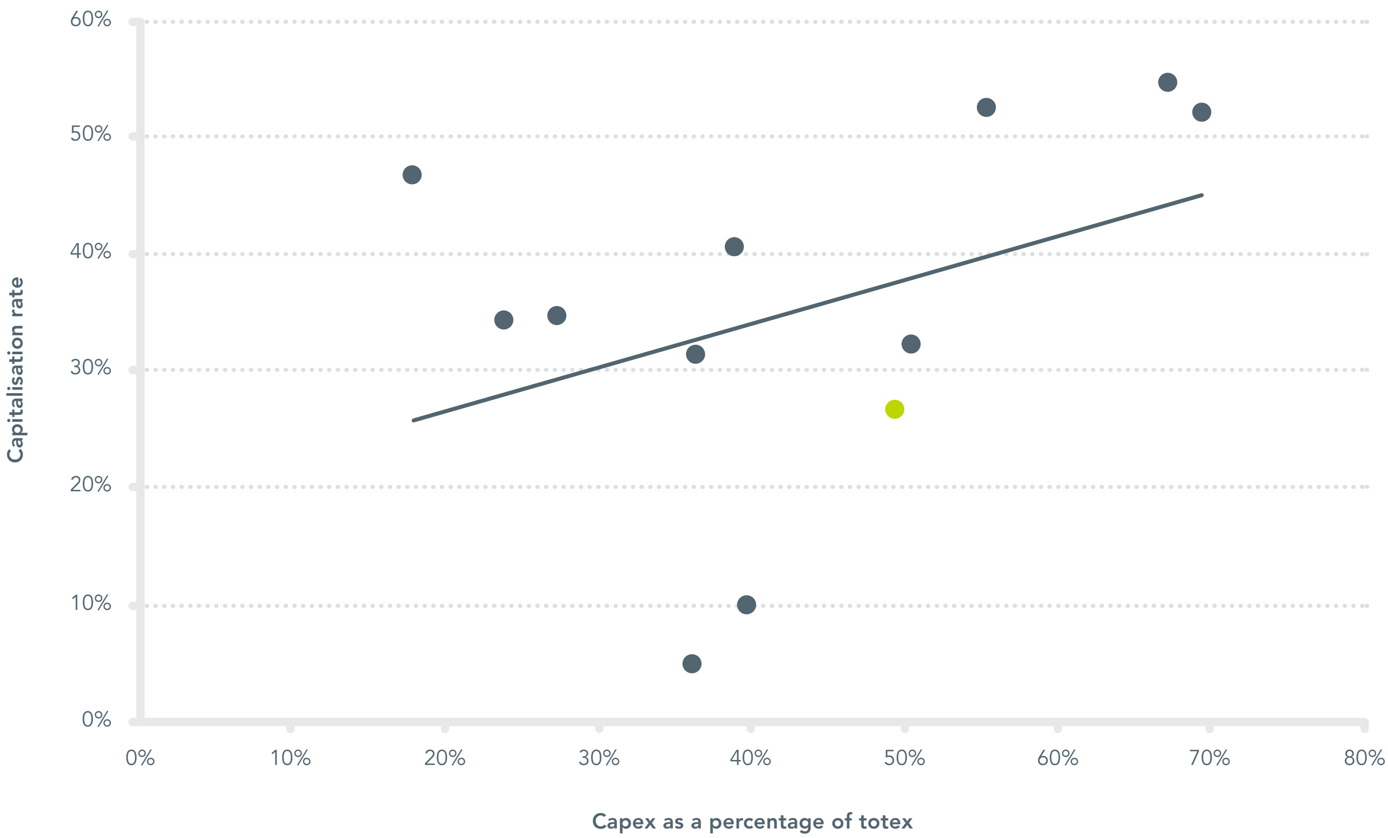
At the time of our 2014-19 proposal the AER assessed the efficiency of our total overheads. The AER considered that our total overheads per customer from FY09-13 of $307 (real, 2018-19), which was 7th in the NEM at the time, was high compared to other DNSPs. Since then we have improved our performance against this measure with average total overheads per customer from FY14-17 of $258 (real, 2018-19). We consider this provides prima facie evidence that the overall level of our overheads and the amount capitalised are efficient.

Fixed nature of our overheads

In assessing the appropriateness of our capex forecast we assessed the extent to which our overheads are fixed or variable. In recent determinations, the AER has adopted a 75:25 fixed/variable split in the absence of alternative evidence being provided by the DNSP. It is difficult to quantify the exact degree to which capitalised overheads are variable, however 25 percent appears to be a high estimate based on the available information.

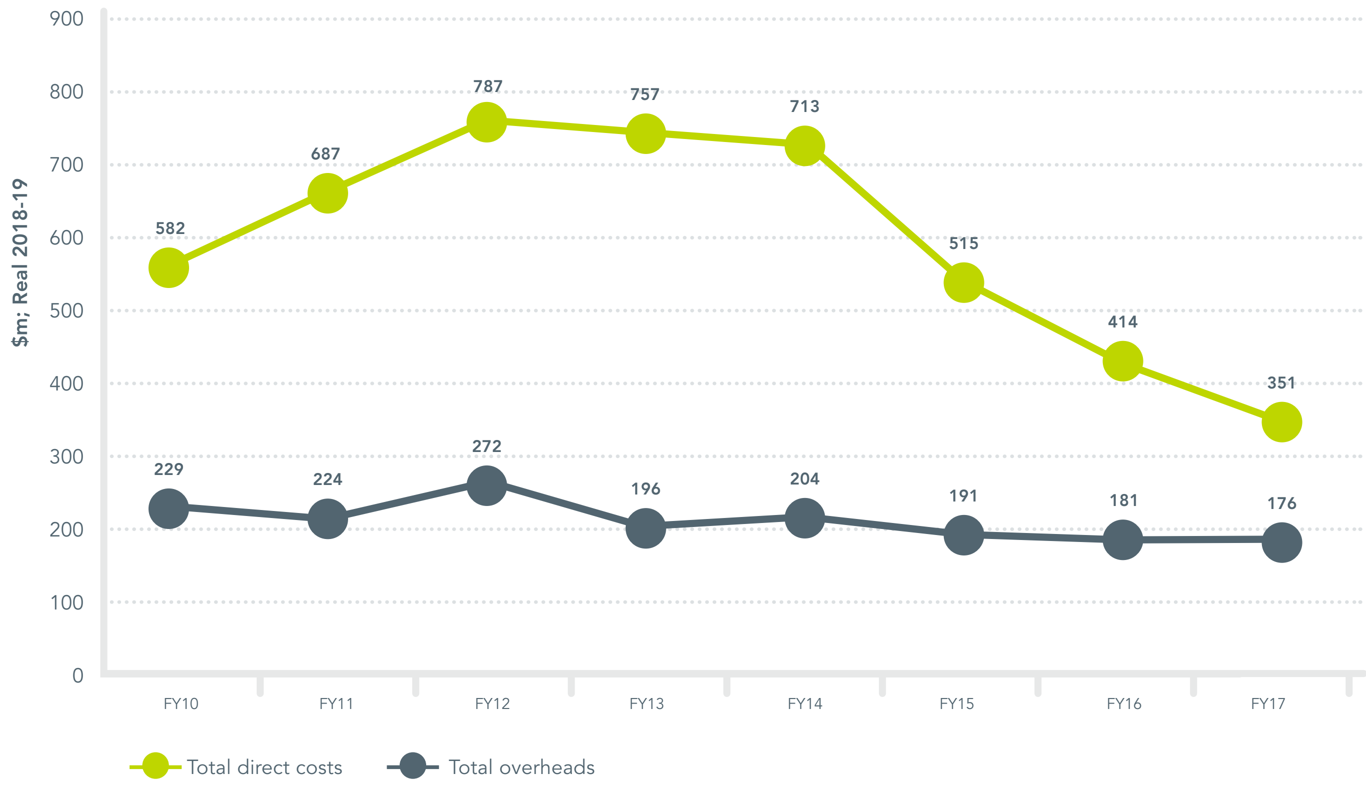
A key driver of capitalised overheads is the relative mix between capex and opex over time. Across the NEM the capitalisation rate increases as capex makes up a higher proportion of totex.

Figure 10.12 Capitalisation rate compared to capex as a percentage of totex (FY09-FY16 average)



Notably, our capitalisation rate is lower than most DNSPs despite capex making up a relatively higher portion of our totex. This is because our overheads have been largely fixed over several years despite variations in our levels of direct totex.

Figure 10.13 Total direct expenditure and overheads over time



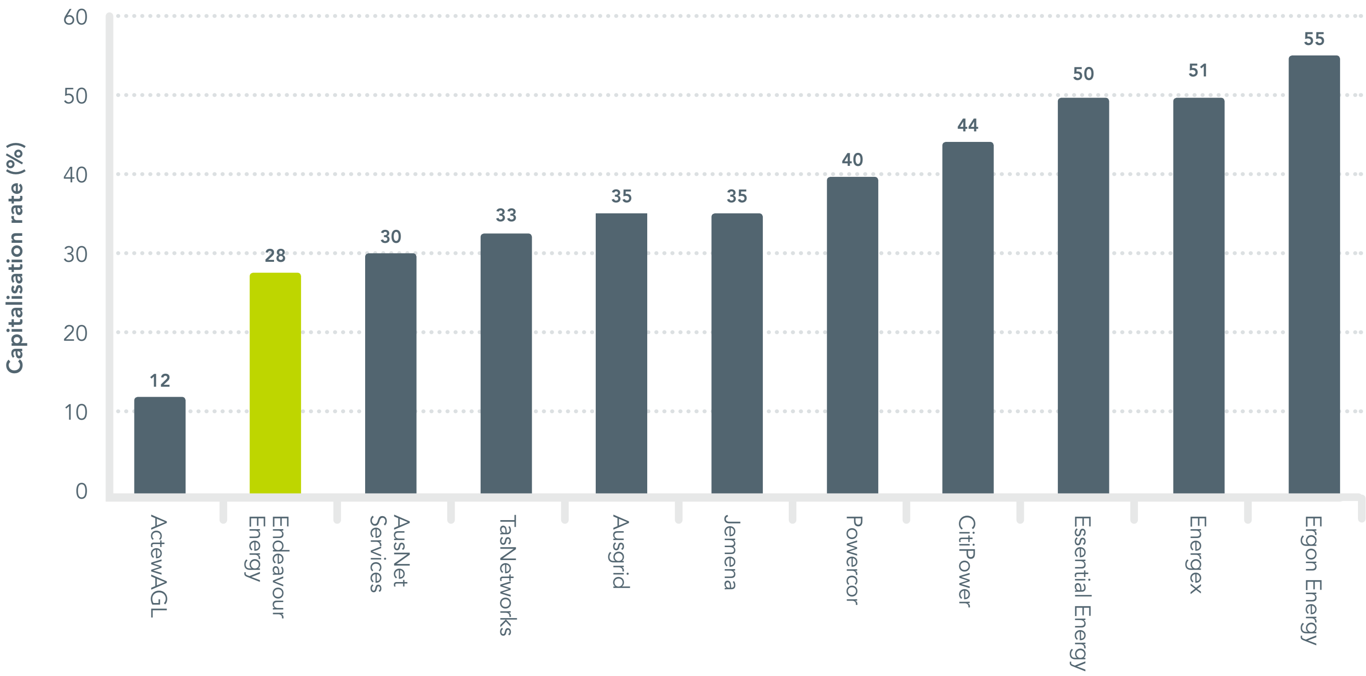
As evident in Figure 10.13 above, this trend continues into the 2019-24 period; while direct capex increases by 49 percent from 2014-19 levels, capitalised overheads only increase by 10 percent. This is most likely driven by the capex/opex mix, which results in a higher proportion of labour being utilised by the capital program. This increases the amount of overheads capitalised as labour is one of the primary overhead allocators.

Efficiency of our capitalisation rate

The final part of our assessment was testing the appropriateness of our overhead capitalisation rate. As noted above, our capitalisation method complies with AASB 116. To test the reasonableness of our capitalisation method we compared our capitalisation rate to other DNSPs in Australia.

As evident in Figure 10.14 below, our capitalisation rate is relatively low compared to other DNSPs in Australia. We consider this is appropriate as it means we are adding less overhead costs to our RAB compared to our peers.

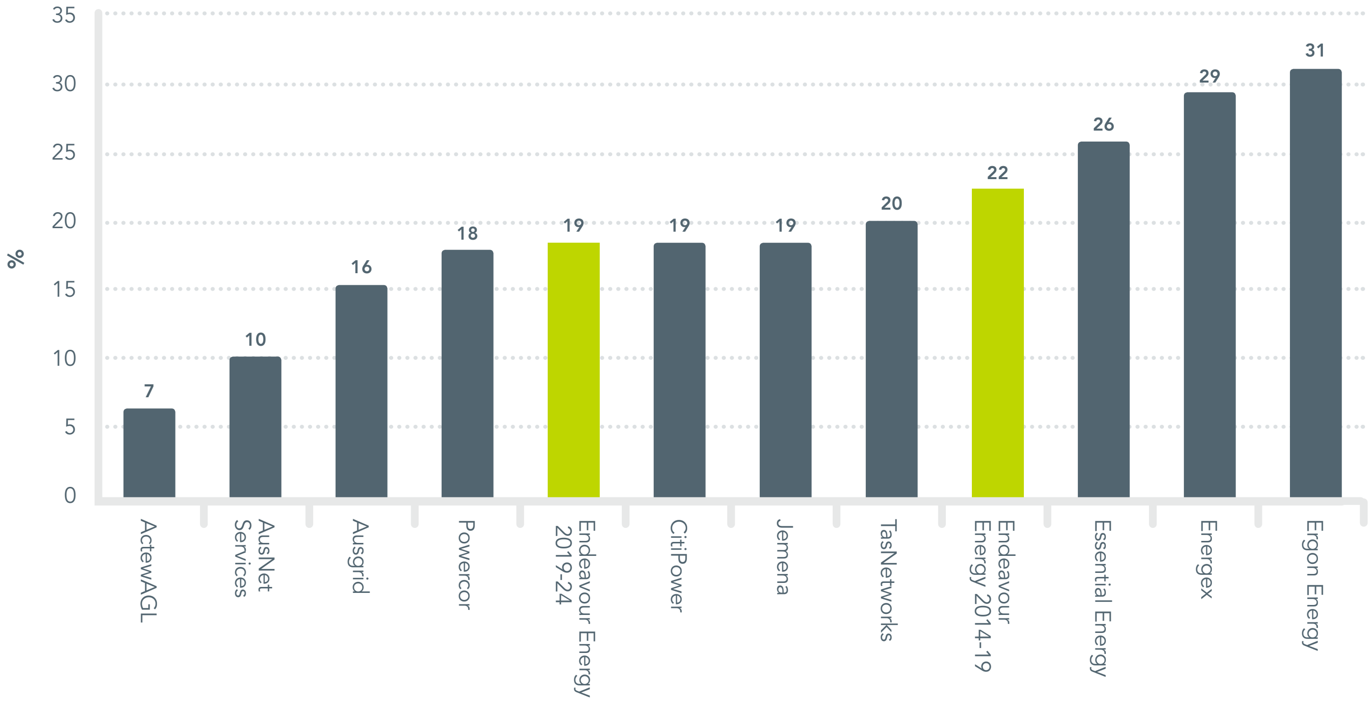
Figure 10.14 DNSP capitalisation rates (%) (FY12-FY16 average)[49]



49 Source: Category Analysis RIN Data, which was not available or comparable for SA Power Networks and United Energy.

Our forecast capex seeks to maintain this level of capitalisation. Because of this, capitalised overheads will make up a lower proportion of our total capex for the 2019-24 period compared to 2014-19 and other DNSPs. This is a result of our total overheads remaining largely fixed despite increases in direct totex.

Figure 10.15 Capitalisation overheads as a percentage of capex comparison (%) (NEM average FY09-FY16)



10.5.7 Non-system capital expenditure

The non-system capital expenditure category includes expenditure which supports the operation of the regulated network system (not directly related to the construction or replacement of system assets). This expenditure is required to safely and reliably service our asset base and deliver the outcomes defined in our network strategy.

Our non-system capex includes land and buildings, vehicles, furniture and fittings, plant and equipment (other) and information and communications technology (ICT), and is shown in Table 10.14.

Table 10.14 Proposed non-system capital expenditure for FY20-FY24

$m; Real FY19	2014-19 Allowance	2014-19 Actual/Forecast	2019-24 Forecast
ICT	91.0	120.8	91.2
Motor Vehicles	29.0	17.8	22.1
Land and Buildings	43.9	38.0	38.1
Other Non-System	18.4	13.3	18.7
Total Non-System Capex	**182.3**	**190.0**	**170.1**

ICT

ICT provides critical business support to meet our obligations as a DNSP in line with our strategic direction. More specifically, ICT provides the technology tools and data to enable the business to efficiently manage our current network safely and reliably, supports the effective planning of the network, fulfils our corporate and regulatory obligations, and with the prudent adoption of technology it enables the delivery of better services to customers at a lower cost over time.

ICT capex has a standard asset life of five-years given the faster pace of technological change. We have not invested significantly in ICT since the replacement or implementation of a few major systems in 2010-11. Because of this our current technology platforms are beyond end-of-life, poor performing, expensive to maintain, without ongoing support in some instances and will not facilitate the customer service and productivity improvements available with modern technology.

We therefore commenced a technology transformation program during 2014-19 which will be completed in the first year of the 2019-24 period.

Our ICT regulatory proposal includes a total capital expenditure of $91.2 million as we return to BAU operating levels. The focus areas and benefits of our forecast ICT capex are as follows:

Table 10.15 Proposed ICT capex focus areas and benefits

Engage the customer: improve customer engagement, mobility and automation enablement	
Service and operational benefits	• **Strengthen issue resolution** through personalised customer service. • Improved ability to service culturally diverse and **vulnerable customers**. • Improved customer service through **self-service**: availability of information, improved lodgement processes and status update tracking. • Higher quality **outage communications** including a customised process for managing vulnerable customers which will enable accuracy and consistency in notification details.
How we measure success	• Number of customer complaints relating to notifications. • Cost related to notification/outage communications.
Enable network service efficiency and maintain core systems: automation and process improvement, data, analytics and insights and consolidate and rationalise applications	
Service and operational benefits	• Reliable and **high quality field data** leading to improved asset utilisation and prudent investment decisions. • Better **visibility of work and information** for decision-making will result in more efficient delivery of field work and back office functions, leading to more value added time-on-tools as opposed to back end data capture and manual processing. • **Simplified ICT architecture** and **reduced ICT complexity** to enable faster and more efficient responses to changing business and regulatory requirements. • Improved **self-service capability** for the business and customers.
How we measure success	• Reductions in repex. • Number of process errors. • Service efficiencies through consolidated systems. • Productivity gains through the automation of business processes for field and office workers. • Reduced vendor costs.

Compliance with licence conditions and maintaining security standards: comply with network operator licence conditions, improve web and mobile security and vulnerability management	

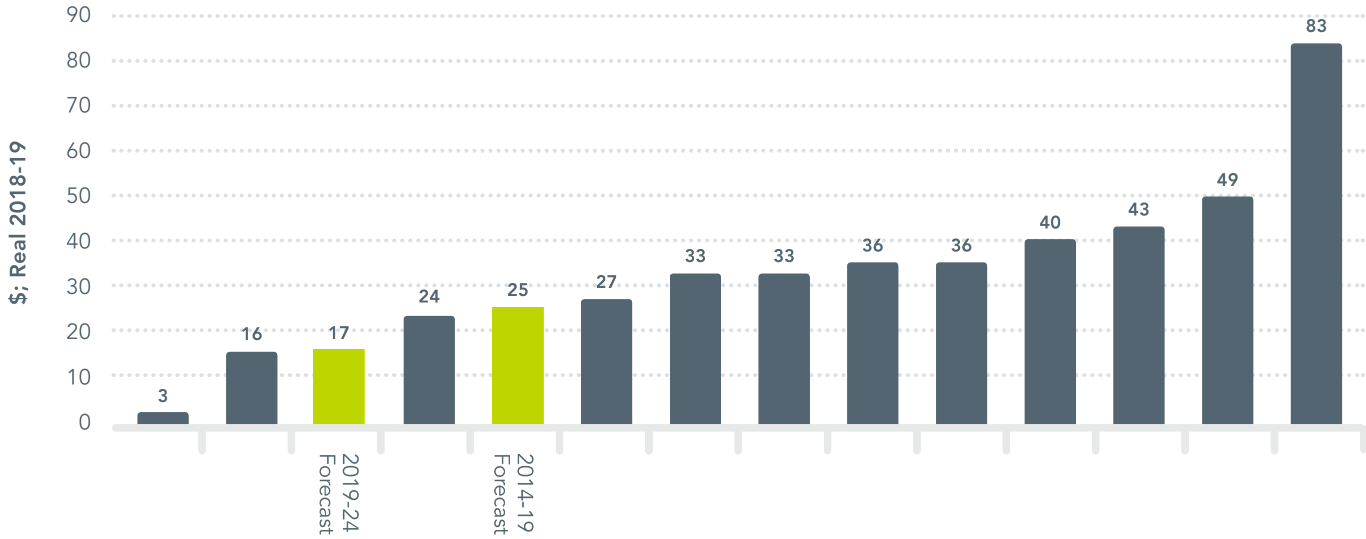
Service and operational benefits	• Support the **ENA/CSIRO Electricity Network Transformation Roadmap** while maintaining security controls for the protection of customer usage and potentially sensitive data.
	• Achieve and maintain regulatory and legislative **compliance** with:
	  • **Critical Infrastructure Conditions and Data Security** – need to ensure network control and operation is not compromised and is protected from cyber-attack.
	  • **Code of Practice** – need to meet the Code of Practice record keeping requirements for environmental assessments of all network driven and customer funded works.
	  • **Environmental and asset management systems** – need to improve our data capture, integration, storage and analysis tools to achieve and maintain compliance with the relevant standards (ISO/AS 14001 and ISO/AS 55001 respectively) within two years of the licence coming into effect.
	• Providing **mobile devices that are secure** and do not introduce addition risk factors.

How we measure success	• Costs to recover from a critical cyber related incident. • Costs related to ICT operations – expect reduction through single sign-on capability. • Comply with licence conditions and codes of practice.
Sustain reliability of ICT services: infrastructure and end-user computing, telecommunications, ICT operations and cloud infrastructure.	
Service and operational benefits	• **Flexibility in ICT infrastructure** to enable quick ICT response times to changing customer engagement models and broader industry transformations as envisaged by the ENA/CSIRO Electricity Network Transformation Roadmap. • Ensure resiliency of **telephony infrastructure** which underpins the efficient operation of all customer and network services. • Improvement in the capability to respond to customers and stakeholders with **safety information** in the event of an emergency and improved levels of customer services in response to changing expectations.
How we measure success	• Response times and complaints particularly during emergencies. • Monitoring resilience of our telephone network.

Our proposed ICT capex is efficient for the following reasons:

- Lower than previous periods: our ICT capex is less than the amount spent in the 2009-14 and 2014-19 periods;
- Market tested: we source our ICT applications from the market and implement and operate them using an outsourcing model;
- Governance: we have a detailed governance process and evaluation criteria that optimises ICT investment on an NPV and risk basis; and
- Benchmarking: we have tested the efficiency of our ICT capex through a number of measures. For instance, our ICT capex is lower than other DNSPs:

Figure 10.16 NEM comparison of average annual ICT capex per customer (NEM average FY12 – FY16)



We also engaged KPMG to conduct more detailed benchmarking.The results support the efficiency of our forecast, some key results include (see Attachment 10.28 for further details):

- our ICT totex per customer in 2016 was equal to the industry average;
- our ICT totex per employee has been consistently below the industry average;
- our ICT capex per customer has been consistently below industry level and has been at the minimum in 2010 and 2012; and
- forecast ICT capex as a percentage of total capex is 4.2 percent compared to the 2016 industry average of 7.2 percent

Refer to Attachment 10.27 for our ICT Investment Plan which provides a detailed overview of our investment context, governance framework, forecasting methodology and planned expenditure for the 2019-24 period.

Fleet

Our $22.1 million (real, 2018-19) motor vehicle capital expenditure program is directly related to the expected number of staff employed, particularly in field-based roles, which have the highest use of commercial vehicles, trucks and plant.

Our forecast fleet expenditure over the 2019-24 regulatory period primarily comprises replacement expenditure for existing fleet, which is driven by our documented vehicle replacement policies. See Attachment 10.29 for further details on our approach to fleet management and forecast requirements.

Land and buildings

Our $38.1 million land and buildings capital expenditure program is a result of renewal and compliance-based drivers. We must accommodate the required number of personnel required to support the forecast program and the associated ongoing maintenance and operational requirements.

We continue to meet our compliance requirements and community expectations regarding safe and environmentally sound work practices. Meeting these requirements necessitates expenditure on both new and existing facilities.

Refer to Attachment 10.30 for further details on our approach and forecast requirements.

Other non-system (furniture, fittings, plant and equipment)

Our $18.7 million furniture, fittings, plant and equipment capital program is made up primarily of capitalised tools and equipment which support the network construction and maintenance programs. It also includes the furniture and fittings component of the land and buildings program.

Our furniture, fittings, plant and equipment expenditure has historically been equivalent to one percent of our system capex forecast. The 2019-24 forecast is line with the previous two regulatory periods at one percent of the system capex forecast. We consider this provides evidence that the forecast is efficient and aligned with previously approved levels of expenditure. Refer to Attachment 10.30 for further details.

10.6 Contingent projects

Contingent projects are network projects that are reasonably required to be undertaken in order to achieve the capex objectives. However, unlike other proposed capex projects, the costs, timing and/or need for the project are not sufficiently certain. To ensure customers do not pay for uncertain investments, expenditure for such projects does not form a part of the AER's assessment of the total forecast capex. Instead, expenditure for a project is proposed but not included in our allowed revenue unless a defined 'trigger event' occurs. If the trigger event occurs the expenditure is subject to further specific review and approval by the AER before it is included in our allowed revenue for the period.

We have reviewed our proposed capital investment plans to determine whether any projects would satisfy the requirements of the Rules to quality as a contingent project.[50] In particular, we reviewed our capex for servicing the numerous growth centres in our network area following feedback we received from PIAC:[51]

> Endeavour Energy ensures it has a strong empirical basis for expenditure on expanding the network due to population growth in greenfield areas and, where appropriate, to include such expansions as contingent projects.

In response to this feedback, we have assessed both our asset replacement and growth related capex against the contingent project criteria in the Rules. A key aspect of this is determining whether a 'trigger event' exists that will necessitate the commencement of the related capex project if it occurs. It must be probable during the 2019-24 period that the trigger event or condition will occur but the inclusion of capex in relation to it is not appropriate because:

- it is not sufficiently certain that the event or condition will occur during the period; or
- the costs associated with the event or condition are material but not sufficiently certain.

Additionally, a cost materiality threshold needs to be met or exceeded for a project to be considered a compliant contingent project. This threshold is the higher of $30 million or five percent of the forecast annual revenue requirement for the first year of the 2019-24 period. For Endeavour Energy, this is the latter, resulting in a materiality threshold of $43.9 million for the 2019-24 period.

We have assessed two specific projects against the contingent project criteria. These are:

- Western Sydney Airport Growth Area; and
- 132kV Guildford-Parramatta-Camellia underground oil-filled cable replacement project.

Table 10.16 Cost materiality of proposed contingent projects for FY20-FY24

Contingent Project	Forecast Project Cost	5% of FY20 ARR	Materiality Threshold
Western Sydney Airport Growth Area	61.2	43.9	Exceeded
132kV oil-filled cable replacement	39.6		Not Exceeded

Our assessment of each of these proposed projects and appropriate trigger events is provided below. Proposed trigger events have been made with reference the requirements under clause 6.6A.1 of the Rules.

50 NER Cl 6.6A.1
51 Attachment 5.01 - Customer and Stakeholder Engagement Activities and Findings, April 2018, p.244

10.6.1 Western Sydney Airport Growth Area

Set to open in 2026, the Western Sydney Airport located in Badgerys Creek is a major, nationally significant infrastructure project designed to meet Sydney's growing population and aviation needs. The airport is forecast to generate economic activity and create thousands of employment and business opportunities. To facilitate the development, the Australian Government established the WSA Co. as the entity responsible for the construction of the airport.

The site of the airport is largely rural and currently absent of the significant infrastructure requirements needed to support the planned airport development and surrounding regions. New major electricity network infrastructure will need to be built to supply the growing demand emanating from the area. The rapid pace of development means that temporary solutions would quickly become inadequate and incremental staging of projects to match capacity with demand would place significant risk on the progress of construction work. Existing surrounding network infrastructure is manifestly inadequate to support airport development requirements and is an unviable option.

The WSA Co. has advised that they are assessing electricity supply options to meet the project requirements. One option would require us to construct new feeders and substations to link the airport development to the grid. The total cost to Endeavour Energy for this option is $61.2 million (real 2018-19). We note that irrespective of the supply option WSA Co. selects, we will need to invest in network infrastructure to supply the surrounding area. The decision instead impacts the timing of this required investment.

WSA Co. has not yet made a decision on how they plan to access their electricity requirement. This investment uncertainty prohibits us from including projected costs in our building block proposal at this stage. Therefore, we propose to manage this investment uncertainty by nominating the Western Sydney Airport development as a contingent project.

WSA Co. has indicated a decision on electricity supply arrangements is expected to be made in 2018. Formalisation of this decision prior to December 2018 will allow us to remove this proposed investment as a contingent project at the time of submitting our revised regulatory proposal to the AER. In the absence of a decision from WSA Co. prior to this date, we expect to again nominate this project as a contingent project in our revised proposal.

Trigger Event

We nominate the occurrence of the following event to trigger the proposed contingent project.

- Endeavour Energy enters into an agreement with WSA Co. (or other entity responsible for the Western Sydney Airport construction) at any time during the 2019-24 regulatory control period for the primary purpose of providing electricity supply to the airport where:
  - the project requires a material amount of shared network augmentation during the 2019-24 regulatory control period;
  - a completed RIT-D demonstrating positive net market benefits; and
  - the capital expenditure for this network augmentation is not included in the capital expenditure forecasts for the ARR for the 2019-24 regulatory control period.

Proposed position

Stakeholders were supportive of this project being a nominated contingent project for the 2019-24 period given its occurrence is dependent on the decision of a third party exogenous to Endeavour Energy.

For this reason, we nominate the Western Sydney Airport Growth Area as a contingent project for the 2019-24 period with the trigger events as defined above.

10.6.2 132kV Guildford-Parramatta-Camellia underground oil-filled cable replacement project

Our sub-transmission network around the Parramatta CBD and nearby industrial regions is interconnected by six 132kV oil-filled cables. These cables were installed during the 1960s and 1970s and their advancing age and potential deterioration means their condition forms the most significant issue facing our underground sub-transmission network.

Several stakeholders were opposed to this project as a contingent project. As a replacement project, stakeholders considered that the decision to replace the assets is a decision that is within Endeavour Energy's control and expert judgment. In addition to this, the project is unlikely to satisfy the materiality threshold as evident in table 10.16 above. For these reasons we have choosen not to propose this project as a conitngent project for the 2019-24 period. We will not specifically include this project in our proposed capex for the 2019-24 period either. Instead, we will manage the risk of the need arising during the 2019-24 period within the allowed revenue allowance.

11.0 Operating Expenditure

CHAPTER 11

11.1 Overview

Operating costs per customer will improve from an average of $306 in 2014-19 to an average of $274 in 2019-24.

Our base year opex is $64.1 million (real, 2018-19) lower than it was in 2013-14 and is now better than the benchmark amount set by the AER. This reduction will directly flow through to lower prices for customers. This reduction will also improve our benchmarking performance, as our Opex MPFP benchmarking score for the 2017-18 year will improve by approximately 17 percent compared to the 2016-17 year.

We have worked hard to deliver our services at the lowest cost to customers without compromising safety, service quality or our ability to comply with our obligations. We market tested and outsourced several functions over the 2014-19 period and improved our efficiency through our *Endeavour 2020* transformation program to ensure our workforce and practices are right sized, efficient and prudent.

Customers and stakeholder groups expect us to meet or better the AER's opex target and to use the AER's preferred 'base-step-trend' model to forecast our opex requirements for 2019-24. We have met these expectations.

The 'base-step-trend' approach involves taking the 2017-18 base year opex and trending this amount over the 2019-24 period. We have not applied any 'step changes' to our forecast associated with new obligations or requirements. Instead we will absorb these costs through further efficiencies. We have applied a trend consistent with the AER's benchmark weightings to account for expected labour cost increases and the growing size of our network.

Importantly, the average cost to each customer declines when compared to previous periods. Our average opex per customer was $356 per annum (real, 2018-19) for the 2009-14 period. Through our *Endeavour 2020* transformation program we improved this to $306 per annum (real, 2018-19) for the 2014-19 period. This compares favourably with the $274 per annum (real, 2018-19) we are forecasting in the 2019-24 period. This is an improvement of over 10 percent from the 2014-19 period.

The forecast opex is the efficient cost of meeting the opex objectives and includes expenditure to: meet and manage the expected demand for standard control services over the 2019–2024 regulatory period; comply with all applicable regulatory obligations; and ensure our distribution system and network services, meet relevant safety, quality, reliability and security of supply standards.

The forecast for 2017-18 is better than the AER's own benchmark amount. We have been able to achieve more efficiencies than those established by the AER in the current period. These are immediately passed through to customers for the 2019-24 period. The change in costs for each year is consistent with the AER's own methodology.

Table 11.1 Forecast standard control opex over the FY20-FY24 regulatory control period (excluding debt raising costs)

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Opex	278.8	286.7	296.7	306.8	316.5	**1,485.5**

11.2 Customer insights

In accordance with the NEO, our objective is to manage and maintain the network in a way that best serves the long-term interests of customers. In preparing a proposal it is therefore critical to engage with customers and test our plans and priorities with them to ensure our proposal advances their long-term interests.

Customer and stakeholder engagement is vital to meeting the long-term energy needs of our customers, in providing a safe, reliable and affordable electricity supply. In Chapter 5 and Attachment 5.01 we provide a detailed overview of who our customers are, how we engage with them, and how we respond to their concerns and priorities in our proposal for the 2019-24 period.

Below we summarise how our proposed opex responds to these concerns and advances customers' interests.

11.2.1 Customer feedback and our opex response

We will continue to constrain our contribution to customers' electricity bills

We have made significant reductions to our opex over the 2014-19 period to ensure our base year provides an efficient estimate of our opex requirements for the 2019-24 period. We have reduced our opex[52] from $330.3 million (real, 2018-19) in 2013-14 to $266.3 million (real, 2018-19) in 2017-18. This improvement will be reflected in our benchmarking performance. We forecast our FY18 Opex MPFP score will improve by approximately 17 percent from FY17 following this reduction to our opex.

We have used the 2017-18 year as our base year for forecasting our opex for the 2019-24 period. This means the $64.1 million (real, 2018-19) reduction we have made to our opex since 2013-14 will be passed through to customers in our forecast opex over 2019-24. Additionally, to provide further assurance that our base year is efficient we note it is below the AER's efficient allowance from the AER's April 2015 Determination for the 2014-19 period.

In addition to this, we have decided against proposing any step changes for the 2019-24 period. This decision results in the avoidance of approximately $10 million annually in our forecast opex. These costs will be offset by ongoing efficiency and productivity improvements.

We will provide a safe and reliable supply of electricity

In making these reductions to our opex over the 2014-19 period we have not compromised our safety, service quality or our ability to comply with our obligations. Our reliability performance has been steady over the entire period and we have continued our focus on safety.

We consider the base-step-trend method will produce an opex forecast that will be in the best interest of our customers and will allow us to continue to meet our obligations and maintain service levels at an efficient cost.

52 Reported opex for EBSS purposes as per Attachment RIN0.03.

We will manage vegetation in accordance with mandatory standards

Customers told us they support the need to manage trees for safety and reliability reasons but asked us to work more closely with councils to provide information on appropriate tree species for residents and improve trimming practices. Managing vegetation is an essential service that is critical in ensuring we provide a safe and reliable supply of electricity. Our vegetation management program complies with mandatory industry standards and is outsourced to ensure we get the best value for money.

In the most recent year, 2016-17, we cleared 98 percent of our network area in accordance with mandatory vegetation clearance standards. We acknowledge the vital role we play in bushfire mitigation and remain committed to adhering to our obligations at an efficient cost.

We will trial and deploy innovative technologies where it is efficient to do so

We note that customers expressed interest in the possibilities associated with future grid technologies. However, there were mixed views as to whether customers should have to fund research and innovation in these technologies at an increased cost. We feel that the AER's new DMIS and DMIA strikes an appropriate balance. We will consider and propose innovative trials and new technologies in accordance with the planning arrangements in the Rules, in consultation with stakeholders and the DMIS and DMIA.

We will provide customers with greater choice on the timing of planned outages

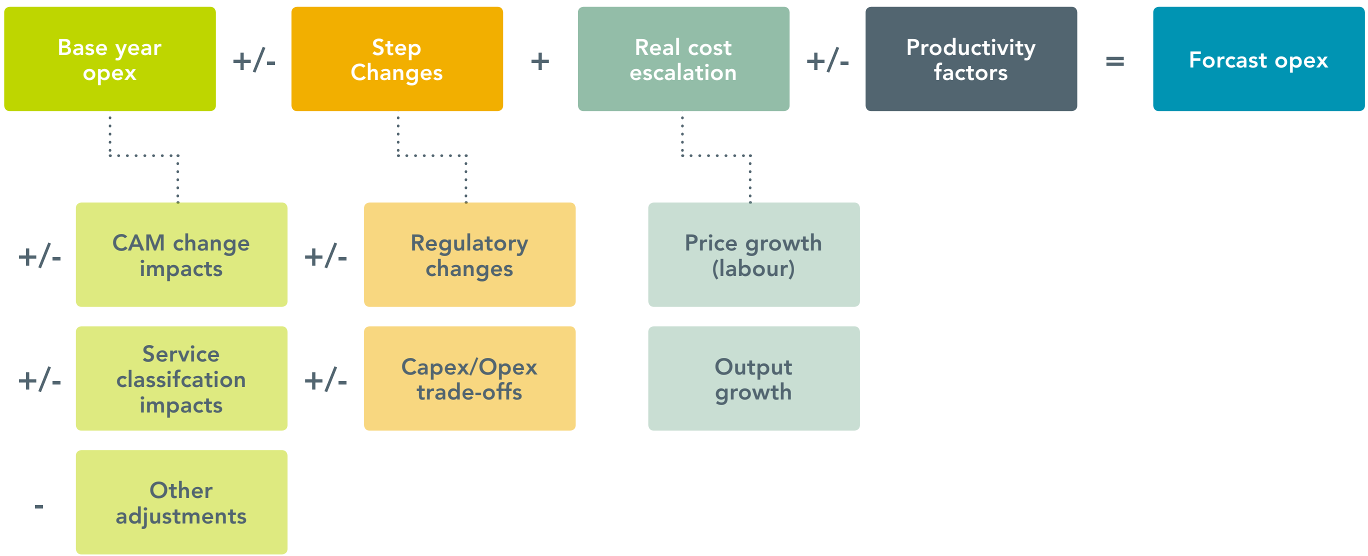
Our policy had previously been to conduct all planned outages during business hours in order to minimise costs and ensure all customers were not unnecessarily funding overtime. Following feedback from small business customers about the inconvenience planned outages causes them we have proposed a new ancillary network service. This service allows a customer to pay the additional amount of costs required to shift a planned outage to outside of business hours on request.

11.3 Opex forecasting method

11.3.1 Our forecasting approach and method

The forecasting method adopted is critical in deriving a forecast opex that reasonably reflects the opex criteria and is sufficient for us to achieve the opex objectives. We have used the base-step-trend methodology for estimating our forecast opex requirements. In applying this approach we have used the AER's top-down Opex Model which can be described as follows:

Figure 11.1 The base-step-trend forecasting approach



We note that there are a number of key steps involved in the application of a base-step-trend forecasting method to ensure the resulting opex forecast reasonably reflects the operating objectives, criteria and factors.

First, it is necessary to assess the extent to which the base year used for forecasting purposes is both efficient and sufficient to allow a DNSP to meet its obligations and maintain a safe, secure and reliable supply. Secondly, it is necessary to assess, as far as practicable, the extent to which this base year opex amount will allow a DNSP to efficiently and sustainably deliver the outcomes discussed above into the future. This requires an assessment of potential changes in our:

- service classification;
- Cost Allocation Methodology or capitalisation policies;
- regulatory obligations;
- productivity levels;
- costs of inputs; and
- operating environment and network scale.

Our approach to each of the forecasting stages above is discussed in further detail in sections 11.5 to 11.7 of this Chapter.

We also note that our forecast opex has been prepared in accordance with; the CAM that applies to Endeavour Energy (approved 8 March 2018) and the requirements of the Reset RIN, Attachment RIN0.01 to this proposal.

11.3.2 Forecasting assumptions

The Rules require that we provide details of the key assumptions underpinning our forecast opex and a directors' certification as to the reasonableness of these key assumptions.

The directors' certification is provided at Attachment 0.08. The summary below provides details of assumptions underlying our forecast opex. These are assumptions relating to facts or circumstances, the truth or correctness of which underpins or is highly material to the forecast of opex. We note that there are other key assumptions which apply solely to forecast capex and have been identified in Chapter 10.

Table 11.2 Our opex forecasting assumptions

Assumptions	Description
Our current structure and industry structure	We have prepared our forecast opex based on our current organisational structure and current financial system. We assume that there will be no material changes to these in the 2019-24 period.
Legislation and regulatory framework	The opex forecast had been developed based on: • the current applicable regulatory framework including the current version of the National Electricity Laws and National Electricity Rules in force at the time of developing the proposal; and • current legislation applying to Endeavour Energy.
Base year	The opex we will incur for the provision of standard control services in 2017-18 has been adopted as the efficient base year for deriving a forecast of recurrent opex. This forecast opex has been adjusted for cost items that do not reflect the underlying operating profile to ensure that the proposed forecast opex reasonably reflects the efficient costs that a prudent operator would require to achieve the opex objectives, taking into account a realistic expectation of the demand forecast and cost inputs required.
Cost escalation	We have forecast that the real cost escalators used will be sufficient to reasonably reflect a realistic expectation of the cost of inputs in the 2019-24 period. In addition, we have also forecast: • wages for staff will rise in line with the Electricity, Gas, Water and Waste Services (EGWWS) wage forecasts; and • there are no real cost changes for other non-labour cost inputs (i.e. these are assumed to change with CPI).
Customer engagement	We have engaged with stakeholders in developing this regulatory proposal in accordance with the stakeholder engagement process outlined in the Rules.

Other opex
Non-routine costs are not a function of the current base year costs; therefore the base-step-trend 'revealed cost' method would not be appropriate. Our debt raising costs are set using benchmark costs. We use the AER's method for the calculation of debt raising costs. That is, debt raising costs are calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

11.4 Our performance in the 2014-19 period

In the 2014-19 regulatory period we were set a significant challenge. We determined an increase from our 2009-14 actual opex was required in order to meet our vegetation management obligations. Also, we considered it reasonable that a transitional period be provided in order to reduce staff numbers and operating costs in a sustainable and safe manner and in accordance with our obligations.

The AER set an opex allowance that was 28 percent lower than the 2009-14 opex allowance. This was 17 percent below the amount we considered was necessary to meet our obligations and maintain existing service quality.

We expect to reduce our opex from $330.3 million (real, 2018-19) in 2013-14 to $266.3 million (real, 2018-19) in 2017-18 (our base year) which is a reduction of $64.1 million (real, 18-19).[53] This immediately benefits customers.

Table 11.3 Actual and forecast expenditure for the FY15-FY19 period

$m; Real FY19	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Actual/forecast[54]	322.6	336.3	325.9	266.3	271.5	**1,522.6**
AER Allowance	256.4	260.4	264.5	269.1	274.3	**1,324.6**

As evident in the table above, we have managed to reduce our opex by 16 percent over the 2014-19 period. We achieved this reduction while connecting over 95,000 additional customers to the network, maintaining network reliability and improving our safety performance.

The most significant driver of this reduction was the *Endeavour 2020* transformation program and the recent partial lease of Endeavour Energy to an Australian-led consortium of investors with extensive experience in managing energy assets. We discuss this in more detail below.

11.4.1 Our efficiency initiatives

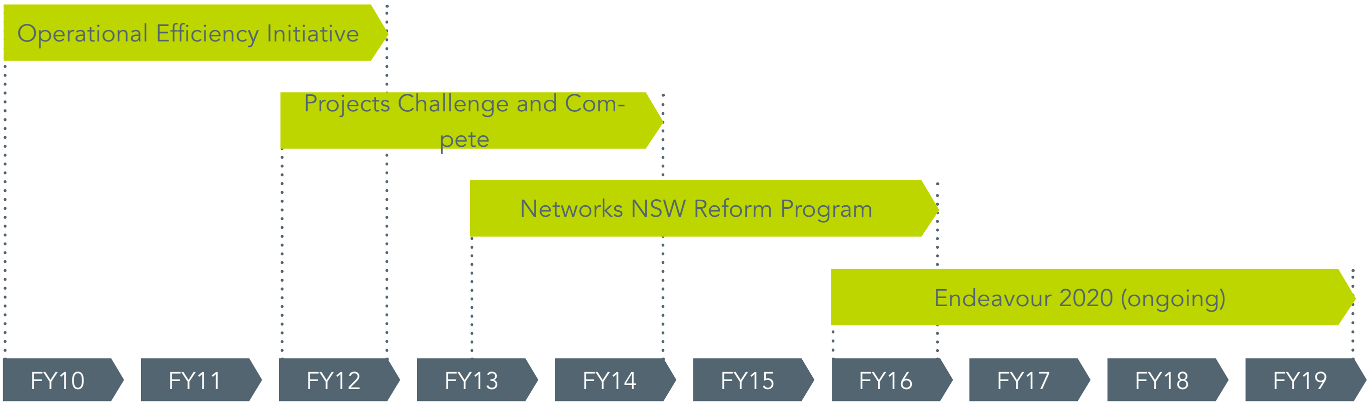
History of reform

We have an established track record of transformation since 2009. Community concern in response to double digit price increases triggered our focus on improving productivity and efficiency outcomes. Since then, we have continuously committed to substantive, organisation-wide efficiency programs designed to reduce costs and manage our contribution to electricity prices.

53 In accordance with NER S6.1.2(7), opex for each of the past regulatory years of the previous and current regulatory control period is provided at Attachment 11.02.

54 For comparison, this actual expenditure excludes amounts relating to DMIA, movements in provisions and debt raising costs

Figure 11.2 Our reform program history



These programs have also been associated with key changes to our organisational structure over the past several years. For instance, earlier efficiency programs such as Projects Challenge and Compete, were established to achieve cost reductions to offset the retail sale related dis-synergy costs of $54 million[55] (real, 2018-19). The Networks NSW Reforms were an amalgamation of certain functions across the three NSW distribution businesses designed to put downward pressure on electricity prices across the state through scale efficiencies.

Since Networks NSW, Endeavour Energy has focussed on achieving cost efficiencies in preparation for the partial lease. This focus has continued with the recent change in our ownership structure following the transaction as evident in the significant cost reductions we have made over the 2014-19 period. This is discussed further below.

Endeavour 2020

Endeavour 2020 was our organisation-wide efficiency transformation program for the 2014-19 period.

Following the AER's 2014-19 determination and in advance of the partial 99-year lease of our assets to private investors, we conducted a review of our operations to identify cost improvement opportunities in order to reduce the shareholder funded opex to the lowest amount possible.

This review identified cost reductions from three perspectives:

- Transformational business model changes;
- Process/efficiency improvements for corporate functions; and
- Process/efficiency improvements for network functions.

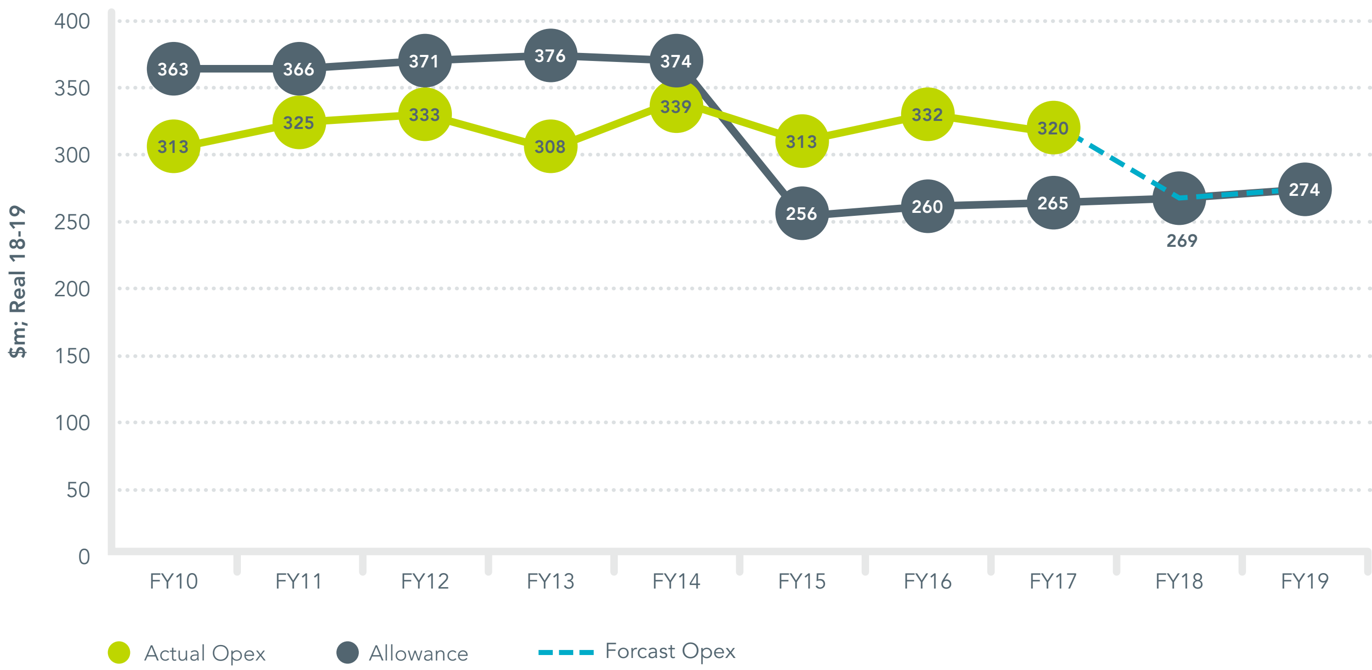
The review identified a number of initiatives to transform the business and drive efficiency across the breadth of operations. These initiatives were grouped under five work streams – Asset Management, Works Management, Corporate, Procurement, and Local Management Initiatives.

55 Figure as per the AER's Retail cost-pass through decision for Endeavour Energy March 2012. The pass-through was for EBSS purposes only i.e. we did not adjust our revenue allowance for the 2009-14 period to pass the additional opex costs through to customers. Instead, these costs were excluded from our opex for EBSS purposes so that we were not unreasonably penalised for these unforseen costs.

The treatment of surplus labour was a key point of contention for the 2014-19 period. Notably, through the *Endeavour 2020* initiatives we have reduced our FTEs, in excess of the AER's opex allowance, from 369 to zero. Since 2012, we have reduced our workforce by almost 1,000 FTEs to make our business more efficient.

Reducing our FTEs has resulted in higher opex amounts in the earlier years of the 2014-19 period. The short-term cost increases, particularly in 2015-16, are associated with exiting staff and restructuring which was required to deliver longer-term opex savings. The benefits of these are forecast to be realised in the 2017-18 opex which is $64.1 million (real, 2018-19) below our opex in the 2013-14 year. As 2017-18 is our base year for forecasting purposes, these benefits will continue to be passed through to customers over the 2019-24 period.

Figure 11.3 Our opex performance FY10-FY19 ($m; Real 2018-19)



It is worth noting that we have reduced our opex despite facing the following additional cost pressures:

- We had to increase our vegetation management costs by more than $10.0 million annually (real, 2018-19) to ensure compliance with the required safety standards.
- We had to absorb a $54 million (real, 2018-19) increase in annual corporate support costs being directed to the network business arising from the sale of our Retail business.
- We had to absorb a short-term cost increase to fund the *Endeavour 2020* efficiency initiatives and redundancy costs.
- We had to supply resources to support the connection of an additional 98,000 customers and maintain, repair, and operate a network with an additional 176,000 assets. Including:
  - 2,700 km of network power lines and cables;
  - 22,500 poles;
  - 3,500 distribution substations; and
  - 115,000 service lines.

- We had to comply with changes in our regulatory obligations, including the Power of Choice reforms; and
- We had an increase in emergency response due to storm and other abnormal events.[56]

The *Endeavour 2020* program has achieved its objective of transitioning our opex to the AER's final year opex allowance for the 2014-19 period. Through our transformative efficiency programs we have managed to reduce our costs in real terms while managing the above additional cost pressures. Additionally, we have managed to deliver more for less with a 30 percent reduction in FTE count from 2009-10 to 2016-17.

11.4.2 Vegetation management

Vegetation management represents a substantive and critical activity. Over 85 percent of our franchise area is bushfire prone as identified by the NSW Rural Fire Service. There are mandated standards that set out the minimum clearances required for the safe operation of the distribution network. We have a comprehensive strategy to manage the risk of bushfires being initiated by our network which has been subject to a formal safety assessment by IPART. Our bushfire risk safety management system is subject to an ongoing audit program by IPART as the technical regulator.

To ensure our program is targeted and prudent we employ leading edge LiDAR (light detection and ranging) technology to accurately identify vegetation that is too close to the network. Our pre-summer program includes annual inspections of our assets in bushfire prone areas and associated maintenance work, vegetation management, and capital works to target specific high risk assets.

To ensure that we deliver value for money services we externally source a significant majority of this function.

During the 2014-19 period we continued to see improved conformance with the standards compared to the 2009-14 period. In 2012-13, we cleared 76 percent of our network area in accordance with the NSW Government standard ISSC 3 for $47.0 million (real, 2018-19). We have steadily improved our performance over the 2014-19 period. In our most recent year of actuals, 2016-17, we cleared 98 percent of our network area in accordance with ISSC 3 at a more efficient price.

We also note that during the 2014-19 period we appeared in the Coronial Inquiry into the causes of the 2013 Springwood and Mount Victoria bushfires. We also settled two class actions in relation to the Springwood bushfires for $4 million and $18 million respectively. These settlements (less excess) were funded through our insurance coverage rather than standard control service customers and made without any admission of liability by Endeavour Energy.

These events reiterate the loss and hardship residents in our franchise area can experience as a result of bushfires and the critical role we have in mitigating the risk our network presents. Our 2019-24 opex forecast, provides for a continuation of existing expenditure levels and improved performance from the 2014-19 period with the ongoing objective of compliance with industry standards.

56 April 2015 event, November 2015 event, January 2016 event, July 2016 event, October 2016 event, March 2017 event

11.5 Efficiency of the base year

A key aspect of determining the efficiency of our forecast opex is assessing the extent to which the base year is efficient. The revealed cost framework that applies to us, incentivises the pursuit of achieving operational efficiency. Our own performance over time when compared with our peers is therefore central to assessing the allocative and productive efficiency of our base year. A key indicator of the efficiency of our base year opex is that it is below the benchmark efficient opex allowance set by the AER.

In this section we provide more detail on why our base year can be considered to be efficient. We then outline the forecast 'trends' and 'step changes' which address the dynamic efficiency of our forecast, i.e. that our opex remains efficient over time.

11.5.1 Our base year is efficient

Base Year Selection

The base-step-trend 'revealed cost' forecasting approach necessitates an efficient base year level of expenditure be utilised. In deciding whether or not the AER is satisfied that our proposed opex forecast meets the expenditure objectives at an efficient and prudent cost the AER relies on the expenditure criteria and the expenditure factors.[57] Broadly, the expenditure criteria and factors combined are directed at assessing the efficiency and prudence of the forecast. In selecting our base year for the 2019-24 period we have considered prudency and efficiency as follows:

- **Efficiency:** no objective, external factors that can be relied upon to demonstrate that the overall level of the opex forecast is perfectly efficient. Instead, partial indicators exist that can be used to assess the efficiency of the overall level of costs. We have therefore considered our past expenditure in response to the EBSS, benchmarking and outsourcing as indicators of efficiency.
- **Prudency:** we have assessed the extent to which our recent actual costs have allowed us to meet our obligations and maintain existing service levels.[58] We have also assessed whether any trend or step factors are required to ensure we can continue to meet our obligations and maintain existing service levels. Our forecasting process, and its prudency, is addressed in further detail in Attachment 0.07.

Based on this assessment, we have selected the 2017-18 year as the base year for forecasting purposes. Our rationale/steps are as follows:

Efficiency measures

Our past performance:

- We have achieved a better opex outcome in 2017-18 than the AER set as the efficient allowance for that year.
- Our base year fully reflects the cost reduction initiatives we have implemented as part of our *Endeavour 2020* transformation program and post-lease implementation.
- We have responded efficiently to the incentive regime as evidenced by our positive EBSS carryover benefit.
- The EBSS provides the strongest incentive to Endeavour Energy to "reveal" its most efficient cost.

Benchmarking: as a result of the opex reductions we have made over the current period our benchmarking performance has improved:

- Our Opex MPFP score will improve by approximately 17 percent in 2017-18.
- Our opex per customer will improve from an average of $306 during the current period to $274 in the 2019-24 period.

57 Clauses 6.5.6(e) of the rules

58 For the purposes of S6.1.2(4) of the NER, we can confirm the objective of our opex forecast is to maintain existing levels of reliability. Forecast maintenance programs are not designed to improve the performance of Endeavour Energy under the STPIS.

Outsourcing: we have outsourced and market tested a number of activities as part of the *Endeavour 2020* program. As a result, approximately a third of our base year opex will reflect market tested and/or outsourced activities.

Change in ownership: 2017-18 is the first full year under our new ownership arrangement and therefore more likely to be reflective of our operating costs in future years. The consortium of investors who have leased Endeavour Energy have extensive, international experience in efficiently managing and operating energy businesses.

Prudency measures

Our actual expenditure has been enough to satisfy our obligations and maintain our reliability and service quality. For instance:

- we were compliant with our licence conditions;
- our reliability performance (SAIDI and SAIFI) has been steady over the 2014-19 period;
- we cleared 98 percent of our network area in accordance with our vegetation management clearance standards (up from 76 percent in 2012-13);
- our safety performance has continued to trend favourably over the period; and
- while above target, we continued to improve our NECF performance.

We discuss these items in further detail below.

Our past performance and the incentive regime

The base-step-trend 'revealed cost' methodology works together with the EBSS to provide us with a continuous incentive to become more efficient in a sustainable way.

A critical aspect of assessing forecast opex is therefore determining whether a DNSP has been responding efficiently to the revealed cost framework and EBSS over the current regulatory control period. If a DNSP is responding to incentives its actual opex, the nominated base year, can be relied upon for forecasting purposes.

In section 11.4, we provided a detailed explanation of the efficiency initiatives we implemented, the cost pressures we managed and the key events that have occurred to date over the 2014-2019 period. Our actual performance over the 2014-19 period demonstrates that we have responded to the incentive scheme by reducing our opex over the period while improving our vegetation management compliance, maintaining our increasing base of network assets and customer connections and continuing to meet our broader licence conditions and obligations while maintaining our service quality.

Benchmarking

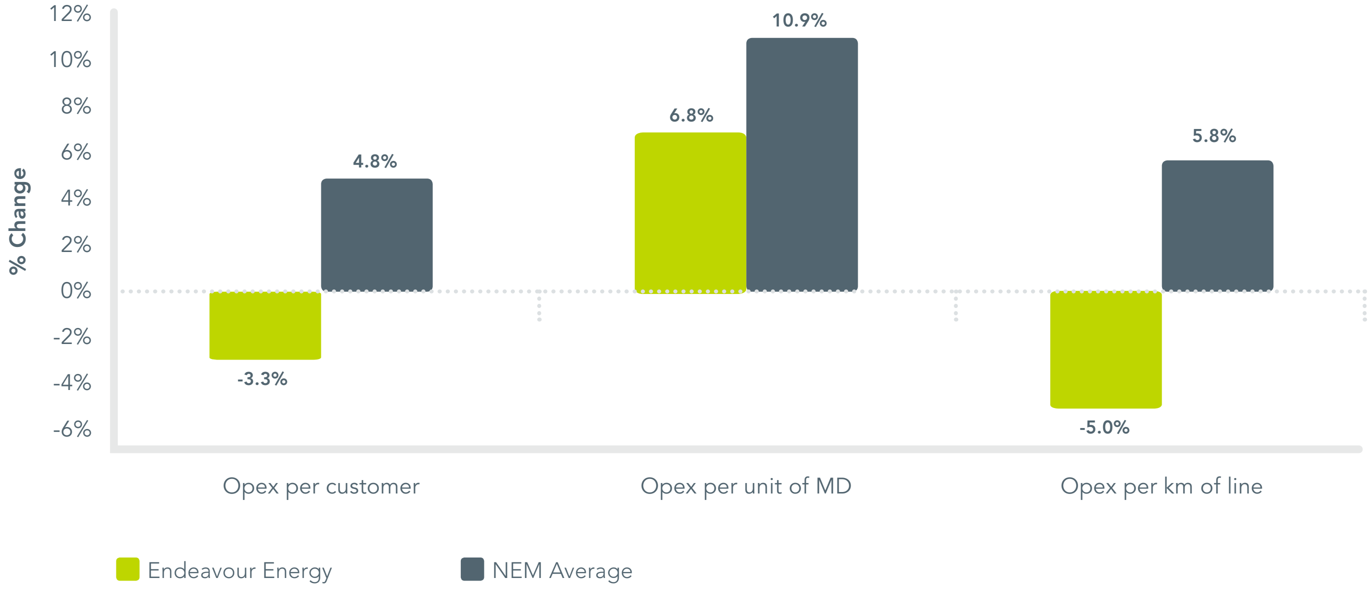
Generally, we consider benchmarking total opex is preferable to category level forecasts as these can be subject to disparate accounting and reporting practices which impacts comparability. For similar reasons we also consider benchmarking is of more probative value for assessing the individual performance of a DNSP over time.

We note that the AER releases an Annual Benchmarking Report which measures the benchmark performance of Australian DNSPs. Our annual and average performance against these measures has seen Endeavour Energy consistently rank amongst the middle of DNSPs in Australia.

To assess the efficiency of our base year we have updated the AER's measures for our forecast performance in our base year (2017-18). Based on this analysis, it is evident our performance is improving given our expected opex reductions from 2013-14 to 2017-18. We forecast a 17 percent improvement in our Opex MPFP score in 2017-18. Furthermore, our opex per customer over this period is expected to reduce from an average of $306 per annum to $274 per annum.

We have also examined a number of key PPIs the AER typically examine to check the reasonableness of econometric benchmarking results and the MTFP and MPFP models. Our performance against these opex PPIs is amongst the most improved in the NEM over the last few years as evident in Figure 11.4 below. Notably, our opex per customer and per km of line have both been reducing while the NEM average has been increasing.

Figure 11.4 Endeavour Energy percentage change in opex PPIs compared to NEM average (FY13-FY16)



We consider these measures indicate our opex efficiency has improved and our 2017-18 base year represents an efficient forecast.

Use of outsourcing

As noted by NERA Consulting:[59]

> Where a DNSP's expenditure forecasts are based on cost estimates for activities that have been sourced from an effectively competitive market, this provides a prima facie indicator that the level of that expenditure is efficient……. where the relationship clearly is at arm's length, then the use of cost information derived from an effectively competitive market provides a strong basis for the presumption of efficiency.

We have consistently sought to market test functions and outsource activities where it is efficient to do so. The nature of the work outsourced has ranged from small scale works, like ongoing routine work through to major initiatives such as vegetation management. We have consistently been effective in managing the development and implementation of workplace reforms, including outsource proposals which have consequently helped reduce our workforce numbers.

59 NERA Economic Consulting, Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules – Supplementary Report, 8 May 2014, p. 29

As discussed in section 11.4.1, a number of the *Endeavour 2020* initiatives involved market testing and outsourcing of both network activities and back office support functions. Below, we list the functions we have market tested and identify the results of this (i.e. retained, blended or outsourced):

- Vegetation management – outsourced.
- Back office processes (Accounts Payable, Payroll, "Connections-to-Collections") – retained.
- Regional network operations (pole replacement, service mains replacement, etc.) – blended.
- Facilities maintenance (incl. substation civil maintenance and mailroom) – blended.
- Fleet maintenance – blended.
- Network data capture – outsourced.
- OT hardware and application support – outsourced.
- Records scanning – outsourced.
- Security locking – blended.
- Security patrols and guardhouse – outsourced.
- Technical training – blended.

Overall, approximately 33 percent of our base year opex will reflect market tested and/or outsourced activities. This provides significant comfort that our forecast opex represents an efficient and realistic estimate of the costs a prudent operator would require to achieve the opex objectives.

11.6 Rate of change

Actual opex in the base year reflects the prevailing economic and network conditions. It is reasonable to expect that known changes in conditions are incorporated in the forecast to ensure it remains efficient over the course of the period. For example, increases in demand and customer numbers result in additional network investment which in turn increases our opex (such as increased inspection and maintenance work). We have sought to account for these known changes through the trend factors that are applied as part of the AER's preferred base-step-trend forecasting methodology.

The AER's Expenditure Assessment Forecast Guideline sets out the following reasons why efficient opex in the forecast period may differ from the base level of expenditure:[60]

- **Real price growth:** this relates to changes in the prices of the key inputs we use in our operations including labour, materials and contractors. Real price growth is the growth in the rate of prices relatives to growth in the CPI.
- **Output growth:** this relates to changes in the scale of the network over time in response to customer and demand growth. It is reasonable that as the scale of operations increases our efficient costs will increase.
- **Productivity growth:** this relates to changes in the level of expenditure required to deliver the same level of services to customers. Productivity growth may be a result of productive, allocative or dynamic efficiency improvements.

We have developed forecasts for each of these components and applied these to develop our opex forecasts. Our trend factors forecasts are as follows:

Table 11.4 Opex trend factors for FY20-FY24

$m; Real FY19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Base opex	271.5	271.5	271.5	271.5	271.5	**1,357.5**
Price growth	4.6	8.8	14.3	19.8	25.4	**72.9**
Output growth	2.7	6.4	10.9	15.5	19.5	**55.1**
Total opex	**278.8**	**286.7**	**296.7**	**306.8**	**316.5**	**1,485.5**

60 AER, Expenditure forecast assessment guideline for electricity distribution, November 2013, p. 34.

11.6.1 Price growth

Labour price growth

We have engaged CEG and BIS Oxford Economics to estimate cost escalation factors in order to assist us in forecasting future opex based on changes in input costs for the 2019-24 regulatory period.

We have found that over the 2019-24 period input prices for labour and contracts (which are mostly labour based) are forecast to grow at a faster rate than CPI. We have therefore included real escalators for these inputs in the AER's Opex model (and our capex forecast). We outline our approach to labour escalation and some of the key issues in more detail below.

There are a number of issues to address in developing a forecast of labour price growth. Based on advice received from CEG and BIS Oxford Economics we have taken the following positions:

- **Wage Growth:** our EBA wage growth outcomes reflect efficient and robust negotiations in accordance with the Fair Work Act 2009 (Cth). However, we have used a Wage Price index (WPI) for the EGWWS sector to estimate both EBA and non-EBA wage growth as this is the AER's preferred efficient benchmark.
- **Productivity adjustments:** we note that in recent decisions the AER has considered productivity-adjusted real wage growth indices or adopted the lower range of a forecast to capture the effects of productivity improvements. We consider a non-productivity adjusted wage growth index should be used. This is because productivity is implicitly included within the WPI we have used as explained in Attachments 0.10 and 0.11 to our proposal.
- **Labour/Non-labour weightings:** to date the AER has utilised a benchmark labour/non-labour split to account for wage growth. We have used the proportion of labour used by Economic Insights in preparing the recently published 2017 Annual Benchmarking Report (ABR).

We discuss some of these issues below in greater detail.

Total labour price growth

The labour escalators in the table below represent the real cost escalators to be applied in developing forecast opex by financial year. These forecasts are based on the forecast wage price index for the utilities sector in NSW as provided by BIS Oxford Economics. The BIS Oxford Economics report and calculation methodology are provided at Attachment 0.10.

Table 11.5 Real labour escalators for FY20-FY24

Real cost escalators (%)	2019-20	2020-21	2021-22	2022-23	2023-24
Labour – WPI EGWWS-NSW	1.55	2.04	2.41	2.40	2.00
Proportion of labour	64.8	64.8	64.8	64.8	64.8
Labour price growth	1.00	1.32	1.56	1.55	1.30

In line with AER preferences, we will continue to use an industry wage price index to forecast opex rather than known EBA figures. However, it is worth noting that our EBA agreement covering the period of December 2017 to December 2020 has recently been finalised with wage growth above the industry estimates we have relied on. Also, the first increase under this EBA occurs midway through our 2017-18 base year, which means our base year understates our labour costs. These factors effectively act as a productivity factor in our forecast opex which we discuss further below.

Productivity

We note that Deloitte Access Economics typically provides the AER with "productivity adjusted" real wage growth indexes that the AER has correctly not used in recent decisions. We support this decision for the reasons noted by CEG in Attachment 0.11 to this proposal:[61]

> This is correct because the 'productivity' measure embedded in them is a measure of labour per unit of MWh for the industry – such that 'productivity' increases with increased economies of scale across generation and transport. This is not the relevant measure of productivity for a regulated distribution business because the AER does not derive its cost estimates on the basis of per MWH input costs. To the extent that any productivity gains are to be modelled, these should be modelled directly in the opex and capex programs and explicitly justified on the basis that fewer workers are required to deliver the necessary maintenance/expansion projects.

We also note that the WPI is a conservative estimate of labour price growth as it assumes that wage increases associated with changes in job classification are perfectly offset by increases in productivity. This is incorrect as some wage increases are necessary to retain staff in a competitive labour market rather than simply acknowledging productivity improvements. Furthermore, we note that labour price growth in the electricity industry is generally higher than other utilities meaning the combined EGWWS WPI is likely to understate our likely wage growth.

Benchmark proportion of labour

We have adopted the AER's benchmark labour proportion for forecasting purposes. We note the proportion has been revised from 62.6 percent to 64.8 percent by Economic Insights in the 2017 Annual Benchmarking Report based on data provided by all DNSPs.[62] For consistency, we have adopted the value used by Economic Insights of 64.8 percent in developing our opex forecast.

Material price growth

We use a range of electricity distribution equipment such as transformers, conductors, poles and circuit breakers. Forecast price changes in the commodities that this equipment is derived from such as steel, oil and copper were examined. Based on this analysis, we expect our material input prices will grow at approximately the same rate as the CPI. We have therefore not included real price escalation in the materials component of our opex (and capex) forecast for the 2019-24 period.

61 Attachment 0.11: CEG - Escalation factors affecting expenditure forecasts, December 2017, p.9
62 Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report, 6 September 2017, p. 2

11.6.2 Output growth

Output growth relates to changes in the size of the network and the quantity of services that we are required to provide. Growth in the scale of our network is a result of growth in our customer numbers and network demand. As previously mentioned, it is important to consider output growth to ensure the total opex forecast is dynamically efficient. Dynamic efficiency refers to remaining efficient in a changing environment. Accounting for step changes and output growth are the primary way of ensuring the base year is appropriately adjusted so that the resulting opex forecast reasonably reflects the expenditure criteria.

To measure output growth, the AER has developed three industry standard weighted output variables that align to economic benchmarking variables used by Economic Insights. These measures, and their respective weights, are as follows:

- Customer numbers (67.6 percent).
- Circuit length (10.7 percent).
- Ratcheted maximum demand (21.7 percent).

The AER considers these measures are appropriate as they align with the objectives contained in the NEL and Rules, they reflect the services provided to customers, and they are material. The core operating cost is maintaining and operating the network which involves inspections, vegetation management, maintenance (preventative and broad-based) and fault and emergency response. These activities are self-evidently highly variable and dependent on the physical size of the network.

We accept these outputs measures and the industry standard weightings the AER apply. We do not have any evidence at this stage which suggests additional factors or alternate weightings should be considered. As the scale of the network increases the cost of maintaining our service quality across a larger network will increase. We therefore consider the above measures are appropriate for estimating the impacts of output growth on opex over the period. We note that to avoid the potential for double counting, economies of scale are considered as part of the assessment of total productivity change.

In Table 11.6 we summarised how we estimated each of the output change measures listed above. Estimates for each of these are contained in the RIN and included below for reference:

Table 11.6 Forecast growth rates in output variables (%)

Annual growth rate (%)	2019-20	2020-21	2021-22	2022-23	2023-24
Customer numbers	2.23	1.93	1.88	1.85	1.91
Ratcheted maximum demand	0.00	0.00	2.10	1.81	1.71
Circuit line length	1.66	1.63	1.61	1.58	1.56

Our forecasting methodology for each of these output factors is described in Chapter 7 of this proposal or our Reset RIN Basis of Preparation, Attachment RIN0.05.

11.6.3 Productivity factors

Productivity change can result from technical change, efficiency improvements and economies of scale and is important to consider in developing a forecast opex that is dynamically efficient.

In previous decisions the AER has generally made an efficiency adjustment to a DNSP's base year to immediately move them to the efficient frontier rather than relying on a productivity factor to do so over the course of a period. Further, for those DNSPs within what the AER considered to be the 'efficiency frontier' no productivity factor was applied as its benchmarking analysis did not provide any evidence in support of potential productivity growth in the distribution industry.

In principle, we do not consider it appropriate to include an assumed productivity benefit which may or may not occur within an opex forecast. Broadly, this is for the following reasons:

- **Undermines the EBSS and incentive-based regulation:** the EBSS is designed to provide DNSPs a consistent and continuous incentive to reduce their costs in a timely and sustainable manner over the course of a regulatory period. The benefits of these savings are then shared by both customers and the DNSP. A productivity factor would skew the sharing ratio of the EBSS and reduce a DNSPs incentive to reduce costs beyond the built-in productivity factor.
- **Forecast error**: there is no basis to accurately forecast expected productivity changes. There is little information on the likely benefits of future productivity changes as future innovations are uncertain and unknown and the benefits associated with existing technological improvements are likely to diminish over time. This potential for inaccuracy is inconsistent with the Rules as there is a high likelihood that it would result in an opex forecast that is less than the efficient costs of operating the network to achieve the opex objectives.
- **Declining productivity:** The available data suggests that industry productivity is declining on a totex and opex level:
  - Opex partial factor productivity for Australian DNSPs with a rate of approximately 0.8 percent over the 2006-16 years.
  - Total factor productivity for Australian DNSPs decline at a rate of approximately 1.2 percent over the 2006-16 years.
  - The Productivity Commission found that multi-factor productivity for the utilities industry declined by 2.0 percent per year over the 2007-08 to 2015-16 years.[63]
  - NSW Trade and Investment found multi-factor productivity in the NSW utilities industry declined by 1.86 percent between 1995 and 2013.[64]

We note the AER's recent Annual Benchmarking Report for Australian DNSPs includes new measures of productivity compared to previous reports. Specifically, the total and opex productivity measures have been split between the 2006-12 and 2012-16 periods and both with and without redundancy costs included. We have a number of concerns with this analysis and caution against its use by the AER in upcoming determinations.

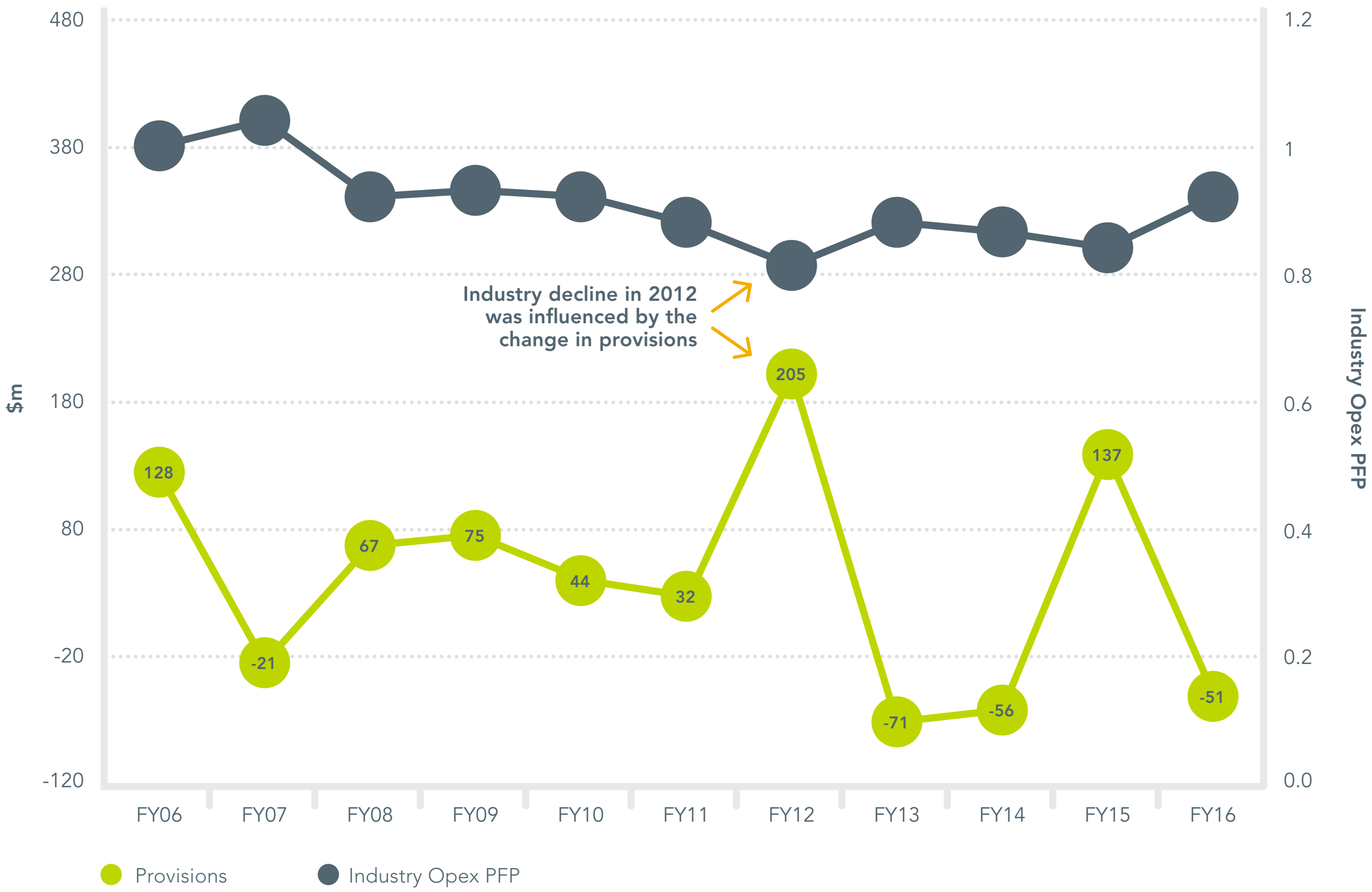
Our primary concern would be the application of an average productivity movement based on opex excluding redundancy costs. This would undermine the EBSS, revealed cost framework as a DNSP would incur redundancy costs and receive the associated EBSS dis-benefit without the opportunity to earn the subsequent EBSS benefit from reduced opex in future periods as these savings have been embedded in the productivity factor. In this scenario the customer receives 100 percent of the benefit rather than the 70:30 percent sharing ratio that should occur under the EBSS.

63 Productivity Commission, Shifting the deal: 5 year productivity review supporting paper no.1 productivity and income – the Australian story, 3 August 2017, p. 16.
64 David Buckland and Harley Smith, NSW Trade and Investment, Productivity in NSW, 18 September 2014.

We also have a number of concerns with the calculation of the productivity factors included in the ABR. Estimating an average annual growth rate to estimate productivity change rests on the assumption that the differences between the start and end-point being relied upon are solely reflective of efficiency movements and that these two points are reflective of the actual opex required to provide distribution services.

The evidence suggests that this is not the case. For instance, annual fluctuations in movements in provisions data have a significant impact on the productivity changes over the 2012-16 period. As evident in Figure 11.5 below, a large increase in provisions in 2012 driven by a significant contribution by Ausgrid led to a reduction in industry productivity followed by an increase in productivity in 2016 driven by a reduction to provisions.

Figure 11.5 Industry opex productivity scores versus movements in provisions FY06-FY16



As noted previously by the AER:[65]

> We considered that to reward or penalise a service provider for changes in provisions would reward or penalise it for changes in assumptions, not efficiency improvements. This undermines what the EBSS is intended to do.

We also note that the approach contained in the ABR, an average annual growth rate between 2012-16, is inconsistent with the technique used by the AER in recent determinations for TransGrid and AusNet. In these decisions a trend approach is used which measures a line of best fit between changes in productivity growth. As noted by the AER:[66]

> The trend growth rate method, on the other hand, will more closely reflect the underlying trend rate of growth over the entire period. It will not track the series from endpoint to endpoint exactly, however. An advantage of the trend method is that it moderates the impact of sudden changes in opex levels.

The trend line for transmission businesses was calculated over the 2006-15 period rather than 2012-16. We are concerned that modifying the period for DNSPs constitutes cherry-picking a preferred productivity growth rate. As evident in the table below, the choice of years can materially impact the productivity growth rate.

Table 11.7 Opex productivity growth rates

Annual growth rate (%)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Average annual growth	-0.8	-1.4	-0.1	-0.2	-0.0	0.9	3.1	1.2	2.3
Trend line	-1.5	-1.4	-0.7	-0.6	-0.1	0.9	1.9	0.7	2.3

Note: Opex productivity growth rates using average annual growth, trend growth and different starting years.

For these reasons, we have not included a specific productivity factor value to derive our efficient opex for the 2019-24 period. Instead, our forecast opex includes productivity through the following mechanisms:

- Using a WPI for the EGWWS which is below our known EBA wage growth factors and is a conservative estimate of wage growth as detailed in section 11.6.1.
- Our decision not to include up to $10 million per annum in step changes in our forecast opex.

In achieving these efficiencies we will continue to respond positively to the EBSS incentives. The benefits of any improvements will be shared with customers through the EBSS in accordance with the revealed cost framework.

The AER, in the Expenditure Forecast Assessment Guideline considers that step changes may arise from either a change in regulatory obligations or a substitution between forecast capex and opex or vice versa. We also note that unforeseen changes, that are material, will be managed separately via the pass-through mechanism as discussed in section 6.3 of this proposal.

65 AER, Attachment 9, Operating Expenditure Final Decision Ausgrid, Distribution determination, April 2015, p. 8
66 AER, Attachment 7, Operating Expenditure Draft Decision AusNet Service Transmission determination, July 2016, p. 57

11.7 Step changes

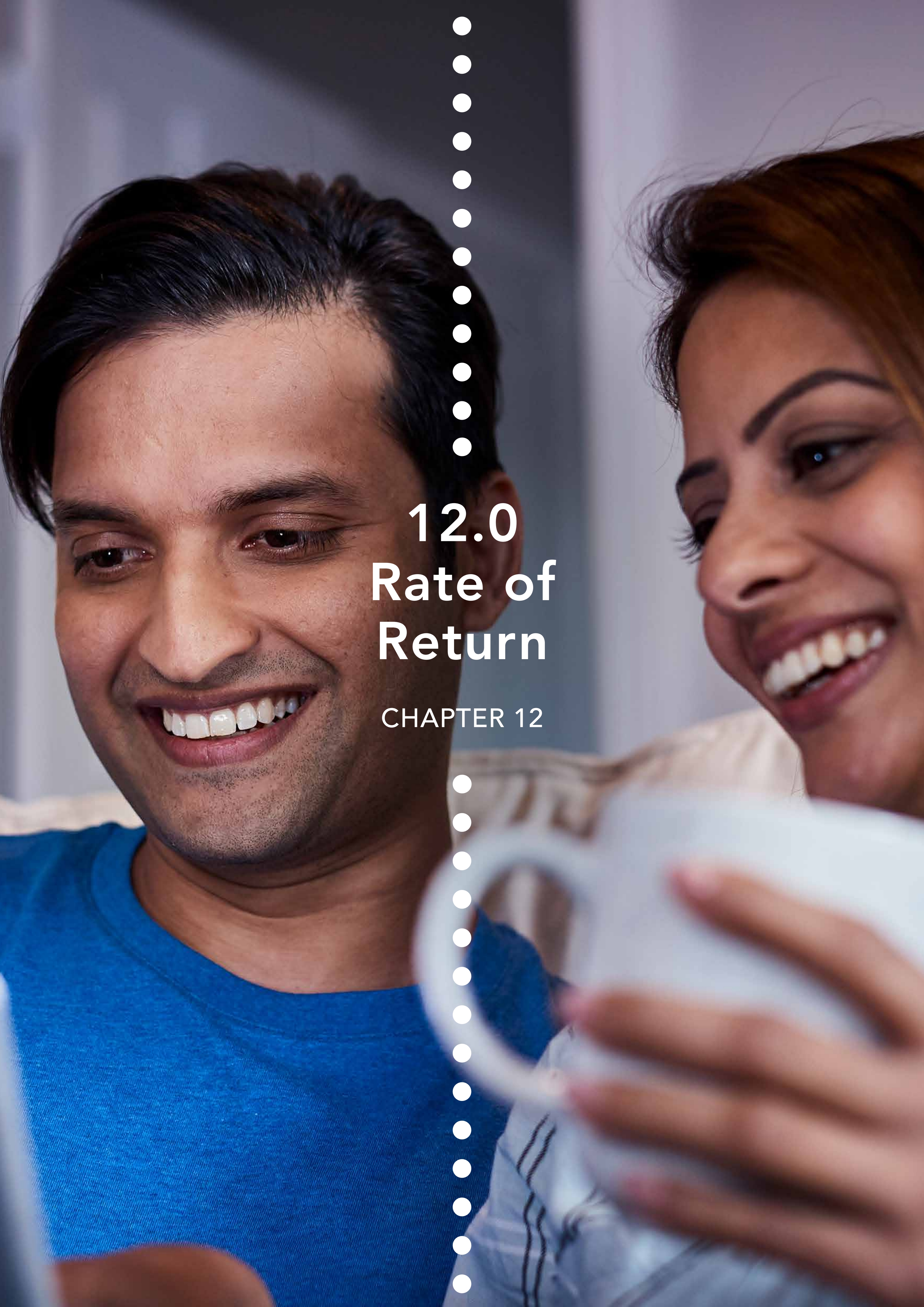
11.7.1 Step changes for the 2019-24 period

We identified a number of potential step changes for the 2019-24 period, which include:

- an increase in ICT licensing costs associated with a change in our ownership structure;
- dis-synergy costs arising from the organisational restructuring required by the AER's new ring-fencing guideline;
- Power of Choice related cost pressures such as having to procure metering data from metering coordinators for planning purposes;
- increased reporting and auditing costs associated with newly imposed IPART requirements;
- education on tariff reform and implementation of tariffs; and
- additional planning and reporting costs associated with expansion of the Regulatory Investment Test for Distribution (RIT-D) requirements.

Despite the potential cost pressures these changes may create over the 2019-24 period, we have decided against proposing any step changes at this time. Instead, we are absorbing all step changes as a productivity improvement.

This decision is primarily in response to concerns raised by stakeholders regarding affordability. The step changes identified above totalled approximately $10 million p.a. (nominal). We consider that removing this opex from our forecast in response to customer concerns will help contribute to our ongoing commitment to constrain our contribution to electricity bills.



12.0 Rate of Return

CHAPTER 12

12.1 Overview

We have applied the AER's 2013 Rate of Return Guideline in deriving our estimated rate of return.

We propose an average rate of return on capital of 6.11% for the 2019-24 period. This rate of return has been developed using the AER's 2013 Rate of Return Guideline ('Guideline'). The proposed rate of return takes into consideration the need to promote efficient pricing and long-term stability for customers and equity holders while maintaining stability and predictability of the regulatory outcomes.

The clear message from our customer engagement program is that customers expect that our rate of return estimate is efficient in order to put downward pressure on electricity prices. When we sought an extension on lodging this proposal, customer advocates were explicit in their expectation that we should apply the methodologies, models and estimates contained in the AER's 2013 Rate of Return Guideline, as applied by the AER in recent decisions.

We have achieved our customer expectations in regards to our rate of return estimate by not departing from the AER's Guideline. This results in a rate of return that is 50 basis points lower than the average rate of return which applied during the 2014-19 period and up to 65 basis points lower than the initial estimate included in our 2019-24 Directions Paper.

The proposed rate of return complies with the Rules. In particular, it:

- reflects the financing costs of a benchmark firm with a similar degree of risk;
- has been calculated using a weighted average of the return on equity and the return on debt;
- is determined on a nominal vanilla basis;
- incorporates an estimate of the value of imputation credits ('gamma') consistent with the market's valuation; and
- reflects prevailing market conditions for equity funding and historical market conditions for debt funding.

Table 12.1 Initial proposal rate of return estimate

Parameter	Proposed value (%)
Inflation	2.5
Return on debt (five-year average)	5.39
Return on equity	7.19
Gearing	60
Gamma	40
Corporate tax rate	30

12.2 Customer insights

In accordance with the NEO, our objective is to set a rate of return that incentivises an efficient level of investment in the network serving the long-term interests of customers. In preparing a proposal it is therefore critical to collaborate with customers and test our plans and priorities with them to ensure our proposal advances their long-term interests.

As described in Chapter 5 and Attachment 5.01 of this proposal, we have consulted extensively with our customers in preparing our plans for 2019-24. This includes our Directions Paper released in August 2017. In this section we highlight the insights of customers with respect to our rate of return and how we have sought to respond to these insights.

12.2.1 Our proposed cost of debt follows the AER's preferred methodology

We will adopt all components of the AER's 2013 Rate of Return Guideline as applied by the AER.

At the time of publishing our Directions Paper, there were several ongoing appeal processes. Due to this uncertainty we developed forecast pricing outcomes using a WACC range of 6.25 to 6.75 percent. Our initial position on each WACC component was as follows:

- Cost of debt: 10 year trailing average with no transition.
- Cost of equity: derived from a range of estimation methods consistent with the AER's 2013 Rate of Return Guideline.
- Value of imputation credits: a market valuation approach that supported an estimate of 0.4.
- Inflation: set at the midpoint of the RBA target range as a placeholder noting it will be updated at the time of the AER's final decision.

We received feedback from stakeholders and customers that affordability remains the primary issue and that this should be a key consideration in setting an appropriate rate of return. Stakeholder groups suggested that we fully adopt the AER's 2013 Rate of Return Guideline in responding to their concerns.

We have considered this feedback and changed our position to deliver a more affordable outcome for customers. We have fully adopted all components of the AER's 2013 Rate of Return Guideline. This, along with more up to date market information, results in a WACC that is between 15 to 65 basis points lower than the range used in our Directions Paper. This is a positive result for our customers and delivers on our commitment to continue putting downward pressure on electricity bills.

In subsequent discussions with stakeholders they have been supportive of this decision and the application of the AER's 2013 Rate of Return Guideline. We note that our commitment to the 2013 Rate of Return Guideline was a key feature of our proposal to extend the time for lodging this proposal and was acknowledged by the AER as a key component of their decision to approve our request.

Notwithstanding this, we are aware that COAG may be considering applying an updated 2018 Rate of Return Guideline with immediate effect, due to be completed by the AER before 17 December 2018. We would not be supportive of this as it would undermine an outcome that has been discussed and agreed to by Endeavour Energy and our stakeholders.

It would also be inconsistent with the Rule change proposal put forward by the AER to amend the timing of the release of the next Rate of Return Guideline. Endeavour Energy supported the proposed Rule change on the basis of the transitional arrangements contained in the final Rule decision. The transitional arrangements specified that the 2018 Rate of Return Guideline would apply to Endeavour Energy for the 2024-29 regulatory period.

An updated guideline will not be completed until one month before Endeavour Energy is required to lodge its revised regulatory proposal and therefore it will not provide us an opportunity to model the impacts on the 2019-24 period and consult with customers on this. On this basis we support the application of the 2013 AER Rate of Return Guideline for this determination process.

12.3 Cost of debt

Endeavour Energy proposes an average cost of debt of 5.39 percent based on the application of the 10-year trailing average approach,[67] transitioned over 10 years,[68] consistent with the AER Guideline using observations from the most recent averaging period for debt to inform future expectations. This value will be updated with data obtained in the five averaging periods nominated by Endeavour Energy consistent with the AER Guideline.

The proposed cost of debt applying the AER's methodology includes:

- application of the 10-year trailing average approach with transition commencing from 2014-15;
- 10-year benchmark debt term;
- Australian corporate bond yield data from the Reserve Bank of Australia (RBA) and Bloomberg;
- equal weighting of the two yield curves;
- yields for BBB rated bonds;
- an extrapolation of the RBA and Bloomberg curves to an effective tenor of 10 years; and
- annual updates to cost of debt allowance.

12.3.1 Our proposed cost of debt follows the AER's preferred methodology

Endeavour Energy has utilised historic data from the 2014-19 regulatory period to develop estimates of the trailing average cost of debt for the regulatory period 2019-24. Based on actual cost of debt observations over the current regulatory period, we have calculated an average cost of debt of 5.39 percent.

Our proposed cost of debt estimates are consistent with the AER's preferred calculation methodology and the AER's published views including advice from Chairmont utilised by the AER in previous regulatory determination processes.

Table 12.2 Summary of reasoning behind parameter assumptions

Parameter	Assumption	Reasoning
Debt term	10 years	AER's preferred approach[69]
Base rate	Interest rate swaps	AER's preferred approach[70]
Debt management strategy	Transition to trailing average	AER's preferred approach
Data sources	Simple average of RBA and Bloomberg curves	AER's preferred approach
Averaging periods	Averaging period nominated in accordance with the AER's Guideline	Consistent with AER precedent and Guideline

Source: CEG

67 AER, Final rate of return guideline, December 2013, p19
68 Ibid, section 6.3.1, p19
69 AER, Final rate of return guideline, December 2013, p4
70 AER, Endeavour Energy distribution determination 2015-16 to 2018-19, Final Decision, Attachment 3 – Rate of Return, April 2015, pp3-161 to 3-162

12.3.2 Debt raising costs

The process of raising debt finance incurs significant transaction costs that should be recognised in regulated revenue allowances over the 2019-24 regulatory period. The AER's standard practice has been to recognise these costs as benchmark efficient operating expenditure and this is reflected in the AER's post-tax revenue model (PTRM). The AER's PTRM requires input of benchmark efficient debt raising costs in basis points per annum (bppa) that is applied to the regulatory asset base.[71]

The AER's approach for forecasting debt raising costs first divides the benchmark debt share (60 percent) of the RAB by a benchmark bond size ($250 million). The upfront costs associated with issuing these bonds are then amortised using the nominal vanilla WACC from the PTRM, to be expressed in basis points per annum.[72]

Endeavour Energy has adopted the AER's approach for determining the 8.2 bppa benchmark debt raising cost, as shown in Table 12.3. These calculations assume a nominal vanilla WACC of 6.11 percent for amortisation purposes.

Consistent with the AER's approach, this benchmark debt estimate will then be multiplied by the debt component of the projected RAB in order to determine the debt raising cost allowance.

Table 12.3 Summary of reasoning behind parameter assumptions

Number of bonds	Value	1 bond issued	16 bonds issued
Amount raised		$250m	$4000m
Arrangement fee	7.05 bp	7.05	7.05
Bond Master Program (per program)	$56,250	0.31	0.02
Issuer's legal counsel	$15,625	0.09	0.09
Company credit rating	$77,500	0.42	0.03
Annual surveillance fee	$35,500	0.14	0.01
Up-front issuance fee	5.2bp	0.71	0.71
Registration up-front (per program)	$20,850	0.11	0.01
Registration- annual	$7,825	0.31	0.31
Agents' out-of-pockets	$3,000	0.02	0.02
Total (basis points per annum)		9.2	**8.2**

Source: CEG

71 AER, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008, pp. 8-9.
72 See: AER, AusNet Services Gas access arrangement 2018 to 2022, Attachment 3 – Rate of return, Draft Decision, July 2017, pp. 3-445 to 3-446.

12.4 Cost of equity

Endeavour Energy has applied the Guideline methodology and used the point estimates as per the AER's 2013 Rate of Return Guideline within the Sharpe-Lintner (SL) CAPM framework to determine the benchmark efficient cost of equity of 7.19 percent.

In estimating our proposed cost of equity of 7.19 percent we have:

- used the SL CAPM as the foundation model;
- updated the risk-free rate using the Guideline methodology;
- applied the AER's equity beta point estimate of 0.7, noting that the most recent empirical evidence suggests the equity beta estimates have moved up;
- applied the AER's MRP point estimate of 6.5%, noting that the application of the Guideline methodology to updated and current data produces MRP estimates well above 7%; and
- adopted a gamma estimate of 0.4.

Table 12.4 Proposed cost of equity using CAPM point estimate

Parameter	Assumption	Reasoning
Risk free rate, Rf (nominal)	2.64%	Guideline methodology
Equity beta, ß	0.7	AER point estimate
Market risk premium, MRP	6.50%	AER point estimate
Gamma, y	0.4	AER preferred methodology
Overall cost of equity estimate (nominal)	**7.19%**	

12.4.1 The nominal risk-free rate is estimated using the guideline methodology

Endeavour Energy has adopted a nominal risk free rate of 2.64 percent for the purposes of this proposal based on recent observations. This will be updated to reflect the risk free rate measured over the averaging period proposed to the AER. In accordance with normal practice the nominated averaging period is for a future period and will remain confidential until such time as the averaging period has passed. The proposed approach is consistent with the Guideline methodology.

12.4.2 The proposed equity beta is the AER's point estimate of 0.7

In its 2013 Rate of Return Guideline the AER adopted a range of equity beta estimates of 0.4 to 0.7 for a benchmark efficient entity by analysing a relatively small sample of domestic regulated utilities. In a series of decisions that followed, the AER indicated that the "best statistical estimate" of beta was 0.5, though it selected a top of the range estimate of 0.7 due to a number of additional considerations.

We propose not to deviate from the AER's point estimate of 0.7. However we consider this level does not compensate the benchmark efficient entity operating in a workably competitive market for the systemic market risk it faces. We will therefore engage with the AER on the appropriate equity beta level as part of the ongoing consultation process on the Rate of Return Guideline Review.

Our position that the 0.7 point estimate represents the 'floor' for the best equity beta estimate for a benchmark efficient entity in the prevailing market conditions. Our analysis indicates that since 2013 the equity beta estimates for regulated network comparators have increased well above the AER's "best statistical estimate" of 0.5, even after applying the regulator's estimation approach . It logically follows that the "best statistical estimate" has also moved up, establishing a point estimate of 0.7 as a conservative measure of the systematic risk facing the benchmark efficient entity.

12.4.3 The proposed market risk premium value is 6.5

We propose a conservative MRP estimate of 6.5 percent, which is a long-standing point estimate applied by the AER. We observe however that the vast majority of regulators who sought to estimate the MRP over the past 12 months adopted estimates above 7.0 percent as evidenced by the AER's own analysis.

Further, the observable market evidence indicates that the risk-free rate and MRP tend to move in opposite directions as equity investors seek stability of expected returns.[75] Consequently, the expected MRP would have move upwards in the current low interest rate environment.

Table 12.5 Updated estimates of the MRP

Methodology	Range of updated MRP estimates
Historical excess returns[76]	6.0 - 6.5
Two-Stage DGM[77]	7.14 - 8.18
Three-Stage DGM[33]	7.25 - 8.11
Surveys[78]	6.0 - 8.5
Other regulators' decisions[79]	6.5 - 7.7

Source: Frontier Economics

75 FERC Docket ER14-500-000, January 2014, pp. 35-36; Duarte, F. and C. Rosa, 2015, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York Economic Policy Review, December, p54;Dobbs, R., T. Koller, S. Lund, S. Ramaswamy, J. Harris, M. Krishnan, D. Kauffman, 2016, "Diminishing Returns," McKinsey Global Institute, May, p12; IPART, Review of our WACC method, Issues Paper, July 2017, p. 16

76 AER Historical excess returns estimates, updated to end 2016 by Frontier Economics. Theta of 0.6, arithmetic averages only consistent with the AER's application of the 2013 Guideline in its most recent decisions.

77 AER dividend growth model, estimates over June-July 2017 computed by Frontier Economics. Growth rates in the range between 4%pa and 5.1%pa.

78 Fernandez, P., V. Pershin and I.F. Acin, Discount rate (risk-free rate and market risk premium) used for 41 countries in 2017: A survey, April 17, ssrn.com/abstract=2954142

79 AER, TransGrid Draft Decision, 2017, Attachment 3, Figure 3-15, p236.

12.4.4 The proposed value of imputation credits is 0.4

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.[80]

The AER's view has been that gamma should reflect the utilisation rate of imputation credits which has been upheld by the most recent round of appeals and the Federal Court. Notwithstanding the AER's 2013 Rate of Return Guideline indicating a gamma of 0.5, the AER has consistently applied a gamma of 0.4. Endeavour Energy proposes a gamma of 0.4 consistent with the AER's application of its 2013 Rate of Return Guideline.

12.4.5 Equity raising costs

Raising equity finance incurs costs that should be recognised in regulated revenue allowances over the 2019-24 regulatory period. The AER's standard practice has been to recognise equity raising costs as capex within the PTRM and amortise these costs over the life of the assets that they are used to fund.[81] Endeavour Energy has applied the AER's standard cash flow analysis sheet within the PTRM to estimate the benchmark efficient equity raising costs that are estimated over the 2019-24 regulatory period. The components are:[82]

- seasoned equity offering (SEO)/Subsequent equity raising costs – 3 percent over the 2019-24 period; and
- dividend re-investment plan cost – 1 percent over the 2019-24 period.

80 NER, clause 6.5.3.

81 See for example AER, Final decision, ElectraNet 2013-14 to 2017-18 transmission determination 2013-14 to 2017-18, p. 87; AER, Final Distribution Determination Aurora Energy Pty Ltd, 2012-13 to 2016-17, April 2012, p. 78; AER, Final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012, pp. 107-108; AER, Final decision, Victorian distribution determinations 2011-2015, Appendix O, pp. 505–506; AER, Final decision, Qld Distribution determination 2010-11 to 2014-15, May 2010, p. 201;

82 AER, Powerlink transmission determination 2012-13 to 2016-17 April 2012, p. 108

13.0 Building Blocks

CHAPTER 13

13.1 Overview

We will continue to put downward pressure on electricity bills for our customers by using the building block approach prescribed in the Rules.

We provide a range of services that are classified by the AER as standard control services. These are attributable to the shared network and are central to providing access to a safe and continuous supply of electricity from the grid. We propose a regulatory control period of five-years commencing 1 July 2019 with a proposed total revenue requirement for this period of $3.9 billion (nominal, NPV).

To calculate the revenue required to provide these services we have used the building block approach prescribed in the Rules. The building blocks relate to return on and of capital, operating and tax costs and other revenue adjustments (such as incentive scheme benefits). Our approach and forecasts for each respective building block are detailed in Chapters 8 to 12 of this proposal.

In addition to these building blocks, we have lodged a proposal to remake the 2014-19 re-determination with the AER. As part of this we will be returning $226.7 million (real, 2018-19) to customers over the 2019-24 period.

Based on our forecast plans and the settlement of the 2014-19 determination, we expect our contribution to customers' bills to decrease by approximately one percent p.a. in real terms over the 2019-24 period. Customer advocates asked us to make clear the impact of the 2014-19 regulatory proposal on proposed network charges for the period 2019-24. Our proposed decreases reflect our lower rate of return and our ongoing efforts to reduce operating costs. They also reflect the efficient addition of 20,000 new customers each year.

Our proposed pricing outcome for 2019-24 is maintained at a decrease of 1 percent when we also consider the incentive payments from the EBSS of $235m and our remittal proposal to return $227m to customers. Therefore the impacts of the 2014-19 regulatory period on our 2019-24 proposal are offset.

The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2019-20 to 2023-24 are outlined in Table 13.1 below:

Table 13.1 Forecast standard control revenue requirement over the FY20-FY24 regulatory control period

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total (NPV)
Return on capital	397.9	420.8	441.9	462.6	482.7	**1,842.3**
Return of capital	101.8	115.1	125.3	133.4	129.2	**504.3**
Operating expenditure	289.4	305.0	323.5	342.8	362.4	**1,354.3**
Cost of corporate tax	40.6	40.3	47.5	51.6	50.6	**192.1**
Revenue adjustments	(207.7)	73.5	85.7	71.7	1.0	**(1.5)**
Total unsmoothed revenue	622.1	954.6	1,023.9	1,062.2	1,025.9	**3,891.6**
Smoothed ARR	877.7	902.8	926.6	953.5	988.5	**3,891.6**

13.2 Proposed revenue requirements and indicative prices

13.2.1 Annual revenue requirements

We set out our proposed building blocks above. By adding these building blocks together, we derive our proposed total unsmoothed annual revenue requirement (ARR) for the 2019-24 regulatory period. This revenue will be recovered from our customers via network tariffs (or charges). These charges reflect the recovery of the efficient expenditure we need to invest in our network, to operate and maintain it and comply with our regulatory obligations. They also provide a reasonable return on our investment in the network.

To smooth the lumpy profile of these revenue requirements and limit customer price volatility between years, the Rules allow the AER to constrain revenues to follow a CPI-X path. The section below outlines our proposed X-factors to deliver sustainable pricing outcomes over the 2019-24 period.

Proposed smoothed revenue and X-factors

Our customer engagement activities have consistently revealed stakeholder preference for stable, smooth price movements between years.

To minimise price variations over time we need to take into account fluctuations in the ARR over the course of the regulatory period. In deciding on the proposed smoothed revenues and the resultant X-factors we have derived an adjustment that complies with the Rules and consistent with principles ensuring the:

- net present value of smoothed and unsmoothed revenue over the 2019-24 period are equal;
- pricing impact is smooth and consistent over the period; and
- difference between smoothed and unsmoothed revenue in 2023-24 is as low as reasonably possible in order to minimise pricing volatility between regulatory periods.[83]

The resulting revenue X-factors are provided in the PTRM, Attachment 0.04. The revenue requirement and pricing X-factors that underpin them are provided in Table 13.2 below.

Table 13.2 Proposed unsmoothed and smoothed annual revenue requirement for FY20-FY24

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Unsmoothed revenue requirement	622.1	954.6	1,023.9	1,062.2	1,025.9	**3,891.6**
Revenue X-Factors*	-1.5%	-0.36%	-0.13%	-0.39%	-1.14%	
Real price movement (%)	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	
Smoothed revenue requirement	877.7	902.8	926.6	953.5	988.5	**3,891.6**

*A negative revenue X-factor denotes a real revenue increase.

As discussed in the sections below, in proposing X-factors that result in the smoothed revenue profile, we have carefully considered:

- forecast changes in energy consumption over time (see Chapter 7);
- the final year difference between smoothed and unsmoothed revenues; and
- the impacts of the remittal of the 2014-19 determination.

Final year pricing difference 2019-24 period

As aforementioned, the Rules require that the difference between smoothed and unsmoothed revenue in the final year of a regulatory control period be as low as reasonably practicable in order to minimise pricing volatility between periods.

We consider we have complied with this requirement in smoothing our forecast revenue for the 2019-24 period. As evident in table 13.2 above, the final year difference between smoothed and unsmoothed revenue in the final year for the 2019-24 period is -3.6 percent, which we consider to be reasonable.

83 NER, cl. 6.5.9(b)(1)

Impact of set aside 2014-19 determination and remittal

In the absence of a regulatory determination, Endeavour Energy gave, and the AER accepted, an Enforceable Undertaking (Undertaking) for 2016-17 and 2017-18, under section 59A of the National Electricity Law (NEL). We intend to propose an additional Undertaking for the 2018-19 year and will reflect the outcomes of the agreed Undertaking in our revised proposal.

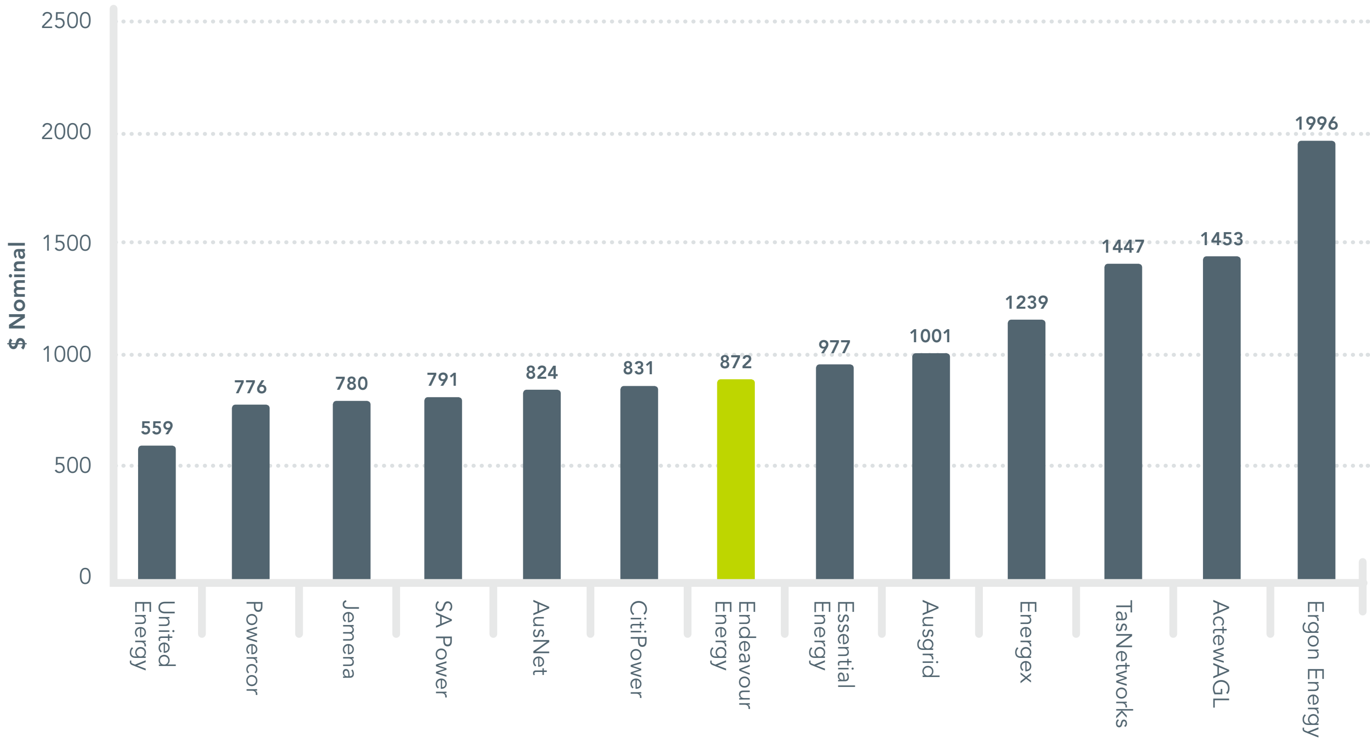
We expect that the AER will re-determine the revenue allowance for the 2014-19 period in the coming months. To manage the risk of a large amount of revenue having to be recovered in the final year of the 2014-19 period we, along with the other NSW DNSPs, initiated a rule change process to allow the outcomes of the 2014-19 re-determination to be collected in the 2019-24 period. The AEMC published amendments to the Rules in August 2017 allowing the proposed changes.

During the 2014-19 period we expect to recover an additional $336.7 million (real, 2018-19)[84] in DUOS revenue compared with the AER's 2014-19 determination. We have lodged a proposal to the AER to settle the 2014-19 re-determination. We are proposing to retain $110.0 million (real, 2018-19) of the over-recovery and return $226.7 million (real, 2018-19) to customers during the 2019-24 period[85] in order to resolve the outstanding matters of dispute from our 2014-19 remittal. This will help contribute to our 2019-24 proposal delivering an outcome of prices increasing at or below CPI.

13.2.2 Indicative charges and bill impacts

We have worked hard over the current regulatory control period to keep downward pressure on network prices. By focussing on making broad and targeted improvements to make our business more efficient, network charges for the average residential customer's bill have fallen by 11.2 percent over the past five years.

Figure 13.1 Average revenue per customer 2016 ($ nominal)



84 Includes interest.
85 This amount includes the unrecovered STPIS payments in accordance with the August 2017 revenue smoothing rule change. We will update the STPIS amounts in our revised proposal for any adjustments (if any) the AER makes to our allowed revenue in its 2014-19 re-determination.

Through our cost saving initiatives, we continue to examine our strategies, processes and procedures to identify scope for further savings. This reflects our commitment to alleviate price pressures and our ongoing effort to be effective and efficient in everything we do, without compromising the safe, sustainable and reliable supply of electricity.

Indicative DUOS prices for 2019-24 based on our proposed bundled revenue and our latest forecast of energy volumes are provided in Table 13.3 below.[86]

Table 13.3 Indicative average DUOS for 2017-24 (exclusive of metering)

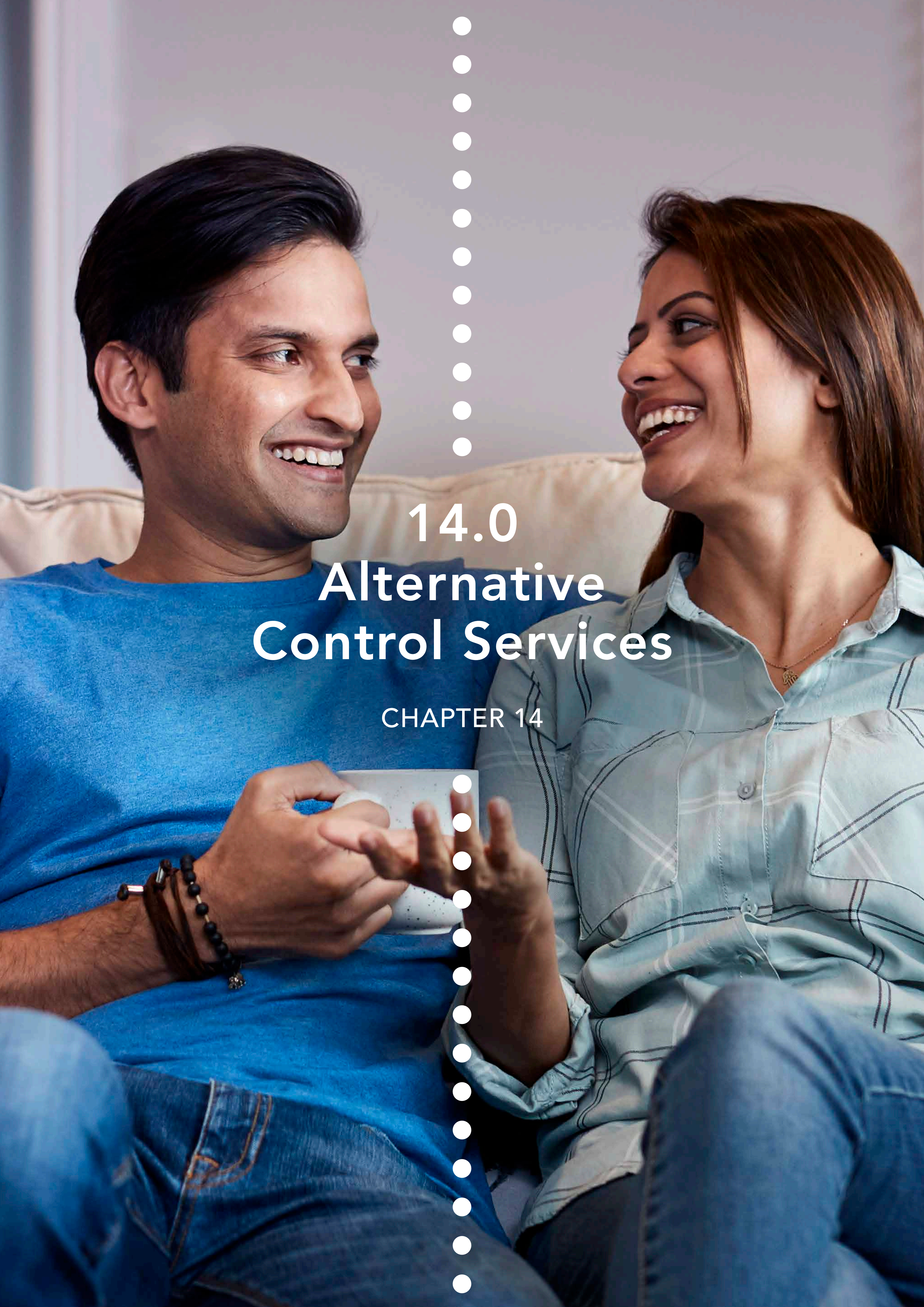
$; Real 17-18	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Residential customer consuming 5MWh p.a.	492.0	491.4	486.5	481.6	476.8	472.0	**467.3**
Small business customer consuming 10MWh p.a.	838.3	837.3	828.9	820.6	812.4	804.2	**796.2**

The prices outlined above are indicative only and will be updated in our pricing proposal for each year of the 2019-24 period to reflect:

- the AER's decision on allowed revenue for the remade 2014-19 determination and any differences between this revenue amount and revenue collected under enforceable undertaking arrangements with the AER;
- updated energy consumption forecasts;
- actual CPI;
- updated cost of debt; and
- any changes in the relative portion of revenues recovered from each tariff and tariff component.

We also note that the prices outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF). These components are outside our control.

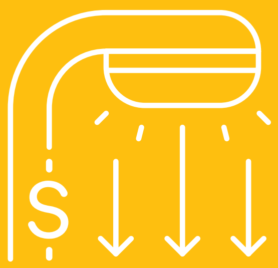
86 For a full listing of indicative prices, as required by clause 6.8.2(c)(4) of the NER, and bill impacts for the 2014-19 period, refer to tables 7.6 and 7.7 of the Reset RIN and our PTRM attached to this proposal.



14.0 Alternative Control Services

CHAPTER 14

14.1 Overview



We have responded to customer feedback and adopted a more cost reflective approach to pricing alternative control services. This has led to real savings for public lighting and metering customers.

Alternative control services (ACS) are distribution services that are attributable to a single customer or location or have the potential to be provided on a competitive basis. The costs of providing these services are recovered directly from individual customers and do not form part of our revenue requirements as proposed through the building block approach.

For public lighting we have engaged with our customers to understand their priorities and concerns. Based on this feedback we have included the latest street lighting technologies in our pricing model and updated our assumptions to reflect the benefits LED technology provides to offer a differential pricing option to traditional technologies. We have made these changes while reducing our overall public lighting revenue requirements by almost eight percent.

For metering we engaged Energeia to test the efficiency of our metering opex and develop assumptions on the transition to full metering contestability which commenced 1 December 2017. Our prices reflect a cost-reflective and simple metering charge that supports the transition to metering contestability.

For existing ancillary services, we have applied the same assumptions the AER used in setting fees for the 2014-19 period. For new services we have developed prices using the AER's benchmark labour rates and the assumed time and quantity of inputs required to provide the service. We have applied X-factors to our ancillary services prices to smooth the price impacts evenly over the 2019-24 period.

14.2 Public lighting

We are committed to providing public lighting services that effectively and efficiently meet the needs of our customers. In response to favourable customer feedback, our proposed approach to public lighting services is consistent with that of the current regulatory period. Meeting at least the minimum standards detailed in the NSW Public Lighting Code continues to guide our public lighting service plans.

In this section we identify the method by which we have developed prices for the public lighting services we provide our customers with.

14.2.1 Public lighting services

Public lighting is important in providing safety and security for pedestrians and vehicle traffic as well as enhancing the visual environment. Public lights are typically installed in street locations including residential streets and main roads using either existing electricity poles or dedicated public lighting poles (often referred to as 'columns'). The type of lighting required depends upon the road type and customer requirements.

The vast majority of public lighting construction projects are contestable, in which case the public lights may be installed by a customer or gifted through land development protocols. Once completed and operating, we are responsible for the ongoing maintenance and repair of the lights. These activities are not contestable and can only be provided by Endeavour Energy. We also directly undertake the construction of minor public lighting works and other public lighting projects at the customer's request.

Legislation, regulations, standards and codes

We abide by the following legislation, regulations, standards and codes when installing and maintaining public lighting:

- NSW Public Lighting Code.
- Customer nominated requirements within the range of services offered.
- AS/NZS1158 series of standards for lighting of roads and public places.
- Electricity Supply Act 1995.
- Endeavour Energy electrical safety rules.
- Endeavour Energy company policy 9.2.13 – Property tenure for network assets.
- Endeavour Energy company policy 9.6.8 – Public lighting.
- Endeavour Energy General Terms and Conditions for connection of public lighting assets.

NSW Public Lighting Code

The service performance standard agreed between providers and public lighting customers is set out in the NSW Public Lighting Code. This Code seeks to provide a basis for expected service quality by DNSPs with reference to the Australian Standard (AS1158) for public lighting which details illumination and other technical requirements. Although compliance is not mandatory (at this stage), the Code provides a basis from which DNSPs and public lighting customers may wish to negotiate alternative service performance outcomes.

Our public lighting forecasts reflects our adherence to the current minimum standards and guaranteed service levels set out in the Code.

Public Lighting Management Plan
A requirement of the Code is for each public lighting provider to prepare a Public Lighting Management Plan (PLMP). Our PLMP (Attachment 14.07) has been developed to provide an overview of the business structure, processes and decision support systems we have in place to manage and operate a safe and reliable public lighting network. It also provides an overview of strategies we have put in place for continuous improvement in the standard of public lighting services provided to customers.

Engaging with our customers
We currently serve 29 public lighting customers, including 23 local councils, with approximately 205,000 installed lights. The number of public lights is steadily increasing at around one percent per annum. This growth is due mainly to installations in several rapidly expanding growth areas within our network.

We have undertaken extensive consultation with our public lighting customers. This consultation has been extended beyond the regular meetings twice a year with each council in our network area to understand the specific needs of our customers and receive feedback on our performance.

As summarised in Attachment 5.01, customers were supportive of our continued commitment to facilitate new, energy efficient lamp replacements that reduce maintenance requirements and operating costs, and improve the quality of public lighting. Affordability remains their primary concern with a high value on price stability and receiving value for money.

Consequently, we are proposing real bill decreases for councils[87] for the 2019-24 period while maintaining our existing service levels and implementing tariff reforms requested by councils in our network area. We will also continue to work with councils on increasing the take-up of new, more energy efficient lamp technologies. We provide further detail on these areas below.

14.2.2 Public lighting objectives

Our public lighting decisions are made with reference to key objectives that ensure investments are in the best interest of customers and in accordance with the NSW Public Lighting Code.

Support new lighting technology
Our customers continue to express their desire to benefit from technological developments in lighting. Energy efficient light sources with longer life expectancy may result in:

- reduced frequency of bulk replacement programs;
- increased periods between scheduled maintenance;
- reduced energy consumption;
- lower lamp failure rates;
- lower light output deterioration rates; and
- improved environmentally sustainable outcomes.

87 With the exception of one council, for which we are not the primary supplier, who will receive a real increase totalling less than $100 per annum.

Our Energy Efficient Replacement Practices

Luminaires that are no longer supported or obsolete are replaced with energy efficient luminaires on the current standard list at the end of their useful life through Endeavour Energy's maintenance process.

For minor road lighting, Endeavour Energy has three energy efficient options (LED, T5 linear fluorescent and 42W compact fluorescent) available for replacement. Public Lighting Customers can nominate their default option for luminaire replacement on minor roads. Endeavour Energy will use StreetLED18 (total system wattage 22W) where no default option is nominated by the Public Lighting Customer. With changing technologies and improving total cost-effectiveness of energy efficient lighting, we continually review opportunities to introduce new default options.

For major roads, Endeavour Energy has energy efficient high-pressure sodium vapour luminaires on the standard equipment list, which are used to replace mercury vapour luminaires when they fail or become unserviceable.

We support the introduction of new street lighting technology and conversion to LED street lights that can deliver these benefits to our customers. LED luminaires now account for 15 percent of all our public lighting installations and we expect this to grow significantly over the next few years supported by more cost reflective pricing.

We work closely with our public lighting customers to identify opportunities to introduce new equipment. We conduct product assessments including field trials, which monitor equipment performance including failure rates, not; deterioration of light output over time and colour shift. Other factors such as cost, energy efficiency and environmental impact are also considered and public lighting customers are kept informed about the progress of the trials through regular meetings.

To improve the cost reflectivity of our public lighting prices and incentivise the adoption of more efficient LED lighting technology we have developed differential LED public lighting prices. While the current volume of LED lighting is not large enough to materially reduce our current maintenance costs, we consider a pricing differential will further incentivise the uptake of LED lighting, which is strongly desired by our public lighting customers. As a result we are proposing to implement lower maintenance charges for LED technologies in advance of those cost savings being realised, in the expectation that the lower charges will encourage sufficient take-up to deliver the necessary cost savings.

The maintenance charges for LED lights will be set at 15 percent less than the charges for older technology lighting. We have achieved this while ensuring that the bill outcome for councils is at or below CPI despite each council having different levels of LED lighting within their respective areas.

Minimum service levels

As part of this regulatory proposal, we propose to continue targeting the standards set out by the NSW Public Lighting Code.

Based on the feedback received from our customers, we are satisfied that our service performance is commensurate with our pricing offerings and their expectations. We propose to continue the existing arrangements to the extent possible where they satisfy our customers' needs.

Minimise total lifetime cost
In our efforts to reduce public lighting costs over the complete asset lifetime, we continue to focus on offering and promoting energy efficient lighting options to customers. Increased service life and reliability performance from LED technology can lead to reduced replacement and maintenance requirements, putting downward pressure on future costs. The potential long-term cost savings offered by energy efficient lighting are incorporated in our public lighting prices. Furthermore, our focus on containing costs and driving productivity improvements through increased use of market delivered solutions will continue into the next regulatory period.

Our Bulk Lamp Replacement Cycles
Central to meeting our network performance standards is the management of bulk public lighting lamp replacements. Determining bulk lamp replacement cycles requires an understanding of lamp failure rates and the serviceable life of the various lamps used on our network. Cycles are optimally undertaken immediately prior to failure after which lamps would otherwise require a spot replacement response which would incur a high per lamp operating cost.

As part of our broader efficiency improvement programs, in July 2013 we conducted a review to seek out the lowest cost bulk lamp replacement cycle of each of the eight most prominent lighting types in the Endeavour Energy network. The findings of the analysis found that a hybrid replacement program would be the most cost effective approach.

Our bulk replacements consist of a rolling program of three years for all lamps with the exception of 150W, 250W and 400W High Pressure Sodium lamps. These time frames are deemed to be the optimum cycle to ensure efficient and safe operation of the system to achieve agreed maintenance standards and to maintain the designed lighting technical parameters of luminaires at lowest total cost. LED lights, which do not have a lamp, are instead cleaned every six years to ensure efficient output.

Maintaining network performance
The Public Lighting Code outlines the principle obligations for public lighting service performance. It is a voluntary code that was introduced to help clarify the relationship between public lighting service providers and customers, and sets out benchmarks to assist local councils. Our public lighting systems and processes are designed to satisfy the Public Lighting Code.

Our decision to comply with the Public Lighting Code for the 2019-24 period materially impacts our public lighting expenditure. Non-compliance with the Code would reduce our public lighting service costs and reduce prices however this would lead to service deterioration that would conflict with expectations and requirements of our customers. Therefore, our forecast public lighting revenues are those required to efficiently maintain current service level performance for the 2019-24 period.

Maintaining customer performance

We have implemented a public lighting compliance framework to satisfy the service standards described in the Code. Elements of the framework include:

- operating a 24-hour call centre and online form to receive fault reports from customers;
- establishing a management plan and reporting system for the design and construction of public lighting assets;
- cleaning, inspecting and repairing luminaires during re-lamping;
- ensuring that repairs of public lighting assets are undertaken within an average of eight working days per customer per year from receipt of the reported fault;
- endeavouring to provide repairs more quickly in high priority cases; and
- supplying reports to all major customers.

14.2.3 Pricing methodology

We have used our Public Lighting Pricing Model for the purposes of determining the public lighting charges for the 2019-24 regulatory period (Attachment 14.09). The model contains the proposed unit cost inputs for labour and material categories used to calculate these charges.

Costs

There are three main costs in providing public lighting services: capital, operating costs and corporate overheads.

- **Capital costs:** These refer to costs relating to the installation of public lighting assets either for brand new connections or replacing assets due to poor performance or being made obsolete due to new technology. Capital costs include the purchase of the physical items being installed and the capitalisation of labour costs required to undertake the installation.
- **Operational costs:** These refer to the ongoing costs to maintain/repair the installed assets as well as the replacement of lamps for each installation at appropriate intervals.
- **Overheads:** These relate to the operational and strategic support costs such as IT systems to support asset and billing information, safety management, procurement activities etc.

These cost categories are most influenced by labour and material unit costs.

- **Labour:** we use a combination of internal and competitively tendered external labour to provide public lighting services. This gives us confidence that our current labour unit costs are efficient. We have applied real labour cost escalation consistent with the rates proposed for standard control services.
- **Materials:** A variety of direct materials, such as luminaries, brackets, outreaches, etc. are required to provide public lighting services. The prices in our public lighting model reflect the current contracted market price for these materials.
- **Rate of Return:** We have used a rate of return consistent with that applied to standard control services.

Our ongoing focus on efficiency has resulted in reductions to our direct and overhead costs recovered through our public lighting charges. This has enabled us to deliver a pricing outcome at our below CPI for councils while introducing a differential charge for LED lighting.

Price tariffs

We propose to continue applying the current tariff structures and component based pricing over the next regulatory period, based on supportive feedback provided by councils in our network area on the current structures. The tariff classes are broken down into two key subgroups, tariffs for assets installed before 8 August 2009 and those after this date:[88]

- **Tariff class 1:** is an aggregate capital recovery and maintenance tariff. This applies where the asset was initially funded by us and was included as part of the RAB determined by IPART prior to 8 August 2009. Capital cost recovery built into this tariff class will trend in line with the residual RAB value reducing over time and historical price escalation constraints. Assets priced under tariff class 1 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class.
- **Tariff class 2:** is a maintenance cost recovery only tariff. This applies to assets where we did not fund the initial construction which occurred prior to 8 August 2009. As we did not fund the construction we are not entitled to any capital recovery charges for these assets. Similarly with tariff class 1, assets priced under tariff class 2 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class.
- **Tariff class 3:** is an aggregate capital recovery and maintenance tariff similar to tariff class 1, however this tariff class is priced using an annuity approach and only applies to assets installed after 8 August 2009. Unlike tariff class 1 there is no RAB value driving variable prices over time and is specific to the asset installed.
- **Tariff class 4:** is a two-part tariff; the first element being a maintenance cost recovery only charge similar to tariff class 2. This applies to assets where we did not fund their initial construction which occurred after 8 August 2009. As we did not fund the construction we are not entitled to any capital recovery charges for these assets. However, we are required to pay income tax on assets gifted to us in this manner. The second element of tariff class 4 is a tax cost recovery charge that is paid through an annual amount over the life of an asset that is gifted to us by our customers after 8 August 2009.
- **Tariff class 5:** is a pure capital recovery tariff that is paid in a lump sum at the time of agreeing to replace an asset before the end of its useful life. This tariff class does not have specified prices but rather a specified formula for calculating the residual unrecovered capital and tax costs when a customer requests an early replacement of assets paid for by us.

Differential pricing for LED public lights

As discussed above, to improve the cost reflectivity of our public lighting prices and incentivise the adoption of more efficient LED lighting technology we have developed differential LED public lighting prices reflective of the anticipated potential maintenance cost benefits.

The maintenance charges for LED lights will be set at 15 percent less than the charges for older technology lighting. We have achieved this while ensuring that the bill outcome for all councils is at or below CPI despite each council having different levels of LED lighting within their respective areas.

Compliance with control mechanism

In compliance with the Rules, we propose the following forms of control for public lighting services over the 2019-24 regulatory period consistent with the AER's F&A decision:

- A schedule of fixed prices for public lighting services for the first year of the regulatory period.
- A price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted public lighting model.

88 Even though the AER cut-off date for switchover of charges from legacy rates to annuity rates was 1 July 2009, on demand from its Public Lighting Customers and ASPs, Endeavour Energy agreed to a date of 8 August 2009 to cater for completion of projects that were already under way and to give time for Public Lighting Customers and ASPs to understand the new rates.

14.3 Metering services

Historically, as a DNSP we had the sole responsibility of providing small customers with metering services in our network area. Following the AEMC Rule change which sought to establish a competitive market for metering services throughout the NEM, metering contestability came into full effect on December 1, 2017. The suite of changes made under the Power of Choice reforms have contributed to the decentralisation of several metering related activities from distribution networks. Through technological and regulatory changes, customers are increasingly able to access a wider range of metering services to help them make better decisions on their energy usage.

In anticipation of these changes, for the 2014-19 period metering services were reclassified from standard control services to alternative control services and separately priced so that customers could make efficient decisions when metering contestability was introduced.

Under the Power of Choice, reforms metering contestability will be introduced on a gradual basis. All new meters installed from 1 December 2017 will be provided by a Metering Coordinator on a contestable basis.[89] This means many customers will retain their existing metering until it fails or they agree to replace it. We will therefore continue to provide metering services for these existing meters as a transitional Metering Coordinator.

14.3.1 Type 5 and 6 metering

The existing meters we refer to are our Type 5 and 6 meters, which are defined as follows:

- Type 6 meters are the most commonly installed type of meter in our network and are a basic accumulation meter that is manually read on a quarterly basis.
- Type 5 meters are less common in our network and are an interval meter that can be read remotely.

Metering customer volumes

We expect over time, the proportion of Type 5 and 6 meters will decline as they are steadily replaced with Type 4 ('smart meter') equivalents after failure or through mutual consent between customers and their respective retailer. New installations will also increase the penetration of smart metering.

Energeia has provided an estimate of the likely churn in our metering customer base based on a number of factors. On average, we are expecting 4.1 percent of our Type 5 and 6 meter customer base will transition to smart metering each year. As noted by Energeia, this volume forecast represents a realistic expectation of the demand for our metering services as they have been developed as follows:[90]

- They extrapolated historical trends when they are likely to be a relatively likely indicator of future trends, such as with abolishments, metering installation reconfigurations and in-situ meter faults.
- The drivers have been adjusted to reflect declining Type-5/6 customer numbers over time.
- The alternative to trend forecasts are supported by evidence-based assumptions, such as the Meter Asset Management Plan (MAMP), retailer business case driven meter rollouts and changes in the solar PV feed in tariff.
- The alternative forecasts reflect conservative assumptions as indicated for retailer business case rollouts, solar PV installations and Gross FiT conversion volumes.

See Attachment 14.01 for further details on each of these considerations.

89 We note that due to implementation difficulties, Metering Coordinators may elect for the LNSP to continue to provide metering services alongside competitive metering service providers temporarily until March 2018.
90 Energeia, Forecast of Efficient Metering Operating Costs, November 2017, p.23

This piecemeal transition of customers to contestable metering can create asset stranding risks and diseconomies of scale in our operating activities. We discuss the impact of this on our capex and opex forecasts below.

Recovery of capital costs

For all Type 5 and 6 meters installed after July 1, 2015 we recovered the capital costs upfront rather than requiring an annual capital payment. However, there were replacement costs over the 2014-19 period and unrecovered amounts from previous periods that remain outstanding. Our opening metering asset base for the 2019-24 period is forecast to be $16.1 million (nominal).

Our pricing approach has been to recover these costs from all customers (through their retailers) that had an Endeavour Energy meter prior to 1 July 2015. We propose to continue with this pricing approach as we consider it to be fair, simple and practical. However, the technical remaining life for the asset base at the commencement of the 2019-24 period is 18 years. We note the transition to competitive metering is likely to accelerate in coming years and a shorter lifespan may be appropriate. To address this issue, we consider the metering asset base recovery options are as follows:

- **Existing approach:** recover the metering asset base from pre 1 July 2015 customers over the remaining technical life of the assets. For the 2019-24 period this equates to an annual capital charge of approximately $2.19 per annum on average.
- **Accelerated approach:** as above with an adjustment to the remaining life of the assets to 10 years to better reflect their likely economic life. For the 2019-24 period this equates to an annual capital charge of approximately $2.25 per annum on average.
- **Standard control recovery:** for the 2014-19 period we suggested the remaining metering asset base was recovered as part of the standard control services RAB as these investments were made as a standard control service at the time. However, the AER considered this approach was not permissible under the transitional Rules which applied to the 2014-19 determination. We would be interested in exploring this option further if the AER considers it is viable.
- **Exit fee:** for the 2014-19 period we also proposed an exit fee of approximately $64 to recover our outstanding metering asset base. The AER and stakeholders considered this fee would present a barrier to competition. We have not prepared an exit fee for the 2019-24 on this basis.

Our preference, as it was at the time of the 2014-19 proposal, is to exit the metering market as quickly as reasonably and affordably practicable to facilitate the transition to metering competition. We have based our proposal on the existing approach consistent with the AER's recent decisions. However, we would be interested in the views of stakeholders on which option is preferable and whether the AER considers any of the alternative options are appropriate.

Our capex forecast for the 2019-24 relates to testing equipment given we will be required to continue testing and identifying meter populations for replacement by Metering Coordinators. Our capex forecast for the 2019-24 period is $0.5 million (real; 18-19) which is less than three percent of the allowed capex requirement for 2014-19 following the impacts of the Power of Choice Rule change.

Metering operating costs

As a transitional Metering Coordinator for existing Type 5 and 6 meters we will continue to have meter operating, data storage and reading costs. Similar to standard control service opex, we have applied the base-step-trend methodology for forecasting our metering opex. Our proposed metering opex for the 2019-24 period is set out in Table 14.1 below.

Table 14.1 Proposed metering opex for the FY20-FY24 period

$m; Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Metering opex	19.2	19.0	18.8	18.7	18.6	**94.3**

Below we provide an overview of the efficiency of our metering operations and the impact of diseconomies of scale associated with the metering contestability transition.

Metering opex base year efficiency

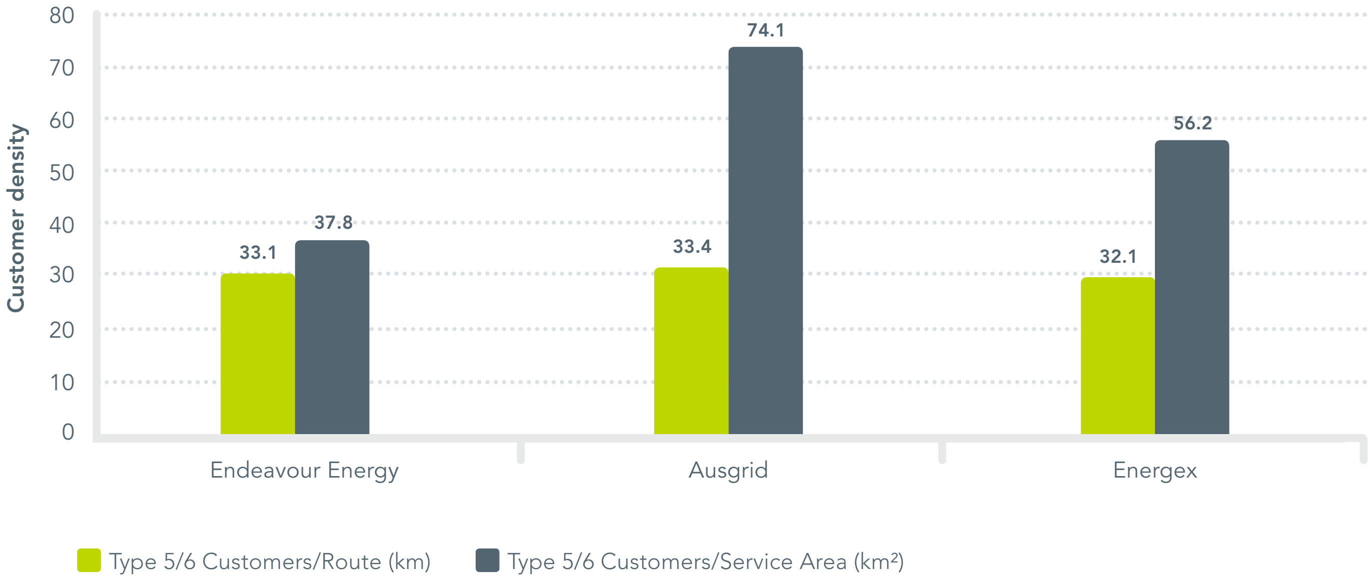
We engaged Energeia to provide a forecast of opex accounting for the diseconomies of scale associated with a decline in our metering customer numbers following Power of Choice.

For forecasting purposes Energeia used the average of the past five years of actual expenditure to estimate our base year opex. This approach is consistent with the AER's approach in recent decisions on metering opex. We consider the following evidence demonstrates that our base year metering opex is efficient:

- **Outsourcing:** a significant portion of our metering operations are market sourced which provides prima facie evidence of efficiency. We have outsourced the following metering activities:
  - Off-cycle meter reading.
  - Routine meter reading.
  - All activities associated with our Type 5 metering.
- **Benchmarking:** our benchmarking performance on a metering opex per customer is comparable to our peers.
- **Detailed review:** we engaged expert consultant, Energeia, to review our metering operations and develop our opex forecast independently.

The primary benchmarking measure relied upon by the AER in the 2014-19 determination was metering opex per total customer numbers by route line length compared to that of Energex. This approach means that Endeavour Energy appears to be as dense as major metropolitan networks like Ausgrid and Energex despite being considerably less dense on a customer per network area (square kilometres) basis.

Figure 14.1 Comparison of Customer Density Metrics among key benchmarks DNSPs



Energeia considers metering opex per total customer numbers by route line length is an unreasonable comparator and therefore tested a number of different explanatory variables. Their findings are summarised below:[91]

- **Type-5/6 Customers/Route Length:** The more customers per km of route length, the less distance the meter reader must travel between each meter read. However, Energeia notes that route length shows Endeavour Energy has a higher customer density than Energex and Ausgrid, suggesting the variable is likely to be flawed, at least with respect to customer density.
- **Type-5/6 Customers/Service Area:** The more customers per km^2 of service area, the less distance the meter reader must travel between each meter read. Unlike the route length metric, network area results in customer density relativities that are consistent with common understanding that the Sydney and Brisbane CBDs and surrounding areas are more densely populated than Endeavour Energy's largely suburban network.
- **Type-5/6 Meters/Type-5/6 Customers:** The more meters per customer, the longer the meter reader must spend at each meter site reading all the meters. Also, the more meters per customer, the larger the number of data streams and assets to manage per customer.
- **Number of Type-5/6 Customers:** The more customers, the greater the economies of scale (arising from lower fixed costs on a per customer basis). The greater the role of fixed costs on opex, the greater the role this variable is likely to play in total metering opex/customer.

91 Attachment 14.01: Energeia - Metering Cost Report, November 2017, p.35

Based on its knowledge of metering opex drivers, and the regression analysis, Energeia selected metering opex per metering customer as the target variable. The explanatory variables used in Energeia's model satisfy the AER's three OEF criteria as follows:

- **Exogeneity:** They are all beyond the DNSP's control. The meters per customer is within the DNSP's control, but likely due to a historical business case showing it was more cost effective at the time, e.g. three single phase meters being lower cost than a single three phase meter.
- **Duplication:** the three explanatory variables are intended to represent three different drivers of Metering Opex per Type-5/6 Customers. While the collinearity result suggests there is some duplication, the use of the regression model helps ensure that the duplication is corrected overall.
- **Materiality:** the explanatory variables together account for 85 percent of differences in the Metering Opex / Type-5/6 Customers across the three DNSPs and three years considered, making them material according to the AER's five percent materiality threshold.

The detailed benchmarking results are provided in Attachment 14.03 and are summarised in Table 14.2 below.

Table 14.2 Comparison of Estimated versus Actual Metering Opex per Type 5/6 Customer

FY$17	Endeavour Energy			Energex			Ausgrid		
	Model	Actual	Diff	Model	Actual	Diff	Model	Actual	Diff
FY14	20.9	21.4	2.6%	10.1	10.2	0.9%	15.7	18.0	14.2%
FY15	19.9	20.4	2.3%	11.5	10.5	-8.5%	15.4	15.0	-2.5%
FY16	19.8	18.6	-5.9%	13.7	14.7	7.1%	16.8	15.0	-10.7%
Average	20.2	20.1	**-0.3%**	11.8	11.8	**-0.1%**	16.0	16.0	**0.3%**

Source: Energeia

Notably, we have outperformed the benchmarking models' expected opex over the past few years by a larger margin than both Ausgrid and Energex. As a result, Energeia has concluded that Endeavour Energy's metering opex is efficient and can be relied upon for forecasting purposes.[92]

Metering step changes

We are not proposing any step changes for metering opex for the 2019-24 period.

92 Attachment 14.01: Energeia - Metering Cost Report, November 2017, p.34

Trend factors

There are fixed and variable components of our metering opex. As the number of our Type 5 and 6 metering customers continues to fall the variable metering costs will not reduce on a 1:1 basis. This is because diseconomies of scale will arise that will limit the amount of metering opex reductions that are achievable as our metering activities reduce. We engaged Energeia to provide an estimate of the likely impacts of metering contestability on our metering opex at a category level. This analysis provides the basis of the trend factors we have applied in deriving our forecast metering opex and is summarised below.

Table 14.3 Assumed per customer adjustment and rationale by cost category

Category	Adjustment	Rationale
Meter Reading	Pro-rate 25% per customer	Field labour is 50% of total, savings is 50% of field labour
Maintenance	Pro-rate 0% per customer	No impact on testing
Data Services	Pro-rate 100% per customer	Reductions can be 100% managed

Energeia's rationale in developing these estimates is as follows:[93]

- Meter Reading – Meter reading costs are mainly driven by travel times. Meter readers can skip houses, but must still travel past them, so the only time savings arise from avoiding going into the house and reading the meter. Energeia estimates avoidable effort represents approximately 50 percent of the meter reader's total effort and meter reader labour to be approximately 50 percent of total meter reading costs (other costs include the service provider's overheads, as well as the cost of maintaining the meter reading technology and vehicles). This translates to a 25 percent cost saving per customer reduction.
- Meter Maintenance – Meter maintenance volumes are largely set by the condition of metering assets and statutory testing obligations under the Rules and AEMO's Metrology Procedure. Meter populations, the key driver of testing requirements, are expected to stay relatively constant, as are testing equipment, labour and infrastructure costs. Based on this analysis, Energeia concluded that Endeavour Energy is likely to see little to no cost saving per customer reduction over the five-year forecast period.
- Data Services – Data services are mainly carried out by Endeavour Energy's back office staff, and its costs are driven by the number of no access sites (because those bills have to be estimated) and the number of data streams. While Endeavour Energy's EBA creates some rigidity, Energeia estimates that reductions in data stream volumes and no access sites due to reductions in customers can be managed over the next five-years to the extent that a 100 percent cost saving per unit customer reduction is reasonable.

Together, this means that for each metering installation that is replaced with a smart meter, we will only recoup 23 percent of the unit costs over the next five-years. Refer to Attachment 14.01 for further details.

93 Attachment 14.01: Energeia - Metering Cost Report, November 2017, p.31

14.3.2 Proposed prices for the 2014-19 period

Our proposed pricing approach is the same as that which applied for the 2014-19 period for the same reasons. To summarise, we have split metering services between primary and secondary categories. The latter are metering services that are in addition to the basic network service most customers receive, such as off-peak hot water or solar PV meter services. These additional services result in only marginally higher overall costs and therefore attract a lower incremental charge.

This means that a customer will pay a greater amount for their first metering service as this creates the majority of costs we incur as their meter provider. This approach also ensures that customers who have more metering services than a basic accumulation service will pay more to reflect the additional services being provided. We consider this balances the need for cost reflectivity and fairness. Our approach involves the following:

- **Existing metering assets:** We will seek to recover the existing capital costs for Type 5 and 6 meters during the course of the 2019-24 period. The collection of existing meter costs will be on a per-customer basis to avoid penalising customers for past decisions. The average charge will be $2.19 p.a. for each customer.
- **Opex:** Ongoing costs such as maintenance, meter reading, meter testing and data services will be recovered via a cents per day charge. The prices for ongoing opex have been developed on a per-service basis. This means that each unique data stream will attract a price. For example, a basic metering charge and an off-peak metering charge equates to two data streams and two services.

As aforementioned, our metering customer numbers are forecast to decrease at 3.9 percent per annum on average over the course of the 2019-24 period due to the introduction of metering contestability. Metering is subject to a price cap form of control meaning prices to recover the forecast costs from the expected customer base are set for each year of the period. As metering customer numbers are declining at a faster rate than our costs this means metering prices will increase compared to the 2014-19 period by approximately $4-$7 across residential and small business customers.

We consider this is an unfortunate by-product of the introduction of metering contestability. However, it is important that we provide a price signal that reflects the growing diseconomies associated with regulated metering services. This will encourage customers to electively transfer to a contestable metering service where it is efficient to do so. We have smoothed our metering prices to manage this issue as best as possible. Our resulting prices are as follows:

Table 14.4 Proposed metering prices for the FY20-FY24 period

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24
Residential anytime	21.27	21.80	22.35	22.91	23.48
Residential TOU – Type 6 meter	43.93	45.02	46.15	47.30	48.49
Residential TOU – Type 5 meter	177.52	181.96	186.50	191.17	195.95
Small business anytime	31.16	31.93	32.73	33.55	34.39
Small business TOU – Type 6 meter	73.58	75.42	77.31	79.24	81.22
Small business TOU – Type 5 meter	207.17	212.35	217.66	223.10	228.68
Controlled load	6.97	7.14	7.32	7.50	7.69
Solar	6.97	7.14	7.32	7.50	7.69

Compliance with control mechanism

The Rules require that a regulatory proposal includes:

- the proposed control mechanism;
- a demonstration of the application of the proposed control mechanism; and
- the necessary supporting information for alternative control services.

In compliance with the Rules, we propose the following forms of control for metering services over the 2019-24 regulatory period consistent with the AER's F&A decision:

- a schedule of fixed prices for metering services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted metering services model.

Please see Attachment 14.06 for our pricing model and price list.

14.4 Ancillary network services

Ancillary services are services which involve a variety of non-routine activities that are provided to customers on an 'as needs' basis. As with other alternative control services, the AER will regulate ancillary services through establishing price caps for each year of the 2019-24 regulatory period. The prices we will directly charge our customers for each ancillary service activity is required to reflect the efficient cost of providing these activities.

Ancillary service prices are provided to customers as either:

- **Fee based services:** The work involved in some ancillary service activities are relatively fixed and are charged on a per activity basis. Fees are derived from the relevant labour rates and average time required to perform the task and are charged irrespective of the actual time taken to complete the activity; or
- **Quoted services:** Costs for some ancillary service activities may vary considerably between jobs. This is often the case for one-off activities that are specific to a particular customer's request. For quoted services, charges are levied on a time and materials basis. Prior to commencing work, customers are informed of the per hour cost with the final total charge payable dependent on the time taken to complete the respective activity.

For the 2019-24 period, we propose to provide most of the ancillary service activities that were provided to customers in the current regulatory period. We have also proposed to provide several new activities to reflect recent regulatory and service classification changes that require us to provide them to our customers. See Attachment 14.10 for a full listing of our ancillary services for 2019-24.

14.4.1 Our ancillary network service prices

Our ancillary services prices are required to reflect the efficient cost of providing these services. To ensure our prices are considered efficient we have adopted the labour rates used by the AER to set our prices for the 2014-19 period.

Existing ancillary service fees

These labour rates were informed by a benchmarking study prepared by Marsden Jacobs. Our main concern with this study is that it included a significant number of labour markets that we do not have access to and therefore does not reflect a realistic expectation of our cost inputs. Furthermore, the labour rates included an overhead factor that was not derived in accordance with the prevailing CAM. However, we adopted these labour rates, and the implicit overhead factors, in the interests of affordability for ancillary service customers and continuity.

This means that for existing ancillary services our prices are simply a continuation of those which applied during the 2014-19 period. The process we followed for existing services can be summarised as follows:

Step 1: Identify the current price charged to customers for the respective activity. For transparency our ancillary service model commences from 2014-15 in order to demonstrate that it reconciles to the approved fees which applied for the 2014-19 period.

Step 2: Review whether any of the following assumptions have changed:

- The type of tasks involved in performing each service.
- The type and number of personnel and skills required to undertake each task.
- The time taken to complete individual tasks.
- The type and number of non-labour resources/materials.

Step 3: Based on this review we did not identify any adjustments that were required for existing ancillary service fees. We therefore developed our proposed prices using the same time and cost assumptions that applied to 2014-19 and then applied X-factors to reflect forecast increases in labour costs.

New ancillary services

For the majority of new fee based services we have developed prices using the same labour rates applied to an assumed quantity of labour and/or materials estimate. This is with the exception of our security flood lighting services which are more akin to public lighting and therefore priced separately to the ancillary services model. Our approach to pricing security lights is outlined below.

Security lights

Security lighting for private customers is similar to public lighting with installations typically attached to existing distribution network poles and structures. Customers are able to select from a variety of lighting equipment which is mounted on nearby network poles and positioned to provide optimal illumination according to their needs. We operate and maintain these lights which are commonly used by public buildings, sports arenas, shopping centres and car yards. As of 30 June 2017, we provide this service to 1,351 customers with 2,693 luminaires.

For the 2019-24 regulatory period, prices for our security lighting services will now be regulated by the AER. This was seen as necessary to avoid the need to have this service ring-fenced from our regulated distribution network services. The rationale behind this decision was that this service could only reasonably be provided by us as access to distribution assets is restricted and not practically provided by a different provider – ring-fenced or otherwise.

Until the commencement of the 2019-24 regulatory control period these services have been provided as an unregulated service with the price set at each site being directly negotiated with the prospective customer. Customers have been under no obligation to acquire the service offered, nor has Endeavour Energy been under any obligation to supply.

Recognising that each service currently provided has been established under bespoke contractual and pricing arrangements we are proposing to initially grandfather all existing contracts to minimise the impact on our customers. We will examine opportunities to transition customers to the new pricing arrangements over the course of the 2019-24 regulatory period. New services offered and accepted after 1 July 2019 will be priced using the attached pricing model.

For the purposes of transitioning this service to regulation by the AER we have proposed a forward looking pricing methodology for security lights similar to that of public lighting tariff 3. Customers are required to pay a one-off installation cost and a monthly rental charge. These charges will vary depending on the type of lighting service requested and length of the contractual period. The ongoing charge will cover the costs of operating, maintaining and replacing the assets as required. As an unmetered supply of electricity the charge is also inclusive of an estimated amount of electricity consumption calculated in accordance with published load tables and our contracted energy rates. We will seek to engage with the AER on this approach noting that energy costs are unique to this service.

For simplicity, we have set prices based on the service provided to a customer i.e. the amount of illumination required. This allows us to maintain a common set of service outcomes for customers over time while providing flexibility to adopt different technologies to suit the location and/or different technologies as they become cost competitive.

Our price list includes a list of lighting services customers can choose from. Given the similarities to public lighting our security lighting fees are priced on a similar basis, refer to Attachment 14.10 for our proposed security lighting prices.

Compliance with control mechanism

In compliance with the Rules, we propose the following forms of control for ancillary network services over the 2019-24 regulatory period consistent with the AER's F&A decision:

- A schedule of fixed prices for ancillary network services for the first year of the regulatory period.
- A price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted ancillary network services model.

Please see Attachment 14.10 for our pricing models and price list.

15.0 Glossary

CHAPTER 15

Term	Meanings
AASB	Australian Accounting Standards Board
ABR	Annual Benchmarking Report
ACS	Alternative Control Service
ADMD	After Diversity Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AER CCP	Australian Energy Regulator's Consumer Challenge Panel
ANS	Ancillary Network Service
ARR	Annual Revenue Requirement
AS	Australian Standards
ATO	Australian Taxation Office
BASIX	Building Sustainability Index
BESS	Battery Energy Storage System
BSC	Blacktown Solar Cities
Capex	Capital Expenditure
CAM	Cost Allocation Methodology
CAPM	Capital Asset Pricing Model
CASH	Capital Allocation Selection Hierarchy
CBD	Central Business District
CCC	Customer Consultative Committee
CCF	Climate Change Fund
CEG	Competition Economists Group
CESS	Capital Efficiency Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DFA	Dual Function Assets
DGM	Dividend Growth Model
DMIA	Demand Management Innovation Allowance

Term	Meanings
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabling Devices
DRP	Debt Risk Premium
DUOS	Distribution Use of System
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
EGWWS	Electricity, Gas, Water and Waste Services
ENA	Energy Networks Australia
ENTR	Electricity Network Transformation Roadmap
ESS	Energy Saving Scheme
F&A	Framework and Approach
FR	Frequency Rate
GDP	Gross Domestic Product
GSL	Guaranteed Service Levels
GWh	Gigawatt hour
HV	High Voltage
ICT	Information and Communications Technology
IPART	Independent Pricing and Regulatory Tribunal of Nsw
ISO	International Organisation for Standardisation
ISSC	NSW Industry Safety Steering Committee
kV	Kilovolt
kVA	Kilovolt Ampere
kWh	Kilowatt hour
LED	Light-Emitting Diode
LiDAR	Light Detection and Ranging
LTI	Lost Time Injury
MAMP	Metering Asset Management Plan
MAPE	Mean Absolute Percentage Error
MAR	Maximum Allowable Revenue
MED	Major Event Day

Term	Meanings
MEPS	Minimum Energy Performance Standards
MPFP	Multi-Partial Factor Productivity
MPU	Major Projects Unit
MRP	Market Risk Premium
MTFP	Multi-Total Factor Productivity
MVA	Mega Volt Amperes
MWh	Megawatt hour
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NSW	New South Wales
NSW DRP Licence Conditions	The NSW Design, Reliability and Performance Licence Conditions
NUOS	Network Use of System
OEF	Operating Environment Factor
Opex	Operating Expenditure
OT	Operational Technology
PIAC	Public Interest Advocacy Centre
PLMP	Public Lighting Management Plan
PMA	Post-Modelling Adjustment
PoE	Probability of Exceedance
PPI	Partial Productivity Indicator
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RFM	Roll-Forward Model
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
Rules	National Electricity Rules

Term	Meanings
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
TCMD	Temperature Corrected Maximum Demand
TOU	Time of Use
TRI	Total Recordable Injuries
TSI	Total System Import
TSS	Tariff Structure Statement
UDIA	Urban Development Institute of Australia
VCR	Value of Customer Reliability
VDA	Value Development Algorithm
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WPI	Wage Price Index
WSA Co	Western Sydney Airport Corporation
WSROC	Western Sydney Regional Organisation of Councils
ZS	Zone Substation

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