AusNet Electricity Services Pty Ltd

Electricity Distribution Price Review 2016-20

Submitted: 30 April 2015

About AusNet Services

AusNet Services is a major energy network business that owns and operates key regulated electricity transmission and electricity and gas distribution assets located in Victoria, Australia. These assets include:

- A 6,574 kilometre electricity transmission network that services all electricity consumers across Victoria;
- An electricity distribution network delivering electricity to approximately 680,000 customer connection points in an area of more than 80,000 square kilometres of eastern Victoria; and
- A gas distribution network delivering gas to approximately 572,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

AusNet Services' purpose is 'to provide our customers with superior network and energy solutions.'

For more information visit: [www.ausnetservices.com.au.](http://www.ausnetservices.com.au)

Contact

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Glossary

Abbreviation	Full Name
ABC	Aerial Bundled Cable
ABS	Australian Bureau of Statistics
ACS	Alternative Control Services
AEDT	Australian Eastern Daylight Time
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
AMI	Advanced Metering Infrastructure
ARR	Annual Revenue Requirement
ASX	Australian Securities Exchange
AWOTE	Average Weekly Ordinary Time Earnings
Augex	Augmentation expenditure model
B2B	Business to Business
BAU	Business as usual
BPS	Bairnsdale Power Station
CAM	Cost Allocation Methodology
CAPM	Capital Asset Pricing Model
Capex	Capital Expenditure
CBs	Circuit Breakers
CBD	Central Business District
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Security
COAG	Council of Australian Governments
CPI	Consumer Price Index
CROIC	Cost Recovery Order in Council
Current regulatory period	Regulatory control period of 1 January 2011 to 31 December 2015
DBs	Distribution Businesses
DEPI	Victorian Department of Primary Industries
DFA	Distribution Feeder Automation

Abbreviation	Full Name
DGM	Dividend Growth Model
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabled Device
DRP	Debt Risk Premium
DUOS	Distribution Use of System
EBAs	Enterprise Bargaining Agreements
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
EGWWS	Electricity, Gas, Water and Waste Services
EPMO	Enterprise Project Management Office
EPPM	Enterprise Portfolio Management
ERW	Emergency Recoverable Works
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
ETU	Electrical Trade Union
EUAA	Energy Users Association of Australia
EWOV	Electricity and Water Ombudsman Victoria
EY	Ernst & Young
F&A	Framework & Approach
FTE	Full-Time Equivalent
FSL	Fire Service Levy
GESS	Grid Energy Storage System
GFC	Global Financial Crisis
GIS	Gas Insulated Switchgear
GSL	Guaranteed Service Level
GST	Goods and Services Tax
HBCA	Highest Bushfire Consequence Area
HBRA	High Bushfire Risk Area
ICT	Information and Communication Technology
IT	Information Technology

Abbreviation	Full Name
LNSP	Local Network Service Provider
LRMC	Long Run Marginal Costs
LV	Low voltage
MAIFI	Momentary Average Interruption Duration Index
MCR	Marginal Cost of Reinforcement
MED	Major Event Day
MTFP	Multilateral Total Factor Productivity
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMA	Network Management Automation
NMI	National Meter Identifier
NPV	Net Present Value
NSP	Network Service Providers
NUOS	Network Use Of System
OHL	Overhead Line
OH&S	Occupational Health and Safety
Opex	Operating and Maintenance Expenditure
OT	Operating Technology
PBST	Powerline Bushfire Safety Taskforce
PPI	Partial Performance Indicators
PoC	Power of Choice
PRF	Powerline Replacement Fund
PTRM	Post-Tax Revenue Model
PV	Present Value
RAB	Regulatory Asset Base
REFCL	Rapid Earth Fault Current Limiter
Regulatory Proposal	AusNet Services' proposal for the next regulatory period
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RoR	Rate of Return

Abbreviation	Full Name
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TGN	Traralgon (Zone Substation)
TNSP	Transmission Network Service Provider
TSS	Tariff Structure Statement
WACC	Weighted Average Cost of Capital
WDV	Written Down Value
WPI	Wage Price Index
VBRC	Victorian Bushfire Royal Commission
VCR	Value of Customer Reliability
VESI	Victorian Electricity Supply Industry
ZSS	Zone Substation

Highlights

Stabilising prices are a priority

Stabilising both prices and network investment are a priority if the distribution network is to continue to provide a viable and reasonably priced service to customers. The revenue proposal slows the growth in average distribution charges to 0.4% per annum over 2016-20. Inclusive of metering, the network component of typical residential bills will fall by 2.3% per annum over five years (from an average of $720 to $630).

AusNet Services has unique environmental challenges

AusNet Services' electricity distribution network delivers electricity to customers under a diverse set of circumstances from the heavily forested and mountainous areas of the Great Dividing Range through the low lying and coastal regions of Gippsland to the highly populated suburbs on Melbourne's northern and eastern fringes. This area contains some of the most difficult terrain and hazardous bushfire risk areas in Australia.

Investment in safety improvements will continue

AusNet Services has clear legislative and regulatory obligations to minimise the risk electricity assets present to both the public and its employees. Accordingly, AusNet Services will continue to invest appropriate amounts of the revenue it receives from customers to ensure it meets those responsibilities and improves its safety performance. The investment required to reduce bushfire risk and replace deteriorating assets limits AusNet Services' ability to deliver price relief.

Increasing peak demand

Peak demand continues to increase on AusNet Services' network, despite falling energy consumption and increasing solar penetration. This shows customers still want network services and there is a continued need for network investment.

Evident efficient outcomes

AusNet Services has managed these operating pressures within its expenditure allowances and independent benchmarking analysis concludes that AusNet Services is one of the most efficient rural distribution businesses in Australia.

Incentive regulation works

AusNet Services' strong record of delivering lower operating costs and improved service levels demonstrates the incentive framework is working. Therefore, the AER's intention to apply the full suite of incentives in Victoria, including the new stronger capital efficiency incentive, is supported.

Customers will benefit from lower interest rates and debt costs

AusNet Services is proposing a fair return on its assets from both a customer's and an investor's perspective. In particular, the large fall in interest rates and debt costs are being passed back to customers. AusNet Services has set aside the AER's Guideline approach because, in a record low interest rate environment, it does not deliver a return to equity holders which is reflective of market realities. AusNet Services' alternative proposed cost of equity is lower than that in the current period.

A proposal that balances conflicting pressures

By taking steps such as absorbing step changes in operating expenditure, and investing in broad based demand management to curb future augmentation expenditure, AusNet Services' proposal delivers the necessary investment to meet customers' expectations for their network service, particularly, to improve community safety, and keeps prices on a sustainable path.

Executive Summary

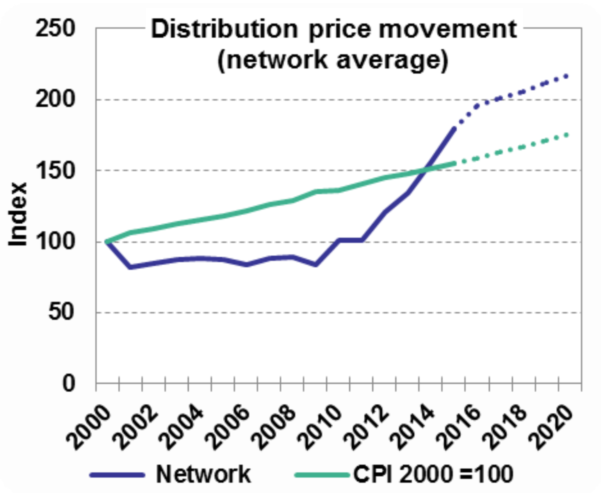
AusNet Services[1] (formerly SP AusNet) owns and operates the electricity distribution network that provides services to customers located in the eastern half of Victoria, spanning from the northern and eastern suburbs of Melbourne eastward to Mallacoota, and north to the Murray River.

This proposal sets out AusNet Services' plans for the electricity distribution network for the next five years (from 1 January 2016). It also sets out the revenue that will be required to deliver those plans.

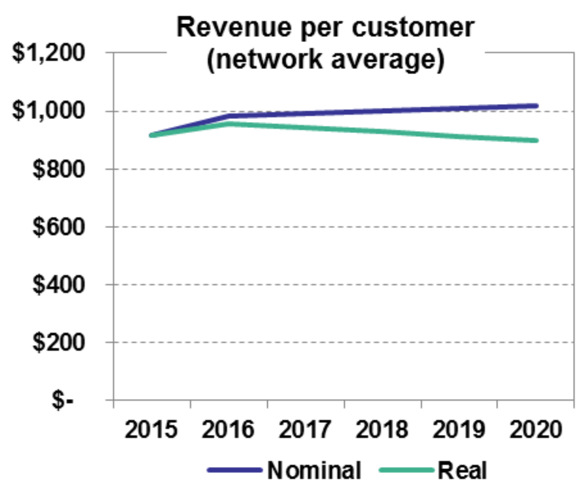
Slower price growth, flat electricity bills and commitment to maintain service levels

Over the next five years, AusNet Services' regulatory proposal will result in small increases to the distribution component of its prices, and an impact on the network component of an average customer's bill that is flat. Inclusive of metering charges, average bills for residential customers will fall.

Price growth will slow…



…and customer bills will be flat.



Throughout the development of this submission, we have returned to the theme of delivering sustainable prices. The effect of a program of over half a billion dollars to reduce the bushfire risk of the distribution network, at a time when per capita energy consumption is falling, has seen AusNet Services' prices increase rapidly in recent years. For customers, higher electricity network charges have left less money available for everything else. For AusNet Services, rapid price growth increases the risk of precipitating the so-called 'death spiral', where the future number of customers remaining connected to the network cannot support the remaining costs of assets that have been installed over many decades.

However, AusNet Services knows that network services are still very much in demand, and it must continue to deliver on its obligations. Cost cutting must not be driven to a point where it impacts service levels because customers are largely satisfied with their existing service. This regulatory proposal balances seeking to deliver long term sustainable prices with the immediate needs to invest in improving community safety and replace aging assets of the network in support of, and consistent with, the National Electricity Objective (NEO).

[1] The relevant licenced entity is AusNet Electricity Services Pty Ltd (ABN 91 064 651 118).

The need to stabilise prices

In recent years, a confluence of factors has driven up network prices for AusNet Services' customers, including:

- safety programs – investment of over $500 million in safety programs in the current regulatory period to minimise bushfire risk;
- mandated metering program – involved upfront costs before the long term benefits can be felt (i.e. meters give customers the power to limit future network investment, but this takes time to take effect);
- unwinding of government subsidisation of customers of rural networks – when Victoria's networks were privatised, the government made adjustments to the sale prices so that bills were roughly equal in each of the five network areas. But, the network costs are different;
- cost of capital – the GFC and subsequent upheaval in financial markets increased costs of building and maintaining the network because the large capital investments involved require large amounts of equity and debt. Although, it is noted that this factor will stop driving prices next period;
- falling energy use is not reducing network costs – peak demand is still growing on AusNet Services' network.

In coming years, the emergence of new technologies poses a greater challenge to AusNet Services' business if future price growth cannot be constrained. As the cost of small scale generation and storage is expected to fall, some customers may choose to disconnect from the grid.

Getting the balance right

Exclusive of metering, AusNet Services' revenue proposal slows the growth in the network component of average customer bills to 0.4% per annum. In real terms this means AusNet Services' customers' bills will fall over the next five years, falling by two percent per year on average. The proposal will see AusNet Services' prices stay below the average 2013 price for distribution services in the Australian National Electricity Market through til 2020.

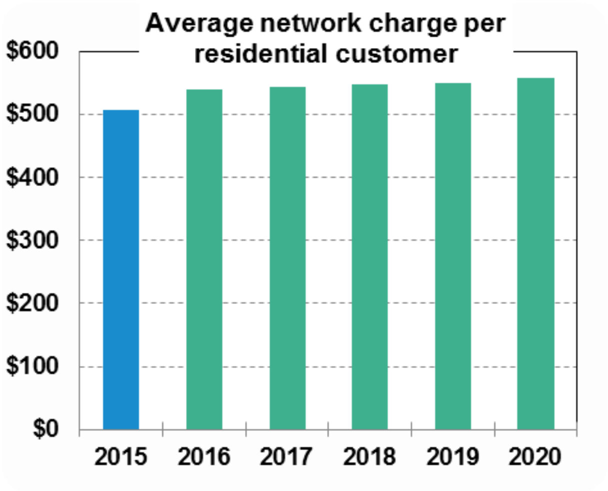
The revenue proposal balances each of the elements of the National Electricity Objective (NEO) in the way that best serves the long-term interests of consumers. AusNet Services achieved this by continuing to invest significant network capital as is required to meet customers' expectations for their network service and, particularly, to improve community safety. Simultaneously, the proposal seeks to constrain current prices, or take the necessary steps to deliver a network service that is sustainable in the long term.

Features of the regulatory proposal aimed at delivering sustainable long term network prices include:

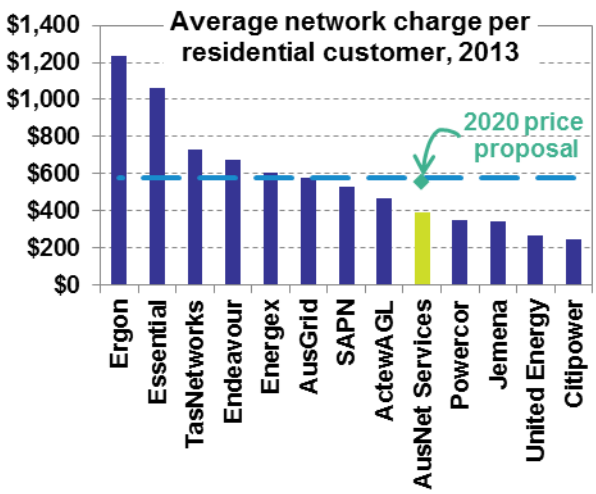
- Passing back to customers the benefits of lower interest rates;
- Reducing the augmentation program, in line with lower forecast demand growth and an increased demand management portfolio;
- Asking newly connecting customers to pay a fairer share of connection costs;
- Deferring non-safety related replacement by incorporating the lower Value of Customer Reliability set by AEMO in 2014;
- Absorbing operating expenditure step changes; and
- Accelerated recovery of the value of equipment removed as part of the extensive safety programs (lowering the Asset Base Value).

While cost reflective tariffs present a core tool to promote sustainability of investment and prices over the medium and longer term, this proposal focuses on non-tariff solutions. Tariffs will be the focus of a separate submission, the Tariff Structure Statement, in September this year.

Network charges to grow slowly …



… still compares favourably to Australian DNSPs



Source: AusNet Services forecasts and AER 2014 Economic Benchmarking RIN data

However, we cannot hope to completely address the competing drivers for increased investment and maintaining affordability for distribution network services in this submission alone. For instance, the question of what is an appropriate funding mechanism for safety investment is appropriately a jurisdictional one, rather than one to be resolved by the AER. In many respects, the significant fall in the rate of return will help shield customers from some of the underlying tensions of the operation of the distribution network.

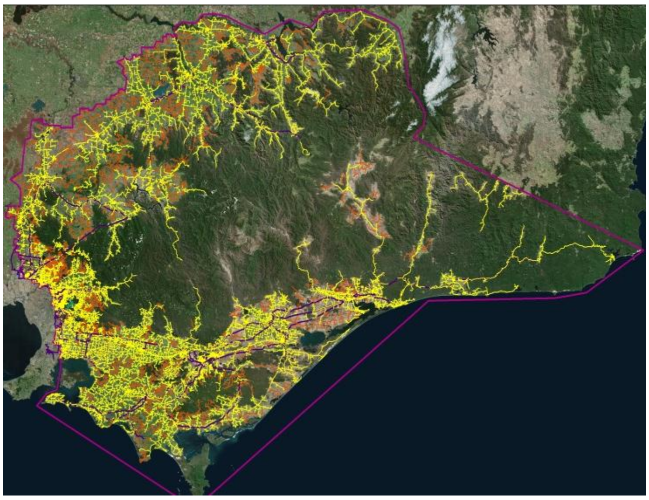
A distribution network serving predominantly residential customers in a harsh environment

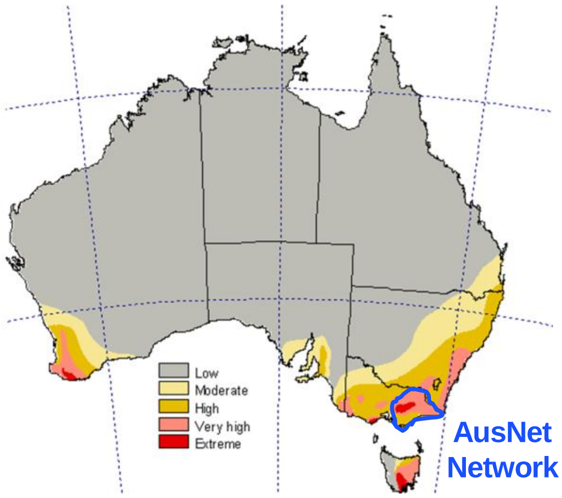
AusNet Services' electricity distribution network delivers electricity to 605,000 households and 75,000 businesses. The network is made up of 44 thousand kilometres of electricity lines, predominantly overhead network traversing rural areas and built over the period from the 1950s to the present.

Split by the Great Dividing Range, the network covers heavily forested and mountainous areas, as well as the low lying and coastal regions of Gippsland. On the northern and eastern fringes of Melbourne, the network services highly populated suburbs including through the heavily vegetated Dandenong Ranges.

The environment of eastern Victoria presents unique challenges for operating an electricity network, the most significant of which is managing the risk of bushfire ignition. Eastern Victoria is subject to a highly risky combination of climate, terrain and vegetation, in which substantial communities have settled, making it one of world's worst areas for bushfires with the potential to cause catastrophic losses to life and property.

The network covers difficult terrain … **... with very high fire risk**

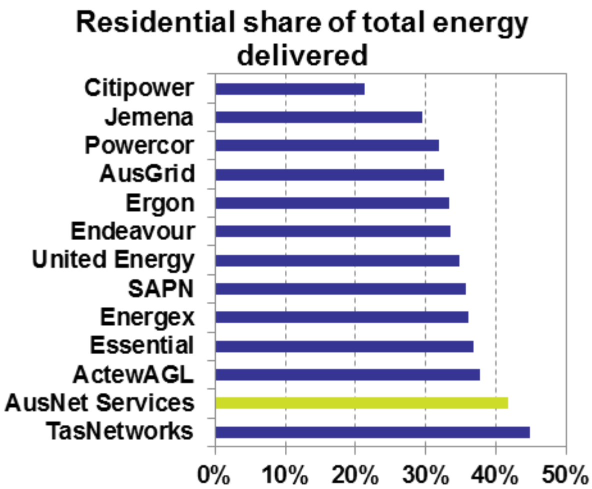


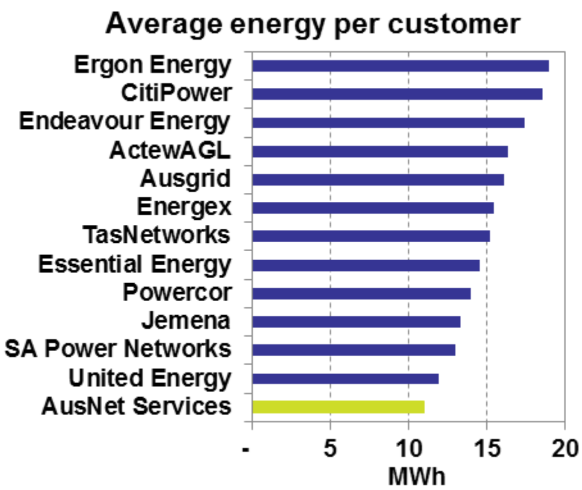


Electricity assets are inherently risky. Following the devastating Black Saturday bushfires of 2009, Victoria has reassessed both the consequences of bushfire and the way it manages that risk. For electricity networks, this has meant a step change in investment to drive down the risk of bushfire from the electricity distribution network. This includes investment and changes to network operations that implement the recommendations of the Victorian Bushfire Royal Commission (VBRC), Energy Safe Victoria (ESV) Directions, Government funded undergrounding programs, and programs identified by AusNet Services as having the potential to reduce fire starts.

The other characteristic feature of AusNet Services' distribution network is its customer demographics. While the network spans an area of over 80,000 square kilometres, the majority of customers are located in suburban Melbourne or in regional centres and towns, meaning the majority of the network services a very low density of customers. The customer base is also largely residential – amongst the highest proportions in the Australia – which is reflected in the network having the lowest energy delivered per customer in the national electricity market (NEM). AusNet Services' industrial customer base contains a large trade-exposed manufacturing sector which has been particularly affected by the high Australian dollar of the current period.

High proportion of residential customers … **... low consumption per customer**





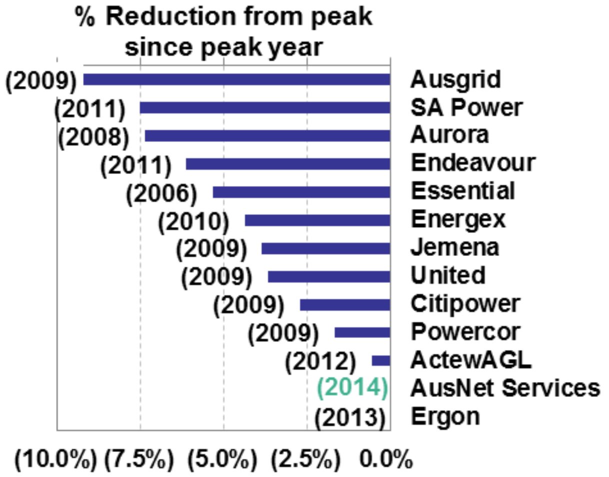
Source: AER 2014 Economic Benchmarking RIN data

While AusNet Services has been affected by the same changes to customer energy consumption behaviour as elsewhere in Australia – including suppressed economic conditions, increasing household and commercial energy efficiency and the increased take up of solar – its highly residential customer base has important implications for the way these changes have affected the business. The largely residential customer base has meant:

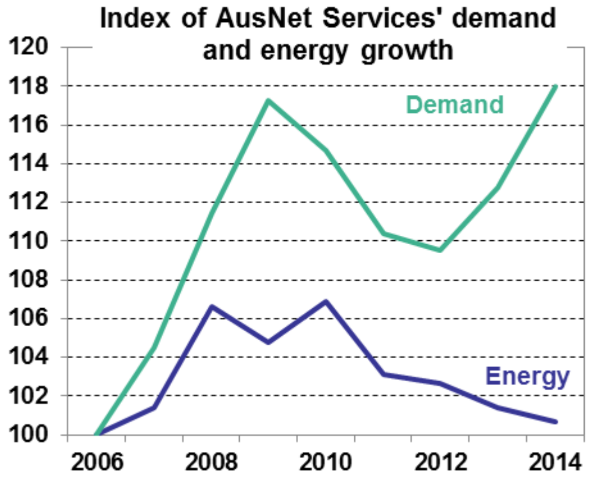
- energy use is peaky, driven by air-conditioning use;
- energy efficient housing and appliances are having a substantial impact on electricity consumption;
- peak demand occurs in the evening, reflecting commuting times of residents of outer metropolitan Melbourne; and
- while there are 80,000 customers with solar connections, the timing of the network peak on AusNet Services' network, means that solar energy is reducing overall energy delivered but not reducing the demand peak.

This has resulted in continued growth in the network peak energy demand even as energy consumption has stagnated. However, that growth is heavily concentrated on where population growth is highest in Melbourne's northern (South Morang) and south eastern (Pakenham) growth corridors.

Unlike most of our peers …



... peak demand continues to grow



Source: AusNet Services and AER 2014 Economic Benchmarking RIN data

Stabilising prices while reducing risk of bushfire ignition will require investment in innovation

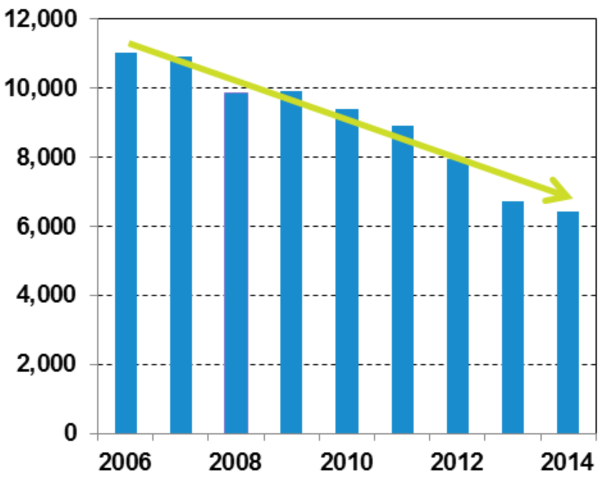
AusNet Services is driving down safety risk to its community and employees …

Electricity supply infrastructure is inherently hazardous. The principal hazards relate to fire ignition, particularly in high bushfire risk areas on total fire ban days, and exposure to electric shock. Other hazards include traffic hazards and the historic use of asbestos in some substation infrastructure.

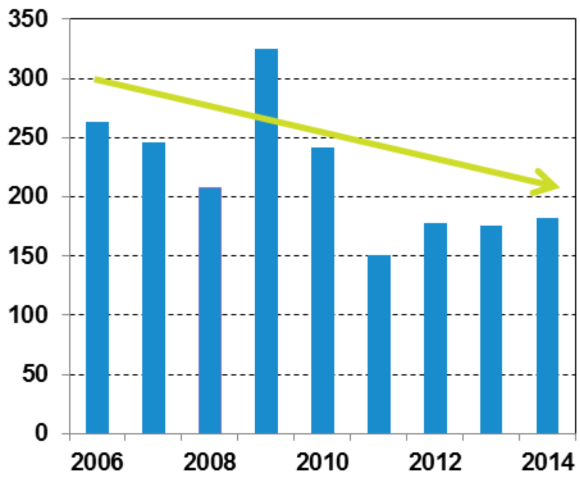
AusNet Services has clear legislative and regulatory obligations to minimise the risk electricity assets present to both the public and its employees, and is committed to meeting those obligations. AusNet Services invests large amounts of the revenue it receives from customers in ensuring it meets those responsibilities and improves it safety performance. Approximately, 15% of the average network bill is dedicated to funding these costs.

The large increases in expenditure are delivering improved safety outcomes for the community. Both the number of incidents with the potential to cause a fire and the number of actual fire starts caused by AusNet Services' assets have fallen since 2009.

Potential fire start incidents and …



… actual fire starts are falling



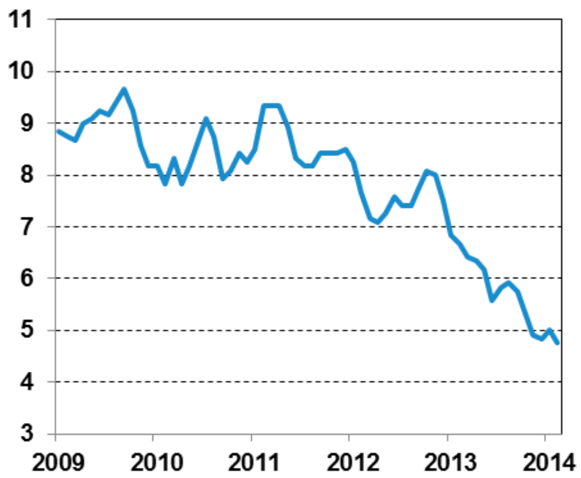
Source: AusNet Services

Nonetheless, it should be stressed that the weather also drives variability in actual outcomes. For example, the ending of the drought in 2009 has led to more benign operating environment in recent years.

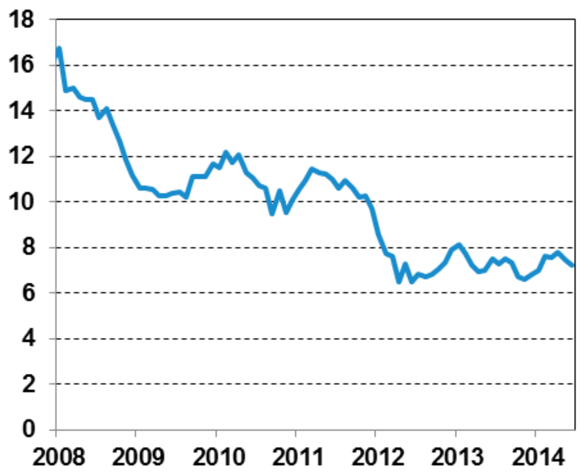
AusNet Services' investment in innovation has also delivered impressive safety outcomes for the community. Of note, the smart meter network is being utilised to detect failures in customers' service lines that have the potential to cause electric shocks. This unique capability results from investment in IT programming and systems and a specialist team dedicated to extracting network benefits from "smart grid" research. As a result, electric shocks from service failures has been reduced by 40% and may be completely eliminated when the system is fully operationalised (see figure below).

For its employees, AusNet Services implemented its "Mission Zero" policy to promote a culture within the organisation that is focussed on reducing injuries in the workplace. This cultural change is supported by various current and planned investments in systems that allow the network to be operated and maintained more safely. Again, the outcomes from these programs are impressive with the rate at which employees are hurt falling from 16 per million hours worked to 7 per million hours worked over the last six years.

Electric shocks to the public and …



… injuries to employees are falling



Source: AusNet Services

… But this has increased costs

The electricity industry began implementing the findings and recommendations of the VBRC and subsequent Powerline Bushfire Safety Taskforce over the current regulatory period. The major recommendations included:

- Increased vegetation management standards (the removal of previous exemptions);
- Increased conductor replacement;
- Targeted undergrounding and insulating of conductors in the highest risk areas;
- Retro-fitting of vibration dampers and armour rods;
- Automating protection and control equipment;
- Significant research and development programs focussed on smarter network protection and control.

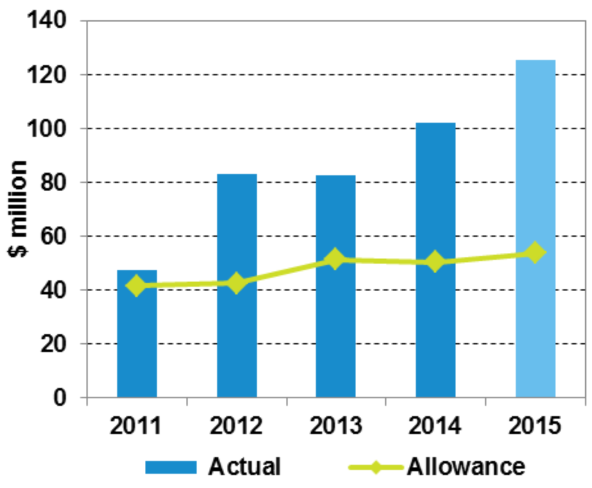
A pass-through application funding extra capex and opex associated with the VBRC recommendations was approved by the AER in 2012. While many are Victoria-wide, the majority of cost falls in the two rural distributors' areas.

In addition, AusNet Services has accelerated several replacement programs, with the endorsement of the ESV, where it has identified significant further safety benefit.

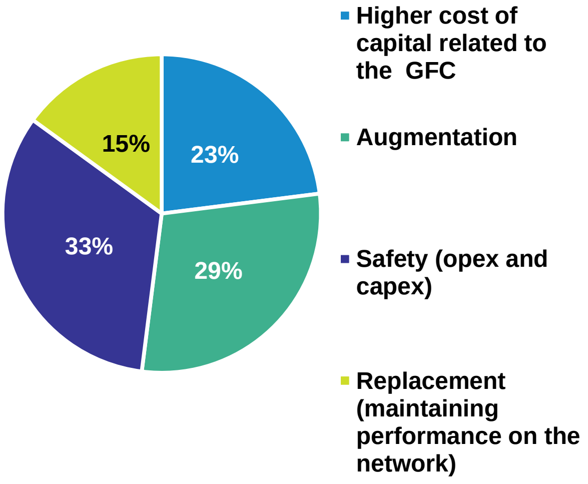
As a result, the cost of safety programs has been rising rapidly, contributing to around one third of price rises over the last five years.

The State Government also provides significant funding in these areas.

Safety expenditure has markedly increased …



… and has been increasing customers' bills



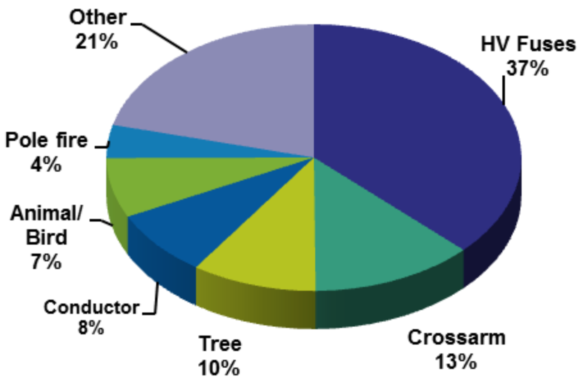
Source: AusNet Services

AusNet Services' customers expressed a strong preference for all Victorians to share the cost of safety and bushfire mitigation programs, as they considered all Victorians enjoyed the benefits that high fire risk areas provide such as food, recreation and environmental value.

Continued commitment to reducing bushfire risk and improved safety outcomes

AusNet Services has proposed an expenditure program which will continue to reduce the safety risks to the community and its workforce. This is consistent with the governing principle that AusNet Services uses in relation to its safety expenditure to keep identified risk as "low as reasonably practicable". AusNet Services uses cutting edge fire risk modelling in developing their investment programs and operational changes.

Data on fire causes…



Causes of asset and ground fires, 2006-14

… directs programs to reduce fire risk

EDO fuse replacements - target fuse types associated with greatest number of fire incidents

Cross arm replacments - replace wooden cross arms with steal cross arms

Vegetation managment and overhang removals - reduce risk of trees falling on network assets

Conductor programs - conductor replacement, undergrounding and installation of armour rods and vibration dampers

Animal and bird proofing - targets assets in high bushfire risk areas

Source: AusNet Services.

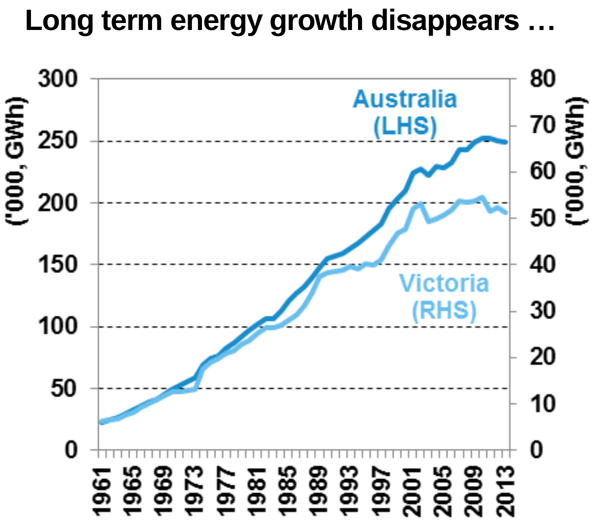
Collectively the expenditure should reduce the risk by 20% by 2020.

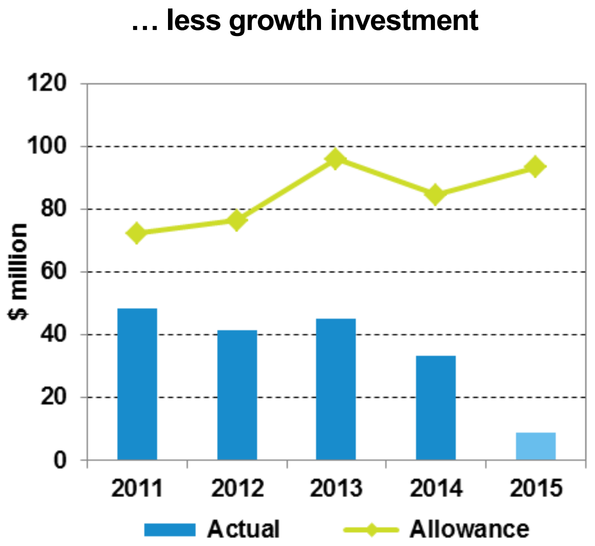
Some of the promising research and development being undertaken in collaboration with the State Government on Rapid Earth Fault Current Limiters is expected to result in a substantial augmentation program to roll out the technology across the network. However, as the volume and cost of the program is uncertain at this time, rather than including the program in the capital expenditure proposal, AusNet Services is proposing that the pass through event framework in the NER is the best mechanism to facilitate this investment.

Changing customer behaviour, new technology

The dramatic changes in energy consumption trends that have occurred during the current regulatory control period were not predicted and the turning point was almost immediately following the last regulatory determination in 2010.

Declining energy consumption has been associated with suppressed economic conditions, improved energy efficiency, changes in customer behaviour, including in response to rising prices, and the take-up of solar generation options. Relatively mild weather, including the breaking of the drought, has also contributed to declining energy consumption this period due to lower demand from less water pumping. Yet, peak demand has continued to grow, albeit at a historically slow rate.





Source: Bureau of Resources and Energy, and AusNet Services

At the same time, energy supply and transport is being transformed by technology. Some changes are potentially long term challenges to the network service. For example, distributed generation used in combination with battery storage allows a customer to dispense with a network service completely. Other changes potentially increase the importance of the network to balancing supply and demand, particularly managing two way energy flows as customers wish to export and sell excess generation they produce. Finally, network reliability and costs can be transformed by the same information technology and big data that is transforming the rest of the economy, for example, the roll out of smart meters across the network has transformed the availability of data for network management and planning.

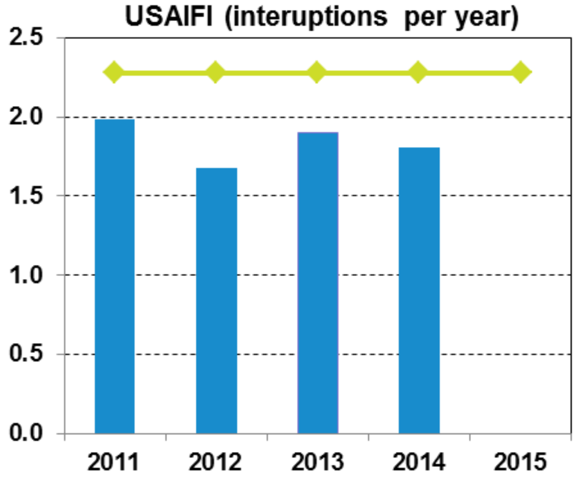
AusNet Services is at the forefront of transforming the potential from this technological change into real benefits for customers. Its existing investments in innovation have delivered large benefits to consumers in lower future costs and improved reliability and safety of the electricity supply system.

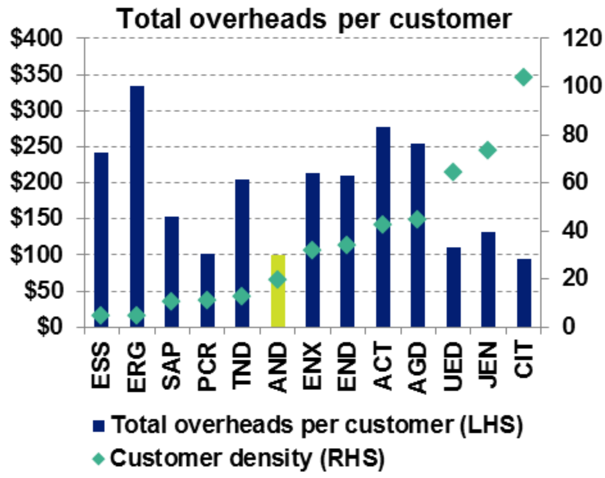
For example, with respect to reliability, expenditure on the distribution feeder automation project has delivered a 15% improvement in underlying reliability. This project uses 'smart' switches to divide the network into self-healing units, thus reducing the number of customers affected by any given outage. This fault isolation happens automatically within seconds and requires substantial IT system support.

AusNet Services' investment in research and development of demand management technology and its track record of operationalising that research allows AusNet Service to manage one of the largest portfolios of flexible demand management solutions as an alternative to network investment, further lowering long term costs to its customers.

Finally, AusNet Services' large investment in IT and innovation also facilitates cost control in other areas of the business. For example, both corporate and network overheads benchmark well against other distribution networks.

Innovation allows better service and … **… lower costs**





Source: AusNet Services and AER 2014 Economic Benchmarking RIN data
AND = AusNet Services

Continued innovation is required to deliver further network benefits at a reasonable cost

Technology, such as wide-spread solar generation and smart meters, are transforming energy supply and transport, particularly affecting how electricity customers interact with their electricity network. Likewise, new technology and innovation will be critical to AusNet Services' long term ability to deliver distribution services at sustainable prices.

AusNet Services' regulatory proposal includes the investment in innovation to:

- deliver broad-based demand management, particularly targeting residential customers, which can slow the long-term rate of asset augmentation investment, creating long-term benefits for customers through lower prices;
- modernise its ICT applications and tools that support efficient electricity distribution business processes, and ready the organisation for a future operating environment that is more uncertain and complex as customers' investment more in disruptive technologies such as local solar PV generation and battery storage;
- provide the services customers expect, from the many applications of smart meters and the use of data to better manage the network, such as improved demand forecasting, to the identification of innovative ways to reduce safety risk, such as being better able to identify faults that could cause electric shocks.

An aging network

Large volumes of assets are reaching the end of their useful and safe life and the asset condition has driven increasing asset replacement programs in the current regulatory period, driven by:

- deterioration in asset condition associated with increasing asset age, environmental conditions (such as the Gippsland floods) and identified fleet problems (such as stringy bark wooden poles);
- reduced opportunity to replace poor condition assets as part of augmentation related projects;
- asset failure risk, which may cause reliability impact, risk of collateral asset damage, safety risk to public and field personnel), environmental damage from asset failure (oil spills);

While replacement expenditure has increased considerably since 2011, AusNet Services has limited ability to reduce expenditure on asset replacement. Safety considerations mean that for many asset classes, it is not an option to let asset condition deteriorate because the consequence would be an unacceptable risk to community (e.g. pole failure or conductor failure can result in downed powerlines). And, while some of the planned replacement expenditure, particularly in areas with low customer density, may exacerbate the prospect that future customers will not be prepared to pay for a share of today's expenditure, there is no alternative given AusNet Services' service obligation to continue to provide a network service to those who want it. Replacement expenditure incurred on this basis is therefore required to ensure AusNet Services complies with its regulatory obligations and requirements, and maintains existing network reliability and security.

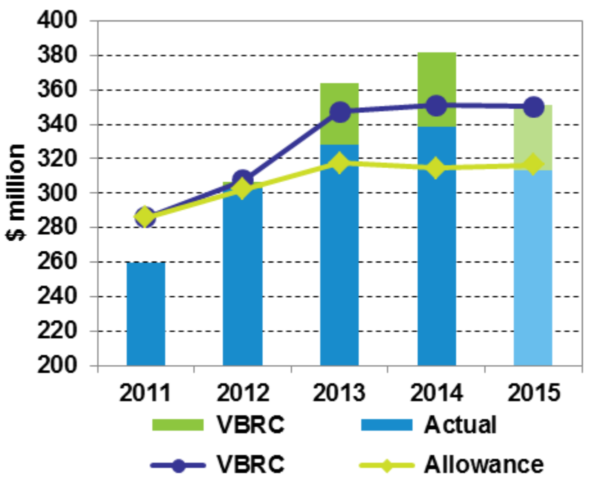
Despite increases in asset replacement, many classes of assets continue to increase in average age. For example, the volume of pole replacements has increased markedly over the period, constituting a considerable proportion of replacement costs, but still remains below levels that would stabilise the average age.

Meeting the needs of the network efficiently

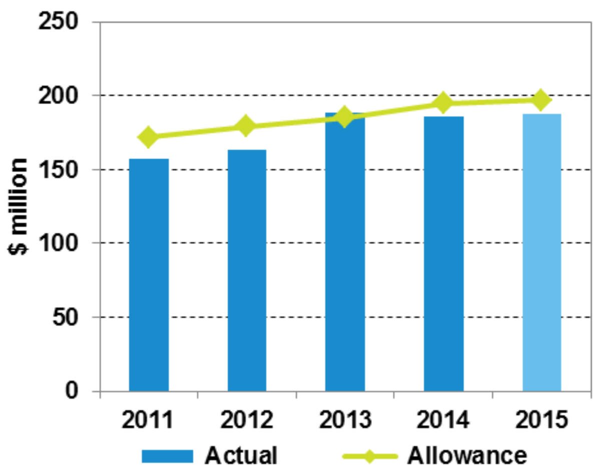
In the current regulatory control period, in spite of large changes in the operating environment, expenditure has been held in line with allowances set in the 2011-15 Distribution Determination and subsequent pass through determinations. AusNet Services' focus on cost control has been particularly important given the extra safety obligations imposed on the network mid-period and the decline in revenue growth caused by the fall in energy consumption to a level well below that approved by the AER.

Inclusive of the VBRC expenditure, total capital expenditure net of customer contributions is projected to be 1% under the comparable approved allowance. Controllable operating expenditure is projected to be 5% below the allowance set by the AER.

Capex is slightly below benchmark while …



… controllable opex is 5% below



Source: AusNet Services, capex includes pass-throughs, opex excludes uncontrollable costs.

AusNet Services' rigorous, analytical and externally certified approach to asset management has been critical to delivering on obligations and services standards, while constraining costs in a changing operating environment.

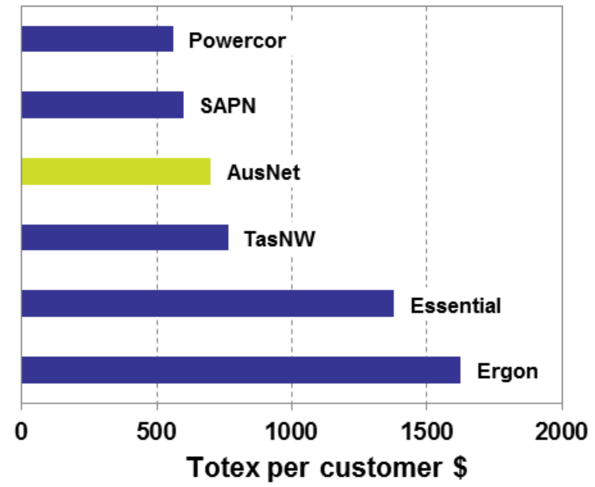
The efficiency performance of the distribution network demonstrates efficient management of a network with the characteristics and requirements of AusNet Services' distribution network.

Overall efficiency

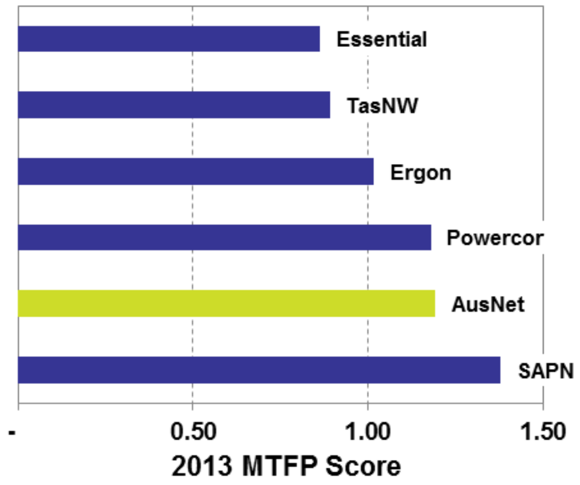
AusNet Services' costs are prudent and efficient. As outlined above AusNet Services has responded to efficiency incentives and kept expenditure under the regulatory allowances for the period, despite significant cost pressures relating to safety obligations. This is reflected in AusNet Services' average totex (capex plus opex) per customer over 2009-13, which is one of the lowest in the NEM, and is relatively low compared to the other rural DNSPs (those with customer densities of less than 20 customers per km line length).

AusNet Services provides an efficient level of productivity for the costs it incurs. The AER's preferred Multilateral Total Factor Productivity (MTFP) economic benchmarking method shows AusNet Services' productivity has improved since 2009 (corrected to remove bushfire and safety opex from the inputs). In 2013 AusNet Services had the second highest MTFP score of the rural networks.

Totex per customer is amongst the lowest..



… and total productivity is second highest



Source: AusNet Services and AER 2014 Economic Benchmarking RIN data

The above high-level indicators of efficiency show that AusNet Services performs well in terms of overall efficiency.

Opex efficiency

The AER's own analysis has found AusNet Services to be one of the most efficient businesses for opex efficiency. In assessing data from 2006 to 2013, the AER's consultant, Economic Insights, identified AusNet Services as one of five distributors within the top quartile of DNSPs with respect to opex efficiency (along with CitiPower, Powercor, SA Power Networks and United Electricity Distribution).[2]

The distribution network also performs well when opex is broken into its major categories. These metrics demonstrate that AusNet Services benchmarks favourably when compared to businesses of similar customer density and across the NEM.

Customer Engagement

AusNet Services undertook several engagement activities aimed at gauging its customers' attitudes to different aspects network investment and trade-offs between reliability and safety outcomes and operating costs. These were not a substitute for detailed independent analysis or risk modelling such as bushfire risk modelling; rather, they were helpful in illuminating customer attitudes to AusNet Services' chosen investment approaches and forecasts. Where appropriate, AusNet Services modified its proposal to ensure the proposal delivers an outcome that best serves the long-term interests of customers.

The feedback received was categorised into four broad themes:

- Prices;
- Safety;

[2] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, pp. 47-48.

- Reliability; and
- Innovation/Efficiency.

The feedback made clear that households and small businesses were concerned about rising energy costs over the preceding five years. Customers considered networks have a responsibility to manage costs over the long term to avoid the need for large short term price rises.

With respect to the recovery of AusNet Services' revenue, customers were hostile to both fixed charges (associated with a loss of control over their bill) and locational prices (which they felt penalised people for decisions they couldn't easily change and was strongly linked to the cost of safety expenditure which they believed benefited all Victorians).

The operation of AusNet Services' network in a safe manner was considered non-negotiable. Customers were very supportive of investment that improved community safety, particularly where it reduced the risk of fire ignition from electricity assets. They also strongly supported the proposed further reduction in risk. This support remained even when presented with the significant costs of proposed programs.

Customers expressed a strong preference for current reliability levels. This satisfaction was shared across different customer groups. There was a strong resistance either to pay for further reliability improvement or allowing reliability to decline for lower prices in the future.

Finally, there was general support for continued investment in innovation (as opposed to large network investments), particularly where it resulted in lower long term costs or higher community benefits such as improved safety or reliability.

AusNet Services has taken care to ensure its regulatory proposal details where, why and how customer feedback influenced or did not influence the proposals presented. At a high level, however, it has led to a series of coordinated decisions that stabilise price rises for AusNet Services' customers while still delivering the improvements in community safety desired.

Continued innovation is required to deliver further network benefits at a reasonable cost

Technology, such as wide-spread solar generation and smart meters, are transforming energy supply and transport, particularly affecting how electricity customers interact with their electricity network. Likewise, new technology and innovation will be critical to AusNet Services' long term ability to deliver distribution services at sustainable prices.

AusNet Services' regulatory proposal includes the investment in innovation to:

- deliver broad-based demand management, particularly targeting residential customers, which can slow the long-term rate of asset augmentation investment, creating long-term benefits for consumers through lower prices;
- modernise its ICT applications and tools that support efficient electricity distribution business processes, and ready the organisation for a future operating environment that is more uncertain and complex as consumers' investment more in disruptive technologies such as local solar PV generation and battery storage;
- provide the services customers expect, from the many applications of smart meters and the use of data to better manage the network, to the identification of innovative ways to reduce safety risk, such as being better able to identify faults that could cause electric shocks.

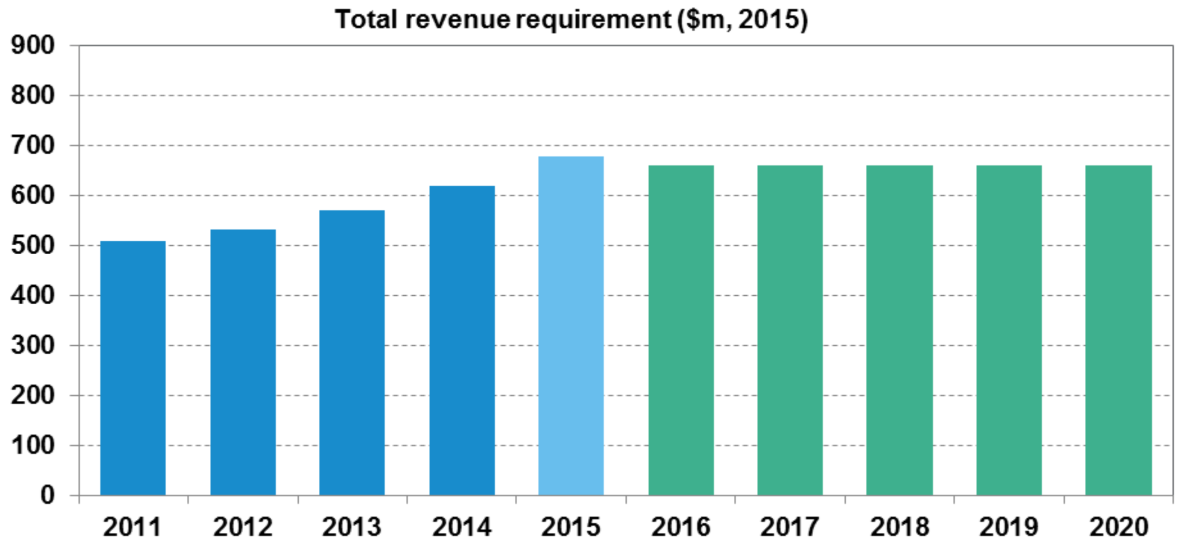
A little detail on AusNet Services' Revenue Proposal

As a result of its significant efforts to identify and implement strategies to reduce its required revenue, AusNet Services is able to propose a lower forecast than a piece by piece approach to addressing the key drivers outlined above would support. The revenue proposal has the effect of reducing the price impact on customers without compromising investment incentives or the quality, safety, security or reliability of AusNet Services' electricity services.

AusNet Services is including a number of costs in the forthcoming regulatory control period that were previously recovered outside the price cap in the current period. Specifically:

- The cost of a large network support contract, previously recovered through an adjustment to the tariffs during the annual tariff setting process; and
- Costs associated with the smart meter related program upgrades to core distribution systems (such as the billing system) where it is now appropriate to subsume them into the standard control distribution service.

Therefore, any meaningful like-for-like comparison between the current and forthcoming periods must either include or exclude this revenue from both. The figure below illustrates real revenue over the current and forthcoming period, net of STPIS payments, and shows that revenue will be $399 million higher in the next period on a like-for-like basis. After a period of annual average growth of 7.4% in the current period, annual revenue falls by 2.4% in 2016, and remains flat to 2020.

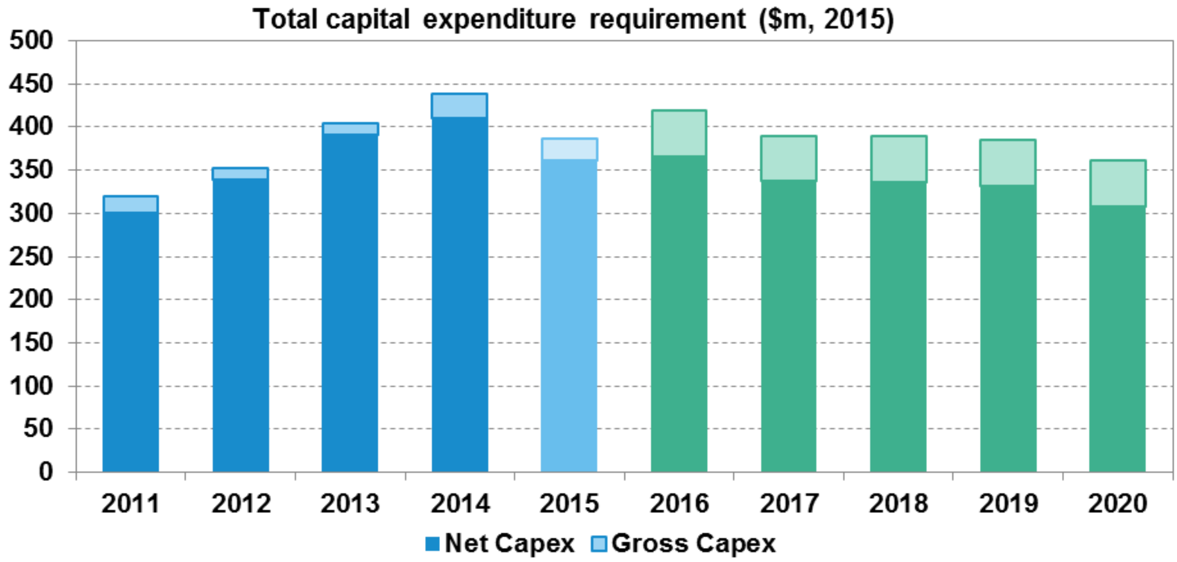


The **capital expenditure** forecast is not a traditional 'maintain' case. Rather, expenditure is proposed that would continue to reduce bushfire risks from the distribution network. Also, proposed replacement and augmentation expenditure is associated with a slightly lower level of reliability (three minutes per annum for the average customer) than is currently experienced, reflecting new information about the value customers place on reliability.

AusNet Services' total forecast of 2016-20 capital expenditure (capex) is $1,964 million (gross), a net impact of $1,690 million[3] after government and customer contributions. The forecast represents a 2% increase in total (gross) capex, and a 4% decrease in net capex.

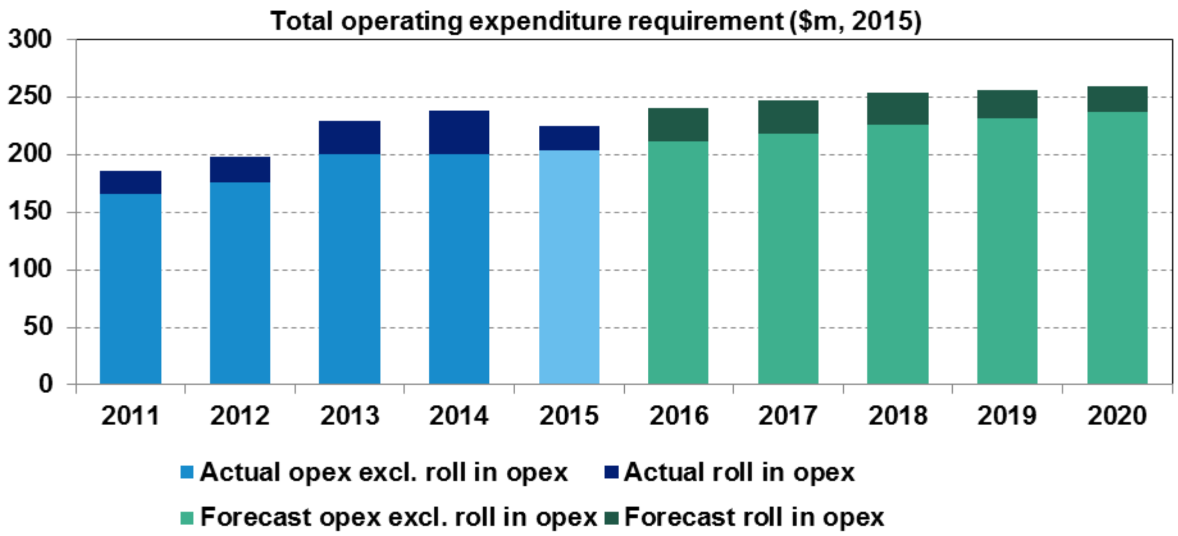
Expenditure is expected to be relatively flat over the five years, with safety obligations and programs to reduce bushfire risk making up the largest component of capital expenditure. Augmentation, the capital required to expand network capacity, makes up a portion of the overall capital expenditure that is small by historical comparison.

3 Before disposals.



Forecast **operating expenditure** reflects a 'business as usual' outlook, based on current expenditure levels, and expected increases in line with network growth and labour costs.

- Forecast insurance costs have not been calculated using the base year roll forward approach. Reflecting the high consequence of bushfire risk in its distribution network area, the costs AusNet Services faces are not typical of industry averages. Therefore, a bottom up forecast is included.
- AusNet Services has identified many step changes to opex, but, excepting demand management, is not proposing to recover these costs from customers. Rather, the business will look for the efficiencies needed to absorb them, in the interest of stabilising network costs.



Electricity distribution is a very capital intensive business, therefore, the "financing costs" or return on and of capital make up the majority of network charges. Alone, the **return on capital** on sunk and new assets makes up 42% of the proposed revenue.

AusNet Services is proposing a fair return on its assets from both a customer's and investor's perspective. In particular, the large fall in interest rates and debt costs are being passed back to customers. However, AusNet Services considers that, in a record low interest rate environment, the AER's Guideline approach does not deliver a return to equity holders which is reflective of market realities. This therefore distorts the balance between an equitable return to customers, on the one hand, and to investors, on the other hand. Despite setting aside the AER's approach, AusNet Services is proposing a cost of equity which is lower than that in the current period.

The industry has presented substantive evidence that cost of equity does not fluctuate in line with the underlying interest rate; rather, it is counter-cyclical. This was best illustrated in the fallout from the Global Financial Crisis, where central banks around the world cut interest rates to protect their economies while a simultaneous reassessment of risk by investors sent equity premiums upwards.

AusNet Services has submitted alternative cost of equity models which better reflect this reality than the AER's chosen foundation cost of equity model – the simple but largely superseded Sharpe-Lintner CAPM. AusNet Services considers that the use of models that better reflect the observed real life outcomes in equity markets actually leads to less volatile price outcomes for customers as well as businesses as equity premiums fall when interest rates are above their long term averages.

Revenue requirements for **taxation** and **depreciation** have been calculated based on the AER's Roll Forward Model (RFM) and Post Tax Revenue Model (PTRM). In the case of taxation, the use of the AER's regulatory models reflects a change in methodology from the historical approach which was a legacy of the Victorian regulatory approach. An allowance $110 million for accelerated depreciation of assets that have been or will be removed from the network prior to the end of their regulatory lives has been calculated, as has standard regulatory depreciation for the remaining asset base.

Incentive regulation works. AusNet Services has a strong record of delivering lower operating costs and improved service levels in response to the incentive framework under which it operates. Therefore, the AER's intention to apply the full suite of incentives in Victoria, including the new stronger capital efficiency incentive, is supported.

An important component of the framework in the current period was the Demand Management Incentive Allowance. This has allowed research and development to be undertaken into demand management technologies where benefits to customers of the technologies have been uncertain or long term. Without this component of the incentive framework, longer term research is discouraged even where long term benefits have the potential to be large. An example from this period is research into the use of energy storage as a credible demand management option at the grid or household level.

AusNet Services is proposing to expand this valuable component of the incentive framework for the 2016-20 period, with a focus on supporting research into how households can use storage to support the grid and reduce future energy bills.

Conclusion

The amendments in recent years to the National Electricity Law and Rules and the merits review framework affirm that a distribution determination is intended to deliver outcomes which best serve the long-term interests of consumers. The discourse surrounding these amendments has also affirmed the need for participants in the regulatory review process to balance the various factors embedded in the NEO to deliver the outcome which best achieves this goal.

AusNet Services believes its regulatory proposal best serves the long-term interests of its customers. The proposal balances delivering the immediate needs of the network, its customers and the community with a longer term vision for the network that sees the network continuing to provide an efficient source of distribution services.

AusNet Services has carefully balanced these long-term customer interests against the need to attract and retain long-term investment to provide assurance that its electricity distribution business remains viable and sustainable well into the future.

Part I –
Operating Environment

missionzero

1. Operating Environment

1.1 Overview

This regulatory submission sets out AusNet Services' proposal for its electricity distribution network for the next regulatory control period, which commences 1 January 2016 and runs through til 31 December 2020.

Part I of this proposal provides the scene setting or context in which AusNet Services' plans for 2016 and beyond have been developed.

Network Characteristics

The important physical and environmental characteristics that impact AusNet Services' costs and the service it provides are:

- the distribution network, predominantly consisting of overhead lines, traverses suburban, regional and rural areas in the east of Victoria;
- the location of the distribution network has among the world's highest level of bushfire risk, meaning significant expenditure is required to manage and reduce the risk of fires being initiated from the distribution network;
- the rural service area means a low customer density. This means there is typically a greater length of network per customer, with associated higher costs.

The customer base which AusNet Services' serves has a smaller share of commercial and industrial customers than most DNSP's in the NEM, and residential customers account for a larger share of energy delivered. This means:

- AusNet Services' customers consume the lowest energy per customer;
- Peak demand on the network is also driven by our residential customers, occurring in the early evening of hot summer days when customers across the distribution area return home and switch on their air conditioning; and
- Energy consumption per customer is falling due to factors such as increases in energy efficiency and solar generation, but peak demand has continued to grow because new customers continue to connect to the network.

Details of the important characteristics of AusNet Services' distribution Network are provided in Chapter 2 Network Characteristics.

Customer Engagement

As part of this Review, AusNet Services undertook a customer engagement program that, for the business, was unprecedented in its nature. This program provided insights into customer attitudes. While these views were diverse and wide ranging, some common themes emerged:

- Prices – The feedback made clear that households and small businesses were concerned about rising energy costs over the preceding five years. Customers believed that networks had a responsibility to manage costs over the long term to avoid the need for large, short term price rises.
- Safety – The operation of AusNet Services' network in a safe manner was considered non-negotiable. Customers were very supportive of investment that improved community safety, particularly where it reduced the risk of fire ignition from electricity assets.
- Reliability – Customers expressed a strong preference for current reliability levels. This satisfaction was shared across different customer groups. There was a strong resistance

either to pay for further reliability improvement or allowing reliability to decline for lower prices in the future.

- Innovation – there was general support for continued investment in innovation (as opposed to large network investments), particularly where it resulted in lower long term costs or higher community benefits such as improved safety or reliability.

The findings from AusNet Services' customer engagement program have not been used to make expenditure decisions on a stand-alone basis, but rather, these insights have shaped and refined our plans. This reflects a realistic assessment of AusNet Services' maturity with broad-based customer engagement and current levels of engagement.

Details of the findings of AusNet Services' engagement program and how they were incorporated in this regulatory proposal are provided in Chapter 3 Customer Engagement.

Demand and Energy

Forecasts for how customers will use the distribution network in 2016 and beyond (customer numbers, energy consumption and peak demand) are a critical determinant of AusNet Services' expenditure plans contained in this regulatory proposal.

In this area of customer behaviour, dramatic change has occurred in the current regulatory period, as a decades-long trend of increasing energy consumption has ended, and peak demand as has increased only slowly compared to recent years of rapid growth.

In response to these dramatic changes, as well as criticisms made of the forecasting processes adopted at the last EDPR, AusNet Services has considerably developed and matured its forecasting approach during the current period, leveraging off the investment in ICT architecture and the availability of smart meter data.

For 2016-20, AusNet Services is forecasting:

- Maximum demand – is expected to grow at 1.1% per annum at the network level, a similar rate of growth to that experienced in the current regulatory period. Growth will be concentrated in the corridors to the north and south east of Melbourne.
- Energy consumption – is expected to fall by 0.1% per annum. Residential and commercial energy consumption is forecast to continue declining on a per capita basis, but these declines are expected to be largely offset by customer growth and stronger industrial consumption
- Customer numbers – are forecast to grow by around 1.5% per annum, although there is expected to be a continued decline in the commercial customer base.

Details of AusNet Services' energy, demand and customer forecasts are provided in Chapter 4 Demand and Energy.

Benchmarking

Benchmarking has been added to the factors that the Australian Energy Regulator (AER) must explicitly consider in assessing expenditure proposals. AusNet Services has long supported the use of productivity benchmarking tools, in addition to other assessment techniques (such as econometric modelling and cost category analysis), for establishing the efficient cost of delivering services for each distribution network.

Benchmarking can provide a top-down view to complement the detailed bottom-up, or program based, view of expenditure requirements and can be used to compare the relative performance of peer firms.

However, different benchmarking techniques are at different phases of maturity. For some techniques, such as the total factor productivity measures that are starting to be adopted, the findings are sensitive to model specification, and the explanatory power of the results still needs to be established. There are also important differences between distribution networks which affect measures of productivity and these need to understood and accounted for.

With the above caveats in mind, key findings in relation to AusNet Services' benchmarked performance include:

- Investments in safety which have improved safety outcomes impact negatively on benchmarking results as they increase costs without a corresponding uplift to measured outputs. The effect of safety expenditure should be excluded to provide a fair comparison.
- Overall productivity performance – AusNet Services operates its network efficiently in comparison to similar firms. Against the AER's preferred Multilateral Total Factor Productivity (MTFP) measure, corrected to remove bushfire and safety opex from the inputs, AusNet Services had the second best score of the rural networks in 2013.
- Opex and capex efficiency – against a number of measures, AusNet Services' capex and opex compare well relative to peers. AusNet Services' asset base cost per customer is one of the lowest in the NEM and 28% lower than the industry average, while AusNet Services was identified by the AER as being one of five distributors within the top quartile of DNSPs with respect to opex efficiency.

Details of how AusNet Services' benchmarks to its peers are provided in Chapter 5 Benchmarked Performance.

1.2 Supporting Documents

AusNet Services' regulatory proposal has been prepared with reference to the following documents:

- Appendix 1A – Cost Allocation Methodology;
- Appendix 1B – Service Classification Proposal; and
- Appendix 1C – Related Party Arrangements.

Further supporting material, which is specific to individual aspects of the proposal, are listed in the relevant sections of this document.

2. Network Characteristics

This chapter describes the physical, environmental and customer demographic characteristics of AusNet Services' electricity distribution network and their implications for its network performance and expenditure.

2.1 Physical and Environmental Characteristics

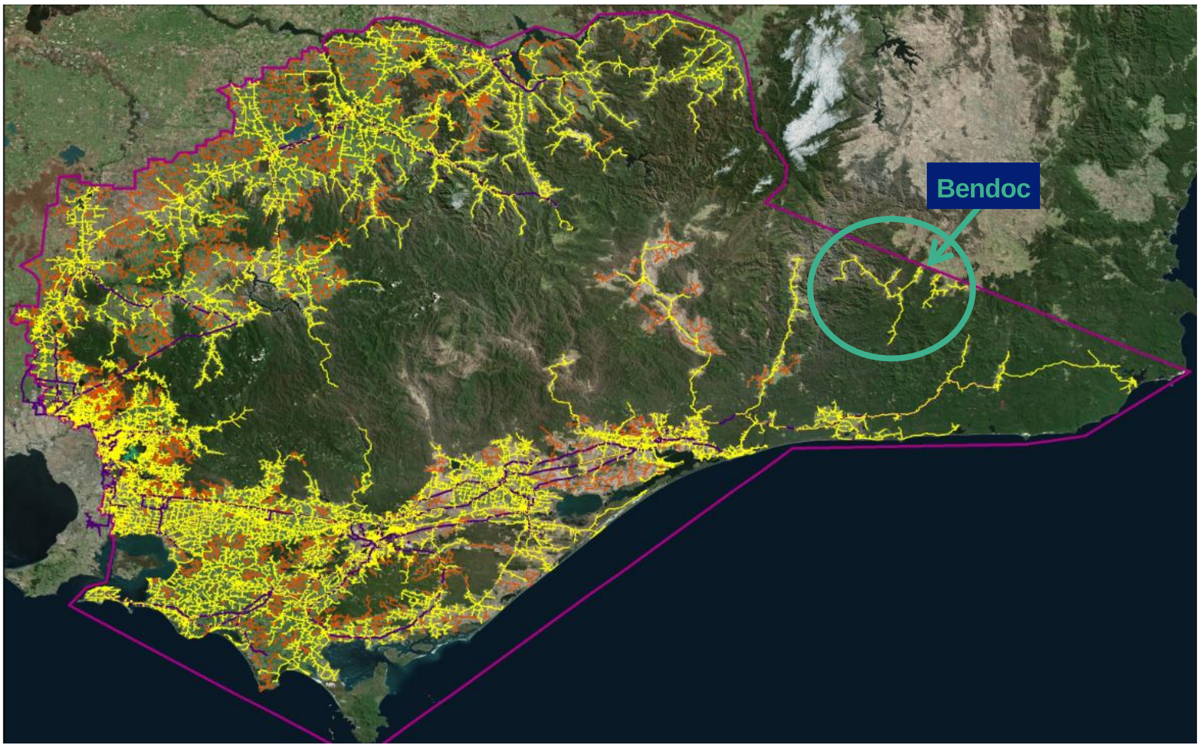
AusNet Services' electricity distribution network is made up of 45,000 kilometres of electricity lines, predominantly consisting of overhead network traversing rural areas, which have been built over a period spanning from the 1950's to the present.

AusNet Services' electricity distribution system consists of a 'sub-transmission' network operated at 66kV and a 'distribution' network operated at voltages of 22 kV, 12.7 kV, 11 kV, 6.6 kV and 240/415 V and 240/480 V. AusNet Services' distribution system contains:

- 53 66/22 kV zone substations;
- 61,000 distribution substations;
- 383,000 power poles; and
- 44,800 kilometres of underground cable and overhead lines.

In 2012, operational management of the Bendoc/Bonang area was transferred from Essential Energy to AusNet Services. Essential Energy and its predecessors operated the local network in the Bendoc/Bonang area since the early 1990s, under an arrangement established between the New South Wales and Victorian governments. With expiry of that agreement in 2012, electricity distribution assets in the region, as well as approximately 270 customers, were transferred to AusNet Services.

Figure 2.1: AusNet Services' electricity distribution network



Source: AusNet Services and Google Maps

Split by the Great Dividing Range, AusNet Services' network spans from the northern and eastern suburbs of Melbourne eastward to Mallacoota, and north to the Murray River, covering heavily forested and mountainous areas, as well as the low lying and coastal regions of Gippsland. This area includes alpine regions, rural areas, highly populated suburbs, forested areas with few customers and coastal areas that are subject to high winds and salt.

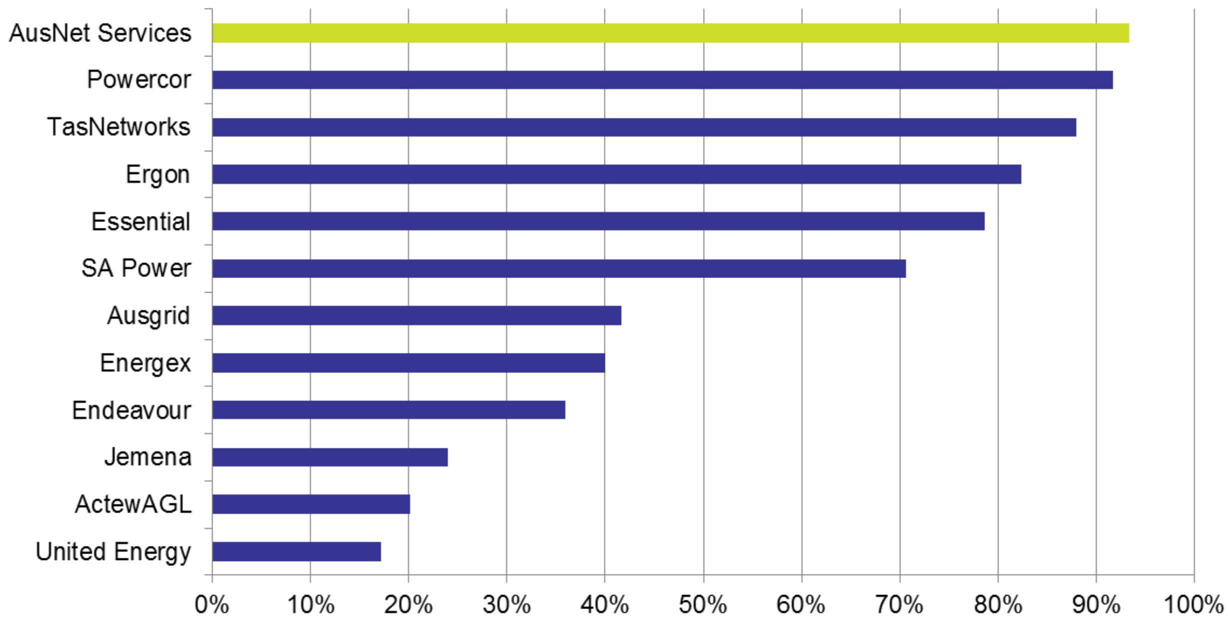
The physical and environmental attributes of AusNet Services' network area affect its performance and expenditure. The Great Dividing Range imposes a physical separation between AusNet Services' northern and eastern regions, reducing network operational flexibility, with the mountainous terrain also giving rise to higher vegetation management costs than in flatter regions. For example, service teams must be placed within close proximity to regional centres that are separated by the Great Dividing Range (e.g. Bairnsdale and Wadonga or Wangaratta), resulting in lower resource utilisation than other rural networks with less difficult terrain. Further, the heavily vegetated nature of parts of AusNet Services' network area means that vegetation related outages are the primary cause of supply interruptions during storms.

Generally, rural networks have higher expenditure per customer than urban networks. This is because of the combination of challenging terrain rural networks usually cover, and the low customer density of rural networks. The AER has recognised these factors in its annual benchmarking report:

> *"Network density will affect the benchmark performance depending on the benchmark applied. Low density networks such as predominantly rural distributors will have low costs per km of line length and high costs per customer. This is because the customers of a rural distributor are more dispersed than those of an urban distributor."*[1]

The below figure shows that over 90 per cent of AusNet Services' network (by line length km) is located in rural areas. More than 80 per cent of this is located in high bushfire risk areas (HBRA). The highly rural nature of AusNet Service' network should be taken into account when comparing its expenditure against other DNSPs.

Figure 2.2: Proportion of network in rural area (km line length) in 2013



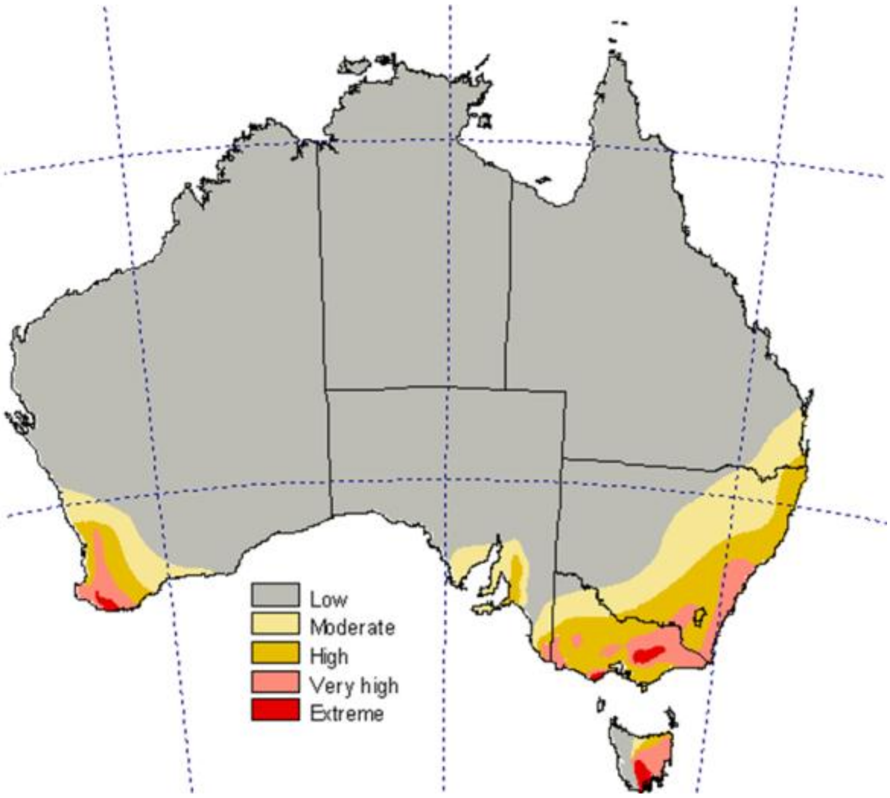
Source: AER RIN data. Reported by DNSPs as distribution line route length classified as short rural or long rural in km / total network line length.

[1] AER, *Electricity distribution network service providers – Annual benchmarking report*, p. 18.

2.1.1 Bushfire risk environment

The climate, terrain and vegetation of eastern Victoria contribute to the region's high level of bushfire risk. Accordingly, AusNet Services' service area is exposed to a particularly high level of bushfire risk, as evidenced by recent bushfire activity in the region, including the catastrophic 2009 Black Saturday bushfires. The below figure shows the high level of bushfire risk in eastern Victoria relative to other jurisdictions. The level of bushfire risk is defined as, for a given ignition source, the likelihood of a bushfire developing multiplied by the consequence of a bushfire in that area.

Figure 2.3: Bushfire risk in Australia



Source: Blong.R.J, Sinai.D and Packham c2000

Substantial communities have settled within eastern Victoria, including in areas which are considered to have an 'extreme' level of bushfire risk. This makes parts of AusNet Services' service area some of the world's worst areas for bushfires with the potential to cause catastrophic losses to life and property.

The evidence indicates that the impact of bushfires in terms of lives lost and buildings destroyed is significantly more pronounced in Victoria than in other Australian states and territories. The below table shows that between 1900 and 2009, there were 537 deaths as a result of bushfires in Victoria. This is more than twice the combined number of bushfire related deaths across the other jurisdictions, and demonstrates the catastrophic consequences bushfires have had in Victoria over the last century.

Table 2.1: Deaths as a result of bushfires by state, 1900 – 2009

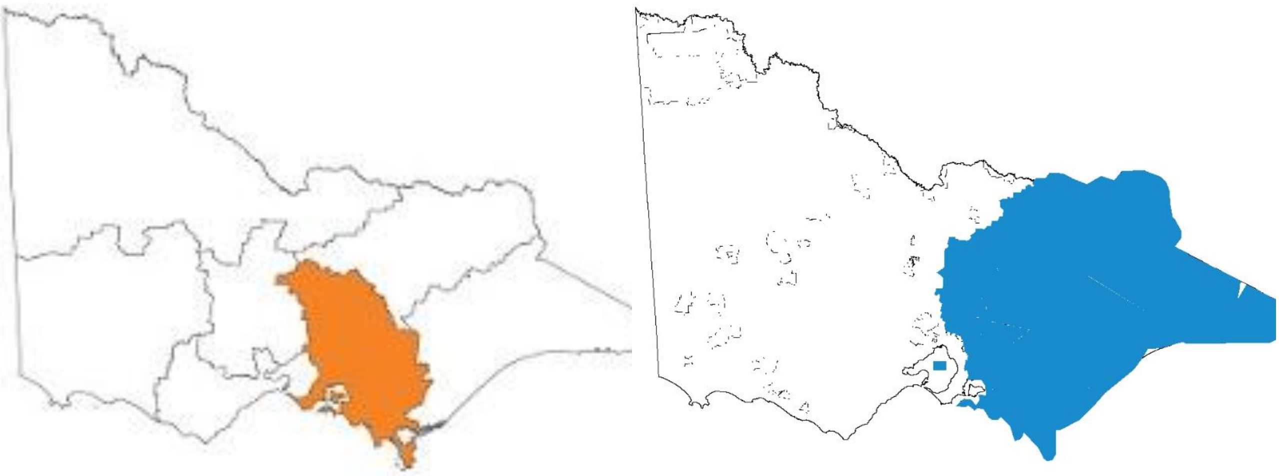
	ACT	NSW	QLD	SA	TAS	VIC
Deaths	9	105	17	46	64	537

Source: Aon, Insurance Premium Forecast – AusNet Services Electricity Distribution, April 2015, Appendix 3.

According to the Victorian Department of Primary Industries' (DEPI) *Strategic bushfire management plan* for the East Central bushfire risk landscape,[2] this region, most of which falls within AusNet Services' network area, accounts for 31 per cent of Victoria's total bushfire risk, despite comprising eight per cent of the state's land area.[3] This amount of risk is in addition to the bushfire risk in the other two regions falling within AusNet Services' network area (Alpine and North East and Alpine and Greater Gippsland), which is yet to be published by DEPI. The below figure demonstrates that the East Central region lies predominantly within AusNet Services' network area.

Figure 2.4: Comparison of East Central region and AusNet Services' network area

East Central bushfire risk landscape ***AusNet Services' network area***



Source: DEPI, Strategic bushfire management plan – East Central bushfire risk landscape, October 2014; AusNet Services.

Of Victoria's seven bushfire risk landscapes, the East Central region has the most risk, with over half the bushfire fatalities in Victoria since European settlement having occurred within this area. This is a result of the high population density within the area – in 2011, 59 per cent of Victoria's population lived within this region – much of which is settled close to forests and grasslands, containing some of the most flammable types of vegetation on earth.[4]

The following table shows major bushfires within the East Central region since 1851. According to DEPI, "the potential for similar bushfires exists, and will continue to exist into the future."[5]

2 The East Central bushfire risk landscape extends north and east of Melbourne, from the High Country around Lake Eildon, south-east to the Latrobe Valley and south to Wilsons Promontory. It includes the Yarra Valley, Dandenong Ranges, Thomson and Upper Yarra Catchments, Mount Baw Baw and the Mornington Peninsula.

3 DEPI, Strategic bushfire management plan - East Central bushfire risk landscape, October 2014, p.10.

4 Ibid.

5 Ibid.

Table 2.2: Major Bushfires in East Central since 1851

Year	Location	Size (ha)	Losses
2014	Warrandyte, Darraweit Guim, Hernes Oak	41,000+	40+ houses
2009	Kilmore East, Churchill, Kinglake, Marysville, Yarra Valley, Dandenong Ranges, Narre Warren, Upper Ferntree Gully, Wilsons Promontory, Bunyip State Park, Delburn (Black Saturday)	232,000	173 people 2,007 houses
2006-07	Walhalla (Great Divide bushfire)	1,048,238	1 person 51 houses
2005-06	Yea, Moondarra, Kinglake	25,000	4 people
1997	Dandenong Ranges, Arthurs Seat	569	3 people, 41 houses
1983	Belgrave South, Cockatoo, Beaconsfield Upper (Ash Wednesday)	93,500	47 people 2,000 houses or other buildings
1968	The Basin, Upwey	1,920	53 houses 10 other buildings
1962	The Basin, Christmas Hills, Kinglake, St Andrews, Hurstbridge, Warrandyte, Mitcham	30,321	32 people 450 houses
1944	Yallourn, Morwell, Traralgon	Unknown	9 people 136 houses
1944	Beaumaris	Unknown	63 houses
1942	South Gippsland	Unknown	1 person 20 houses
1939	Noojee, Warrandyte, Yarra Glen, Warburton, Erica (Black Friday)	2,000,000	71 people 650 houses
1926	Warburton, Noojee, Kinglake, Erica, Dandenong Ranges	Unknown	31 people
1898	South Gippsland	260,000	12 people 2,000 buildings
1851	Dandenong Ranges (Black Thursday)	Unknown	12 people

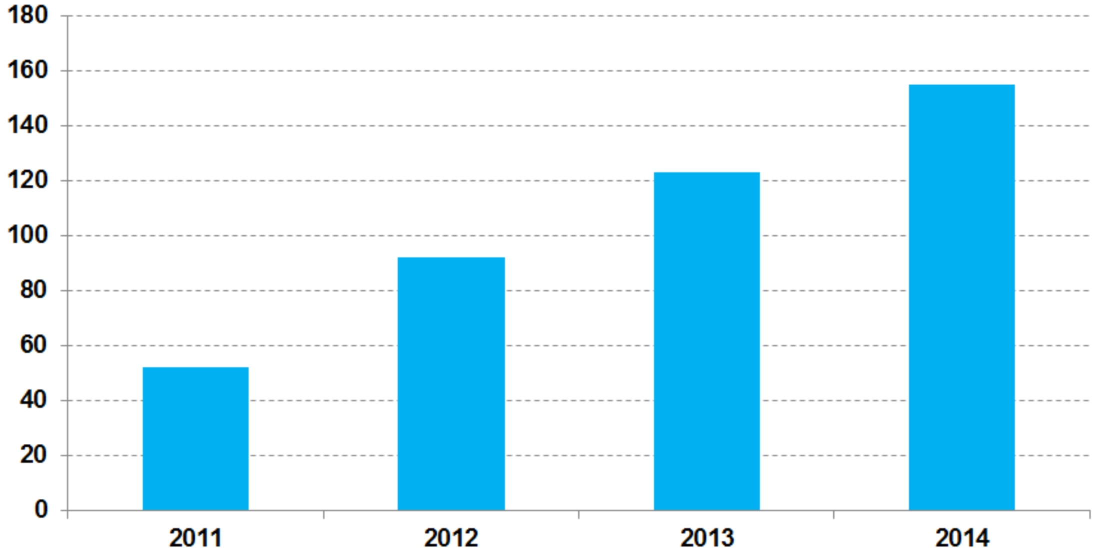
Source: DEPI, Strategic bushfire management plan – East Central bushfire risk landscape, October 2014, p.12.

2.1.2 Managing a network in an extreme bushfire risk area

The unique level of bushfire risk AusNet Services' network area is exposed to requires significant capital investment to manage and reduce the risk of bushfire ignition from the electricity network. Particularly, following the devastating Black Saturday bushfires of 2009, Victoria has reassessed both the consequences of bushfire and the way in manages that risk. For electricity networks, this has meant a step change in investment to drive down the risk of bushfire from the electricity distribution network, including substantial investment to replace powerlines following the recommendations of the 2009 Victorian Bushfire Royal Commission (VBRC).

Between 2011 and 2015, AusNet Services' operating and capital expenditure on bushfire related costs is forecast at around 19 per cent of total expenditure. The below chart, which shows AusNet Services' actual safety capital expenditure from 2011 to 2014, demonstrates the substantial expenditure that has been invested to date to address the recommendations of the VBRC.

Figure 2.5: Historical safety capital expenditure ($m, real 2015)



Source: AusNet Services

Note: Small amounts of expenditure in this category are for non-bushfire safety related projects.

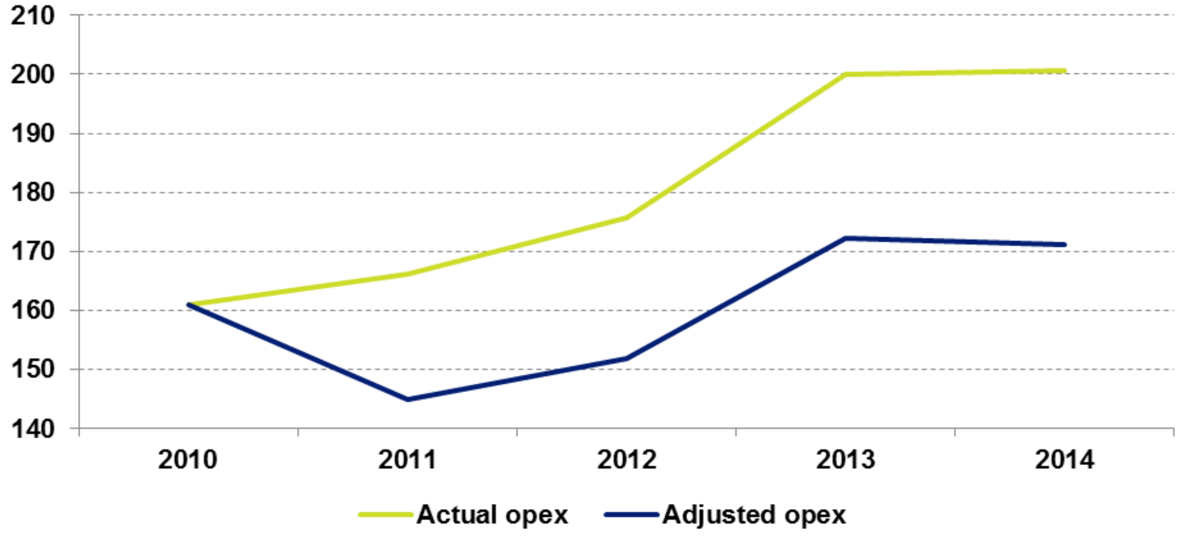
Safety has also had a significant impact on operating expenditure. Vegetation management step changes to comply with vegetation management and inspection obligations following Black Saturday accounted for $72 million, or around ten per cent, of AusNet Services' opex between 2011 and 2014, demonstrating the impact of safety on AusNet Services' opex.

Bushfire liability insurance, which forms a central part of AusNet Services' risk management strategy, also accounts for a significant proportion of operating expenditure. In 2014, insurance premiums of $10 million (real 2015) accounted for more than five per cent of total opex.

Commensurate with the level of bushfire risk of its service area (as assessed by Aon), AusNet Services has the highest bushfire liability insurance limit of any utility in Australia. Coupled with the market's response to the Black Saturday bushfires, obtaining this limit has driven substantial increases to AusNet Services' insurance costs since 2009.

The figure below compares AusNet Services' actual opex between 2010 and 2014 with opex adjusted to remove expenditures associated with bushfire safety (including cost increases caused by changes in vegetation management obligations, growth in insurance premiums and implementation of the VBRC recommendations). These costs accounted for approximately $102 million between 2010 and 2014, or 11 per cent of total opex. In the absence of these costs, opex would have increased at an average annual growth rate of 1.5 per cent over this period, compared with an actual growth rate of 5.5 per cent.

Figure 2.6: Actual opex against opex excluding bushfire-related expenditure ($m, real 2015)



Source: AusNet Services

Note: Includes debt raising costs; excludes movements in provisions and Bairnsdale Power Station costs.

As well as materially impacting its expenditure, bushfire risk also affects the service levels AusNet Services is able to deliver. For example, AusNet Services has the highest level of planned outages in the NEM, which is largely due to the need to carry out safety works.

Importantly, as detailed in Chapter 7 Capital Expenditure, the safety programs are delivering measurable reductions in bushfire risk. Details of AusNet Services' forecast safety expenditures are provided in Chapter 7, Chapter 8 (Operating and Maintenance Expenditure) and Chapter 11 (Cost Pass Through).

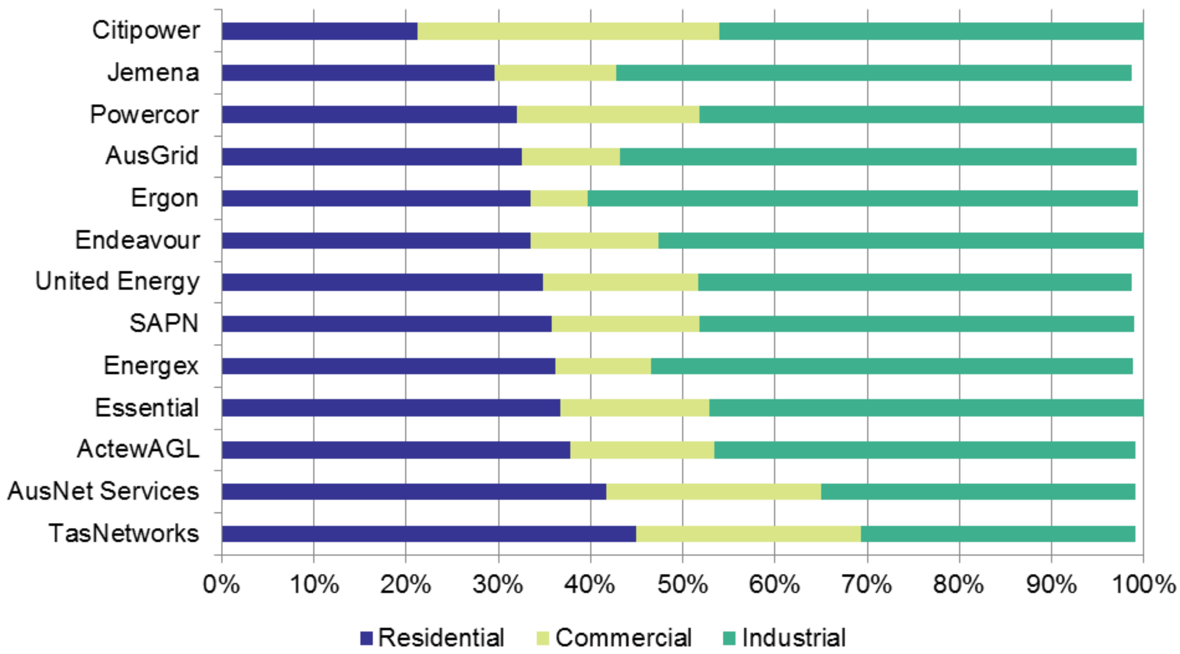
2.2 Customer Demographics

AusNet Services' distribution network provides access to electricity for an estimated 605,000 households and 75,000 businesses. On the northern and eastern fringes of Melbourne, the network services highly populated suburbs including through the heavily vegetated Dandenong Ranges, as well as the densely populated growth corridors including South Morang and Pakenham.

While the network spans an area of over 80,000 square kilometres, the majority of customers are located in suburban Melbourne or in regional centres and towns, meaning the majority of the network services a very low density of customers.

AusNet Services has among the highest residential proportion of its customer base in Australia, with approximately 90% of its customers classified as residential. When examining residential load as a proportion of total load, AusNet Services has the second highest in the NEM.

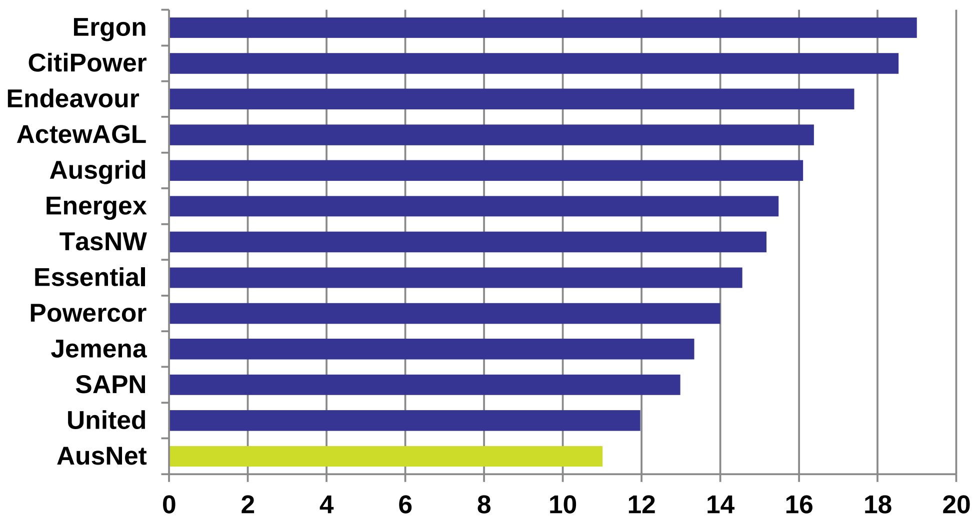
Figure 2.7: 2013 residential energy consumption as % of total consumption



Source: AER RIN data. Commercial load based on "energy delivered to non-residential customers not on demand tariffs" and industrial load based on "energy delivered to non-residential customers on high and low voltage demand tariffs."

While AusNet Services has been affected by the same changes to customer energy consumption behaviour as elsewhere in Australia – including suppressed economic conditions, increasing household and commercial energy efficiency and the increased take up of solar – its highly residential customer base has important implications for the way these changes have affected the business. For example, the high residential proportion of customers has amplified the reductions in electricity consumption caused by energy efficient housing and appliances. This has contributed to AusNet Services having the lowest energy consumption per customer in the NEM.[6]

Figure 2.8: Comparison of NEM DNSPs' 2013 energy delivered (MWh) per customer



Source: AER RIN data

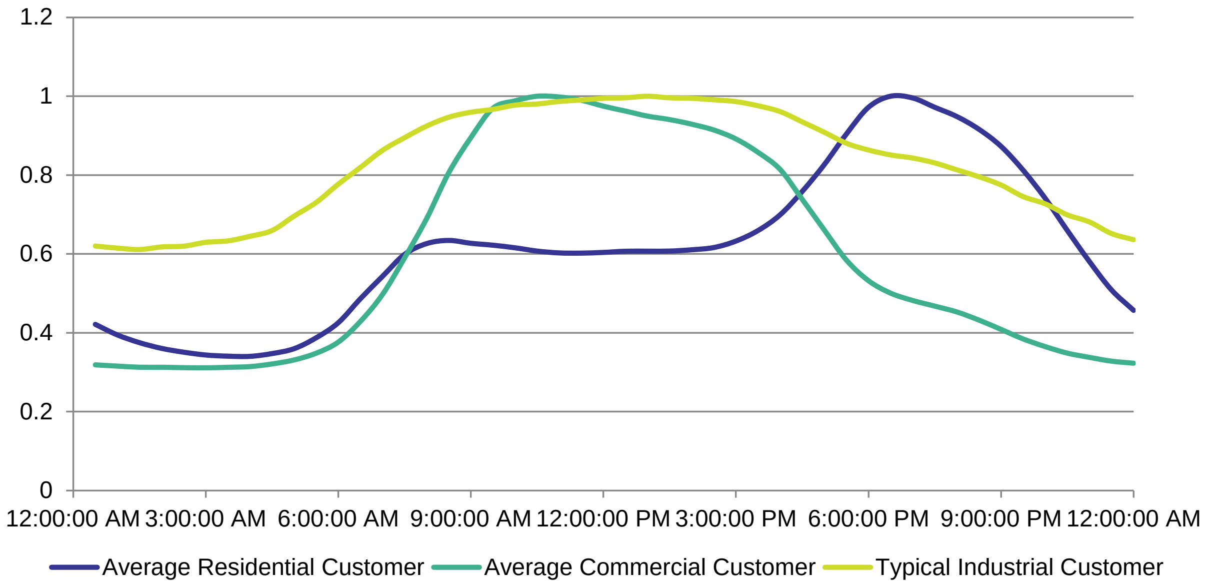
[6] See AER, *Electricity DNSPs 2014 Annual Benchmarking Report*, p. 27.

The largely residential customer base has also meant that energy use is peaky, driven by air-conditioning use, meaning that AusNet Services has needed to ensure the network can meet maximum demand which only occurs on a few days of the year. While industrial load is more often flat and supported by back up generation, residential load is highly peaky and largely exclusively reliant on network supply or solar.

However, AusNet Services' peak demand occurs in the evening, reflecting the commuting times of residents of outer metropolitan Melbourne. Consequently, while there are 80,000 customers with solar connections, the timing of the network peak means that on AusNet Services' network, solar energy is reducing overall energy delivered but not peak demand.

The following figure shows how the demand profile of residential customers is highly peaky compared to that of commercial and industrial customers, which results in the network capacity AusNet Services provides not being used to as large an extent as it would if it served a flatter load profile.

Figure 2.9: Typical demand profiles of AusNet Services' customers over 24 hours



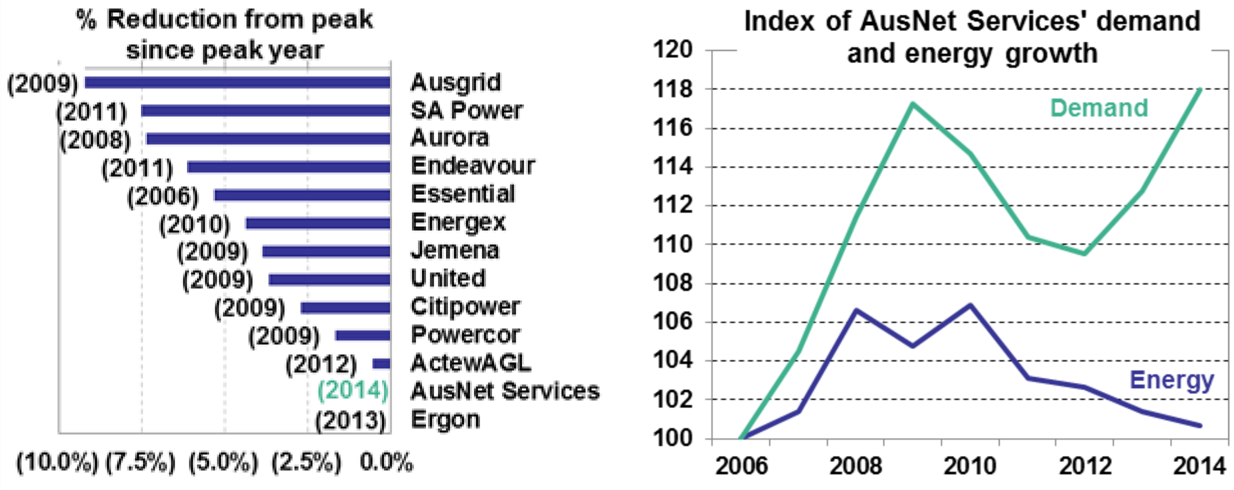
Source: AusNet Services, 2014 data

Note: The vertical axis shows an index of demand, with the value of 1 representing peak demand for each typical customer.

The aforementioned demographic factors have resulted in continued growth in the network's peak energy demand even as energy consumption has stagnated, requiring ongoing capex investment to augment or expand the network. However, a highly residential customer base also provides opportunities to deploy broad-based residential demand management programs that have the potential to slow the long-term rate of asset augmentation investment, creating long-term benefits for consumers through lower prices. AusNet Services' proposed broad-based demand management programs are discussed in Chapter 9 Demand Management.

The following figure shows the year of each DNSP's highest historical level of peak demand – 2014 for AusNet Services – and AusNet Services' historical growth in peak demand and energy.

Figure 2.10: Timing of highest peak demand and AusNet Services' historical energy and demand growth



Source: AusNet Services and AER 2014 Economic Benchmarking RIN data

As well as impacting a network's peak demand and thus augmentation expenditure, customer demographics have important implications for operating expenditure. For example, because the guaranteed service levels (GSL) scheme applies to residential customers, all else equal, DNSPs with high proportions of residential customers incur relatively high levels of GSL payments.

Residential customers typically generate higher levels of customer call centre activity (e.g. responding to customer enquiries and complaints) than industrial or commercial customers, driving up customer service staff costs, particularly during low reliability events.

Further, residential customers tend to be more geographically dispersed than industrial and commercial customers, which tend to be more centralised (e.g. in industrial estates). DNSPs with denser customer bases typically have lower per customer costs.

2.3 Supporting Documents

The following documentation is provided in support of this chapter:

- Appendix 2A – Strategic bushfire management plan - East Central bushfire risk landscape; and
- Historical Changes to Bushfire Safety Obligations in Victoria.

3. Customer Engagement

3.1 Overview

3.1.1 Introduction

While customer engagement has always been part of the electricity distribution price review (EDPR) process in Victoria, it was limited in nature, often occurring at the end of the process. This was largely due to industry perceptions that the complexity of issues to be reviewed in the process, posed a significant barrier to meaningful engagement with the average customer. This situation was compounded by generally low levels of interest from customers.

During the current regulatory period, a series of developments has led to a paradigm shift in the way network service providers (NSP) view their customers. Traditionally, NSPs would demonstrate that customer needs were being served through meeting customer service performance metrics. What has emerged in recent years is a growing need for NSPs to build direct relationships with end-user customers, rather than relying on other parties, such as retailers, to manage those relationships.

AusNet Services has recognised that in order to be sustainable as a business, there is a need to undertake broader customer engagement. This will enable the business to understand customer views and concerns, and to develop plans that address them. Since 2013, AusNet Services has significantly increased the level and extent of customer engagement undertaken as part of, and beyond, the review process.

3.1.2 Chapter structure

This chapter describes how AusNet Services has engaged with customers, and how the findings from those engagement activities have been reflected in this Proposal and future plans.

In particular:

- Section 3.2 explains AusNet Services' approach and objectives of customer engagement;
- Section 3.3 describes the range of engagement activities undertaken;
- Section 3.4 summarises the findings of customer engagement;
- Section 3.5 outlines AusNet Services' commitment to ongoing improvement of customer engagement in future; and
- Finally, Section 3.6 lists the support material for the chapter.

3.1.3 Definition of 'customers'

The terms 'consumer' and 'customer' are often used interchangeably and in the same context. This is recognised in the AER's guideline, which consistent with the Rules, specifically refers to 'consumers'. The term 'consumer' is defined as 'end-user'.

For this Proposal, AusNet Services has adopted the term 'customers' in lieu of 'consumers'. In AusNet Services' view, the term 'customer' implies a broader meaning than 'consumer'. A consumer can be interpreted as any person or entity that only consumes energy supplied by AusNet Services' distribution network. However, increasingly AusNet Services' customers are also active participants in the energy supply chain, often supplying energy back in to the grid.

3.2 Customer Engagement Approach

AusNet Services' approach to broader customer engagement was developed based on:

- Commencing a program of customer engagement within the review process that could ultimately be embedded to enhance business-as-usual (BAU) engagement across all business operations;
- A realistic assessment of the maturity of the business in this area; and
- The requirements of the Rules and the AER's guideline.

3.2.1 Objectives of customer engagement

To achieve the overarching aim of establishing ongoing customer engagement, the primary objectives within the review process were to:

- Build enhanced customer understanding of AusNet Services, its obligations, network issues and trade-offs;
- Increase AusNet Services' understanding of consumers' views and preferences on electricity supply;
- Build long term, trust-based relationships with customers and key stakeholders;
- Align the regulatory proposal with customer preferences where possible and, where this has not been possible, explain why this is the case; and
- Establish processes to incorporate consideration of customers' views to improve delivery of a safe, reliable and efficient distribution network.

3.2.2 Internal capability assessment

AusNet Services has a solid history of customer and local community engagement as part of planning and construction of major capital projects. The engagement approach adopted for these projects is based on best practice community engagement principles as set out in the *International Association of Public Participation* (IAP2) engagement spectrum.

In these cases, the engagement process is well-defined and understood, and stakeholders are highly engaged as they are directly impacted by the project.

By comparison, outside of day-to-day operational responses such as communication related to emergencies, outages, new connections and customer complaints, AusNet Services has had limited experience of direct engagement with its broader customer base. Developing and implementing a robust strategy and approach in this area will take time.

Based on AusNet Services' own experience and insights from industry forums, it is clear that broader customer engagement across the energy industry is challenging and engagement levels are low. What is still unclear is what constitutes best practice in the execution of high-level principles of customer engagement specifically for NSPs. AusNet Services believes that this can be established through a trial-and-error approach at an individual business level, with learnings shared across the industry.

Given the level of maturity of the business and the industry in undertaking broader customer engagement, it was deemed more effective and financially prudent to gain actual experience in this area, before attempting to develop detailed long term strategies and policies.

As a result, AusNet Services has adopted a realistic and pragmatic approach to customer engagement. This approach was centred on devoting resources and effort to establishing a relationship with end-user customers and their advocates, and building internal capability through practical experience of customer consultation.

AusNet Services strongly believes that high-level strategies and policy will be better informed after completing this first comprehensive program of broader customer engagement as part of the current review process.

AusNet Services recognises that its customer engagement practices are still developing and that the timeframe for embedding broader customer engagement in the business will continue beyond the current price review. It is, however, committed to building capacity and capability over time to engage effectively with customers more broadly as part of BAU operations.

To this end, the business has been mindful of the need to provide value for money in its engagement processes. In developing this proposal, AusNet Services has not included any step-up in expenditure as a consequence of delivering better customer engagement. A conscious decision was made to minimise the use of external consultants, except where independence was essential or where the expertise could not be developed within the limited timeframe of the review process.

3.2.3 Requirements of the Rules and the AER

Following the substantial changes to the National Electricity Rules (NER) in 2012, provisions now explicitly require network businesses to engage with consumers as part of, and beyond, the regulatory determination process.

In accordance with the changes to the NER in December 2012, AusNet Services has provided an outline of how it has engaged with its customers and sought to address any relevant concerns identified through this engagement in the overview paper provided with this regulatory proposal.

In November 2013, as part of its better regulation reform program, the AER published a *Consumer Engagement Guideline*. This does not have a binding status under the NER but identifies clear expectations in relation to consumer engagement.

This guideline includes an expectation that consumer consultation is an ongoing BAU practice. The AER describes the Guideline as providing ‘a high level framework to integrate consumer engagement into [network businesses’] business-as-usual operations’.

In developing a customer engagement approach for the current review process, AusNet Services has adopted the AER’s best practice Consumer Engagement Principles:

- *Clear, accurate and timely communication* – set timelines and provide info that is simple to understand.
- *Accessible and inclusive* – engagement not just for submission proposal; educate customers to overcome complexity hindering engagement.
- *Transparent* – manage expectations; explain how consumer views will be used; report consumer views both positive and negative.
- *Measureable* – establish KPIs (qualitative and quantitative); measure performance against KPIs; report performance.

For the purposes of this review process and in the absence of a broader customer engagement framework, AusNet Services has also adopted the IAP2 engagement spectrum. This framework was referred to in the AER’s Guideline, and as previously mentioned, already used by AusNet Services to consult with customers and local community on major capital projects. This framework identifies that there are a range of levels on which consumers’ views can be sought, and they do not always result in subsequent plans reflecting customers’ views.

Due to the regulatory and licence obligations AusNet Services must meet when providing its services, and the highly technical nature of the activities for which the business is funded through its revenue cap, it was expected that most aspects of the regulatory proposal would fall into the ‘Inform’ or ‘Consult’ category. Accordingly, AusNet Services has been mindful of managing customer expectations around how much impact their views can have on the proposal. Nonetheless, customers views have genuinely been sought and recorded and, where possible, have shaped the manner in which AusNet Services balances the competing objectives of the NEO as part of its long-term planning.

3.3 Engagement Activities

AusNet Services engages directly or indirectly in many forms of company initiated and industry driven customer engagement. These can be grouped into three broad areas:

- Business as usual (BAU) interaction with customers, including planning meetings, connection enquiries, outage planning and metering;
- Price review specific engagement focused on gaining direct customer feedback during the development of the proposal; and
- Industry processes which establish specific customer information used by the distributors in planning their network and operations. For example, the AEMO value of customer reliability study or Electricity and Water Ombudsman Victoria (EWOV) customer complaints data.

These are discussed in detail in the following sections.

3.3.1 BAU customer engagement

Typical engagement activities undertaken with customers in planning and operating the network have been summarised in the table below.

Table 3.1: BAU engagement activities

Type	Description of Activity
Coalface Engagement	
Planned interruptions notification and planning	To reduce the impact of these interruptions on our customers AusNet Services: • Plans interruptions approximately 2 weeks in advance and provides notifications to impacted customers with no less than 4 days' notice; • Proactively contacts customers using life support equipment to ensure adequate preparations, including contingency plans are in place, on top of written notification; • Takes into account essential services, medical and aged care, schools, large customers with sensitive loads and consults with chambers of commerce and local councils; • Provides additional explanations to the standard notifications and a dedicated 24/7 interruption hotline; and • Notifies customers who have registered their mobile numbers to receive SMS notifications.
Fault response	During emergencies such as significant wind storms or heat related events, AusNet Services: • Reviews priority of faults based on danger and impact to customer and community; • Provides updates on the status of faults through the website and media responses, and responding to customer calls with estimated time of restorations; and • Coordinates with the local CFA, the MFB, Police, the SES and other emergency services that are involved in the response.

New connections	In managing the connection process under Guideline 14, AusNet Services: • Provides customers with costings and explanations of different connection options; • Manages tender processes on the customer's behalf; and • Helps with coordination of connections, including setting up and managing pioneer schemes where appropriate.
Customer complaints	AusNet Services attempts to resolve all customer complaints in first instance, as quickly as possible through the operational teams that are directly responsible. Where complaints are escalated, AusNet Services has a dedicated team accountable that proactively manages these to understand and identify possible systemic issues. As part of this process, AusNet Services monitors trends, analyses EWOV customer complaints data and reports internally on these. Importantly, where a systemic issue exists, AusNet Service identifies opportunities to prevent future complaints of the same nature. For example, during 2015, several internal reviews were undertaken to improve how AusNet Services coordinates, executes and communicates its planned outages for maintenance and projects. As a result, total customer complaints across every category decreased 11.6% between April and December 2014, compared to the same period in 2013. In particular, during the same period specific customer complaints on being 'inconvenienced' by planned outages and 'no notification' also decreased, 29 and 40 per cent, respectively.
Large Augmentation/ Replacement Projects	Planning staff and regional community liaison managers regularly meet and communicate with customers to identify network issues or changes in supply requirements. This ensures customer plans and opportunities to address supply issues are well integrated in network planning.
Local Reliability Issues	Planning staff meet with affected customers on identified network issues to explore potential solutions, including network investment and non-network alternatives.
Demand Management Contracts	AusNet Services manages one of Australia's most progressive commercial and industrial customer demand response programs. During 2014/15 alone, AusNet Services engaged with 42 commercial and industrial customers across its franchise area. This work included presentations to multiple staff at customer sites. As a result, AusNet Services successfully contracted with 17 of these customers, encompassing 32 individual sites, and making up 21MW of total network support.

Example of community consultation: Mallacoota case study

Mallacoota, located in far eastern Victoria, is an example of a town with localised reliability issues. These are primarily related to flora and fauna impacts (e.g., the large local bat population) along the highly vegetated and remote sections of power line between Bairnsdale and Mallacoota. This region is also susceptible to bushfire and flooding and these can cause extended power outages. As the power line is serviced by AusNet Services' Bairnsdale depot, it can take repair crews several hours to reach some sections. Being a radial line rather than a loop, power cannot be re-routed to residents during an outage.

In 2011, AusNet Services embarked on a project with the Mallacoota community, in response to their concerns about reliability levels. This project involved community consultation, a comprehensive analysis of reliability performance and identification of solutions.

In the consultation phase, AusNet Services undertook a series of meetings with the community and the East Gippsland Shire Council, and set up communication channels that included regular newsletter updates.

The reliability performance analysis identified a number of opportunities to reduce the impact of short duration outages through network-based solutions. These were subsequently initiated by AusNet Services and included animal-proofing in specific locations, a trial of bark-catchers to reduce bark initiated faults and network control improvements. To address longer duration outages, a site was prepared in Mallacoota to allow fast connection of emergency backup generation.

Recognising that there is a limit to how far network reliability can be improved cost effectively, AusNet Services also developed the concept of a mini-grid in conjunction with the local community. Powering Mallacoota from local generation via a mini-grid would allow the town to maintain supply in "islanded" mode during major outages of network supply. The community also expressed a desire for local and environmentally sustainable energy supplies.

A preliminary feasibility study for a sustainable energy solution was commenced as a collaboration between the local community, East Gippsland Shire Council and AusNet Services. The results of the study form the basis of further investigations in reliability improvement. These include the possible development of biogas production capability at the local sewerage plant. This could potentially be used to power a backup generator to supply the Mallacoota township.

3.3.2 EDPR specific engagement activities

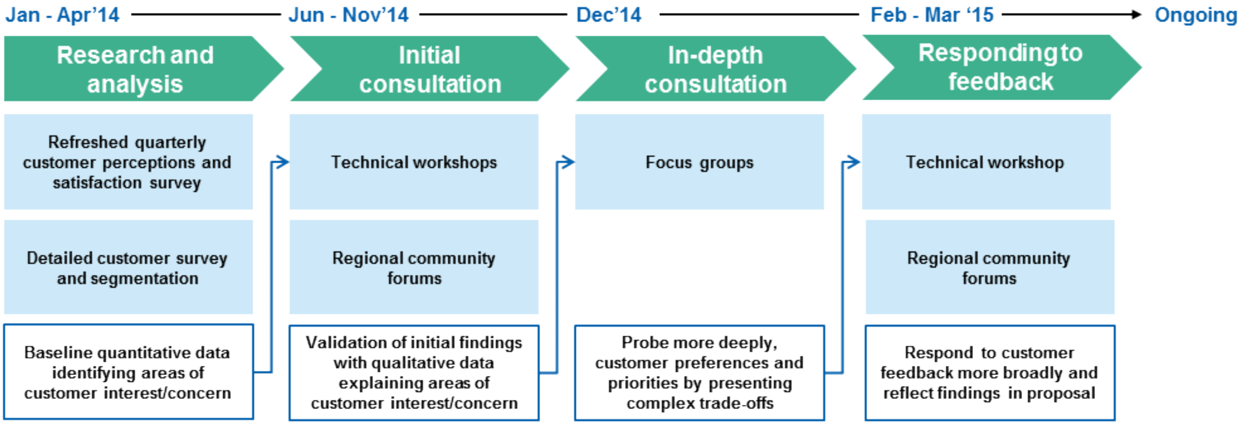
A summary of EDPR specific customer engagement activities undertaken is outlined in the figure and table below.

This program was designed to allow for a process of continuous improvement. The key learnings from each stage of the program were used to inform the development of the priorities for discussion and consultation with customers at the next stage.[1]

In addition to this program, the website was updated to enhance its capacity as a communication tool for the EDPR process. This change made complex information about the process and the issues of importance to the review readily available and more accessible to the broader customer base. Findings from the customer engagement process were also published on the website.

[1] It should be noted that despite significant but efficient promotion of each event, and scheduling events at times and locations considered likely to be most convenient for many, relatively few numbers of customers attended.

Figure 3.1: Summary of EDPR customer engagement program



A more detailed summary of the above activities is documented in the table below.

Table 3.2: EDPR specific engagement activities

1. Research and Analysis

Overview

AusNet Services commenced its customer engagement program with a review of existing customer research.

Activities

Detailed review of findings from the following research:

- Quarterly benchmarking survey, referred to as AusNet Services' Quarterly Electricity Monitor (QEM) Benchmark Survey. This survey was conducted by Wallis Market and Social Research and involved computer assisted telephone interviewing, with a quota of 400 interviews per quarter (85% residential/farm, 15% business) to measure and understand general sentiment towards and perceptions of AusNet Services and satisfaction with service delivery, and also explored current topics of interest to the company (e.g., preferred communication channels and uptake of new energy technology).
- Detailed customer survey and segmentation undertaken by Deloitte and Nature Customer Research completed in March 2014. This comprised telephone interviews of 2,358 customers (in broadly two groups, residential and SME) gauging customers' perceptions of AusNet Services' and preferences to current and future service offerings. Separately, customer segmentation was undertaken based on a survey of ~2,000 residential customers and ~700 small businesses.

Findings

- Identified a general lack of awareness about AusNet Services.
- Highlighted four areas of customer interest/concern:
  - Energy forecasting and tariffs;
  - Network safety and bushfire management;
  - Reliability and planned outages; and
  - Demand management and alternative technologies.

Outcomes

- Identified customer engagement activities targeting two types of customer groups:
  - end-user customers, being residential customers and small to medium business owners; and
  - customer advocate groups representing diverse interests, such as industrial and commercial customers, environmental groups, disadvantaged customers and alternative energy technologies.
- A focus on customer advocate groups was considered the most effective way to gauge the views and preferences of broader groups of customers who were otherwise difficult to reach, e.g., vulnerable customers and industrial and commercial customers.
- As industrial and commercial customers were considered able to adequately represent their own interests, less focus was placed on tailoring a specific engagement activity for this group. Rather, efforts were directed towards meeting with larger individual customers, particularly where network augmentation was being undertaken or planned.

2. Initial Consultation

Overview

To cater for differing information needs, AusNet Services opted for a mix of community forums and technical workshops.

- Community forums allowed any customer to discuss the aspects of electricity that mattered to them.
- Technical workshops addressed specific aspects of electricity distribution in more detail and were intended for specialised audiences such as industry, environmental and vulnerable customer advocacy groups.

Activities

Regional community forums

- Four forums were held over July to September 2014 in Pakenham, South Morang, Seymour and Warragul.
- A total of 63 customers attended across the four forums, representing smaller customers in both urban and regional areas of the network.
- Primary objectives of these forums were to:
  - build understanding about role and services provided by AusNet Services;
  - facilitate customer engagement in the review process; and
  - gauge customers' views and preferences.

Technical workshops	• A series of four workshops were held over June to August 2014 targeting bodies and organisations representing AusNet Services' key customer groups. • A total of 59 participants were involved across the four workshops, representing diverse interests, including customers working in farming, agriculture or dairy, vulnerable customers, environmental groups and government. • Expert insights were shared and tested on the four key themes identified in the initial consultation as being of most interest to customers. • These workshops allowed information on key issues to the review, many of them complex, to be imparted in an accessible manner and aimed to assist external parties to engage in the price review process.
Outcomes	• Initiated establishment of relationships with customers, local community groups and their advocates, with the potential to build a network for ongoing customer engagement. • Identified opportunities to improve customer engagement across all operations in the business. These findings were a key input into a broader process to develop a detailed customer engagement roadmap, which outlines actions over the next three years to address any relevant concerns and feedback identified as a result of engagement activities. • Due to the timing of the initial engagement activities being prior to availability of preliminary expenditure forecasts, customer preferences' with respect to expenditure trade-offs were not explicitly been gauged. Instead, activities largely reflected more general discussions of challenges, issues, historical trends and drivers. A key learning from this process was that a different method was required to explore customer preferences in more depth. • As part of the Technical Workshop series, there was an intention to engage with the industrial and commercial customers through peak bodies, including EUAA and AIG. Due to resource constraints and competing demands, representatives from these bodies were unable to attend the workshops or meet one-one one. It is understood that these bodies were heavily focused on NSW Price Reviews and the issue of rising gas prices. As a result, AusNet Services' sought to directly engage with individual industrial and commercial customer group as part of BAU activities.

3. In-depth Consultation

Overview

In recognising the limitations of the initial consultation work, AusNet Services commissioned Colmar Brunton to conduct a series of eight independently facilitated focus groups.

Activities

- During December 2015, a total of 58 AusNet Services' customers participated in focus groups held in Chadstone, Traralgon and Benalla, with these locations selected to ensure an even mix of Melbourne Metropolitan and Regional customers. Participants of the Chadstone based focus groups reflected a mix of customers from Dandenong, South Morang, Cranbourne, Pakenham and surrounding areas.
- The primary objective of these focus groups was to probe more deeply customer preferences and priorities in a forum that allowed complex trade-offs involved in network decisions and impacts, particularly costs, to be presented.
- Customer focus group discussions were selected due to the ability to deliver complex technical information in a manner that could be clearly understood by participants. It ensured a two way dialogue with opportunities to respond to, and clarify key discussion topics.
- The allocation of focus groups was structured by age, with focus groups held among customers aged 18-34 and customers aged 35+, with a representative mix of gender, bill size, income, children/no children. Further to this, Benalla and Traralgon focus groups each included 2-3 participants that worked in farming, agriculture or dairy.

Outcomes	• Five consistent and universal expectations of AusNet Services as an electricity distributor emerged. - **Expectation 1: Ensure reliable, uninterrupted supply of electricity to all customers.** Customers view reliable supply of electricity to their homes as a basic, core expectation. Whilst there is acceptance that the occasional short, planned outage is acceptable, customers anticipate and expect current reliability levels to be maintained, or slightly improved but not reduced. - **Expectation 2: Zero contribution to fire or safety related issues** Customers expect AusNet Services to place a full and thorough focus on safety, with the benchmark being prevention rather than minimisation. There is a universal expectation that appropriate maintenance and inspection programs be in place, and asset upgrades be implemented where ageing assets have the potential to contribute to fire or safety related risks. - **Expectation 3: Reasonable contribution to electricity costs** Whilst customers understand the need for reliability and safety to be maintained, and place a high importance on these areas, there is also a core expectation that efficiencies be put in place to minimise upward pressure on electricity bills. - **Expectation 4: Efficient, well planned investment and expenditure** Customers expect AusNet Services to be fully engaged in forward planning, to identify and put in place asset, infrastructure and network upgrades that create mid and longer term efficiencies. There is a clear view that investment should be spread and planned over time, so as to minimise instances where large scale investment (contributing to spikes in distribution costs) is required in any short period of time. - **Expectation 5: Proactive approach, with high levels of responsiveness when required** There is an expectation that AusNet Services act proactively when planning network infrastructure requirements, rather than reactively, and act with high levels of speed and responsiveness when issues emerge. • These expectations were used to confirm or question initial internal proposals and plans.

4. Responding to Feedback

Overview

AusNet Services held follow-up sessions with participants of the regional community forums and Technical Workshops to present the regulatory proposal itself, including specific projects, programs, expenditure levels and price impacts.

Activities

- During February to March 2015, four regional community forums were held in the same locations as those visited during the initial consultation. Whilst a total of 94 customers registered for these events, only 59 customers attended on the day. It was interesting to note that despite adopting different methods to promote the forums and encourage attendance, customer engagement was still low.
- A follow-up session with customer advocates was held on 16 February 2015. While an invitation was extended to all participants of the first series of workshops, attendance was low, despite efforts to reschedule the timing of the event to accommodate availability of advocates.
- The primary purpose of these sessions was to:
  - continue building a relationship with customers and their advocates by sharing what was learnt to date;
  - respond to some of the earlier feedback by presenting on topics that were previously raised by customers as areas of interest at future forums;
  - understand customer views and concerns;
  - involve customers in the review process by outlining the proposal, including specific projects, programs, expenditure levels and price impacts, and seeking their feedback; and
  - raise understanding of AusNet Services' role in the energy supply chain and awareness of AusNet Services' brand.

Findings

- Based on qualitative and quantitative feedback from customers on formal evaluation forms, the forums appeared to be largely effective in building relationships with customers and raising awareness of AusNet Services.
- There was less consensus on effectiveness of forums for involving customers in the planning process. This was a strong indication that forums were not ideal for imparting complex information and seeking detailed feedback. These findings also gave support for the need to undertake further focus groups.
- It was evident in the types of questions raised and in written feedback, that there was a high level of interest in subjects such as solar and battery storage. Customer feedback also indicated a need for more information about smart meters, tariffs and costs.
- A recurring theme from advocates was that whilst there was a strong interest in attending, due to the number of competing customer engagement activities held within and outside of the energy sector and the limited resources available, there were practical challenges to participation.
- Of those advocates who did attend, feedback at the session suggested that the material presented addressed important issues, and was transparent and helpful, with an appropriate level of detail.

3.3.3 Industry engagement

AEMO VCR Study

This is the key Victorian electricity industry customer engagement process to establish a robust willingness to pay value for reliability for use in industrywide planning. Once established it is used as an input into regulatory processes, including planning for augmentation and replacement, setting service standards and optimising trade-offs between operating and capital expenditure solutions.

3.4 Findings

AusNet Services undertook several engagement activities aimed at gauging customers' attitudes to different aspects of network investment, and trade-offs between that investment with reliability, safety outcomes and operating costs. However, the business has been realistic in the way this feedback has been used.

These activities were not an attempt to substitute the use of detailed independent analysis (such as AEMO's VCR study), and NPV and risk modelling (such as our RCM and bushfire risk modelling). Rather, engagement activities were intended to illuminate customer attitudes to AusNet Services' chosen investment approaches and forecasts.

Due to the general nature of the majority of the feedback received, as well as the limited sample size of customers consulted (despite reasonable efforts to seek to engage with representatives of the customer base), AusNet Services does not consider customer endorsement on a stand-alone basis to be sufficient to make expenditure decisions that balance the objectives of the NEO.

Instead, feedback has been used to confirm or question initial internal proposals and plans. As a result some ideas have been dropped from the final proposal, while other parts of the proposal have been strengthened by customer endorsement.

A detailed discussion about the key themes from customer feedback and how they have been incorporated into this Proposal is set out below.

3.4.1 Safety

AusNet Services' safety obligations are mandatory but the costs of maintaining a safe network are a significant component of what customers pay. Therefore, customer engagement activities focussed heavily on this aspect of our proposal and also the broader policy issues associated with community safety around the electricity supply infrastructure.

Customers expressed very strong support for current levels of safety expenditure and for continual improvement of safety performance even when presented with the significant cost burdens this imposed. Strong support was also expressed for the current regulatory arrangement, where an independent regulator oversees the distributors' safety obligations.

Undergrounding was commonly raised as an option but there was widespread ignorance of the substantial cost increment of such a solution to an overhead system.

Vegetation management options were also canvassed with customer focus groups. With respect to the trade-offs between amenity, cost and safety, customers' strong initial responses were to remove trees or prune them back significantly if they possessed any risk. However, once discussion developed it became clear that there are many instances where trees were highly valued by their communities (particularly in towns) and that they sought either protection via undergrounding or 'sensitive' lower impact trimming. Away from sensitive urban areas the removal or more severe cutting of trees was more acceptable.

Our customer base expressed a strong preference for urban customers to share the costs of these programs, rejecting any proposal to charge higher tariffs in areas of high bushfire risk. Attitudes could be best summarised as all Victorians enjoy the benefits of the regions, whether eating its food or using for recreation, therefore, should help pay for programs that reduce the risks of bushfire.

How they were incorporated into this proposal

With respect to safety, AusNet Services has proposed an expenditure case that should further reduce the risk of bushfires and electric shocks arising from our assets. We consider this approach has received a strong endorsement from our customer base as well as the safety regulator and Victorian Government.

While strong support was expressed for undergrounding existing conductors, we consider the Victorian Government Powerline Relocation Fund is the appropriate mechanism as this spreads costs across the entire Victorian community and the total investment has been established using an appropriate cost benefit analyses.

3.4.2 Reliability

Generally, customers expressed a strong preference for current reliability levels. This satisfaction with current reliability levels was shared across customer groups. In the focus groups, in particular, there was both recognition that reliability was generally very good, outside of storms, and that reliability had improved over the last 10 years. There was nonetheless, instances where localised reliability issues caused considerable customer inconvenience and compliant. These were particularly exacerbated where communications with our customers had failed or were deemed unsatisfactory.

There was a strong resistance to pay for either further reliability improvement or allowing reliability to decline for lower prices in the future. This was expressed in general terms in answer to questions such as “Do you think lowering the value of a reliable energy supply reflects community views?” and when confronted with the specific detailed trade-offs under consideration for the proposal.

Customers also did not want to pay more for improved performance during extreme weather events or to ensure localised problems were addressed. In particular, customers appeared forgiving of unplanned outages during extreme weather events and considered our network crews used best endeavours to restore supply quickly and efficiently.

Finally, customers were strongly resistant to paying more for reduced planned outages or for the company to receive payments under an incentive scheme to reduce them. This reflected both an understanding of the necessity for these outages, particularly in rural areas where preparing the network for the fire season received strong support, and a general feeling that these outages created little inconvenience if communicated well in advance.

The was general support for continued investment in innovation (as opposed to large network investments) that resulted in reliability benefits, allowed improved planning of outages or improved customer communications.

How they were incorporated into this proposal

Initially, with respect to reliability, it was planned to propose:

- a lower ongoing reliability as result of incorporating the lower VCR into network planning;
- a planned outage incentive scheme;
- expenditure on an improved customer service and communication, in particular a Customer Relationship Management system; and
- a new STIPS exemption for demand management contracts.

As a result of the strong customer feedback on planned outages, plans to introduce an incentive scheme to minimise planned outages have been dropped. Network programs have also been costed without substantial live line work (which are more expensive but reduce planned outages).

AusNet Services' demand management program, including its reliability aspects, is discussed under innovation below.

3.4.3 Innovation

Customers considered investing in innovation was good business practice providing benefits to the business as well as the community. They were concerned that they do not pay twice where benefits pay for themselves.

Innovation was more strongly supported when delivering benefits to the broad customer base, such as improvements in:

- Reliability;
- Community Safety; or
- Efficiency.

When first mentioned, there was some scepticism towards the concept of the 'smart grid' and some concern expressed that investments in alternative technology benefits only a minority of the customer base. However, when provided with examples of benefits generated from the current period customers were impressed with what could be achieved, particularly with the data from smart meters. Customers considered the core benefits from smarter grid technology were:

- Ability to detect faults;
- Ability to connect/disconnect customers in real time;
- Increased ability by customers to monitor usage data;
- Ability of alternative energy sources to reduce pressure on the network.

While customers were impressed with network benefits the smart meter data allowed, they expressed a strong desire that this data was made available more broadly in a user friendly format. In particular, the inability to see their own consumption data on AusNet Services' *myHomeEnergy* web portal was a common complaint. This reflects genuine customer frustration with the much publicised problems AusNet Services is having with its smart meter communication systems.

A $7M increase in the Demand Management Innovation Allowance proposed by AusNet Services was tested in focus groups and received positive support.

How they were incorporated into this proposal

We consider that AusNet Services proposal meets both the concerns over cost control and support for innovation. Generally, we have been careful to seek upfront customer funding for innovation only where it supports the maintenance of existing platforms and capability. AusNet Services has not sought customer funding for investments or operating costs where future cost savings or reliability benefits under the incentive framework make the business case for the change self-funding.

For example, while forecast IT expenditure is being reduced when compared to the current period, we are nonetheless, proposing a large investment in this area. This investment will also provide a stable base from which the business can make the additional internally (non-customer) funded investments in innovation which deliver the lower costs and improved service outcomes over the long term as demonstrated over the current period.

Another important component of the framework in the current period was the Demand Management Incentive Allowance. This has allowed research and development to be undertaken where benefits to customers have been uncertain or long term. Without this component of the incentive framework, longer term research is discouraged even where long term benefits have the potential to be large or where the major benefits accrue to the community rather than the company.

Therefore, AusNet Services is proposing to expand from $3M to $10M this valuable component of the incentive framework for the 2016-20 period, with a focus on supporting research into how households can use storage to support the grid and reduce future energy bills.

Finally, AusNet Services has proposed an extensive and cutting edge demand management program. This program is particularly effective given the improved spatial demand forecasting that is possible as result of innovation spending during the current period. We believe the program is particularly effective during a time of uncertainty around investing further in long term assets when energy consumption is falling and embedded generation and off network energy solutions are becoming more viable. Demand management ensures reliability can be maintained without locking customers into paying for long-term network costs.

3.4.4 Communication with Customers

AusNet Services sought feedback from customers on both the method and content of communication with its customers.

With respect to planned outage notifications there was a continuing preference to receive written communications. Electronic communication was not seen as a substitute but rather as another way to remind customers.

Customers felt that electronic communication and website information on unplanned outages could be improved, particularly with respect to the location, description of the cause and time to restoration.

Customers were also interested in more detail on how their money was spent but did not seek specific contact with the business on this topic. Rather they considered this information was best delivered with the bill itself.

With respect to website information, customers considered far more effort could be put into providing user friendly data on many issues including network performance, tariffs, solar and demand management. AusNet Services' website was not considered easy to navigate around.

How they were incorporated into this proposal

AusNet Services is proposing to make many improvements to its customer communications and its coordination of planned outages with customers. The business is not seeking extra revenue from its customers to fund these changes, rather it will reassign and reprioritise internal resources to deliver these improvements.

We are also planning an investment in a Customer Relationship Management system as part of our IT proposal. This system, which would embed a reliable customer database for the first time, is an essential requirement to improving the quality and accuracy of customer communications.

3.4.5 Tariffs and pricing

Customers expressed concern about rising energy bills in an environment where many households and businesses were 'doing it tough'.

With regards to overall price levels there was strong expectation that the distributor should plan its investments and operating costs in a manner that keeps prices level over time and, in particular, avoid large short term increases.

With respect to how revenue is collected from customers through tariffs rather than the revenue itself, several cost reflective concepts were tested with customers in focus groups. The concepts were only tested at a 'principle' level, and were largely not supported.

AusNet Services considers that efficient price signals are an important ingredient in keeping long term network prices at sustainable levels. The network is largely rural, requiring significant safety investment in predominantly low density rural areas. We therefore sought customer views on the merits of introducing locational cost allocation, which would be aimed to avoid inefficient connection that imposes increasing costs on the rest of the customer base, and to incentivise off-grid solutions where these would be cost efficient.

Locational cost to serve price signals were rejected, even, somewhat surprisingly, by focus groups chosen exclusively of urban customers who would benefit from the unwinding of the urban rural cross subsidy. This reflected views that the cost of safety expenditure, which had been previously linked to increasing prices, be spread across the community and that this tariff design penalised customers for sunk decisions on where they had chosen to live. Regional customers expressed a strong view that all customers were entitled to a reliable supply of electricity at a reasonable cost, regardless of where they live.

When asked about consumption based tariffs, the concept of peak usage in late afternoon is well understood. However, this is generally thought of in terms of electricity consumption rather than grid capacity. While peak pricing signals were more acceptable than locational signals, it was also clear that consumers do not distinguish between the network and energy consumption elements of their electricity bill and, therefore, already consider themselves to be paying more for using more during peak times.

Paying fixed charges to cover sunk network capacity was also rejected as it was considered unfair that there was no reward for cutting consumption.

During one of the face-to-face meetings arranged with large customers, one customer expressed a level of dissatisfaction with the existing design of their tariff.

How they were incorporated into this proposal

In formulating the proposal, AusNet Services has incorporated many features aimed at delivering sustainable long term network prices including:

- Absorbing operational cost step changes that have been identified and not included these in the forecast revenue requirement;
- Continued investment in demand management and innovation to provide future alternatives to capital investment;
- Passing on to customers the benefits of lower interest rates and debt costs;
- The removal of any uncertain expenditure from the proposal, to be replaced by pass-through mechanisms, so customers do not pay for investment that may not eventuate. For example, uncertain costs associated with the introduction of ‘power of choice’ and research and development being undertaken in conjunction with the State Government on protection systems that may reduce bushfire ignition from electricity assets;
- Accelerated depreciation of the remaining asset value associated with assets that have been or will be removed from the network as a result of the large safety programs. This is fair to ensure future generations do not continue to pay for assets that no longer provide services while also paying for the new safer assets installed; and
- A low augmentation expenditure, reflecting a low demand growth forecast and lower value of customer reliability. AusNet Services development of forecasting capability in the current period has provided greater confidence to defer network upgrades (a less conservative approach to network planning taking advantage of greater forecasting accuracy).

The tariffs proposed for the first year of the new regulatory control period retain AusNet Services existing tariff structures. These do not incorporate locational attributes for small customer tariffs. During the course of developing tariffs for the subsequent years of the regulatory control period, to be submitted via the Tariff Structures Statement in September, we propose to consult extensively with stakeholders to refine the appropriate tariff structures for the AusNet Services network.

3.4.6 Customer Connections

Customer focus groups were not concerned about removing cross-subsidies of new customer connection by the existing customer base, seeing their removal as fair. If another customer made a conscious decision to build a new home requiring a new connection, the connection costs should be the responsibility of that particular customer, or the property developer. This was notable because there was strong resistance to removing other cross subsidies (for example, low fire risk areas subsidising high fire risk areas).

Whilst this was a clear and near universal view, there was a qualification where assets would directly benefit the broader customer base. In these cases, there was some isolated acceptance that a higher portion of costs could be spread, provided the customer benefiting the most from this new investment absorbed a higher share of the costs.

How they were incorporated into this proposal

AusNet Services considers that its proposal to increase the share of customer connection capex funded upfront by connecting parties to better reflect the customer specific costs they are imposing on the network is accepted by the community.

3.5 Ongoing Engagement

Based on AusNet Services' experience with implementing its first comprehensive program of broader customer engagement, the business has concluded that this undertaking was valuable but very challenging. This reflects a combination of factors prevalent across the energy industry, and also those unique to AusNet Services.

One key factor has been the level of maturity in processes, practices and systems for engaging customers and more broadly, managing customer relationships. The importance of having customer engagement embedded as a BAU activity across all business operations was best summarised in a quote from Andrew Reeves, the AER Chairman at the time. Mr Reeves stated that *"We [the AER] do not think the businesses can effectively engage around their network proposal if they do not engage effectively more broadly."*[2]

Beyond the regulatory proposal, customer engagement activities completed to date have identified a wealth of opportunity to improve engagement across all operations in the business. These opportunities have the potential to improve customer service and satisfaction levels, deliver bottom line savings and identify new competitive service offerings.

In particular, customer feedback has highlighted many ways that AusNet Services can improve communication and access to information. This is fundamental to building meaningful customer engagement as part of everyday business practices.

These customer insights have been a critical input into the development of the AusNet Services' customer strategy and supporting detailed roadmap. This roadmap outlines the tactical initiatives the business will undertake over the next three years to become more customer focused.

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[2] AER, *Better Regulation – Consumer Engagement Guideline for Network Service Providers*, November 2013.

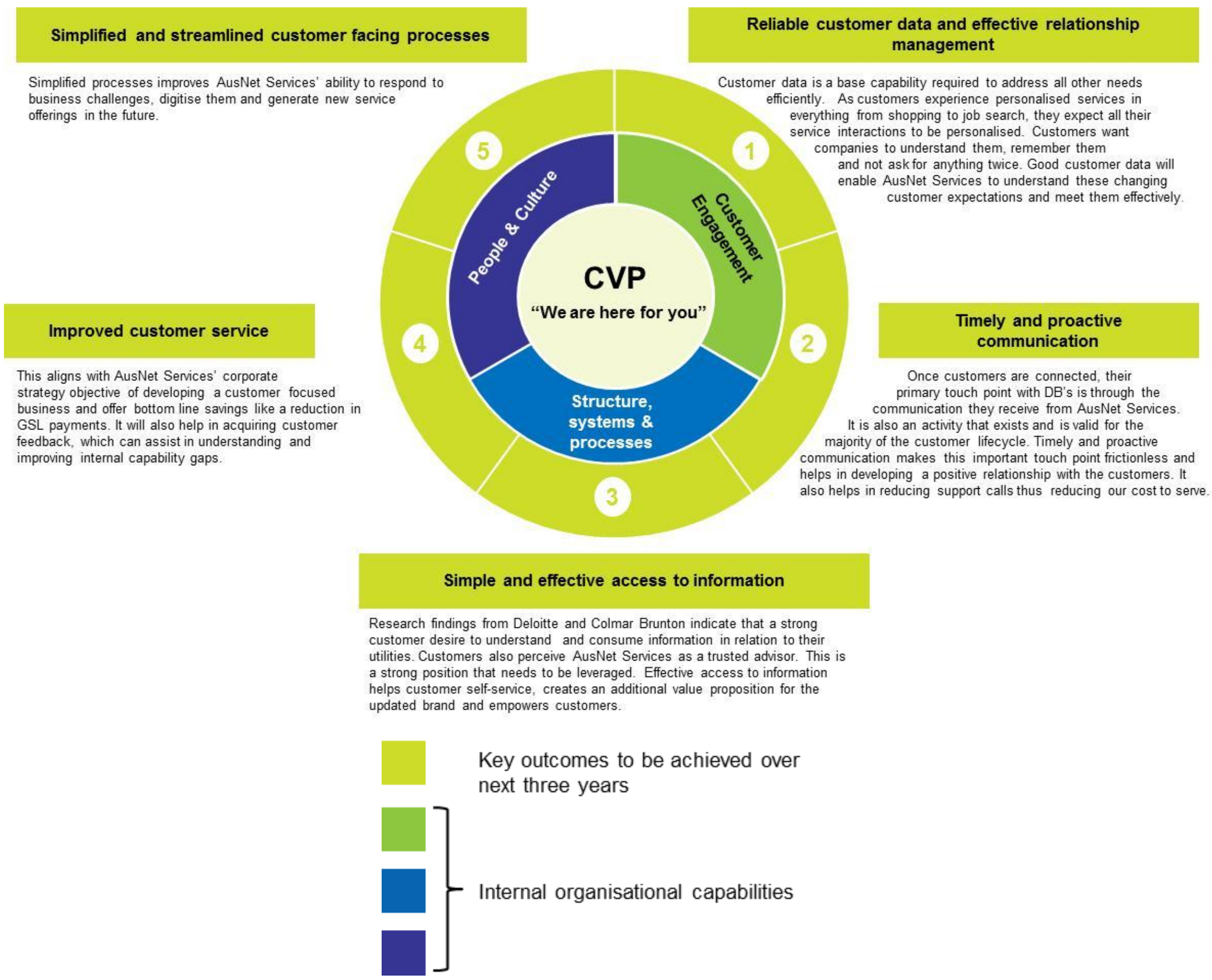
At a high level, AusNet Services' customer strategy aims to achieve five key outcomes over the next three years:

1. Reliable customer data and effective relationship management;
2. Timely and proactive communication;
3. Simple and effective access to information;
4. Improved customer services; and
5. Simplified and streamline customer facing processes.

In order to achieve these outcomes, AusNet Services has identified tactical initiatives to improve internal capabilities across three broad categories people and culture, customer engagement and structure, systems and processes.

This strategy has been summarised in the figure below.

Figure 3.2: Summary of AusNet Services' customer strategy



The figure above shows that AusNet Services is committed to improving customer engagement across the business. While the scope and key deliverables of each initiative in AusNet Services' customer roadmap are yet to be finalised, customer engagement initiatives will broadly include:

- Embedding a new customer engagement operating model, which identifies customer touch points, interfaces and contacts, and clarifies roles, accountabilities and responsibilities;
- Developing a customer engagement policy and approach, which outlines how the business intends to engage with its customer and then, communicate this policy internally and externally;
- Developing a suite of clear company policy/position statements on a range of issues identified as of interest/concern to customers, and then communicate these policies internally and externally;
- Undertaking a holistic review of, and improvement to, customer communication channels to ensure channels are diverse, user friendly and accessible; and
- Developing a framework for establishing a cycle of customer engagement that consolidates feedback and learnings, and then effectively disseminates this information across the business.

3.6 Support Documentation

The following documentation is provided in support of this chapter and is also provided on AusNet Services' website for customers to access:

- AusNet Services EDPR Customer Engagement Program Report, '*What our customers are telling us*', December 2014 – a report summarising the findings from our initial customer consultation work. The aim of this report was to capture the general sentiments of the majority of customers who were involved in this work;
- Colmar Brunton Focus Group Report, 'AusNet Services customer engagement research', December 2014 – a report summarising the key themes and findings generated from a series of eight focus groups, covering regional and metropolitan customers. This research was commissioned to deliver context and understanding of customer expectations to help AusNet Services ensure their expenditure plans reflect customer views and expectations;
- AusNet Services technical papers, 'Energy Insights series', January 2015 – a series of papers that seek to explain some key areas of customer interest around electricity distribution. These papers were based on material presented at our Technical Insights Workshops, held between June and August 2014; and
- AusNet Services' EDPR Customer Engagement Program Report, *'Community Forums, Phase 2, Summary*', April 2015 – a high-level summary of four regional community forums held between 17 February and 23 March. This update consolidates customer feedback gathered at these forums.

4. Demand and Energy

4.1 Introduction and Overview

4.1.1 Introduction

Forecasts of customer numbers, demand and energy play an important role in network planning and pricing. In this context, 'demand' refers to the total volume of electricity required to be available to distribution network customers at a point in time. 'Peak' or 'maximum' demand is the point in time where this requirement is at its greatest. This measure is important because the network must be designed in such a way to efficiently meet the maximum demand and therefore investment decisions are reliant on forecasts of what maximum demand is expected to be in the future. This applies not only to investment decisions on traditional network infrastructure, but also to demand management technologies – identifying the areas in which demand management offers the most efficient outcome for customers relies on accurate predictions of maximum demand.

'Energy', on the other hand, refers to the volume of electricity delivered over a certain timeframe. In the current environment, the majority of AusNet Services' tariffs are 'energy-based'. That is, network tariffs are based on the amount of energy consumed by customers over a given period. By extension, the revenue earned by a DNSP is strongly linked to the amount of energy consumed by its customers.

Customer number forecasts are the basis for both demand and energy forecasts, since the number of customers in the network is a key determinant of both demand and energy.

4.1.2 Overview

The key features of AusNet Services' demand and energy forecasts in this proposal are:

- AusNet Services' customer base is forecast to grow by around 1.5% per annum, in line with the Victorian Government's 2014 *Victoria in Future* planning document;
- The commercial customer base, which has been declining since the Global Financial Crisis, is expected to continue this decline, as the rate of disconnections outweighs connections;
- Maximum demand is forecast to continue growing, although at a slower rate than recorded over the current regulatory period;
- Residential and commercial energy consumption is forecast to continue declining on a per capita basis but these declines are expected to be largely offset by customer growth and stronger industrial consumption;
- Declines in residential and commercial energy consumption per capita are being led by improvements in energy efficiency, the growth of solar installations and other price-responsive changes in customer behaviour; and
- The impact of emerging technologies/policies, such as electric vehicles and batteries, is currently not known to a sufficient degree of confidence to warrant including in energy or demand forecasts. Further, decreases in energy requirements from one technology (e.g. batteries) may be offset by increases in energy requirements from other technologies (e.g. electric vehicles).

4.1.3 Chapter structure

The remainder of this chapter is structured as follows:

- Section 4.2 provides some commentary on the insights AusNet Services has gained from improvements in systems and forecasting accuracy during the current regulatory control period;
- Section 4.3 describes AusNet Services' customer forecast methodology and proposed customer forecast for the 2016-2020 EDPR period;
- Section 4.4 describes AusNet Services' energy forecast methodology and proposed customer forecast for the 2016-2020 EDPR period;
- Section 4.5 describes AusNet Services' demand forecast methodology and proposed customer forecast for the 2016-2020 EDPR period.

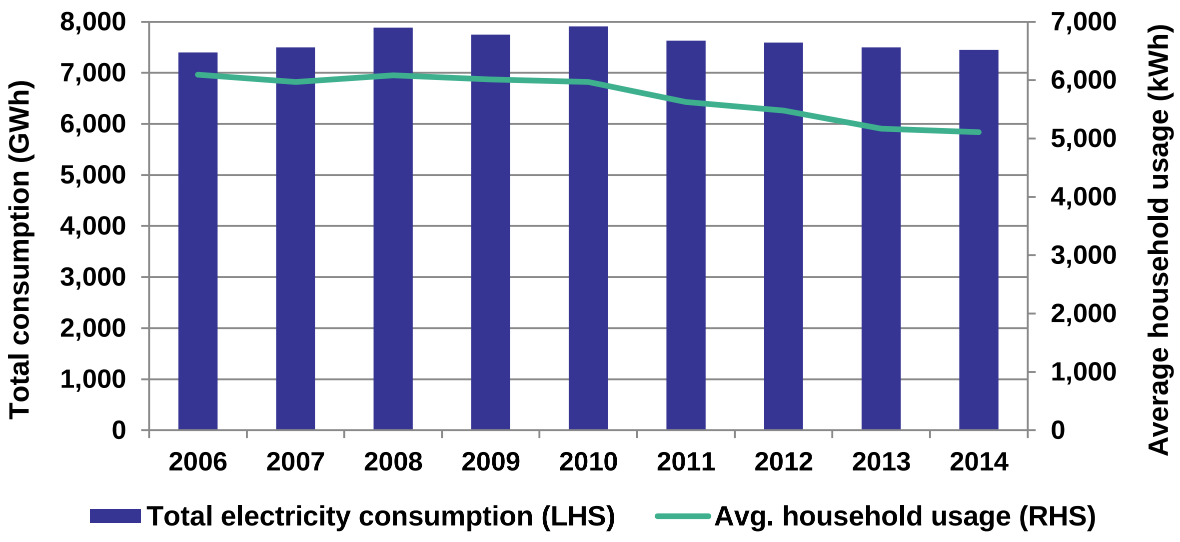
4.2 Demand and Energy Insights

4.2.1 Background

In the current regulatory period, the AER approved an energy consumption forecast for AusNet Services that grew on average by 0.3% between 2010 and 2015.[1] Instead, in the four years to 2014, AusNet Services' energy consumption has declined by 1.6% p.a. and is now close to energy consumption levels last recorded in 2006.

At a household level, residential electricity consumption per capita has been declining since 2006, however, as can be seen in the Figure below, the rate of change altered significantly in the current regulatory period. Between 2006 and 2010, residential electricity consumption per household on the AusNet Services' network declined by an average of 0.5% per annum. Since 2010, the average annual decline in household electricity consumption has been 3.8%. Put another way, the average household in 2014 uses 14% less electricity than it did in 2010.

Figure 4.1: AusNet Services' total electricity consumption (LHS) and residential energy consumption per household (RHS)



Source: AER economic benchmarking data.

[1] This was the highest forecast consumption growth of any Victorian DNSP. Other forecasts approved by the AER in its Victorian price determinations ranged from 0.2% p.a. growth (Powercor) to a 1.1% p.a. decline (Jemena).

This fall in energy consumption was not confined to AusNet Services, or even Victoria. Across the NEM, six out of 13 DNSPs have experienced falling energy since a peak year of 2010, with a further three peaking one year before (2009) or after (2011).

4.2.2 Drivers of changing energy and demand

Several factors influenced the decline in electricity consumption. These include:

- improvements in the energy efficiency of electrical appliances;
- building standards incorporating energy ratings in the design and build of houses, offices, etc.;
- growth in the number of rooftop solar PV installations and other embedded generation assets;
- changes in consumer behaviour stemming from increasing electricity prices and education on greenhouse emissions and other demand management opportunities; and
- weakened economic conditions, which led to declines in the commercial and industrial sectors.

This fall in energy had both positive and negative consequences for DNSPs. In AusNet Services' case, lower energy translated into maximum demands that were not as high as forecast in the 2011-15 EDPR. Since maximum demand is a key driver of augmentation expenditure, the approved capital expenditure allowance for augmentation expenditure was higher than was ultimately required. On the other hand, AusNet Services (and the other Victorian DNSPs) operated under a price cap, which meant that lower volumes translated into lower revenue.

In order to keep ahead of this emerging trend, AusNet Services invested heavily during the current regulatory control period to improve its internal demand and energy forecasting capability. This investment has been supported by data provided by smart meters and the ICT platforms available to the forecasting team. AusNet Services is the only DNSP in the NEM to prepare its demand and energy forecasts using solely internal resources.

This investment also responded to concerns raised by the AER during the 2011-15 EDPR. In the 2011-15 review, the AER's consultants ACIL Tasman concluded that AusNet Services' (SP AusNet, at the time) demand forecasting methodology was not sound and cited concerns about the level of judgment required by planners in deriving the forecasts and the lack of transparency and repeatability of the process. The AER further noted that ACIL Tasman had found "there is no systematic adjustment for the influence of temperature on demand, and there is only a general relationship between other objective data and the forecasts."[2]

As discussed in section 4.5.1 of this chapter, AusNet Services engaged ACIL Allen Consulting (ACIL Allen) to conduct a review of AusNet Services' demand forecasting methodology. ACIL Allen (which was formed after a merger between ACIL Tasman and the Allen Consulting Group) has found that AusNet Services' current demand forecasting methodology follows a reasonable approach, indicating that AusNet Services has addressed the shortcomings of AusNet Services' old methodology as highlighted in the 2011-15 EDPR.

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[2] AER, *Draft Decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015*, June 2010, p. 129.

4.2.3 Outcomes of AusNet Services' investment in forecasting

As a result of AusNet Services' investment in its forecasting capability, its accuracy has improved such that its annual energy forecasting is now within 2% accuracy on a weather-corrected basis. This investment in understanding consumption data, and its associated positive impact on forecasting accuracy, has a range of benefits, including:

- using smart meter data to understand in more detail:
    - temperature-energy correlations, which can now be calculated with a significantly higher degree of accuracy due to interval data, rather than using quarterly billing data;
    - energy profiles for houses built at different times, which illustrates the impact of energy efficiency;
    - energy profiles for solar v. non-solar customers, which quantifies the impact of energy savings from solar installations and impact of solar at time of peak;
    - the impact of different price structures on different customers;
- the ability to provide customers, customer groups and government agencies with data that imparts insights they have not had access to before. Recent examples include:
    - presenting energy and demand insights during AusNet Services' 2016-20 EDPR customer consultation;
    - the provision of interval data from smart meters to better inform the Victorian Government's My Power Planner website;
    - the provision of energy consumption data to agencies such as the Northern Alliance for Greenhouse Action and the South Gippsland Shire Council;
- assisting the demand management activities in the business through the provision of short to medium term forecasts to identify opportunities for non-network alternatives;
- more informed augmentation expenditure planning, based on improved long term demand forecasts. To illustrate the impact that demand forecasts can have on capital expenditure, AusNet Services was able to defer approximately $100 million ($2015) of augmentation expenditure in the current regulatory control period due to lower demand than forecast in the EDPR;
- short term operational benefits from timely and accurate short term demand forecasts (see case study, below);
- more efficient operating and capital expenditure as a result of more informed decision making.

4.2.4 Case study: practical application of demand forecasting techniques

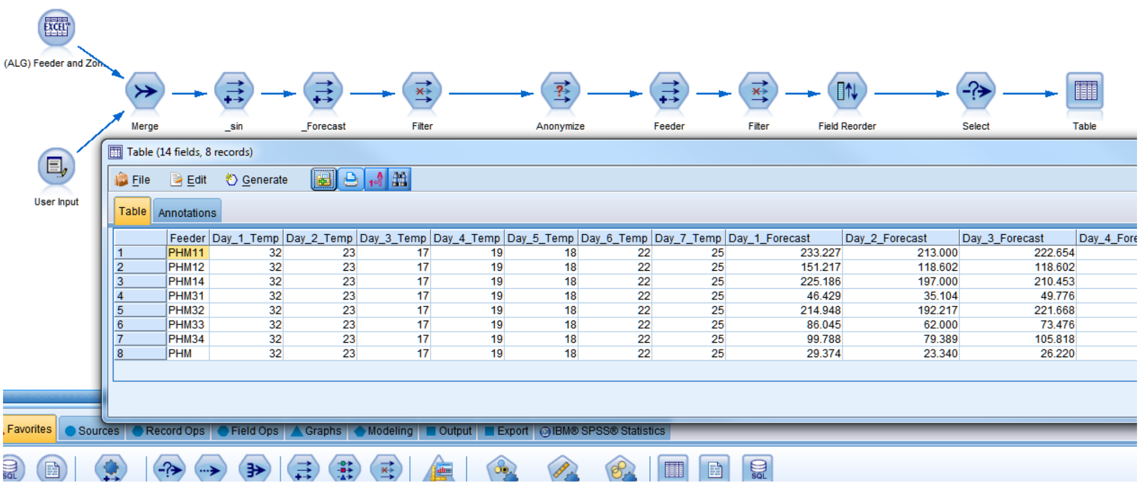
In addition to long term demand forecasts that inform network capital expenditure planning, AusNet Services' growing expertise in demand forecasting has other practical applications. The box below describes how AusNet Services has used its demand forecasting techniques to improve short term operational decision making, driving improvements in operational efficiency and reliability for customers.

Box 4.1: Short term demand forecasting: a case study

One of the practical applications of AusNet Services' improved demand forecasting techniques is its ability to quickly provide short term (e.g. next five days) demand forecasts at the feeder level. Accurate, timely forecasts of this kind can improve the efficient operation of the network, as the below case study explains.

On 10 November 2014 Pakenham Zone Substation (ZSS) 3rd Transformer failed. Failure of a second transformer would have resulted in customers being without supply. The forecast temperature for 12 November was 36 degrees and this required a detailed forecast to ensure that appropriate contingency plans were created so that all load could be served in the event of a subsequent outage. The consequence of not knowing what the demand on the zone substation would be was either: (1) unnecessarily transferring load which has an associated short-term cost to plan and implement, or (2) thinking that there was sufficient capacity when there was in fact not, which could result in customer outages.

AusNet Services' forecasting team built a model to produce a short term demand forecast for Pakenham ZSS and each associated feeder. The model and its output can be seen below:



	Feeder	Day_1_Temp	Day_2_Temp	Day_3_Temp	Day_4_Temp	Day_5_Temp	Day_6_Temp	Day_7_Temp	Day_1_Forecast	Day_2_Forecast	Day_3_Forecast	Day_4_Fore
1	PHM11	32	23	17	19	18	22	25	233.227	213.000	222.654	
2	PHM12	32	23	17	19	18	22	25	151.217	118.602	118.602	
3	PHM14	32	23	17	19	18	22	25	225.186	197.000	210.453	
4	PHM31	32	23	17	19	18	22	25	46.429	35.104	49.776	
5	PHM32	32	23	17	19	18	22	25	214.948	192.217	221.668	
6	PHM33	32	23	17	19	18	22	25	86.045	62.000	73.476	
7	PHM34	32	23	17	19	18	22	25	99.788	79.389	105.818	
8	PHM	32	23	17	19	18	22	25	29.374	23.340	26.220	

On the basis of this model, Network Planning and Network Operations developed and implemented contingency plans to avoid transformer overloads and station blackouts in the event of a second transformer failure. The loads on several Pakenham feeders were transferred to feeders of neighbouring ZSS, which were all subsequently below their ratings (despite the increased load), as predicted by the model.

Now that this model has been created, it can be used to generate future forecasts for any Feeder or ZSS within the network on an ad hoc basis using forecast weather conditions. This highlights the benefits of AusNet Services' continued investment in forecasting resources and technologies.

4.3 Customer Number Forecasts

4.3.1 Customer forecast methodology

AusNet Services prepares two sets of customer forecasts:

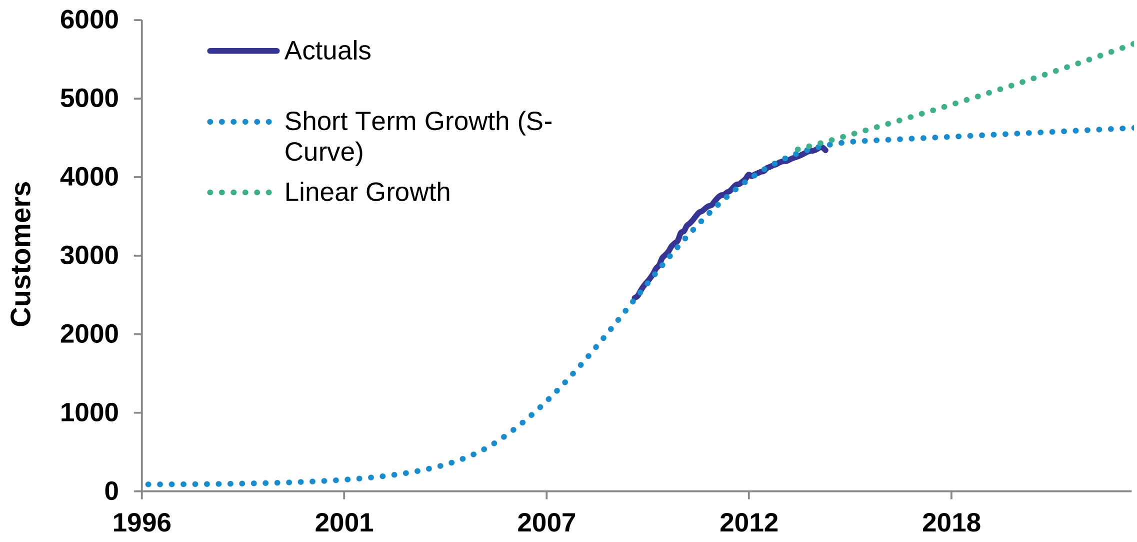
- A spatial forecast, for maximum demand forecasting purposes;[3] and
- A tariff code forecast, for price setting and revenue forecasting purposes.[4]

AusNet Services' customer forecasting methodology has improved considerably in the current regulatory period. Traditionally, customer forecasts were based on straight line extrapolations from historic growth, adjusted for known housing developments. Whilst this methodology has proved reliable over the short term, it can lead to longer term errors when trends do not continue. The consequence is that forecasts are less likely to overstate medium term customer growth.

Customer growth rates by feeder are a key input to AusNet Services' demand forecasts (see section 4.5). The feeder-level customer numbers are also converted into customer forecasts at the tariff code level for the purposes of energy and revenue forecasting. Given the importance of customer growth rates by feeder, over the past twelve months AusNet Services has developed customised, in-house algorithms which predict where in the growth cycle a particular feeder is. That is, if the feeder has experienced strong growth in recent years, the algorithm can model whether the growth can be expected to continue, or start to moderate.

As an example, detailed analysis of the actual growth in the area serviced by the feeder depicted below suggests the area in question is nearing its carrying capacity,[5] even though a shorter term trend analysis could justify a straight line extrapolation of continued growth.

Figure 4.2: Forecast growth rate on a slowing feeder



Source: AusNet Services

[3] As section 4.5.1 explains, these customer forecasts and the resulting demand forecasts, are key inputs to augmentation expenditure (chapter 7) and demand management decisions (chapter 9). Capital expenditure on new connections uses 'gross' customer connections, whilst demand and energy forecasts use 'net' connections, with the number of abolishments (disconnections) the difference between the two. Further, connections capital expenditure is based on the number of physical connections, rather than the number of customers. This is particularly relevant for non-residential connections. For example, a new shopping centre will count as one 'connection' for capital expenditure forecasting purposes, but many new 'customers' for energy forecasting purposes. Therefore, the 'connections' in regulatory template 2.5 will not equal the 'customers' in AusNet Services' demand and energy forecast models.

[4] Refer chapters 19 and 20.

[5] That is, the number customers that can reasonably fit into the area.

Results of the forecasts are calibrated to the *Victoria in Future* (VIF) planning document published by the Victorian Department of Transport, Planning and Local Infrastructure (DTPLI). This ensures that the theoretical growth rate on a collection of feeders does not exceed the VIF growth rate for the entire Local Government Area in which those feeders are located.

Since customer number forecasts are a key input into maximum demand and capital expenditure planning, the improved accuracy of AusNet Services' customer forecasts flows through to improve the accuracy of these other forecasts.

The evidence suggests that AusNet Services' approach to customer forecasts is correctly predicting where the growth will occur. As an example, AusNet Services' demand forecast for the Cranbourne area is being driven by customer number projections on two out of six main feeders. In February 2015, AusNet Services' Forecasting team was informed of the need to factor in a recently announced expanded development in Cranbourne which would increase load on feeder CRE31. In fact, the forecasting algorithms had already predicted that CRE31 would be one of the two feeders around Cranbourne that would experience strong growth, almost a year before this announcement. Whilst this only provides anecdotal evidence of the predictive power of AusNet Services' new approach to customer forecasting, there has not been a single instance of new developments which have not been forecast since the new 's-curve' forecasting approach was adopted for the 2015-20125 demand forecasts.

4.3.2 Customer numbers – historical and forecast

AusNet Services' total customer base has been growing by approximately 1.5% per annum during the current regulatory period.

Table 4.1: AusNet Services' customer numbers (2010-2014) [6]

Customer Type	2010	2011	2012	2013	2014
Residential	562,744	574,753	585,503	593,569	603,713
Small / medium commercial	68,556	68,501	68,380	68,309	67,351
Industrial	1,924	1,980	2,045	2,108	2,175
Total	**633,224**	**645,234**	**655,928**	**663,986**	**673,239**

Since 2011, AusNet Services' small to medium commercial customer base has contracted, with disconnections outpacing new connections to the network. Economic conditions have led to a number of small businesses closing down.

At the same time, there has been strong industrial customer growth, particularly by large (predominately low voltage) businesses such as supermarkets and homeware/hardware stores which are more energy-intensive than the commercial segment. Many of these large customers are therefore connecting to service the growth in the residential customer base.

AusNet Services is forecasting continued net customer growth of approximately 1.5% per annum over the next regulatory period.[7] This growth is led by the residential and industrial sectors, although 'industrial' in this context includes several residential-led businesses, such as supermarkets, hardware stores, etc. Whilst there is some possibility of economic recovery in the next five years, the economic pressures on the small to medium commercial customer base is forecast continue and

6 This customer number forecast is for active NMIs. It does not reconcile to the economic benchmarking data published by the AER, which includes deactivated NMIs.

7 This number is calculated as the total number of new connections, less abolishments (disconnections).

therefore this customer segment is forecast to contract over the regulatory control period as the rate of disconnections continues to outpace connections.

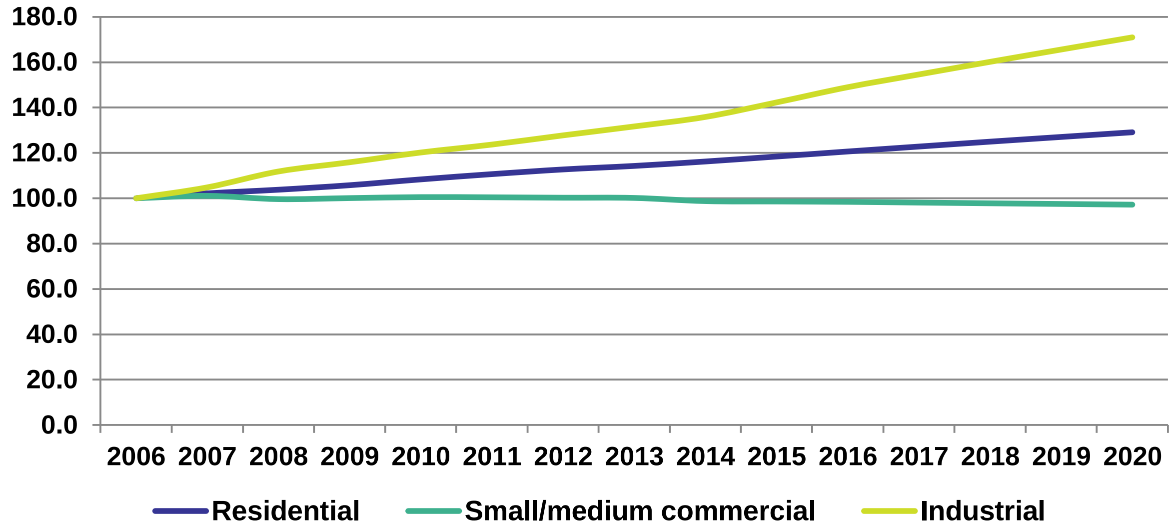
AusNet Services' customer number forecasts are presented in the Table below.

Table 4.2: AusNet Services customer number forecasts 2016-2020 (year ending)

Customer Type	2016	2017	2018	2019	2020
Residential	626,609	637,929	649,134	659,942	670,684
Small / medium commercial	67,129	66,911	66,695	66,491	66,289
Industrial	2,385	2,475	2,564	2,651	2,737
Total	**696,123**	**707,315**	**718,393**	**729,084**	**739,710**

The actual and forecast growth rate for each customer group since 2006 is depicted in Figure 4.3. Because of the large differences in customer numbers, Figure 4.3 is presented as an index, with each customer segment's growth baselined at 100 in 2006.

Figure 4.3: AusNet Services' customer growth 2006-2020



Source: AusNet Services

4.4 Energy Consumption Forecasts

4.4.1 Energy consumption forecast methodology

When the sharp reduction in energy consumption began to materialise in 2011, AusNet Services invested in improving its internal energy forecasting capabilities.

AusNet Services' approach to energy forecasting now includes the following:

1. **Forecast customer numbers by individual tariff**. The net growth in customers in each of AusNet Services' tariff codes, including any transfers between tariffs.
2. **Weather correlations**. Like the demand forecasting methodology, regression analysis is used to determine the relationship between weather and energy consumption, at the tariff level. As a result, each tariff code has its own correlation which is used to profile energy consumption over the year.
3. **New v. existing customers.** Using smart meter data, AusNet Services knows that new customers use less energy per capita than the average of the existing customer base. Therefore, any new customers added to the model are separately modelled, using lower energy per customer volumes.
4. **Impact of solar PV uptake**. AusNet Services forecasts the number of customers who will install solar PV over the period, and the associated reduction in energy delivered from the network at times of solar generation.
5. **Price elasticity**. Retail electricity price forecasts are sourced from AEMO's National Electricity Forecasting Report (NEFR) and price elasticities for residential, commercial and industrial customers are applied to these prices.[8]
6. **Future energy efficiency impact.** Any continued energy efficiency improvements/schemes are able to be separately modelled.
7. **Impact of new technologies/policies.** The energy forecast model contains modules for the inclusion of emerging technologies and the impacts on energy consumption. However, AusNet Services does not presently include forecasts for the uptake of such technologies and policies because of the high degree of uncertainty in regards to their timing, materiality and direction (i.e. increasing or decreasing energy).

In addition to monitoring actual energy against the AER-approved 2011-15 EDPR forecast, AusNet Services produces annual and five-year forecasts for price-setting and business planning purposes. Since building the energy forecasting model and refining its inputs, AusNet Services' annual and longer term energy forecasting accuracy has improved significantly. In 2011, before the model was built, actual energy consumption was 4.7% below AusNet Services' annual forecast (per Figure 4.1, this is the first year that the large reduction in residential energy usage became apparent). In 2014, actual energy consumption was within 2% of the annual forecast once weather was accounted for.

Another illustration of AusNet Services' improvement in energy forecasting is highlighted in the table below. AusNet Services' energy forecasting model was developed prior to the commencement of CY2013. Table 4.3 compares the monthly 'year 1' accuracy of AusNet Services' old energy forecasting model (which applied in CY2012) to the first and second versions of the new energy forecasting model, which applied in CY2013 and CY2014 respectively. The table shows how many months were within a given accuracy band for the first calendar year of the model, and there is a clear trend that AusNet Services' forecasting accuracy has improved over time.

[8] Frontier Economics (2014), *Economic and Energy Market Forecasts*, p. 87.

Table 4.3: Monthly forecast accuracy – 'Year 1' comparison of models (no. of months)

Model Version	≤2%	>2%	>3%	>4%	>5%
	more accurate				*less accurate*
CY2012 model	5/12	7/12	6/12	4/12	4/12
CY2013 model	5/12	7/12	7/12	4/12	2/12
CY2014 model	**8/12**	**4/12**	**3/12**	**1/12**	**1/12**

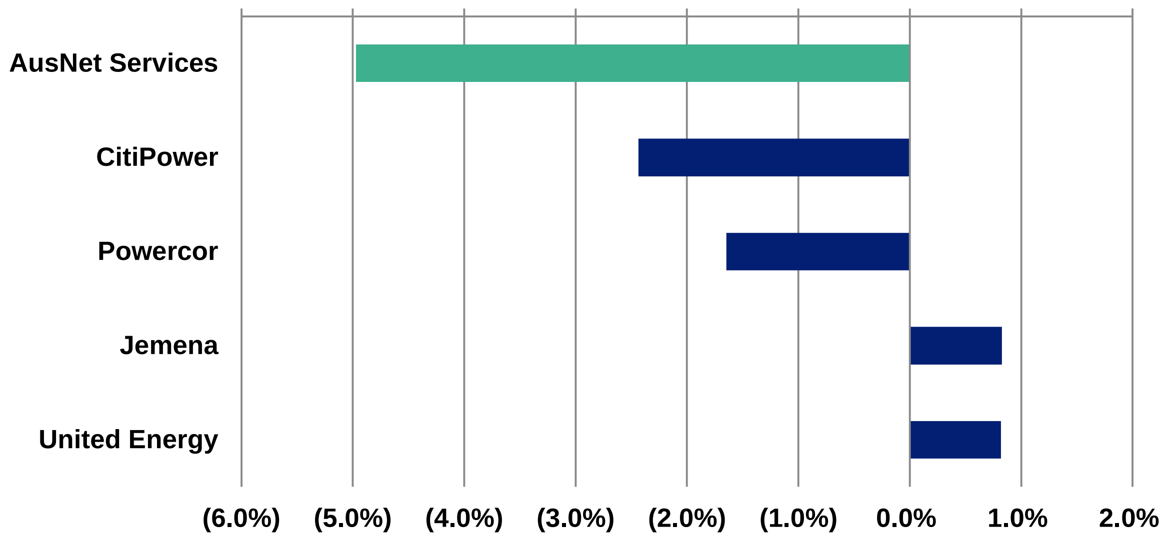
Source: AusNet Services

The CY2014 forecast model was within 2% of the actual (weather-normalised) volume in eight out of the 12 months in CY2014, and only worse than 4% accuracy in one month. This compares favourably against both the CY2012 and CY2013 models, with the CY2013 model itself being an improvement on the CY2012 model.

4.4.2 Historic and forecast energy consumption

As foreshadowed in section 4.2.1, AusNet Services' total energy consumption has been falling since 2010. The impact of this reduction in energy delivered relative to the AER's 2011-15 approved forecast is shown in the figure below. The data presented only covers the first three years (2010-2013) of the current regulatory period, as it draws from the AER's economic benchmarking data, for which 2014 data has not yet been published.

Figure 4.4: Actual energy delivered in 2011-13 v. EDPR (% greater than AER approved forecast)



Source: AER economic benchmarking data

Compared to the other Victorian DNSPs, AusNet Services has a relatively high proportion of residential consumption. According to the economic benchmarking data published by the AER, AusNet Services distributed 42% of its energy to residential customers, compared to CitiPower (21%), Jemena (30%), Powercor (32%) and United Energy (35%). Combined with the highest EDPR energy growth forecast of all Victorian DNSPs, this means that the sharp reduction in residential usage per capita (Figure 4.1) has had a larger impact on AusNet Services relative to its peers.

Over the 2016-2020 period, AusNet Services is forecasting electricity consumption to flatten off in the next regulatory period, although this is largely influenced by low voltage industrial customers servicing residential customer growth (as discussed above). Residential and commercial energy consumption is forecast to continue to decline, on both a total and per customer basis, for the duration of the next regulatory control period.

Despite the advances made in AusNet Services' ability to accurately forecast energy, there is still a significant degree of uncertainty in the outer years of the 2016-2020 regulatory control period in terms of the impact of new technologies or policy decisions. This includes, but is not limited to, the impact of:

- Electricity storage;
- Electric vehicles;
- Customers switching from gas to electricity due to higher gas prices;
- Advances in other energy sources (including solar, wind and other renewables); and
- Changes in tariff structures.

AusNet Services' view is that each of the above issues is highly likely to impact the amount of energy distributed over the next regulatory control period. Furthermore, some of these issues will result in higher energy (e.g. electric vehicles, fewer gas connections) whilst others will result in lower energy (e.g. solar combined with storage, or new tariff structures).

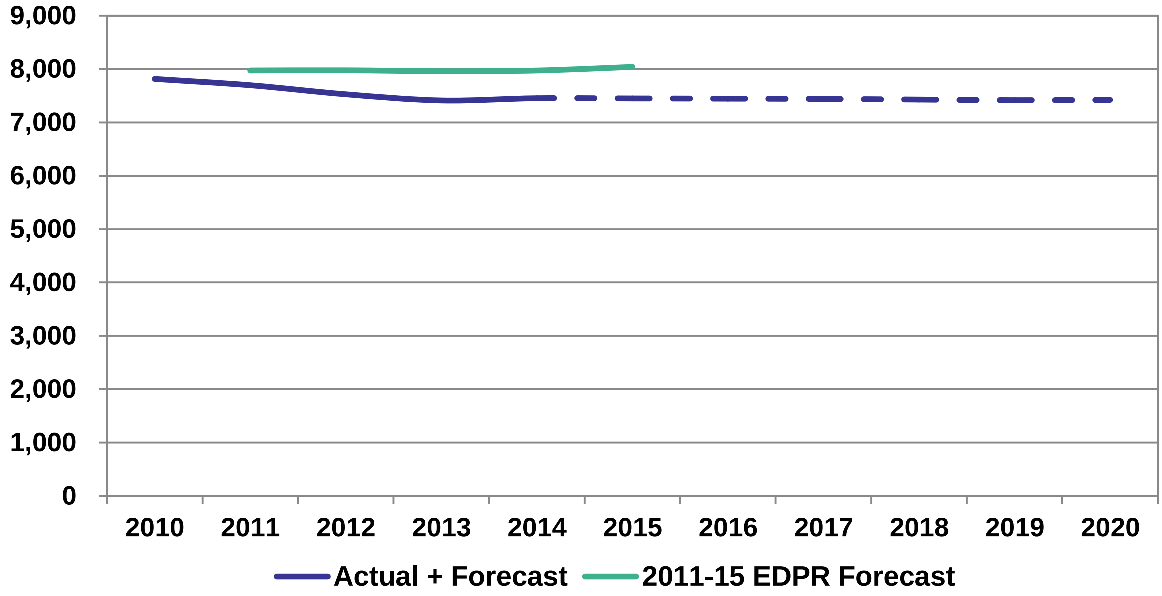
Under the revenue cap form of price control, the five year energy forecast has a diminished role in setting prices (see chapter 19).[9] However, annual changes in prices will still be "trued up" for any differences between actual and forecast revenue. AusNet Services' annual energy forecast accuracy, which as explained in section 4.4.1, is extremely high, will minimise price impacts from over or under-forecasting electricity volumes.

AusNet Services considers that the prudent approach to forecasting energy in the 2016-20 period is to forecast on the basis of currently known drivers of energy consumption. When the impacts of the above technologies / policies is known with more certainty, they will be factored into annual energy forecasts for price setting purposes. This removes any potential bias for selecting those impacts that only add to, or detract from, potential energy consumption.

AusNet Services energy forecast for the 2016-2020 regulatory control period, together with weather-normalised actual energy and the AER-approved 2011-15 EDPR forecast, is presented in the figure below.

[9] The residential volume forecast is the basis for the price path presented in chapter 20. To the extent that actual volumes deviate from this forecast, the price path depicted in chapter 20 will therefore change, although the total revenue earned by AusNet Services will not.

Figure 4.5: Weather normalised energy – actual (2010-2014) and forecast



Source: AusNet Services

The forecast energy over the regulatory period is further disaggregated into customer segments in the table below.

Table 4.4: AusNet Services' electricity volume forecasts 2016-2020 (GWh)

Customer Type	2016	2017	2018	2019	2020
Residential	3,129	3,108	3,086	3,066	3,065
Small / medium commercial	1,482	1,438	1,393	1,348	1,304
Industrial	2,837	2,896	2,951	3,003	3,054
Total	**7,447**	**7,442**	**7,429**	**7,418**	**7,423**

Source: AusNet Services

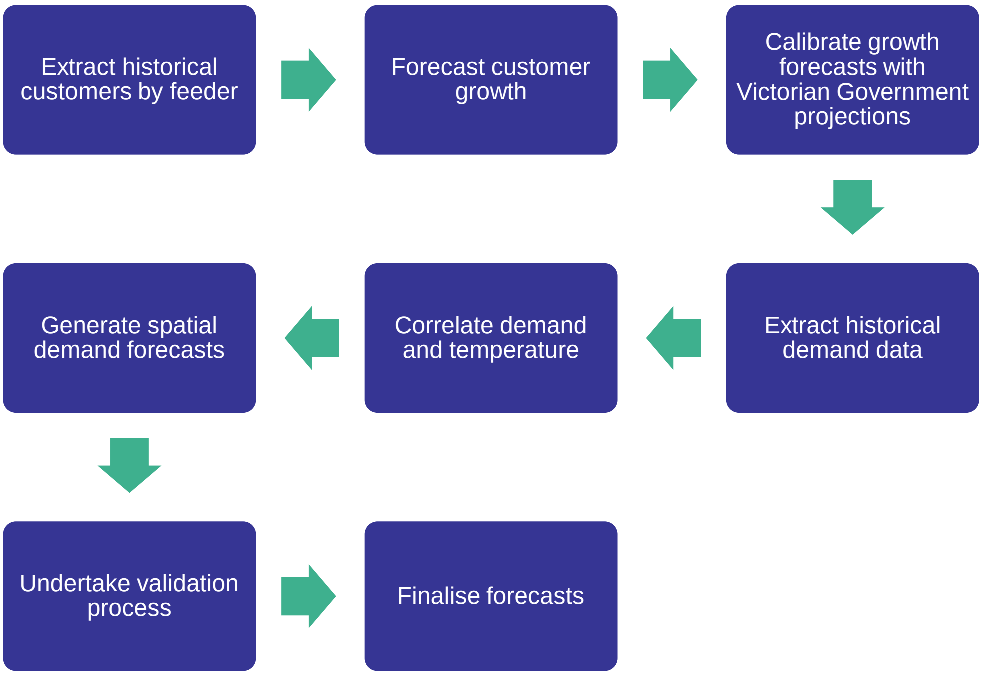
4.5 Maximum Demand Forecasts

4.5.1 Maximum demand forecast methodology

AusNet Services' approach to forecast maximum demand is set out in detail in Appendix 4A. The forecast demand on assets such as feeders and zone substations play a key role in other forecasts presented in this submission. The outputs from AusNet Services' demand forecasts are used by network planners as an input to their augmentation capital expenditure deliberations (chapter 7). Demand forecasts are also used to determine where demand management options can be most efficiently implemented (chapter 9).[10] In summary, the key steps involved in preparing demand forecasts are set out in the figure below.

[10] AusNet Services forecasts on a MW basis at the zone substation and terminal station level, whilst feeder forecasts are in Amps. Forecasts are on a non-coincident basis – AusNet Services does not forecast coincidental demand.

Figure 4.6: Overview of demand forecasting methodology



As the above diagram illustrates, the two key components of the demand forecasting methodology are (1) customer numbers and (2) the relationship between temperature and demand.[11] The most recent summer's actual demands (for summer peaking feeders) are used as the basis of the forecast.[12] Due to the timing of the 2016-2020 EDPR submission, that means the 2016-2020 demand forecast is based on 2014 demand. The revised proposal will include an updated demand forecast which takes into account the demand recorded (and the associated correlations with temperature) in 2015.

With ongoing improvements in energy efficiency, one of the key components of a maximum demand forecast is how these energy efficiency improvements are factored into demand forecasts. The Box below describes AusNet Services' methodology for including efficiency at peak demand times.

11 As explained in AusNet Services' demand forecasting methodology (Appendix 4A) and ACIL Allen Consulting's review (Appendix 4B), AusNet Services' approach to forecasting demand does not entail or require weather-correction to historical demands. AusNet Services calculates the relationship between temperature and demand and applies this to projected customer growth. Weather-normalised historical demand trends are therefore not used to forecast future demand, however temperature is still a key factor in the demand forecasting process.

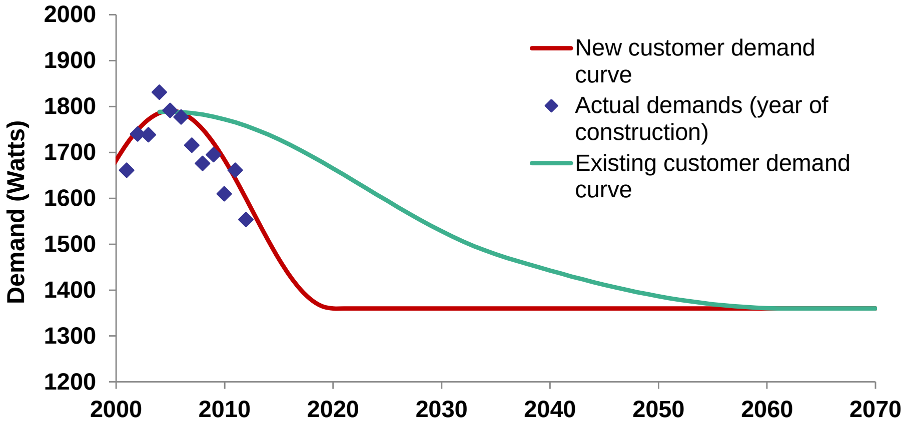
12 Actual (historic) demand is recorded in MW for zone substations and Amps for feeders.

Box 4.2: How is demand efficiency factored in?

AusNet Services' demand forecasts are adjusted to take into account the impact of energy/demand efficiency. Since the early-to-mid 2000s, there has been a clear trend of new dwellings consuming less energy at peak demand times. This is likely due to improvements in housing design and new appliance efficiency, which have in part been driven by the 6 Star Energy Rating building requirements.

In addition to new dwellings, existing customers have also reduced their energy requirements, as replacement household appliances become more energy efficient.

AusNet Services factors both types of energy efficiency into its demand forecasts. In the below chart, the blue markers depict the actual maximum demand on a single day for premises constructed in a specific year (i.e. the blue marker lining up with 2010 on the x-axis is the average demand for premises constructed in 2010). AusNet Services assumes that new customers connecting between now and 2020 will follow the red curve – that is the demand of premises constructed will decline until levelling off in 2020. Existing dwellings' demand follow the green curve – that is, as an existing customer's appliances are replaced and the house itself is renovated, they eventually become as efficient as a house built in 2020.



Source: AusNet Services.

As explained in section 4.2.2, AusNet Services engaged ACIL Allen to conduct an independent review of its maximum demand forecasting methodology. In 2013 AEMO engaged ACIL Allen (ACIL Allen) to prepare a consistent methodology for forecasting at the connection point (terminal station) level. ACIL Allen has prepared a comparison of AusNet Services' methodology and the ACIL Allen methodology accepted by AEMO. ACIL Allen's report on its findings is included as Appendix 4B.

ACIL Allen's review concluded that, AusNet Services' methodology was a reasonable approach to forecasting demand. ACIL Allen noted that AusNet Services' customer forecasting methodology, which is reconciled to DTPLI projections was sound and that AusNet Services' approach to data preparation, growth rates, demand efficiency, and post-model adjustments were appropriate.

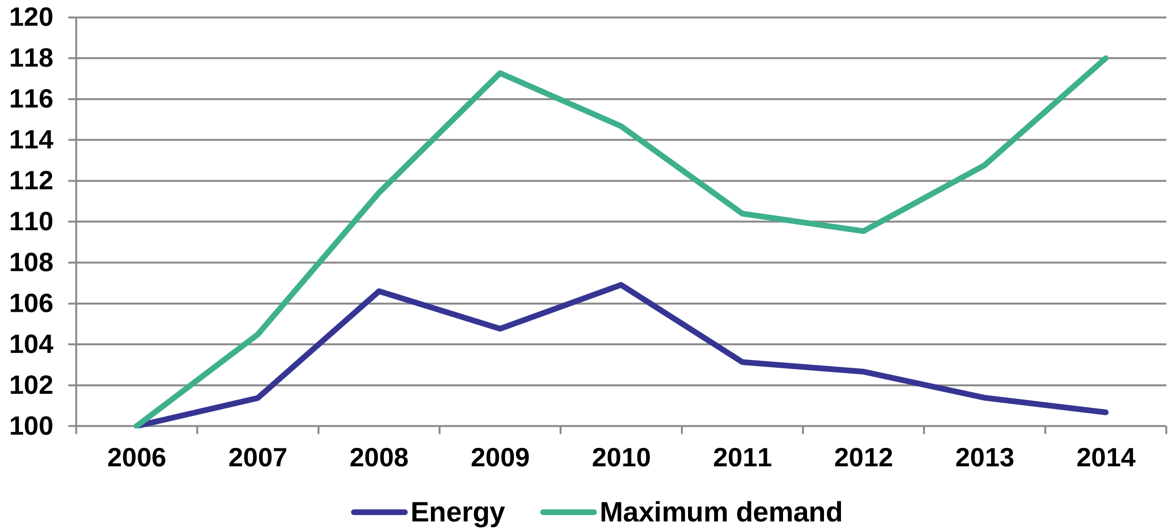
ACIL Allen recommended using a longer time period to calculate POE10 and POE50 temperatures, and to consider the adoption of a 'top-down' forecast to reconcile to AusNet Services' bottom-up forecast. However, in AusNet Services' view, the current 10 year sampling period for weather more appropriately reflects the climate which is likely to prevail over the next 10 years, and as ACIL Allen notes, AusNet Services' 's-curve' approach diminishes the impact of very high temperatures because demand levels off as temperature increases. Regarding the top-down reconciliation, AusNet Services notes that its bottom up forecast results in a demand forecast that, at the system level, is in line with observed historical demand. This lends support to AusNet Services' bottom-up methodology and given AusNet Services' objective to constrain costs and stabilise prices for customers, the continued development of the bottom up approach represents better value for money than developing, building, testing and implementing a new top-down model.

4.5.2 Historic and forecast maximum demand

Over the longer term, maximum demand has grown significantly more than energy consumption (Figure 4.7). Importantly, the growth in demand during the period 2006-2009 was strong evidence for the large augmentation capital expenditure program approved in the 2011-15 distribution determination. As Figure 4.7 shows, demand grew by around 17% between 2006 and 2009. Whilst AusNet Services did not expect growth to continue at the same rate, the AER accepted AusNet Services' forecast that maximum demand would grow by between 4.1% and 4.5% per annum.

Whilst demand declined in the period 2010-2012 (influenced by mild weather), demand has grown in 2013 and 2014. In fact, AusNet Services' maximum demand reached a new peak in 2014 – 1,886MW.[13]

Figure 4.7: Energy consumption/maximum demand index 2006-2014 (2006 = 100)



Source: AER economic benchmarking data

Over 2011 to 2014 Victoria was the only state in the NEM in which several DNSPs recorded increasing maximum demand. AusNet Services' growth in maximum demand has been driven by customer growth and increased penetration of air conditioning units. Residential customers comprise a higher proportion of total energy in AusNet Services' network compared to the other Victorian DNSPs,[14] and therefore the impact of air conditioners at peak times is likely to be more pronounced in the AusNet Services' region.

The impact of air conditioning units on maximum demand is illustrated in Figure 4.8. Using smart meter data, AusNet Services has been able to categorise residential customers into likely 'low' cooling households (no air conditioning), 'medium' cooling (one air conditioner) or 'high' cooling (two or more air conditioners).[15] Figure 4.8 shows the demand profile for each cooling category in the first

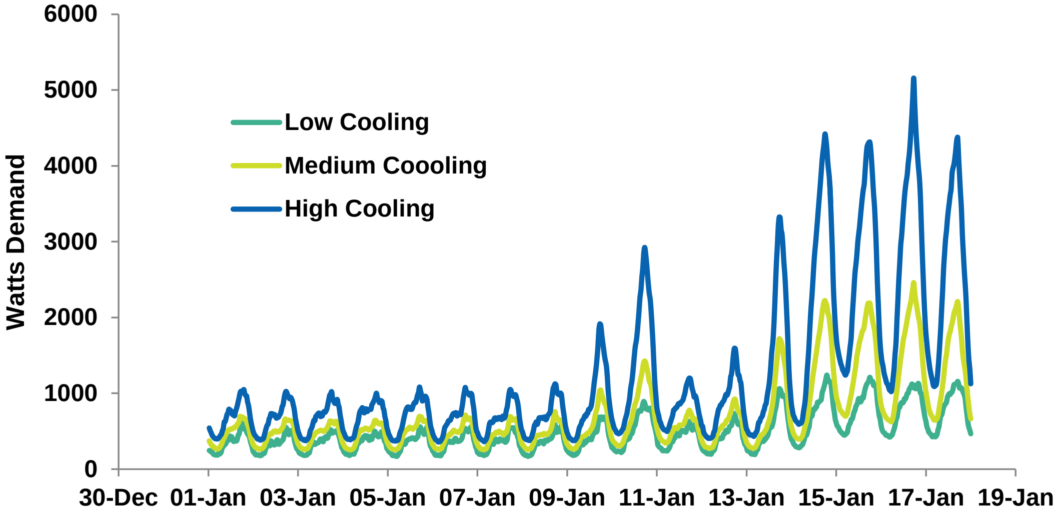
13 Raw non-coincidental demand at the zone substation level. Sourced from economic benchmarking data.

14 Sourced from economic benchmarking data.

15 Using an algorithm developed to identify step changes in residential load, for which the most likely explanation is an air conditioner being switched on. Whilst it is possible that some other energy-intensive device is responsible for the change in load for some customers, the categorisation should be accurate over a large sample of customers.

half of January 2014, up to and including the heatwave that Victoria experienced in the four days to 17 January 2014.

Figure 4.8: Demand profiles for different cooling categories, January 2014

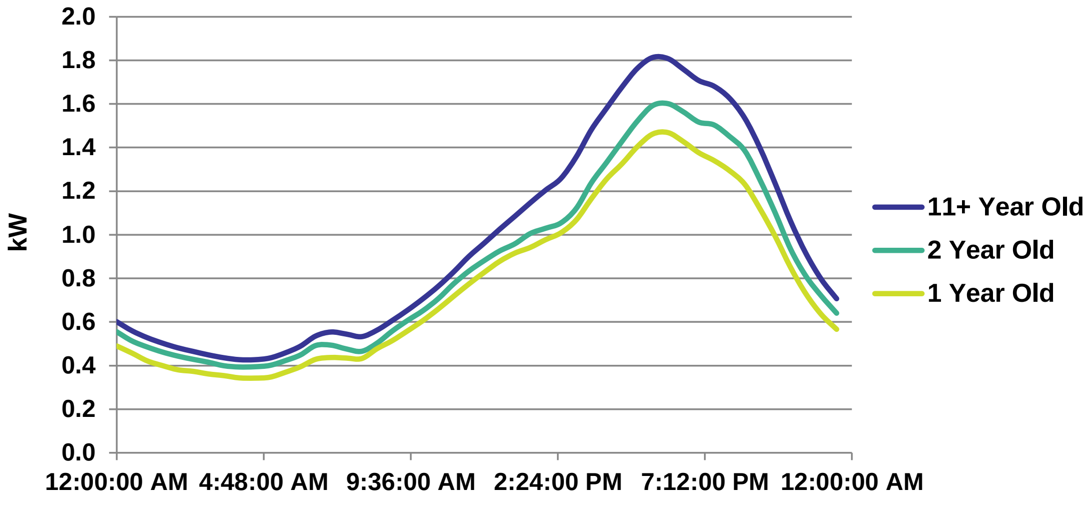


Source: AusNet Services smart meter data

The major factor offsetting growth in demand has been the increasing efficiency of households and household appliances and a recent trend towards smaller houses compared to those built last decade. That is, despite the growth in customers and air conditioners, households are becoming more energy efficient, and this reduced demand for electricity at peak times (although efficiency at peak times is counter-balanced by the impact that higher temperature has on air conditioner efficiency – refer section 4.5.3 for further commentary).

Smart meter data has again been used by AusNet Services to highlight the increasing energy efficiency and impact of dwelling size over time. Figure 4.9 plots a residential demand curve on a 35 degree day for premises of different ages. There is a clear trend towards less energy in newer houses, which are built to new energy efficiency standards and which typically feature newer, more energy efficient appliances.[16]

Figure 4.9: Residential demand profile on a 35 degree day



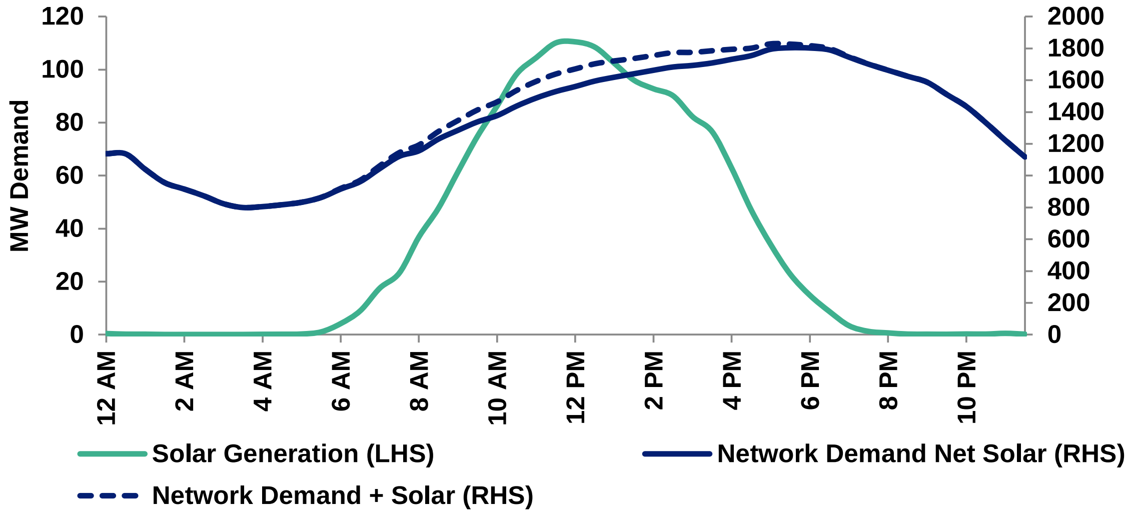
Source: AusNet Services smart meter data

[16] As outlined in the National Construction Code Volume Two. Summary available at http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx (accessed 20 March 2015).

Whilst energy efficiency has undoubtedly reduced peak demand over the last few years, the impact of solar PV installations has been negligible for most of AusNet Services' region. As noted earlier, the fact that AusNet Services has the largest proportion of residential energy of any Victorian DNSP means that, at a network level, its time of peak demand is relatively later in the day than other DNSPs.

One consequence of this is that by the time AusNet Services' network reaches its demand peak, the output from solar installations is minimal, meaning that solar customers rely on the AusNet Services' network, rather than their solar panels, to meet their demand for electricity. This is illustrated in the figure below.

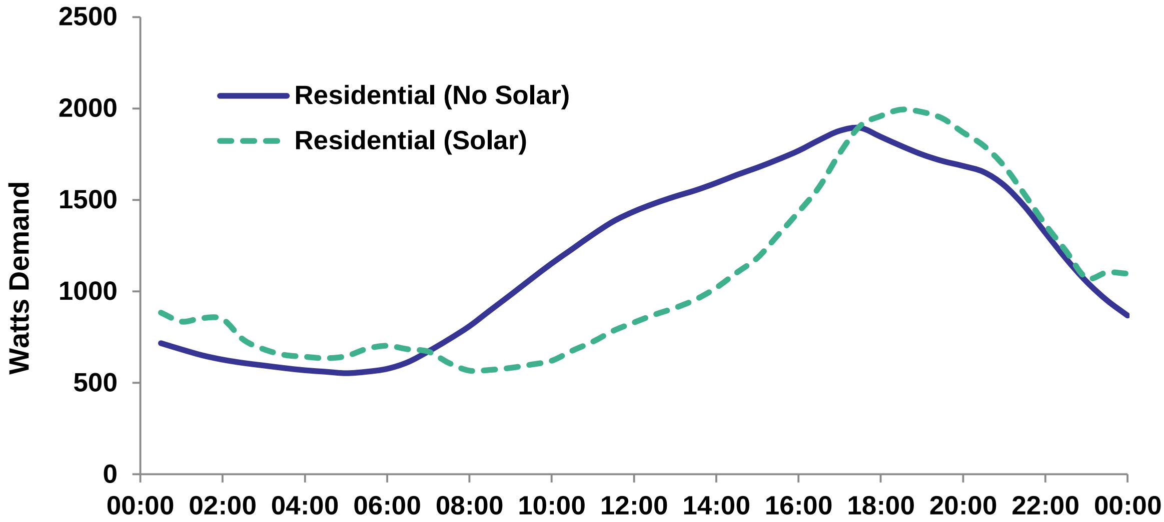
Figure 4.10: Solar generation profile v. network load profile



Source: AusNet Services smart meter data and internal solar forecasting model.

In fact, smart meter data again shows that solar customers use *more* electricity from AusNet Services' network at peak times, compared to non-solar customers, as shown below.

Figure 4.11: Residential demand profile – solar v. non-solar customers

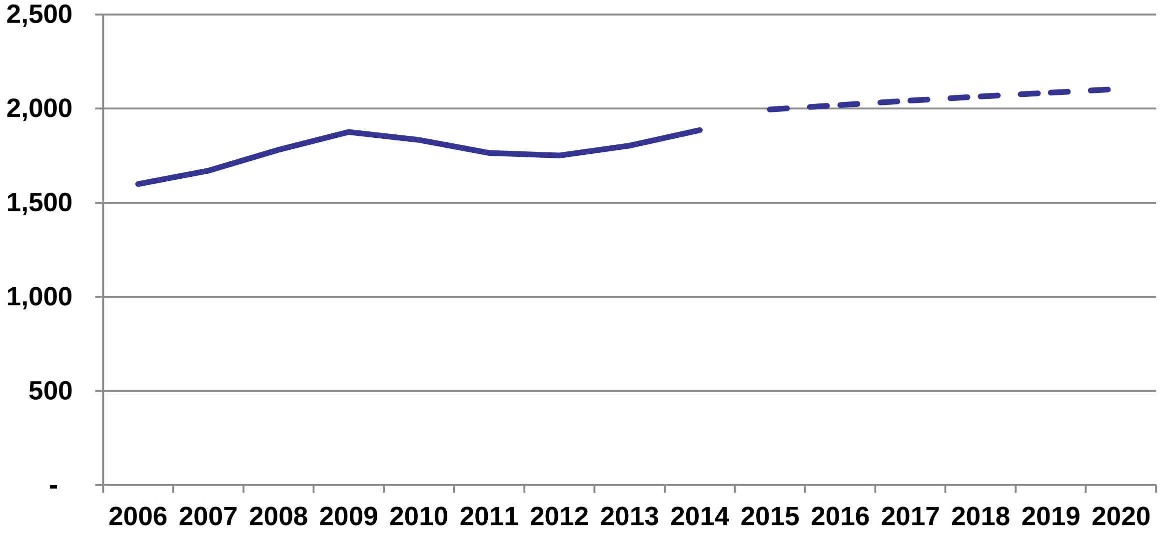


Source: AusNet Services smart meter data.

These findings have been taken into account in AusNet Services' maximum demand and energy consumption forecast models.

AusNet Services' forecasts moderating growth in maximum demand over the forthcoming regulatory period, which is consistent with demand growth in the current regulatory period. Over the 2015-2020 period, maximum demand is expected to grow at 1.1% per annum at the network level, as depicted below.

Figure 4.12: AusNet Services' maximum demand 2006-2020 (non-coincidental, MW, at zone substation, POE10)



Source: AER economic benchmarking data and AusNet Services internal forecasts (POE10).

Table 4.5: AusNet Services' maximum demand: current and forecast regulatory period (non-coincidental, MW, at zone substation, POE10)

	2011	2012	2013	2014	2015[17]	2016	2017	2018	2019	2020
Demand	1,765	1,751	1,803	1,886	1,995	2,019	2,043	2,064	2,085	2,104

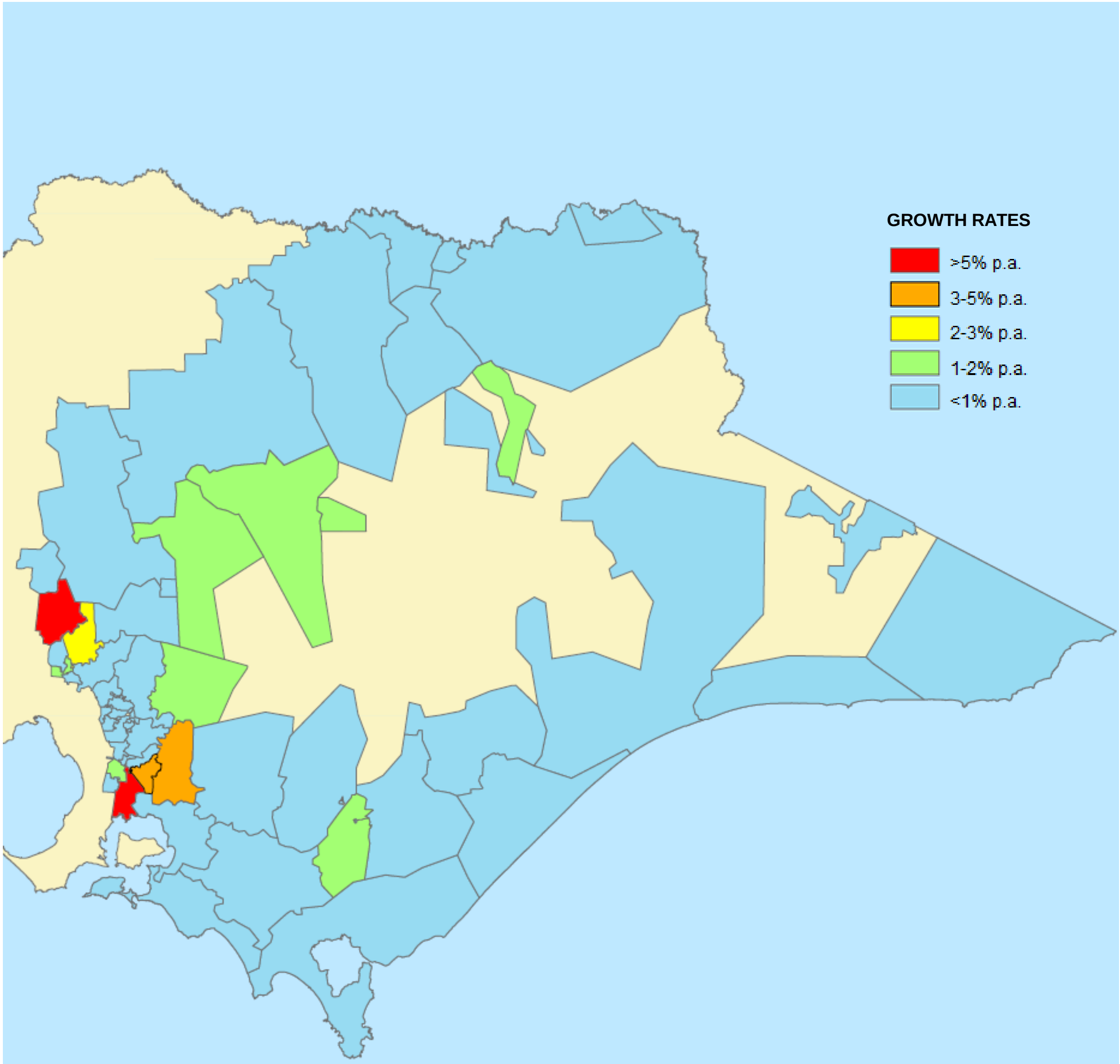
Demand growth for AusNet Services' network is focused in two major growth corridors in Melbourne's north and south-east. Two-thirds of growth in demand is isolated to population centres served by six of AusNet Services' 52 zone substations:

- Clyde North;
- Officer;
- Pakenham;
- Kalkallo;
- Doreen; and
- Thomastown.

[17] 2015 demand is an estimate based on actual 2014 demand. The 2016-2020 forecast was derived prior to final 2014 demand numbers being available, so was based on a forecast of 2014 demand, which was lower than actual. The impact of the higher 2014 demand will be included in the demand forecast prepared for the revised proposal.

The figure below shows that the majority of AusNet Services' network is expected to have minimal growth in demand over the 2016-2020 period (less than 1% per annum).

Figure 4.13: AusNet Services' maximum demand growth per annum (average) 2016-2020, by zone substation



Source: AusNet Services

4.5.3 Comparison to AEMO

In September 2014, AEMO released its maximum demand forecasts for Victoria, at the terminal station (transmission connection point) level.[18] For the terminal stations within AusNet Services' region, AEMO is forecasting flat demand over the 2015-2020 period (POE10). Whilst this is lower than AusNet Services' forecast of 1.1% growth per annum, AusNet Services notes the following:

- AEMO's forecasts assume the time of peak demand is the same across Victoria, and occurs at 1730 AEDT (POE10, medium scenario). The majority of AusNet Services' zone substations and terminal stations peak around 1800 to 1900 AEDT. The earlier time of peak demand in AEMO's forecasts means the contribution of solar is exaggerated for

[18] AusNet Services prepares demand forecasts at three levels. The lowest level is feeder level, of which there are over 300 in number. These feeders then roll up to the zone substation level and the zone substation forecasts again roll up to the terminal station level. AEMO, which is responsible for planning decisions in Victoria's transmission network, produces forecasts only at the terminal station level.

AusNet Services' region. As Figure 4.10 in section 4.5.2 shows, the contribution of solar beyond 1800 AEDT is minimal.

- AEMO assumes that the following dwelling types are available for rooftop PV: separate houses, semi-detached row or terrace houses, townhouses, blocks of flats, units and blocks of apartments.[19] AEMO's assumptions will likely over-state the potential for solar installations because a number of those dwelling types are unlikely to be good candidates for solar. For example, a block of apartments would be much less likely to install solar panels than a free standing house due to both roof-space and multiple ownership reasons. Further, AEMO's assumptions about how solar installation rates vary with occupant type, location, topography, etc., are unknown and could potentially be another source of forecasting error. For example, rental properties are much less likely to have solar PV installed than owner-occupied properties because the benefits of cheaper electricity bills do not accrue to the landlord. Similarly, properties whose orientation limits the effectiveness of solar PV are less likely candidates for solar. These assumptions would be additional factors leading to forecasting error.
- AusNet Services understands that AEMO uses the ratio of average hourly energy consumed to maximum demand as the basis for converting its energy efficiency assumptions to the amount that energy efficiency contributes at peak times. That is, if maximum demand is 1.5 times average hourly energy consumed, AEMO assumes that an annual energy efficiency of 2% would equate to 3% at the time of peak. This significantly overstates the impact of energy efficiency at peak times. For example, on a peak summer day of 42 degrees, both a new 'energy efficient' 2kW air conditioner and an older 2kW air conditioner will be using 100% of their power (i.e. 2kW) to cool a residence to, say, a thermostat setting of 22 degrees. The energy efficiency is lost as the air conditioner just works harder to get to the 22 degree setting, which is never reached. For this reason, AusNet Services assumes that demand efficiency is less than energy efficiency – in the example given above, an energy efficiency assumption of 2% will lead to a demand efficiency of less than 2%, rather than more than 2%.
- As mentioned above, the majority of AusNet Services' demand growth is in the north and south-eastern growth corridors. AEMO's forecasts for the terminal stations that service these growth corridors appear on face value to be low. The two main Local Government Areas (LGAs) in AusNet Services' region serviced by the Cranbourne Terminal Station (CBTS) are Casey and Cardinia (the Officer, Clyde North and Pakenham zone substations are located in these LGAs). The Victorian Government is expecting the number of households in these LGAs to grow by 2.6% and 5.0% respectively between 2016 and 2020, yet AEMO's forecast growth for CBTS is only 2.1%. Similarly, the Kalkallo zone substation is connected to the South Morang Terminal Station (SMTS), which itself is located in the Whittlesea LGA. Expected household growth in Whittlesea over the 2016-2020 period is 4.1% per annum, however AEMO is only forecasting demand growth of 2.0% per annum for SMTS.

4.6 Support Documentation

AusNet Services has included the following documents as support to its maximum demand forecast:

- Appendix 4A – Demand forecasting methodology; and
- Appendix 4B – ACIL Allen Consulting's report 'Distribution Demand Forecasting: Comparison of AusNet Services and ACIL Allen Methodologies'.

[19] AEMO (2014), *Forecasting Methodology Information Paper: National Electricity Forecasting Report 2014*, July, p. 30.

5. Benchmarking

5.1 Overview

5.1.1 Introduction

The AER must now consider benchmarking as part of its assessment of forecast costs. NER 6.5.6(e)(4) and 6.7.6(e)(4) state that the AER, in assessing forecast capex and opex must have regard to:

> *"the most recent annual benchmarking report and the benchmark opex/capex incurred by an efficient DNSP over the regulatory control period."*

In recognition of this obligation, AusNet Services has presented benchmarking information as part of this regulatory proposal to inform the AER's assessment.

Benchmarking can take a number of forms:

- Comparing a firm against its own historical performance;
- High level cost comparisons between the capex, opex or the asset base of firms;
- Detailed cost category analysis which compares categories of opex (such as corporate costs, maintenance or vegetation management) or capex (augmentation, replacement, non-network) between firms;
- Productivity benchmarking which use normalised outputs and inputs where outputs (including energy transported, network capacity and customer numbers) are analysed against inputs (opex and asset base). This may be at the total productivity level or the partial level (partial performance indicators (PPIs)) where analysis focuses on the inputs used to produce a single output.

The current focus of economic benchmarking in energy network regulation in Australia is total factor productivity. In its recent decisions[1], the AER used Multilateral Total Factor Productivity (MTFP) to measure the productivity of the electricity distribution sector over time and the productivity of DNSPs in the NEM relative to each other. The AER, through its consultant, Economic Insights, has employed a range of statistical techniques to measure productivity and collected historical data to enable it to measure productivity.

This chapter is focused on measures of overall productivity. AusNet Services' benchmarking performance by cost category is addressed in the relevant expenditure chapters (Chapter 7 Capital Expenditure and Chapter 8 Operating Expenditure).

5.1.2 Benchmarking in context

Appropriate use of benchmarking

AusNet Services supports the use of benchmarking to form a high level comparative view of efficiency where relevant. Benchmarking can be used to compare the relative performance of peer firms to support regulatory decision making and to work in combination with incentive schemes such as the EBSS to drive efficiency improvements.

The AER will no doubt appreciate the need to ascertain how useful benchmarking is in explaining the efficiency of DNSPs and how it can be applied to explain and distinguish the differences between them. MTFP analysis is still in an early development stage in our regulatory regime and there are a number of issues which still need to be addressed in its development for regulatory use:

- refinement and testing of the preferred specification including inputs and outputs;

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1 AER, *Draft Decision: AusGrid/Endeavour/Essential Distribution Determination 2015-19 Attachment 7: Opex*, November 2014.

- application and consideration of alternative MTFP specifications;
- proving the explanatory power of benchmarking results;
- developing appropriate methods to account for firm-specific environmental and operating factors; and
- improving the consistency and comparability of data across businesses.

Given the above, it is difficult to draw any concrete conclusions from the AER's first set of overall MTFP results. It would be inappropriate and inconsistent with good regulatory practice to apply benchmarking deterministically at this stage. However, once benchmarking has been well established, it can potentially be applied by the AER to support regulatory decisions in pursuit of attaining the objectives of the NEO.

A prudent approach to using overall MTFP benchmarking at this point would be to recognise the range of results that are possible and be informed by the relative performance of groups of distributors (i.e those above or below the industry average, or, those in the top quartile and bottom quartile). For example, in the Draft Decision for NSW Electricity DNSPs[2], the AER compared the results of its opex partial TFP model with three econometric models.[3] The results of these were largely consistent and stable, and gave the AER an indication of the higher and lower levels of relative efficiency within the electricity distribution sector. A reasonable approach to using this information would be to continue to use revealed costs in assessing the opex forecasts of firms which appear relatively efficient. This also allows these firms to continue to respond to efficiency incentives provided in the regulatory regime.

In situations where benchmarking evidence might be used to adjust base opex, adjustments should be based on the most recent measured levels of productivity, not historical averages. This is because historical measures of productivity do not reflect the implied efficiency frontier existing today. Targeting a productivity level from the past fails to adequately account for the inputs required to provide network services today- that is, with current regulatory obligations, service scope and input costs.

Benchmarking is one of a number of factors which the AER must take into account in assessing forecasts. As such, weight given to benchmarking should not only reflect how meaningful the benchmarking results are but also the quality and availability of other assessment information. Namely, the availability of benchmarking data does not mean the AER should not continue to investigate a firm's efficiency through direct and thorough engagement with the business.

Safety and productivity

The Victorian community and Government have made an explicit decision to reduce the risk of bushfires. In response, AusNet Services has responsibly invested both capex and opex and made significant advances in bushfire mitigation. Positive outcomes since 2009 which AusNet Services views as productive include:

[2] AER, *Draft Decision: AusGrid/Endeavour/Essential Distribution Determination 2015-19 Attachment 7 Opex*, November 2014

[3] The opex cost functions used were: Cobb Douglas Stochastic Frontier Analysis (SFA CD); Cobb Douglas Least Squares Econometrics (LSE CD); and Translog Least Squares Econometrics (LSE TLG).

- an 85% decrease in cross-arm related fires;
- a 50% decrease in high voltage fuse related fires; and
- a 30% decrease in electric shock incidents.

However as safety is not captured or accounted for in the AER's modelling of productivity, the costs associated with the above improvements fail to be balanced by a corresponding boost to productivity. This is despite the obvious correlation between enhanced safety and the attainment of key elements of the NEO.

While AusNet Services' overall performance under the AER's MTFP analysis shows that it is among the more productive NSPs, its year on year productivity appears to be declining under the AER's approach to TFP due to the model not capturing the productivity value of safety improvements.

5.1.3 Chapter structure

This chapter describes AusNet Services' performance against a number of benchmarking measures and provides information to assist the AER in considering benchmarking in its assessment of forecasts. The chapter is structured as follows:

- Section 5.2 highlights AusNet Services' benchmarked performance in a number of measures.
- Section 5.3 addresses firm-specific factors and operating environment considerations which must be considered to ensure AusNet Services' benchmarking results are interpreted accurately.

5.2 Benchmarked Performance

5.2.1 Multilateral Total Factor Productivity (MTFP)

MTFP can be derived from a range of input and output specifications and each specification may include different weightings of inputs and outputs.

In its 2014 Annual Benchmarking Report,[4] the AER reported MTFP scores which used a specification of inputs and outputs developed by its consultant, Economic Insights, as set out in the table below.

[4] AER, *Electricity Distribution Network Service Providers Annual Benchmarking Report*, November 2014, p. 42.

Table 5.1: AER MTFP input/output specification[5]

Inputs
Opex $ (deflated by EGWW index)
Overhead lines – subtransmission (>33kv) MVAkms
Overhead lines – distribution (<33kv) MVAkms
Underground cables – subtransmission MVAkms
Underground cables – distribution MVAkms
Transformer capacity (excluding the first stage of two stage transformation) MVA

Outputs	Weighting
Energy	13%
Ratcheted maximum demand	18%
Customer numbers	46%
Circuit length	24%
Reliability (minutes off supply)	Treated as a negative output

Source: Economic Insights

According to the AER's November 2014 MTFP analysis, AusNet Services ranked eighth out of thirteen DNSPs for MTFP in 2013 with a score of 1.12, just below the industry average productivity score of 1.15, and 31% from the efficiency frontier.[6]

Impact of safety and bushfire expenditure on MTFP results

Significant expenditure on safety and bushfire mitigation has impacted AusNet Services' MTFP score. As explained above, AusNet Services has invested heavily in safety and bushfire mitigation since the 2009 Black Saturday Bushfires and this is an operating factor which should be taken into account in benchmarking analysis. On some views, the region covered by AusNet Services' distribution network can be considered amongst the most bushfire-prone in the world. This causes benchmarking analysis to be somewhat inadequate in appropriately reflecting the imperative to inject spending into bushfire mitigation programs.

AusNet Services therefore urges the AER to give minimal weight to benchmarking analysis which does not properly accommodate this important distinction.

To enable clearer comparison of performance under the AER's MTFP analysis, it is important to see results where AusNet Services' safety and bushfire mitigation opex and capex over 2011-13 (when additional expenditure was incurred following the VBRC) is excluded from the inputs. These results are shown in the figures below which illustrates AusNet Services' 2013 MTFP score against the rest of the distributors in the NEM, and its MTFP score over time when safety expenditure is included and excluded from the analysis.

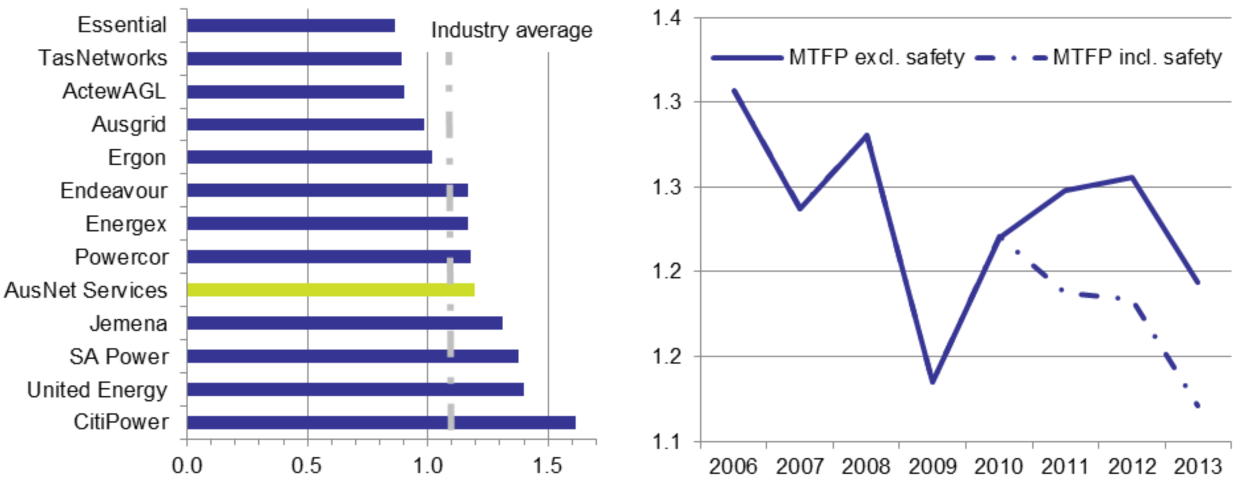
5 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs* - November 2014, pp. 9-13.

6 AER, *Electricity Distribution Network Service Providers Annual Benchmarking Report*, November 2014, p. 42.

Figure 5.1: Comparative MTFP Scores

2013 MTFP scores excluding AusNet Services' safety opex and capex

AusNet Services' MTFP since 2006 with and without safety opex and capex



Source: AER's 2014 Annual Benchmarking Report MTFP data and AusNet Services data. MTFP scores calculated using AER's MTFP specification. Safety and bushfire capex and opex from 2011-13 excluded.

The above figures show that the impact of safety expenditure on total productivity is material. When safety expenditure is excluded, AusNet Services' 2013 productivity score is 1.19, rather than 1.15. This score is higher than the industry average of 1.15 and places AusNet Services fifth out of thirteen DNSPs and 26% from the efficiency frontier. Further, AusNet Services' productivity trend over time has clearly been affected. Productivity can be observed to have increased since 2009 rather than declined in the absence of safety expenditure. While the analysis still shows a negative productivity trend from its 2006 starting point, the drop in AusNet Services' MTFP score since 2006 is 9%, rather than 14%.

MTFP results are highly sensitive to the outputs measured and AusNet Services notes that there are a number of other valid approaches to measuring outputs which should be considered in analysing performance in economic benchmarking.

Insights from an alternative MTFP approach

For example, MTFP analysis conducted by Huegin for AusNet Services uses the same inputs and model specification as the AER but different outputs, yielding quite different results.[7] Huegin's modelling uses system capacity and customer connections as the two outputs (weighted at 25% and 75% respectively), an approach which reflects the AER's original MTFP modelling from July 2014 which used system capacity as an output. The raw MTFP scores have then been adjusted (using second stage regression) for customer density. Adjustment of raw scores using second stage regression to take into account operating factors was recognised by the AER/ACCC as a useful method in the development of the Better Regulation Guidelines:

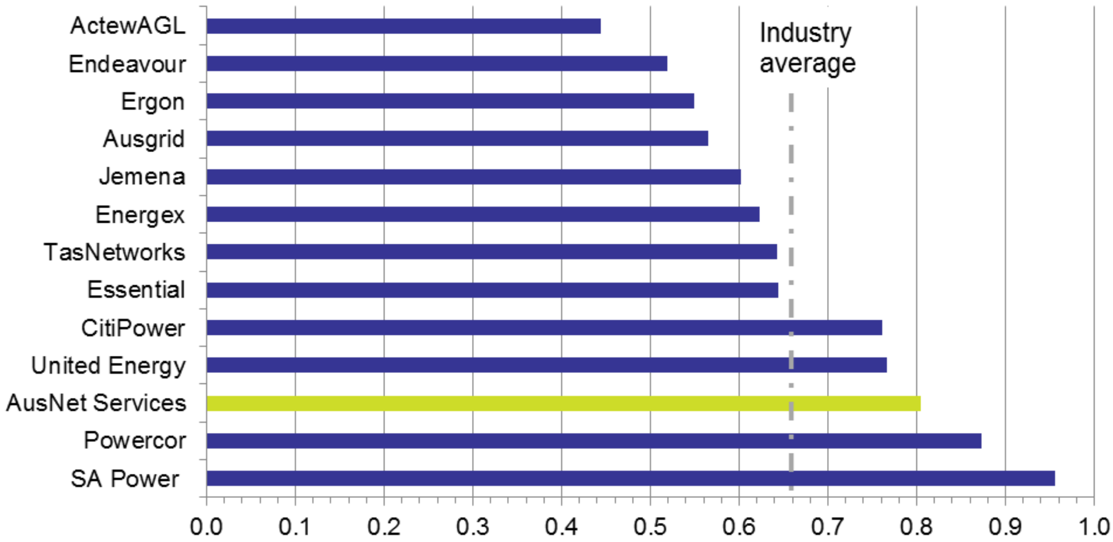
7 The inputs in this analysis, to mirror the AER's inputs, include AusNet Services' safety and bushfire expenditure over 2011-13.

"For meaningful comparison using benchmarking, it is important to consider and, where necessary, control for business environment differences that are out of management control but have a material impact on productivity and efficiency performance…in practice, where more diverse NSPs might be included for economic benchmarking it would be necessary to explicitly model the impact of key operating environment factors that may affect NSP performance.

One way to model the impact of operating environment factors is to run two-stage regression analysis of raw MTFP result..."[8]

Huegin considers that customer density is a critical environmental variable that is both exogenous to management control and has a material impact on a DNSP's productivity score (when using this output/input specification). As such, it is prudent to factor it into the analysis before inferences as to relative efficiency can be made. Huegin's MTFP analysis is shown in the figure below.

Figure 5.2: Huegin 2013 MTFP Results



Source: Huegin Consulting, using AER's 2014 Annual Benchmarking Report MTFP data including AusNet Services' safety and bushfire expenditure over 2011-13. MTFP scores calculated using AER's MTFP specification with system capacity and customer connections as the two outputs (weighted at 25% and 75% respectively).

The above results show that under this different specification of the AER's model, and taking into account customer density, AusNet Services ranks third in MTFP in 2013 with a score of 0.8, placing it only 16% from the efficiency frontier.

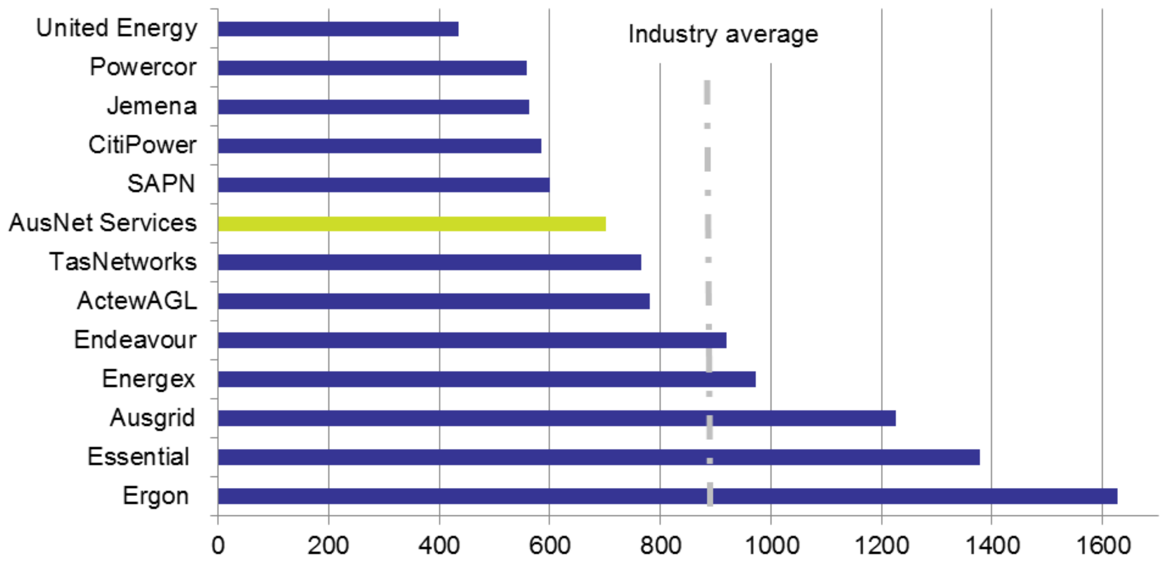
This confirms that MTFP results are highly sensitive to the outputs measured and that a range of results are possible depending on the specification of the model. Given this, it is important to consider the results of alternative approaches in interpreting benchmarked performance.

5.2.2 Total cost

Total cost or totex (the sum of opex and capex) provides a view of all inputs (costs) required for production (network service). The figure below shows the average totex per customer for each business from 2009-13.

8 ACCC Regulatory Development Branch, *Economic Benchmarking Model: Technical Report*, November 2012, pp. 4-5.

Figure 5.3: 2009-13 average totex (capex plus opex) per customer ($)



Source: AER RIN data

With an average totex cost of $701 per customer over 2009-13 AusNet Services compares well against its peers on this measure as AusNet Services' customers pay 18% less than the industry average of $855.

5.2.3 Opex efficiency

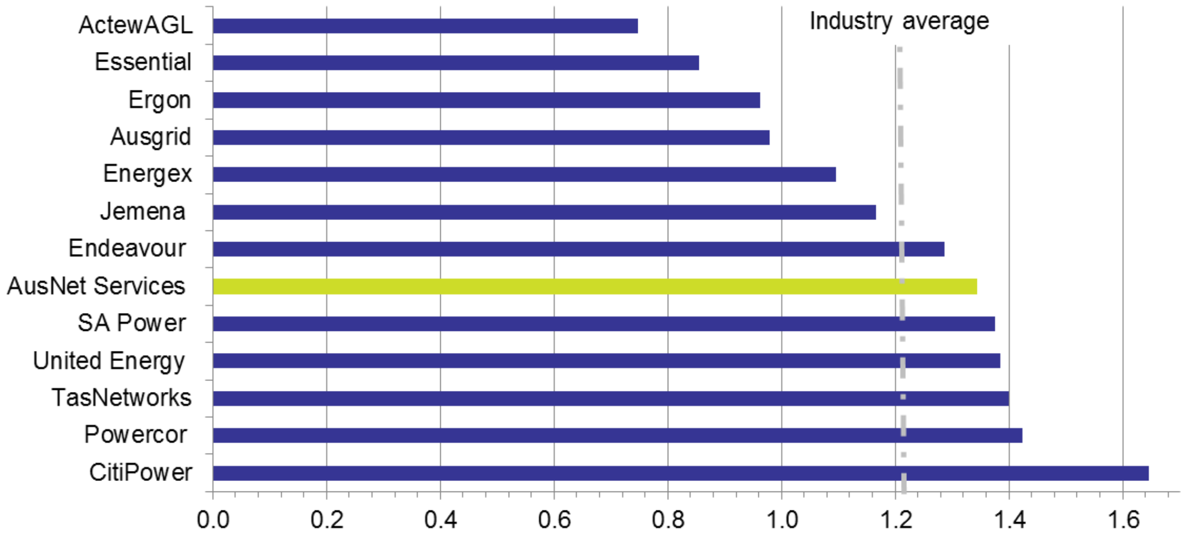
Benchmarking conducted by the AER's consultant Economic Insights and relied upon in the draft decisions for NSW/ACT DNSPs identifies AusNet Services as one of five distributors within the top quartile of DNSPs with respect to opex efficiency (along with CitiPower, Powercor, SA Power Networks and United Electricity Distribution).[9] The 2006-13 average opex productivity scores of these businesses were used to set an efficiency benchmark against which the efficiency of NSW/ACT DNSPs was assessed.

However, due to the impact of significant additional costs incurred as part of the bushfire mitigation program, AusNet Services' performance in opex partial factor productivity (PFP) in 2013 shows it ranked eighth out of thirteen firms, with an opex PFP score of 1.13, and below the industry average. As such, safety expenditure should be excluded from the analysis to allow a clearer comparison of opex productivity performance.

As shown in the figure below, AusNet Services' performance ranks sixth out of thirteen when safety and bushfire expenditure is excluded from the AER's opex PFP analysis.

[9] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, pp. 47-48.

Figure 5.4: 2013 Opex PFP Scores excluding AusNet Services' safety/bushfire opex



Source: AER's 2014 Annual Benchmarking Report MTFP data and AusNet Services' data. MTFP scores calculated using AER's MTFP specification. Safety and bushfire and opex from 2011-13 excluded.

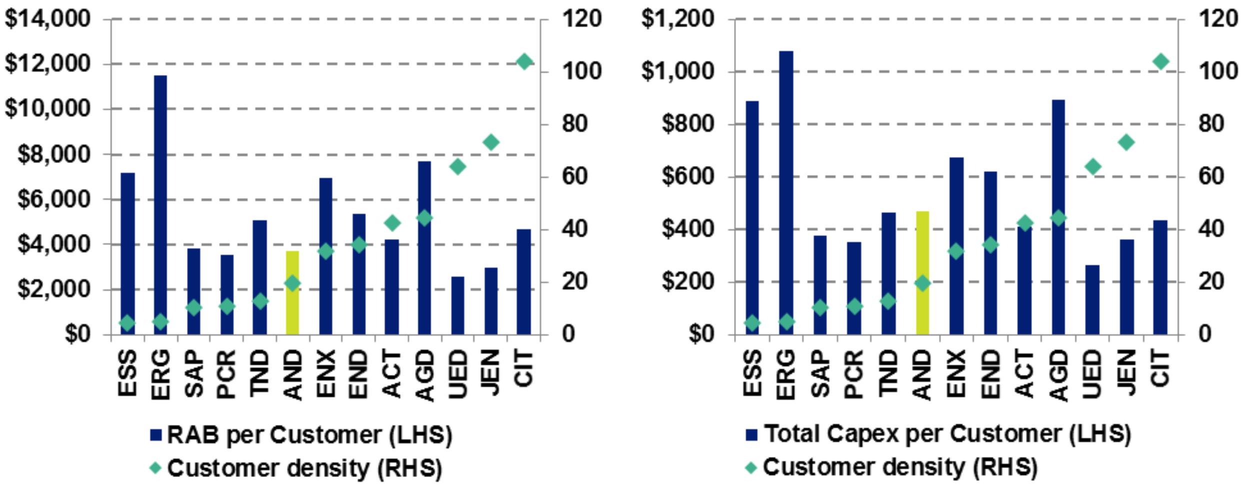
The above figure also shows that when safety expenditure is removed from the analysis AusNet Services' opex PFP score of 1.34 is better than the industry average of 1.21. This reflects the view of Economic Insights (based on the 2006-13 average opex productivity scores) which is that relative to other firms, AusNet Services' opex productivity is efficient.[10]

5.2.4 Capex efficiency

A firm's regulated asset base and average capex gives a view of the capital inputs used by a network to provide energy supply and is a representation of a cost faced by customers (as firms earn a return on and return of capital in the regulated asset base). The figures below show the cost per customer for each firm's opening asset base in 2013 and the average 2009-13 total capex against customer density.

[10] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, pp. 47-48.

Figure 5.5: 2013 Asset Base per customer and 2009-13 Average total capex per customer $



Source: AER RIN data, AusNet Services shown as AND. 2009-13 average capex has been sued as capex can be lumpy in nature, therefore an average over five years gives a better comparison of capex than a single year.

AusNet Services compares well on the above measures of capex efficiency against its peers. AusNet Services has an asset base cost per customer of $3,843 which is 28% lower than the industry average of $5,332, placing it fourth out of thirteen DNSPs. Average capex per customer of $378 is 33% less than the industry average of $561. It is noted however that since 2010 AusNet Services' asset base and capex costs per customer have been growing as the business has invested heavily in safety capex and will continue to do so over the forecast period.

5.3 Considerations in Interpreting AusNet Services' Benchmarked Results

Performance differences in the AER's benchmarking results may not relate to efficiency but, rather, may be driven by firm-specific factors. For example, the extent of vegetation management that is required on a network will be affected by the location of its power lines (urban environments or through bushland) and environmental factors may affect the deterioration rate of assets (coastal locations suffer corrosion damage).

Therefore, in order to interpret results accurately, firm-specific factors which impact benchmarking outcomes should be taken into account. In AusNet Services' case, there are two principal factors which impact its overall productivity:

- **Residential customer base:** Approximately 90% of AusNet Services' customers are residential, which means it has one of the peakiest loads in the NEM and the lowest energy consumption per customer.
- **Rural network:** Over 90% of AusNet Services' network (by line length km) is located in rural areas and can be reasonably expected to have lower overall levels of network rel than urban networks. Also, because more than 80% sits in high bushfire risk areas (HBRA), AusNet Services is subject to significant community safety and bushfire compliance and expenditure requirements.

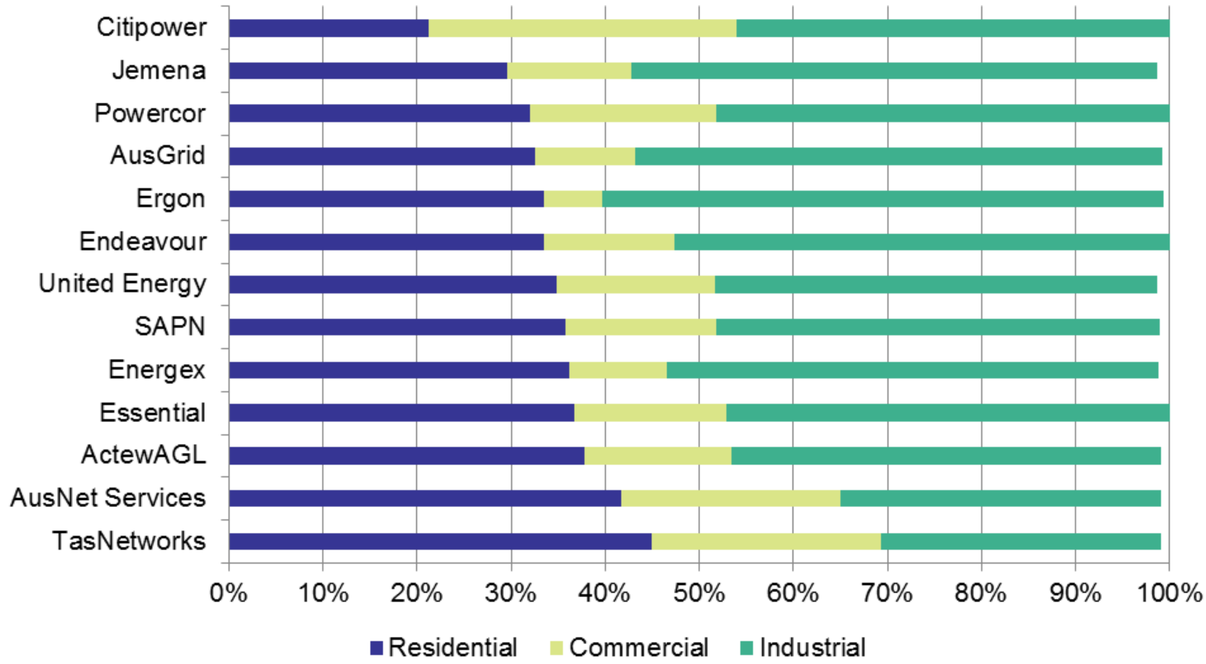
The impact of these factors on AusNet Services' benchmarked performance is explained in further detail below.

The consequence of these factors is that they drive relatively higher capex and opex requirements (inputs), and lower energy throughput and network reliability (outputs), which affect AusNet Services' productivity. It is therefore crucial that AusNet Services' benchmarking outcomes be interpreted in a manner which takes into account these firm-specific factors.

5.3.1 Residential customer base

Approximately 90% of AusNet Services' customers are residential. When examining residential load as a proportion of total load, AusNet Services has the second highest proportion of residential load in the NEM, and the second lowest proportion of industrial load. This is shown in the figure below.

Figure 5.6: 2013 residential, commercial and industrial energy consumption as % of total



Source: AER RIN data. Commercial load based on "energy delivered to non-residential customers not on demand tariffs" and industrial load based on "energy delivered to non-residential customers on high and low voltage demand tariffs."

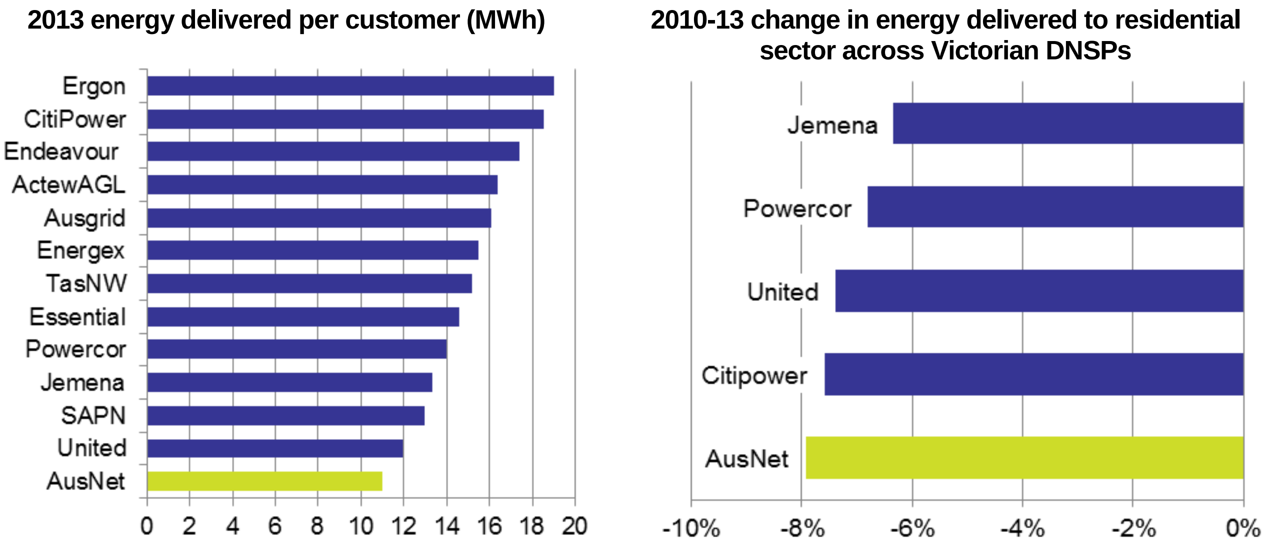
The figure above shows that AusNet Services has the most residential customer base in Victoria. In 2013, 42% of AusNet Services' energy was delivered to residential customers, compared to United Energy (35%), Powercor (32%), Jemena (30%) and CitiPower (21%).

AusNet Services' high residential and low industrial customer base has two significant impacts on productivity: lower energy throughput and peakier demand.

Lower energy throughput

A high proportion of residential load leads to lower energy consumption per customer, as residential customers do not use as much energy as commercial and industrial customers. In 2013 AusNet Services had the lowest energy consumption per customer in the NEM as shown in the figure below.

Figure 5.7: Low and falling energy delivered



Source: AER RIN data

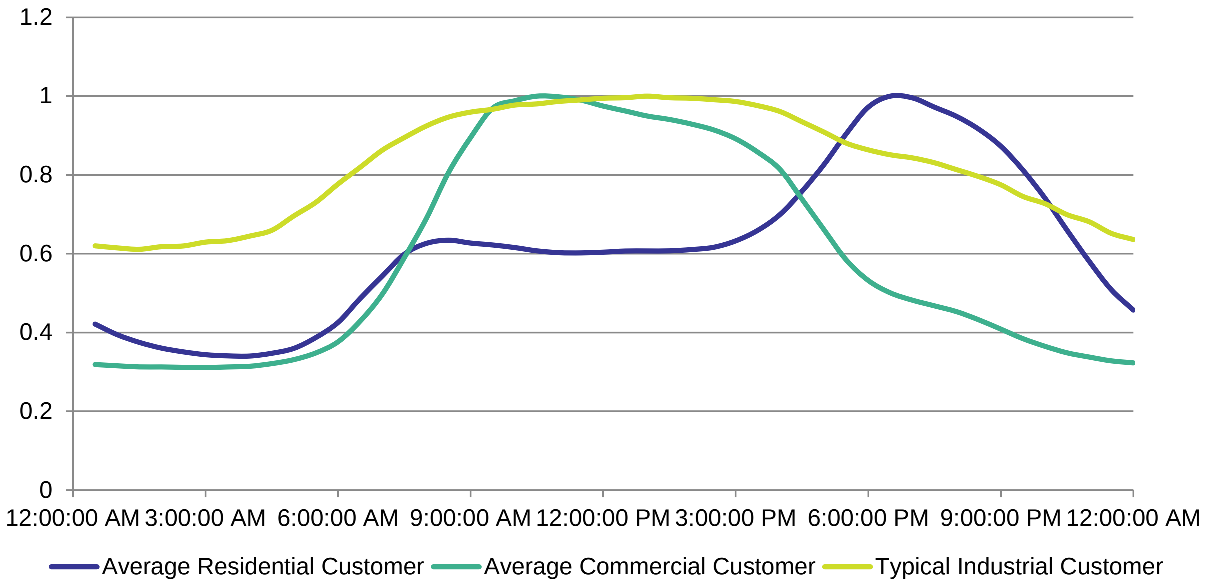
The figure above also shows that since 2010 (when total energy consumption peaked in Victoria), AusNet Services has recorded the largest fall (8%) in residential energy consumption of all Victorian DNSPs. This is driven by greater uptake of solar energy, changed customer behaviour in response to rising energy prices and increased energy efficiency in the residential sector.

Given the AER's productivity benchmarking features energy throughput as a measured output, AusNet Services' low and falling energy throughput depresses its measured productivity. As this is directly a result of AusNet Services' customer base, it is outside of the business's control, and should be taken into account as a relevant factor in interpreting benchmarked results.

Amplifies demand peak

The residential nature of AusNet Services' load is a major contributing factor to network demand being highly peaky. This is because residential customers generally use energy at the same time (when people wake up or get home from work) and are highly sensitive to weather. At the same time, AusNet Services has the second lowest industrial load on its network compared to its peers (as shown in Figure 5.6 above). The demand profile of industrial load is generally flatter as production is run across more of a 24 hour period. The following figure illustrates this, and shows how the demand profile of residential customers is highly peaky compared to that of commercial and industrial customers.

Figure 5.8: Typical demand profiles of AusNet customers over 24 hours



Source: AusNet Services, 2014 data.

Note: The vertical axis shows an index of demand, with the value of 1 representing peak demand for each typical customer.

For network reliability reasons, AusNet Services must ensure the network has sufficient capacity to meet forecast peak demand. Where peak demand is growing, as is the case in AusNet Services' network (albeit at a slower rate than in the past) this normally involves investing capex to augment or expand network capacity to meet that peak.[11] However, the peakiness of demand on AusNet Services' network means that the total network capacity provided is not utilised as much as it would be with a flatter load.

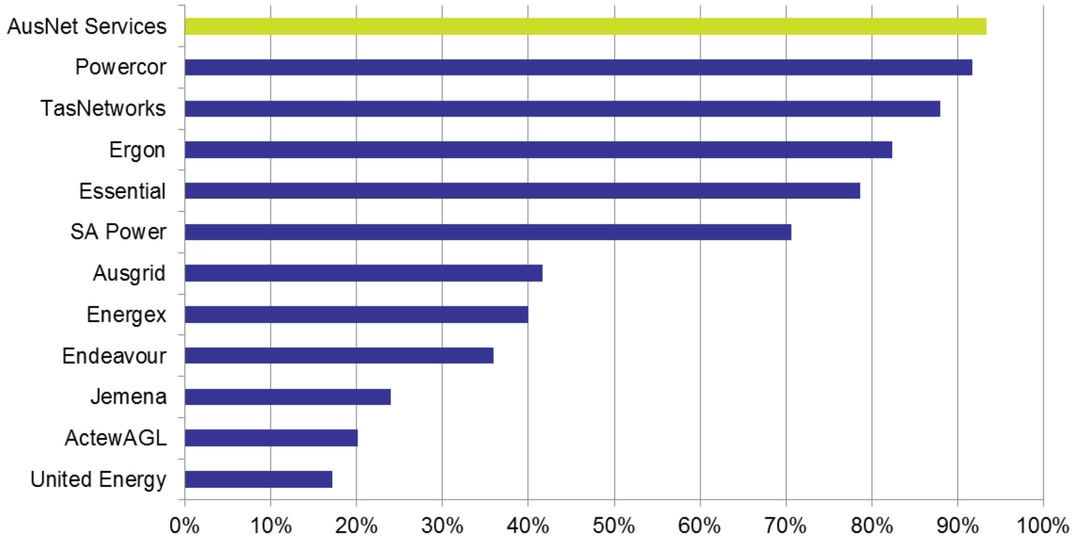
A consequence of this is that it increases AusNet Services' inputs (capex) relative to outputs, thus reducing measured productivity in the AER's benchmarking. As this is largely a result of AusNet Services' customer base and is outside of the business's control, it should be taken into account as a relevant factor in interpreting benchmarked results.

5.3.2 Rural network and safety investments

In 2013 the DNSP with the highest proportion of its network (by km of line length) located in rural areas was AusNet Services at 93%, as shown in the chart below.

[11] Although in cases where a non-network solution is feasible and cost-effective, it will be implemented.

Figure 5.9: Proportion of network in rural area (km line length) in 2013



Source: AER RIN data. Reported by DNSPs as distribution line route length classified as short rural or long rural in km / total network line length. CitiPower not reported as it has 0% of lines in rural areas.

A main impact of having a highly rural network is that it generally delivers lower overall reliability compared to an urban network. This is reflected in the AER's STPIS targets which set much lower reliability targets for rural areas. Given that the AER's benchmarking includes network reliability as one of the outputs measured, the lower reliability levels which naturally correspond to owning a rural network would contribute to lowering AusNet Services' measured productivity.

The highly rural nature of AusNet Services' network requires it to invest heavily in safety and bushfire mitigation. Substantial additional expenditure was incurred during the current regulatory control period in order to comply with recommendations of the 2009 Victorian Bushfire Royal Commission (VBRC) and the subsequent changes to AusNet Services' ESMS (Safety Scheme). These costs have contributed to higher opex and capex (inputs) from 2011 onwards and consequently reduced overall productivity because safety is not measured as an output under the AER's MTFP production function.

As shown above in section 5.2, the impacts of the significant capex and opex invested in safety since 2011 has clearly affected AusNet Services' benchmarked results and depressed productivity scores.

Given the above, any interpretation of AusNet Services' benchmarking outcomes should take into account how our reliability performance is impacted by owning a rural network and our specific safety and bushfire obligations. Further benchmarking modelling should be adjusted to account for normalised service performance and the costs associated with safety and bushfire obligations.

Part II –
Standard Control Services

missionzero

6. Building Block / Revenue Requirement

6.1 Overview

6.1.1 Introduction

Part II of this regulatory proposal (including Chapters 6 through 16) focuses on Standard Control Services (SCS). These are the primary distribution network services consumed by AusNet Services' customers, and involve the provision of continuous connection and availability to the electricity grid. AusNet Services is adopting the service classification set out in the AER's final Framework and Approach paper to determine which services are included in SCS.[1]

This chapter details the calculation of AusNet Services' annual revenue requirement, in accordance with the building block approach outlined in the NER and the AER's PTRM. A summary of the building block components, the unsmoothed and smoothed revenue for each year of the forthcoming regulatory control period is presented.

Chapters 7 to 16 provide the detail of AusNet Services' regulatory proposal for Standard Control Services.

6.1.2 Chapter structure

The remainder of this chapter is structured as follows:

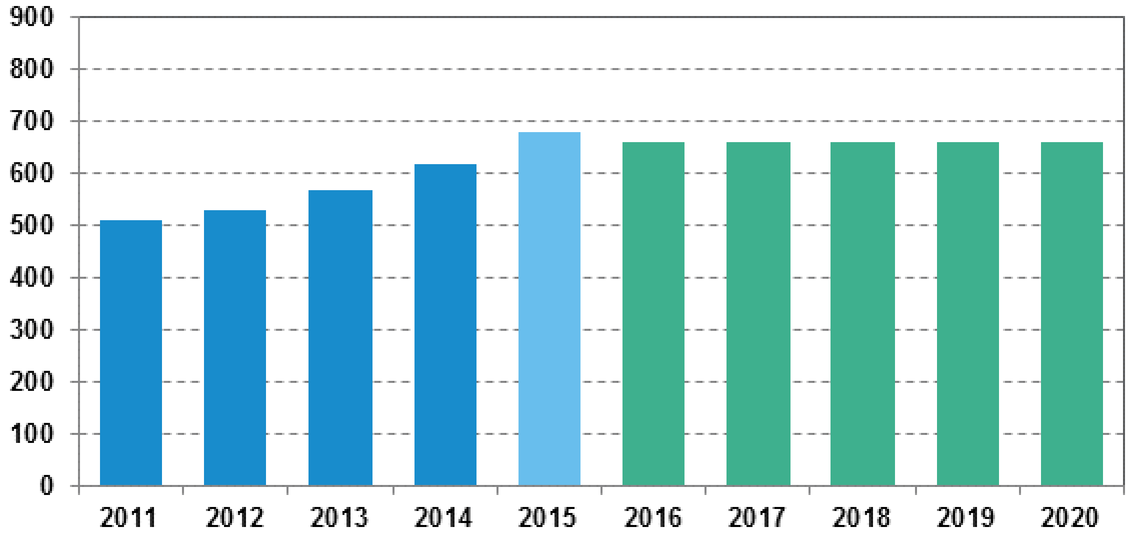
- Section 6.2 presents AusNet Services' revenue requirement;
- Section 6.3 presents a summary of the building block components of the revenue requirement;
- Section 6.4 presents AusNet Services' smoothed revenue requirement for each year of the forthcoming regulatory period, including a description of the X-factors adopted;
- Section 6.5 describes the revenue requirement adjustments that may occur in the forthcoming regulatory control period; and
- Section 6.6 lists the supporting documentation for this chapter.

6.2 Summary of AusNet Services' Revenue Requirement

Based on the detailed inputs described and calculated in this Proposal, AusNet Services' smoothed revenue requirements for 2016-20 is $661 million per annum (2015 real).

1 Appendix 1B – Service Classification Proposal.

Figure 6.1: Revenue 2011 to 2020 ($m, real 2015)



Source: AusNet Services.

Note: Shows actual revenue to 2014 excluding STPIS revenue and including costs that are rolling into Standard Control Services in the next regulatory control period (Bairnsdale network support contract and from AMI program), 2015 revenue is estimated.

6.2.1 Comparison to previous period

AusNet Services is including a number of costs in the forthcoming regulatory control period that were previously recovered outside the price cap in the current period. Specifically:

- The cost of a large network support contract, previously recovered through an adjustment to the tariffs during the annual tariff setting process; and
- Costs associated with the AMI smart meter program upgrades to core distribution systems (such as the billing system) where it is now appropriate to subsume them into the standard control distribution service.

Therefore, any meaningful like-for-like comparison must either include or exclude this revenue from both the current and forthcoming period. The figure above illustrates real revenue over the current and forthcoming period, net of STPIS payments, and shows that total revenue will be $399 million higher in the new period on a like-for like basis. After a period of annual average growth of 7.4% in the current period, annual revenue falls by 2.4% in 2016, and remains flat to 2020.

6.3 Building Block Components of the Revenue Requirement

The building block components and AusNet Services' unsmoothed annual revenue requirements for each year of the forthcoming regulatory control period are depicted in the table below.

Table 6.1: Unsmoothed Revenue Requirement

(Nominal $M)	2016	2017	2018	2019	2020
Return on Capital	255.2	274.4	293.9	312.4	333.9
Depreciation	126.0	92.3	106.9	78.7	74.4
Operating & Maintenance Expenditure	246.8	259.4	273.6	282.4	293.9
Revenue Adjustments	1.5	-6.1	-7.3	13.2	-0.5
Benchmark Tax Liability	61.6	47.0	54.1	53.4	45.9
Unsmoothed Revenue Requirement	**691.0**	**666.9**	**721.2**	**740.3**	**747.5**

Note: The AER PTRM includes the DMIA in the opex building block.

The unsmoothed annual revenue requirement is calculated as the sum of the building block components, which are described in the sections below, and detailed in the Chapters that follow.

6.3.1 Regulatory Asset Base

AusNet Services' Regulatory Asset Base (RAB) has been calculated in accordance with the requirements of Clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capital expenditure (capex) forecasts set out in Chapter 7 of this proposal, the opening RAB based on expenditure in the current regulatory period as detailed in Chapter 14, and depreciation calculated in Chapter 15. The table below sets out a summary of the derivation of AusNet Services' RAB for the forthcoming regulatory control period.

Table 6.2: Regulatory Asset Base for the Forthcoming Regulatory Control Period

(Nominal $M)	2016	2017	2018	2019	2020
Opening RAB	3,547.2	3,814.5	4,084.8	4,343.2	4,641.5
Net Capex	393.4	362.5	365.3	377.0	368.5
Economic Depreciation	-126.0	-92.3	-106.9	-78.7	-74.4
Closing RAB	3,814.6	4,084.8	4,343.2	4,641.5	4,935.6

6.3.2 Return on Capital

Consistent with the requirements of Clause 6.4.3(a)(2) of the NER, and in accordance with the AER's PTRM, the return on capital is calculated by applying the post-tax nominal vanilla WACC to the RAB for each year of the regulatory control period. The table below illustrates the calculation of the return on capital building block. The WACC used in this calculation was determined in accordance with the provisions set out in Clause 6.5.2 of the NER. Full details of the WACC calculation are set out in Chapter 12 of this proposal.

Table 6.3: Return on Capital for the Forthcoming Regulatory Control Period

(Nominal $M)	2016	2017	2018	2019	2020
Opening RAB	3,547.2	3,814.5	4,084.8	4,343.2	4,641.5
Return on Capital	255.2	274.4	293.9	312.4	333.9

6.3.3 Depreciation

The calculation of regulatory depreciation was carried out in accordance with the AER's PTRM and Clause 6.5.5 of the NER, and is detailed in Chapter 15 of this proposal. Consistent with the requirements of Clause 6.4.3(a)(1) and (3) of the NER, AusNet Services has incorporated an allowance for depreciation in its building block revenue requirement. The table below lists the regulatory depreciation building blocks for each year of the forthcoming regulatory control period.

Table 6.4: Depreciation for the Forthcoming Regulatory Control

(Nominal $M)	2016	2017	2018	2019	2020
Nominal Depreciation	215.5	188.6	210.0	188.4	191.5
Less Indexation	-89.5	-96.3	-103.1	-109.6	-117.1
Economic Depreciation	**126.0**	**92.3**	**106.9**	**78.7**	**74.4**

6.3.4 Operating Expenditure

Consistent with the requirements of Clause 6.4.3(a)(7) of the NER, AusNet Services has included a forecast of operating expenditure (opex) in its building block allowance. As explained in Chapter 8 of this proposal, the opex forecast has been prepared in accordance with all applicable requirements of the NER and the RIN. The opex forecast, excluding the amounts shown in the table above is summarised in the table below. The AER's PTRM includes the Demand Management Innovation Allowance (DMIA) in the opex building block. Details of AusNet Services DMIA proposal are included in Chapter 9.

Table 6.5: Operating Expenditure for the Forthcoming Regulatory

(Nominal $M)	2016	2017	2018	2019	2020
Operating Expenditure	246.8	259.4	273.6	282.4	293.9

6.3.5 Other revenue adjustments

Consistent with the requirements of Clause 6.4.3(a)(5),(6) and (6A), AusNet Services has incorporated the amounts that have been determined under the efficiency benefits sharing scheme (EBSS), the true up of the old jurisdictional S-Factor scheme and shared assets guideline. The detailed calculation of each of these building blocks was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 10 Incentive Schemes, and Appendix 6A Shared Assets. The building block costs are listed in the table below.

Table 6.6: EBSS, S Factor and shared assets for the Forthcoming Regulatory Period

(Nominal $M)	2016	2017	2018	2019	2020
EBSS Carry-over	24.1	-5.7	-6.8	13.7	-
S-Factor Carry-over	-22.2	-	-	-	-
Shared Assets	-0.4	-0.4	-0.5	-0.5	-0.5
Total Carry-over	**1.5**	**-6.1**	**-7.3**	**13.2**	**-0.5**

Note: The AER PTRM includes the DMIA in the opex building block.

6.3.6 Tax Liability

Consistent with the requirements of Clause 6.4.3(a)(4) of the NER, AusNet Services has incorporated an allowance for its benchmark tax liability into its building block allowance. The detailed calculation of the cost of tax is presented in Chapter 16 of this proposal. The cost of tax calculation accords with the requirements of Clause 6.5.3 of the NER, and is summarised in the table below.

Table 6.7: Benchmark Tax Liability for the Forthcoming Regulatory Period

(Nominal $M)	2016	2017	2018	2019	2020
Tax Payable	82.1	62.6	72.1	71.2	61.2
Less Value of Imputation Credits	-20.5	-15.7	-18.0	-17.8	-15.3
Benchmark Tax Liability	**61.6**	**47.0**	**54.1**	**53.4**	**45.9**

6.4 Smoothed Annual Revenue Requirement

AusNet Services has calculated a smoothed revenue requirement by applying an X-factor for each year of the forthcoming regulatory control period as described in the sections below. The proposed smoothing is based on the methodology of the AER's PTRM.

The preferred smoothing approach is reliant on the AER's preliminary determination for the total revenue requirement. Given the transitional arrangements that are in place for this regulatory review result in the preliminary determination (which is similar in practice to a usual draft determination) applying to 2016 tariffs, AusNet Services expects the AER to consult with DNSPs on the 2016 X-factor to ensure tariff volatility is minimised and deliverability of the approved expenditure program is not compromised. Setting the X-factor for 2016 so that expected revenue is equal to the approved 2016 Annual Revenue Requirement does not automatically satisfy these objectives.

6.4.1 X-Factor

The X-factors presented in the table below meet the requirements set out in Clause 6.5.9 of the NER. In particular, AusNet Services has calculated the X-factor using the AER's PTRM, so that it:

- minimises the variance between the annual revenue requirement in the final year of the forthcoming regulatory control period and the building block revenue requirement for that year[2]; and
- equalises, in net present value terms, AusNet Services' total revenue requirement for the forthcoming regulatory control period with the expected smoothed revenue requirement.

The table below presents AusNet Services' X-factors for the forthcoming regulatory control period.

Table 6.8: Proposed X-Factor for the Forthcoming Regulatory Control Period

%	2016	2017	2018	2019	2020
X-Factor	-6.30%	0.00%	0.00%	0.00%	0.00%

6.4.2 Smoothed Annual Revenue Requirement

The application of AusNet Services' X-factors in conjunction with AusNet Services' 'Unsmoothed Revenue Requirement' produces the following 'Smoothed Revenue Requirement'.

Table 6.9: Smoothed Revenue Requirement

(Nominal $M)	2016	2017	2018	2019	2020
Unsmoothed Revenue Requirement	691.0	666.9	721.2	740.3	747.5
Smoothed Revenue Requirement	**678.2**	**695.3**	**712.8**	**730.8**	**749.3**

The AER's PTRM attached to this proposal demonstrates that the smoothed and unsmoothed revenue requirements are equal in net present value terms in accordance with the requirements of Clause 6.5.9(b)(3) of the NER. The smoothed revenue for each year is also net of estimated non-tariff revenue from alternative control services.

6.5 Revenue Requirement Adjustment in Forthcoming Regulatory Period

The revenue requirement set out in this chapter will be subject to adjustments in accordance with the control mechanism (set out in Chapter 19 Tariffs for Standard Control Services of this Proposal) to account for:

- The actual CPI, in accordance with the provisions set out in Clause 6.2.6(a) of the NER;
- The annual return on debt update;
- AusNet Services' actual service standard performance, relative to its service standard targets, under the Service Target Performance Incentive Scheme; and
- Any deemed cost pass though event, as nominated in Chapter 11 of this proposal along with those pass through events specified in Cause 6.6.1 of the NER.

[2] Under transitional Rule 11.60.3(b)(1), Clause 5.5.9(b)(2) does not apply under to this determination. However, AusNet Services' proposal satisfies the clause.

6.6 Support Documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 6A – Shared assets.

7. Capital Expenditure

7.1 Overview

Introduction

This Chapter sets out AusNet Services' plans and expenditure for investment in the assets (capital) used to provide network services, such as poles, wires and transformers, for the five year regulatory control period commencing 1 January 2016.

Drivers of capital expenditure

AusNet Services' capex program for the next regulatory control period will focus on replacing assets at risk of failure due to their asset condition, and installing equipment and technology to reduce the risk of bushfire. New customers will continue to be connected to the network, but a forecast of only small increases in demand means that historically low levels of network upgrades will be sufficient to meet the additional load.

The focus of the capex program reflects the key drivers for expenditure in the next regulatory control period:

Safety expenditure, specifically projects targeted at reducing bushfire risk from the distribution network, will continue to drive significant capital expenditure to 2020. Investment is required to implement the recommendations of the Victorian Bushfire Royal Commission (VBRC), and to deliver other programs that deliver cost-effective reductions in risk that are part of AusNet Services' agreed safety program accepted by Energy Safe Victoria (ESV). The Victorian Government funded program, to install insulated conductor or underground powerlines in some of the highest risk areas, will also continue in the next period.

Reliability, asset condition and network risk – As existing assets age and wear, there is a greater risk of them failing and causing interruptions to supply. AusNet Services' asset management strategies use information on the consequences of asset failure for reliability, network risk and risk to the community and on the probability of asset failure to determine when assets require replacing.

In previous regulatory reviews, asset replacement programs were developed based on a 'maintain case'; that is, the program was based on the level of replacement required to maintain existing levels of reliability. Due to a recent reduction in the official Value of Customer Reliability (VCR) measure, it may be economically efficient for a DNSP to adopt a slower rate of asset replacement because customers are willing to accept a lower level of reliability of supply. Nevertheless, the condition of the existing AusNet Services network is such that a significant program of asset replacement is planned.

Growth on the network is limited to the northern and south-eastern growth corridors of Melbourne (centred around South Morang and Pakenham respectively). Elsewhere on the network, no growth is forecast. These trends in network use are driven by increasing energy efficiency and solar penetration. Therefore, as peak demand and energy consumption are predicted to grow at historically slow rates, relatively small amounts of capital expenditure will be required to meet capacity requirements in coming years. However, as new customers are expected to connect to the network at rates similar to long term averages, capital expenditure will continue to be required to extend the network to these customers.

The current capacity of the distribution network will be largely adequate for the next five years. However, work will be required during that period to ensure that network functionality continues to meet the needs of electricity network users beyond 2020, including supporting customers to more actively manage their energy consumption and network use (e.g. responding to Power of Choice tariffs that are cost reflective, through use of smart meter data, solar generation, and potentially through more widespread adoption of battery storage).

AusNet Services' approach to capital expenditure planning and forecasting

In the lead up to this five yearly regulatory review, AusNet Services has engaged with customers to understand their attitudes and priorities for the electricity grid at a time of uncertainty and change for the industry. Customer feedback clearly indicated that electricity prices could not continue to grow at recent rates. However, most customers felt that prices should be managed without sacrificing safety investment or allowing service levels to deteriorate. They understood that there are costs of the network that need to be paid.

The feedback received from customers underscored the importance of balancing the (often competing) components of the National Electricity Objective (NEO). Stabilising prices and network investment are a priority if the distribution network is to continue to provide a viable service to customers in the face of emerging technologies and potential alternatives to grid connection over the medium to longer term life of the installed asset base. Given the investments required to reduce bushfire risk and replace assets at risk of failing, striking an appropriate balance between investment and price stability is a pressing challenge for AusNet Services.

Accordingly, AusNet Services' approach to forecasting its capital expenditure requirement for 2016-20 is to limit investment to that which is necessary to meet its legal, regulatory and service obligations and maintain a safe, reliable and secure network. This will minimise the amount of increases in customer bills without jeopardising safety or reliability of supply. AusNet Services considers its approach produces a capex forecast which is in the long term interests of customers.

AusNet Services' asset management approach:

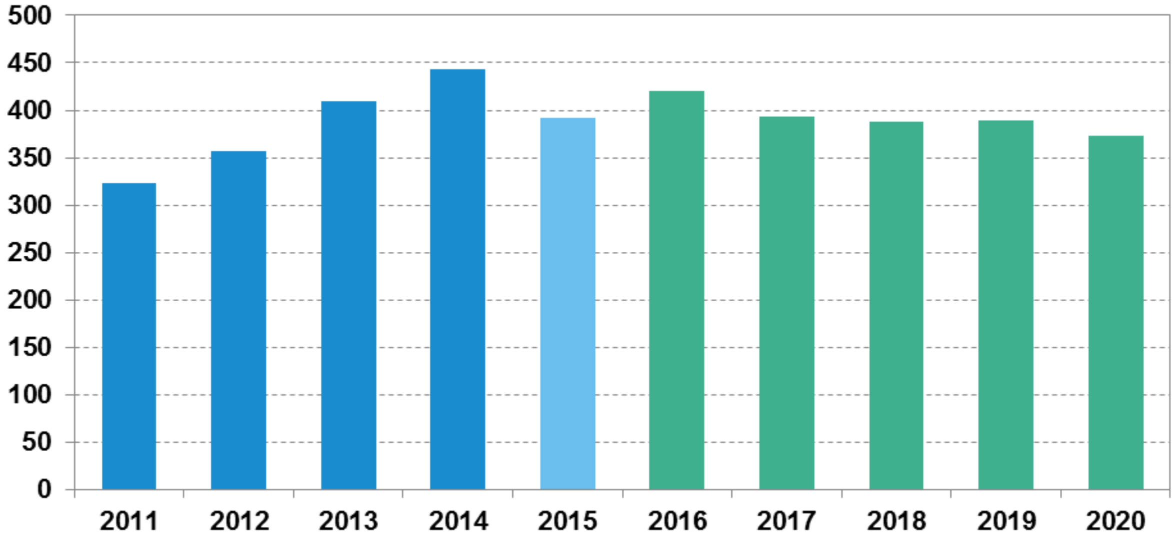
- **is rigorous, analytical and externally certified**[1] – our asset management processes are considered to be Australian best practice. Expenditure programs and projects have been developed based on data and risk modelling. The overall program has been subject to top down assessment;
- **continues to invest in innovation** – AusNet Services strongly believes that continual investment in innovation to keep driving efficiency and capability enables it to deliver on safety and other service commitments, without driving up network costs unsustainably;
- **identifies opportunities to stabilise RAB growth** – AusNet Services will achieve this by requiring higher customer contributions and, outside of the capital program, by adopting accelerated depreciation for assets no longer in use.

Expenditure overview

Total forecast capital expenditure for the next regulatory control period will be similar to the current period, as continued investment to reduce the risk of bushfire ignition is essential to meet community and government expectations that these risks are eliminated as far as is practicable. This is also an imperative for the achievement of sound business practices of a well-run business. The risk to safety, reliability and service standards that deteriorating assets pose, also justifies substantial expenditure on asset replacement.

[1] ISO 55001.

Figure 7.1: Gross capex by year, proposed and actual ($m, real 2015)



Source: AusNet Services.

Note: Figures for 2015 are estimates.

It is anticipated that significantly less investment will be required to add capacity to the network (network augmentation). There will also be lower expenditure on information technology as AusNet Services embeds the investments made in the current phase of the technology plan. Finally, existing customers will be asked to pay less of the costs of connecting new customers to the network, as AusNet Services acts to remove the cross-subsidy that has arisen from changing patterns of energy consumption in recent years.

In 2015, it is expected that capex will dip due to cyclical effects in IT and replacement programs, and continued decline in augmentation.

Benefits of the capital expenditure program

The proposed capital expenditure program delivers on the needs of the network and customers, in an efficient manner.

It is expected that over 2016 to 2020:

- community safety will increase, with reductions expected in the number of incidents that have the potential to cause a fire start, and the number of electric shocks sustained;
- the annual outage duration experienced by customers will increase by three minutes from the current average of 150 minutes, reflecting the lower VCR; and
- the flexibility and capability of the network will improve, better positioning the network to deliver the services that customers will demand in 2021 and beyond.

The forecast total capex contributes to the achievement of the National Electricity Objective

AusNet Services' forecast total expenditure will deliver a capex program that best serves the long term interests of consumers. The forecast represents the most appropriate balance between the need for ongoing, efficient network investment, and customers' concern that existing levels of safety, service and reliability are maintained without continuing recent price increases.

AusNet Services' forecast promotes efficient network investment because it represents the level of expenditure required to achieve the capital expenditure objectives. In the forthcoming regulatory period, continued capex remains necessary in order to:

- Meet expected demand, which is principally driven by new customer connections given that peak energy demand and energy consumption are expected to grow more slowly;

- Enable AusNet Services to comply with its applicable regulatory obligations and requirements, which most notably include investment in safety initiatives which implement the recommendations of the VBRC and amendments made to AusNet Services' ESMS; and
- Maintain reliability and security of supply and of the distribution network by undertaking a focussed asset replacement program and investment to reduce the risk of electricity assets igniting bushfires. The capex program expressly takes account of the change in the VCR to avoid over-investment.

The forecast total capex also promotes efficient use of the network by improving pricing transparency by amending certain cost-based methodologies i.e. AusNet Services' customer contributions policy.

AusNet Services analysed the efficiency of its proposed capex program from the perspective of its customers using information obtained through its community consultation program. AusNet Services has endeavoured to reflect customer attitudes to pricing, security, reliability and specific elements of AusNet Services' proposed investment program in its forecast where doing so best contributes to the long-term interest of consumers.

AusNet Services' forecast total capex also reasonably reflects the capital expenditure criteria. The total forecast is consistent with the impact of key drivers on capex expenditure, such as the lower VCR and changes in demand forecasts and cost inputs. Further, the program includes a number of projects where capex was deferred because employing an opex or demand management solution better contributes to the achievement of the NEO. As such, AusNet Services is confident that its total capex forecast reasonably reflects the efficient costs that a prudent DNSP would incur in achieving the capex objectives.

7.1.1 Structure of this chapter

The remainder of the chapter is structured as follows:

- Section 7.2 describes the **operating environment** that will be faced by AusNet Services' distribution network from 2016 to 2020, including an overview of recent history and of the trends and challenges that will continue to shape AusNet Services' capital expenditure requirements.
- Section 7.3 outlines AusNet Services **approach to developing capital expenditure plans** for the next regulatory control period.
- Section 7.4 contains the details of the **capital expenditure forecast** at both a category and overview level.
- Section 7.5 highlights the **expected benefits of the capital program** and demonstrates that the proposed capital expenditure requirement is necessary to deliver outcomes that are in the best interests of customers.
- Section 7.6 illustrates that the capital program has been developed to ensure its **deliverability**.

7.2 Operating Environment

7.2.1 Environment

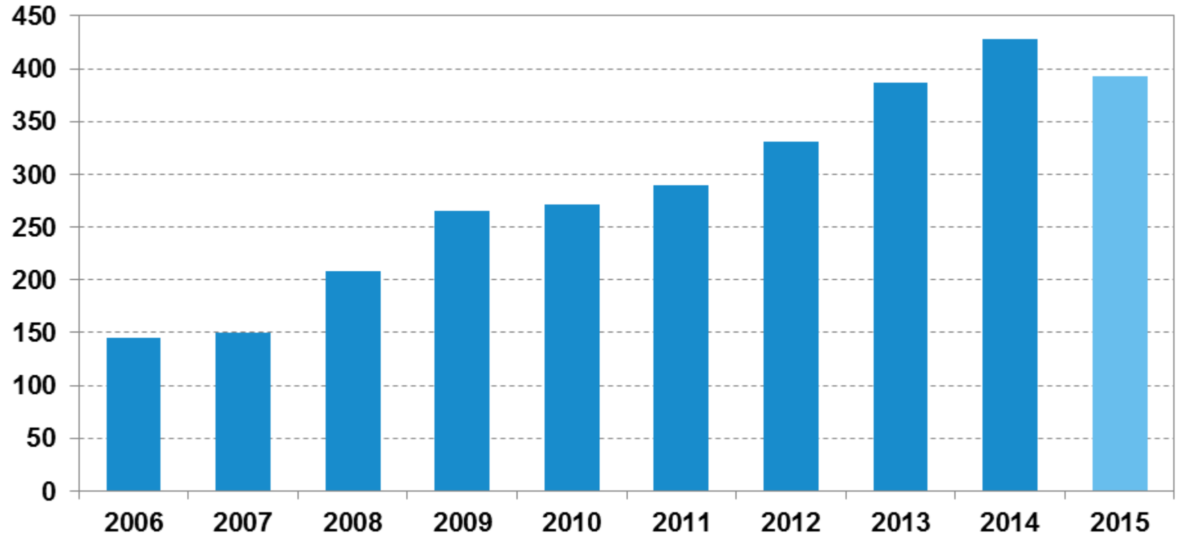
As outlined in Part I of this regulatory proposal, AusNet Services' distribution network operates across the diverse environment of eastern Victoria. Split by the Great Dividing Range, the network covers heavily forested and mountainous areas, as well as the low lying and coastal regions of Gippsland. On the northern and eastern fringes of Melbourne, the network services highly populated suburbs including through the heavily vegetated Dandenong Ranges.

These characteristics, particularly the low average customer density and high bushfire risk, affect efficient expenditure levels.

7.2.2 Historical capex trends

Over the last decade, AusNet Services has been increasing the level of capital expenditure, initially to service rapid demand growth, and more recently, to replace deteriorated assets and to reduce bushfire ignition risk.

Figure 7.2: Total Gross Capex[2] ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates, includes pass through government funded safety expenditure.

Capital expenditure during the current regulatory period has been significantly impacted by two contrary forces:

- Significant falls in growth rates for peak demand, resulting in reduced growth capital; and
- Significant increases in replacement and safety expenditure (including that required to meet additional obligations arising from the VBRC recommendations).

Capital expenditure during the previous regulatory period was affected by:

- Very high peak demand growth concentrated in Melbourne's northern and south eastern growth corridors; and

2 Refer to "Previous and Current Period Capital Expenditure - Clause S6.1.1(6)" for a detailed breakdown of AusNet Services' historical expenditure by category driver.

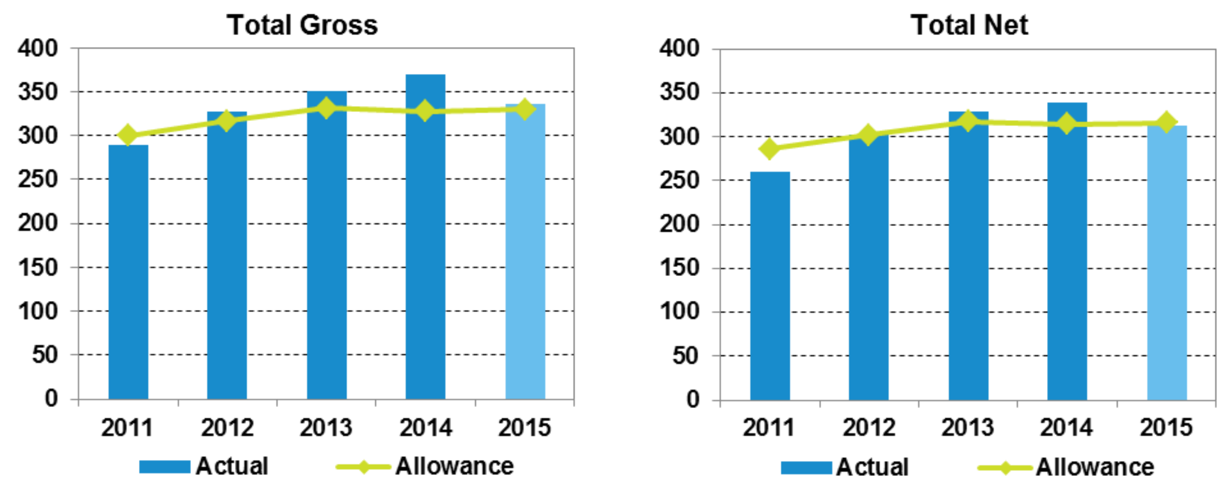
- A series of rare extreme weather events that affected both reliability and expenditure. These included the 2007 Gippsland floods, the 2009 bushfires and major wind storms in 2008 and 2009.

7.2.3 Current period performance against regulatory allowances

The AER's 2011-15 Price Determination included allowance for safety expenditure required to meet additional obligations arising from the VBRC recommendations. In 2012, the AER approved a pass through for further expenditure to deliver on additional VBRC recommendations that were implemented via Directions from Energy Safe Victoria (ESV). In 2014, AusNet Services commenced delivering a program, funded by the Victorian Government's Powerline Replacement Fund (PRF), to underground powerlines in some of Victoria's highest bushfire risk areas.

As the expenditure required to implement the VBRC recommendations was approved as a positive pass through amount, the performance of AusNet Services' capital program in the current period is presented against the 2011-15 EDPR benchmark allowances exclusive and inclusive of the pass-through allowance. Exclusive of the VBRC and PRF programs, net capex is projected to be 0.4% above benchmark by the end of the period. Inclusive of the VBRC expenditure, net capex is projected to be 1.3% under the combined EDPR+VBRC benchmark.

Figure 7.3: Total Capex Gross and Net, excluding VBRC and PRF ($m, nominal)



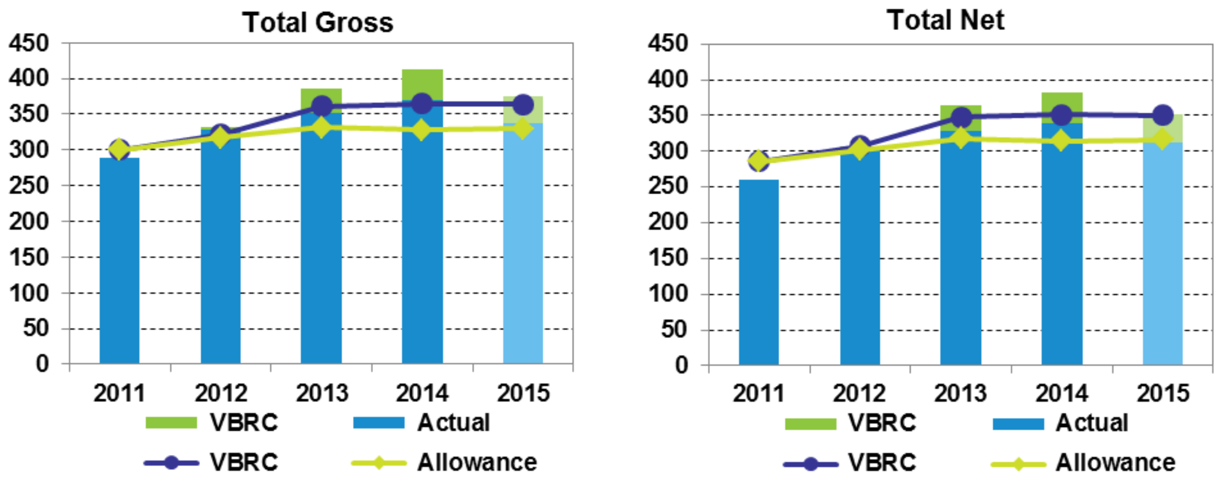
Source: AusNet Services

Note: Figures for 2015 are estimates

Gross capex reflects the total expenditure on capital, while Net capex reflects the portion of capital expenditure funded through distribution prices, that is, after upfront contributions from connecting customers, and from government.

The projected fall in capex in 2015 reflects the re-profiling of the capex program within the current period which brought forward expenditure to meet safety obligations and to deliver IT programs critical to delivering efficiency improvement.

Figure 7.4: Total Capex Gross and Net with VBRC Pass-through ($m, nominal)



Source: AusNet Services

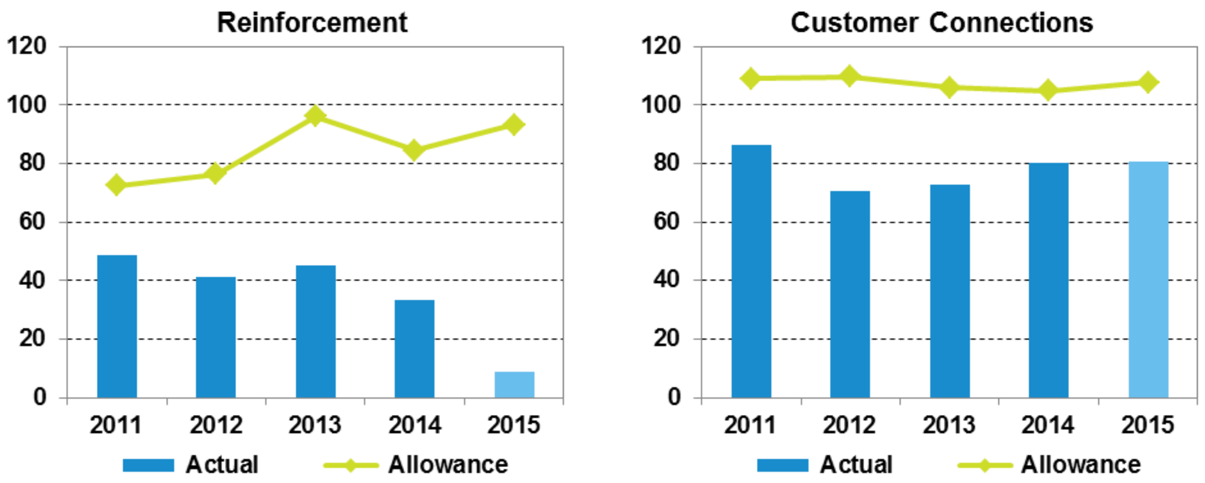
Note: Figures for 2015 are estimates.

Growth Capex

Forecast peak demand growth on the network has been continually downgraded throughout the current period and has been well below the 2011-15 EDPR forecast (see Chapter 4). While residential customer number growth has been largely on target, industrial and commercial growth has been well below forecast.

This has resulted in significant underspending against the approved benchmark allowance in the growth-related reinforcement (also referred to as augmentation) and customer connection capex categories. The figures below illustrate the underspend is projected to be 58% and 27% for each category respectively.

Figure 7.5: Reinforcement and Gross Customer Connection Capex ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates.

Replacement and Safety Capex

The replacement and safety capex has significantly increased above the 2011-15 EDPR allowance.

The primary drivers of the 80% increase above allowance in replacement capex have been stations, poles and conductor replacements. AusNet Services has overspent the AER approved allowance for stations which reflected a substantial cut to AusNet Services' proposed requirement. Lower than expected demand in 2011-15 deferred some station rebuild projects, but it has also meant that *replacement* (due to condition) has overtaken *augmentation* as the driver for some rebuild projects. The result is that replacement of station assets has been closer to AusNet Services' 2010 forecast than the AER approved allowance.

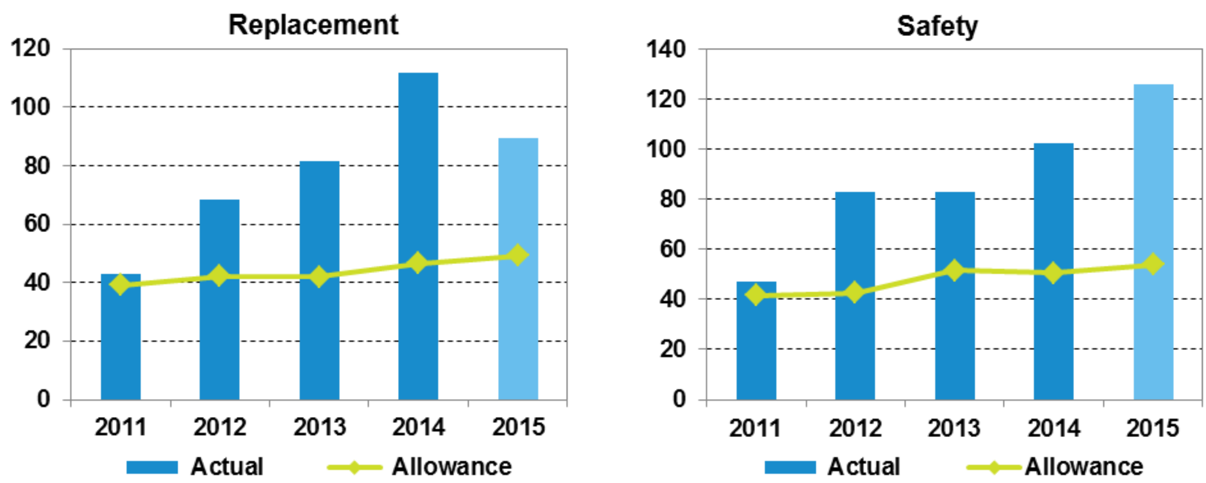
The volume of poles replaced in the current period has been substantially higher than forecast. As pole replacements are dictated by inspection results, the replacement volumes have been driven by asset condition (assets reaching end of life).

Unit rates for pole replacements and conductor replacement have been considerably above the 2010 unit rates underpinning the allowance for replacement capex. AusNet Services competitively tenders external providers for this work, so the higher rates reflect market conditions.

Replacement expenditure is expected to dip temporarily in 2015 due to over-delivery in 2014. In 2013, significant effort was made to increase the delivery capacity to ensure that the necessary 2014 replacement and safety volumes were delivered. The increase in delivery capacity involved engaging external contractors who exceeded expectations by delivering more volumes than planned during 2014. This resulted in some 2015 safety and replacement volumes actually being delivered in 2014, resulting in a higher spend in 2014 and lower forecast spend in 2015.

The safety capex program is projected to be 84% over the allowance by the end of the period primarily as a result of higher than approved unit rates[3], particularly for conductor replacement. In addition, AusNet Services initiated some safety work that was not funded under the EDPR or VBRC pass-through such as the Rapid Earth Fault Current Limiter[4] (REFCL) at Kilmore South and replacement of high voltage conductor with Aerial Bundled Cable (ABC) at high risk sites, which has contributed to the overspend of the approved allowance for safety capex.

Figure 7.6: Replacement and Safety Capex ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates

Non-EDPR funded network capex

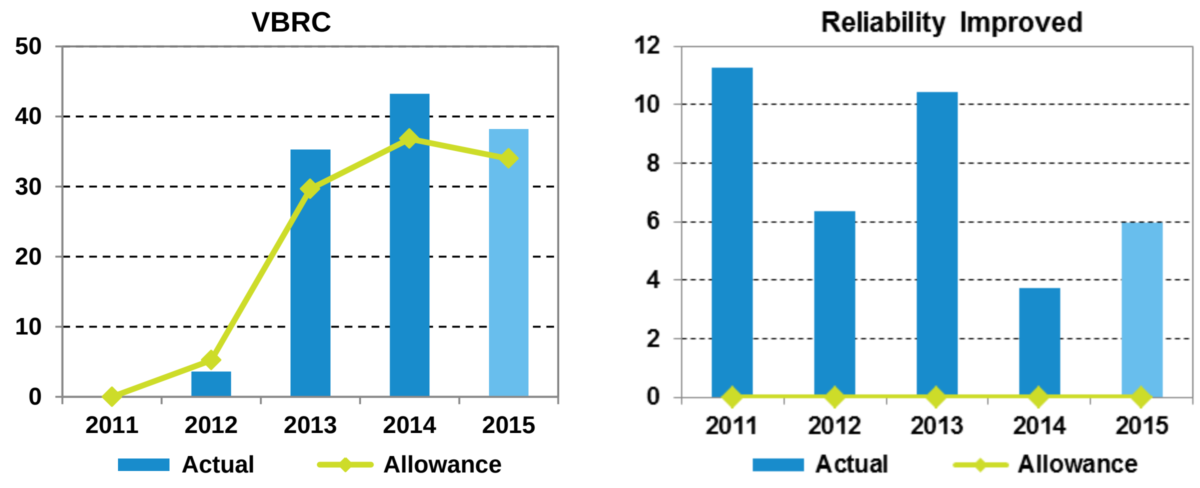
In 2012, the AER approved a pass-through for an additional $105 million for six new capex programs associated with changes required by the ESV to AusNet Services' Electricity Safety Management Scheme (ESMS) in response to recommendations from the VBRC.

3 Volumes are agreed and fixed with the ESV.

4 Equipment that is being trialled which may prevent ground fires caused by broken conductors.

By the end of the period, AusNet Services is also projected to spend $38 million on programs that improve the reliability performance of the network. These improvements are not directly funded through the current EDPR, but rather through future STPIS incentive payments if the projects successfully improve reliability.

Figure 7.7: VBRC Pass-through and Improved Reliability Capex ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates.

SCADA IT

SCADA IT provides monitoring and control functionality on the distribution network. AusNet Services has historically allocated SCADA IT capex in the following manner:

- Remote SCADA assets on the network (such as Remote Terminal Units (RTUs), station controllers and distribution feeder devices (DFDs)) have been allocated into the system sub-transmission and distribution categories (reinforcement or reliability and quality maintain); and
- Network control hardware, software and associated IT systems have been allocated into their own SCADA IT category.

While this arrangement was acceptable for the purposes of the 2006 and 2010 price reviews, it is no longer appropriate to continue recording and reporting these costs in this way for two main reasons:

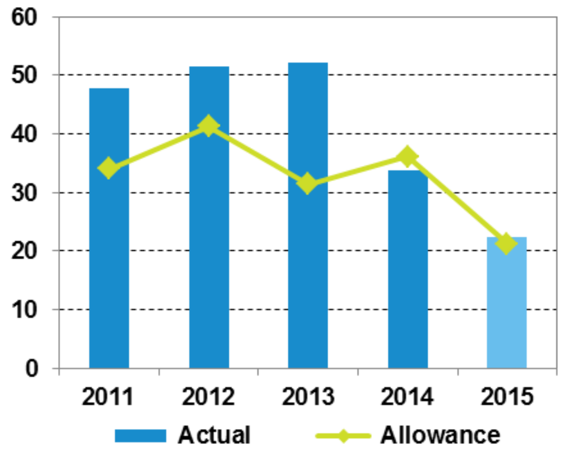
- Recent developments in regulatory reporting and cost category analysis mean that the current arrangements may lead stakeholders to interpreting these costs as network SCADA costs, when in fact they are not. To enable clearer comparison of key and material network SCADA capex costs, it is helpful to move all IT-related costs into general IT; and
- Technology has changed over the past decade which has led to SCADA IT and general IT becoming increasingly integrated and difficult to separate. This is common across the industry as operating technology (OT) and information technology (IT) increasingly converge over time. SCADA IT is used to provide 'smart grid' services and enable real time information to inform the decision making of customers and asset managers. The storage and transportation of this information is based upon IT infrastructure and results in increasing levels of integration between OT and IT services.

Given the above, AusNet Services has forecasted SCADA IT as part of the general IT capex category from 2016 onwards. For the purposes of reporting performance in the current period, the regulatory allowance and actual expenditure for SCADA IT have been rolled into the allowance and actual capex reported for general IT (as set out below).

Information Technology

In 2011-15, AusNet Services has invested $208 million in IT capex which is $44m million or 27% higher than the regulatory allowance set in the 2011 EDPR Determination. Annual actual IT capex against the regulatory allowance is shown in the figure below.

Figure 7.8: IT and SCADA IT Capex ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates.

Expenditure was higher in the first three years of the regulatory period largely due to the delivery of two major projects: network management automation (NMA) and the enterprise asset management and enterprise resource planning (EAM/ERP) program. The overspend against regulatory allowance was driven by the above two projects and Advanced Metering Infrastructure (AMI).

The NMA program was necessary to update and upgrade AusNet Services' aged network management systems and integrated Distribution Outage Management, Graphical Information and Supervisory Control and Data Acquisition systems; establishing a real-time, spatially aware, remote management and monitoring of the network. Following the 2011-15 EDPR final determination the NMA project scope was reassessed and it was concluded that a significantly broader scope was necessary to deliver a workable solution which meets industry standard, which also increased the cost of the project. This significant program totalled $62m (nominal) over the period.

The implementation of the core EAM/ERP solution is the cornerstone investment of AusNet Services' strategic enterprise approach to modernise and transform the ICT applications that support the electricity distribution business. The EAM/ERP program replaces 140 business applications with a single modern platform which integrates financial and asset management systems, providing a single fit-for-purpose platform, using SAP, to meet current and future business and customer needs. This project totals $55m (nominal) over the period.

The cost of the overall AMI programs was higher than forecast, and as such the portion attributed to the distribution business was higher than forecast (in accordance with the AER-approved cost allocations between the AMI project and the distribution network). This resulted in $14m in AMI program cost for the distribution network.

Within the period AusNet Services re-prioritised capital to support transformational investments, deferred some projects and extended the life of some IT assets.

IT investments delivered over the 2011-15 period have enabled and supported innovation and integration which have delivered benefits to consumers by containing future costs and ensuring network reliability and safety even as the operating environment becomes more complex. These programs include:

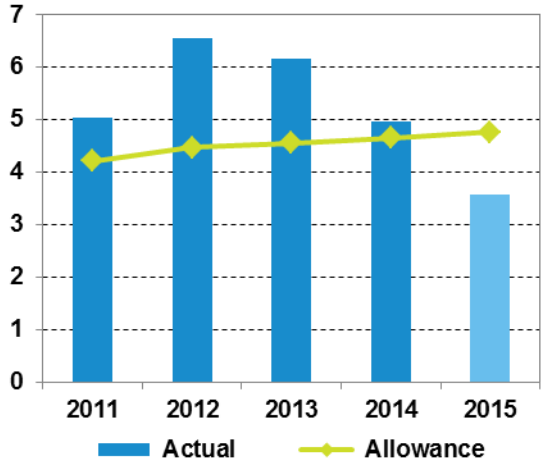
- Network automation, including a new advanced network management system and distribution feeder automation. This has resulted in improvements in reliability and response times for emergency maintenance.
- The financial and asset management systems linking financial, GIS and asset management information. This has enabled improvements to asset management and supported information provision into regulatory processes without requiring step changes in opex.

The major projects delivered in the current period provide AusNet Services with a strong foundation to modernise its ICT offering in the next regulatory period and enable business transformation for future periods.

General Capex

General non-system capex is also projected to be 16% above the 2011-15 EDPR benchmark.

Figure 7.9: General Capex ($m, nominal)



Source: AusNet Services

Note: Figures for 2015 are estimates

7.2.4 Short and long term outlook

The period to 2020 is expected to see the continuation of trends that have emerged in recent years:

- Energy consumption will be flat, but demand will continue to grow, forecast at 1.2% per annum, concentrated in concentrated growth corridors in the northern and eastern fringes of Melbourne;
- Implementation of VBRC recommendations will continue to shape AusNet Services' safety obligations. While a number of the VBRC programs will be completed by 2020, new obligations are likely to emerge, particularly as new technologies are identified as effective in reducing the risk of bushfire ignition. Specifically, the roll out of Rapid Earth Fault Current Limiters is expected to be mandated in Victoria within the next regulatory period;
- Technological developments will continue to shape customers' use of the distribution network. Established technologies such as small scale solar generation and smart meters will become further embedded. Other technologies, particularly small scale battery storage and electric vehicles, are likely to be more widely adopted, although the pace at which such investments will become economically attractive to customers is less certain.
- Market structures in the electricity supply chain will continue to develop to reflect the state of technology. Metering contestability is on the current policy agenda.

7.3 Approach to Developing Capital Expenditure Plans

This section provides an overview of AusNet Services' approach to determining its capital expenditure requirement for 2016-20, including:

- Asset management approach;
- Consumer attitudes, expectations and behaviour;
- Objectives; and
- Assumptions and inputs.

Further detail on the forecasting methodology used to determine the capital expenditure requirement for AusNet Services' distribution network can be found in Appendix 7A – Network Capital Expenditure Overview and in the Asset Strategies.

7.3.1 Asset management approach

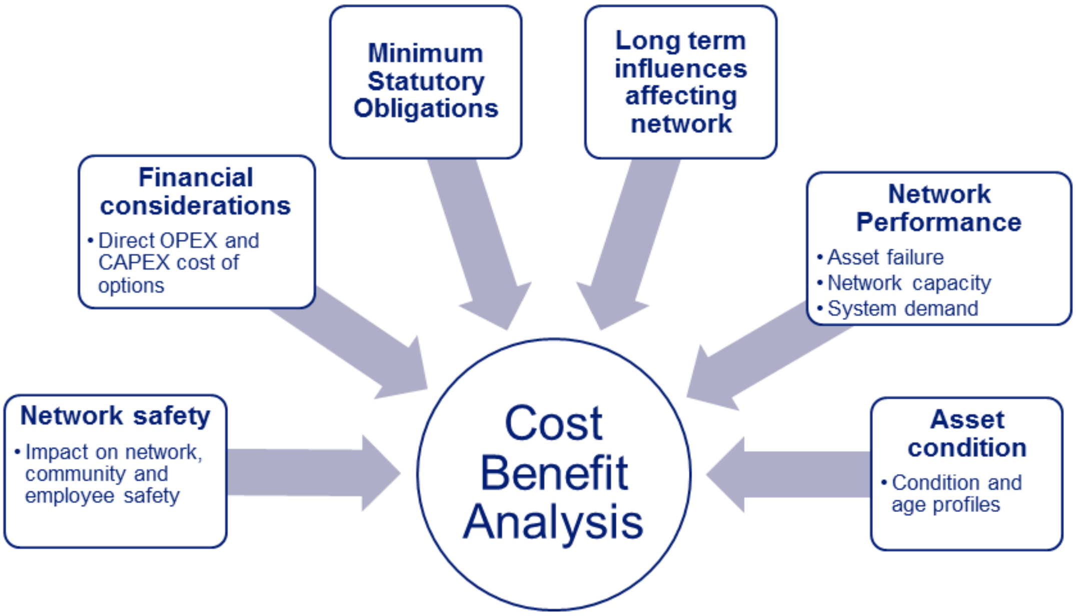
AusNet Services is focused on delivering optimal distribution network performance at an efficient cost. Except in the case where outputs are mandated, this requires an explicit cost benefit analysis to be undertaken in order to assess whether the overall economic value of capital expenditure is positive.

In doing this, AusNet Services assesses the incremental costs of delivering an incremental change in network performance to customers, relative to the incremental benefits accruing to customers from the delivery of that enhanced network performance. In determining the benefits, the revised Value of Customer Reliability (VCR) published by AEMO in November 2014 has been used.

The asset strategy therefore ensures that all decisions to augment, replace or maintain network assets are examined against economic grounds and are underpinned by safety objectives. The benefits are a function of the explicit customer value proposition, or proxy via the adoption of minimum performance standards which are stipulated in legislation or other statutory or regulatory instruments.

The various drivers that are brought to bear when undertaking AusNet Services' Cost Benefit Analysis are summarised in the Figure below.

Figure 7.10: Cost Benefit Analysis Drivers



Source: AusNet Services

An assessment of the above drivers – both individually and collectively – are fundamental to the cost benefit analysis that underpins AusNet Services' approach to managing its network.

The approach used to develop AusNet Services' capital expenditure forecast is consistent with the approach taken for budgetary, planning and governance processes used in the normal running of AusNet's business.

The quality assurance steps taken to ensure that the capex forecast is free from error include:

- review of historic rates and volumes;
- inclusion of competitively tendered contract conditions;
- internal review and governance processes across Finance, Service Delivery and Asset Management divisions.

Capex / Opex interactions

In general, although individual capital expenditure projects can affect levels of operating expenditure required for the network (e.g. deferred replacement of zone substation assets due to VCR may increase inspection and maintenance requirements), a detailed build-up of the opex impact of capex projects has not been prepared. As detailed in Chapter 8 Operating and Maintenance Expenditure, opex is forecast on a top-down basis, with the implicit assumption that the net effect of the capex program is captured by the growth and productivity trends in the 'rate of change' methodology. This approach relies critically on the forecast capex program, which is sufficient to maintain the condition of network assets to a level that will not significantly alter the required volume of maintenance activity.

In relation to IT, the forecast expenditure program is expected to result in increased IT opex. However, as detailed in Chapter 8, AusNet Services believes it can absorb these changes through other opex efficiencies and has not included the forecast step change in its opex proposal.

The Demand Management (DM) program, which primarily involves opex, has been accounted for in the development of the capital expenditure program. The capex forecast assumes that the forecast DM program will constrain demand. Further details of the DM program are provided in Chapter 9 Demand Management.

7.3.2 Consumer attitudes, expectations and behaviour

AusNet Services undertook several engagement activities aimed at gauging our customers' attitudes to different aspects of network investment and trade-offs between that investment with reliability and safety outcomes and operating costs. The consultations were not an attempt to substitute for detailed independent analysis (such as AEMO's VCR study) and NPV and risk modelling (such as our RCM and bushfire risk modelling), rather they were helpful in illuminating customer attitudes to AusNet Services' chosen investment approaches and forecasts.

Engagement activities

Initially, AusNet Services undertook a broad based survey of 2,358 customers to gain an underlying baseline for further customer engagement.

This was followed by a series of community forums and technical workshops with advocacy groups where some of the reliability cost trade-offs that are used in our network planning were explained.

A series of independently run focus groups were held in different regions and with different demographic groups throughout our network. These groups provided detailed feedback on general and specific options and trade-offs that AusNet Services faced in preparing our investment plans.

Finally, as part of usual planning practice, specific meetings were held with large customers either in response to customer- or AusNet Services-initiated network expansion plans to ensure large replacement and augmentation work could be integrated with local business plans.

Relevant findings

There is an overarching customer concern around escalating energy prices and a clear expectation that network costs be managed and smoothed over time to avoid short term increases in prices.

With respect to AusNet Services' investment plans:

- Customers saw the operation of our network in safe manner as non-negotiable and were very supportive of investment that improved community safety, particularly where it reduced the risk of fire ignition from electricity assets. They also strongly supported continued improvement. This support remained even when presented with the significant costs of proposed programs.
- Customers expressed a strong preference for current reliability levels. This satisfaction with was shared across different customer groups. There was a strong resistance either to pay for further reliability improvement or allowing reliability to decline in exchange for lower prices in the future.
- Customer focus groups were not concerned about removing cross-subsidies of new customer connection, seeing their removal as fair. This was notable because there was strong resistance to removing other cross subsidies (for example, low fire risk areas subsidising high fire risk areas).
- There was general support for continued investment in innovation (as opposed to large network investments) particularly where that resulted in lower long term costs or higher community benefits such as safety or reliability.
- Customer feedback both through the EDPR-specific engagement process and existing complaints processes indicated the need to invest in improved communication processes, particularly around network outages.

How they were incorporated into our proposal

Reliability and reinforcement investment

While customers are clearly resistant to lower ongoing reliability, AusNet Services does not consider this justifies a reconsideration of its decision to incorporate the lower VCR into network planning. The STPIS provides AusNet Services with the incentives necessary to maintain reliability despite the lower VCR.

Customers and advocacy groups have been supportive of investment in innovation and improved customer service particularly where that can be substituted for network costs. AusNet Services also considers that community views on reliability support its demand management proposal which underpins and supports the lower investment in network upgrades in the current lower demand growth environment.

Bushfire risk reduction

Many customers raised the idea that relocating overhead conductor underground would be the safest way to reduce the risk of bushfire ignition for the distribution network. AusNet Services believes the Victorian Government's Powerline Replacement Fund is addressing community desire to underground assets in the highest risk areas of the state. AusNet Services forecast delivers other programs to reduce bushfire risk.

Customer connections investment

AusNet Services considers that its intention to increase the share of customer connection capex funded upfront by connecting parties is accepted by the community.

IT investment and innovation

AusNet Services considers that its IT proposal satisfies both the concerns over cost control and support for innovation. While forecast IT expenditure is being reduced when compared to the current period, we are nonetheless, proposing a large investment in this area. This investment will also provide a stable base from which AusNet Services can make the additional internally (non-customer) funded investments in innovation which deliver the lower costs and improved service outcomes over the long term as demonstrated over the current period. In particular, AusNet Services understands there is strong customer support for its proposed investment in improved customer service and communication through a Customer Relationship Management system.

7.3.3 Objectives

The Asset Management Policy summarises AusNet Services' fundamental asset management objectives for its networks. The policy has been developed to support the successful delivery of AusNet Services' purpose. Four primary asset management objectives govern how the electricity distribution network is operated and maintained, as detailed in the table below.

Table 7.1: Asset management objectives

Asset Management objective	Drivers
1. Modernise the network	• Changing service paradigm • Technology benefits • Cost to serve
2. Improve safety	• Bushfire mitigation • Electric shock • Harm – asset failure
3. Meet or manage customer demand	• New customers • Asset utilisation
4. Improve reliability	• Customer focus • STPIS reward • Customer expectations

7.3.4 Assumptions and Inputs

The key assumptions and inputs underpinning AusNet Services' capex forecast are outlined below, including:

- Demand forecasts;
- Reliability;
- Asset condition and risk assessments, and failure data;
- Capex / Opex interactions;
- Project cost estimates and unit rates;
- Cost escalators; and
- Overheads.

The capex forecast is consistent with the AER's classification of Standard Control Services in the Framework and Approach, and AusNet Services' Cost Allocation Methodology.[5] There are no related party margins in the capex forecast.

Demand forecasts

Details of the demand forecasts that underpin the capital expenditure forecast are provide in Chapter 4.

The key assumption here is that demand growth will continue to be very low relative to historical levels. If this assumption is wrong then network augmentation and demand management expenditure will increase.

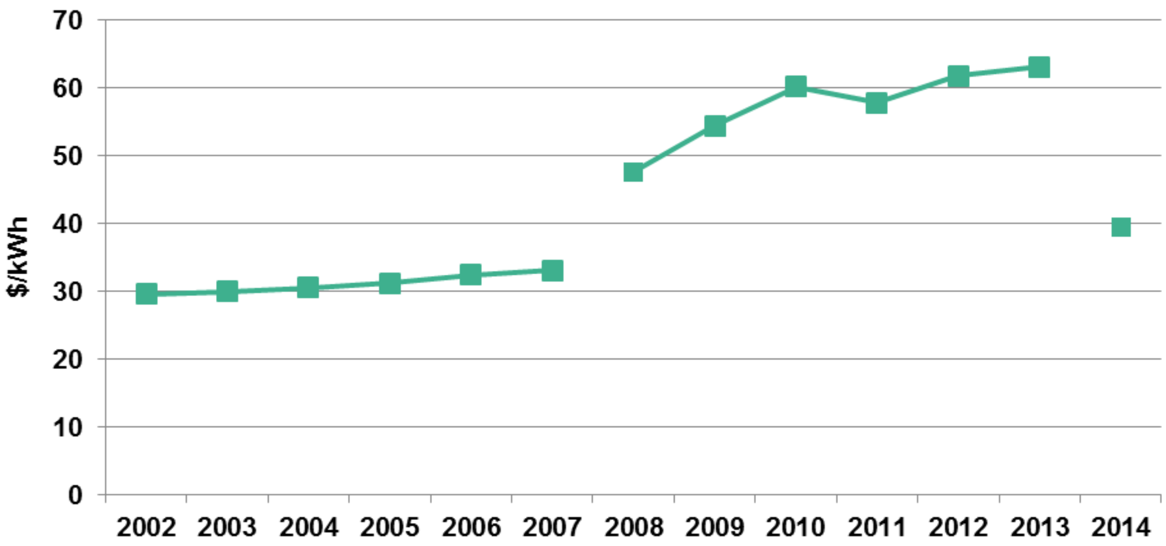
Reliability

In Victoria, the Australian Energy Market Operator (AEMO) has undertaken detailed studies to set the value the community places on a reliable electricity supply. This is called the Value of Customer Reliability (VCR). This value is an important input in determining when augmentation and asset replacement is economically justified. An increase in the VCR indicates the community places a higher value on network outages and, therefore, will be prepared to pay more for improved reliability. Historically, the VCR has tended to rise over time; however, the most recent study has resulted in a reduction in the VCR.[6]

[5] Appendix 1A Service Classification Proposal, and Appendix 1B Cost Allocation Methodology.

[6] AEMO, 2014.

Figure 7.11: The value of the Victorian VCR over time



Source: AEMO

The reduced VCR value changes the balance between proposed expenditure and reliability outcomes from a maintain case to one where expenditure will be deferred, thereby reducing costs, and where reliability is allowed to decline marginally.

AusNet Services has applied AEMO's most recently published VCR in determining the required capital expenditure for augmentation and replacement. Details of the impact of the lower VCR on deferral of projects and on reliability is included in section 7.4.3 Replacement and section 7.4.4 Augmentation below.

AusNet Services' capex forecast does not include any expenditure for reliability improvement. In Victoria, reliability improvement is funded by an incentive scheme (the STPIS) that uses the VCR to determine the incentive rate. Detail of the reliability incentive scheme is provided in Chapter 10 Incentive Schemes.

Project cost estimates and unit rates

Project cost estimates are prepared as part of a standardised approach to developing, managing and reporting projects and programs of works, as is described in Appendix 7D Project Cost Estimating Methodology. Estimates are prepared in accordance with defined project execution procedures and practices. Estimates are subject to reviews and a sign-off process based on consistent clear lines of responsibility and accountability that ensure costing standards and controls are applied to any estimate released.

Cost estimates used to determine forecast capex have been prepared on a P50 basis, which is an estimate that has a 50% confidence factor of not being exceeded by cost at project completion. AusNet Services' standard estimating procedures generate both P50 and P90 estimates for projects, with P90 estimates used for internal planning and budgeting processes.

Unit rates used to develop forecast expenditure are primarily based on the rates incurred in recently completed work. These unit rates reflect efficient costs of delivering similar projects in AusNet Services' network area. Project and programs are delivered utilising an efficient combination of competitively tendered and internal resources. Pre-qualified panels of design and installation service providers have been established to undertake design and installation works for major projects such as zone substation rebuilds. These panels were established by competitive tender and ensure that providers have the skills and resources to undertake the required work in a safe and competent manner and can comply with works management processes. Forecast unit rates and their basis are described in Appendix 7C Unit Rates.

Asset condition and risk assessments

AusNet Services has developed an asset management methodology that incorporates condition assessment of assets together with relevant risk assessments. This methodology identifies the quantity of assets that is likely to require replacement during the EDPR period and allows prioritisation of these assets according to the associated risk that failure would introduce to the network and community.

Specific condition assessment ratings have been developed for each of the major asset categories and assessments are recorded in the asset management system. Risk assessments have been based on the value of unserved energy and bushfire risks for relevant assets.

Cost escalators

The price of inputs (material and labour) significantly impacts the total expenditure that will be required to deliver the identified capital work program for the next regulatory control period.

AusNet Services is a 'price taker' for most of the inputs it uses in the delivery of its capital expenditure program. That is, the price AusNet Services pays for asset components such as conductor and transformers (materials) and the wages it pays for labour are determined in competitive national and international markets.

The current outlook for inputs costs is for moderate growth. Labour costs are expected to grow at rates slightly above the long term average, while growth in material costs are expected to slow to the general rate of inflation as the mining boom subsides.

Cost escalation is heavily influenced by macroeconomic factors and AusNet Services expects it will need to update its forecasts of cost escalators using current information in the Revised Proposal.

Labour prices

Details of AusNet Services' labour forecasts are provided in Chapter 8 – Operating and Maintenance Expenditure and in Appendix 8C (CIE labour price forecast report).

The following assumptions have been made in applying labour forecasts in developing the capital expenditure requirement:

Internal labour:	EBA rates are incorporated for the term of the existing agreements (agreements expire in late 2016); EGWWS WPI forecast is used for the remaining period.
Contracts:	Construction WPI forecast is used from 2016 to 2020.

Materials prices

AusNet Services has assumed that materials prices will increase in line with the general rate of inflation over the 2016-20 period.

AusNet Services does not agree with some of the AER's statements from recent draft determinations that suggest uncertainty regarding future commodities prices justifies the use of CPI to forecast future changes in materials prices. For instance, the AER has stated:

> *"…we consider the degree of the potential inaccuracy of commodities forecasts is such that there should be no escalation for the price of input materials used by Ausgrid to provide network services."*[7]

Potential inaccuracy generally is an insufficient reason to reject a forecast. Moreover, all forecasts inherently involve some level of uncertainty; no forecast is 100% accurate. However, the inherent uncertainty of a forecast does not mean that a substitute of zero represents a "more reliable" estimation. This argument, taken to its natural conclusion would mean that all forecasts are of no value given the inherent uncertainty about the future.

[7] Draft Decision Ausgrid Electricity Determination 2015-19, Att. 6: Capex, p. 111.

Nevertheless, recent publicly available forecasts of key commodities prices, summarised in the AER's draft determinations, suggest that CPI is a reasonable proxy for the current forecast of price changes over the total expenditure forecast. This is because, while varied, forecast price changes are for relatively moderate real price movement. Given, the extent to which forecasts can be expected to change between now and the revised proposal, CPI reflects a sufficiently accurate proxy of price forecast at this point in time.

AusNet Services did not seek an expert forecast of materials prices in the preparation of this regulatory proposal.

Given that forecasts of price changes will always improve when prepared as close in time to the forecast period as possible, CPI is a reasonable proxy forecast to be used until a more timely forecast can be developed.

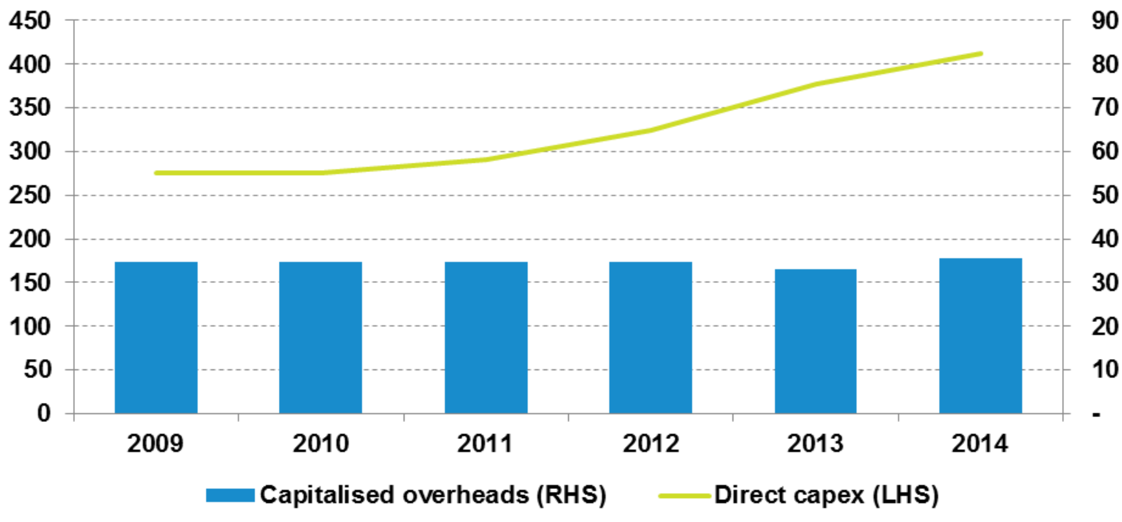
The best forecast of materials costs for 2016-20, will be established closer to the start of the period. For instance, in recent months, the Australian dollar has materially depreciated against most major currencies. The effect of this recent development on materials prices used for electricity distribution is still being assessed. If the dollar settles at this lower exchange rate, it is expected that the price for materials which are predominantly imported will increase. AusNet Services is monitoring the impact of the exchange rate on the price of our major input materials. It is expected that this may necessitate an update to unit rates in the revised proposal.

Overheads

AusNet Services is forecasting a fixed pool of capitalised overheads, equivalent to $35 million per annum (real 2015). This assumes no change in capitalisation policy to the current period, consistent with AusNet Services' policy.[8]

As shown in the Figure below, AusNet Services capitalised overheads have been relatively flat. Capitalised overheads did not grow in line with the large increases in total direct capex in the current period. Hence it is reasonable to assume that current levels of expenditure on capitalised overheads provide the best forecast of future overheads.

Figure 7.12: Capitalised overheads and direct capital expenditure – historical ($m, real 2015)



Source: AusNet Services

Note: Direct capex includes contractor overheads.

The capitalised overhead pool is allocated at a fixed rate for IT capex, consistent with internal accounting practices. The remaining overhead pool is allocated proportionally to expenditure.

8 Refer to "Accounting Policy Manual.doc".

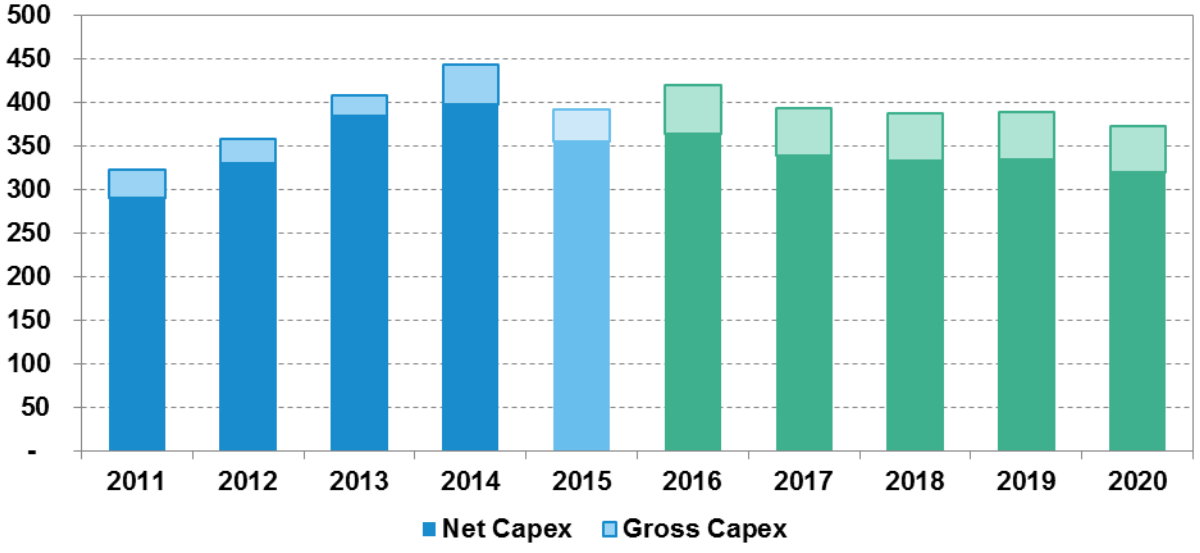
Roughly, the assumed overhead pool equates to an overhead rate of 11% for network capex and 4.7% for IT capex.

7.4 Capital Expenditure Forecast

AusNet Services' total forecast of 2016-20 capital expenditure (capex) is $1,964 million (gross), a net impact of $1,690 million[9] after government and customer contributions.[10] The forecast represents a 2% increase in total (gross) capex, and a 4% decrease in net capex compared to the current regulatory control period. It reasonably reflects the efficient costs that a prudent DNSP would require to achieve the capital expenditure objectives, based on a realistic expectation of demand and cost inputs.

As shown in the figure below, expenditure is expected to be relatively flat over the five years, with expenditure higher than average in 2016 and lower than average in 2020, due largely to a tailing off in IT capex. The peak in capital expenditure in 2016 is due to the agreed timing of safety programs, particularly the removal of 56Ms[11], which was deferred with the ESV's agreement from the current period.

Figure 7.13: Gross capex, actual and forecast ($m, real 2015)



Source: AusNet Services

Note: Figures for 2015 are estimates.

Further details of the capex forecast are provided in Appendix 7A Network Capital Expenditure Overivew.

Categorisation of capital expenditure

Since the amendments in recent years to the NEL and NER that facilitated greater use of benchmarking in determining expenditure requirements, the AER has sought to standardise the categorisation of capex to facilitate comparison of DNSPs across the NEM. The table below shows AusNet Services' capital expenditure forecast split into the AER's preferred categories (AER Categories).

9 Before disposals.

10 All figures are 2015 real dollars unless otherwise stated.

11 56Ms refers to situations where vegetation clearances cannot be achieved by trimming or removing trees, e.g. due to heritage protection. In these circumstances, alterations to the network are required, such as moving the conductor, to achieve safe clearances.

Table 7.2: Annual and total capital expenditure forecast, AER categories

Capex category	2016	2017	2018	2019	2020	2016-20 total
	$m, real 2015					
Replacement expenditure	191.2	179.0	177.2	180.8	172.5	**900.7**
Connections	74.3	74.1	74.5	72.3	73.0	**368.2**
Augmentation expenditure	82.6	64.7	60.7	53.1	52.8	**313.8**
Non-network	37.4	41.5	41.1	48.0	40.6	**208.6**
Capitalised network overheads	23.3	23.3	23.3	23.3	23.3	**116.5**
Capitalised corporate overheads	11.2	11.2	11.2	11.2	11.2	**56.2**
Total gross capex	**420.0**	**393.8**	**388.1**	**388.7**	**373.4**	1964.0
Contributions	55.5	55.4	55.4	53.8	54.0	**274.0**
Total net capex	**364.6**	**338.5**	**332.7**	**334.9**	**319.3**	1690.0

Source: AusNet Services

Note: Contributions include forecast Victorian Government contributions from the Powerline Replacement Fund.

While the standardisation of capex categories is sensible, the AER's chosen capex drivers obscure the picture of what is driving capex on AusNet Services' network.

In contrast to the categories used for AusNet Services' capex in the current regulatory period, the AER does not include safety as one of its new categories. Rather, safety expenditure can be categorised as either replacement expenditure or augmentation expenditure depending on the nature of the program.

As flagged throughout this proposal, and detailed in Section 7.4.2 below, mitigation and reduction of the risk of bushfire ignition is a major driver of expenditure on AusNet Services' network. Indeed, in 2016-20, safety is forecast to drive the largest component of capex (almost one third of gross capex).

Recent experience has clearly demonstrated that safety considerations must form part of the assessment of efficient, prudent capex. Failure to consider safety as an element of capex otherwise undermines, or at least compromises, the attainment of key elements of the NEO.

To facilitate a transparent discussion of AusNet Services' capex forecast, expenditure is also presented according to the categorisation that has been used in the current regulatory period, albeit with a minor variation (AusNet Services categories). As explained in Section 7.2.3, and Chapter 15 Depreciation, the SCADA IT capex which has historically been forecast under the non-network SCADA category will be re-categorised and rolled into general IT capex in the forecast. A separate SCADA category will capture all network SCADA capex forecast for the next regulatory period. Because of this change, in the table below SCADA captures network SCADA, while IT SCADA is reported within the IT category.

Table 7.3: Annual and total capital expenditure forecast, AusNet Services categories

Capex category	2016	2017	2018	2019	2020	2016-20 total
	$m, real 2015					
Augmentation	9.1	22.5	19.2	12.2	12.0	**75.0**
Customer Connections	81.6	82.0	82.6	80.3	81.3	**407.7**
Replacement	124.7	118.3	118.4	122.3	115.9	**599.6**
Safety	156.3	118.5	118.6	117.7	116.3	**627.4**
SCADA	9.5	9.4	6.5	6.4	5.8	**37.6**
IT	32.8	35.7	36.2	41.5	34.1	**180.2**
Other Non-system	6.1	7.4	6.6	8.4	8.0	**36.4**

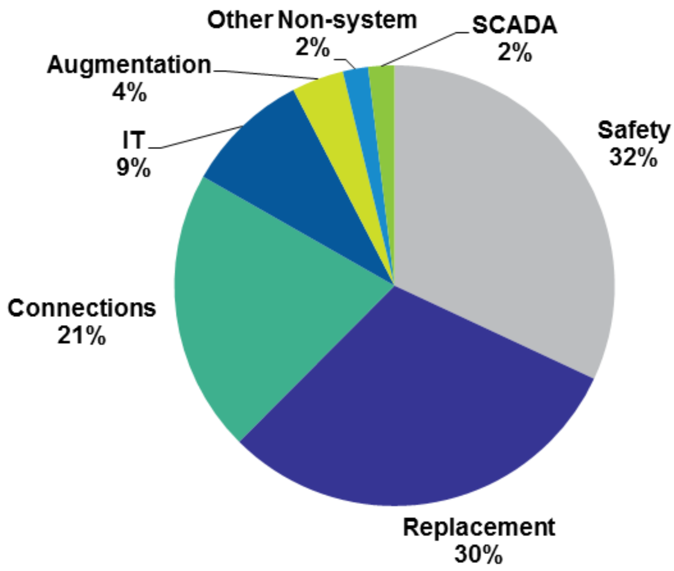
Capex category	2016	2017	2018	2019	2020	2016-20 total
	$m, real 2015					
Total gross capex	**420.0**	**393.8**	**388.1**	**388.7**	**373.4**	1,964.0
Customer contributions	55.5	55.4	55.4	53.8	54.0	**274.02**
Total net capex	**364.6**	**338.5**	**332.7**	**334.9**	**319.3**	1,690.0

Source: AusNet Services

Note: Safety includes all capex that would meet 'Environment, Safety and Legal' category definition in current regulatory period; Augmentation is equivalent to 'Reinforcement'; Replacement is equivalent to 'Reliability and Quality Maintained'.

The figure below shows the composition of the required capital expenditure by primary expenditure driver. Safety obligations and programs to reduce bushfire risk make up the largest component of capital expenditure. Augmentation—capital required to expand network capacity—makes up a proportion of the overall capex that is small by historical comparison.

Figure 7.14: Gross capex by category, AusNet Services categories, 2016-20 (percentage)

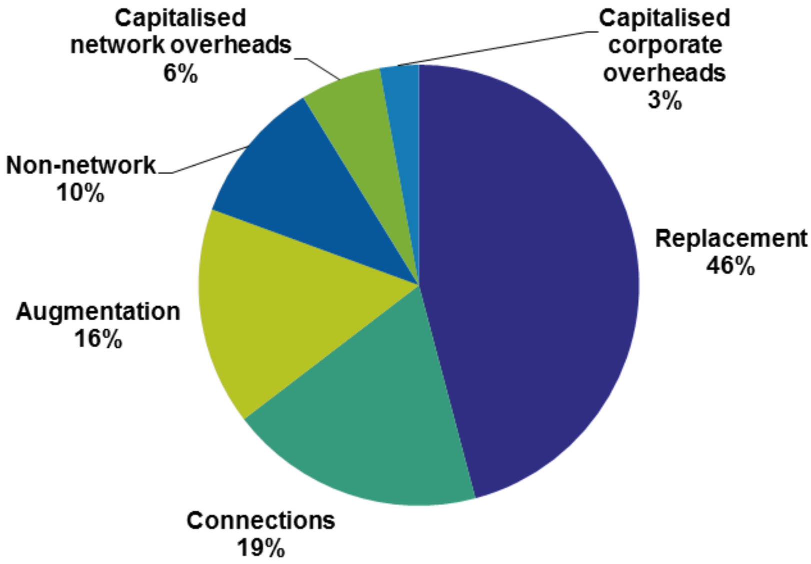


Source: AusNet Services

Looking at the composition of the capex using the AER's preferred categories, of the $627 million in capex that has a primary driver of safety, $273 million have been identified as augmentation, and $354 million have been identified as replacement programs.

Using the AER's breakdown, expenditure on asset replacement will make up the largest component of the capex program in 2016-20.

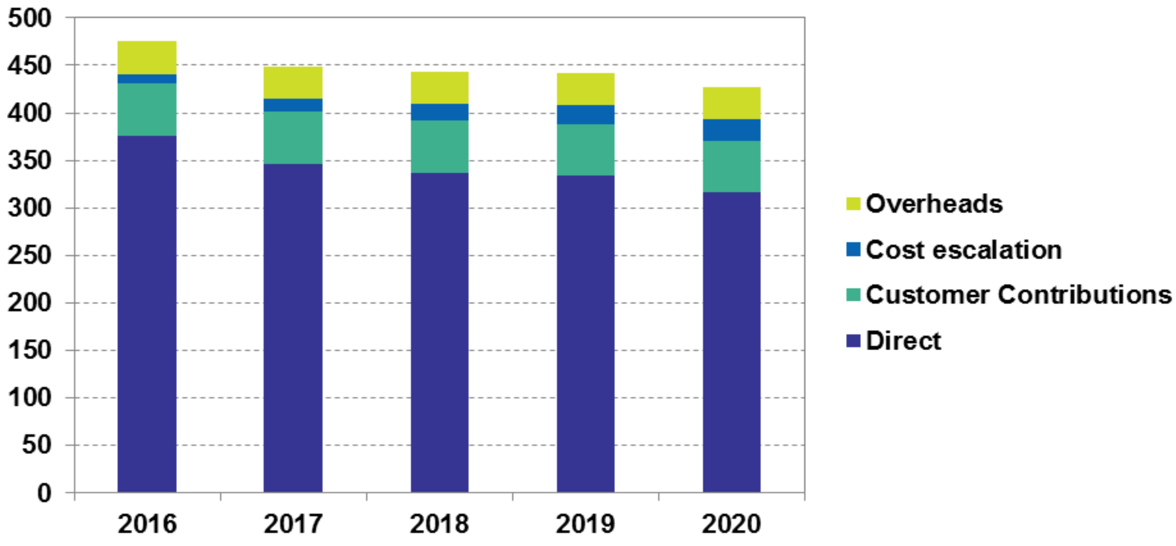
Figure 7.15: Gross capex by category, AER categories, 2016-20 (percentage)



Source: AusNet Services

The figure below shows the forecast capital expenditure broken down into direct costs, price escalation and capitalised overheads. AusNet Services expects to be able to maintain its low pool of capitalised overheads. External costs escalation is expected to contribute $74 million to 2016-20 capital expenditure requirement.

Figure 7.16: Gross capex breakdown, direct costs, overheads and escalation ($m, real 2015)



Source: AusNet Services

7.4.1 Value and Prudency of forecast expenditure

In determining the overall capital expenditure requirement, the total capital program was reviewed using a top-down methodology to manage overarching sustainability and efficiency, including by having regard to recent benchmarking results. As a result of adopting this approach, AusNet Services' capital expenditure forecast reasonably reflects the capital expenditure criteria and contributes to the achievement of the NEO.

Top-down adjustment

The capital expenditure forecast reflects the expenditure AusNet Services requires to achieve the capital expenditure objectives, with particular focus on meeting customers' reliability, growth and safety expectations sustainably. AusNet Services has actively sought to constrain expenditure where possible (especially augmentation expenditure) to promote long-term, sustainable investment in network assets. This approach recognises that demand growth is slowing and energy use is falling, and that past levels of expenditure cannot be maintained.

In applying the top-down adjustment, AusNet Services made the following modifications to the bottom-up forecast:

- Incorporating the new VCR rate;
- Omitting projects characterised by a level of uncertainty which is likely to impact on the accuracy of the capex forecast for that project;
- Assuming that an improved technique can be implemented to limit the number of pole replacements;
- Utilising conservative assumptions to forecast replacement volumes for some asset categories; and
- Excluding minor and incidental programs from the forecast.

The VCR was revised in November 2014 after AusNet Services completed its initial forecast for augmentation and major asset replacements. A change in VCR has a material impact on the proposed program as the economic assessment used for both augmentation and replacement programs use VCR as a key input. Incorporating the new VCR resulted in AusNet Services deferring a sub-transmission line augmentation project, several zone substation rebuild projects and major zone substation plant replacements.

Several projects were included in the bottom-up capex forecast which AusNet Services has not incorporated into its proposed capex program for the forthcoming regulatory control period because the uncertainty about project scope, timing or expected cost adversely impacts on the accuracy of the expenditure forecast. Affected projects include IT projects relating to 'Power of Choice' rule changes, the roll-out of Rapid Earth Fault Current Limiters to reduce the risk of bushfire ignition and recent amendments to the Emergency Management Act concerning the declaration of vital critical infrastructure. Further detail about these projects and how AusNet Services proposes to utilise the regulatory framework to manage this uncertainty is included in Chapter 11 – Cost Pass Through.

Pole replacement is the largest single component of the asset replacement program in the forthcoming period. Pole replacement rates have increased as timber poles rot and no longer have sufficient strength to remain in service. Pole reinforcement (staking) provides a means of extending the life of a pole. The pole replacement expenditure forecast assumes that new methods of timber and steel pole reinforcement can be adopted to enable poles that would otherwise require replacement to remain in service.

Limited asset condition data is available for some assets such as underground cables. Age-based modelling suggests that large programs of replacement are warranted however there is uncertainty around the size of replacement programs. The expenditure forecast has been based on historical levels of expenditure which are significantly smaller than a forecast based on age based modelling.

A bottom up forecast of replacement expenditure includes a provision for every asset category. A number of categories have not been included in the forecast such as insulators and pole top capacitors.

The risks associated with these top-down adjustments have been considered. The risks associated with the deferral of projects are primarily an increased probability of network outages. The risks associated with other adjustments are that unforeseen expenditure will be necessary requiring a reprioritisation of works or spending in excess of regulatory allowances.

Benchmarking performance

One of the capital expenditure factors that the NER requires the AER to have regard to when assessing capex forecasts is the most recent annual benchmarking report.[12] However, the weight given to the benchmarking report should not only reflect how meaningful the benchmarking results are but also the quality and availability of other information relevant to the AER's assessment.

AusNet Services supports the use of benchmarking to form a high level comparative view of efficiency where relevant. While benchmarking can provide some insights into capex levels, it is more valuable as an information tool, rather than as a basis for setting a firm's forecast capex deterministically due to the complexities of planning and forecasting investment. A prudent approach to using overall MTFP benchmarking would be to recognise the range of results that are possible and be informed by the relative performance of groups of distributors.

It is also noted that MTFP results are highly sensitive to model specification and that a range of results are possible depending on the specification applied. Given this, it is important to consider the results of alternative approaches in interpreting benchmarked performance.

Generally capex benchmarking is assessed by cost category, using methods such as historical cost trends, partial performance indicators (PPIs) and engineering-based analysis.[13] Consistent with this, AusNet Services has taken into account how it benchmarks against historical capex performance (net of customer contributions), PPIs and relevant areas of category analysis.

An interpretation of benchmarking results needs to take into account network-specific factors which would impact the results. In AusNet Services' case, factors which impact overall capex productivity include:

- the highly residential nature of AusNet Services customer base which depresses energy throughput and increases the peaky nature of demand, thus lowering productivity; and
- the high proportion of AusNet Services' network which is located in high bushfire risk areas (HBRA). This means that the business incurs significant costs related to community safety and bushfire requirements which reduces measured productivity.

The above factors are explained in detail in Chapter 5 – Benchmarked Performance and the impact of safety and bushfire expenditure on productivity results is demonstrated in that chapter also.

Benchmarking is one of a number of factors which the AER must take into account in assessing forecasts. As such, weight given to benchmarking should not only reflect how meaningful the benchmarking results are but also the quality and availability of other assessment information. Namely, the availability of benchmarking data does not mean the AER should not continue to investigate a firm's efficiency through direct and thorough engagement with the business.

Historical capex

AusNet Services is forecasting average annual net capex to be 5% lower than the equivalent in the 2011-15 period. The figure below shows how safety capex has grown significantly since 2011, while the net capex excluding safety capex has remained stable. The figure illustrates how safety drives a significant proportion of capex, a consequence of the unique safety and bushfire mitigation circumstances which apply to AusNet Services' network.

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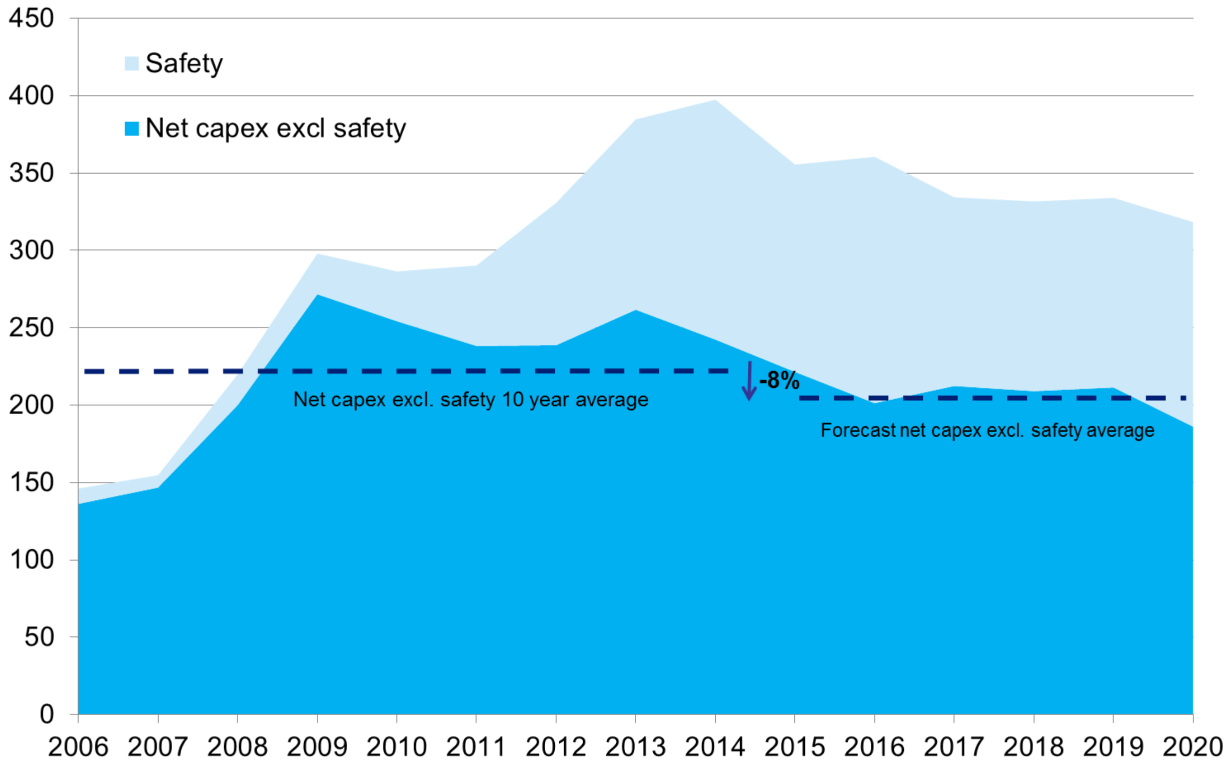
[12] NER, clause 6.5.7(e)(4).

[13] ACCC, Regulatory Practices in Other Countries: Benchmarking opex and capex in energy networks, May 2012, p 3

Figure 7.17: Historic and forecast net capex and safety capex ($m, real 2015)



Source: AusNet Services

The figure above also demonstrates how the forecast capex, net of safety capex, is in fact 8% below the long term historic average.

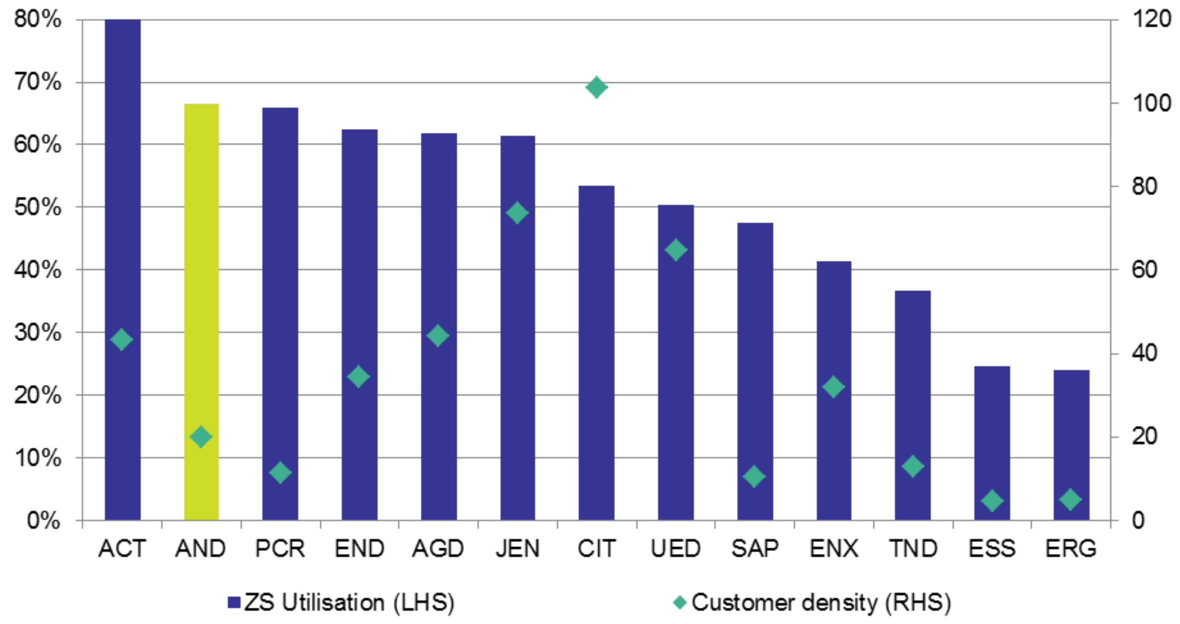
Network utilisation

Network utilisation is a good indication of how efficiently a business is investing capex in its network. AusNet Services is careful to manage network investment prudently as demonstrated in the charts below which show that AusNet Services compares well in the measures of zone substation utilisation across the NEM.

Utilisation levels refer to the degree to which an asset's full capacity is being used to transport electricity. A higher utilisation rate indicates less spare capacity in the network, and vice versa.

The figure below shows the 2013 utilisation rates across the NEM. More precisely, the utilisation measure shown in the figure below is the ratio of coincident maximum demand MVA at all zone substations to the sum of all ratings (or technical capacity) MVA of all zone substations in the distribution network.

Figure 7.18: 2013 zone substation utilisation (%)



Source: AER RIN data.

Note: AusNet Services shown as AND. Customer density is number of customers per km line route line length.

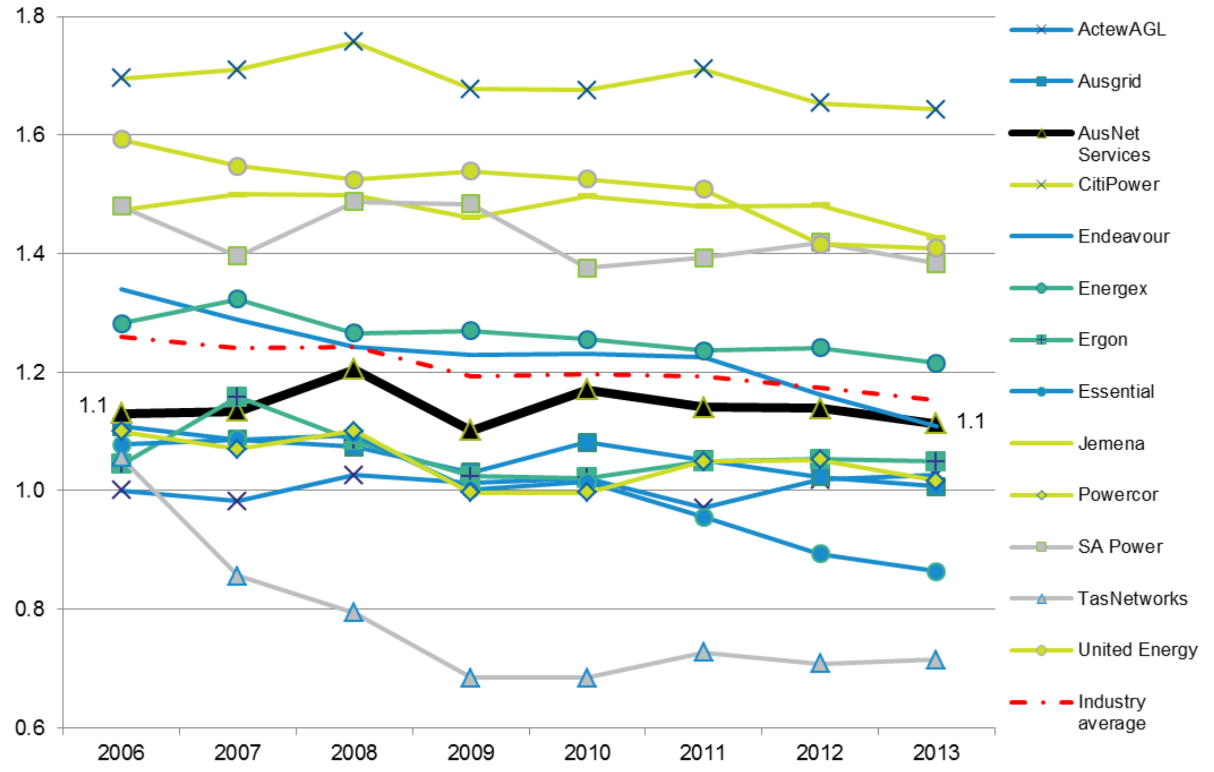
The above figure shows that AusNet Services has the second highest utilisation level for zone substation capacity in the NEM with 67%, behind ActewAGL's 80%. This is a clear indication that relative to other DNSPs, AusNet Services does not hold a significant level of spare capacity in its network and has invested efficiently. The above results are shown against customer density which indicates that density is not a real factor in the results.

Capex Multilateral Partial Factor Productivity (MPFP)

Capex productivity results are more useful in indicating an overall trend rather than levels of efficiency, given the sensitivity of TFP results to model specification and the fact that capex is less stable over time than opex.

The AER's 2014 Annual Benchmarking Report showed the industry-wide trend of capex productivity declining. However, despite this, AusNet Services' productivity of capital has remained stable over the 2006-13 period, and its performance ranks sixth in the sector in 2013, where it was previously seventh in 2006. This is shown in the figure below.

Figure 7.19: Capex MPFP Scores



Source: AER MTFP model

Note: Data adjusted to remove AusNet's bushfire and safety capex from 2011-13.

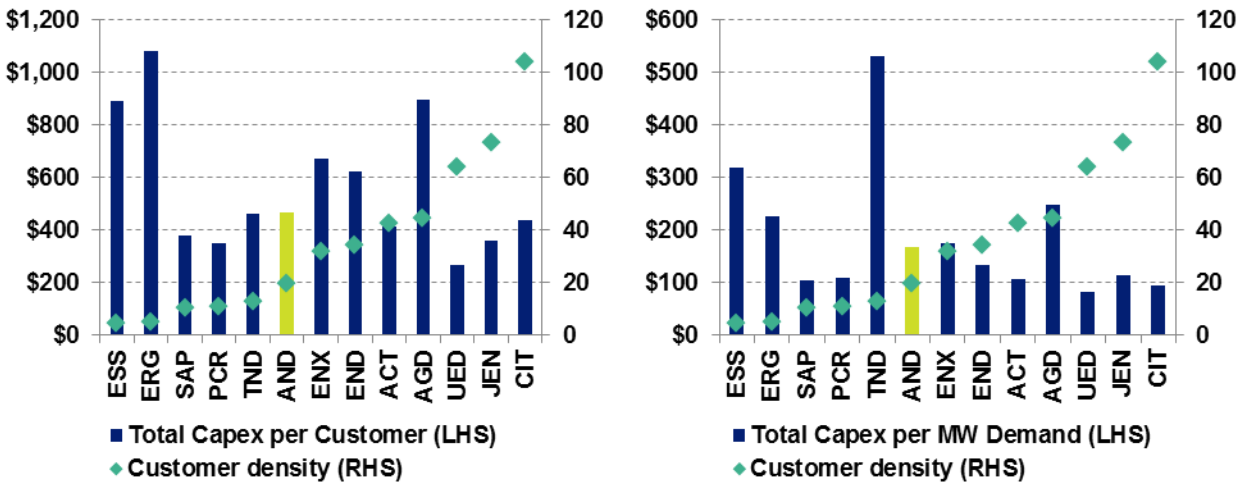
The above chart reflects data adjusted to remove AusNet Services' bushfire and safety capex from 2011-13. While, this did not materially affect capex MPFP results or AusNet Services' position in relation to its peers in the time period shown (2006-13), it is expected that it will clearly impact future results as the significant bushfire and safety capex program to be delivered over 2016-20 will increase the asset base, depressing capex productivity.

Partial performance indicators

Partial performance indicators (PPIs) are used to compare the performance of businesses in delivering one single type of output. PPIs allow us to focus on particular aspects of a firm's operation and highlight capex costs with respect to specific outputs.

The PPI results below show that in a range of relative capex efficiency metrics, AusNet Services' performance compares well relative to the rest of industry. Results are based on 2009-13 average data and are normalised against customer density, consistent with the AER's preference to use customer density to manage differences between urban and rural networks.

Figure 7.20: Total capex per customer **Total capex per MW demand***



*Source: AER RIN data, *non-coincidental maximum demand*

The above figure shows AusNet Services compares relatively well on a total capex per customer measure, using 2009-13 average capex and customer figures. It also shows AusNet Services sits near the average industry performance on a total capex per MW of demand measure, using 2009-13 average capex and customer figures. However this performance is impacted by the fact that AusNet Services has very low consumption per customer and highly peaky demand due to its high proportion of residential load. This impairs performance because it increases capex per customer and per MW of demand, as explained in section 5.X.

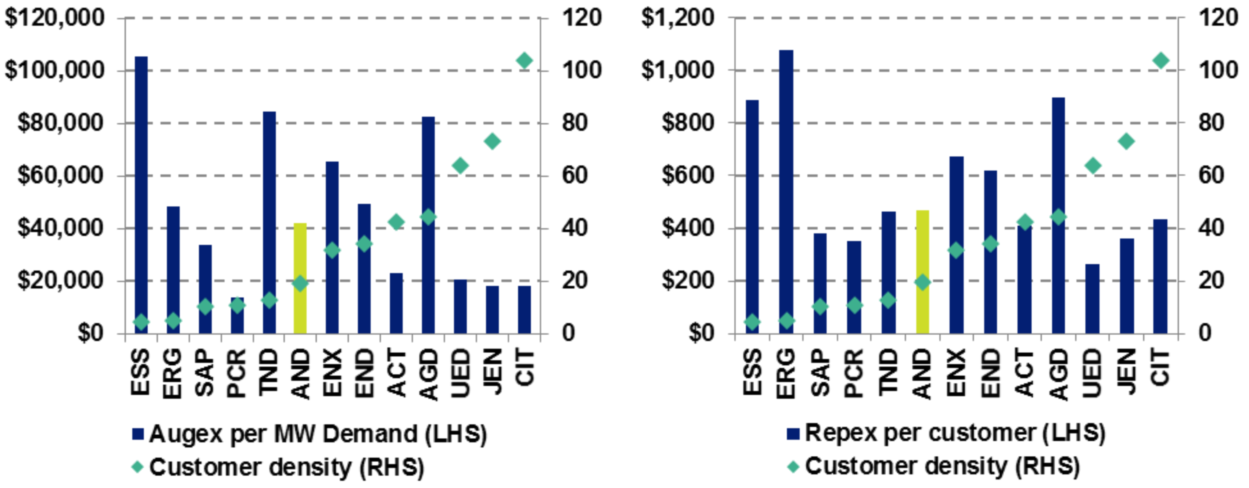
Category benchmarking

Detailed cost category analysis allows comparison of various areas of cost such as replacement or augmentation capex, or non-network capex across firms. The level of meaningful comparison provided by cost category analysis hinges upon costs being reported on a like-for-like basis.

The category analysis results below show that in a range of comparators, AusNet Services' performance compares well relative to the rest of industry. They also show that forecast capex efficiency is likely to remain relatively constant with current levels. Results are based on 2009-13 averaged data and are normalised against customer density, consistent with the AER's preference to use customer density to manage differences between urban and rural networks.

The figure below shows that per MW of demand, AusNet Services augmentation capex cost per MW of maximum demand compares relatively well to the rest of the sector. However, around half of the measured augmentation capex is in fact safety capex which does not increase network capacity but must be categorised as augmentation under the AER's data collection definitions because it does not qualify as replacement capex. Therefore, performance under this measure could be expected to be better excluding safety capex.

Figure 7.21: Augmentation capex per MW demand* and Replacement capex per customer



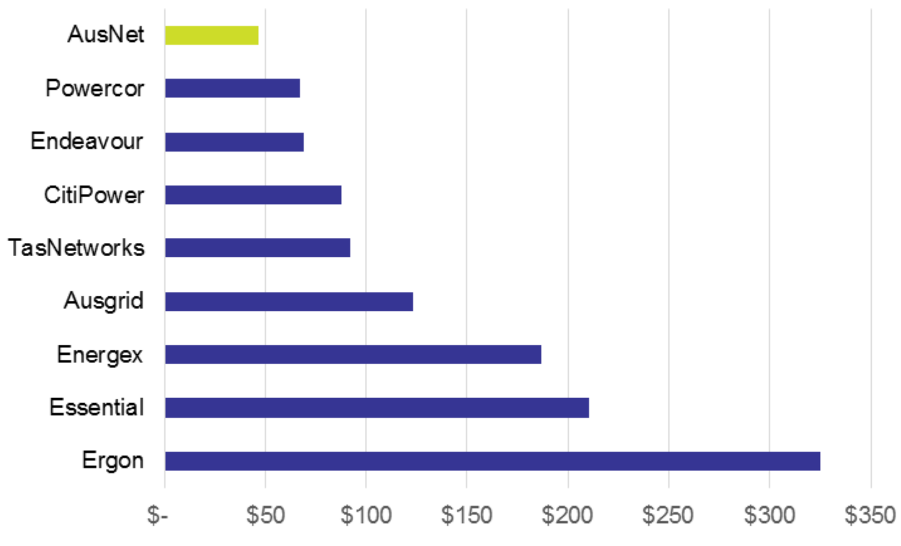
Source: AER RIN data,

*Notes: *demand is non-coincidental maximum demand. Capex values are 2009-13 average.*

The figure above shows that AusNet Services average replacement capex cost over 2009-13 against customer density compares relatively well to the rest of the sector. Further, forecast replacement capex would improve performance under this measure in the next regulatory period.

AusNet Services leads the sector in the comparative efficiency of its capitalised overheads. The figure below shows AusNet Services has low capitalised overheads compared to its peers, taking the total cost of corporate and network capitalised overheads per customer.

Figure7.22: Capitalised overheads per customer

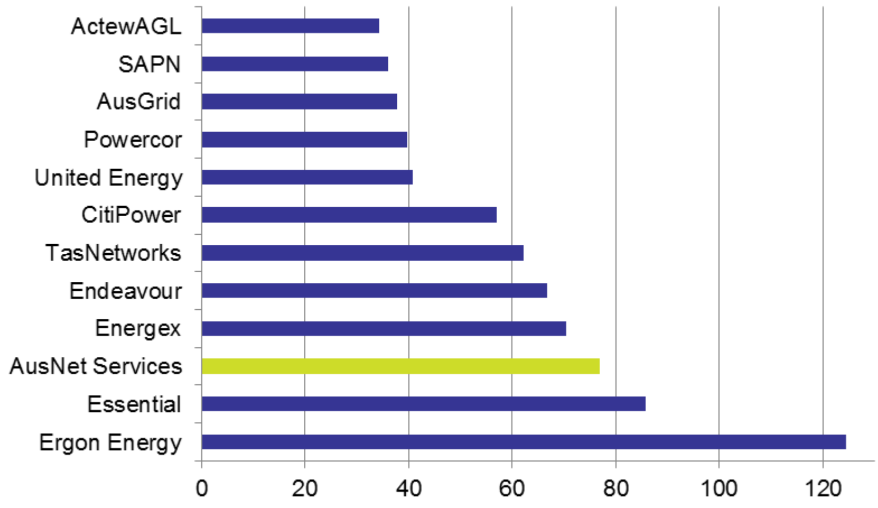


Source: AER RIN data. Overheads values are 2009-13 average.
Note: ActewAGL, Jemena, SA Power and UED excluded due to data being unavailable/inconsistent.

IT Capex

Cost category analysis has highlighted to AusNet Services that its IT costs do not compare well against its peers. Analysis of AusNet Services' average IT totex (capex plus opex) over 2009-13 shows that AusNet Services' has the third highest IT cost per customer in the NEM, as shown in the figure below. Totex is an appropriate measure of IT costs as it is neutral as to whether a business utilises opex (eg: infrastructure as a service (IAAS)) rather than capex (eg: owns and operate their own IT infrastructure) for ICT services.

Figure 7.23: 2009-13 Average IT Totex per Customer $



Source: AER RIN data

Given the above performance, it is important to understand what has driven IT costs and what the benefits of past investments are. AusNet Services is also taking action to respond to these benchmarking results.

Drivers of ICT costs

The two main drivers of AusNet Services' ICT costs are:

- Current position in ICT capex lifecycle; and
- The increasing integration of ICT with network management.

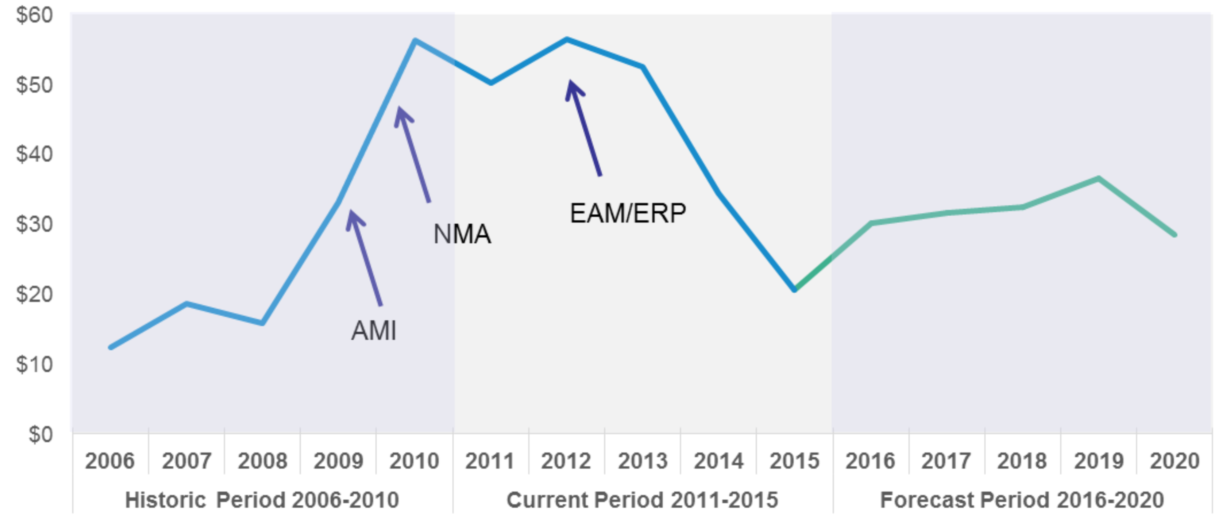
ICT capex, like network capex, can occur in waves. While regular replacement and upgrades are driven by technology and software obsolescence, other investments are made in response to where ICT sits in a longer term lifecycle driven by business needs.

In the 2006-10 regulatory period the focus of ICT was maintaining the disparate legacy IT systems resulting from the merger of TXU and SPI PowerNet. This was a capex intensive period as it involved shifting from a lease model to an own-operate model, as well as dealing with a number of complex legacy systems and platforms such as Maximo (asset management system), COGNOS (reporting platform) and PowerOn (network and work management system). IT investments at this time were aimed at managing the level of risk, reliability and security required by the business functions.

Following this, a capital investment uplift occurred from 2010 as significant investments have been made to establish a managed environment for the reliable delivery of IT and communications services. A key project aimed at consolidating IT services is Project WorkOut (which replaces 140 business applications with a single enterprise asset management and enterprise resource planning-system) totalled $55m (nominal) over the period. In addition, AusNet Services invested $62m (nominal) in the Network Management Automation (NMA) program to leverage the increasing advantage in using ICT to optimise network performance. The NMA program integrated Distribution Outage Management, Graphical Information and Supervisory Control and Data Acquisition systems; establishing a real-time, spatially aware, remote management and monitoring of the network.

The growth in ICT costs since 2006 reflects where AusNet Services is in its ICT evolution. Against this context, AusNet Services historic and forecast IT capex, with key projects highlighted, is shown in the following figure.

Figure 7.24: AusNet Services ICT capex investment profile



Source: AusNet Services

Along with the ICT investment in AMI ($15m), the NMA and EAM/ERP projects provide AusNet Services with a strong foundation to modernise its ICT offering in the next regulatory period and enable business transformation for future periods.

For the 2016-20 regulatory period, AusNet Services is focused on modernising its applications; the tools that ICT provides to support electricity distribution business processes. This involves completing the modernisation of these applications and retiring those that they replace. Once this change is complete, it is expected future ICT costs will remain steady notwithstanding the increased complexity of the business environment and the requirements it places on ICT.

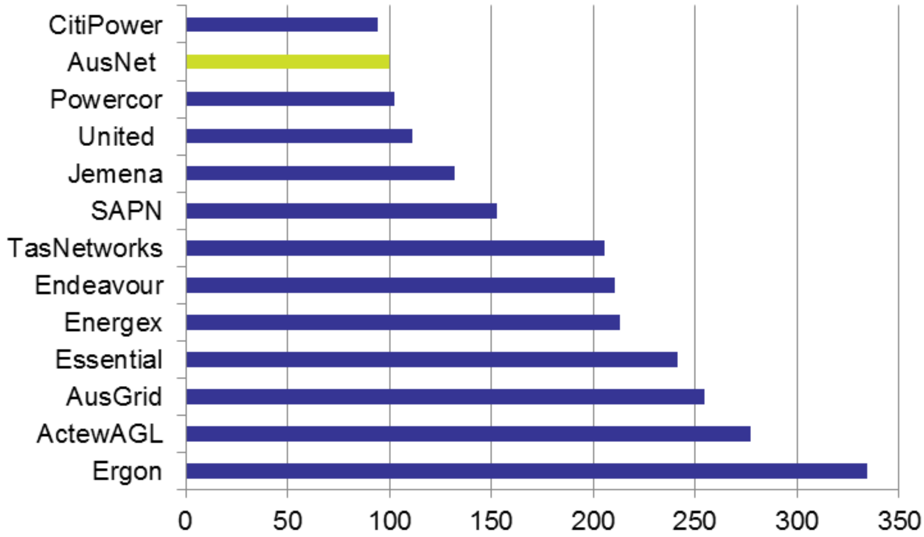
Benefits of investing in ICT

ICT investments delivered over the 2011-15 period have enabled and supported innovation and integration which have delivered benefits to consumers by containing future costs and ensuring network reliability and safety even as the operating environment becomes more complex. These programs include:

- Network automation, including a new advanced network management system and distribution feeder automation. This has resulted in improvements in reliability and response times for emergency maintenance.
- The financial and asset management systems linking financial, GIS and asset management information. This has enabled improvements to asset management and supported information provision into regulatory processes without requiring step changes in opex.

AusNet Services is at the forefront in using ICT efficiently and economically as a tactical enabler for the delivery of increasing value from core business. That is, AusNet Services uses ICT to drive lower corporate and operational costs. This is shown in AusNet Services having the second lowest total overheads per customer in the NEM at $100 per customer.

Figure 7.25: 2009-13 average total overheads cost per customer



Source AER RIN data.

Controlling ICT costs

AusNet Services' ICT capex is forecast to decrease over the next regulatory period and progressively normalise as the business continues its enterprise-wide transformation journey. AusNet Services has self-funded part of the EAM/ERP initiative (ie: it was not all funded through regulatory allowance) as the EBSS appropriately rewards investments which are aimed at delivering operating efficiency.

Despite the lower capex forecast for the 2016-20 regulatory period, ICT cost comparisons have highlighted the importance of sound programme execution and system rollout techniques. AusNet Services is working on improving these capabilities through a range of initiatives:

- Project management methodologies consolidated through an Enterprise Project Management Office (EPMO);
- Enterprise portfolio management (EPPM) and staged funding for major projects; and
- Updated Project Delivery model and System Integrator panel for ICT project delivery.

The successful progress of the large and complex EAM/ERP initiative and the forecast commissioning of the core solution is evidence of the effectiveness of these initiatives to manage and control the execution of ICT Capex. Further detail on these processes is provided in the *ICT Strategy 2016-20, Appendix A – EDPR CY 2016 - CY 2020 – Methodologies and Processes.*

While AusNet Services expects some ICT opex increases due to increasing levels of virtualisation and use of cloud storage solutions, it is not forecasting a step change in IT opex for this as it is proactively seeking opportunities to control ICT opex costs to ensure they do not increase above current levels.

Use of economic predictive models (e.g. Repex and Augex)

Predictive expenditure models such as Repex and Augex provide useful insights into the makeup of expenditure forecasts, however AusNet Services believes these models alone should not be used to determine the allowed expenditure levels.

A robust capex forecasting approach should be built upon good asset management information including empirical data on asset condition, deterioration trends and the criticality of specific assets to the network. Such models are necessarily complex due to the range of factors and considerations which asset managers must balance in making investment plans. Top down analysis, including applying predictive models, to test and adjust the forecast forms a part of a sound forecasting methodology.

The AER has published a top-down predictive model (the **Repex model**) which can be used to test a capex forecast. The repex model is a high level probability-based model which takes the number and age of assets in service, the assumed replacement age of these assets (with asset age acting as a limited proxy for asset condition) and the corresponding unit costs to generate a range of repex estimates. The range of estimates is driven by different replacement ages and unit cost inputs.

Replacement expenditure represents a considerable proportion of the proposed capital expenditure and the Repex model will provide some insights into the appropriate level of expenditure during the regulatory period. However the Repex model is a relatively simple age based model and does not consider asset condition or network risk in formulating the forecast. AusNet Services has developed and is continuously improving asset management models that incorporate asset condition, failure history, and risk into the development of replacement forecasts to produce robust forecasts.

For the forecast period the type of Augmentation related expenditure contemplated by the **Augex model** (i.e. Augex related to demand and customer growth) is forecast at a historically low level. However, other expenditure that has been mandated by the safety programs will also be classified as augmentation expenditure and the Augex model does not model this type of expenditure and therefore will not provide validation of the level of expenditure proposed.

7.4.2 Safety

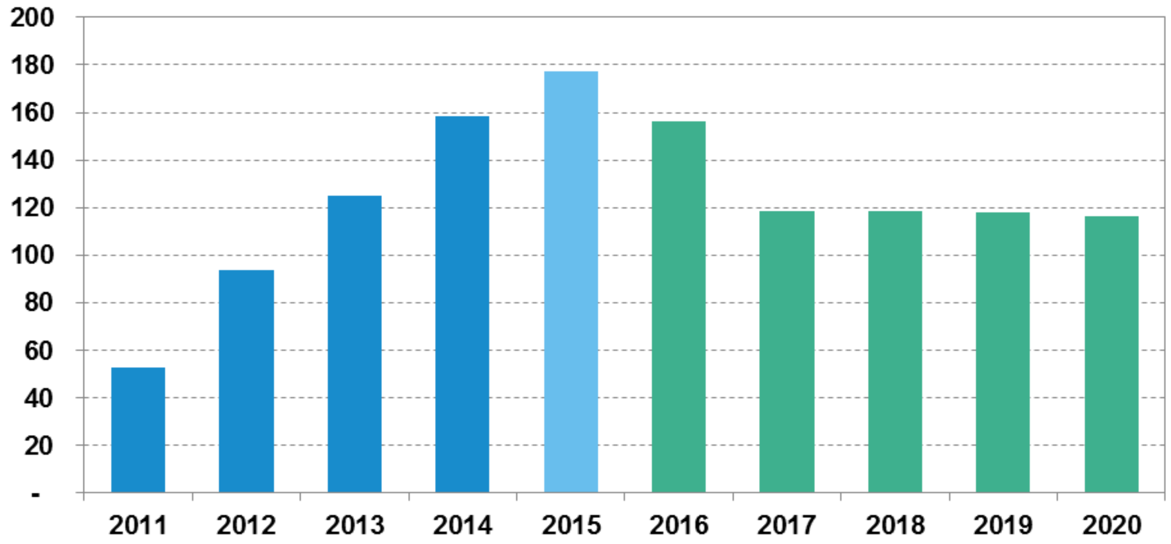
Summary

The capital expenditure forecast in this section, is for programs required to manage and mitigate safety risks from the distribution network, and to meet compliance and legal obligations.

As shown in Figure 7.26 below, the total expenditure forecast for 2016-20 for programs with a safety driver is $627 million (2015, real). This includes an expected $60 million for powerline replacement funded by the Victorian Government via the Powerline Replacement Fund (PRF). The proposed expenditure does not include capex for the roll out of Rapid Earth Fault Current Limiter (REFCL) technology. While some promising research and development that is being undertaken in collaboration with the State Government is expected to result in a substantial augmentation program to roll out REFCLs, due to uncertainty regarding the scope and cost of the program, AusNet Services is proposing that the pass through event framework in the NER is currently the best mechanism to facilitate this investment. Details of the Pass Through proposal are included in Chapter 11.

The forecast is predominately for programs to reduce the risk of bushfire ignition, with 3.5% of the total for other programs to improve safety and network security. The expenditure associated with a number of these programs is required in order to meet new or existing regulatory obligations, or to maintain or meet community expectations regarding the ongoing safety, reliability and security of the AusNet Services' network and its services.

Figure 7.26: Safety capex by year, actual and forecast ($m, real 2015)



Source: AusNet Services

Notes: Shows gross safety capex inclusive of overheads. Includes Powerline Replacement Fund and VBRC pass through programs. Figures for 2015 are estimates.

Electricity assets are risky and risks must be managed

Electricity assets are inherently risky, and a central tenet of the design, construction, operation and maintenance of the distribution network has always been the mitigation and management of these risks. The two major risks are the risk of electrocution and the risk of fire ignition, but other risks exist including risks to employees as they work on the network.

The risk levels and the consequence of bushfires for AusNet Services' distribution network are particularly high due to the natural environment in which it is located, and the proximity of communities to areas with high fire risk. Eastern Victoria couples weather conditions and fuel loads (densely forested or bush areas) associated with high bushfire risk and intense bushfire activity. As detailed in Chapter 2 – Network Characteristics, the risk for AusNet Services' network is the highest in the NEM.

Victorian framework for managing safety risks from the electricity grid

Victorian electricity safety law and regulations are focussed on bushfire ignition risks. The obligations of a network service provider to manage assets and nearby vegetation are specific. Sophisticated risk assessment, installation, inspection, maintenance, operation, performance monitoring and audit regimes have been developed over forty years to manage these safety risks and the obligations.

It is a requirement of the Electricity Safety Act 1998 that AusNet Services, as a major electrical company (MEC), design, construct, operate, maintain and de-commission its supply network to **minimise as far as practicable** the hazards and risks:

- to the safety of any person, and
- of damage to the property of any person.

It is also a requirement of the Electricity Safety Act 1998 that a MEC submit to Energy Safe Victoria (ESV) an electricity safety management scheme (ESMS) in respect of the design, construction, operation, maintenance and de-commissioning of each supply network.

ESV may accept an ESMS when it is satisfied that the documented scheme is appropriate to the supply network to which it applies, and that it complies with the Electricity Safety Act and Electricity Safety (Management) Regulations 2009.

Once accepted by ESV, AusNet Services must comply with its electricity safety management scheme. ESV conducts annual compliance audits.

In this way, the Victorian framework for electricity safety creates an overarching (or general) obligation on AusNet Services to develop an ESMS that will minimise risks and hazards as far as practicable and to comply with an ESMS accepted by ESV.

The Victorian arrangements also impose specific obligations. Many of the recommendations of the 2009 Victorian Bushfire Royal Commission (VBRC) have been implemented either through legislation or through ESV Directions. Further details of these specific obligations are detailed below in relation to the relevant capex programs.

AusNet Services revenue proposal includes capital expenditure to meet the obligations described above. This is consistent with the Revenue and Pricing Principles, which include the requirement that network service providers be given a reasonable opportunity to recover the efficient costs incurred in complying with a regulatory obligation or requirement.

Although the details are still to be determined, it is expected that the Victorian Government will amend safety legislation to set obligations regarding the roll out of REFCLs. The pass through framework under the NER is expected to provide an appropriate mechanism for approving expenditures aligned with the specifics of the eventual obligations.

Step change to safety programs

Because of the high level of bushfire risk faced by AusNet Service's network, the expenditure required to address safety risks is greater than for other networks in the NEM. This has been particularly pronounced since the 2009 Victorian bushfires, when new obligations and expectations have applied.

Assessment of the 2009 bushfires resulted in major changes to the safety framework. Substantive new obligations have been placed on the distribution businesses by external parties and the internal risk assessments undertaken by the businesses have been updated for material risk assessment changes. These risk assessments are incorporated into a network's ESMS which, as described above, has been made compulsory feature of the legislative framework. Changes to obligations imposed by external parties manifest in three ways:

- Firstly, regulations have been changed by the ESV or exemptions to meet the regulations have been rescinded. For example, the Electricity Safety (Electricity Line Clearance) Regulations 2010.
- Secondly, the distributors are issued an ESV 'Direction' to complete a change to their existing practice. A Direction does not result in new regulation but must be complied with, generally dropping away once compliance has been achieved and incorporated into the network's ESMS. For example, the application of vibration control to powerlines.
- Finally, specific recommendations arising from the Victorian Bushfire Royal Commission and Powerline Bushfire Safety Taskforce (PBST) have been directly incorporated into the network's ESMS. For example the Victorian Government's $200 million powerline replacement program.

Further details of the changes to Victorian bushfire safety obligations following the 2009 bushfires are provided in the document "Historical changes to bushfire safety obligations in Victoria".

The bulk of the initiatives are being completed over the period from 2011 to 2020, resulting in a ten years surge to safety driven capex. The figure below shows the phasing of the implementation of bushfire safety programs in the current and forecast regulatory periods.

Figure 7.27: Phasing of activity for bushfire safety program

Status	Project Area	Volume Replacements 2010-2015	2016-2020
Largely completed	Insulator Replacement	**5,650**	
	SWER & 3-Phase ACR Replacement	**760**	
	Relay Replacement	**110**	
	Line Clearance Survey	**10,240**	
Ongoing	Cross-arm Replacement	**46,790**	**45,645**
	Overhang Removals	**1,620**	**655**
	Line Clearance Construction	**50**	**435**
	Conductor Replacement	**1,760**	**1,360**
	Steel	*1,430*	*1,050*
	Copper	*280*	*300*
	HV ABC	*50*	*10*
	High Voltage Fuses	**31,590**	**9,500**
	Animal/Bird Proofing	**13,000**	**21,250**
	Vibration Dampers & Armour Rods	**59,650**	**110,000**
	REFCL Technology	**2**	**To be determined**
Emerging	Advanced Protection and Control		**To be determined**
	FOLCM/Isolators		
	Bare Wire Powerline Replacement in declared areas		

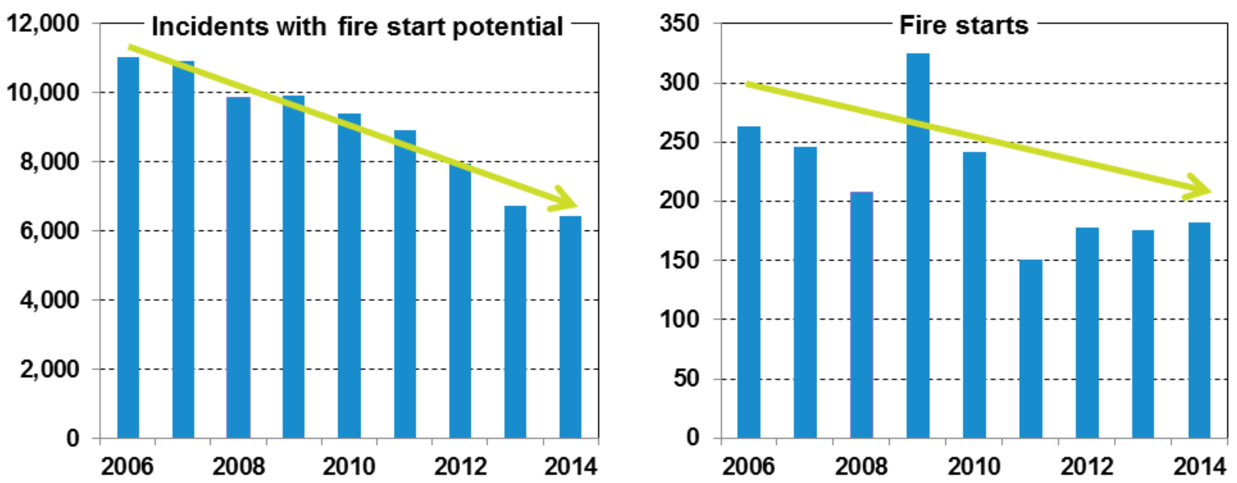
Source: AusNet Services

The profile of AusNet Services' historic and forecast safety expenditure (shown in Figure 7.25) is dictated by the phasing of activity outlined in the figure above. While much work has been completed in the current regulatory period to implement the VBRC recommendations, a significant program remains to be delivered between now and 2021.

Safety investments are delivering measurable reductions in bushfire risk

The large increases in expenditure in the current regulatory period are delivering improved safety outcomes for the community. Both the number of incidents with the potential to cause a fire and the number of actual fire starts[14] caused by AusNet Services' assets have fallen since 2009.

Figure 7.28: Fire risk indicators, all causes



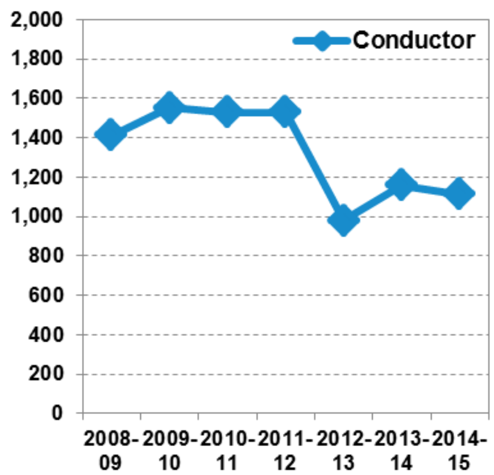
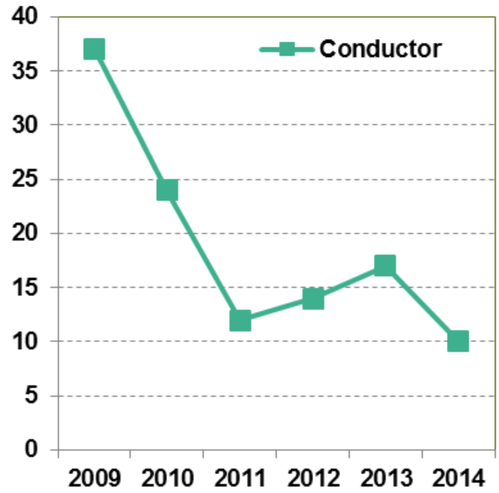
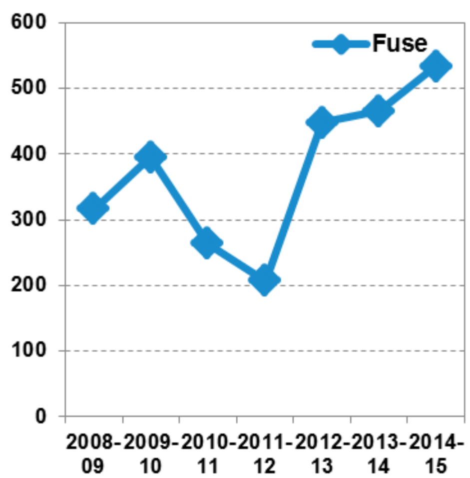
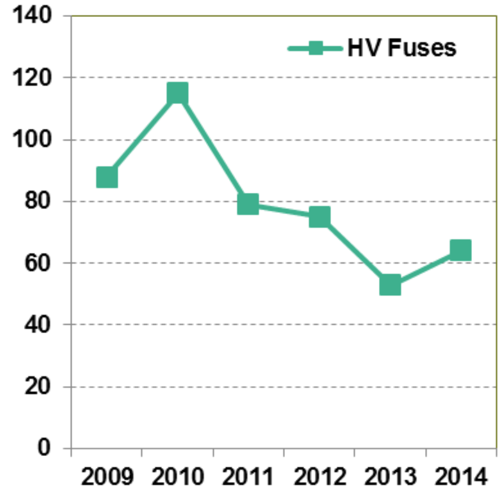
Source: AusNet Services

14 Fire starts include asset and ground fires. Most fire starts are contained events and do not progress to bushfire.

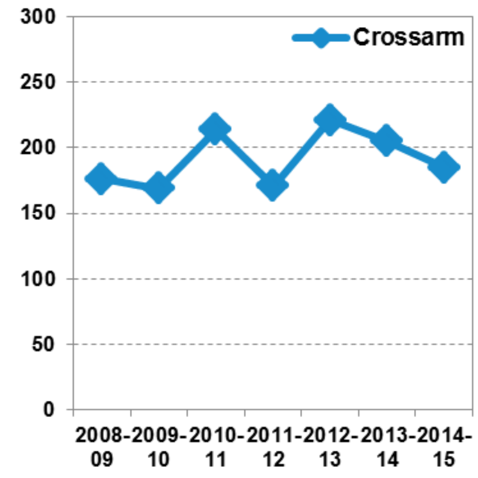
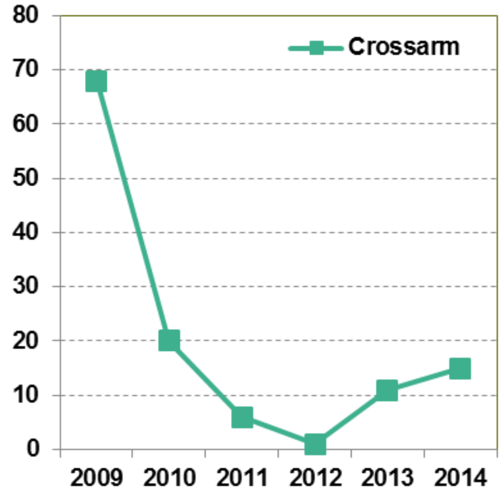
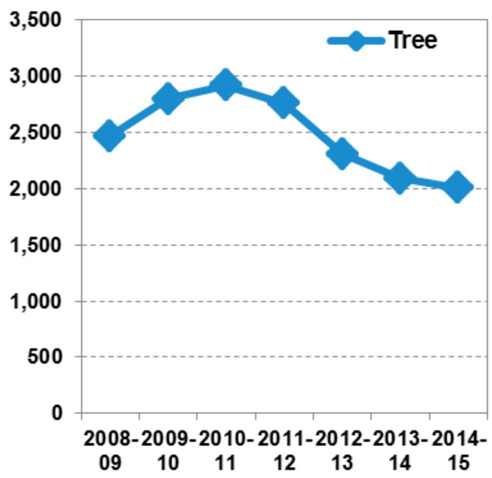
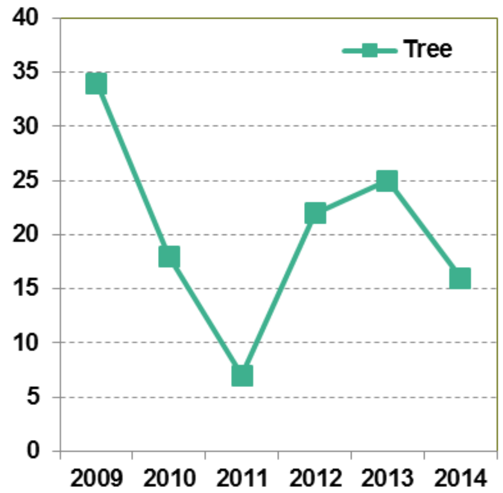
Although the volume of fire starts is partially driven by weather conditions, and is therefore volatile, in every year of the current regulatory period there has been a lower number of fire starts than for each of the preceding five years.

The following figures show the trends in fire starts and incidents with the potential to start a fire for assets that have been targeted with bushfire mitigation programs in the current regulatory period.

Figure 7.29: Fire risk indicators by asset type

Bushfire mitigation program(s)	**Incidents with fire start potential[15]**	**Fire starts**
Conductor replacement Powerline Replacement; Other conductor replacement		
EDO fuses;		

15 Incidents data are for AusNet Services' financial years (April – March). Fuse incidents include LV incidents.

Bushfire mitigation program(s)	Incidents with fire start potential[15]	Fire starts
Cross arms; Insulators		
Overhang Removals. Vegetation management (opex) Hazard tree program		

Source: AusNet Services

Forecast bushfire safety programs

Bushfire safety programs can be categorised into three groups:

1. Compliance – programs or projects for which AusNet Services has an explicit and specific obligation.
2. Justified based on calculated risk reduction – these programs have been modelled based on the costs, probability and consequence.
3. Enhanced protection and innovative risk reduction.

The table below illustrates the composition of the bushfire safety program, by justification.

Table 7.4: Bushfire safety program by justification ($ real 2015, direct costs excl overheads)

Program	Description	Expenditure
Justification: Compliance		
Vibration dampers and Armour Rods	Installation of vibration dampers to conductors and armour rods to provide a protective shield at the point of contact	$141M
Overhang Removals	Reconfiguration of the network to remove spans of bare conductor where overhanging trees cannot be removed	$31M
Line clearances & low services	Rectifications of clearance breaches identified with conductor clearance survey undertaking in the current regulatory period, and cyclic asset inspection.	$14M
Replace SWER OCRs with ACRs	Update of reclose technology to enable setting changes during bushfire season. Completion of program that has primarily occurred in the current regulatory period.	$1M
Bare powerline replacement	Projects funded by the Victorian Powerline Replacement Fund, to replace bare overhead conductor from highest risk areas with insulated cable technologies.	- ($60M Vic Govt funding)
Rapid Earth Fault Current Limiters	Smart technology being deployed to limit current in circumstances of line faults which should reduce instances of fire ignition – Ground Fault Neutraliser.	To Be Determined (Likely pass-through event)
Total		**$187M**
Cross Arms	Removal of wooden cross arms in all HBRA areas, replaced with steel cross arms.	$121M
Conductor Replacement	Replacement of deteriorated overhead conductor in areas with extreme bushfire consequences	$87M
Animal & Bird proofing	Installation of animal & bird proofing on high voltage structures to prevent the ignition of ground fires	$57M
EDO fuses	Replacement of fuses that have the potential to ignite ground fires when they operate	$7M
Total		**$272M**
Justification: Prudent innovation		
Protection projects	Projects targeted at limiting the amount of energy released to network faults	$25M
Total		**$25M**
Bushfire safety programs (Total)		**$484M**

Source: AusNet Services

1. Compliance programs

The major compliance programs in the capex forecast are described below.

Armour rods and vibration dampers are currently required on overhead conductors in line with Victorian Electricity Supply Industry (VESI) standards. Subsequent to the 2009 Victorian Bushfires Royal Commission recommendations, ESV issued a Directive, dated 4 January 2011, for AusNet Services to prepare a plan for the fitting of vibration dampers and armour rods to its network in accordance with the VESI standards[16]. The Directive requires the plan to address the program in two broad stages as follows:

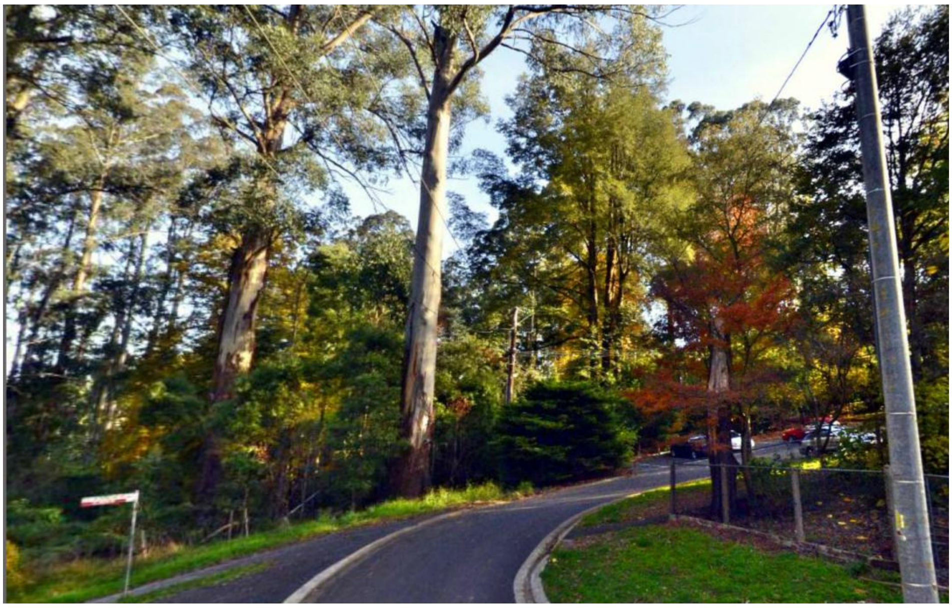
- Stage 1 – hazardous bushfire risk areas (HBRA) before 1 November 2015; and
- Stage 2 – all other areas by 1 November 2020.

The agreed program, accepted by ESV, has ensured that the highest risk areas as determined by the Fire Loss Consequence Model (FLCM) are addressed in Stage 1 of the program in accordance with the Directive. Remaining HBRA assets will be addressed together with remaining assets in Stage 2. The project created to carry out this program involves the installation of approximately 60,000 armour rods and vibration dampers by 2015 and a further 110,000 sites by 2020.

Overhang removals: The Electricity Safety (Electric Line Clearance) Regulations 2010 introduced a new requirement that prohibits vegetation to overhang bare overhead powerlines in HBRA. It was previously possible to conduct an assessment of the health of tree branches overhanging the clearance space.

Under the previous regulations it was standard AusNet Services' practice to maintain the prescribed clearance space above bare overhead powerlines in hazardous bushfire risk areas clear of vegetation. However, in a limited number of cases (approximately 2,000 spans) it was impracticable to maintain the clearance space above these powerlines. These spans are typically in areas containing vegetation considered 'significant', such as mountain ash, predominantly in the Dandenong Ranges and have existed since initial electrification of these areas. Accordingly, in accordance with the regulations, these spans (coded as 56Ms) were assessed annually by a qualified arborist to ensure limbs and branches overhanging the powerlines were healthy.

Figure 7.30: Mountain Ash overhanging distribution powerlines (56M)



Source: AusNet Services

16 Standards VX9/7037 and VX9/7037/1

Introduction of the new regulations in 2010 removed the assessment option and AusNet Services subsequently implemented a program to augment the 2,000 spans over a period of time with insulated or underground cables. Completion was originally scheduled for 29 June 2015 in accordance with an exemption from the regulations provided by ESV. However, rescheduling of the program was granted to allow the completion of urgent replacement works of poor condition HV ABC has required an extension to the scheduled completion date for transition to compliance.

Line Clearances: Subsequent to the 2009 Victorian Bushfires Royal Commission recommendations, Energy Safe Victoria (ESV) issued a Directive, dated 4 January, 2011 for AusNet Services to prepare a plan requiring;

- Fitting of low voltage spacers to its network in accordance with the VESI standard VX9/7020/150, and
- Maintenance of separation of conductors in accordance with clearances contained within Section 10.3 – Conductors on the same supports (same or different circuits and shared spans) of the current release of the Energy Networks Association document C(b)1 – Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines.

The Directive requires the program ensures:

- Low voltage spacers are audited for compliance prior to 1 November each year; and
- Maintenance of conductor clearances is achieved in HBRAs by 1 November 2015; and
- Maintenance of conductor clearance in 'all other areas' by 1 November 2020.

Additional line clearance involves reconfiguration of the overhead lines through measures such as installing taller poles or rerouting circuits.

A spacer survey (opex) was conducted in the current period, funded through the 2012 VBRC pass through. It found greater than anticipated default rates. AusNet Services commences circuit to circuit clearances (capex) involving reconfiguration of the overhead lines through measures such as installing taller poles or rerouting circuits in the current period, with additional volumes to be completed in the forecast period. A revised plan for the additional spans was submitted to the ESV in February 2015.

This program meets the AER definition of a forecast capex step change as it is an externally imposed change in the scope or scale of required capex. It is non-recurrent.

Powerline Replacement Fund[17] The regulatory proposal includes $60 million (2015 real) for projects to install insulated conductor or to underground powerlines in some of the highest bushfire risk areas of the distribution network. The proposal assumes that half of the Victorian Government's remaining fund is allocated to projects in AusNet Services' distribution area.

These projects are entirely funded by the Victorian Government's Powerline Replacement Fund (a government contribution equal in size to the capital expenditure is also included in the regulatory proposal), and are included in the regulatory proposal to ensure that the tax allowance appropriately reflects the impact of the government contribution. AusNet Services is currently seeking an Australian Tax Office ruling on the treatment of similar revenue and expenditure in the current regulatory period. The regulatory proposal will be revised to reflect the outcome of that ruling as appropriate.

2. Programs to reduce fire risk, where it is economically justified

Targeted bushfire safety programs have been developed by:

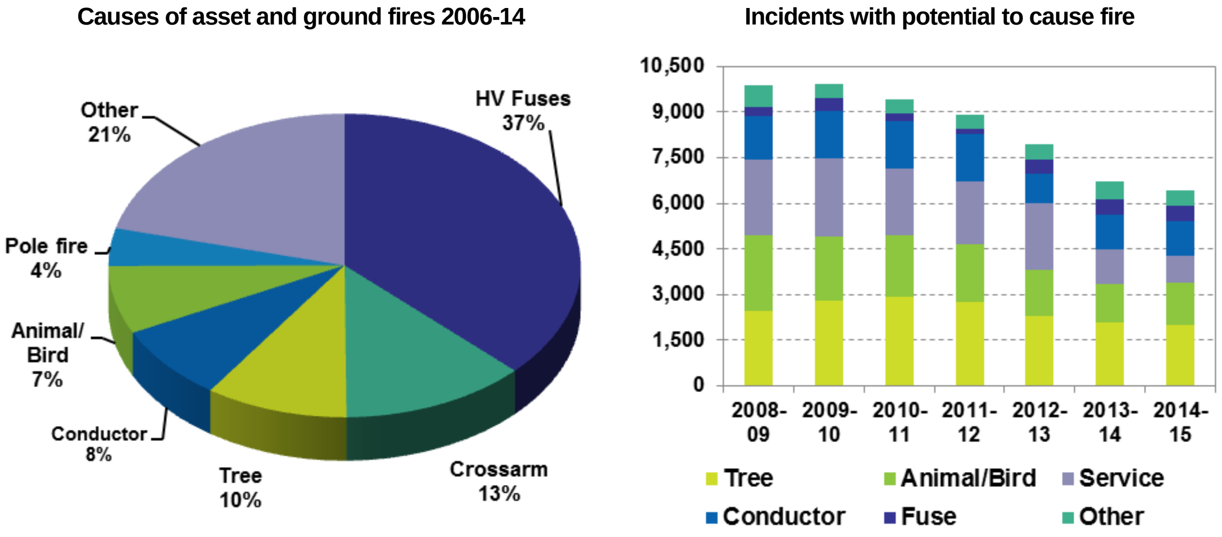
- identifying incident trends;
- analysing individual causes of failure and the potential consequence of incidents; and

[17] http://www.energyandresources.vic.gov.au/energy/safety-and-emergencies/powerline-bushfire-safety-program/powerline-replacement-fund

- developing a cost effective safety program to reduce or manage network risk.

The figure below shows the two key data sources for identifying causes of fires, and therefore where safety programs need to be targeted.

Figure 7.31: Identifying incident trends and causes of fire



Source: AusNet Services analysis.

The above pie chart shows the most common causes of asset and ground fires between 2006 and 2014 were high voltage fuse failure and cross-arm failure.

The chart showing network incidents by asset category, measures ‘lead indicators’ of risk. These incidents do not necessarily result in fire and/or electric shock, but have the potential to cause such events.

In order to minimise risk as far as practicable, economic analysis of safety programs targeted at key causes of fire ignition has been carried out to determine the volume of activities that should be undertaken. This analysis has been applied to four of the top five causes of recent fires[18]:

- Cross-arms;
- Conductor;
- Animal & Bird proofing; and
- EDO fuses.

The analysis has been utilised on assets located in bushfire risk areas where the major consequence of failure[19] is a ground fire with the potential to start a bushfire.

The cost of replacing assets or installing Animal and Bird proofing is based on the historical cost of these activities.

The benefit of replacing assets or preventing flashovers is calculated by multiplying the probability of an asset igniting a bushfire by the consequence of a bushfire starting at that location. The benefits

18 Tree incidents, the third most common cause of fires, are predominantly managed via vegetation management (operating expenditure), and the overhang removal program (described under compliance programs).

19 EDO fuses and Animal & Bird proofing are not strictly related to asset failures. EDO fuses have the potential to ignite fire through operation of the fuse. Animal & Bird proofing prevents an animal or bird creating a flashover by removing the possibility of the animal or bird becoming a conductive path for high voltage electricity.

are the avoided cost (consequence) of a bushfire which is calculated using the Fire Loss Consequence Model (FLCM) developed by Dr Kevin Tolhurst[20] of Melbourne University.

The FLCM provides the consequence, measured in houses lost, of a fire start at any location in Victoria on a day of extreme fire risk[21]. The network has been overlayed on the FLCM so that the consequence of an asset failure can be determined.

The probability of an asset failure igniting a bushfire is based on the probability of an asset failing modified by the probability of the failure occurring on a day of extreme fire risk.

3. Prudent innovation

In addition to projects targeting individual causes or asset types, enhanced protection projects are planned to reduce the risk of fire ignition. Fires are ignited by network assets when an uncontrolled release of energy occurs. The risk of fire ignition can be reduced by limiting the amount of energy that can be released. The amount of energy released can be controlled through means such as limiting the number of reclose operations or limiting the current that can be delivered to a fault.

Several projects are planned to limit the time and magnitude of current delivered to a fault. The projects involve replacing relays and improving communications systems so that the number of reclose operations is limited, or improving protection systems by installing equipment which is sensitive enough to detect faults. In addition, two projects are planned to install fault limiting equipment at zone substations that are not currently fitted with standard fault limiting systems.

Non-bushfire related safety expenditure

A portion of AusNet Services' safety and compliance-driven capital expenditure is for projects addressing non-bushfire safety risks. The table below identifies these projects.

Table 7.5: Non-bushfire safety program ($m, 2015, direct costs excl overheads)

Program	Description	Expenditure
Infrastructure security	Replacement and improvement to zone substation fencing, lighting and access systems.	$2M
Asbestos removal	Removal of asbestos in zone substation buildings.	$2M
Environmental	Including oil controls	$3M
Fall arrest systems	Installation of safe climbing systems of steel lattice towers to prevent fall during inspection and maintenance works.	$9M
SWER Earths	Remediation of non-compliant earths on SWER MV concrete poles[22]	$3M
Total		**$19M**

Source: AusNet Services

The largest non-bushfire safety program is to address the risk of tower fall arrests.

In March 2004, the OHS (Prevention of Falls) Regulations 2003 came into effect creating a new higher standard for preventing falls. The regulations had application to AusNet Services' fleet of distribution and transmission line structures and station rack structures. AusNet Services began the installation of a rail-based fall arrest system on its Transmission network but shortly after commencing the program, implemented a review of the chosen system design following an

[20] Tolhurst Phoenix RapidFire: A Bushfire Risk Assessment for the AusNet Services Network 2013.

[21] The FLCM has versions for different fire risk days.

[22] This addresses a combination of bushfire and electric shock risks.

unrestrained fall. This review, which resulted in a delay to the program, revealed the fall to be an isolated incident and confirmed that Transmission Network Service Provider (TNSP's) in the UK and Europe were also transitioning to similar methods of fall restraint on line and station structures.

Furthermore, a change in obligations that has increased the inspection frequency of distribution towers to once every 36 months (previous every 5 years), escalated the need for the program as the exposure of line workers to fall from heights risk increased.

AusNet Services commenced the widespread installation of fall arrests on towers in 2010. The system installed on transmission towers is now proven and has been assessed as suitable for installation on the relatively smaller number of towers that exist on the distribution network.

This program meets the AER definition of a forecast capex step change as it is an externally imposed change in the scope or scale of required capex. It is non-recurrent.

Safety, Replacement and Augmentation

As detailed earlier, under the AER categories expenditure identified by AusNet Services as having a safety driver can either fall into the 'Replacement' or the 'Augmentation' category.

The AER defines replacement expenditure as:

> *The non-demand driven capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life. Capex has a primary driver of replacement expenditure if the factor determining the expenditure is the existing asset's inability to efficiently maintain its service performance requirement.*[23]

The AER defines augmentation expenditure as:

> *Has the meaning prescribed in the National Electricity Rules, and also includes work relating to improving the quality of the network, for example, to meet regulatory obligations.*[24]

Significant safety programs that are classified as replacement or augmentation under the AER's categories, include:

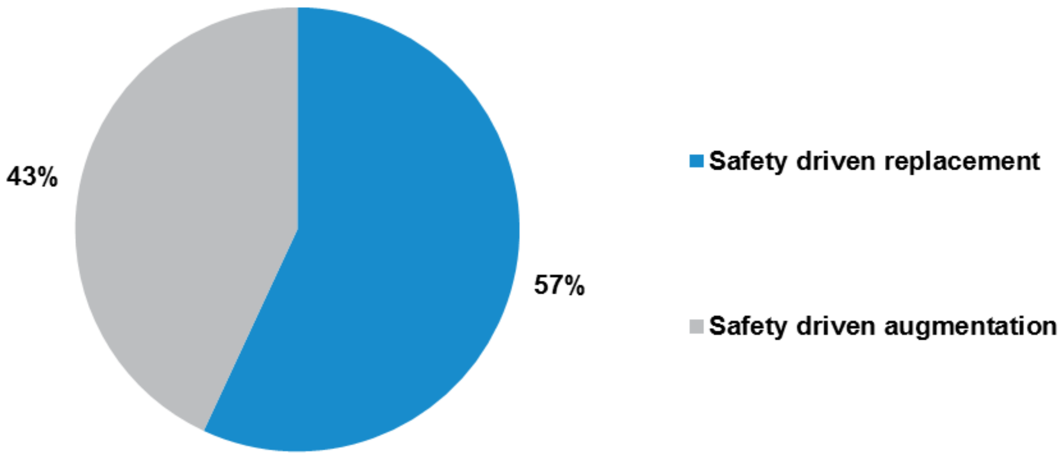
- Cross-Arms (*replacement*);
- Conductor (*replacement*);
- Vibration Dampers and Armour Rods (*augmentation*);
- Animal / Bird Proofing (*augmentation*); and
- Overhang Removals (*augmentation).*

In keeping with the current framework, AusNet Services also presents its capex program consistent with the AER's preferred categorisation. The figure below shows the allocation of safety capex between replacement and augmentation.

[23] Victorian distribution reset RIN – notice – AusNet Electricity Services, Appendix F - Definitions, p. 118.

[24] Ibid, p.73.

Figure 7.32: Safety capex – allocation to replacement and augmentation



Source: AusNet Services

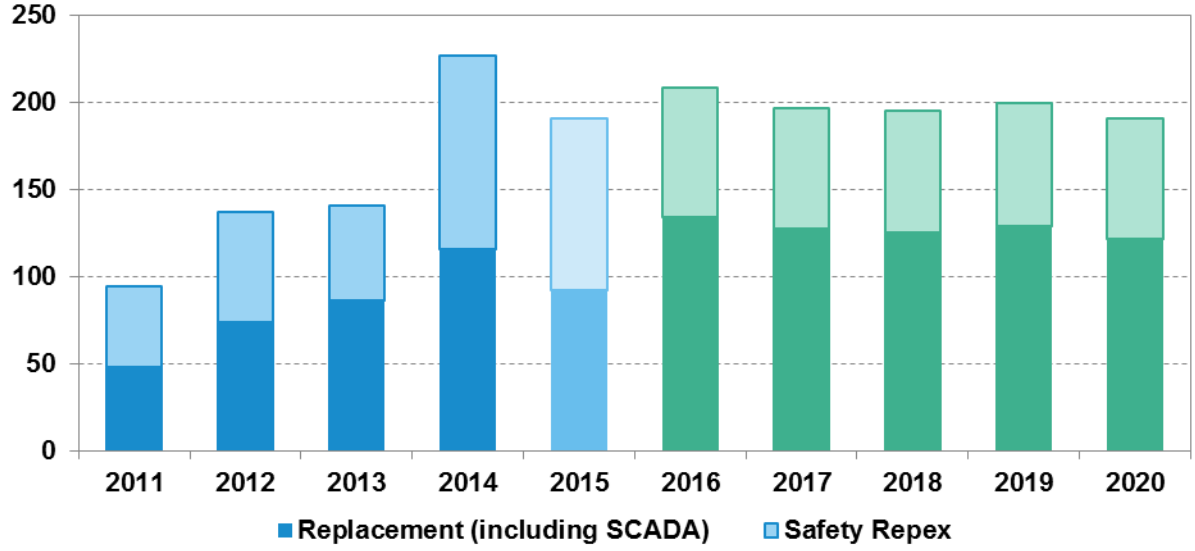
In the sections that follow, Replacement and Augmentation expenditure is presented inclusive and exclusive of programs that have a safety driver.

7.4.3 Replacement

Summary

Capital expenditure for replacement of existing assets due to condition and failure risk (replacement expenditure or repex) has been steadily increasing in the current regulatory period but is forecast to stabilise in 2016-20. A total of $600 million, or $120 million per annum[25], is forecast for replacement expenditure that is not safety driven[26]. Additionally, $37 million is forecast for the replacement of Network SCADA for 2016-20.

Figure 7.33: Asset replacement capex, actual and forecast ($m, gross, real 2015)



Source: AusNet Services, Includes overheads

Notes: Includes Powerline Replacement Fund and VBRC programs in Safety Repex. Network SCADA is included in forecast Replacement to provide like-for-like comparison. Figures for 2015 are estimates.

The figure above illustrates two different measures of 'asset replacement'. As outlined in the previous section, the AER defines replacement expenditure to include safety driven replacement and network SCADA. Historically, AusNet Services has not included safety driven capex in the replacement category. Using the AER's definition, AusNet Services forecasts $991 million for replacement expenditure in 2016-20.

The analysis that follows focuses on programs that are not safety driven. Safety driven replacement programs were described in Section 7.4.2 above.

The drivers of forecast repex include:

- deterioration in asset condition associated with increasing asset age, environmental conditions (such as the Gippsland floods) and identified fleet problems (such as stringy bark wooden poles);
- reduced opportunity to replace poor condition assets as part of augmentation related projects;
- asset failure risk, which may cause reliability impact, risk of collateral asset damage, safety risk to public and field personnel), environmental damage from asset failure (oil spills);

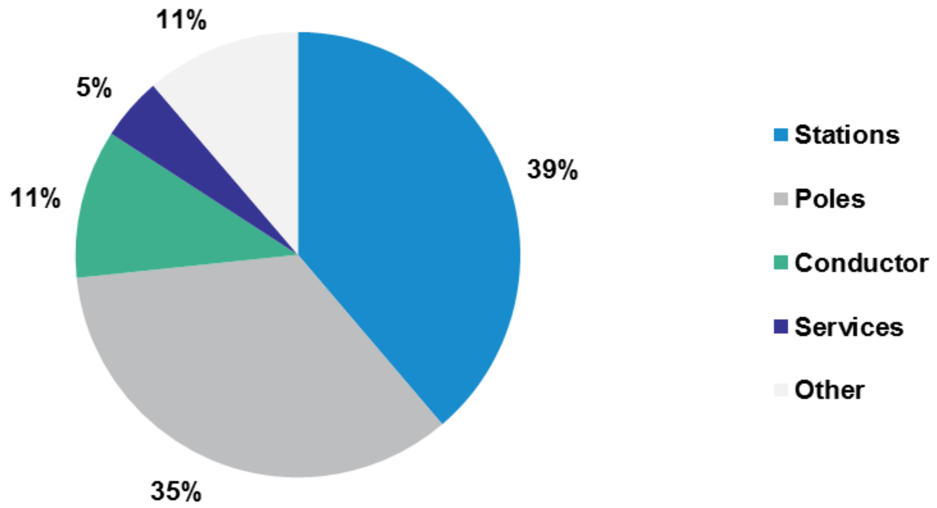
25 Includes overheads.

26 Here, 'safety driven' refers to expenditure that in the current regulatory period would be categorised as 'Environment, Safety or Legal', and is predominantly programs for bushfire mitigation. Even when this expenditure is not included in the 'replacement expenditure' category, programs may still have safety concerns as a driver, such as electric shock risks to the community from fallen powerlines.

- technical obsolescence; and
- third party damage.

As shown in the figure below, expenditure is focused principally on the asset categories of stations, poles, conductor and services.

Figure 7.34: Composition of replacement capex, by asset class (% of direct costs)



Source: AusNet Services, Excludes safety driven replacement

AusNet Services' repex forecast has been prepared with:

- improved asset age and condition data; and
- application of more advanced asset management techniques and analysis.

The planned replacement program is expected to have the impact of maintaining the existing level of network risk, but will see average asset age continue to increase for many of the major asset categories.

While replacement expenditure has increased considerably since 2011, AusNet Services has limited ability to reduce expenditure on asset replacement. Safety considerations mean that for many asset classes, it is not an option to let asset condition deteriorate because the consequence would be an unacceptable risk to community (e.g. pole failure or conductor failure can result in downed powerlines). And, while some of the planned repex, particularly in areas with low customer density, may exacerbate the prospect that future customers will not be prepared to pay for a share of today's expenditure, there is no alternative given AusNet Services' service obligation to continue to provide a network service to those who want it. Repex incurred on this basis is therefore required to ensure AusNet Services complies with its regulatory obligations and requirements, and maintains existing network reliability and security.

Programs by asset class

This section provides brief descriptions of the major replacement programs to be completed in the 2016-20 period.

Zone substation rebuild projects

Nine zone substation rebuilds are planned to commence during the 2016-20 period including Morwell, Myrtleford, Leongatha, Watsonia, Thomastown and Maffra. A further six zone substation rebuilds commenced in the current regulatory period are due to be completed next period. Total expenditure on station rebuilds is forecast as $116.3 million ($2014 direct).

A range of options have been considered for each project, including whether to replace deteriorated transformers, circuit breakers and associated assets in whole or in part. The proposed projects are based on the optimal combination of asset replacement, balancing a reduced risk of asset failure and associated consequences with the value of customer reliability. In most cases a complete rebuild of the station is not the most economic option and therefore the projects are partial zone substation rebuilds.

In addition to station rebuild projects, \$57.6 million (\$2014 direct) is forecast for replacement of stations assets. The bulk of the forecast is for the replacement of 70 of the oldest 1950's and 1960's 22 kV bulk oil circuit breakers, 12 of the oldest 1950's and 1960's 66 kV oil circuit breakers and 11 of the oldest transformers mostly installed in the 1940's to 1960's.

The replacement program for zone substations has been influenced by two developments in the current regulatory period. Firstly, the slower-than-trend growth in peak demand has reduced the number of stations where aging assets are upgraded in the course of augmentation projects. This means that some additional replacement projects have been required. Secondly, the lower VCR has deferred the efficient rebuild date for a number of the projects in the forecast.

1. Impact of slower growth in peak demand.

Between 2011 and 2014 the growth in maximum demand on the AusNet Services' electricity distribution network fell considerably from the forecasts of 5% to 1% per annum. Accordingly, AusNet Services did not reinforce the network capacity of the network to the extent outlined in its regulatory proposal for the 2011-15 EDPR. Some 27 proposed reinforcement projects were cancelled or deferred beyond the 2011 to 2015 period reducing network reinforcement expenditures by 45% compared with the 2010 revenue proposal.

Lower levels of demand have deferred the timing of some zone substation asset replacement projects but at Bairnsdale, Pakenham and Traralgon zone substations, new asset replacement projects worth around \$40 million were commenced to manage the failure risks associated with deferring network reinforcement projects.

2. Impact of lower VCR

The table below shows the year in which planned station rebuilds become economically justified under the old and new VCRs.

Table 7.6: Timing of zone substation rebuild projects under different VCRs

Project	Year	
	Old VCR timing	New VCR timing
Pakenham rebuild	2015	2016
Wonthaggi rebuild	2016	2017
Seymour rebuild	2016	2021
Morwell rebuild	2015	2017
Myrtleford rebuild	2017	2019
Watsonia rebuild	2016	2017
Thomastown rebuild	2015	2016
Philip Island rebuild	2015	2017

Source: AusNet Services

Projects are timed for completion when the failure risk costs exceed the annualised project cost. Sensitivity analysis of each input to the economic modelling provides a robust expenditure program. Projects cannot always be completed in time for when they first become economically justified, and commonly are completed within a couple of years of this milestone.

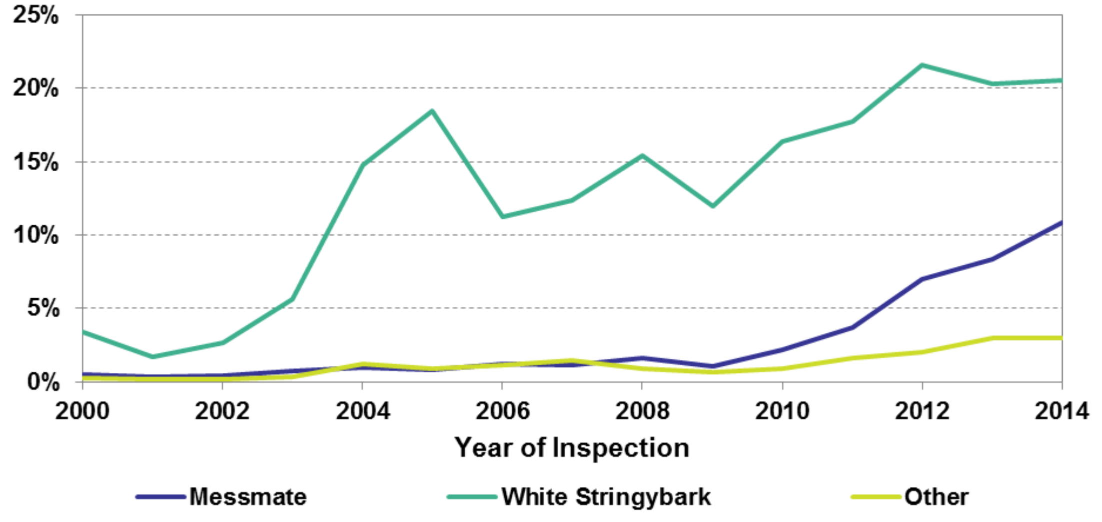
Three projects (Leongatha, Moe, and Maffra) have no VCR sensitivity, as they are required on safety grounds.

Poles

As discussed in Section 7.2.2 (above), there has been a large increase in expenditure on pole replacement in the current regulatory period. It is expected that the volume of poles requiring replacement will continue to increase.

The chart below shows the percentage of poles inspected that fail inspection i.e. the poles that need reinforcement (staking) or replacement.

Figure 7.35: Percentage of poles that failed inspection



Source: AusNet Services

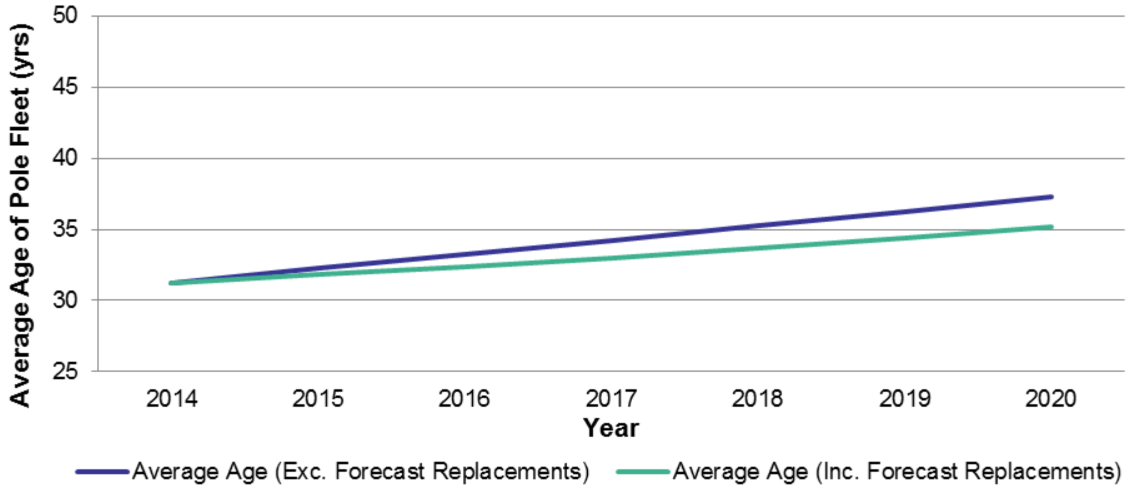
Around the start of this century, practically no poles failed inspection so AusNet Services had low rates of pole replacements. A few years later, White Stringybark poles (about a 12% of the timber pole fleet) started failing inspection. Then, in 2009-10, Messmate poles, which form about a third of the timber pole population, starting failing inspection. In 2010 the remainder of the timber poles began to fail inspection.

The quantity of poles needing to be replaced next regulatory period will increase 50% from approximately 2,000 per annum (2011-15) to 3,000 per annum (2016-20). The increase in forecast pole replacements is due to trends in asset condition.

Economic evaluation suggests that a volume of more than 5,000 pole replacements per annum is justified. However, the proposed pole replacement program is limited to around 3,000 per annum and combined with an aggressive pole reinforcement program for the remaining poles to constrain expenditure. This equates to expenditure of $170.5 million ($2014 direct) over five years. This approach appropriately addresses safety risks associated with the population of deteriorating poles. A case study of how AusNet Services determined the efficient pole replacement program is provided in the next section.

Despite the forecast increase in pole replacements, the average age of poles will continue to increase over the forecast period.

Figure 7.36: Average age of poles on the distribution network



Source: AusNet Services

Conductor

A significant conductor replacement program was undertaken in the 2011-15 period to improve safety by reducing bushfire risk. The safety-related conductor replacement program will continue at a reduced level of approximately 270 km per annum over the forecast regulatory period in areas of high fire loss consequence. In addition, analysis of asset condition data supports the replacement of 171 km of conductor with deteriorating condition per annum in areas with low or no fire loss consequence.

The conductor replacement program that is not bushfire-risk related, is forecast to require expenditure of $53.5 million ($2014 direct).

After accounting for both the safety and non-safety conductor replacement programs, the average asset age for conductor will continue to increase on AusNet Services' network over 2016-20.

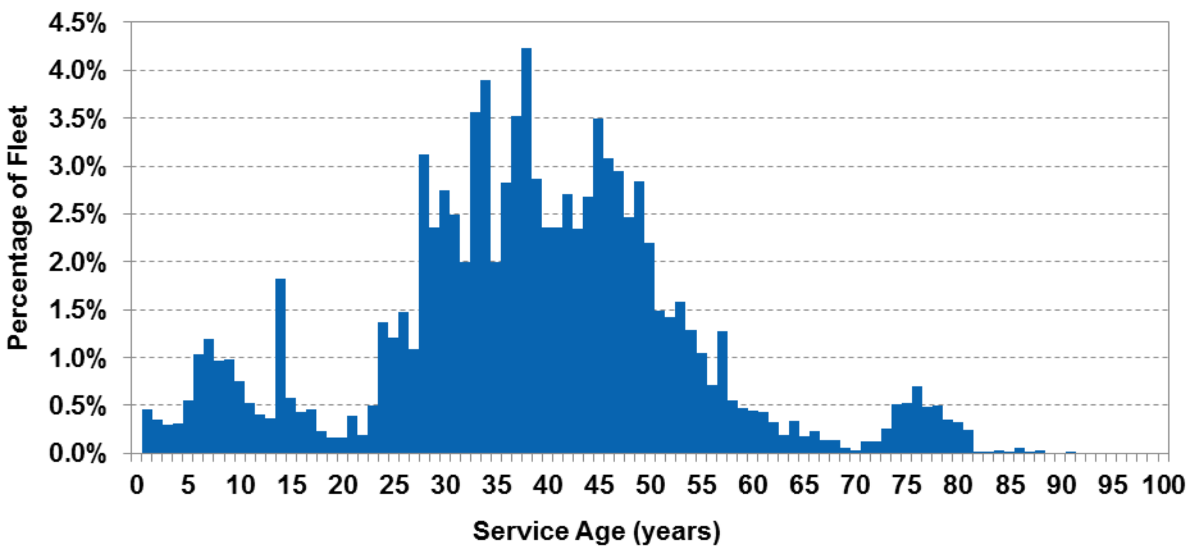
Services

The targeted program to replace aluminium neutral screened aerial service cables, which are in poor condition, will continue from the current period. Forecast expenditure for the program is $22.6 million ($2014 direct).

Case study – approach to poles replacement program

AusNet Services is actively extending the life of assets to minimise replacement expenditure in response to the existential risk to the distribution system of reducing electricity consumption, and technology developments reducing the cost of isolated power supplies. This is effective and is the methodology adopted where risk factors can be adequately mitigated using this approach. An example of AusNet Services' asset stewardship is outlined here for the category of poles. AusNet Services has 372,000 poles in its distribution network which carry circuits and electrical equipment. In addition there are more than 53,000 public lighting poles. The poles are wood, concrete or galvanised steel construction, each with their own modes of failure and remedial treatments. Wood poles represent 56% of the population at just over 200,000 poles and present a significant refurbishment and replacement workload due a wide variety of failure modes and the service age of the fleet (see figure below). Therefore this fleet of wood poles is actively managed through significant condition monitoring and analysis to maintain a safe and reliable network.

Figure 7.37: Age of wood pole fleet on AusNet Services' distribution network



Source: AusNet Services

The 28 species of wood poles have an expected average service life of 45 years with a standard deviation of 8 years when employed in an electricity distribution network in eastern Victoria. However, the figure above illustrates that approximately one third of the wood pole population has exceeded this nominal expected service life of 45 years. Analysis of wood pole failure modes has shown that although age has traditionally been used as a proxy for condition, this is not an accurate technique (and, therefore, the repex analysis is not accurate). Deterioration of wood poles is determined by the wood species and treatment of the wood before installation as well as the local environmental conditions such as weather, ground conditions, termite concentration and location relative to roadways. This explains why some poles are providing a more than adequate service at 60 years of age and why a few fail after 20 years of service. A replace-on-age strategy would require the replacement of 25% more wood poles each year over the next decade compared with AusNet Services' replace-on-condition strategy.

Objective measurements of the remaining sound timber in each wood pole is used to map each wood pole onto a five point condition assessment scale from which its remaining service potential is forecast. This has fundamentally changed the assessment from an age-based analysis where the standard deviation of the expected service life is high to a condition based remaining service potential that is updated every 5 years in low bushfire risk areas and every 37 months in high bushfire risk areas and, therefore, is a much more accurate prediction of the future volumes of deteriorated poles. When coupled with the potential bushfire consequences of a wood pole failure via the use of Dr Tolhurst's bushfire consequence values,[27] a risk based economic program of proactive pole replacements and major refurbishments has been established.

The risk based economic forecast replacement level for poles is about 5,000 per annum. Historically about 30% of deteriorated wood poles have been life-extended via pole-stakes rather than replaced by a new pole. In response to reducing energy consumption and low growth in peak demand AusNet Services is pursuing new staking techniques which will allow up to 50% of the potential pole replacements to be avoided over the five-year review period. This defers the costs of establishing many new long-life assets during a period of uncertainty and allows the development of alternative options in the 10-15 year timeframe when the outlook is clearer.

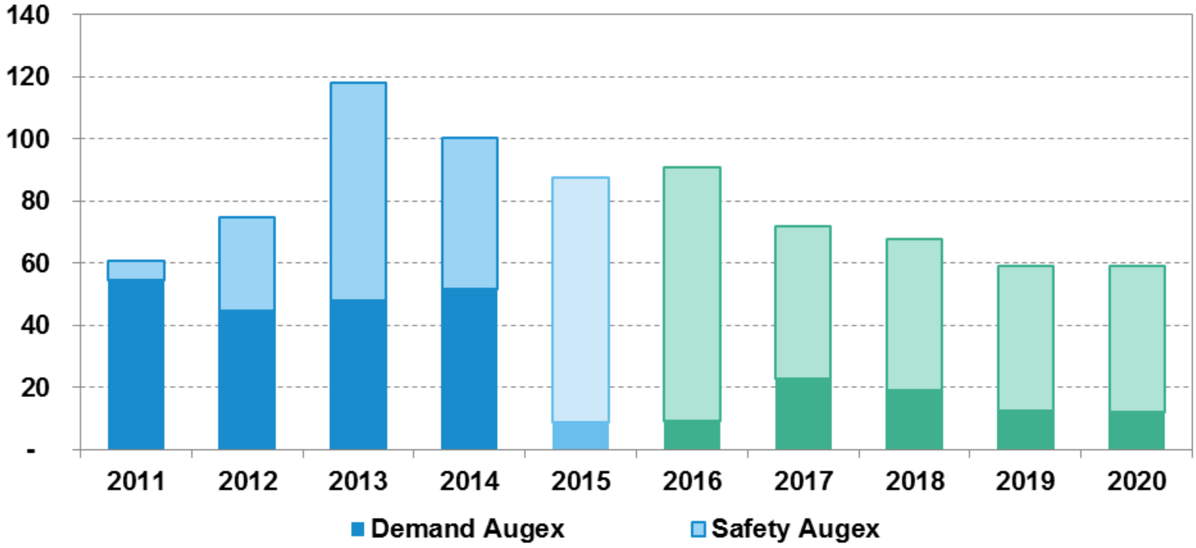
7.4.4 Augmentation

Summary

Capital expenditure for augmentation of the network due to increasing demand (augmentation expenditure or augex) is expected to be at historically low levels. Augex is forecast at $75.1 million over five years, an average of $15 million per annum. This forecast is consistent with AusNet Services' demand forecasts (detailed in Chapter 4). This is illustrated in the Figure below.

27 Tolhurst Phoenix RapidFire: A Bushfire Risk Assessment for the AusNet Services Network 2013.

Figure 7.38: Augmentation capex by year, actual and forecast ($m, real 2015)



Source: AusNet Services, Includes overheads.

The forecast augmentation capex for 2016-20 is focussed on the high growth, residential estate corridors in the Central region of AusNet Services' network. No new zone substations and no additional zone substation transformers are forecast in the 2016-20 period.

The augex forecast includes one project, for the Kalkallo to Doreen line, that has been subject to a Regulatory Investment Test for Distribution (RIT-D).[28]

As is clear from the Figure above, under the AER's preferred categorisation of capex, the substantial majority of Augmentation Expenditure is in fact driven by safety. Safety driven augmentation programs are described in Section 7.5.2 above. Programs that have a safety driver are not able to be forecast by the AER's Augex model which only forecasts growth related network augmentation.

Key Issues

The role of VCR

The augmentation forecast is based on AEMO's November 2014 Value of Customer Reliability (VCR), which is lower than the VCR used in earlier planning. A capex forecast that reflects the lower VCR promotes efficient network investment by better reflecting the drivers for investment. Ensuring that investment does not occur beyond the level necessary to satisfy the value customers place on reliability best serves the long-term interests of consumers and therefore contributes to the achievement of the NEO.

Incorporating the revised VCR resulted in deferral of the sub-transmission line augmentation project and a reconductoring project.

[28] The final RIT-D report: "Network Consultation Conclusions Report – Maintain reliability of electricity supply to Kalkallo substation customers" is provided as a supporting document to this submission.

Table 7.7: Timing of augmentation projects under different VCRs

Project	VCR year	
	Old timing	New timing
Kalkallo to Doreen line	2015	2019
MWTS to Leongatha number 2 reconductoring	2015	2025

Source: AusNet Services

Relationship to Demand Management

Traditionally network augmentation has been a driver of significant capex. AusNet Services has forecast a significant reduction in augmentation capex in response to lower forecast demand growth and the successful implementation of demand management techniques such as contracted demand management and critical peak tariffs utilising non network solutions to resolve network constraints.

7.4.5 Customer connections

Customer connections capex is defined as expenditure to establish new customer connections to the network at the customer request, including that part of the cost recovered through customer contributions towards connection/augmentation work.[29] The amount a customer contributes to the cost of their connection is calculated in accordance with the Victorian Essential Services Commission's *Guideline 14*.

Facilitating growth of the network and meeting our obligations to connect customers in our distribution area, the customer connections capex program is required to meet the requirements of NER 6.5.7(a)(1) and (2).

AusNet Services understands that the Victorian Government is currently reviewing connection arrangements in Victoria. This class of capex will be heavily impacted if the Victorian Government decides to adopt the connection framework set out in the National Electricity Customer Framework (NECF). In particular, AusNet Services would become subject to the relevant parts of Chapter 5A of the National Electricity Rules and the AER's *National Electricity Connection Charge Guidelines* would replace *Guideline 14*. Such a change would require both a reconsideration of the service classification and material change in net capex requirements. In the event of such a change arising from the current Victorian Government review, AusNet Services would revise and resubmit its customer connection capex forecasts to the AER.

Historical customer connection and reinforcement projects have separate work codes in AusNet Services' accounting systems and are allocated accordingly in the RINs.

Historic performance

For the 2011-15 EDPR Determination, AusNet Services' proposed capex in this category that would meet gross new connections of 74,025 over the period from 2011 to 2015. Actual gross new customer connections are forecast to be 73,392 by the end of the current regulatory period.

However, while overall connections are expected to be higher than forecast, the mix of connections has been significantly different. The number of residential connection projects has been around 10% higher than forecast but the number of commercial connection projects has been almost half (46% lower). The likely cause of this difference has been subdued economic conditions in Victoria exacerbated by the high Australian dollar's impact upon the export sector. AusNet Services' industrial customer base contains a large trade exposed manufacturing sector.

[29] AusNet Services Customer Connections Guide is attached as a support document.

Customer contributions have been higher than forecast, therefore, while gross capex is expected to be 29% below the 2011-15 EDPR benchmark, net capex will be 45% below.

Proposed Changes to the approach to calculating customer contributions

For the new regulatory control period, AusNet Services proposes to introduce a marginal cost of reinforcement (MCR) to better reflect the true costs borne by AusNet Services (and other customers) when a new customer connects. AusNet Services' published customer connection policies will be changed accordingly to ensure customers understand the basis of the calculation.

The AER has approved the introduction of a MCR for other Victorian DNSPs in previous regulatory decisions.[30] AusNet Services considers its proposed methodology is consistent with these previous decisions.

Along with changes to the proposed X-Factor used in the calculation of the incremental revenue and other minor changes to the contribution model, AusNet Services' new approach is expected to increase the contribution rate from an average of 32% to 52% in the 2016-20 period.

The new approach advances the NEO because:

- it reduces an inefficient cross-subsidy from our existing customer base to new customers, thereby reducing longer term costs;
- it is more aligned with the national connections framework making a future transition easier both for AusNet Services and new connecting customers;
- it reduces the longer term stranding risk on the network as more cost has been recovered upfront from the causer;
- it was discussed with our existing customer base with no strong objections raised.

These changes and the forecasting methodology as a whole are described in more detail in the Connections Capex Forecast Model.

Gross capex forecasting methodology

Established unit rates for respective customer connection categories are utilised to establish budget forecasts. Customer unit rates for each year are derived by dividing annual expenditure by the number of lots created for the respective activity codes. AusNet Services' connection categories are:

- Low Density Housing;
- Medium Density Housing (large scale multi-lot developments);
- Underground Service Installation;
- Undergrounding existing Private Overhead Electric Lines;
- Business Supply Projects; and
- Cogeneration Projects.

With the exception of low density housing, the high volume and relatively consistent scope of residential customer connections generates unit rates with low variance over time, therefore, a base-trend approach can be utilised for the forecast. AusNet Services has used 2014 base year unit rates for these categories and the trend is forecast consistent with the connection volumes set out in Chapter 4 and the real cost escalation set out in section 8.3.4 of the Opex chapter.

Larger commercial and industrial connections and low density housing development (particularly in rural areas) are more volatile over time and the scope of an average non-residential connection can,

[30] AER, *Guidance Paper – The AER's Conclusion on the Benchmark Upstream Augmentation Charge Rates for Citipower's Network* - 25 June 2010

therefore, fluctuate a lot from year to year. As such, an historic average unit rate over 2010 to 2014 has been established for these categories as shown in the table below.

Similarly for cogeneration projects the value of and demand for these connections fluctuates over time and therefore a historic average value of actual costs incurred over 2010 to 2013 has been established for this category as shown in the table below.

AusNet Services has used these average unit rates and the trend is forecast consistent with the connection volumes set out in Chapter 4 and the real cost escalation set out in section 8.3.4 of the Opex chapter.

Table 7.8: Connections Forecast Assumptions

Connection Category	Unit Rate	Volume
Medium Density Housing	CY14 historical unit rate	Historical proportion of forecast residential connections
U/Ground Service Installation	CY14 historical unit rate	Historical proportion of forecast residential connections
Business Supply Projects	5 yr historical average unit rate (2010-14)	Historical proportion of forecast non-residential connections
Private Electric Line Replacement	5 yr historical average direct costs incurred (2010-14)	N/A – forecast driven by historical costs incurred
Low Density Housing	5 yr historical average unit rate (2010-14)	Historical proportion of forecast residential connections
Cogeneration Projects	4 yr historical average direct costs incurred (2010-13)	N/A – forecast driven by historical costs incurred

Source: AusNet Services

Contribution forecasting methodology

The contribution rate has been calculated by applying AusNet Services' proposed changes in its application of Guideline 14.

The level of customer contribution is calculated using the following formula:

CC = [IC – IR] + SF

Where:

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

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

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

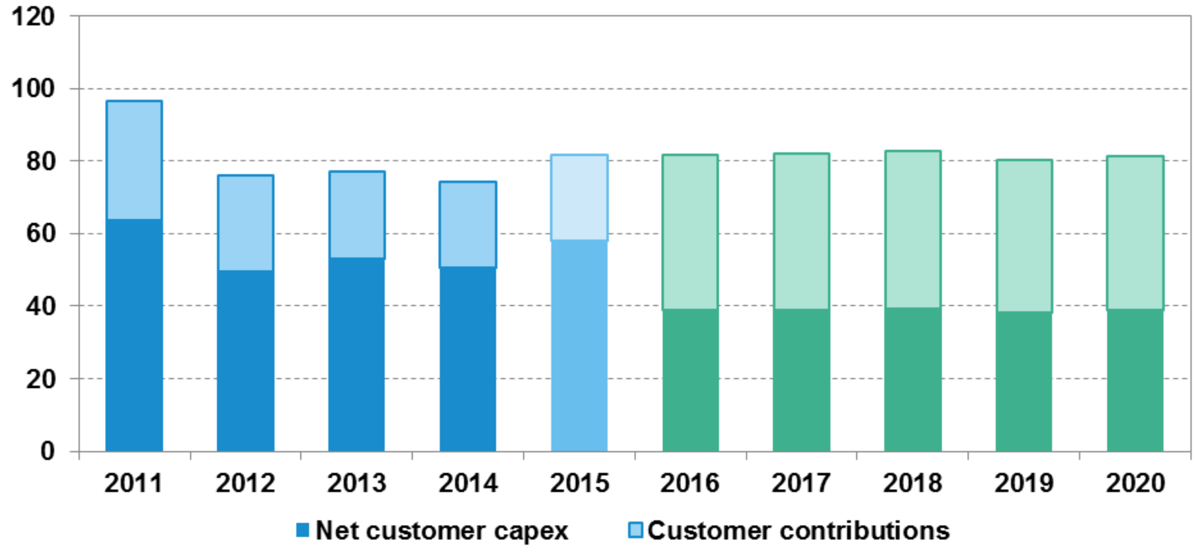
SF is the amount of any security fee under the connection offer.

As discussed above, AusNet Services is making material change to the incremental cost calculation through the inclusion of a marginal cost of reinforcement. In addition, the incremental revenue calculation will be impacted by a much lower X-Factor than the current period. All else being equal, this will decrease the value of incremental revenue.

Proposed customer connection capex

AusNet Services is proposing a "business as usual" gross capex forecast, however, net capex will be lower because of the forecast increase in contributions. AusNet Services' proposed gross and net customer connection capex is shown in the figure below. The forecast gross connection capex is 0.5% higher than the current period (on a real $2015 basis), that is, it is largely consistent with historical average over the previous period.

Figure 7.39: Gross and net customer connections, actual and forecast ($m, real 2015)



Source: AusNet Services

Note: Includes overheads, excludes government contributions. Figures for 2015 are estimates.

7.4.6 Information Technology

ICT capex is required to support the business and maintain network security and reliability. AusNet Services' 2016-20 ICT Strategy (provided at Appendix 7E) underpins the forecast ICT investments for the next regulatory period to enable AusNet Services to meet the capex objectives efficiently and prudently.

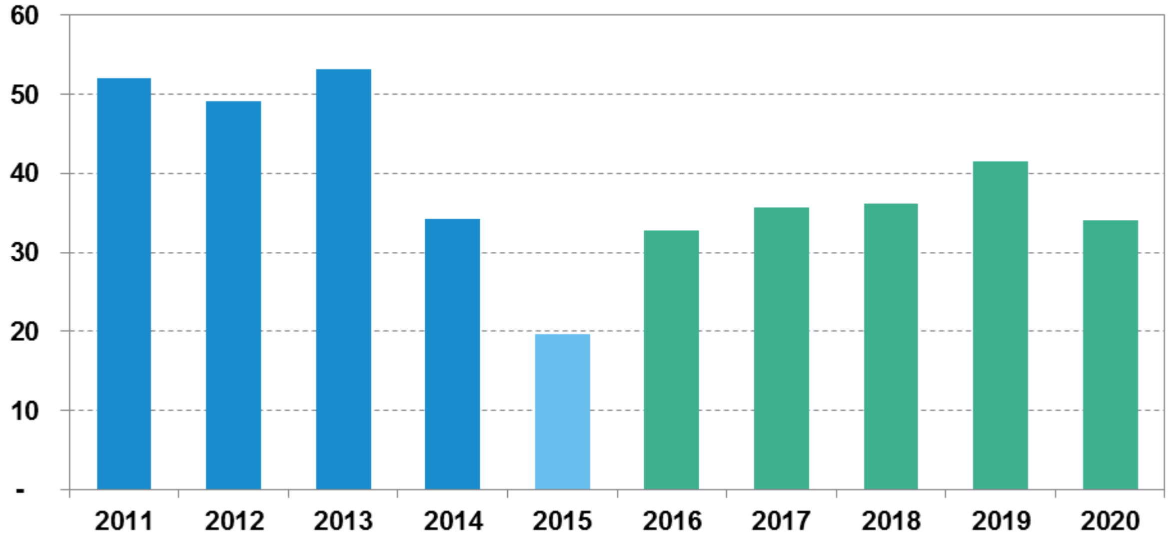
AusNet Services is forecasting IT capex of $180m for the 2016-20 regulatory period. This includes capex which was previously categorised as SCADA IT, as explained in section 7.2.3 above. The overall ICT capital requirements for 2016-20 will be lower compared to the current period as AusNet Services has recently completed a number of significant IT investments and is approaching a point in its IT investment profile which requires less capital investment.

The focus in the forecast period (2016-20) will be on delivering the remaining core elements of the enterprise strategy. Namely, AusNet Services will:

- finish IT application modernisation;
- begin deploying new IT capabilities across the business; and
- retire legacy IT environment.

The annual forecast IT capex is set out in the figure below, alongside actual and expected IT capex from the current period.

Figure 7.40: IT capex by year, actual and forecast ($m, real 2015)



Source: AusNet Services

Note: Includes overhead. Figures for 2015 are estimates.

The seven key programs of work in the ICT capex forecast are summarised below.

Table 7.9: Forecast ICT Capex ($m, real 2015)

Initiative	Program summary	Capex
Corporate	Leverage EAM/ERP solution including providing a secure and consistent view of data throughout the organisation	6
Information Management	Improve the management of networks and assets through improved data and analytics capabilities	20
Information Security	Protect distribution network, and customer and business information through enhanced 'protect and detect' capabilities	10
Metering & Customer Services	Meet customer demand for information and communication through a centralised customer relationship management solution and enhanced digital capabilities	32
Network Management	Increase safety, network reliability and performance by automating network monitoring and responses; data consolidation and improved visualisation of network performance	43
Works & Asset Management	Improve network reliability and operational efficiency by leveraging the EAM/ERP investment to rationalise, consolidate and optimise business processes	13
Information Technology	Lifecycle refresh of storage backup hardware, enterprise server, desktop and laptop fleet, corporate network and communications and investments in storage and virtualisation enablement.	57
Total IT Capex		**$180M**

Source: AusNet Services

These programs of work are discussed in more detail in the ICT Strategy 2016-20 (Appendix 7E).

Scene setting

AusNet Services' IT has evolved over time in response to the changing needs of the business, as well as developments in the operating environment and technology.

AusNet Services' IT program for the current regulatory period has been focused on establishing a managed environment for the delivery of IT and communications services. Prior to this period, the focus of ICT was maintaining the disparate legacy IT systems resulting from the merger of TXU and SPI PowerNet (and later, the gas distribution business) and shifting from a lease model to an own-operate model. IT investments at this time were aimed at managing the level of risk, reliability and security required by the business functions. The evolution of ICT at AusNet Services is summarised in the table below.

Table 7.10: Evolution of AusNet Services ICT

	2006-2010	2011-2015	2016-2020	2021-2025
Business environment	Stable & predictable	Changing	Uncertain and more complex	Major disruption
AusNet IT Theme	Maintain IT	Manage IT	Modernise Business Tools	Enable Business Transformation
Initiatives	• Support inherited (fragmented) IT environment • Limited IT infrastructure consolidation & modernisation	• Formal service management • IT Infrastructure modernisation • Initial IT application modernisation	• Finish IT application modernisation • Pilot business deployment of new capabilities • Retire legacy IT environment	• Full-scale rollout of new IT-enabled business model • Condition-responsive electricity network management • Electricity capex optimisation • Realtime, optimised electricity business decision making
Benefits	• Continuity of IT services	• Risk-managed IT • Secure IT • Reliable IT	• Flexible IT • Controlled IT cost	• Controlled business costs • Dynamic business environment managed

Source: AusNet Services ICT Strategy 2016-20

As shown in the above table, for the 2016-20 regulatory period, AusNet Services will focus on modernising its applications: the tools that ICT provides to support electricity distribution business processes. This involves completing the modernisation of these applications and retiring those that they replace. Once this change is complete, it is expected that ICT costs will be contained, notwithstanding the increased complexity of the business environment and the requirements it places on ICT.

Forecast investments are also aimed at readying AusNet Services to evolve in response to the expected business environment post-2020; that is, a more uncertain and complex electricity environment with customers' investment in disruptive technologies such as local solar PV generation and battery storage significantly impacting AusNet Services' business. Sound information technology will be critical to supporting AusNet Services' increasing role in balancing residential generation and supply of electricity with residential demand. The modernised ICT environment established in 2016-20 is intended to provide the basis to enable the business to deal with the uncertain future.

Drivers of Forecast IT Capex

The forecast IT capex has been developed in response to the following drivers:

- **Internal Drivers** including business demand for enhanced decision support through improved analytics, reporting and data management; provisions of technologies to enable work to be performed on mobile devices; optimising costs by providing tools to manage assets across their lifecycle; and greater integration and automation of processes and systems across the enterprise.
- **External Drivers** including the ability to comply with industry regulations and requirements such as regulatory information notices (RINs); meet community expectations for the management of safety and the environment; and adapt to changing customer needs and expectations.
- **Technology Drivers** such as opportunities presented by smart devices, big data and the convergence of information and operational technology; increased and evolving threats to data, systems and assets; and the availability of technologies such as cloud computing and server virtualisation.

In forecasting IT capex AusNet Services has undertaken a bottom-up approach which includes assessing the risk of preferred options, identifying appropriate mitigation strategies and completing cost and benefit assessments. Following this bottom-up forecasting method, AusNet Services applies top-down testing which involves a prioritisation process to ensure forecast projects deliver the best value, aligned with our corporate and asset strategies. More details in relation to the forecasting approach are set out in the AusNet Services' 2016-20 ICT Strategy (provided at Appendix 7E).

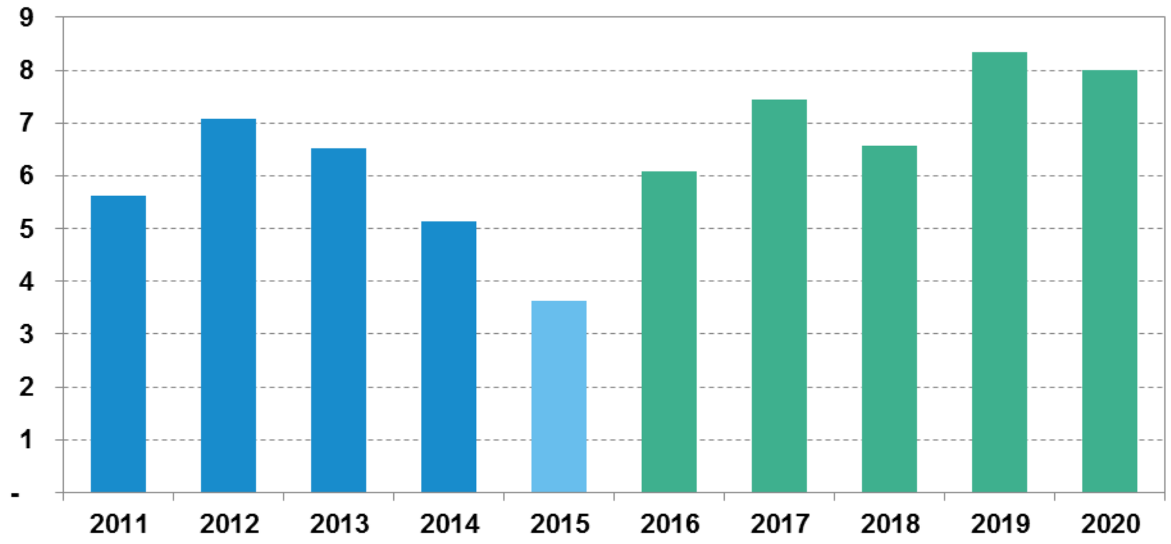
7.4.7 Other

Other capex includes capex on motor vehicles, buildings, tools and test equipment. In the current regulatory period this category of expenditure has been labelled 'non-network general'.

The $36 million forecast 'Other' capex, accounts for less than 2% of the gross capex forecast, and assumes that for vehicles and buildings there will be no change in the rates of ownership vs lease arrangements (i.e. no change to capex/opex mix). The forecast includes:

- replacement of existing vehicles that meet defined replacement criteria (distance travelled and age);
- non-network buildings expenditure for specifically identified capital items; and
- other expenditure (such as tools) based on historical rates.

Figure 7.41: Other non-network capex by year, actual and forecast ($m, real 2015)



Source: AusNet Services

Notes: Includes overhead. Figures for 2015 are estimates.

7.5 Expected benefits of the capital program

This section reiterates what AusNet Services will deliver through its capital expenditure program in 2016-20, focusing on the impacts of the program on:

- network risk and reliability;
- safety and safety compliance;
- responding to new technology, customer technology and potential changes in market structure; and
- innovation and efficiency.

7.5.1 Network risk, including safety

A principal benefit of the capex proposal outlined above is that it is expected to reduce bushfire risk. Other types of risks are expected to be maintained at current levels. The capex proposal includes replacement of selected high-risk assets in the distribution network where economic analysis confirms there is a net benefit.

The key risks that drive capital expenditure are asset failure, external damage (primarily through trees and branches contacting overhead lines), and network overloading. Asset failure risks are commonly mitigated by ensuring that deteriorated equipment is replaced before it fails in-service (capital expenditure). External damage risk arising from trees and branches is primarily mitigated by operational programs involving vegetation cutting and clearing. Network overloading risk is mitigated through network augmentation or demand-side response to peak loading.

Risk by asset category

AusNet Services' proposed network capital expenditure program comprises four major components that have varying impact on network risk:

- Customer connections, forms 21% of network capex program and is not expected to alter existing levels of network risk;
- Augmentation, forms 4% of network capex program and addresses the risk of network overloading. Network overloading can lead to network outages (unserved energy) or

damage to network components (such as transformer failure due to overheating). The incorporation of the new VCR, reflected in the proposed augmentation program, results in deferral of $140 million (real 2014) in augex, and consequently a higher risk of overloading.;

- Asset Replacement, forms 31% of network capex program and reduces risk by preventing the consequences of asset failure, further detail is provided below; and
- Safety, forms 33% of capex program and 95% of the proposed expenditure is targeted to reduce bushfire initiation risk, further detail is provided below.

Asset replacement and Safety & environmental expenditure are the major categories of expenditure and are the categories where trade-offs can effectively be made between risk and expenditure. The impact of these expenditure programs are discussed in further detail below.

Asset replacement

Most asset replacement capital expenditure is intended to prevent the consequences of asset failure, including: Failure to supply energy (unserved energy); Fire ignition; Electric shock (to employees, public and animals); Environmental damage (oil leaks); Damage to other network components. Secondary consequences such as physical damage to a person or property resulting from an asset failure also exist.

Most asset replacement risk arises from seven asset types and over 80% of forecast asset replacement expenditure is targeted at these assets. Failure to supply energy is the major consequence of asset failure for all of these asset types except for Conductor where fire ignition is the major consequence. Secondary consequences for overhead lines assets include fire ignition and electric shock. For zone substation assets and distribution transformers, environmental damage and damage to network components are secondary consequences.

These asset types and the consequences of failure relating to each asset type are shown below.

These asset types and the impact of the forecast asset replacement expenditure and an assessment of risk is shown in the table below.

Table 7.11: Risks by asset type

Asset Type	Program	Risk Assessment
Poles	Replace when measured wood thickness indicates failure is imminent	Maintains risk
Pole top structures (cross-arms, insulators, etc)	Replace when visual assessment indicates failure is imminent	Risk reduction arising from replacement of HV timber cross-arms with steel. , Large volume of replacements resulting from current condition of cross-arms will lead to a better average condition.
Conductors	Replace based on condition assessed by inspectors[31]	Maintains risk
Distribution transformers (pole and ground types)	Visual inspection. Replace either on failure or when external indicators such as oil leaks indicate replacement is necessary.	Maintains risk
Zone substation transformers	Closely monitor transformer condition. Replace some transformers based on risk and condition in rebuild projects. Undertake refurbishment works for other	Increasing risk. The high cost of transformer replacement coupled with lower Value of Customer Reliability (VCR) makes economic replacement of power transformers difficult.

[31] A program of conductor replacement is also included in the Safety & Environmental category.

Asset Type	Program	Risk Assessment
	transformers. Repair or replace failed transformers.	Consequently, transformer failure rates are expected to increase.
Zone substation circuit breakers (CBs)	Replace both in station rebuilds and in CB replacement programs based on risk and condition.	Small reduction in risk as volume of replacements leads to reducing average CB age and failure rate. Also, new technology CBs carry less environmental risk due to less oil.
Zone substation instrument transformers	Replace both in station rebuilds and in instrument transformer replacement programs based on risk and condition.	Maintains risk.

Safety and environmental program

The safety program is expected to continue current rates of improvement, delivering around 20% reduction to incidents with the potential to cause electric shocks or fire starts.

Over 95% of the Safety and Environmental program (32% of total Network Capital expenditure) is targeted at reducing the risk of bushfire ignition.

More than a third of the proposed Safety and Environmental expenditure involves fitting armour rods and vibration dampers, and eliminating the risk from some overhanging trees by undergrounding or installing insulated conductors. This work will be undertaken to meet obligations arising from the findings of the VBRC. 13% of the proposed expenditure is Government funded work involving undergrounding or insulating high bushfire risk lines.

The remaining program of work (approximately 50% of the Safety and Environmental program) is targeted at reducing the risk of bushfire ignition by:

- replacing deteriorated overhead conductor in high fire-loss areas;
- replacing overhead hardware that has the potential to ignite a fire such as EDO fuses;
- installing enhanced protection systems that can detect downed conductors and sectionalise network segments; and
- animal and bird proofing overhead network components to reduce the risk of fire resulting from a flashover caused by animal or bird contact.

Impact of network capex program on risk

The proposed program of work will result in an overall reduction in risk due to the large program of work targeted at reducing the risk of bushfire.

Reductions to the capex program would decrease the rate of bushfire risk reduction (for example, by reducing or eliminating some programs) and increase energy supply risks (by reducing the size of the asset replacement program). Such outcomes would be inconsistent with the capex objectives, and would not promote the achievement of the NEO.

The option to reduce the rate of bushfire risk reduction is constrained by existing commitments to fit armour rods and vibration dampers, and to eliminate the risk from some overhanging trees by undergrounding or installing insulated conductors. Limiting AusNet Services' opportunity to recover the efficient costs of complying with its safety regulatory obligations and requirements is not consistent with the Revenue and Pricing Principles, or with consumer expectations that ongoing safety levels will be maintained. Further, there is limited opportunity to defer or reduce the scope of Government-funded work.

The option to increase energy supply risks is limited to deferring parts of some programs of work. Other programs, such as pole replacement, are difficult to defer as assets are only replaced when there is a clearly identified risk of failure and deferral results in increasing supply and safety risks.

Further, it may not be economic to defer some expenditure as the cost of unsupplied energy coupled with the increased cost of unplanned asset replacement may outweigh the benefits arising from capital deferral. Where it is efficient and does not pose an unacceptable supply risk, AusNet Services has identified opportunities to defer capex and reflected these in its forecast total capex.

Impact of IT capex program on risk

The proposed IT capex program will have risk benefits in the areas of both safety and network risk.

Modernised business applications will enable improvements in the control and monitoring of safety outcomes on the distribution network including capabilities to manage various types of faults that could cause safety issues to the public, damage to either AusNet Services' or customers' assets. Alongside improvements in asset replacement targeting, new capabilities in asset condition monitoring and intervention analysis will deliver better targeted network safety programs. Integration of safety reporting through enterprise systems will eliminate the risks inherent in manual linking and manipulation of different extracts across multiple systems.

As the operating environment for electricity distribution businesses becomes more complex and uncertain, it becomes increasingly difficult to operate and manage distribution networks. The modernised business applications that AusNet Services will deliver in the forecast period will provide the necessary tools and flexibility to respond to changes in the operating environment, including by updating its business processes to ensure it can continue to provide reliability and security of supply at an efficient cost. In so doing, AusNet Services can continue to encourage efficient use and operation of its network in a way that benefits the long-term interests of consumers.

7.6 Deliverability

Deliverability refers to the ability of the business to deliver the proposed program of work, and is dependent on availability of sufficient materials and resources (labour and equipment). The proposed annual program of Capital and Operational works is smaller than the program delivered in 2014 and encompasses similar activities, therefore the proposed program is not expected to present particular delivery challenges.

AusNet Services utilises a hybrid operating model to deliver the works program that includes a mix of internal and external resources. External resources include fully outsourced teams in regional locations, Capital Panels established to provide top-up resources for minor works, and Major Capital Panels for delivery of major works.

The hybrid operating model improves efficiency by providing a mechanism to ensure that internal resources are fully utilised and peaks of work are resourced by engaging additional external resources. External service providers are selected using a competitive process to ensure efficient costs and appropriate quality of services is provided.

Uncertainty in the need or timing of projects can be managed through the use of external resources. AusNet Services' proposed capex program assumes an increase in pole reinforcement as an alternative to pole replacement to prolong asset life and delay capital expenditure. The technology required to deliver a higher reinforcement rate has not yet been identified and this is a deliverability risk that AusNet Services will manage throughout the period.

Several initiatives have been undertaken in the current period to improve the delivery of the works program. These include:

- Establishment of the Enterprise Program Management Office (EPMO);
- Selection of Design and Installation Service Providers to a panel of service providers;
- Project PUMA, involving selection of a single supplier under a long-term contract to deliver works in the Central region; and
- Works integration to bundle works by distribution feeder.

7.7 Supporting Documents

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 7A – Network Capital Expenditure Overview, and all supporting Asset Strategies and technical documents;
- Appendix 7C – Unit Rates;
- Appendix 7D – Project Cost Estimating Methodology.
- Appendix 7E – ICT Strategy;
- Customer Connections Guide;
- Historical Changes to Bushfires Safety Obligations in Victoria;
- Network Consultation Conclusions Report – Maintain reliability of electricity supply to Kalkallo substation customers;
- Capex Model; and
- Connections Capex Forecast Model.

8. Operating & Maintenance Expenditure

8.1 Overview

Introduction

This chapter sets out AusNet Services' proposed standard control services (SCS) operating and maintenance expenditure forecast for the 2016-20 regulatory control period. This expenditure has been allocated to SCS in accordance with AusNet Services' approved cost allocation methodology.

The proposed expenditure is required to operate and maintain the network to a standard that ensures customers have access to a safe and reliable electricity supply, as well as comply with a number of externally driven regulatory obligations and requirements.

Drivers of operating expenditure

AusNet Services' level of opex during the current regulatory control period has been driven by substantial changes to its operating environment. Principally, ensuring compliance with more stringent bushfire mitigation safety regulations has translated to sharp increases to opex. Insurance premium growth in the wake of the Black Saturday bushfires and the expenditure necessary to implement the VBRC recommendations have also had material opex impacts.

The current period has also seen AusNet Services embark on a major overhaul of its IT systems, known as Program WorkOut. While not funded by the opex allowance previously approved by the AER, this project has been delivered on the basis that it will deliver significant long-term benefits to AusNet Services and its customers.

Against this backdrop, controllable opex for the current period is forecast to be around five per cent lower than the allowance approved by the AER. AusNet Services has responded in line with the incentives embedded in the regulatory framework by driving continuous efficiency improvements in key areas of its business.

AusNet Services has also continued its strong track record of delivering outcomes against its approved step changes. Consistent with the NEO, AusNet Services has ensured that the price increases faced by customers during the current regulatory control period have contributed to a safer network, greater customer engagement, improved service levels and more efficient use and operation of the network.

However, the price increases experienced by customers during the current period have created an environment where future price stability is a central concern of AusNet Services' customers, and therefore of AusNet Services.

Accordingly, AusNet Services is proposing an opex forecast that constrains growth in the distribution component of customer bills over the forthcoming regulatory control period, without compromising network safety or reliability. Consistent with customer feedback, the forecast also includes expenditure to further develop AusNet Services' demand management capabilities in the face of uncertainty over future technologies and energy demand and consumption patterns. Other key drivers of the opex increases forecast for the forthcoming regulatory control period include rising input costs, increases in key opex drivers (e.g. customer numbers) and growth in insurance premiums.

AusNet Services' approach to opex forecasting

AusNet Services' opex forecast has been developed using a 'base-step-trend' approach, starting from AusNet Services' actual costs. When actual, revealed costs are efficient this methodology produces a forecast that is prudent and efficient. The AER has recognised the advantages of this methodology by stating that:

> *"Specifically we intend to use the 'base-step-trend' approach. If a NSP has operated under an effective incentive framework, and sought to maximise its profits, the actual opex incurred in a base year should be a good indicator of the efficient opex required."*[1]

The economic benchmarking and partial performance indicator measures developed by the AER provide strong evidence that AusNet Services' base year opex is efficient. For instance, opex benchmarking shows that AusNet Services is among the most efficient Distribution Network Service Providers (DNSPs). The AER's consultant, Economic Insights, identified AusNet Services as being within the top quartile with respect to opex efficiency (along with CitiPower, Powercor, SA Power Networks and United Electricity Distribution).[2] The efficiency levels of these businesses were used by the AER in its draft decisions to set an efficiency benchmark against which the NSW/ACT DNSPs were assessed.

Expenditure overview

The application of the base-step-trend approach to AusNet Services' efficient base year opex produces a total opex forecast that is prudent and efficient, and which is required to achieve the operating expenditure objectives set out in the NER. For example, the opex forecast accounts for expected demand for electricity services by including opex attributable to forecast growth in outputs (e.g. customer numbers).

Further, to ensure the total forecast reasonably reflects the operating expenditure criteria, AusNet Services has taken into account the operating expenditure factors, including:

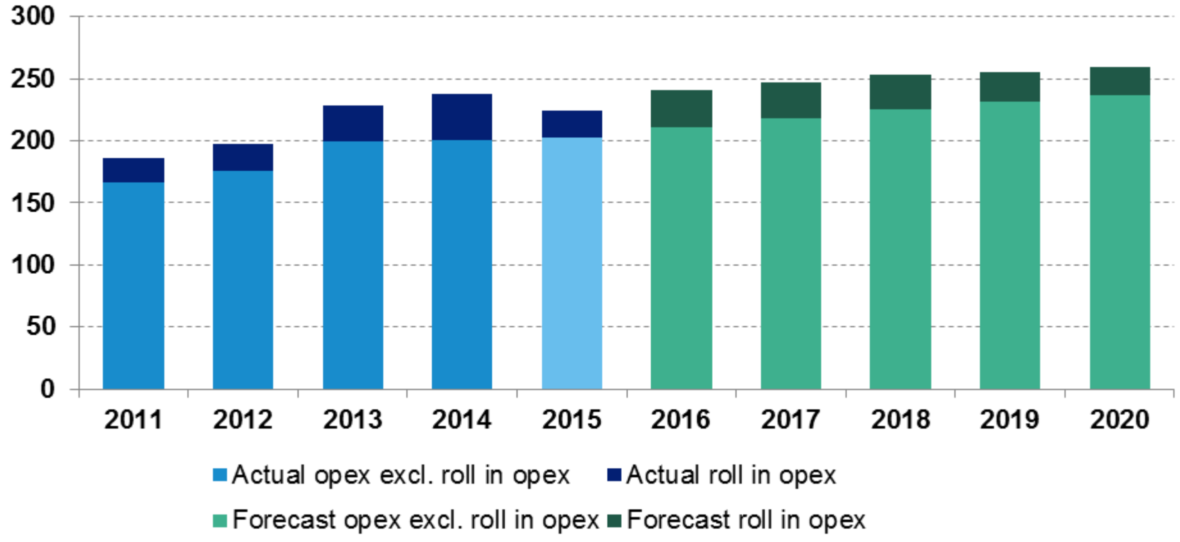
- The AER's recent annual benchmarking report and AusNet Services' actual operations and maintenance expenditure in the currently regulatory control period;
- The relative prices of operating and capital inputs;
- The substitution possibilities of operating and capital inputs;
- Consistency with the incentive schemes being applied to AusNet Services;
- Opportunities for efficient and prudent non-network alternatives; and
- Consumers' concerns about the impact of opex on price stability and reliability of supply.

The below figure shows AusNet Services' proposed opex forecast for the next regulatory control period. The total forecast of opex required to meet the opex objectives is $1.26 billion. Forecast opex is, on average, around $251 million per annum (real 2015), approximately six per cent higher than 2014 opex of $238 million. This equates to average annual growth of 1.5 per cent from 2014 to 2020.

[1] AER, *Explanatory Statement | Expenditure Forecast Assessment Guideline*, p. 61.

[2] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, pp. 47-48.

Figure 8.1: Actual and forecast opex ($m, real 2015)



Source: AusNet Services

Note: Excludes movements in provisions; roll in opex refers to opex associated with the network support agreement between AusNet Services and Bairnsdale Power Station and ongoing opex associated with AMI program upgrades to core distribution systems (e.g. the billing system), which have been recovered outside the price cap in the current period; figures for 2015 are estimates.

Benefits of the proposed operating expenditure

The proposed opex forecast has been developed to deliver value for AusNet Services' customers over the forthcoming period. It reflects a level of expenditure that will ensure continued access to a safe and reliable electricity supply at the lowest possible cost. Accordingly, AusNet Services is confident that its opex forecast contributes to a total revenue forecast that best serves the long-term interests of consumers, and thus contributes to the achievement of the NEO.

AusNet Services has also ensured the total opex forecast is also a reasonable reflection of the opex criteria by, for example:

- Proposing to absorb a number of step changes by finding efficiency savings;
- Adjusting its base year opex to remove non-recurrent expenditure;
- Proposing an efficient capex-opex trade-off that will facilitate long-term customer benefits; and
- Utilising expert forecasters for major cost inputs (e.g. labour costs, insurance premiums).

The proposed expenditure will also facilitate the development of innovative new technologies in response to emerging technologies and changing energy consumption and demand patterns. In this way, the total opex forecast enables AusNet Services to meet and manage expected demand for its standard control services.

8.1.1 Structure of this chapter

The remainder of this chapter is structured as follows:

- Section 2 describes AusNet Services' operating environment and demonstrates the efficiency of its historical opex;
- Section 3 details the methodology used to develop each component of forecast opex; and
- Section 4 sets out AusNet Services' total proposed opex for the forthcoming regulatory period.

8.2 Operating Environment

8.2.1 Environment

While AusNet Services' opex is largely driven by the 'core' activities of an efficient network business, such as customer service, asset inspection, routine and condition based maintenance and emergency response, it is also strongly influenced by operating environment factors external to its control. These include:

- Environmental factors (e.g. mountainous terrain)
- Customer demographics (e.g. low average customer density)
- Regulatory environment (e.g. bushfire mitigation obligations, regulatory reporting requirements, etc.);
- Economic conditions (e.g. demand and supply of labour and contractors);
- Insurance market conditions (e.g. underwriter risk appetite);
- Market developments (e.g. metering contestability); and
- Emerging technologies and alternative energy sources (e.g. solar PV, battery storage).

Many of these factors have influenced expenditure during the current period, and are expected to continue to drive opex over the forthcoming period. Anticipating operating environment change is crucial to the development of an opex forecast that reflects the costs that a prudent operator would require to achieve the opex objectives.

The characteristics of AusNet Services' network are discussed further in chapter two.

8.2.2 Current period performance

AusNet Services is committed to the efficient delivery of safe, reliable and secure electricity distribution services to its customers. The regulatory framework provides powerful incentives to continually seek out opportunities to improve efficiency without compromising its customer service performance or compliance with regulatory obligations.

However, AusNet Services' level of opex during the current regulatory control period has been driven by substantial, externally driven operating environment changes. Despite reductions in demand and energy consumption patterns relative to its forecasts, AusNet Services' opex has continued to increase over the period because of the largely fixed nature of its cost base with respect to these outputs. Key external drivers of opex increases have included:

- More stringent bushfire safety obligations;
- Increases in insurance costs; and
- Enhanced regulatory and reporting requirements, including the provision and audit of benchmarking data.

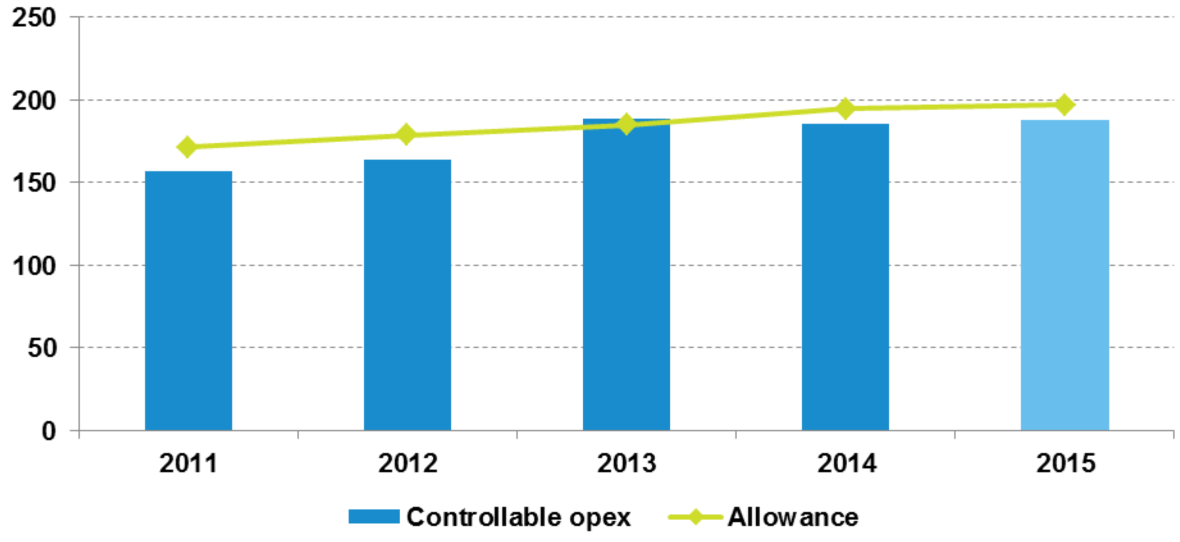
The anticipation of some of these changes led to the AER approving a number of opex step changes at the last review. By achieving the outcomes linked to these step changes, AusNet Services has continued its strong track record of delivering against its opex forecasts and proposed outcomes, and ensured that the price increases faced by customers during the current regulatory control period have contributed to a safer network, greater customer engagement, improved service levels and more efficient operations. AusNet Services' opex spend during the current period achieved the following outcomes:

- Establishment of a demand side management team that has implemented a number of demand management and distributed energy solutions that have effectively deferred augmentation expenditure;
- Compliance with more stringent bushfire mitigation regulations, such as increased vegetation management and inspection activities;
- Implementation of the recommendations of the VBRC;
- Addressed the increase in the number of quality of supply investigations revealed by the AMI data;
- Implementation of Project Workout, which has led to major upgrades to AusNet Services' IT capability and will supersede numerous legacy systems and databases, driving substantial operating efficiency improvements;
- Increase in the level of consumer engagement, including by developing an SMS capability to inform customers of outages, extreme weather events and other important information impacting customers;
- Meeting the requirements of a more comprehensive distribution planning framework; and
- Procuring a significant increase in the policy limit of AusNet Services' liability insurance.

Despite the challenges involved in adapting to shifting operating conditions, AusNet Services' controllable opex[3] for 2011-15 is expected to be $883 million (real 2015), around five per cent less than the allowance set by the AER of $927 million. While AusNet Services' expenditure in 2011 and 2012 was below its allowance, one-off Project WorkOut implementation costs, increases in vegetation management costs and higher customer service costs sharply increased opex in 2013, before it stabilised in 2014.

The below figure compares actual controllable opex from 2011 to 2014 and forecast 2015 opex with the approved regulatory allowances.

Figure 8.2: Actual controllable opex against regulatory allowances ($m, real 2015)



Source: AusNet Services

Note: Excludes uncontrollable costs and movements in provisions; figures for 2015 are estimates.

3 Controllable opex is equal to total opex less costs that were considered uncontrollabe by the AER at the last price review, e.g. self-insurance costs.

By rewarding AusNet Services for any outperformance it can achieve against its regulatory allowances, the Efficiency Benefits Sharing Scheme (EBSS) provides strong incentives to seek out ways to improve opex efficiency. These incentives ensure that AusNet Services' revealed costs reflect an efficient level of expenditure.

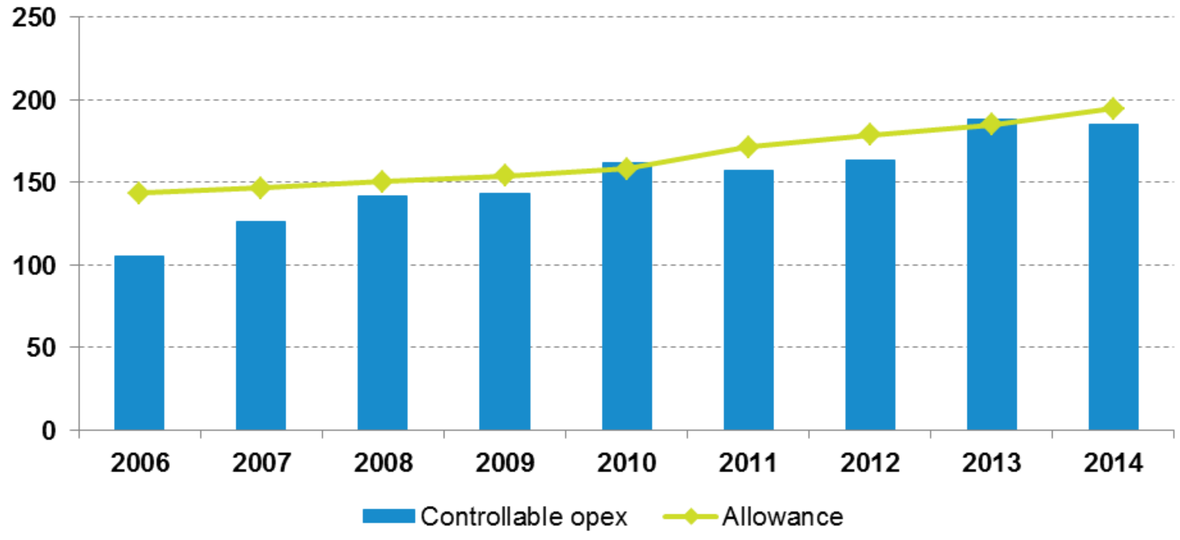
AusNet Services has implemented a wide range of cost saving initiatives during the current period that demonstrate its response to the incentive based regulatory framework. These initiatives include:

- Internalising staff employed by Enterprise Business Services, AusNet Services' shared IT services provider;
- Optimising delegation levels to improve the speed of approvals and reduce unnecessary administrative time;
- Conducting a sourcing review to identify improvement opportunities in the procurement function;
- Discontinuing selected contractor roles and absorbing costs internally or replacing with permanent roles;
- Outsourcing and off-shoring some contact centre activities;
- Optimising meter reading routes given the installation of AMI;
- Standardising designs to ensure assets are constructed with the lowest sustainable life cycle cost while meeting service standards;
- Improving vegetation management contract negotiation and management by hiring specialist negotiators and insourcing assessment processes; and
- Implementing a reliability centred maintenance methodology to optimise inspection cycles and maintenance activities.

While many of these initiatives have been implemented during the current period, benefits associated with some initiatives are expected to be realised over the forecast period. For example, renegotiating more favourable vegetation management service contracts is generally not feasible until existing contracts have expired. This means that while the current period's opex profile incorporates the costs of these initiatives, it does not fully reflect the expected efficiency savings.

AusNet Services' commitment to delivering efficiency improvements is further evidenced when opex is viewed over a longer time period. The figure below shows that AusNet Services' has been able to outperform its benchmark allowances in seven of the nine years between 2006 and 2014.

Figure 8.3: Actual controllable opex against regulatory allowances ($m, real 2015)



Source: AusNet Services

Note: Excludes uncontrollable costs and movements in provisions.

Total opex from 2006 to 2014 of $1,373 million was around eight per cent lower than total allowances of $1,483 million (real 2015), demonstrating that AusNet Services' has a strong track record of responding to the incentives provided by the EBSS and in doing so, providing safe and reliable services at lowest cost. The convergence over time between AusNet Services' controllable opex and its regulatory allowances is also indicative of improvements in AusNet Services' ability to accurately forecast its opex. This is expected to provide comfort to the AER that the opex forecast set out in this chapter is no more than what is required to achieve the opex objectives.

The following section on benchmarking provides further evidence that the incentive regulation AusNet Services is subject to has resulted in a level of revealed costs that is reflective of a prudent and efficient DNSP.

8.2.3 Benchmarking performance

The AER's *Electricity distribution network service providers – Annual benchmarking report* sets out the historical productivity of the electricity distribution industry since 2006, as measured by multilateral total factor productivity (MTFP) calculations developed by Economics Insights. The report also compares opex and capex multilateral partial factor productivity (MPFP), as well as a number of opex and capex partial performance indicators (PPIs).

This section demonstrates that across a range of benchmarking measures, AusNet Services' opex is efficient when compared to its peers.

Economic benchmarking

Economic benchmarking shows that based on data from 2006-2013, AusNet Services is a relatively efficient DNSP, with the AER's consultant, Economic Insights, identifying AusNet Services as being one of five distributors within the top quartile of DNSPs with respect to opex efficiency (along with CitiPower, Powercor, SA Power Networks and United Electricity Distribution).[4] The efficiency scores of these businesses were used to set an efficiency benchmark against which the efficiency of NSW/ACT DNSPs was assessed.

MTFP is one of four economic benchmarking measures considered by Economic Insights. AusNet Services consistently remains within the top five businesses across each measure. This

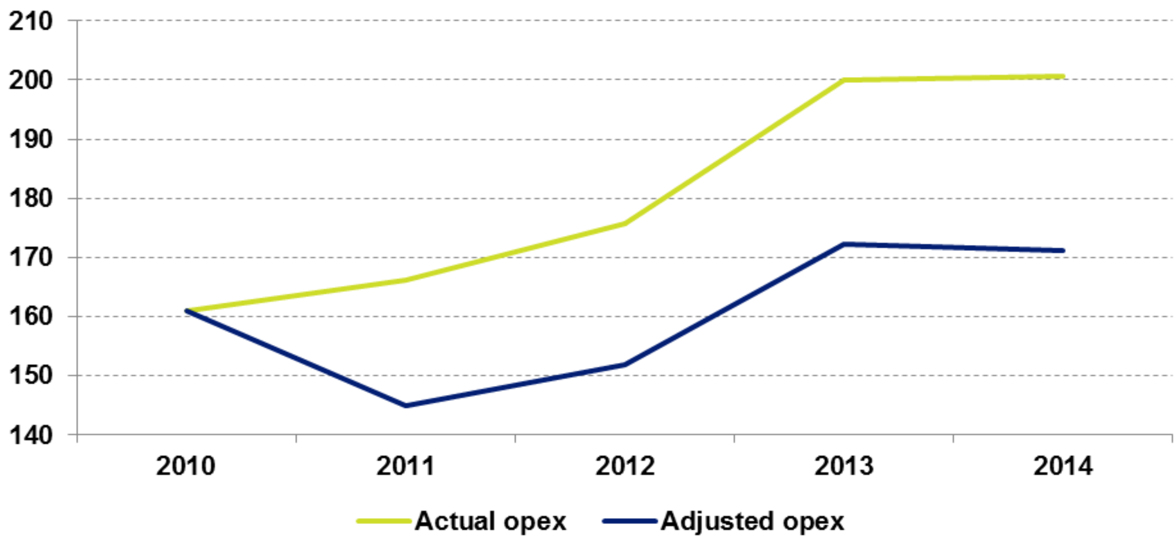
[4] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, pp. 47-48.

indicates that its average level of efficiency across the 2006-2013 has been high relative to its peers across multiple efficiency measures.

AusNet Services' relatively high level of opex efficiency has been achieved against a backdrop of significant operating environment changes that occurred since 2009. In the wake of the Black Saturday bushfires, AusNet Services' saw substantial changes to its bushfire mitigation safety obligations, which resulted in significant increases to its vegetation management costs. Increases in liability insurance premium rates and expenditure to address the recommendations of the VBRC also resulted in large increases in opex.

The figure below compares AusNet Services' actual opex between 2010 and 2014 with opex adjusted to remove cost increases due to changes in vegetation management obligations, growth in insurance premiums and implementation of the VBRC recommendations. These costs are considered largely exogenous to AusNet Services.

Figure 8.4: Actual opex and opex excluding exogenous costs ($m, real 2015)



Source: AusNet Services

Note: Includes debt raising costs; excludes movements in provisions and Bairnsdale Power Station costs.

Exogenous costs accounted for approximately $102 million of total opex of $904 million between 2010 and 2014, or 11 per cent of total opex. Without these costs, AusNet Services' opex would have increased at an average annual growth rate of 1.5 per cent over this period, compared with an actual growth rate of 5.5 per cent.

While external cost drivers have clearly had a material impact on AusNet Services' inputs in the MTFP analysis, they have not been counted as outputs because the MTFP index does not place a value on safety outcomes. The AER has recognised that changes in external obligations will have an impact on productivity:

> *"The reason that overall productivity has been declining across the sector over the last eight years is that some outputs have remained relatively steady or declined while all or most distributors have increased input use significantly. We recognise however, that some of the decrease in productivity may be attributable to changes in obligations on the distributors."*[5]

AusNet Services has been able to achieve a relatively high level of efficiency despite large, exogenous increases to its inputs.

5 AER, *Electricity distribution network service providers – Annual benchmarking report*, p. 29.

AusNet Services considers these external drivers have also contributed to the decline in its opex productivity between 2006 and 2013, as shown by the AER's benchmarking report, rather than a reduction in its level of operating efficiency. In the absence of these drivers and their associated costs, AusNet Services considers its opex productivity would have remained largely constant over the current period.

Declining energy throughput has also contributed to declining productivity over this period. AusNet Services' energy throughput declined in four of the eight years between 2006 and 2013, and was 4.9 per cent lower in 2013 than it was in 2006. Maximum demand also fell by 3.5 per cent between 2010 and 2013. Collectively, energy throughput and maximum demand account for over 30 per cent of the output specification in the AER's preferred MTFP index.

In contrast to the decline in some of its output variables, AusNet Services' opex has increased substantially between 2011 and 2014, in large part due to the external factors explained in the previous section. However, due to the small proportion of AusNet Services' opex that is variable with respect to energy and demand outputs, AusNet Services has been unable to reduce its opex commensurate with the reductions in these outputs. For instance, AusNet Services' asset inspection and routine maintenance costs are driven by the condition and size of its physical asset base, rather than by the volume of energy it delivers. Accordingly, outputs trends in recent years coupled with large increases in opex have contributed to AusNet Services' declining productivity during this period, as measured by the AER's MTFP index.

Partial performance indicators

The efficiency of AusNet Services' opex as demonstrated by economic benchmarking and total opex PPIs – which provide a 'top-down' measure of AusNet Services' efficiency – is supported by a range of 'bottom-up' PPI measures that compare individual opex categories between DNSPs and over time.

The AER describes these measures as follows:

> *"Category analysis metrics are PPIs that focus on particular categories of opex in isolation. They are, therefore, the next level of detail below the total cost and total opex PPIs we presented in section A.3.3. We would not necessarily expect every metric to produce the same results because service providers may allocate opex across the categories differently. This is relevant to our analysis. For instance, a source of apparent inefficiency in the base year could be due to costs associated with a particular category of opex, for which there is a reasonable explanation for the high costs. Similarly, a service provider could appear to perform well on some category metrics but be inefficient overall. Category analysis is, however, useful for identifying areas of high cost and potential inefficiency."*[6]

As noted by the AER, differences in cost allocation to opex categories between DNSPs can contribute to differences in category analysis metrics. However, strong performance across all metrics is evidence of an efficient level of total opex.

In its review of the NSW DNSPs' base year opex, the AER contrasted the opex per customer of the NSW businesses with Powercor's, which it considered to be one of the top performers in economic benchmarking.[7] In relation to opex per customer, the AER also stated:

> *"Under this measure the Victorian and South Australian distributors appear the most productive in their use of opex. They have the lowest ratio of opex to customers regardless of their customer density. This is because they spend the lowest amount of opex per customer at about $200 per customer each. Ergon has the highest opex spend per customer, being approximately double that of the Victorian networks and South Australian networks."*[8]

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6 AER, *Attachment 7: Operating expenditure | Ausgrid draft decision*, p. 77.

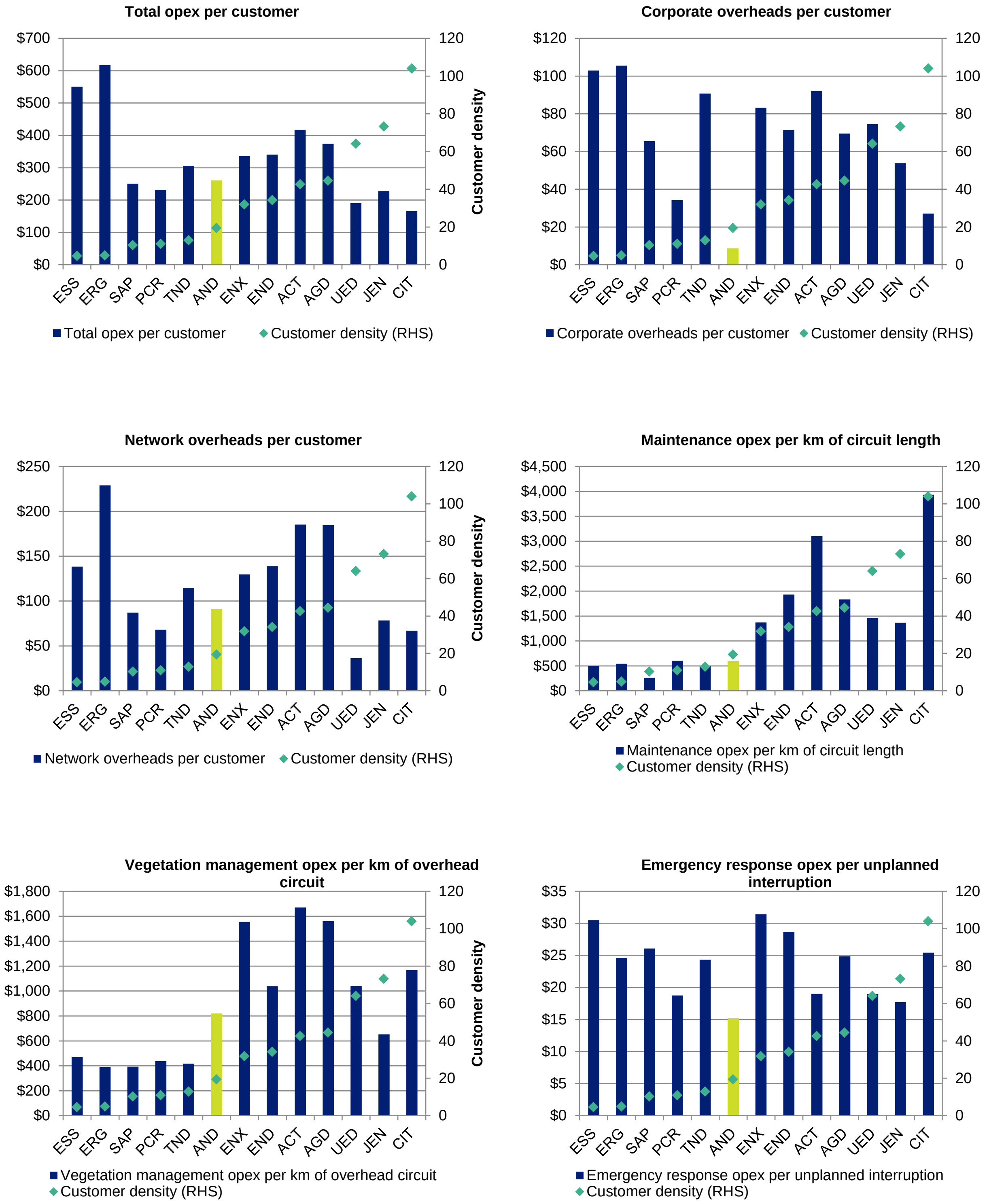
7 Ibid, p. 64.

8 AER, *Electricity distribution network service providers – Annual benchmarking report*, p. 24.

The figure below shows average opex from 2009-2013 for major opex categories, which have been normalised across DNSPs using what AusNet Services considers to be the most relevant cost driver of each category of opex. For example, overheads expenditure has been divided by total customer numbers to normalise this metric because, all else equal, an increase in customer numbers will typically require more overheads expenditure.

Customer density (measured by customers per kilometre of network) has also been included in each chart to allow comparisons between businesses of similar network density. DNSPs have been ordered by density from least dense (left) to most dense (right). AusNet Services is labelled 'AND'.

Figure 8.5: Key category analysis metrics, (average 2009-2013, real 2015)



Source: AusNet Services

Note: Excludes historical AMI expenditure; AND = AusNet Services.

These metrics demonstrate that AusNet Services benchmarks favourably when compared to businesses of similar customer density and across the NEM. In particular:

- AusNet Services' total opex per customer of $260 is comparable with Powercor's $232 and SA Power Networks' $250, which were identified by the AER in its NSW draft decisions as two of the most productive businesses, and have similar customer density to AusNet Services;
- AusNet Services' corporate overheads of $9 per customer are the lowest in the NEM, while its network overheads of $92 are below the NEM average of $119 and comparable to SA Power Networks' $87;
- AusNet Services' maintenance cost per kilometre of circuit of $600 is substantially lower than the NEM average of $1,386, and is similar to Powercors' $602;
- AusNet Services' vegetation management costs are affected by substantial changes to bushfire safety obligations following the 2009 bushfires. Despite this, its vegetation management cost per kilometre of overhead circuit of $820 is lower than the NEM average of $894; and
- AusNet Services' emergency response opex per unplanned interruption of $15 is the lowest in the NEM.

While these PPIs show relatively high opex efficiency for AusNet Services, it should be emphasised that definitional differences and differences in cost allocation between DNSPs are likely to skew some results. These comparability issues mean that PPIs should be used as indicative efficiency measures, which may warrant further investigation in the case of poor performance, rather than as definitive measures of efficiency.

8.3 Approach to Forecasting

8.3.1 Forecasting methodology

AusNet Services has used a revealed cost base-step-trend approach to develop its proposed opex forecast.[9] To ensure this approach produces a prudent and efficient forecast of opex, it must rely on an efficient level of base year opex. For the reasons outlined in the previous section of this chapter, AusNet Services considers that its base year opex is efficient. Accordingly, a base-step-trend approach using revealed costs should be used to forecast AusNet Services' opex requirements over the forthcoming regulatory control period.

At a high level, AusNet Services' opex forecast has been developed by:

- Determining customer attitudes and expectations as they relate to opex;
- Using revealed 2014 expenditure to determine efficient base year costs;
- Applying a rate of change to base year costs to reflect expected changes in input costs, network scale and productivity;
- Incorporating a demand management step change aimed at facilitating capex-opex trade-off, which has been developed on a bottom-up basis;
- Forecasting a number of cost items (e.g. insurance) on a category-specific basis to account for unique drivers of cost increases that are not reflected in the rate of change; and
- Including a number of costs in the forthcoming regulatory control period have been recovered outside the price cap in the current period (e.g. network support contract and ongoing AMI costs).

[9] AusNet Services' use of the base-step-trend approach is subject to some limited exceptions, which are explained later in this chapter.

This approach largely aligns with the AER's Expenditure Forecast Assessment Guideline. AusNet Services considers that the base-step-trend approach set out in the Guideline represents a sensible methodology to forecast opex requirements for an efficient DNSP.

Consistent with the 'top-down' forecasting methodology adopted, AusNet Services has not explicitly identified and quantified non-recurrent expenditure categories over the forthcoming regulatory control period. However, it is assumed that non-recurrent expenditure will rise and fall across the forthcoming regulatory period such that non-recurrent opex is broadly consistent from year-to-year.

The following table provides a breakdown of AusNet Services' forecast opex. The remainder of this section sets out detailed information on each opex component.

Table 8.1: Proposed opex ($m, real 2015)

Opex component	2016	2017	2018	2019	2020	Total
Base opex	183	183	183	183	183	**913**
Rate of change	6	12	18	23	29	**89**
Step changes	0	0	1	1	1	**5**
Other costs	22	23	24	24	24	**117**
Cost roll ins	30	29	28	24	22	**133**
Total opex	**241**	**247**	**254**	**256**	**259**	**1,256**

Source: AusNet Services

8.3.2 Customer attitudes, expectations and behaviour

AusNet Services undertook several engagement activities aimed at gauging the attitudes of its customers to potential changes to future operating expenditure requirements, including trade-offs between capital and operating expenditure. These were not an attempt to substitute for detailed independent analysis, rather they were helpful in illuminating customer attitudes to AusNet Services' opex forecast.

Engagement activities

Initially, AusNet Services undertook a broad based survey of its customers to gain an underlying baseline for further customer engagement.

This was followed by a series of community forums and technical workshops with advocacy groups where drivers of opex were explained, including capex-opex trade-offs and trade-offs between reliability and opex.

A series of independently run focus groups were held in different regions and with different demographic groups throughout our network. These groups provided detailed feedback on general and specific options and trade-offs that the network faced in preparing our opex forecasts.

Relevant findings

There is an overarching customer concern around escalating energy prices and a clear expectation that network costs be managed and smoothed over time to avoid short term increases in prices

With respect to opex specifically:

- Customers expressed a desire to stabilise prices by limiting the opex step changes proposed by AusNet Services;
- Customers felt that additional expenditure and a higher DMIA were warranted in order to develop innovative demand management technologies;
- Customers expressed a strong preference for current reliability levels. This satisfaction with was shared across different customer groups. There was a strong resistance either to pay for further reliability improvement or allowing reliability to decline for lower prices in the future;
- Customers were satisfied with AusNet Services' current approach to vegetation management, and did not express a preference to change future opex requirements by altering this this approach; and
- When presented with the option of increasing opex to improve communications during major event days (MED), customers preferred to maintain existing communication practices.

How these findings have been incorporated into the proposal

To ensure the preferences and views of its customers are reflected in its opex forecast, AusNet Services has:

- Limited its proposed step changes to an increase in opex to expand its demand management capability; and
- Proposed an increase to the DMIA from $3.5 million to $10 million over five years to fund the development of novel demand management technologies.

8.3.3 Base year opex

Selection of base year

As discussed earlier in this chapter, to ensure the base-step-trend approach produces a prudent and efficient forecast, it must use an efficient level of base year opex. AusNet Services has nominated 2014 calendar year opex as the base year for forecasting purposes because:

- It is the most recently regulatory year for which audited regulatory accounts and other financial information is available;
- The operating environment conditions experienced during 2014 are considered representative of those prevailing in the current and forthcoming regulatory control periods (e.g. weather conditions, regulatory and legislative environment);
- Economic benchmarking and category analysis demonstrate that AusNet Services' current level of opex is efficient relative to its peers, indicating that AusNet Services revealed 2014 costs represent an efficient base year; and
- There is a large degree of consistency between 2013 and 2014 opex, presenting prima facie evidence that 2014 opex is representative of efficient costs and has not been affected by cost shifting. Indeed, controllable opex in 2014 was approximately one per cent lower in real terms than controllable opex in 2013.

Adjustments

To determine a level of base year opex that reflects efficient recurrent expenditure, a number of adjustments have been made to AusNet Services' actual 2014 opex. These adjustments are:

- Removal of movements in provisions to align with the AER's treatment of provisions in its recent reviews of TasNetworks and TransGrid;
- Removal of costs that are excluded from the current period's application of the EBBS on the grounds of uncontrollability. These costs are:
  - GSL payments;
  - DMIA costs;
  - Superannuation defined benefit schemes;
  - Self-insurance losses;
- Removal of insurance costs, which have been forecast using a category-specific approach to improve the accuracy of the total opex forecast;
- Removal of costs incurred in 2014 to address the recommendations of the VBRC that are not expected to reoccur over the forthcoming regulatory control period;
- Addition of debt raising costs, which have been included as base year opex for forecasting purposes (discussed further in section 8.3.5); and
- Addition of the 2015 efficient benchmark increase.

By making these adjustments, AusNet Services determined its prudent and efficient base year costs, thereby enabling it to develop a total opex forecast that reasonably reflects the opex criteria.

The following table sets outs the process for adjusting 2014 actual opex to derive base year opex.

Table 8.2: Derivation of base year opex ($m, real 2015)

Actual 2014 opex (excl. debt raising costs)	**198.1**
Movements in provisions	-1.2
GSL payments	-6.6
DMIA costs	-0.1
Superannuation defined benefit schemes	-0.2
Self-insurance losses	-1.7
Insurance	-10.2
Non-recurrent VBRC costs	-1.5
Debt raising costs	3.6
2015 Benchmark increase	2.4
Base year opex	**182.7**

Source: AusNet Services

Base year opex accounts for opex of $913 million over the forthcoming regulatory control period, or around 73 per cent of total opex.

8.3.4 Rate of change

Overview

The rate of change, which is applied to base year opex for each year of the forthcoming regulatory control period, accounts for expected real increases in labour and materials costs, opex increases attributable to network growth (scale escalation) and expected changes in productivity.

In line with the AER's Expenditure Forecast Assessment Guideline, the rate of change has been calculated according to the following formula:

Rate of change = output growth + real price growth – productivity growth[10]

The below table sets out AusNet Services' proposed rate of change escalators.

Table 8.3: Proposed rate of change

Component	2016	2017	2018	2019	2020
Output growth	1.46%	1.42%	1.39%	1.34%	1.30%
Real price growth	1.98%	1.64%	1.61%	1.65%	1.71%
Productivity growth	0.00%	0.00%	0.00%	0.00%	0.00%
Rate of change	**3.47%**	**3.09%**	**3.02%**	**3.01%**	**3.04%**

Source: AusNet Services

The output growth parameters have been calculated according to the approach applied by the AER in its draft decision for the NSW DNSPs. Real price growth has been forecast using a combination of Enterprise Bargaining Agreement (EBA) outcomes for 2016 and a forecast of labour cost increases developed by The Centre for International Economics (CIE). Productivity is forecast to remain flat over the forthcoming regulatory control period.

The opex criteria state that the AER must accept total the opex forecast if it is satisfied that the total forecast operating expenditure reasonably reflects, among other things, a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.[11]

For the reasons set out in the remainder of this section, AusNet Services considers that its proposed rate of change is consistent with the opex criteria.

Output growth

In its Explanatory Statement to the Expenditure Forecast Assessment Guideline, the AER acknowledged that:

> *"Increased demand for NSPs' outputs may require them to expand their networks. It is reasonable that an efficient NSP will require more inputs, and thus greater opex, to deliver more output. We therefore include forecast output growth in the rate of change formula."*[12]

AusNet Services agrees that the rate of change should account for the impact of increased outputs on opex over the forthcoming regulatory control period. For instance, the growth in customer numbers expected from 2016 to 2020 will create additional customer service costs for AusNet Services, and is also a proxy for growth in network size, which drives increases in inspection and maintenance costs.

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10 AER, *Expenditure Forecast Assessment Guideline*, p. 23.

11 NER, clause 6.5.6(c)(3).

12 AER, *EFA Guideline Explanatory Statement*, p. 61.

The AER also provided the following guidance with respect to the selection of output measures used to forecast output growth:

> *"The output measures should:*
>
> - *align with the NEL and NER objectives*
> - *reflect services provided to customers*
> - *be significant."*
>
> *If the productivity measure includes economies of scale then forecast output growth should not be adjusted for economies of scale."*[13]

AusNet Services understands this to mean that the forecast opex increase attributable to output growth should not be adjusted downward to account for the economies of scale that result from "doing more of the same" type of work. This adjustment has been a feature of previous output growth models, which has tended to reduce the output growth forecast approved by the AER

The AER has expressed a preference to account for economies of scale in a single opex productivity measure, rather than in an output growth measure, and has applied this approach in its draft decision for the NSW DNSPs where it forecast output growth using an econometric model developed by Economics Insights.[14] The report titled *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs* report explains Economic Insights' rationale for adopting these cost drivers and weightings.

The AER's approach used customer numbers (with a weight of 67.6 per cent), circuit length (10.7 per cent) and ratcheted maximum demand (21.7 per cent) as outputs and assumed constant returns to scale.

In developing its forecast of output growth, AusNet Services has adopted the AER's approach because it expects the output measures adopted by the AER, particularly customer numbers, to be reasonable drivers of opex increases over the forthcoming regulatory control period.

When applied to AusNet Services' forecasts of the relevant output measures, the AER's approach results in an output growth forecast of $39 million over the forthcoming regulatory control period, which is equal to around three per cent of total opex.

Table 8.4: Proposed output growth ($m, real 2015)

Output measure	2016	2017	2018	2019	2020	Total
Customer numbers (%)	1.68%	1.63%	1.59%	1.52%	1.48%	
Circuit length (%)	0.82%	0.84%	0.91%	0.87%	0.89%	
Ratcheted maximum demand (%)	1.12%	1.07%	1.02%	0.98%	0.98%	
Output growth (%)	**1.46%**	**1.42%**	**1.39%**	**1.34%**	**1.30%**	
Output growth ($)	**2.7**	**5.3**	**7.9**	**10.5**	**13.0**	**39.4**

Source: AusNet Services

13 AER, *EFA*, p. 23.

14 AER, *Ausgrid draft decision | Attachment 7: Operating expenditure*, November 2014, pp. 152-154.

Real price change

The real price change component of the rate of change reflects expected changes in real input prices over the forthcoming regulatory control period. This is recognised by the AER in the Explanatory Statement to the Expenditure Forecast Assessment Guideline:

> *"It is reasonable to assume that the cost of inputs for an efficient firm to produce the same level of output may change at a rate different to CPI. Consequently it is reasonable to account for real cost changes in inputs."*[15]

AusNet Services agrees that the rate of change should account for the impact of increased input costs on opex over the forthcoming regulatory control period. For instance, AusNet Services' historical growth in labour costs has been higher than CPI, and this trend is expected to continue over the forthcoming regulatory control period.

- Internal labour costs;
- External labour costs; and
- Non-labour costs.

AusNet Services has forecast opex to account for real price change of $49 million over the forthcoming regulatory control period, which is equal to around four per cent of total opex.

Internal and external labour costs

Internal labour costs are the costs of AusNet Services' employees and its internal labour hire, while external labour costs are the costs of external contractors engaged to deliver services such as vegetation management and asset maintenance, as well as consultants.

Internal and external labour collectively account for a significant proportion of base opex (46 per cent and 47 per cent, respectively). It is noted that in the AER's draft decisions for the NSW/ACT DNSPs and TransGrid, the AER assumed that total labour costs accounted for 62 per cent of each network's base year opex. The AER's justification for this approach is as follows:

> *"Our weightings which have been used in our economic benchmarking represent a benchmark weighting between labour and non-labour. We consider these weighting represent the weightings for a prudent firm because it has been used in previous economic benchmarking analysis by Pacific Economic Group Research and Economic Insights."*[16]

AusNet Services considers that this approach is inconsistent with an opex forecasting approach that relies on actual, revealed costs, which is the AER's preferred approach to forecasting opex.[17] In responding to the incentives embedded in the regulatory framework, AusNet Services, as an efficient DNSP, has sought to utilise a mix of labour and non-labour inputs that allows it to meet the opex objectives at the lowest possible cost. The imposition of an external benchmark weighting of labour and non-labour inputs is therefore predicated on the assumption that these regulatory incentives are not effective.

As demonstrated in section 8.2, AusNet Services' track record of driving efficiency savings in response to the EBSS has resulted in an efficient level of base year opex. Accordingly, AusNet Services' actual labour and non-labour weights should be inputs into forecast real price change. This approach ensures consistency with the AER's preferred base-step-trend approach using revealed costs.

In line with historical trends, the costs of both internal and external labour are expected to increase at a rate higher than CPI over the forthcoming regulatory control period. Changes in the cost of each type of labour reflect the market dynamics of different labour market segments and therefore require different forecasts of cost increases.

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[15] AER, *EFA Guideline Explanatory Statement*, p. 61.

[16] AER, *Ausgrid draft decision | Attachment 7: Operating expenditure*, p. 146.

[17] AER, *Explanatory Statement | Expenditure Forecast Assessment Guideline*, p. 61.

Accordingly, AusNet Services engaged expert economic consultant CIE to develop forecasts of growth in the Wage Price Index (WPI) for the Electricity, Gas, Water and Waste Services (EGWWS) and Construction industries. CIE has forecast growth in the EGWWS and Construction industry WPIs that exceeds the long-term average annual growth in these indices. The key driver of the forecast growth rate identified by CIE is an upswing in economic activity from 2016 due to:

- Heightened activity in the housing industry fuelled by low interest rates and foreign investment;
- Strong demand from Asian economies for Australian agricultural exports;
- Increased investment in infrastructure by the Victorian Government; and
- A surge in economic activity driven by LNG production in Queensland.

CIE's forecasts account for expected improvements in labour productivity to the extent that this is a driver of real wage growth. However, because the forecasts are projections of changes in the price of labour (as distinct from changes in the *cost* of labour), they do not compensate for any form of labour productivity improvement. This aligns with the AER's preferred approach to forecasting productivity in the rate of change.

CIE's report, which is included at Appendix 8C, sets out the assumptions underpinning its forecasts.

Internal labour costs in 2016 were determined using the rates in AusNet Services' EBAs for the months of that year to which they will apply, combined with CIE's EGWWS WPI forecast for the balance of 2016. External labour costs in 2016 were determined using CIE's Construction WPI forecast.

For labour costs from 2017 to 2020, CIE's EGWWS and Construction forecasts were applied to internal and external labour costs, respectively.

The following table sets out AusNet Services' proposed real labour escalators and cost increases for the forthcoming regulatory control period. In recognition that economic data is subject to change between now and the commencement of the regulatory control period, and that the best forecast of labour costs will be based on the most up to date data set available, AusNet Services will provide an updated labour cost forecast in its Revised Proposal that incorporates the most recently available economic data.

Table 8.5: Proposed labour escalators and cost increases ($m, real 2015)

	2016	2017	2018	2019	2020	Total
Internal labour (%)	1.95%	1.65%	1.61%	1.66%	1.73%	
External labour (%)	2.31%	1.88%	1.86%	1.89%	1.95%	
Internal labour ($)	1.6	3.1	4.5	5.9	7.5	**22.6**
External labour ($)	2.0	3.6	5.3	7.0	8.8	**26.6**
Total labour ($)	**3.6**	**6.7**	**9.7**	**12.9**	**16.3**	**49.2**

Source: CIE, Labour price forecasts final report, December 2014; AusNet Services.

In forecasting its 2016 internal labour costs, AusNet Services has relied largely on EBA rates because these rates reflects the change in AusNet Services' labour costs that it is contractually obligated to incur, and therefore represent a realistic expectation of the cost inputs required to achieve the opex objectives. In responding to the regulatory incentives it faces, AusNet Services has strived to negotiate EBA outcomes that allow it to meet its service obligations at the lowest possible cost. Accordingly, AusNet Services considers its EBAs to be efficient, with the associated wage increases reflecting prudent and efficient costs.

The AER recognised the merits of using EBA outcomes to forecast labour costs in its 2014-17 transmission revenue reset for AusNet Services, and approved a forecasting approach that used actual EBA rates for the period in which they apply to:

> *"Where applicable, labour cost forecasts based on [AusNet Services'] enterprise agreements (EA) reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives"*[18]

In the transmission review, the AER also stated:

> *"There is evidence to support [AusNet Services'] contention that a forecast based on its recent EA outcomes are a realistic expectation of the cost inputs required to achieve the opex and capex objectives"*[19]

While the AER had some concerns with using EBAs to forecast costs because doing so may "promote inefficient wage agreements in the future"[20], the AER considered that AusNet Services' EBA outcomes were comparable with EBAs entered into at a range of other EGWWs network businesses and thus acceptable.[21] It is emphasised that the EBAs and wage rate increases approved by the AER in the transmission review are the same EBAs and rates proposed by AusNet Services in this review.

In summary, AusNet Services considers its 2016 internal labour cost escalator is a realistic expectation of the efficient cost inputs required to achieve the opex objectives because:

- It is underpinned by an efficient EBA and therefore reflects what AusNet Services' actual efficient labour costs will be in that year; and
- The AER's most recent analysis of AusNet Services' forecast labour costs, as part of its 2014-17 transmission determination, concluded that where applicable, labour cost forecasts based on EBAs reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.

In forecasting its 2017-20 labour costs, AusNet Services' forecast relies on the EGWWS and Construction WPI measures for its internal and external labour costs, respectively.

The EGWWS index has been applied to internal labour because the broad mix of occupations it comprises are considered to be reasonably reflective of the composition of AusNet Services' internal labour.

It is noted that the waste services labour component of the EGWWS index does not necessarily reflect the labour resources used by AusNet Services, and may therefore downwardly bias forecasts of this index below the costs AusNet Services will actually incur. This point was made by BIS Shrapnel during AusNet Services' 2014-17 transmission review:

> *"Using a comparison of the historical wages and employment data of EGW versus EGW and Waste Services at the national (Australian) level, annual growth in the combined EGWWS sector is 0.1 per cent less on average than the EGW sector over the period from 1998/99 to 2008/09, and 0.6 per cent less on average over the same period for AWOTE — both of which are significant and can make a material difference to an enterprise's overall labour costs, see table 4.3."*[22]

However, AusNet Services acknowledges that adjusting EGWWS forecasts to remove this bias is difficult in practice, and may be prone to error due to estimation difficulties. AusNet Services has also noted a preference for the use of the EGWWS by the AER in its recent reviews of the NSW and ACT DNSPs. Despite the shortcomings of the EGWWS measure, AusNet Services is nonetheless willing to accept EGWWS as a reasonable proxy for the composition of its internal labour.

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18 AER, *Final Decision – SP AusNet Transmission determination*, p. 58.

19 Ibid, p. 63.

20 Ibid, p. 66.

21 Ibid, pp. 67-68.

22 BIS Shrapnel, *Real Labour Forecasts to 2016/17 – Australia and Victoria*, November 2012, p. 23.

AusNet Services' external labour costs have been escalated using the Construction WPI index because most contractor labour is assumed to undertake construction or maintenance related projects and is more suitably classified to the construction sector. The Construction WPI more accurately reflects the composition of AusNet Services' external labour, and therefore is a better indicator of future increases in the cost of this labour group.

Due to the more generalised nature of its external labour resources, AusNet Services actively competes with other sectors that utilise similar labour resources, including the Construction sector. For example, vegetation management work is typically carried out by general labour that could be deployed in a number of industries. The cost of vegetation management contracts accounted for a significant (44 per cent) proportion of AusNet Services' external labour costs in 2014.

The AER has previously criticised the use of the Construction index for external labour costs. In its draft decision for the NSW DNSP's, the AER stated:

> *"The ABS takes into account the nature of the business, not the nature of the work undertaken, when allocating a job to an industry. The ABS labour price statistics for the EGWWS industry reflects both specialised electricity distribution network related labour and general labour.*
>
> *We consider regardless of the nature of the task, if labour is employed by a business that operates in the utilities industry, then it should be escalated by the EGWWS industry forecast. For this reason we have adopted the EGWWS classification for all labour."*[23]

AusNet Services considers the AER's position does not adequately account for the drivers of wage differentials between internal and external labour resources. While AusNet Services' external labour is indeed engaged to provide services within the utilities industry, the wage growth of that type of labour is a function of the supply and demand drivers it faces. General labour faces demand, and is exposed to supply, from a range of sectors, including the Construction sector. This should be reflected in the choice of WPI used to forecast wage growth for that type of labour.

This point has been recognised by the ABS in determining its classification of the EGWWS industry group:

> *"The Electricity, Gas, Water and Waste Services Division comprises units engaged in the provision of electricity; gas through mains systems; water; drainage; and sewage services. This division also includes units mainly engaged in the collection, treatment and disposal of waste materials; remediation of contaminated materials (including land); and materials recovery activities.* ***Units mainly engaged in the construction of water, gas, sewerage or stormwater drains or mains, electricity or other transmission lines or towers, pipelines, or any other civil engineering projects are included in Division E Construction*** *[emphasis added]."*[24]

In making this classification, the ABS considered that labour involved in the construction of electricity infrastructure is most appropriately allocated to the Construction WPI, despite being employed by EGWWS industry. AusNet Services is of the view that this same principle applies to its external labour. That is, despite being employed by the EGWWS sector, the Construction WPI is a more appropriate escalator than the EGWWS WPI for this category of labour.

Finally, the application of the Construction index to external labour may offset some of the aforementioned bias inherent in the application of the EGWWS index to internal labour. This approach is considered more likely to result in a forecast of total labour costs that reflects a realistic expectation of the cost inputs required to achieve the opex objectives, than if EGWWS is used to escalate all labour costs.

For the above reasons, AusNet Services considers that its approach produces a labour cost forecast that represents a realistic expectation of the cost inputs required to achieve the opex objectives and thus should be accepted by the AER.

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23 AER, *AusGrid draft decision – Attachment 7: Operating Expenditure*, p. 147.

24 http://www.abs.gov.au/ausstats/abs@.nsf/0/00C5F12D56E7B1B0CA25711F00146DA8?opendocument.

AusNet Services' forecast labour cost increases account for $49 million over the forthcoming regulatory control period, which is equal to around four per cent of total opex.

Non-labour costs

Non-labour costs comprise a range of cost categories, including materials, motor vehicle expenses, media and marketing costs and land and building leases. These costs account for around seven per cent of base opex.

AusNet Services has assumed these costs will increase at the same rate as CPI over the forecast period and has therefore forecast no real change in its non-labour costs for the forthcoming regulatory control period.

AusNet Services' approach to materials escalation is discussed in Chapter 7 Capital Expenditure.

Table 8.6: Proposed non-labour escalators and cost increases ($m, real 2015)

	2016	2017	2018	2019	2020
Non-labour (%)	0.0%	0.0%	0.0%	0.0%	0.0%
Non-labour ($)	0.0	0.0	0.0	0.0	0.0

Source: AusNet Services

Productivity

The rate of change formula should account for expected changes in industry-wide productivity over the forthcoming regulatory control period to ensure opex forecasts reflect the costs of a prudent and efficient DNSP. This level of productivity may differ from the productivity improvements that individual DNSPs may be able to achieve through implementing efficiency saving initiatives, which the EBSS is intended to encourage.

The AER has stated in the Explanatory Statement to its Expenditure Forecast Assessment Guideline that productivity forecasts should be firm specific, and take into account both catch up efficiency and shift in the efficiency frontier.[25] The AER has explained this as follows:

> *"As described in the explanatory statement for our draft guideline, the potential productivity change an NSP can achieve in the next regulatory control period should be considered in combination with any base year adjustment. The forecast productivity change of an efficient individual NSP can be disaggregated into 'catching up to the frontier' and frontier shift. Any base year adjustment we apply will capture any catch up required. Thus the forecast productivity change included in the rate of change should represent the forecast shift in the productivity frontier, not average industry performance. To meet the opex criteria forecast productivity change should account for any 'catch up' required and frontier shift."*[26]

While the AER's explanation does not consistently define what the productivity forecast should account for, AusNet Services understands that the AER's intent is to account for any 'catch up' efficiency required by an individual DNSP through a base year adjustment, and to account for forecast shift in the 'efficiency frontier' through the productivity assumption in the rate of change.

[25] AER, *EFA Guideline Explanatory Statement*, p. 69

[26] Ibid, p. 70.

Having established in section 8.2 that AusNet Services' base year opex is efficient, the productivity component of the rate of change should reflect the forecast of industry movements in the 'efficiency frontier'. To avoid double counting productivity, the productivity forecast should not account for any productivity improvements that have been compensated for in the real price change and output growth components of the rate of change. This approach aligns with the AER's preferred approach to forecasting productivity.

This section sets out, among other things, AusNet Services' views on expected productivity change in the electricity distribution sector.

The incentive properties of the EBSS

It has been widely established that the mechanics of the EBSS should provide strong incentives for DNSPs. By offering financial rewards for outperforming an efficient opex benchmark, the scheme creates a powerful incentive for DNSPs to achieve and maintain efficiency savings. These incentives are particularly strong for privately-owned networks.

In its 2013 *Electricity Network Regulatory Frameworks* Inquiry Report, the Productivity Commission explored the incentives faced by private and state-owned electricity networks. The Commission found that differences in the efficiency and performance of networks may in part be explained by differing incentives:

> *"State-owned status is ill-suited to the current incentive regulatory regime. State-owned network businesses appear to be less efficient than their private sector peers. This is not surprising given their multiple objectives, political intervention and the imposition of non-commercial restrictions."*[27]

The Commission was also of the view that:

> *"There are strong arguments for privatisation of these businesses. There is no evidence that the productivity, reliability, quality or cost performance of private sector electricity network businesses is worse than their public sector equivalents. To the contrary, the evidence in Australia and internationally suggests that such private sector enterprises are more efficient. It should also be emphasised that privatisation is not de-regulation. In fact, there is a symbiosis between regulation and privatisation. Strong regulation is needed to achieve the private provision of secure, reliable and appropriately priced electricity network services.* ***And privatisation strengthens the effectiveness of incentive regulation*** *[emphasis added]."*[28]

In the Victorian context, the evidence suggests that incentive regulation has been effective, with the EBSS encouraging businesses to make opex efficiency savings and by doing so, generate long-term benefits for consumers. Since 2006, AusNet Services has regularly outperformed its regulatory allowances by driving ongoing cost reductions. These cost savings equate to $111 million, or eight per cent of the regulatory allowances approved between 2006 and 2014, and are prima facie evidence of AusNet Services' response to the incentives embedded in the regulatory regime.

Through Program WorkOut, AusNet Services has made a significant investment in new IT systems during the current period. Once fully integrated, these systems are expected to drive operational efficiencies across the business, creating significant long-term value for AusNet Services and its customers. The EBSS provides a strong incentive for DNSPs to undertake such projects.

AusNet Services has incorporated efficiency improvements in its forecast opex by proposing to absorb a number of step changes over the forthcoming regulatory period (discussed in section 8.3.7). Further, by proposing to adjust its base year opex to remove non-recurrent costs, AusNet Services' opex forecast incorporates a negative step change from 2014 levels. These factors demonstrate that AusNet Services' forecast is no more than what is required to achieve the opex objectives, and reflects the efficient costs of a prudent DNSP and is therefore in the long-term interests of customers.

[27] Productivity Commission, Electricity Network Regulatory Frameworks Inquiry Report, April 2013, p. 287.

[28] Ibid, p. 25.

The AER has recognised that the EBSS rewards DNSPs for making firm specific efficiency savings that may be over and above the forecast of industry-average productivity:

> *"Forecast opex must reflect the efficient costs of a prudent firm. To do this it must reflect the productivity improvements it is reasonable to expect a prudent NSP can achieve. This is consistent with the productivity improvements an efficient firm operating in a competitive market would be able to retain. All else equal, a price taker in a competitive market will maintain constant profits if it matches the industry average productivity improvements reflected in the market price. If it is able to make further productivity improvements, it will be able to increase its profits until the rest of the industry catches up, and this is reflected in the market price.* ***Similarly, if a NSP is able to improve productivity beyond that forecast, it is able to retain those efficiency gains for a period through the EBSS*** *[emphasis added]."*[29]

The application of a firm specific productivity improvement in the rate of change would effectively be pre-empting the productivity improvements the EBSS incentivises DNSP to achieve. AusNet Services considers this approach would undermine the incentive properties of the EBSS by precluding DNSPs from driving efficiency savings that ultimately flow through to customers.

Accordingly, it is emphasised that the productivity parameter in the rate of change should reflect a view of what the industry may be able to achieve, not the specific firm. However, there are a number of practical difficulties involved in measuring actual productivity in relation to electricity distribution networks, as well as forecasting movements in the industry's efficiency frontier.

Measuring productivity

A key challenge to accurately measuring productivity is appropriately defining and measuring the full range of outputs provided by networks because of the nature of the service they provide (i.e. the operation and maintenance of energy transportation infrastructure). Productivity is therefore often measured using proxies such as energy consumed, maximum demand or customer numbers. However, there are attributes of the network that provide benefit, and thus should be treated as outputs, that are difficult to quantify and account for. For example, the AER's changes in bushfire risk are not counted as output in the AER's opex MTFP benchmarking and productivity analysis, despite the fact that significant expenditure – which is counted as an input – is incurred to mitigate bushfire risk.

Furthermore, step changes that increase opex but leave outputs unaffected will reduce productivity, all else being equal. For example, a number of external factors necessitated the approval of large opex step changes for AusNet Services between 2006 and 2013, including increases in insurance premiums and vegetation management costs. As demonstrated in section 8.2.2, in the absence of exogenous factors AusNet Services' opex would have grown at just 1.5 per cent per annum between 2010 and 2014, compared with an actual growth rate of 5.5 per cent.

The AER has recognised that external factors will have an impact on productivity:

> *"The reason that overall productivity has been declining across the sector over the last eight years is that some outputs have remained relatively steady or declined while all or most distributors have increased input use significantly. We recognise however, that some of the decrease in productivity may be attributable to changes in obligations on the distributors."*[30]

Reductions in energy and demand in recent years, which form part of the AER's MTFP output index, have also contributed to AusNet Services' declining productivity due to the inability of network businesses to reduce opex when faced with declining outputs because of the largely fixed nature of their cost base. In particular, opex is considered fixed in the short- to-medium term with respect to energy.

[29] AER, *EFA Guideline Explanatory Statement*, p. 65.

[30] AER, *Electricity distribution network service providers – Annual benchmarking report*, p. 29.

These factors have heavily influenced the productivity change that AusNet Services has been able to achieve from 2006 to 2013, and must be considered carefully when interpreting the historical productivity trends observed by the AER. AusNet Services considers that in the absence of external factors and recent trends in some output variables, its productivity would have been materially higher than that calculated by the AER.

Productivity forecast

As noted above, the productivity forecast in the rate of change should reflect expected productivity change in the electricity distribution sector.

In its draft decision for TransGrid, the AER applied a productivity assumption of 0.86 in the rate of change, based on the industry average opex MPFP observed from 2006 to 2013. AusNet Services considers that applying this approach to Victorian DNSPs would be problematic. Firstly, it would result in a negative productivity assumption, running run counter to the regulatory regime AusNet Services operates within, which is designed to foster productivity improvement. Further, this approach would be forecasting productivity based on productivity measured over a period that is not indicative of the future levels of productivity, resulting in a forecast of total opex that does not reasonably reflects the opex criteria.

AusNet Services accepts that the AER's opex MTFP analysis is useful in forming a high level comparative view of efficiency where relevant. However, because of the practical difficulties involved in accurately gauging productivity, it is more valuable as an information tool. While these practical difficulties may be addressed as the AER's opex MTFP analysis matures and is refined, in its current form it should not be applied deterministically to set a firm's forecast opex.

Notwithstanding the limitations of the AER's opex MTFP measure, AusNet Services has been identified as among the top quartile of DNSPs with respect to opex productivity (as discussed in section 8.2.3), suggesting it is at the efficiency frontier of the electricity distribution industry. In the absence of evidence that suggests the efficiency frontier is improving, AusNet Services considers that applying a productivity adjustment in the rate of change would not produce the best forecast of total opex. The rate of change should therefore assume no change in productivity over the forthcoming regulatory period.

Accordingly, AusNet Services has not forecast any opex attributable to productivity changes for the forthcoming regulatory control period.

Table 8.7: Proposed non-labour escalators and cost increases ($m, real 2015)

	2016	2017	2018	2019	2020
Productivity change (%)	0.0%	0.0%	0.0%	0.0%	0.0%
Productivity ($)	0.0	0.0	0.0	0.0	0.0

Source: AusNet Services

Because this productivity forecast is not based on historical productivity for the aforementioned reasons, it does not capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice. However, by forecasting opex using an efficient base year, and proposing to absorb a number of step changes over the forthcoming period by making efficiency improvements, AusNet Services considers that its opex forecast meets the operating expenditure objectives and criteria. Despite the negative productivity observed in the industry historically, AusNet Services will continue to respond to the incentives provided by the EBSS by identifying and maintaining firm-specific efficiency savings over the forthcoming regulatory period, thus benefiting customers in the long-run.

8.3.5 Other costs

Insurance and self-insurance

AusNet Services has taken a holistic approach to risk management over the forthcoming regulatory period. AusNet Services proposes to utilise insurance where it is available and cost effective. The cost pass through provisions of the NER also provide a key regulatory mechanism to mitigate low likelihood and high severity risks (discussed in chapter 11).

However, for some risks, self-insurance is the most appropriate risk mitigation mechanism. These are:

- Uninsured risks – risks where the insurance market does not have the capacity or appetite to offer coverage, or risks that AusNet Services has elected to self-insure; and
- Insured risks (within deductible losses) – this covers risks where insurance coverage is utilised and losses fall within AusNet Services' deductible (or self-insured retention).

To develop forecasts of its insurance and self-insurance costs, AusNet Services engaged Aon, an appropriately qualified actuary. Aon has extensive experience forecasting insurance and self-insurance costs for electricity distribution businesses.

Aon provided:

- Insurance forecasts for property, liability, motor vehicle and other minor risk classes, including a new cyber liability policy; and
- Self-insurance forecasts for the poles and wires and bushfire liability risk classes.

Self-insuring the risks associated with poles and wires damage and the bushfire liability deductible is considered the most efficient treatment of these risks. This is because both obtaining insurance for poles and wires damage, or lowering AusNet Services' deductible to a level where within deductible losses are immaterial, would result in substantial increases to AusNet Services' insurance premiums. While AusNet Services has not obtained quotes on these increases, it is anticipated that they would exceed the associated reduction in its self-insurance costs. Consequently, it is in the long-term interests of customers to utilise self-insurance to manage these risks, rather than only externally provided insurance.

By removing poles and wires and bushfire liability losses from its base year opex, AusNet Services has ensured that its forecast self-insurance costs are being recovered solely through its self-insurance forecast and not through any other mechanism.

It is noted that the liability insurance premium includes a portion underwritten by AusNet Services' captive insurance company, AusNet Services Insurance Limited.[31] To ensure this portion of the coverage is procured on an efficient basis, the premium is determined by the captive manager, Aon, who balances global market rates against its experience as a leading provider of captive insurance services and internal rating models.[32]

AusNet Services provided a significant volume of data in order to ensure Aon's analysis accurately accounted for AusNet Services' loss history, thereby improving the robustness of the analysis. Aon's insurance and self-insurance reports can be found at Appendix 8A and Appendix 8B, respectively.

The following tables set out AusNet Services' proposed insurance and self-insurance costs. These costs account for approximately five and one per cent of total proposed opex, respectively.

[31] Because of a lack of cost-effective global capacity for bushfire liability insurance, AusNet Services Insurance Limited was established to increase AusNet Services' policy limit and increase competitive tension in the market.

[32] Aon, *Insurance Premium Forecast*, p. 9.

Table 8.8: Proposed insurance costs ($m, real 2015)

Risk class	2016	2017	2018	2019	2020	Total
Liability	9.2	9.9	10.5	10.8	11.0	**51.5**
Property	1.3	1.3	1.3	1.4	1.4	**6.7**
Motor	0.2	0.2	0.2	0.2	0.2	**1.0**
Other	0.5	0.5	0.5	0.5	0.5	**2.7**
New Policies	0.1	0.1	0.1	0.1	0.1	**0.4**
Total	**11.3**	**12.0**	**12.7**	**13.0**	**13.3**	**62.2**

Source: Aon, Insurance Premium Forecast – Ausnet Services Electricity Distribution, April 2015.

Table 8.9: Proposed self-insurance costs ($m, real 2015)

Risk class	2016	2017	2018	2019	2020	Total
Poles and wires	2.1	2.1	2.1	2.1	2.1	**10.5**
Fire liability	1.2	1.2	1.2	1.2	1.2	**6.1**
Total	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**16.6**

Source: Aon, Self Insurance Risk Quantifications – AusNet Services (Distribution) Ltd, January 2015.

The Aon forecasts represent category specific forecasts of insurance and self-insurance costs. There is a strong regulatory precedent for approval of such methodologies, with the AER approving this approach in AusNet Services' 2011-2015 electricity distribution and 2014-17 transmission reviews.

AusNet Services' current electricity distribution determination includes an explicit self-insurance allowance for poles and wires losses. By leaving fire liability losses in the base year opex used to determine AusNet Services' 2011-2015 opex allowance, the AER also approved an implicit self-insurance allowance for fire liability.[33] These are the same risk classes AusNet Services is proposing to self-insure over the forthcoming regulatory control period.

However, the AER appears to have changed its approach to forecasting self-insurance losses in its reviews of the NSW DNSPs and TNSP:

> *"In our past determinations we have not adopted a consistent approach to forecasting insurance and self-insurance costs. In some decisions we have included bottom-up forecasts for insurance and self-insurance. In other decisions these costs have just been included in base opex. We have reconsidered our approach to forecasting insurance and self-insurance costs and think these costs should be left in the base."*[34]

33 AER, *Victorian electricity distribution network service providers distribution determination 2011-2015 – final decision – appendices*, p. 460.

34 AER, *draft decision: TransGrid transmission determination 2015-18 – Attachment 7 – Operating expenditure*, p. 26.

The AER's justification for this approach is that:

> *"Using category specific forecasting methods for some opex categories may produce better forecasts of expenditure for those categories but this may not produce a better forecast of total opex. Generally it is best to use the same forecasting method for all cost categories of opex because hybrid forecasting methods (that is, combining revealed cost and category specific methods) can produce biased opex forecasts inconsistent with the opex criteria.*[35]

The AER has also stated:

> *"As outlined in our Guideline, base year expenditure is escalated by the forecast rate of change in opex, which includes forecast price change. If we exclude opex categories from our opex rate of change where expenditure is rising faster than total opex then the remaining categories will be rising at a slower rate than total opex or declining. If we apply the total opex rate of change to those remaining categories then the total opex forecast will systematically exceed the efficient level of opex."*[36]

The AER has also stated that "the NER requires us to form a view on forecast total opex, rather than on subcomponents such as insurance".[37]

Despite the AER's concerns, AusNet Services considers that there are strong grounds to separately forecast its insurance and self-insurance costs. The remainder of this section sets out AusNet Services' rationale for this approach.

Due to its weather conditions, climatic conditions and landscape, Australia is subject to a high level of bushfire risk. According to Aon:

> *"From the available data and information, it is apparent that there is a systemic risk of bushfire in Australia with the frequency of major events closely correlated with weather and climatic conditions. Longer and hotter fire seasons increase the risk of major fires and are often referred to as 'mega-fires'."*[38]

AusNet Services' service area is exposed to a particularly high level of bushfire risk, as evidenced by recent bushfire activity in the region, including the catastrophic 2009 bushfires. The evidence indicates that the impact of bushfires in terms of lives lost and buildings destroyed is significantly more pronounced in Victoria than in other Australian states and territories. The below table shows that between 1900 and 2009, there were 537 deaths as a result of bushfires in Victoria. This is more than twice the combined number of bushfire related deaths across the other jurisdictions shown, and demonstrates the catastrophic consequences bushfires have had in Victoria over the last century.

Table 8.10: Deaths as a result of bushfires by state, 1900 – 2009

	ACT	NSW	QLD	SA	TAS	VIC
Deaths	9	105	17	46	64	537

Source: Aon, Insurance Premium Forecast – AusNet Services Electricity Distribution, April 2015, Appendix 3.

AusNet Services' insurance costs have seen significant increases during the last decade, largely driven by increases to its liability policy premium. Aon reports that AusNet Services' liability premium increased sixfold between 2008-09 and 2014-15 due to:[39]

- Significant costs from the Black Saturday Bushfires in 2009 contributed to a direct 227% increase in insurance premiums from 2008/09 to 2009/10;

35 AER, *Ausgrid draft decision – Attachment 7: Operating expenditure*, p. 171.

36 Ibid, 173.

37 Ibid, 173

38 Aon, Insurance Premium Forecast, p. 7.

39 Ibid, p. 6.

- The cessation of a joint insurance program with Jemena at the 2013-14 renewal due to a corporate restructure, resulting in a 17% increase in the overall cost of Liability insurance;
- Increases to the overall policy limit in 2010-11 and 2012-13, which had a modest impact on the overall premium increase; and
- Insurance market factors, which have contributed to steady increases over the period and are expected to continue to influence premiums in the future.

The level of bushfire risk that AusNet Services faces has translated to the need for a liability policy limit that significantly exceeds those of its peers:

> *"AusNet has exhausted cost-effective market capacity for Bushfire Liability insurance in recent years, as evidenced by the fact that they are unable to secure their desired limit for a cost-effective price. … AusNet purchases the single highest bushfire limit of Aon's largest utility clients in Australia and globally and certainly has the highest limit of any utility company in Australia."*[40]

During 2014 and early 2015, AusNet Services settled three class actions arising from the Black Saturday bushfires. Two smaller bushfires that occurred in February 2014 led to two further class actions against AusNet Services, which the company is vigorously defending. AusNet Services does not believe it was negligent and believes it acted prudently at all times. Whilst these matters are still before the courts, they demonstrate the ongoing potential for future liability losses given the high level of bushfire risk AusNet Services' distribution area is exposed to.

In light of these circumstances, AusNet Services is of the view that the AER's approach of rolling forward base year insurance premiums and self-insurance losses at the rate of change should not be applied to AusNet Services.

The AER's preferred approach is particularly concerning for insurance costs because these costs are a significant component of the opex forecast, accounting for approximately $62 million, or around five per cent of AusNet Services' total forecast opex. Under the AER's approach, including these costs in the base year implies that a similarly large amount of opex is rising slowly or declining at a rate that sufficiently offsets insurance cost increases.

As it is not required for the top-down approach used to forecast opex, AusNet Services has not developed a forecast of all individual cost categories to assess whether there are cost items that might offset insurance premium cost increases. However, given the quantum of its insurance premiums relative to other costs, and its identification of negative step changes, AusNet Services considers it a reasonable likelihood that such offsets would not exist.

Accordingly, if insurance costs are rolled forward as part of base year opex, AusNet Services would be unlikely to recover at least its efficient costs at a total opex level given the magnitude of its insurance premiums. Such an outcome would be inconsistent with the Revenue and Pricing Principles. It would also be inconsistent with the NEO because it is not in the long term interests of electricity consumers that a DNSP is constrained in its ability to insure for events that may affect the safety and security of consumers, and of its network.

It is notable that Aon's forecast assumes a modest annual increase in the premium rate (the midpoint of the range of possible increases) to the liability premium. Given the recent class-actions against AusNet Services in relation to the February 2014 Mickleham Road and Yarram fires, there is some likelihood that actual premium rate increases will exceed this assumption.

AusNet Services' benchmark allowance for its insurance costs has historically been set using a category specific forecasting method to account for the unique factors driving insurance costs, and the industry knowledge and expertise required to develop an insurance premium forecast. The figure below shows that AusNet Services' electricity distribution insurance costs have exceeded the forecasts approved in some years of the current period. In total, actual insurance costs have been around four per cent higher than forecast.

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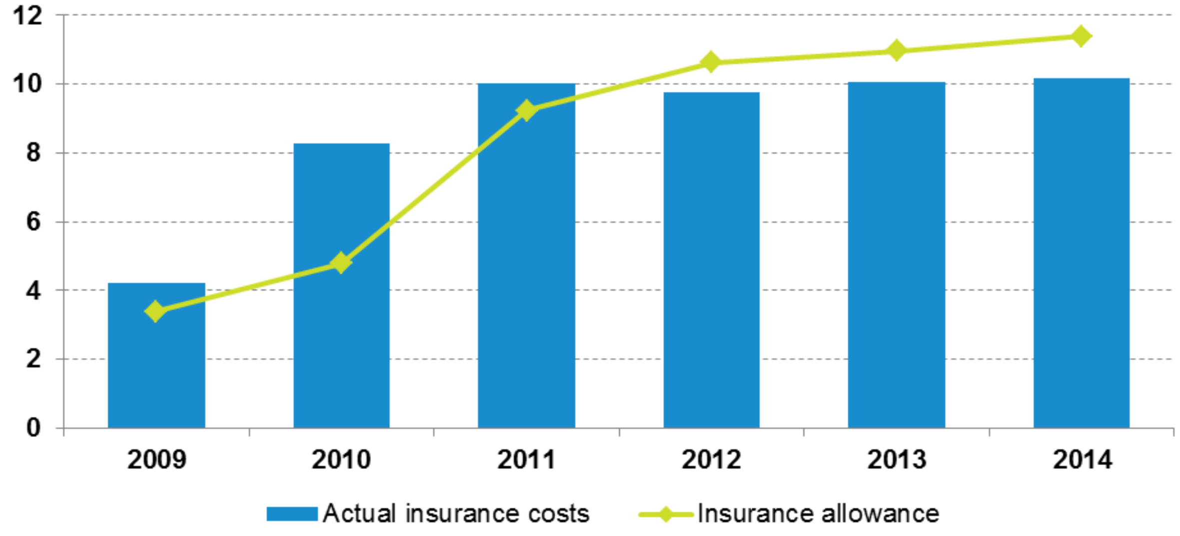
40 Aon, *Insurance Premium Forecast*, p. 9.

Figure 8.6: Actual insurance costs against regulatory allowance ($m, end 2015)



Source: AusNet Services

This figure demonstrates that AusNet Services' forecast insurance costs have been largely accurate. However, it also suggests that rolling forward base year insurance premiums over the next regulatory control period, which typically produces a lower forecast than a category specific method, creates a real risk that AusNet Services will not recover its efficient insurance costs going forward.

Further, in relation to the AER's concern with using a bottom-up approach to forecasting some costs, it is noted that the insurance forecast has been developed by applying a growth rate to AusNet Services' base year insurance costs and is therefore not a bottom-up approach per se. The use of revealed costs as a starting point for forecast insurance costs is expected to give the AER comfort that AusNet Services' insurance forecasts reasonably reflect a realistic expectation of its future input costs.

In relation to self-insurance, the AER's approach assumes that self-insurance losses in the base year will be representative of losses over the forthcoming period. Self-insurance losses are by nature volatile and can vary markedly from year to year. For this reason, the quantification of these losses is best suited to an actuarial analysis that forecasts self-insurance based on expected losses determined from historical data, rather than on actual losses in a single year. The AER's approach is unlikely to result in a more accurate forecast of self-insurance than such an analysis, particularly when base year opex is influenced by abnormal events such as a bushfire.

While the AER has stated that the NER requires it to form a view on total opex, this has not precluded it from approving category specific opex forecasts in recent reviews. For example, in its review of TransGrid's opex, the AER forecast defined benefits superannuation costs on a category-specific basis "because doing so produces a more recurrent and stable opex series."[41] By doing so, the AER used a category specific method for these costs, but a revealed-cost for other opex categories.

The same can be said for the AER's approach to other cost categories in the 2011-2015 electricity distribution price review. In that review, the AER forecast GSL payments using a five-year historical average, rather than base year costs which it considered were not representative of costs over the forthcoming regulatory control period.[42]

This shows the AER's willingness to adopt category specific forecasting approaches where doing so produces a more accurate forecast of total opex. This is consistent with the AER's statutory

41 AER, *draft decision: TransGrid transmission determination 2015-18 | Attachment 7 – Operating expenditure*, p. 28.

42 AER, *2011–2015 Victorian electricity distribution network service providers distribution determination, draft decision*, p. 242.

obligation to perform its economic regulatory functions in a manner that will or is likely to contribute to the achievement of the NEO.

AusNet Services considers that its insurance and self-insurance costs are consistent with a forecast of total opex that represents the costs that a prudent operator would require to achieve the opex objectives, and therefore should be accepted by the AER.

Guaranteed Service Level (GSL) payments

Under the electricity distribution code administered by the ESCV, AusNet Service must provide a guaranteed level of service to customers. This includes minimum standards for appointments, new connections, supply restoration and sustained and momentary interruptions. If these standards are breached for an individual customer, the code requires AusNet Services to give financial compensation to the customer by way of a GSL payment.

AusNet Services' proposed GLS payments have been forecast based on the average of actual GSL payments over the last five years (i.e. from 2010 to 2014). This is consistent with the approach approved by the AER in the 2011-2015 electricity distribution price review. GSL payments account for around two per cent of total forecast opex.

Table 8.11: Proposed GSL payments ($m, real 2015)

	2016	2017	2018	2019	2020	Total
GSL payments	5.6	5.6	5.6	5.6	5.6	**28.0**

Source: AusNet Services

Debt raising costs

AusNet Services proposes to forecast its debt raising costs by rolling these costs forward as part of base year opex. This approach contrasts with the current regulatory control period, where costs have been calculated in accordance with the methodology contained in the PTRM.

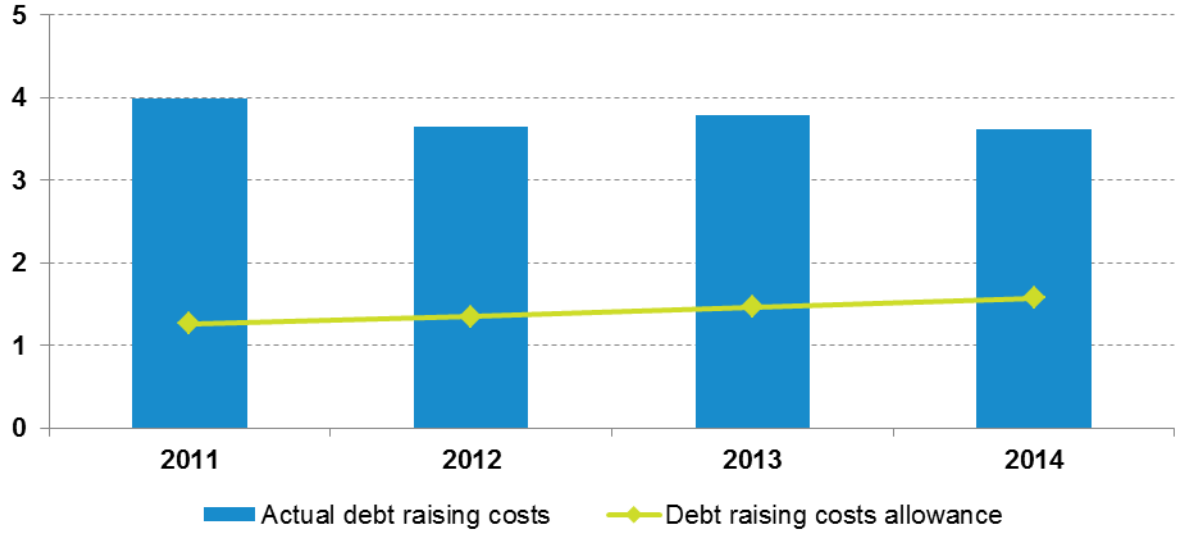
As established in section 8.2, AusNet Services' base year opex is efficient, reflecting the company's response to the incentives embedded in the regulatory framework. The exclusion of debt raising costs from EBSS calculations for the current period strengthens the incentive to minimise debt raising costs because when costs exceed the benchmark, AusNet Services bears 100 per cent of the cost overrun. This contrasts with cost categories included in the EBSS, where 30 per cent of cost overruns are borne by AusNet Services. While this incentive is weakened in the base year, the figure below evidences that AusNet Services' base year costs are reflective of costs in other years of the current period.

The use of an external benchmark to set debt raising costs, rather than revealed costs, has further strengthened the incentive to minimise debt raising costs during the current period. This is because any cost savings achieved against that benchmark are retained, rather than used to set a new, lower benchmark for future regulatory periods.

On this basis, AusNet Services considers that its debt raising costs reflect the costs of a prudent and efficient DNSP, and thus should be rolled forward as part of base year opex.

The below figure, which shows actual and approved debt raising costs during the current period, demonstrates that AusNet Services' actual costs of $15 million have significantly exceeded the AER's allowance of $5.6 million. The figure also shows that actual debt raising costs have been relatively stable from year to year. This reflects the recurrent nature of the activities, and expenses, involved in raising debt each year. It is noted that debt raising costs in the base year are slightly lower than in the other years of the current period.

Figure 8.7: Actual debt raising costs against regulatory allowance ($m, end 2015)



Source: AusNet Services

In its draft decision for AusGrid, the AER has stated that under the previous 'on-the-day' approach to setting the allowed return on debt, it considers that an efficient debt financing practice would have been:

- *"to borrow long term (10 year) debt and stagger the borrowing so that only a small proportion (around 10 per cent) of the debt matured each year*
- *to borrow using floating rate debt (or to borrow fixed rate debt and convert this to floating rate debt using fixed-to-floating interest rate swaps at the time of issuing the debt and which extended for the term of the debt, being 10 years), and*
- *to enter into floating-to-fixed interest rate swaps at, or around, the time of the service provider's averaging period and which extended for the term of the regulatory control period, being typically 5 years)."*[43]

AusNet Services' approach aligns with the AER's view of efficient debt raising practices because its debt raising costs, which include legal fees, banking fees and credit rating agency fees, reflect the cost associated with the first dot point – that is, the cost of issuing debt on a staggered basis.

In summary, AusNet Services proposes to include debt raising costs in base year opex because:

- This approach results in a forecast that more accurately reflects AusNet Services' actual, efficient debt raising costs and thus contributes to a total opex forecast that reasonably reflects the opex criteria;
- Debt raising costs are largely stable from year to year, indicating that base year costs are likely to be reflective of costs over the forthcoming period; and
- AusNet Services' debt financing practices align with the AER's view of efficient practices.

This below table shows AusNet Services' proposed debt raising costs, which account for around two per cent of total proposed opex.

[43] AER, *AusGrid draft decision*, pp. 3-171.

Table 8.12: Proposed debt raising costs ($m, real 2015)

	2016	2017	2018	2019	2020	Total
Debt raising costs	3.7	3.8	4.0	4.1	4.2	**19.9**

Source: AusNet Services

Should the AER continue to use the PTRM benchmark approach, AusNet Services considers that the current assumption of 9.1 basis points should be revised to include liquidity costs and early refinancing costs of debt.

DMIA

AusNet Services has identified a number of high priority projects that will provide an expanded future capability in demand management. The priority projects focus on developing capability in residential demand management technologies, building on the current technical trials of battery storage to move into a commercialisation trial and undertaking technical trials of thermal energy storage as an alternative approach to battery storage. To fund these important projects, AusNet Services proposes a DMIA of $10 million, which accounts for around one per cent of total opex.

Table 8.13: Proposed Demand Management Innovation Allowance ($m, real 2015)

	2016	2017	2018	2019	2020	Total
DMIA	1.5	2.0	2.5	2.5	1.5	**10.0**

Source: AusNet Services

Within the 2016-20 period AusNet Services is planning a rapid transfer into business-as-usual for some of the techniques that will be trialled under the DMIA. In particular, air conditioning load control and peak demand incentives are planned to be developed under DMIA in the early part of the 2016-20 period and then deployed to defer feeder augmentation projects in the latter part of the period. It is therefore critical that these techniques are trialled as a priority.

Chapter 9 provides further information on AusNet Services' demand management strategy, including proposed DMIA project details.

8.3.6 Cost roll ins

AusNet Services is including a number of opex costs in the forthcoming regulatory control period that were previously recovered outside the price cap in the current period. Specifically:

- The cost of a large network support contract, previously recovered through an adjustment to the tariffs during the annual tariff setting process; and
- Ongoing costs associated with AMI smart meter program upgrades to core distribution systems (such as the billing system) where it is now appropriate to subsume them into the standard control distribution service.

These costs are discussed in detail below.

Bairnsdale Power Station network support costs

Since 1998, AusNet Services has contracted with Bairnsdale Power Station (BPS) to provide network support in the East Gippsland region. This generation, which is used to support East Gippsland through the daily hot water and afternoon peaks when demand can exceed the firm capability of the network, has deferred a significant amount of augmentation expenditure.

The cost of this network support during the current period has, on average, been [C-I-C] (real 2015) per annum. These costs are forecast to decline in real terms over the forthcoming period.

The below figure shows actual and forecast network support payments to BPS.

Figure 8.8: Actual and forecast Bairnsdale Power Station network support payments ($m, real 2015)

[C-I-C]

Currently, BPS costs are recovered through the annual pricing process, in accordance with the ESC's treatment of this cost. In March 2011, the AEMC released a rule change determination, specifying that:

- The recovery of Bairnsdale network support payments through the annual pricing process should be grandfathered for the 2011-2015 and 2016-20 regulatory periods; and
- Network support payments should be recovered through the price determination process, rather than through annual pricing submissions.[44]

In accordance with the principles set out in the rule change relating to the recovery of network support payments, AusNet Services propose to include its BPS costs in its proposed opex for the forthcoming regulatory period. This is also consistent with the AER's preferred treatment of network support payments, which is to include them in EBSS calculations.[45]

The table below sets out AusNet Services' proposed BPS costs. These costs account for around [C-I-C] of total proposed opex.

Table 8.14: Proposed Bairnsdale Power Station network support payments ($m, real 2015)

[C-I-C]

44 AEMC, *Rule determination - National Electricity Amendment (DNSP recovery of transmission-related charges) Rule 2011*, March 2011, p. 11.

45 AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, pp.108-109.

Costs from distribution systems upgraded under AMI

Consistent with AusNet Services' approved cost allocation methodology (CAM) and long standing practice, metering charges for the forthcoming regulatory control period will calculated on an incremental costs basis.

Practically, this means that many distribution business systems, as opposed to dedicated metering systems, that were upgraded as part of the AMI project will now be subsumed into the distribution service. Examples include billing and B2B (data to market) systems that are required to fulfil distribution services and would exist even in the absence of a metering service.

Specifically, AusNet Services has included all opex on systems and assets that are required for the standard control network service, and particularly the Local Network Service Provider (LNSP) function outlined in the NER, in its distribution use of system charges.

The new allocation results in the following additions of operating expenditure:

- The inclusion of forecast communication and IT (ex-Meter Management System) opex in the standard control IT opex; and
- Overheads that were previously being allocated into the AMI project now being recovered in the core distribution network service.

The costs are shown in the table below, which account for approximately seven per cent of total proposed opex. The costs are expected to decline by 30 per cent over the period due to lower licencing costs and increasing IT opex efficiency from the remediation investment. AMI costs account for around [C-I-C] of the total opex forecast.

Table 8.15: Costs from distribution systems upgraded under AMI ($m, real 2015)

[C-I-C]

Opex consistency

While they are not new costs, the above cost roll ins are considered significant variations in forecast standard control services operating expenditure from historical standard control services operating expenditure.

In accordance with S6.1.2(7) of the NER, the below table sets out opex for each of the past regulatory years of the previous and current regulatory control period, and the expected operating expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the operating expenditure forecast. As discussed in section 8.3.5, debt raising costs have been forecast as part of base opex for the forthcoming regulatory control period.

Table 8.16: Historical standard control services opex ($m, real 2015)

Regulatory Year	Standard control services	Debt raising costs	Bairnsdale Power Station	AMI	Total
2006	106.7	-	[C-I-C]	[C-I-C]	**[C-I-C]**
2007	130.0	-	[C-I-C]	[C-I-C]	**[C-I-C]**
2008	143.3	-	[C-I-C]	[C-I-C]	**[C-I-C]**
2009	162.0	-	[C-I-C]	[C-I-C]	**[C-I-C]**
2010	159.9	-	[C-I-C]	[C-I-C]	**[C-I-C]**
2011	162.3	4.0	[C-I-C]	[C-I-C]	**[C-I-C]**
2012	171.2	3.7	[C-I-C]	[C-I-C]	**[C-I-C]**
2013	197.1	3.8	[C-I-C]	[C-I-C]	**[C-I-C]**
2014	198.1	3.6	[C-I-C]	[C-I-C]	**[C-I-C]**
2015	200.8	3.7	[C-I-C]	[C-I-C]	**[C-I-C]**
2016	207.4	3.7	[C-I-C]	[C-I-C]	**[C-I-C]**
2017	214.2	3.9	[C-I-C]	[C-I-C]	**[C-I-C]**
2018	221.6	4.0	[C-I-C]	[C-I-C]	**[C-I-C]**
2019	227.7	4.1	[C-I-C]	[C-I-C]	**[C-I-C]**
2020	232.8	4.2	[C-I-C]	[C-I-C]	**[C-I-C]**

Source: AusNet Services

Note: Includes movements in provisions

8.3.7 Step changes

The Explanatory Statement to the Expenditure Forecasting Assessment Guideline sets out the AER's approach to assessing step changes. In short, the AER considers that:

> *"The rate of change may not capture all cost changes that reasonably reflect the opex criteria. For this reason, we will also add step changes to our opex forecast where they are necessary to produce a forecast that is consistent with the opex criteria."*[46]

Accordingly, AusNet Services has taken the opex criteria into account when identifying potential step changes over the forthcoming regulatory control period. In particular, AusNet Services has ensured that any proposed step changes reasonably reflect the efficient costs of achieving the opex objectives. The price impact of these step changes has also been carefully considered, given the impact of opex growth on customer bills.

AusNet Services' approach to identifying step changes involved:

- Determining the impact of anticipated regulatory changes on costs, and the appropriate regulatory mechanism to deal with these impacts (e.g. step change, pass through etc.);
- Reviewing the substitution possibilities between opex and capex to identify opportunities for efficient opex-capex trade-offs; and
- Assessing AusNet Services' ability to fund future cost increases attributable to external obligations by making efficiency savings, particularly through the expected benefits of Project WorkOut.

46 AER, *EFA Guideline Explanatory Statement*, p. 71.

In particular, AusNet Services has elected to address the potential cost impacts of some regulatory changes (e.g. Power of Choice) using the cost pass through provisions of the NER, rather than by proposing step changes. This approach is considered to best serve the long-term interests of consumers given the uncertainty around these cost impacts at the time of this Proposal.

AusNet Services' consideration of these matters takes into account the factors the AER is required to have regard by NER 6.5.6(e) in determining whether it is satisfied whether the opex forecast reasonably reflects the opex criteria.

AusNet Services' step change review process identified nine positive step changes that warranted further consideration.

Table 8.17: Identified step changes ($m, real 2015)

Step Change	Description	2016-20 opex	Proposal treatment
Partial discharge testing of underground cables	New technology to test condition of underground cables to determine replacement requirements, with the intention of reducing replacement capex.	$3.75m	Absorbed
Establishment of Emergency Management Victoria (EMV)	Additional opex may relate to: new training requirements, new reporting obligations, increased security at key distribution assets, software updates to emergency management systems, increased man hours at security desk, etc.	$2.5m	Absorbed
Other Responsible Parties (ORP) Change Responsibility	Additional vegetation management required due to change in legislation relating to ORPs (includes railways, schools, water authorities, etc.).	$2.5m	Absorbed
LIDAR	Use of LIDAR to provide aerial view of overhead lines and vegetation. This technology has been implemented to provide more effective information and reduce risk in overhead network.	$1.5m	Absorbed
Rent increases	Rent increases are expected from 2018 at the Lilydale site.	$0.25m	Absorbed
IT systems	Increased opex associated with the deployment of new SAP systems, the transition to cloud-based solutions for some IT requirements, and supporting regulatory changes and new business capabilities.	$7.0m	Absorbed
Additional spacers survey scope	Based on the results of field audits, there has been an increase in the volume of spans to be surveyed above what was included in the scope of the VBRC cost pass through.	$0.6m	Absorbed
Zone substation decommissioning	Retirement and removal costs for zone substation and line assets in East Region.	$1m	Absorbed
Demand management	Increased opex to defer augmentation capex, mitigate increasing energy at risk and implement broad-based demand management programs.	$4.8m	Proposed
Total step changes		**$24m**	
Total proposed		**$4.8m**	
Total absorbed		**$19.2m**	

Source: AusNet Services

Of the potential positive step changes identified, AusNet Services intends to include only a demand management step change of $4.8 million in the opex forecast. This step change, which accounts for less than one per cent of total proposed opex, is included because:

- These costs are necessary to facilitate an efficient opex-capex trade-off and therefore the expenditure reasonably reflects the prudent and efficient costs of achieving the opex objectives;
- An expanded demand management capability aligns with AusNet Services' response to uncertainty over future technology and energy demand and consumption patterns; and
- The AER has stated that "it may be efficient to increase opex if it reduces a NSP's capital costs."[47]

Importantly, AusNet Services' proposed demand management opex has not been provided for in other components of its opex forecast, such as base year opex or the rate of change.

The proposed demand management step change, which is recurrent in nature and will affect the non-network alternatives costs expenditure category, will allow AusNet Services to:

- Defer a number of augmentation projects slated for forthcoming period, thereby ensuring that the total revenue forecast represents AusNet Services' prudent and efficient costs;
- Mitigate the increasing energy at risk expected over the forthcoming period by expanding the existing portfolio of commercial and industrial demand response contracts; and
- Implement broad-based demand management programs that will generate substantial long-term capex savings.

These initiatives, which represent efficient trade-offs between capex and opex and are thus in the long-term interests of AusNet Services' customers, are discussed in detail in Chapter 9 Demand Management. Given the benefits that will accrue to consumers if AusNet Services proceeds with the demand management step change, excluding it from the total opex allowance will impede AusNet Services' ability to meet and managed expected demand in the most efficient manner. Further, it will preclude AusNet Services from being given a reasonable opportunity to recover the efficient costs it incurs in providing direct control services.

AusNet Services considers the primary risk of not implementing these initiatives and adopting a 'do nothing' approach is increased augmentation expenditure on long-lived network assets, which is not considered prudent at a time when there is considerable uncertainty associated with future demand and energy consumption trends and thus the need for these assets.

AusNet Services also considers that the adjustments made to its base year opex to remove non-recurrent costs constitute negative step changes. These costs, which comprise non-recurrent VBRC costs of $8.1 million and superannuation defined benefit schemes costs of $1.2 million over the forthcoming period, more than offset the proposed demand management step change. Accordingly, AusNet Services is proposing a negative step change from its 2014 base year opex.

[47] AER, *EFA Guideline Explanatory Statement*, p. 72.

The below table shows AusNet Services' proposed step change opex for the forthcoming regulatory control period.

Table 8.18: Proposed step change opex ($m, real 2015)

	2016	2017	2018	2019	2020	Total
Demand management	0.5	0.5	1.1	1.3	1.4	**4.8**
Non-recurrent VBRC	-1.5	-1.6	-1.6	-1.7	-1.7	**-8.1**
Superannuation defined benefit schemes	-0.2	-0.2	-0.2	-0.2	-0.3	**-1.2**
Total	**-1.3**	**-1.3**	**-0.7**	**-0.7**	**-0.6**	**-4.6**

Source: AusNet Services

Note: Non-recurrent VBRC and superannuation defined benefit schemes costs are included in the calculation of AusNet Services' base year opex.

8.4 Total Forecast Opex

The total forecast of opex required to meet the opex objectives is $1.26 billion. This translates to average annual opex over the 2016-20 period of $251 million, around six per cent higher than base year (2014) opex of $238 million. This equates to average annual growth of 1.5 per cent from 2014 to 2020. The below table shows a breakdown of the opex forecast by component, as well as actual opex in 2014 for comparative purposes. Note that 2014 opex includes cost roll ins that have been recovered outside of the price cap during the current regulatory control period.

Table 8.19: Actual and forecast opex ($m, real 2015)

Opex Component	2014	2016	2017	2018	2019	2020	2016-20 Total	
	Current period	Forthcoming period					$	%
Base opex	182	183	183	183	183	183	**913**	**72.7%**
Real price change	n/a	4	7	10	13	16	**49**	**3.9%**
Output growth	n/a	3	5	8	10	13	**39**	**3.1%**
Step changes	n/a	0	0	1	1	1	**5**	**0.4%**
Self-insurance	2	3	3	3	3	3	**17**	**1.3%**
DMIA	0	2	2	3	3	2	**10**	**0.8%**
GSL payments	7	6	6	6	6	6	**28**	**2.2%**
Insurance	10	11	12	13	13	13	**62**	**5.0%**
Cost roll ins	37	30	29	28	24	22	**133**	**10.6%**
Total opex	**238**	**241**	**247**	**254**	**256**	**259**	**1,256**	**100%**

Source: AusNet Services

Note: 2014 opex includes debt raising costs and excludes movements in provisions; 2014 DMIA costs represent only DMIA expenditure attributable to opex; the higher base opex between 2014 and the forthcoming regulatory control period reflects the efficient benchmark increase approved by the AER for the current period; the non-recurrent VBRC and superannuation defined benefit schemes negative step changes are included in the calculation of base year opex.

8.5 Supporting Documents

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 8A – Aon Insurance Report (confidential);
- Appendix 8B – Aon Self-Insurance Report;
- Appendix 8C – CIE Labour Price Forecast Report;
- AusNet Services ASU/APESMA Enterprise Agreement 2013;
- AusNet Services ETU Enterprise Agreement 2013;
- Bairnsdale Power Station Network Support Agreement (confidential); and
- Spreadsheet entitled “AusNet Services - 2016-2020 EDPR Opex Model_PUBLIC.xlsx”.

9 Demand Management

9.1 Overview

9.1.1. Introduction

Managing peak customer and network electrical demand by means other than network asset augmentation offers significant benefits to customers by reducing the level of network capital expenditure that is required to be recovered through tariffs. AusNet Services has a strong history of deploying demand management technologies across its network where doing so promotes efficient network investment and is in the long term interests of customers.

AusNet Services intends to continue to build its demand management capability during the forthcoming regulatory control period to ensure it continues to deliver safe, reliable and secure electricity services at efficient prices. This chapter details the expenditure AusNet Services considers necessary over the forthcoming period to achieve this.

9.1.2 Background

During the current regulatory control period, AusNet Services significantly increased its expertise in demand management and non-network solutions. A dedicated team was established both to undertake demand management trials and to drive the development and implementation of non-network solutions to defer capex efficiently. The work of the demand management team has resulted in AusNet Services, for example:

- Establishing a portfolio of demand management curtailment contracts with selected commercial and industrial customers;
- Introducing a critical peak demand tariff for large customers;
- Installing a permanent embedded generation facility at Traralgon;
- Deploying containerised mobile generators; and
- Undertaking innovative technology trials focussed on battery storage.

These initiatives supplement existing demand management arrangements such as the Bairnsdale Power Station network support contract and using off-setting time-clocks to flatten manage hot water peak loads.

The demand-side solutions deployed to date during the current regulatory control period amount to 25MW in generation, load curtailment and storage, and allowed AusNet Services to defer $11 million of capital augmentation expenditure.

The experience gained during the current regulatory period has increased the range of non-network options AusNet Services has access to, and allows for an increased level of deployment during the coming period. In addition, the wide-scale roll-out of smart meters and reduced costs of storage technologies allows AusNet Services to trial new demand management techniques that directly target residential peak demand. Taking these factors into consideration, AusNet Services proposes an increased level of demand management operating expenditure during the 2016-20 regulatory control period. The impetus for increased demand management opex is in spite of slowing in the growth of forecast aggregate peak demand across the distribution network.[1] This is because in times of slow demand growth, efficient opex-capex trade-offs can still be made by deferring augmentation projects. Broad-based demand management initiatives can also offer long-term benefits to customers by constraining the long term augmentation requirements of the network. Finally, during

[1] Maximum demand (non-coincident summated raw system maximum demand measured at the transmission connection point in MW) grew at an average annual rate of 2.3 per cent from 2006 to 2014, compared with forecast growth of 1.1 per cent for 2016-20 regulatory control period.

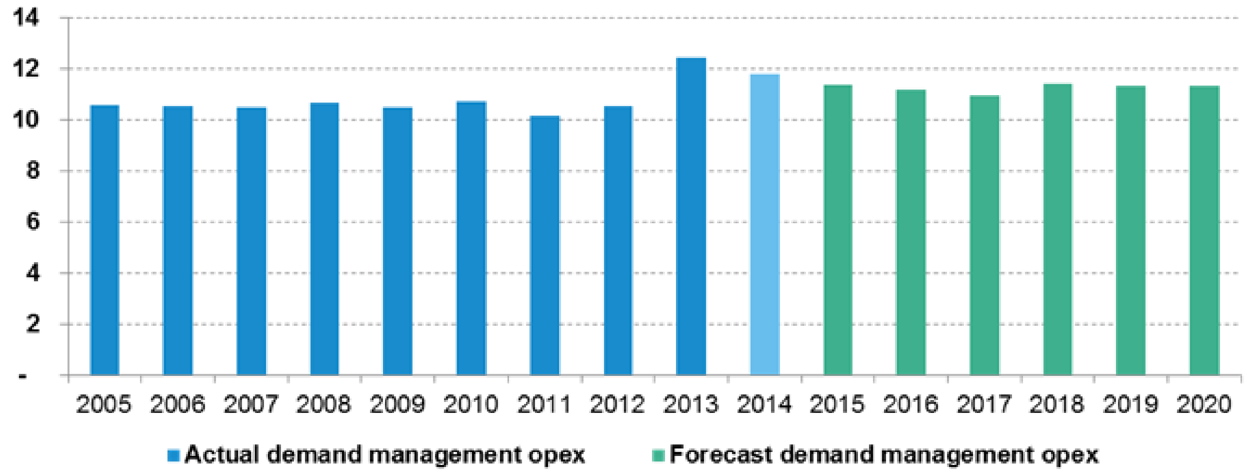
times of slow or flat demand growth, energy at risk (refer to Box 9.1 below) may persist in particular parts of the network for extended periods of time. This creates an opportunity to use demand management techniques to mitigate energy at risk, generating consumer benefits by reducing the likelihood of load shedding events, particularly during periods of high demand or during asset failures.

By the end of the next regulatory period, AusNet Services aims to deploy a further 39MW of demand management alternatives, which are expected to defer an additional $10 million of augmentation capex and significantly reduce the levels of energy at risk to which customers are exposed.

To deliver this program, AusNet Services is proposing demand management opex of $13 million (real 2015), which represents a total step change of $4.8 million (real 2015) over the forthcoming period, as well as an increase in the DMIA from $3 to $10 million. This includes the costs of an additional FTE, which is considered necessary to deliver the proposed larger demand management program.

The figure below shows AusNet Services' actual and forecast demand management opex spending (excluding DMIA). AusNet Services has a proven long-term track record of implementing demand management, including establishing network support contracts with Bairnsdale and Somerton Power Stations that have enabled the deferral of substantive capex.

Figure 9.1: Actual and forecast demand management opex, 2005-20 ($m, real 2015)



Source: AusNet Services

Box 9.1: Key demand management concepts

N-1 refers to the operating condition where one major network element is out of service**.** For example, the capability of a zone substation with one transformer out of service is referred to as the station's 'N-1' rating, with the capability of the station with all transformers in service referred to as its 'N' rating. These scenarios are known as the N-1 and N conditions, respectively. Under a probabilistic approach to electricity distribution network planning, the cost and probability of an outage under the N-1 condition are used to help determine whether network augmentation is justified.

Load at risk measures the maximum forecast load on an asset minus its rated capacity of that asset. For example, a zone substation with a maximum forecast load of 45MW and a rated capacity of 40MW feeder has 5MW load at risk. For a multi-transformer substation, capacity is measured assuming one transformer has failed (i.e. the N-1 condition).

Energy at risk measures the annual amount of energy that would be unable to be delivered to customers in a part of the network under an N-1 scenario. Energy at risk is therefore the load at risk times the number of hours that the asset or station supplying that part of the network is forecast to be above its rated capacity. Figure 9.4 in this chapter provides a visual demonstration of energy at risk.

9.2 Operating Environment

9.2.1 Lower growth projections

The focus of the demand management program is shifting as patterns of network use change. With slower growth in peak demand, there is less need for demand management targeted at deferral of specific capital projects. Increasingly, demand management has a critical role to play in sustainably constraining long term augmentation requirements, and in efficiently managing energy at risk on the network.

Growth in network peak demand is becoming more geographically concentrated on urban residential growth corridors. In these locations, AusNet Services' established non-network solutions, such as embedded generation and commercial and industrial customer demand management contracts, have limited applicability. Developing demand management techniques that address residential peak demand at-source is critical in order to manage demand growth efficiently in these areas. AusNet Services has, therefore, identified a number of new residential-focussed techniques to trial using the Demand Management Innovation Allowance (DMIA). The techniques are expected to include voluntary load control of air-conditioners, incentive-based demand response schemes and aggregated battery storage.

If these residential demand management techniques are successful, and if it is economic to do so, they will be rolled out to defer specific network capex projects, and as broad-based programs to supress network-wide growth in residential peak demand over the longer term. AusNet Services expects these techniques will offer significant long term capex deferral benefits in urban locations.

9.2.2 The smart meter roll-out

The smart meter roll out has also transformed the availability of data for network management and planning, and created opportunities to translate this data potential it into real benefits for customers. For example, deployment of residential focussed demand management and the need to handle increasing levels of customer-driven distributed energy (such as solar generation) will require support from increased network modelling capabilities and toolsets to analyse the performance of the low voltage network as an essential pre-requisite.[2] Capital expenditure to establish this fundamental low voltage modelling capability has been proposed in chapter 7, and will enable the full customer benefits of residential demand management to be realised.

In addition to developing these new techniques, AusNet Services will continue to evaluate and, where economically efficient, deploy existing demand management techniques such as embedded generation and commercial and industrial demand management contracts.

9.2.3 Planning consequences of the Value of Customer Reliability changes

In Victoria's probabilistic planning framework, lower levels of demand growth combined with the lower value of customer reliability will have consequences for customer outcomes because of their impact on future network augmentation. Lower demand growth and value of customer reliability mean that the level of load at risk (refer to Box 9.1 above) on zone substations is forecast to increase only gradually during the 2016-20 regulatory control period. Accordingly, it is unlikely that new zone substations or capacity-driven zone substation projects will be justified. The subsequent longer time period between network upgrades can leave load at risk for many years, even decades. In parts of the network where load is at risk, customers are exposed under peak demand conditions to the risk of load shedding (i.e. being temporarily disconnected from the network) to prevent damage to electrical equipment or the disconnection of all customers in that part of the network.

In order to manage this increasing level of risk efficiently, AusNet Services intends to increase the portfolio of demand management contracts with commercial and industrial customers where the benefits to customers of reducing the risk of asset overloads and load shedding outweigh the long term operating costs.

[2] Low voltage network refers to 230V single phase supplies up to the 22kV side of distribution transformers.

Commercial and industrial demand management contracts also offer a flexible means of efficiently deferring capacity driven capital expenditure on feeders and zone substations. They also offer an additional tool to respond rapidly to contingency events, in effect acting as a form of risk-mitigation.

Given the challenges associated with efficiently managing a large portfolio of demand management contracts, and to optimise the performance of the portfolio, AusNet Services intends to trial an automated management platform that can coordinate the dispatch of demand response events and integrate with network operations.

9.3 Customer Engagement

Demand management and alternative technologies are some of the key areas of customer interest identified by AusNet Services through the community forums and technical workshops it has conducted. In particular, customers have expressed support for continued investment in demand management and innovative technologies to provide future alternatives to capital investment.

Customers considered investing in innovation was good business practice providing benefits to the business as well as the community. They were concerned that they do not pay twice where benefits pay for themselves.

Innovation was more strongly supported when delivering benefits to the broad customer base, such as improvements in:

- Reliability;
- Community Safety; or
- Efficiency.

When first mentioned, there was some scepticism towards the concept of the 'smart grid' and some concern expressed that investments in alternative technology benefits only a minority of the customer base. However, when provided with examples of benefits generated from the current period, such as the ability of alternative energy sources to reduce pressure on the network, customers were impressed with what could be achieved, particularly with the data from smart meters.

Further, a $7 million increase in the Demand Management Innovation Allowance proposed by AusNet Services was tested in focus groups and received positive support.

Consistent with the feedback received from its customers, AusNet Services has proposed an extensive and cutting edge demand management program, including a substantial increase in the DMIA. This program will be effective given the improved spatial demand forecasting capability AusNet Services has developed during the current period. AusNet Services considers expenditure in this area is timely given caution around investing further in long term assets when energy consumption is falling and embedded generation and off network energy solutions are becoming more viable. Importantly, demand management ensures reliability can be maintained without locking customers into paying for long-term network costs.

9.4 Structure of this Chapter

The remainder of the chapter is structured as follows:

- Section 9.2 provides a high level of summary of the demand management proposal;
- Section 9.3 sets out the proposed demand management to defer capex;
- Section 9.4 sets out the proposed demand management to manage energy at risk;
- Section 9.5 outlines broad based demand management initiatives;
- Section 9.6 outlines the proposed demand management innovation allowance;
- Section 9.7 outlines the linked capex projects required; and
- Finally, Section 9.8 lists the support material for the chapter.

9.5 Demand Management Program Summary

The demand management program set out in this proposal is a comprehensive package that builds on AusNet Services' prior learnings, reflects the development of new technologies and aligns with its expenditure forecasts. The program will allow AusNet Services to pursue more non-network opportunities than in the past and maintain its position as a lead innovator in the demand management space.

The proposed demand management program comprises a suite of integrated measures that will:

- Maintain core non-network capability and demand side engagement activities;
- Facilitate innovation to develop new demand management techniques;
- Deploy existing and new techniques for near-term customer benefit within the 2016-20 regulatory control period; and
- Deploy existing and new techniques to realise long-term benefits to customers beyond the next period.

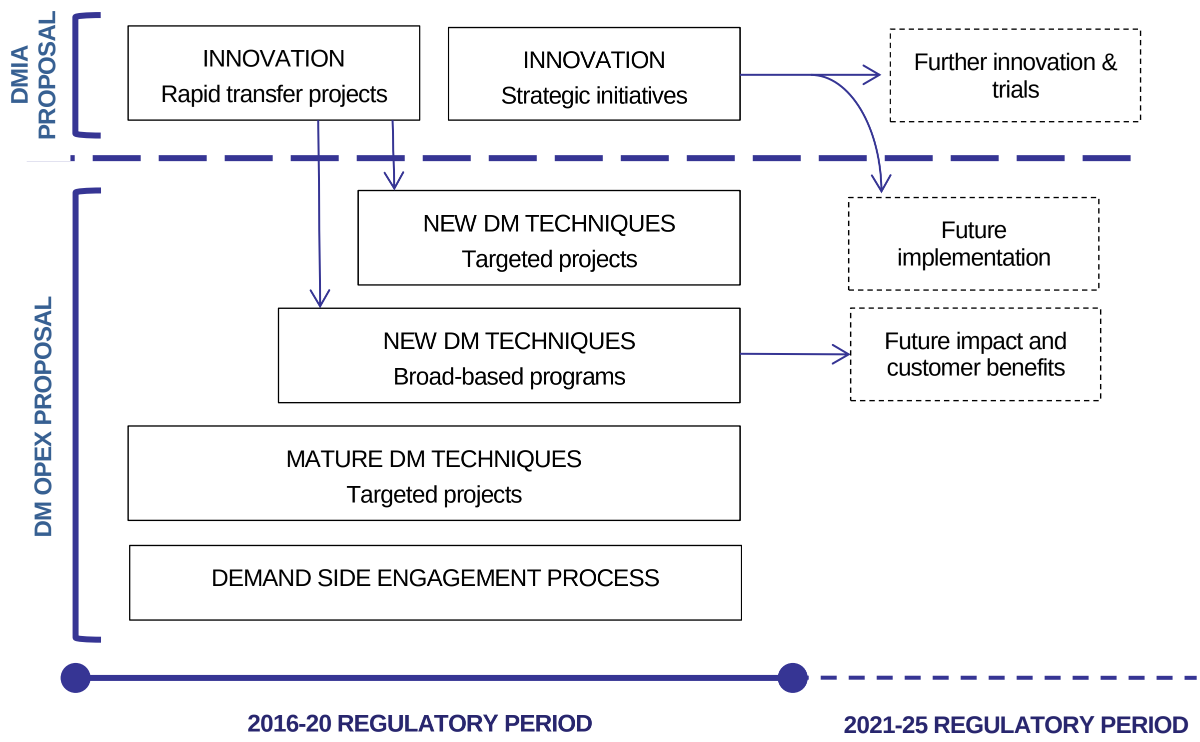
The integration of the different components within AusNet Services' proposed demand management program is shown in the figure below.

To deliver this program, AusNet Services is proposing demand management opex of $13 million (real 2015), which represents a total step change of $4.8 million (real 2015) over the forthcoming period, as well as an increase in the DMIA from $3 to $10 million. This includes the costs of an additional FTE, which is considered necessary to deliver the proposed larger demand management program.

The total and step change expenditure associated with each component of the DM program is summarised in the table below.

AusNet Services notes that the impact of the proposed demand management activities has not been reflected in the demand and energy forecasts set out in chapter 4. This approach allows demand and energy forecasts to be inputs to options analysis comparing network and non-network solutions for individual projects. In addition, it is difficult to forecast the amount and location of demand management to a level of precision that would be required to adjust demand and energy forecasts.

Figure 9.2: Integration of demand management program components



Source: AusNet Services

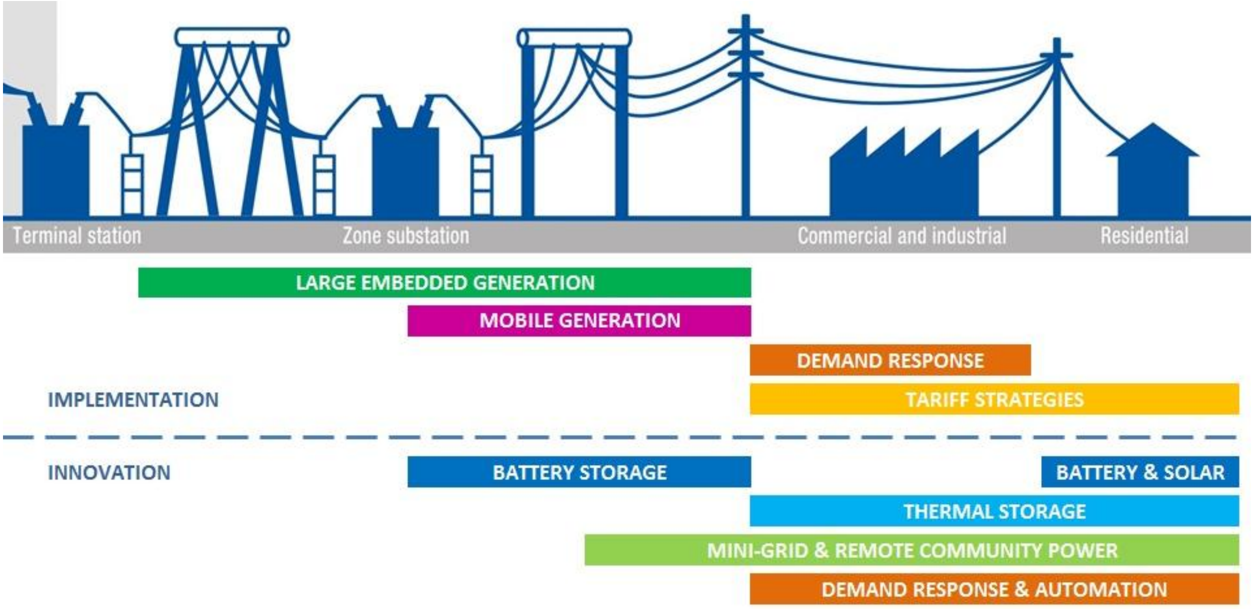
Table 9.1: Demand management program expenditure summary ($M, $2015)

Component	Proposed expenditure	Rationale
Non-networks team	5.3	Provides non-networks expertise, delivery of demand side engagement process and management of non-network projects.
Existing capex deferral projects	1.7	Maintains existing opex that continues to efficiently defer capex projects.
Initiate new capex deferral projects	0.7	Delivers new opex projects in residential growth corridors to defer feeder augmentation capex projects.
Energy at risk reduction projects	3.6	Opex projects that efficiently reduce the level of energy at risk to which customers are exposed. May also result in future deferred capex outside of period.
Broad-based demand management programs	1.6	Opex projects that provide enduring reduction in peak demand growth rate within high-growth areas and reduce the levels of long-term augmentation capex.
Total opex forecast	**13.0**	
Total opex step change	**4.8**	
Demand Management Innovation Allowance	10.0	Reduces the risks associated with developing new demand management techniques that will be deployed in the next and future regulatory periods.

Source: AusNet Services

The proposed demand management program involves activities across the entire distribution network, from the sub-transmission system down to household consumers. AusNet Services' current demand management capabilities are weighted towards the high voltage distribution system and larger commercial and industrial customers. Significant development activity is planned at the lower voltage and customer end of the network to balance out the spectrum of capabilities as shown in the following figure.

Figure 9.3 AusNet Services' demand management activities across the distribution network



Source: AusNet Services

AusNet Services' proposed demand management initiatives for the next regulatory control period demonstrate its commitment to delivering electricity services in a way that best serves the long term interests of consumers. Building on the expertise gained during the current period, AusNet Services will improve its ability to identify, plan and implement the most appropriate solutions to alleviate demand constraints, reduce the severity or duration of energy or load at risk, and defer or avoid capex. Further, the increased flexibility AusNet Services will have to substitute non-network expenditure for direct network investment ensures its total capex and opex forecasts reflect the efficient costs that a prudent DNSP would incur. These outcomes, in conjunction with AusNet Services' improved ability to respond to community concerns about electricity supply, means the proposed demand management program directly contributes to the efficiency of AusNet Services' network investment strategy while maintaining reliability and supply security.

9.6 Demand Management to Defer Capital Expenditure

Operational expenditure on demand management offers significant value when it can defer or reduce the level of network capital expenditure that would otherwise be required to serve customer loads. Demand management opex also offers increased flexibility compared to network capex in that it can be scaled up or down as required, or avoided if peak demand falls in future. This flexibility promotes efficient network investment by lowering the risk of under-utilised network assets and lowering the long term cost of supply to customers, thereby contributing to the achievement of the NEO.

AusNet Services currently spends opex on a number of significant demand management projects which efficiently defer capex. These existing projects will largely be continued during the forthcoming regulatory control period, and additional opportunities for capex deferral will also be taken up. The new opportunities arise in areas of localised peak demand growth, and are facilitated by the continued strengthening of AusNet Services' demand management capability and experience.

The maximum level of opex for a particular deferral opportunity is determined by calculating the value of the deferral of the relevant capex project, which is equal to the financing costs of the capex deferred. This approach ensures opex alternatives represent efficient trade-offs between network capex and demand management opex by ensuring customers do not pay more for the opex solution, but rather have the opportunity to benefit from the increased flexibility that demand management solutions offer over time.

9.6.1 Existing deferral expenditure

AusNet Services currently employs demand management solutions in the form of embedded generation at both the sub-transmission (66kV) and distribution (22kV) levels of the network. These solutions continue to be the most cost-effective way of serving customer demand at their locations, and benefit customers by reducing network expenditure. AusNet Services proposes to maintain these embedded generation solutions throughout the 2016-2020 period.

Bairnsdale Power Station

Bairnsdale Power Station (BPS) is the largest single source of demand management in the AusNet Services network, currently contracted to provide 40MW of network support capacity. The Bairnsdale Power station connects to the Bairnsdale sub-transmission loop and is used to support East Gippsland through the daily hot water and afternoon peaks when demand can exceed the firm capability of the networt.

This infrastructure was established in 1998 as an alternative to the construction of 110 km of transmission line from Jeeralang terminal station to a proposed terminal station at Bairnsdale at an estimated cost of $54 million (in 1997), and has thus deferred significant and costly upgrades to the transmission and sub-transmission networks in the Gippsland region, as well as the return on and of these capital costs.

The cost of network support during the current period has, on average, been [C-I-C] (real 2015) per annum. AusNet Services proposes to continue its network support arrangement with BPS over the forthcoming period, with the associated costs forecast to decline slightly in real terms over the forthcoming period.

Currently, BPS costs are recovered through the annual pricing process, in accordance with the ESC's treatment of this cost. However, as explained in chapter 8, AusNet Services proposes to include BPS costs in its proposed opex for the forthcoming regulatory period.

Traralgon Power Station

In 2012, AusNet Services established an agreement with the Traralgon Power Station to provide 10MW of network support to the Traralgon (TGN) Zone Substation via an existing 22kV feeder (TGN 31). The agreement deferred a $2.9m capital investment in upgrading the second transformer at Traralgon Zone substation and runs for five years from December 2012.

TGN comprises three transformers and supplies more than 16,000 customers in central Gippsland. At the beginning of the current regulatory period, TGN was experiencing rapid growth in demand and was forecast to carry energy at risk where a failure of one transformer at peak load times would result in loss of supply to customers. The network support agreement with the Traralgon Power Station was the most efficient means of addressing this forecast risk.

The load forecast for TGN has now reduced, resulting in a much lower level of forecast energy at risk than experienced during the current period. Proposed Traralgon Power Station opex reflects the revised energy at risk values beyond the end of the existing agreement in 2017. The lower levels of expenditure required from 2018 demonstrates the flexibility that network support options offer in response to changing network conditions, in contrast to capex solutions.

Mobile generation

During the current regulatory control period, AusNet Services established a fleet of four mobile diesel generators that can be connected to the distribution network to reduce network loads and alleviate local network constraints at times of peak demand. The generators are nominally 1MW machines that can run continuously to support the grid at 800kW each on hot summer days. Additional generators can be hired as required, but the AusNet Services' fleet is expected to be sufficient to satisfy the majority of the network's needs.

During the 2013-14 summer peak, generators were deployed as shown in the Table below:

Table 9.2: Deployment of mobile generators during 2013-14 summer peak

Location	Capacity	Driver
Euroa BN1 22kV feeder	2 x 800kW	Deferral of $8.2m capex
Philip Island PHI Zone Substation	800kW	Zone substation risk
Corryong WOTS24 22kV feeder	500kW	Protection reach

Source: AusNet Services

The opex required to operate the existing mobile generator fleet relates to system studies for new locations, semi-permanent and temporary connection works, transport, labour for connection and operation, fuel costs, maintenance costs and project management costs. An efficient level for these costs for the next regulatory control period has been forecast based on the deployment experience during the full 2013-14 summer peak periods. These costs are included in AusNet Services' efficient base year opex, which is discussed in chapter 8.

Proposed expenditure on existing capex deferrals

AusNet Services proposes the following forecast opex to continue existing demand management projects. While Bairnsdale opex relates to an existing capex deferral project, it does not form part of AusNet Services' proposed demand management opex step change.

Table 9.3: Forecast expenditure to continue existing capex deferral projects ($m, $2015)

Project	Forecast opex ($m)
Bairnsdale Power Station	[C-I-C]
Traralgon Power Station	[C-I-C]
Mobile generators	[C-I-C]
Total opex	**[C-I-C]**
Proposed opex	**1.7**

Source: AusNet Services

9.6.2 New deferral expenditure

In addition to continuing existing capex deferral projects, AusNet Services has identified new opportunities to employ demand management techniques that will defer additional capital expenditure.

The nature of peak demand constraints on the network has evolved over the past few years and now presents a significantly different picture to that which prevailed in the lead-up to the last price review. The overall growth rate of peak demand has slowed, and peak demand constraints are increasingly concentrated in localised regions of the distribution network, particularly in urban growth corridors.

These constraints are characterised by residential-driven increases in peak demand resulting from a combination of increased air-conditioning uptake, in-fill housing development and greenfield housing development.

In 2009, gradual peak demand growth on rural feeders offered straightforward opportunities to use demand management solutions to defer capex. The outlook for the 2016-20 period is more complex. Augmentation capex requirements are weighted towards urban areas where the network is more highly meshed and where capex projects are commonly required both to extend the network to new developments and to reinforce existing elements of network. Furthermore, peak demand growth rates can be exceptionally high in these areas such that a demand management solution can only deliver short deferral durations.

These factors limit the degree to which demand management can play a role in future urban augmentation capex deferral. Nevertheless, there remains a strong economic rationale to undertake demand management projects where the network conditions are conducive and where the project would be in the interests of customers and thus contribute to the achievement of the NEO.

Delivering sufficient demand management at the identified locations where demand is primarily residential will require the deployment of existing techniques as well as the development and deployment of new techniques. AusNet Services is focussed on using its opex and the DMIA to establish a capability in residential demand management. Building this capability will ensure the company has access to a suite of demand management options that can be deployed to address a range of network constraints.

Developing such a capability is a central plank of AusNet Services' demand management strategy for the forthcoming regulatory control period. In particular, AusNet Services proposes to utilise the DMIA to undertake trials and develop capability within the early years of the period, with a view to deploying viable solutions as full-scale projects towards the end of the period. In order to achieve deployment within this relatively short timeframe, AusNet Services will leverage off existing industry experience, as well as invest significant innovation expenditure to:

- Develop solutions that suit its network and communications infrastructure;
- Build the necessary technical and customer-focussed capability; and
- Prove the solutions in trials so the risks involved in full-scale deployment are reduced to an acceptable level.

In addition to developing a capability in residential demand management, AusNet Services will continue to identify opportunities to deploy existing techniques such as mobile generation, and commercial and industrial customer demand response contracts.

Mobile generation is generally less suited to deploy in established urban areas due to noise emissions and the availability of space, but there may be deployment opportunities in greenfield urban development areas where suitable noise setback distances exist. Once the two-year innovation trial of the Grid Energy Storage System (GESS) is complete in 2016, this system will also be available to deploy into areas of network constraint. The GESS offers the advantage of lower noise emissions than diesel generation, but has the disadvantage of physical size. These characteristics will inform the most appropriate strategy for post-trial deployment of the GESS. While battery storage at present is generally less economic than mobile generation, the funding of the capital cost of the GESS through the current period's DMIA improves the economic prospects of the GESS.

Further, there are typically few large commercial and industrial customers available to engage for demand response in urban growth areas, but AusNet Services will pursue isolated opportunities where they exist. For example, where housing development is expanding into areas that have established agricultural industries, demand response from the industrial customers may be able to offset the growth in residential demand for a period of time.

Assessment tests for capex deferral

For large capacity-driven capex projects, AusNet Services is not required to apply the Regulatory Investment Test for Distribution (RIT-D) if the most expensive potential credible solution is less than $5 million.[3] No RIT-D studies are expected to be undertaken in the forthcoming regulatory control period because the augmentation of the KLO-DRN sub-transmission line, which is the only capacity driven project included in the capex forecast that exceeds $5 million, has already undergone the RIT-D test.

AusNet Services will, however, continue to assess the opportunity for demand management solutions for all major capex projects and will liaise with suppliers of demand side solutions as opportunities are identified. AusNet Services currently has 17 demand side suppliers listed on its Demand Side Engagement Register and undertakes ongoing engagement with proponents as appropriate.

To identify and test smaller deferral opportunities, AusNet Services applied the following criteria to its list of augmentation capex projects:

- Only capex projects scheduled for delivery in 2018 and onwards were considered for residential demand management, in order to allow sufficient time for a range of residential demand management solutions to be developed and trialled. For projects to be delivered prior to 2018, existing techniques such as commercial and industrial demand management contracts and mobile generation were considered as options;
- Demand management projects were required to generate a marginal deferral benefit of approximately $100k/annum/MVA. Projects that generate benefits significantly below this rate are considered unlikely to be economically efficient, based on AusNet Services' current understanding and experience of costs; and
- Demand management projects were required to generate a total deferral value of at least $30,000 per project in order to justify the fixed costs of project setup and delivery.

This approach ensures that forecast new deferral expenditure reflects only those projects considered practicable and economically efficient over the forthcoming period.

Zone substation and sub-transmission deferral opportunities

As stated above, based on current demand forecasts, AusNet Services is not proposing to augment any zone substations or sub-transmission loops within the 2016-20 period. Some augmentations are forecast to take place beyond the period, with timing sensitive to the ongoing revision of demand forecasts.

There are a number of zone substation rebuild projects being proposed that are driven by the condition of the assets and the resultant risk levels. Demand management solutions were assessed for these projects but were found not to be viable. In many cases, the economic justification for replacement stemmed from the reduction in the level of safety risk associated with failure of the deteriorated assets. Although demand management could reduce the risk of unserved energy, it does not reduce the level of safety risk associated with operation of the asset.

High voltage feeder deferral opportunities

As identified in chapter 7, AusNet Services has planned a number of high voltage feeder augmentation projects for the forthcoming regulatory control period to deliver sufficient capacity to meet forecast customer demand. Non-network solutions were considered for each project according to the assessment tests listed above.

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[3] NER 5.17.3(a)(2). Other exceptions to the requirement to apply the RIT-D are set out in clause 5.17.3(a).

Key observations from this process were:

- Feeder reconfiguration projects tend to have a low cost compared to the increase in capacity that they can deliver, and are therefore not typically suitable for non-network alternatives unless new equipment is also required;
- New feeder projects to extend the network into housing growth areas cannot in themselves be deferred, but may have a deeper augmentation element that can be deferred if the demand growth rate can be slowed; and
- There are typically few commercial and industrial customers within residential growth corridors which limits the opportunity to establish network support agreements.

As a result of applying the above assessment tests, five opportunities were identified to defer feeder augmentation projects as summarised in the following table.

In some cases, the demand management project may defer the capex investment beyond the end of the 2016-20 regulatory period, in which case the capex forecast is adjusted accordingly. In other cases, the deferred capex project will be undertaken at a later year within the forthcoming regulatory period.

The proposed levels of opex are based on the deferral value that the projects offer. As an example, AusNet Services' proposed capex project to construct the new DRN24 high voltage distribution feeder is required to be in service by 2021, with the bulk of expenditure occurring in 2020. Implementing a demand management project to defer this network investment by one year moves the capex investment to outside the regulatory period, i.e. 2021. Accordingly, AusNet Services' total forecast capex for 2016-2020 is reduced by cost of the project, or around $3.3 million (real 2015).

Assuming a discount rate of 7.19% based on AusNet Services' proposed WACC, deferring the $3.3m augmentation project for one year implies a capex deferral value of $0.24 million. Accordingly, if the relevant demand management solution can be implemented at a cost of no more than $0.24m, AusNet Services will have made an efficient trade-off between augmentation capex and demand management opex. Consequently, customers are likely to face lower costs over the long term due to the flexibility benefits of the non-network solution.

Proposed expenditure on new capex deferrals

The following table sets out AusNet Services' proposed opex for new deferral projects, calculated in accordance with the method described above.

Table 9.4: Proposed opex for new capex deferral projects

Project	Capital cost ($m, nominal)	In service date (pre deferral)	Deferral duration (years)	Capex deferred ($m, nominal)	Deferral value ($m, nominal)	Proposed opex ($m, $2015)
DRN24 new feeder	3.7	2021	1	3.7	0.3	0.2
OFR11 & OFR12 new feeders	2.6	2019	1	2.6	0.2	0.2
TT6 & EPG21 feeder reconfiguration	0.2	2018	3	0.2	0.1	0.1
WT9 feeder upgrade	0.7	2016	3	0.7	0.1	0.1
WGL13 feeder upgrade	0.9	2018	2	0.9	0.1	0.1
Total	**8.1**			**8.1**	**0.8**	**0.7**

Source: AusNet Services

Note: Nominal values are based on each project's "in service date (pre-deferral)" year.

9.7 Demand Management to Mitigate Growth in Energy at Risk

Where there is a risk that customer demand on a particular part of the network will not be met under peak demand conditions, the quantity of energy not supplied is referred to as the energy at risk. Under a probabilistic planning regime, augmentation to lower this risk is justified where the value of energy at risk (converted to an economic cost using the VCR) is forecast to be higher than the cost of augmentation. However, before that investment point is reached, the network remains potentially unable to supply all customers in high demand periods.

When demand is growing strongly, these periods of under-capacity tend to be brief as the growing energy at risk quickly justifies further investment. However, at times of slow or flat demand growth, energy at risk may persist in particular parts of the network for extended periods of time. In these situations, where justified by cost-benefit analysis, demand management can be used to reduce the level of risk customers are exposed to.

For example, if a zone substation experiences peak demand levels of 1MVA above its N-1 rating (refer to Box 9.1 in section 9.1.2), adding a new standard sized 20MVA transformer represents a possible capex solution. However, contracting 1MW through a demand management solution is likely to offer a more prudent and efficient solution because of the flexibility it affords. Utilising demand management in this way allows AusNet Services to make efficient investment, implementing an opex rather than capex solution. The level of demand management can be scaled up if demand continues to rise, until a capital solution becomes economically efficient, or demand management can be removed if demand falls.

The substitution possibilities that demand management solutions offer AusNet Services are consistent with the outcomes that the investment efficiency objective embedded in the NEO is intended to bring about. AusNet Services, through its demand management program, is committed to making efficient investment decisions in order to deliver pricing and reliability benefits that are in the long term interests of its customers.

The following figures compare a conceptual energy at risk profile over time under strong growth and slow growth scenarios for a particular network element (such as a zone substation). The extended duration of energy at risk under the low growth scenario highlights the opportunity for demand management or other non-network solutions to reduce the supply risk (i.e. temporary disconnection from the network) faced by customers.

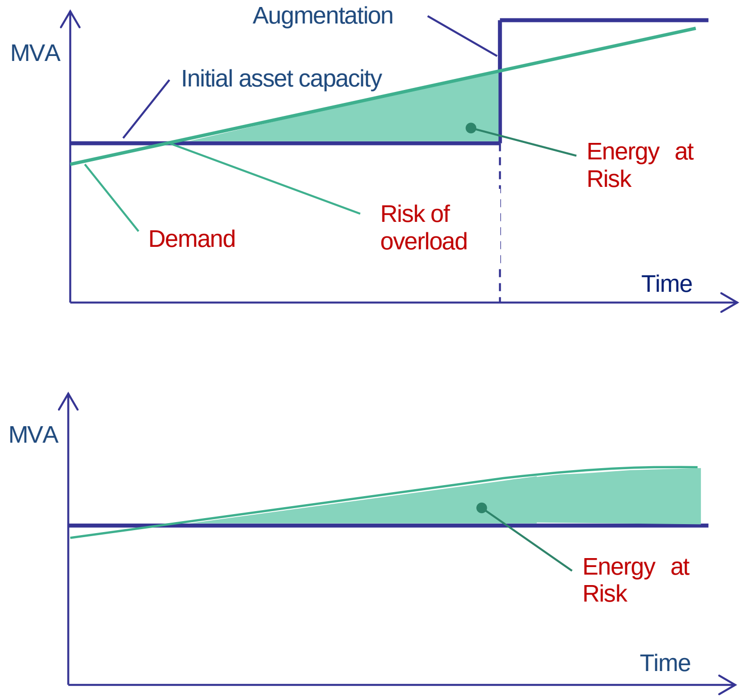
Figure 9.4: Conceptual profile of energy at risk under different demand growth scenarios

1. Strong growth

Augment once energy at risk due to forecast asset overload reaches economic trigger point.

2. Slow growth

Economic trigger point to augment not reached. Customers exposed to extended risk profile.



Source: AusNet Services

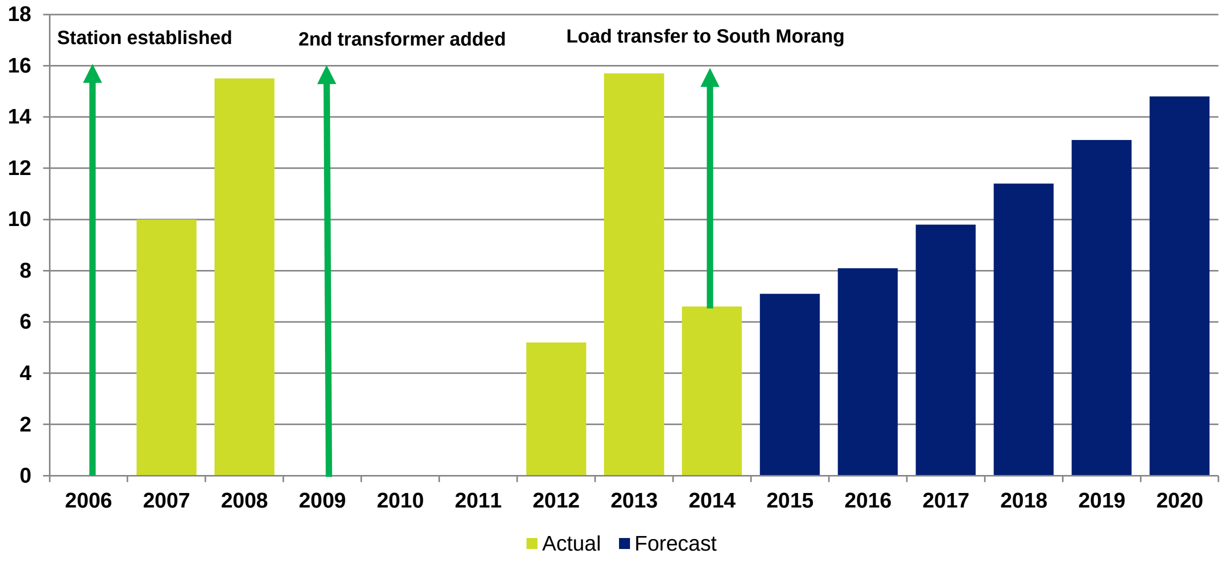
In the past, consistent and strong peak demand growth across AusNet Services' network drove capital augmentation projects which in turn constrained growth in energy at risk. However, the slower aggregate growth in peak demand that is currently present on the network is resulting in slow growth in energy at risk across the network, below the level required to trigger individual capital projects.

The following figure provides an example of how the load at risk on a zone substation, in this case the Doreen zone substation, is forecast to continue increasing.[4] Load at risk, which measures the extent to which forecast electrical loads exceed the capacity of the network's electrical equipment at one or more points across a given planning period (e.g. five years), is a good proxy for energy at risk, with both the load at risk and the energy at risk for a particular asset or section of network varying over time in response to changes in load growth and capacity augmentation.

The initial period of strong demand growth at Doreen saw a second transformer added after two years of operation, removing the load at risk for three years. While load at risk grew in 2012 and 2013, around 16MVA of load was transferred to South Morang zone substation in 2014, substantially lowering the load at risk. Consequently, further augmentation of Doreen zone substation is no longer economically justified under the probabilistic planning framework until well after the 2016-20 regulatory period, leaving customers exposed to load at risk for a prolonged period.

[4] For simplicity, the impact of load transfers as a contingency measure to transformer outages is not factored into the figure.

Figure 9.5: Historical and forecast profile of load at risk (MVA) on Doreen zone substation



Source: AusNet Services

This example demonstrates that some of AusNet Services' customers across the network will be subject to an extended period of increasing energy at risk over the forthcoming regulatory control period, creating an increased likelihood of load shedding (i.e. being temporarily disconnected from the network) to prevent damage to electrical equipment or the disconnection of all customers in that part of the network. This provides an opportunity for AusNet Services to deploy demand management techniques to manage the growing risk. AusNet Services is proposing a step up in its demand management opex to achieve this.

A number of approaches can be used to manage the growth in energy at risk including:

- Commercial and industrial demand management contracts;
- Large-sale embedded generation;
- Mobile generation; and
- Residential demand management techniques.

AusNet Services will consider all techniques, but expects that contracting with commercial and industrial customers for load curtailment, or use of on-site generation, is likely to be most appropriate. AusNet Services therefore proposes an expanded program of commercial and industrial customer demand management. It considers the forecast opex associated with commercial and industrial customer demand management is a prudent and efficient approach to managing energy at risk, and provides AusNet Services with sufficient flexibility to deploy alternate solutions in the event that commercial and industrial demand management is not available or is not the preferred solution in particular parts of its network. The following section explains AusNet Services' commercial and industrial customer demand response program.

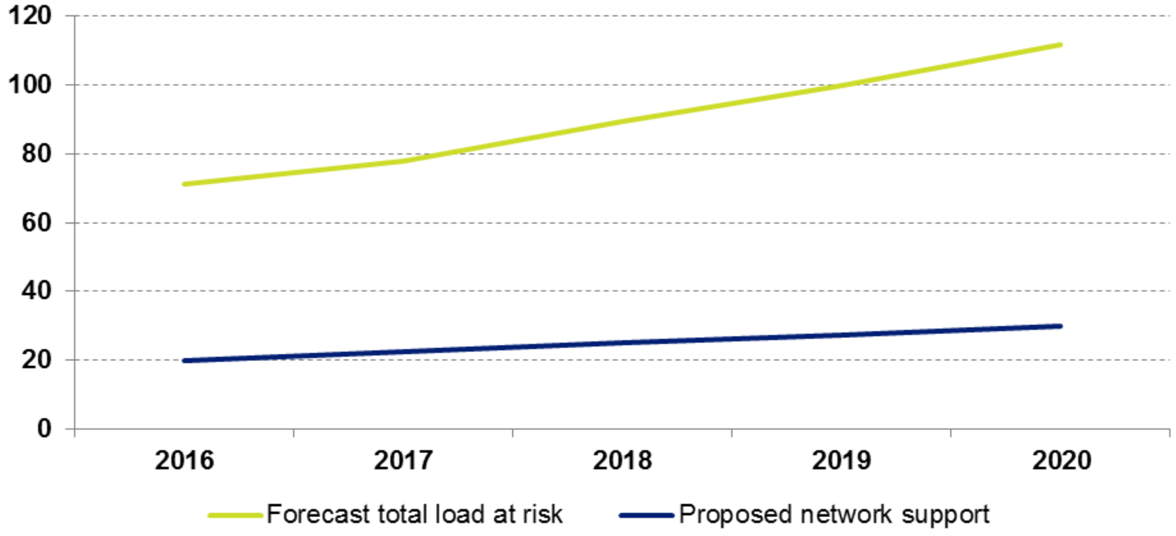
9.7.1 Commercial and industrial customer demand response program

One of the methods AusNet Services has recently developed to address the energy at risk associated with zone substations and 66kV sub-transmission loops is to contract with commercial and industrial customers to occasionally, and voluntarily, reduce their demand on the network when required. These contracting arrangements are also used to mitigate the risk of thermal overload on distribution feeders and defer thermal upgrades.

As at the start of 2015, AusNet Services' portfolio of commercial and industrial demand management contracts stands at 20MW. This portfolio has been built up since 2013 primarily in response to supply constraints on distribution feeders. AusNet Services proposes to gradually increase this level of network support to 30MW over the forthcoming regulatory control period to combat the increasing level of energy at risk on the network, including at zone substations.

The extent of the opportunity for demand management to mitigate growth in energy at risk can be observed from the aggregate quantity of forecast load at risk across all zone substations.

Figure 9.6: Forecast load at risk across (MVA) zone substations and proposed network support



Source: AusNet Services

Note: Load at risk forecasts are on a P50 basis.

The overall quantity of load-at-risk under P50 conditions is forecast to be approximately 71MVA in 2016, with a subsequent growth rate of approximately 10MVA per annum. AusNet Services' proposed increase in network support to 30MW is materially below this, but is expected to make a meaningful reduction in the volume of load-at-risk. While a higher level of network support than 30MW may be justifiable based on the total forecast of load at risk, the practical experience that AusNet Services has gained in procuring its current portfolio is that:

- Demand management is not available at all zone substations;
- Demand management can usually only cover a portion of the risk on a particular zone substation where it is available; and
- It will become increasingly difficult and expensive to grow the portfolio beyond 30MW.

Accordingly, 30MW is considered a realistic and achievable level of commercial and industrial demand response capacity over the forthcoming regulatory period. In some cases, techniques other than commercial and industrial demand management may be deployed such as generation solutions, or the use of residential demand management. It is noted that the development of residential demand management techniques forms a key part of AusNet Services' proposed DMIA.

Contracting commercial and industrial demand response is considered economically efficient because the rate of payment made to customers to reduce demand is less than the value of customer reliability. However, it should be noted that some customers are unwilling to contract at the payment levels offered by AusNet Services. This indicates these customers place a higher financial value on their continuing use of electricity at peak times and cannot provide demand management as a price that AusNet Services considers is efficient.

9.7.2 Proposed expenditure to mitigate Energy at Risk

The proposed level of expenditure on the commercial and industrial demand management program is based on AusNet Services' contracting experience during 2013 and 2014. AusNet Services has developed a good understanding of the price points that are attractive to the type of customers that can provide a reliable demand response.

AusNet Services' network support agreements for commercial and industrial demand management offer the following payments:

- **Annual reserve fee ($/kW/year):** This is equivalent to a capacity payment that reserves the customer's participation in the program. The level of reserve fee in $/kW is aligned to the probabilities involved in the particular network constraint. A higher probability of the constraint occurring warrants a higher level of reserve fee. For pure contingency support, where there is a very low probability of dispatch, no reserve fee is paid.
- **Dispatch performance fee ($/kWh):** This is a performance based payment that is made to compensate for the level of load reduction below normal levels, and the duration that the load reduction is maintained. The performance of a customer during a dispatch event is measured against a baseline load profile for the same time of day, based on previous consumption data. The baseline can also be adjusted to account for the impact of temperature on the customer's load during a dispatch event.

Using expected levels of fee payment rates, AusNet Services proposes the following level of opex to mitigate energy at risk across the network. This opex requirement covers the expected payments to customers based on the above payments structure and does not include internal labour or other program operational costs.

Table 9.5: Proposed expenditure to mitigate energy at risk via commercial and industrial customer demand response program ($m, real 2015)

	2016	2017	2018	2019	2020	Total
Demand response capacity (MW)	20	23	25	28	30	**30**
Proposed opex	**0.5**	**0.6**	**0.7**	**0.8**	**1.0**	**3.6**

Source: AusNet Services

9.8 Broad-based Demand Management Initiatives

Demand management initiatives that result in permanent or long-term reductions in demand may have benefits that extend beyond the forthcoming regulatory control period and beyond current planning horizons. If deployed as a broad-based project or program (i.e. across the whole of the network), such initiatives can slow the long-term rate of asset augmentation investment, even where specific augmentation projects are not yet defined, creating long-term benefits for consumers through lower prices. Investment in these demand management initiatives up to the present value of these future savings is justified under the NEO because doing so is in the long-term interests of consumers.

Rather than seeking to defer specific near-term capital investments, broad-based demand management seeks to suppress the long-term investment path for augmentation capex. Broad-based initiatives are typically deployed at the customer level where the network benefits will accrue at almost all voltage levels, from LV distribution substations, to feeders, to zone substations and the 66kV network (e.g. direct load control of air conditioners). Beyond the distribution network, such initiatives can even reduce peak demands on the transmission network and in the wholesale electricity market.[5] All else equal, long term reductions in peak demand mean that less investment is needed to expand the network, leading to greater network utilisation and improved productivity.

5 This has been the case with the Bairnsdale Power Station network support agreement.

Previous examples of broad-based demand management initiatives include the use of time clocks to control off-peak circuits, and more recently, the randomisation of time clocks via smart meters.

Since the early 2000's, AusNet Services has undertaken a series of projects to address overnight demand peaks caused by the simultaneous switching of many time-switch controlled loads such as hot water and slab heating systems. Depending on the specific tariff, controlled loads would typically switch on at 11pm or 1am. This was found to be a particular problem throughout Gippsland. As well as causing localised feeder peaks, it lead to voltage collapse on the 66kV South Gippsland Loop and caused loads to exceed the N-1 thermal rating, therefore increasing significantly the risk of load shedding. A program was undertaken to randomise time clocks in Phillip Island, Leongatha, Wonthaggi and Foster. In combination with the installation of capacitor banks, this program deferred the need to re-conductor sections of the South Gippsland Loop for several years.

More recently, AusNet Services' randomised time clocks in Mallacoota to reduce the peak demand levels that a backup generator would be required to serve.[6] Mallacoota's location – at the end of a long and forested radial 66kV and 22kV line – exposes it to the risk of multiple day outages. In these situations, temporary generation is deployed to serve the Mallacoota community, and it is important to manage peak demand to within the capability of the generator.

Adjusting time-clocks remains a viable demand management practice and there may be further need to initiate such projects. Dual-element AMI meters are currently set with a randomisation function to switch on dedicated loads between 11pm and 12am, with a hard switch-off at 7am. Randomised settings result in peak demand reductions compared to synchronised time switches with no adverse customer impact because the load control appliances being switched off require only a maximum six hour heating time, and will still have a minimum seven hour window of switched time. Once fully deployed, AMI will also allow time switch settings to be adjusted remotely, and fine-tuned if required.

AusNet Services has now identified an opportunity to deploy broad-based initiatives to counteract the growth in residential demand that is primarily driven by air-conditioner use. Broad-based initiatives offer value when, without demand management, peak demand is expected to grow over time to the extent that network augmentation is required. Therefore, AusNet Services has targeted its planned broad-based initiatives to growth areas within the network, which tend to be outer-suburban housing development areas.

The growth areas are reflected in feeder forecasts and impact the following zone substations:

- CLN – Clyde North;
- CPK – Chirnside Park;
- CYN – Croydon;
- DRN – Doreen;
- EPG – Epping;
- KLO – Kalkallo; and
- OFR – Officer.

The high instance of new housing developments within these areas offers the advantage that broad-based measures which rely on specific appliances or technology (e.g. direct load control of air conditioning) can be incorporated into initial selection, design and installation of electrical appliances, rather than requiring retrofits or replacements, as is common with existing housing stock.

6 This initiative is discussed further in section 9.9.1 of this chapter.

A range of measures are proposed to be investigated for deployment, each of which would be voluntary for customers to take up in response to a financial incentive such as a rebate:

- Load control of air-conditioners;
- West facing solar PV panels rather than north facing;
- Installation of evaporative cooling rather than refrigerative air-conditioning.

These initiatives are discussed in the following sections.

AusNet Services has proposed a DMIA that would allow it to develop the technologies and capabilities necessary to implement its proposed broad-based demand management programs. For example, AusNet Services is proposing to develop a capability during the 2016-20 regulatory control period that will allow it to control residential air conditioners. This will involve a series of tests and trials to scale up from bench-testing to live proof-of-concept in the field.

9.8.1 Benefits of broad-based demand management programs

A broad-based demand management program aims to reduce demand across a network, rather than at a specific point on the network.[7] The direct benefit of broad-based demand management programs to the distribution network stem from the long term reduction in the rate of augmentation capex. AusNet Services has developed benchmark rates for augmentation capex for different elements of its network. The following table, which shows these rates, demonstrates that the cost reduction benefits of customer-level demand management flow through all levels of the distribution network.

Table 9.6: Distribution augmentation unit costs ($/kVA)

Network element	Unit cost
Sub-transmission lines (66kV)	75
Zone substations	256
Distribution feeders (22kV)	159
Distribution substations	210
Total	**700**

Source: AusNet Services augex modelling

Benefits to the transmission network and the wholesale market are not included in this analysis as there is a high degree of uncertainty in their quantification, and they are likely to be minor benefits compared to the direct benefits within the distribution network.

Building a broad base of dispatchable demand response, such as the direct load control of air conditioning, provides indirect benefits in addition to a reduction in long-term augmentation capex. These include:

- Increasing the flexibility of the network to respond to contingency events;
- Offering a mechanism to improve power quality; and
- Improving the ability of customers to manage their own consumption.

[7] AER, *Demand Management and Embedded Generation Incentive Scheme – Jemena, CitiPower, Powercor, AusNet Services and United Energy 2016-20*, 21 November 2014, p. 15.

Once experience has been gained with respect to broad-based demand response, these benefits may justify demand management in their own right.

AusNet Services notes that AusGrid's proposed broad-based DM program was rejected by the AER on the basis that the proposed benefits were overstated because they did not take into account customer response to future tariff reforms (i.e. peak demand reductions and therefore less augmentation capex to defer).[8]

In taking this position, the AER has assumed tariff reform benefits that will not necessarily be realised despite the AEMC rule change on network pricing. Firstly, retailers may mute or alter network price signals in their final retail offer, and may choose to market some tariff structures in preference to others. Indeed, some retailers have indicated they are unlikely to pass on cost reflective price signals. Secondly, state regulators and governments may (and are likely to) impose constraints that severely restrict or slow the rate of change in network tariff reform. Finally, DNSPs must sufficiently account for customer feedback in setting tariffs, which could materially impact the cost reflectivity of tariffs depending on customer preferences.

For these reasons, AusNet Services does not consider it appropriate to reject a broad-based DM program because the supporting cost benefit analysis does not account for customer response to tariff reform. Where the cost reduction benefits outweigh the implementation costs, such a program is likely to be in the long-term interest of customers.

9.8.2 Costs of broad-based demand management programs

Given that the benefits of broad-based demand management measures are based on long-run marginal costs of supply and are discounted over a future time period, their implementation costs must be relatively low compared to measures that mitigate a specific near-term risk. This means that one-time interventions that create an enduring demand reduction tend to be more economically attractive than broad-based demand management techniques that require ongoing expenditure, such as performance payments to customers for voluntary load curtailment.

AusNet Services forecasts that the delivery cost of the programs proposed below are approximately $350 to $400 per kW of peak demand reduction, including equipment costs, financial incentives to participate, and program management costs. This cost level is justified by the present value of future benefits valued at $700/kVA is described above, and constitutes an efficient opex-capex trade-off.

9.8.3 Broad-based air conditioning load control

Once the technical and commercial application of direct load control is proven through a DMIA-funded trial, AusNet Services proposes to begin rolling out the technology in areas of its network that are experiencing high demand growth. This application is separate, and does not overlap, the targeted roll-outs discussed earlier in this chapter, which are aimed at deferring a defined augmentation capex project. The broad-based roll out is proposed to occur from 2018 to 2020 and will target 3,000 customers.

Based on the experience of other network business trial programs, as well as available literature, AusNet Services anticipates a demand reduction of approximately 1kVA per customer, for a total demand reduction of 3MVA across the network. Based on the augmentation unit rates discussed earlier, this translates to a total cost reduction of $2.1 million between 2020 and 2030, which is considered an appropriate time horizon across which to measure the project's benefits.

The following table sets out AusNet Services' forecast of the expenditure required over the forthcoming regulatory period to implement this initiative ($1.2 million). Assuming AusNet Services' proposed WACC, the forecast costs and benefits yield a positive NPV, demonstrating the project's economic merits. AusNet Services' Demand Management Economic Analysis sets out the NPV analysis underpinning this project.

8 AER, *Attachment 7: Operating expenditure | Ausgrid draft decision*, pp. 168-169.

Table 9.7: Proposed broad-based air conditioning load control opex (real 2015)

Cost element	Unit rate (per customer)	Cost ($'000)
Project management		50
Marketing campaign		50
Financial incentives	$150	450
DRED installation	$200	600
Operational costs		40
Total costs		**1,190**

Source: AusNet Services

9.8.4 Broad-based passive demand reduction

AusNet Services also intends to implement an innovative broad-based program that seeks to reduce peak demand levels by passively altering the pattern of customer load profiles. Two potential opportunities that have been identified include providing customer rebates to incentivise customers to:

- Re-orient residential solar PV panels to face west rather than north; and
- Install evaporative cooling rather than refrigerative air-conditioning.

AusNet Services intends to implement a broad-based program utilising one or both of these measures. Both of these initiatives are likely to benefit customers through reduced electricity bills, however AusNet Services believes that a financial incentive is required in order to overcome upfront customer capital requirements and market barriers such as imperfect information and bounded rationality.

Solar PV panel installations continue to favour north-facing installations where roof-space allows due to higher total solar exposure and historical industry practice. For the majority of residential customers that exhibit an evening peak in consumption, orienting solar panels west offers to better align solar production with household consumption and minimise exports that are currently paid a feed-in tariff at a significantly lower rate than retail consumption tariffs. From a network perspective, where north facing solar PV has minimal effect on the evening network peak, facing panels west offers a tangible benefit in both reducing the evening peak and reducing the energy under the peak.

Evaporative cooling consumes less electricity for a given cooling output and will therefore contribute less to growth in the residential evening network peak on hot days compared to refrigerative air-conditioning. By encouraging customers to install evaporative cooling rather than large refrigerative air conditioning systems, AusNet Services can reduce the investment requirements to meet peak demand growth. This is particularly the case in new housing developments where large numbers of customers in a concentrated area face the purchase decision regarding cooling needs.

Under both measures, there will be a proportion of customers that even in the absence of a financial incentive, would have chosen the desired outcome. Offering rebates to these customers cannot be avoided and reduces the efficiency of the overall program. However, these customers are expected to be in the minority and their impact on the program has been taken into account by adjusting the expected demand reductions accordingly.

The program will target a 1,000kVA demand reduction. AusNet Services estimates that this can be achieved, for example, through incentivising 1,700 customers to orient their solar panels westwards, or incentivising 800 customers to install evaporative cooling rather than refrigerate air conditioning. This level of demand reduction translates to total cost reduction of $0.7 million between 2019 and 2030, which is considered an appropriate time horizon across which to measure the project's benefits.

For either approach, a financial incentive per customer of $330 per kW is considered sufficient to encourage broad participation, and is consistent with the typical level of incentives provided under comparable incentive-based programs such as energy efficiency schemes.

The following table sets out AusNet Services' forecast of the expenditure required over the forthcoming regulatory period to implement this initiative ($0.4 million). Assuming AusNet Services' proposed WACC, the forecast costs and benefits yield a positive NPV, demonstrating the project's economic merits. AusNet Services' Demand Management Economic Analysis sets out the NPV analysis underpinning this project.

Table 9.8: Proposed broad-based passive demand reduction program opex (real 2015)

Cost element	Unit rate (per kW)	Cost ($'000)
Project management		90
Financial incentives	$330	330
Total costs		**420**

Source: AusNet Services

9.8.5 Proposed expenditure on broad-based demand management

AusNet Services proposes the following level of opex to broad-based demand management programs that will efficiently reduce future augmentation capex in residential growth areas.

Table 9.9: Expenditure to deploy broad-based demand management programs ($m, real 2015)

Project	Proposed opex
Direct load control of air conditioning	1.2
Passive demand reduction	0.4
Total	**1.6**

Source: AusNet Services

9.9 Demand Management Innovation Allowance

The Demand Management Incentive Scheme (DMIS) was developed by the AER to offer incentives to DNSPs to implement efficient non-network alternatives, and to encourage DNSPs to explore alternatives to network augmentation to manage expected demand for standard control services.[9] AusNet Services proposes that the DMIS apply to it during the forthcoming regulatory control period without modification from the DMIS set out in the AER's Framework and Approach paper.

During the current regulatory control period, AusNet Services utilised the DMIA to embark on major energy storage trials as well as to investigate mini-grids and solar PV uptake. AusNet Services considers the DMIA to be a valuable instrument in allowing network businesses to overcome the innovation risk associated with new technology and techniques. These risks create a disincentive for businesses to steer away from traditional capital based solutions.

The DMIA has allowed research and development to be undertaken where benefits to customers have been uncertain or long term. Without this component of the incentive framework, longer term research is discouraged even where long term benefits have the potential to be large or where the major benefits accrue to the community rather than the company.

[9] NER 6.6.3 and AER, *Demand Management and Embedded Generation Incentive Scheme – Jemena, CitiPower, AusNet Services and United Energy, 2016-20*, 21 November 2014, p. 11.

Accordingly, the DMIA plays a vital role in mitigating the financial risks associated with investing in new and innovative technologies which may offer substantive long-term value for DNSPs and their customers.

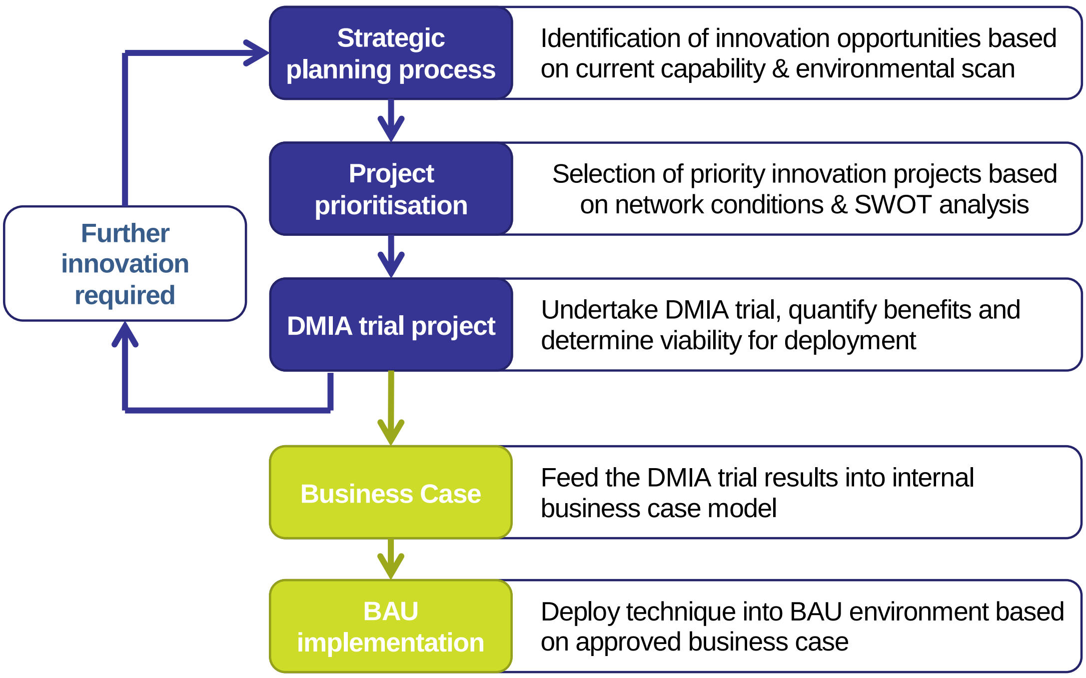
This section summarises the trials undertaken during the current regulatory period and the customer benefits which may derive from these trials, and details the projects AusNet Services would allocate DMIA funding to for the forthcoming regulatory period.

To prepare for the continuing application of DMIA in the 2016-20 regulatory control period, AusNet Services undertook planning and community consultation sessions to identify high priority projects that will provide an expanded future capability in demand management. The priority projects focus on:

- Developing capability in residential demand management technologies;
- Building on the current technical trials of battery storage to move into a commercialisation trial; and
- Undertaking technical trials of thermal energy storage as an alternative approach to battery storage.

During the forthcoming regulatory control period, AusNet Services plans to swiftly transfer some of the techniques that prove successful under DMIA trials into business-as-usual (BAU). In particular, air conditioning load control and peak demand incentives are planned to be developed using the DMIA in the early years of the period, and deployed to defer feeder augmentation projects in the latter part of the period. It is therefore critical that these techniques are trialled as a priority. The below figure shows AusNet Services' strategy for transferring innovate technologies into business as usual operations.

Figure 9.7: Innovation lifecycle for demand management techniques



Source: AusNet Services

9.9.1 DMIA projects in the current regulatory control period

This section summarises the DMIA projects that have been undertaken during the current regulatory period and identifies the ways in which the projects have, or will, benefit AusNet Services' BAU by meeting customer demand more efficiently. The DMIA projects are:

- Grid Energy Storage System (GESS);
- Residential battery storage trial;
- Mallacoota sustainable energy study;
- Mallacoota hot water time-clock adjustment; and
- Solar uptake study.

Grid Energy Storage System

In 2012, AusNet Services initiated a Grid-scale Energy Storage System (GESS) project to trial the application of a large battery storage system. The objective of the project was to defer asset augmentation by managing peak demand, and simultaneously explore other network benefits of storage systems such as power quality improvement. The project involves a large (1 MW / 1 MWh) battery system and includes a 1MW diesel generator set to cost-effectively extend the MWh rating of the battery system to provide full coverage for the duration of the peak demand period.

The project trial was commissioned at the end of 2014 and will run for 2 years. The results will inform future innovation and applications of grid-scale energy storage in other areas of the distribution network. This trial will help to establish whether battery storage is a credible non-network solution to manage peak demand and set the parameters around when it can be economically deployed for the benefit of energy consumers.

The commissioning and trial process to date has built considerable knowledge within the engineering, field and network operations teams regarding energy storage. At the end of the trial period, the GESS will be transferred to BAU as a relocatable resource that can be deployed in areas of the distribution network that require support, in a similar fashion to AusNet Services' fleet of mobile generators. The operating costs of the GESS are reflected in the opex proposed for new capex deferral.

In practice, the GESS will provide 1.5 MVA of network support for a high voltage feeder or zone substation during a typical summer evening demand peak. If the GESS is deployed in a location that requires 4 days of network support on average per year, this will provide approximately $600,000 p.a. of value in avoided unserved energy, or reduced energy at risk.

Residential Battery Storage Trial

The Residential Battery Storage Trial comprises ten battery, PV and inverter systems connected to consumer homes to provide load shifting and localised demand management. The systems can also simulate the impact of electric vehicle charging and the potential capability of vehicle-to-grid enabled electric vehicles. The battery systems are fully programmable and can be remotely controlled by AusNet Services.

The battery systems are intended to shift customer demand from peak to off-peak times by discharging when the customer's demand is high, and by re-charging either overnight when the customer's demand is low or using surplus solar PV generation. The flexibility provided by the programmable inverter makes this type of system capable of both addressing specific network constraints and providing broad-based demand management across the network if rolled-out in sufficiently large numbers.

The two-year trial, which finishes in 2015, provides a technical and economic base from which the future strategy for distributed storage can be developed. The trial results will feed into the design of another larger trial that is aimed at testing the commercial parameters around deployment of distributed storage under the BAU environment.

The potential for residential-scale battery storage to reduce future capital expenditure on AusNet Services' network is expected to be substantial given the gradual reduction in hardware costs, increasing hardware availability, and the strong growth in consumer interest in installing storage behind the meter. If installed in a location that is forecast to experience a typical 4 days of overload per annum, each storage system in AusNet Services' existing residential battery storage trial would incrementally contribute over $900 in value per annum of reduced energy at risk. Deferring a single large feeder augmentation project for 2 years is worth approximately $0.5m[10] and could be achieved through a concentrated roll-out of storage systems within the feeder boundary.

Mallacoota Sustainable Energy Study

AusNet Services partnered with the Mallacoota community through the Mallacoota Sustainable Energy Group (MSEG) and the East Gippsland Shire Council (EGSC) to investigate non-network alternative electricity supplies to the Mallacoota community. Under this arrangement, AusNet Services contributed to funding for a consultant's feasibility study into distributed electricity supply options that provide improved reliability of supply to customers and incorporate sustainable generation technologies.

The study canvasses options to meet customer demand via a mini-grid (embedded generation, storage and control systems) and therefore reduce reliance on bulk network supply. This approach is suited to addressing specific localised areas on AusNet Services' network, such as remote locations, where there is a high cost of augmentation to serve increasing demand or improve reliability. In such locations, the use on non-network alternatives such as mini-grids may provide a significantly lower cost option to network augmentation.

This study means AusNet Services is now better equipped to capture these benefits, both for Mallacoota and other locations, by providing:

- Increased technical and commercial knowledge of options to locally supply remote communities through embedded generation and mini-grids; and
- Increased corporate awareness of the potential reliability benefits of non-network alternatives to remote power supplies.

Mini-grid supplies can provide significant value to customers if they improve reliability or defer capital expenditure. For example, remote rural areas can experience total sustained outages in the order of 1.5 days per annum. For a small town with an average load of 1MW such as Mallacoota, an outage of this duration costs the community approximately $1m based on the recently revised VCR. Using a mini-grid to meet demand locally rather than through the traditional network can avoid this cost if it can be proven technically feasible.

Mallacoota hot water time clock adjustment

As a precursor to the Mallacoota Sustainable Energy Study, AusNet Services undertook a project to improve the management of network peak demand driven by the off-peak hot water heating load in Mallacoota. This area of the network was experiencing supply interruptions and customers were concerned about service reliability.

The project was initiated in response to these customer concerns, and to prepare Mallacoota for potential mini-grid or distributed generation technologies to provide a localised supply and defer significant network investment in the longer term.

The maximum peak demand at Mallacoota (2.5MW) occurred between 12 and 5am due to the timing of hot water units, and this was driving a network peak on the Mallacoota-Bairnsdale line. By analysing the nature of the demand at Mallacoota, engaging the community and rolling-out a program of hot water time-clock adjustment, AusNet Services was able to reduce the overnight peak from 2.5MW to 2MW. This provided a more manageable load profile to potentially supply by either local backup generation or in a potential mini-grid configuration.

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[10] This estimate assumes a $5m project cost and a real discount rate of 5% p.a.

The total cost of grid-connected diesel generation is around $1m per MW. Reducing peak demand by 0.5MW reduced the capital requirement of backup generation by around $0.5m. In a mini-grid configuration the reduction in capital cost would likely be even higher owing to the higher capital cost of generation that provides regular rather than intermittent service.

Solar uptake study

The objective of this study was to provide AusNet Services with a model to understand and predict demand for market uptake of distributed solar power. As a major determinant of the magnitude, profile and variability of demand for network services, it is important for AusNet Services to understand PV market drivers in order to target the development of demand management strategies and projects that are effective in reducing peak demand levels. This includes both broad-based demand management initiatives such as tariffs as well as localised peak demand management technologies such as storage and embedded generation.

A “proof of concept” study was undertaken to develop a preliminary model based on prior work by University of Technology Sydney’s Centre for the Study of Choice (CenSoC) in the Australian market based on consumer behaviour. A spreadsheet model and associated descriptive material were delivered for the project.

Undertaking this project has provided AusNet Services with:

- Improved robustness of solar uptake forecasting as an input to allow more targeted and informed demand management strategies and projects to be developed;
- An improved understanding of factors driving solar uptake, especially customer-driven factors; and
- Exposure to other methods of modelling, including statistical analysis techniques, with the potential to incorporate these methods in future projects including non-solar modelling.

9.9.2 DMIA projects in the 2016-20 regulatory control period

In identifying demand management initiatives that could be funded by the DMIA and undertaken during the course of the next regulatory control period, AusNet Services identified four key themes as important areas for innovation:

- **Developing a residential demand response capability:** AusNet Services has built up a considerable portfolio of demand response contracts from commercial and industrial customers, but has not yet developed a residential demand response technique other than tariff structures. Considering that peak demand on most network assets is driven by residential loads, there is considerable value to be gained by developing such techniques. The finalisation of the AMI roll-out will facilitate development, testing and commercialisation paths for a variety of residential demand response techniques.
- **Continued investigation of energy storage:** Energy storage remains a central plank of AusNet Services’ demand management innovation work as storage solutions are well-suited to managing short-duration peak demands. During the next period, AusNet Services proposes to use the DMIA to test the technical and commercial parameters involved in residential storage at a scale that is sufficient to demonstrate tangible network benefits. As an alternative to battery storage, thermal storage has also been identified as a potential means of managing peak cooling demands for larger customers.
- **Integration of commercial and industrial customer demand response:** The next innovation challenge for AusNet Services in the space of commercial and industrial demand response is to better integrate the management of the resource into a BAU capability. There are different methods to achieve integration, and more effective techniques to manage the resource to optimise its use and improve the firmness of response.

- **Distributed energy solutions to serve remote communities:** Building on the findings of the Mallacoota Energy Study, as well as specific examples such as Mt Baw Baw where AusNet Services operates a stand-alone power system, AusNet Services continues to search for and evaluate opportunities to deploy mini-grids or remote power supplies as alternatives to traditional grid connection. Distributed energy solutions can offer benefits which include avoiding or deferring network augmentation, avoiding or deferring expenditure to maintain reliability, or reducing bushfire risks.

The projects AusNet Services has identified also cover the two main categories of demand management:

- **Demand response techniques**, where the end customers' actual consumption of electricity is modified by either behavioural change or control technology; and
- **Distributed energy technology**, where the local generation or storage of energy is used to offset a customer's consumption of electricity.

The six DMIA projects currently planned for the next regulatory control period align with the above themes and are summarised in the following sections. Further details are provided in Appendix 9A.

Although in practice AusNet Services has discretion to use its DMIA allowance to fund any demand management innovation projects that meet the DMIA criteria, the prioritisation process that AusNet Services has undertaken will ensure the allowance is allocated to projects offering the greatest benefit to customers. AusNet Services will adjust the structure or composition of its projects to ensure they best reflect changes in technology, consumer behaviour and industry practice.

Residential peak demand incentives

AusNet Services has built up significant experience in procuring demand response from commercial and industrial customers, but is yet to develop a comparable residential capability. Despite being similar in concept, residential voluntary demand response requires a vastly different approach in terms of analytics, customer engagement, and commercial structure compared to commercial and industrial.

This project will investigate the use of financial and non-financial incentives to alter the voluntary behaviour of residential customers such that their consumption of electricity at times of critical peak demand is reduced. The financial aspect is often referred to as a peak demand rebate.

Trials have been undertaken by other utilities to prove the use of rebates and financial incentives for residential customers to reduce demand. AusNet Services proposes to build on the available results to not only expedite the planning of its own trial and the building of internal capability, but to test the benefit of non-financial behavioural motivators in improving uptake rates and the level of delivered demand response.

This trial is a critical precursor to the development of a suite of residential demand management tools that can be deployed in the BAU environment to achieve the new capex deferrals discussed earlier in this chapter. The trial is proposed to be undertaken early in the 2016-20 regulatory control period in order to allow the technique to be deployed later within the period, should it prove to be technically and commercially viable.

Expenditure to complete this trial is forecast at $900,000. Further details of the project scope and costs are attached in Appendix 9A.

Residential air-conditioning load control

Developing the ability to control air-conditioners remotely would allow AusNet Services to reduce residential peak loads at source with minimal impact on customers' behaviour and comfort. AusNet Services does not currently have the technical or commercial capability to control residential air-conditioners and has identified this as a critical technique to test and develop during the 2016-20 regulatory control period.

Trials have been undertaken by other utilities to prove the concept of residential air-conditioning load control and AusNet Services proposes to build on the available results in developing its own trial. In addition, many new air-conditioners are compatible with AS4755 for demand response which avoids the need to retrofit or build a bespoke system at the appliance end. The technical characteristics of AusNet Services' smart meter network means that development work is required to ensure the communications and control functionality can operate via the smart meter network. In parallel, AusNet Services will need to evaluate customers' willingness to participate in load control trials and to test different commercial structures to offer to customers.

The trial will involve a series of tests to scale up from bench-testing to live proof-of-concept in the field.

This trial is a critical precursor to the development of a suite of residential demand management tools that can be deployed in the BAU environment to realise capex deferrals. The trial is proposed to be undertaken early in the next regulatory control period and, if it proves to be technically and commercially viable, deployed later within the period.

Expenditure to complete this trial is forecast at $2.0m. Further details of the project scope and costs are attached in Appendix 9A.

Management and automation platform for commercial and industrial demand response

AusNet Services has built up a 20MW portfolio of demand response contracts with commercial and industrial customers across the distribution network. The management of these contracts is a manual process that sits outside the BAU control centre systems. AusNet Services has identified that a management and automation platform could extract better value from the portfolio by:

- Optimising the dispatch of demand response;
- Enabling better integration into existing systems; and
- Improving the firmness of customer response.

There are different approaches to demand response management platforms and AusNet Services proposes to test one or more platforms in order to prove the business case for full implementation.

Expenditure to complete this trial is forecast at $1.0m. Further details of the project scope and costs are attached in Appendix 9A.

Commercial-scale aggregation of residential battery storage

Once the technical capability of individual residential energy storage under the current trial of 10 systems is established, a central challenge for future commercialisation of such technology is to test and verify the aggregation and control systems used to harness and coordinate many hundreds of units to act in harmony as a virtual power station. In addition, the commercial delivery and customer engagement models need to be tested at scale in order to build the value streams that support the business case for economic deployment of residential battery storage to meet peak demand.

The commercial-scale aggregation trial will test both of these elements. AusNet Services proposes to undertake the trial on a non-critical but highly loaded part of the network. The trial will require AusNet Services to test the storage supplier market in terms of technical ability and commercial offerings. An important technical factor will be the ability of the storage aggregation systems to integrate with AusNet Services' BAU network control systems.

This trial is another of the precursors to the development of a full suite of residential demand management tools that can be deployed in the BAU environment. AusNet Services proposes to undertake the trial towards the middle of the 2016-20 period in order to allow the technique to be deployed later within the period if it proves to be technically and commercially viable.

The trial will also allow a full-scale comparison between 22kV grid-scale storage (the 1MW GESS project) and the equivalent scale of aggregated residential storage, from the perspectives of both technical performance and economic value.

Expenditure to complete this trial is forecast at $4.0m. Further details of the project scope and costs are attached in Appendix 9A.

Mini-grid or distributed energy supplies for remote communities

Increasingly, mini-grids or distributed power supplies are playing a greater role in supplying electricity to remote communities. This trend is driven by a number of factors including communities' increasing desires for self-sufficiency, sustainability and increased control over their power supplies. From the network perspective, the cost of augmentation, maintenance and asset replacement can be considerable for remote communities and bushfire risk can be considerable if supply lines cross highly vegetated areas. Establishing new community developments, even in less remote locations, can also require considerable network investment and raises the opportunity for distributed electricity supplies.

Customers taking part in focus groups expressed a preference not to "cut the wires" but rather to rely more heavily on local supplies and use the existing network as a top-up or standby supply.

In order to inform AusNet Services' approach to the technical and commercial challenges presented by the trend towards mini-grids and distributed energy supplies, it proposes to undertake a trial project. This will involve selecting a location and installing mini-grid components and observing the behaviour of the system. AusNet Services also proposes to encourage significant community collaboration and input to determine customer support for such an approach.

Whilst mini-grids have been the subject of many studies and scenarios, it is critical that AusNet Services has direct access to practical information and technical know-how concerning the design and operation of mini-grids. A sound, reliable information base is essential to enabling AusNet Services to chart its future strategy for providing and managing alternatives to traditional network-supplied electricity.

Expenditure to complete this trial is forecast at $1.7m. Further details of the project scope and costs are attached in Appendix 9A.

Thermal storage to manage cooling loads

In addition to its considerable investigations into the use of battery storage, AusNet Services has identified other forms of energy storage that also exhibit peak demand management potential and may be cost-effective. In particular, thermal storage applied to cooling systems offers the ability to shift electrical cooling demand outside peak periods while still satisfying the cooling requirements of customers.

Having investigated the characteristics of thermal storage for cooling applications, AusNet Services believes that the technology is currently most suited to commercial scale loads such as building HVAC or cool-storage facilities, rather than residential cooling.

In order to investigate the technical and commercial value of thermal storage, AusNet Services proposes to undertake a small trial of one or more systems in partnership with a suitable customer. This will require a full evaluation of the technology currently available and investigation of potential customers. The trial will ultimately inform the viability of deploying thermal storage to commercial and industrial customers in order to defer or reduce investment in network augmentation.

Expenditure to complete this trial is forecast at $400,000. Further details of the project scope and costs are attached in Appendix 9A.

9.9.3 Proposed expenditure for the Demand Management Innovation Allowance

AusNet Services proposes a DMIA of $10m for the 2016-20 regulatory control period. The following table summarises the priority projects that AusNet Services intends to deliver using the DMIA.

Table 9.10: Proposed trial project expenditure under the DMIA

Project	Critical for capex deferral within period	Proposed opex ($million)
Demand response trials		
Residential peak demand incentives	Yes	0.90
Residential air conditioning load control	Yes	2.00
Management and automation platform for commercial & industrial demand response		1.00
Distributed energy technology trials		
Commercial-scale aggregation of residential battery storage	Yes	4.00
Mini-grid or distributed energy supplies for remote communities		1.70
Thermal storage to manage cooling loads		0.40
Total		**10.00**

Source: AusNet Services

9.10 Dependent Projects

Delivery of the proposed demand management program relies on two capex projects that are included in the capex forecast. These dependent projects, the costs of which have not been included in the expenditure proposals set out in this chapter, are summarised below.

9.10.1 LV modelling capability

AusNet Services has identified the need for increased capability in modelling the low voltage (LV) network to support a number of functions across the business, including network planning and network operations. Developing this capability is necessary to respond to increasing levels of distributed energy such as solar PV and storage emerging on the network, and also improves AusNet Services' ability to develop residential demand management techniques.

Currently, the distribution network is monitored and modelled down to the 22kV feeder level, and smart meter data is providing a solid base of information at the customer level. The LV network represents the critical gap between these data sets that needs to be filled in order to maintain network reliability, quality of supply and efficiency of asset management, through improved network operations and the planning of efficient network and non-network investments. The operations and planning components are separate projects that require different systems, but they are related in that a common base of GIS data is required in order to build both models accurately.

The proposed expenditure (shown below) to develop this capacity has been included in AusNet Services capex forecast.

Table 9.11: LV modelling project expenditure ($m, $2015)

Project	Proposed capex	Category
LV model for network operations and control	1	Non-network ICT
LV model in network planning and analysis	1	Non-network General
Total	**2**	

Source: AusNet Services

9.10.2 ICT capability to support Demand Response Enabled Devices

To support the development and deployment of appliance load control capability (such as remotely controlled air-conditioning) as set out in this chapter, an ICT project is required to build the relevant functionality in AusNet Services' metering communications and back-end systems. This ICT project forms part of the ICT strategic plan and will support both the DMIA-funded trials of air-conditioning load control and subsequent roll-out into BAU that form part of the demand management program. Although initially focussed on residential air-conditioning, the ICT capability will enable communication to a generic Demand Response Enabled Device (DRED) that could be applied to a number of other consumer appliances such as pool pumps, battery storage systems and electric vehicle charging equipment.

The development of DRED capability within the ICT environment is captured as one component of AusNet Services' non-network capex forecast.

9.11 Support Documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 9A: DMIA Priority Projects; and
- Spreadsheet entitled “AusNet Services 2016-20 EDPR Demand Management Economic Analysis_PUBLIC.xlsx”.

10 Incentive Schemes (Performance & Expenditure)

10.1 Overview

10.1.1 Introduction

This chapter describes AusNet Services' proposed approach to the national and jurisdictional incentive schemes that will be applied in Victoria during the forthcoming regulatory control period including:

- Service Target Performance Incentive Scheme (STPIS);
- Efficiency Benefit Sharing Scheme (EBSS);
- Capital Efficiency Sharing Scheme (CESS);
- Demand Management Incentive Scheme (DMIS); and
- F Factor scheme.

The targets and outcomes from these incentive schemes are fundamentally interlinked to AusNet Services' expenditure proposals as both are an input to and output from the company's asset management strategy and the work programs that underpin this Proposal. AusNet Services' capex and opex proposals are outlined in Chapters 7 and 8.

Incentive regulation works. AusNet Services has a strong record of delivering lower operating costs and improved service levels in response to the incentive framework it has operated under. Therefore, the AER intention to apply the full suite of incentives in Victoria, including the new stronger capital efficiency incentive is fully supported.

10.1.2 Structure of this chapter

The remainder of this chapter is structured as follows:

- Section 10.2 provides important background to AusNet Services' current performance and other external considerations, including customers' views;
- Section 10.3 sets out the STPIS proposal;
- Section 10.4 sets out the EBSS proposal;
- Section 10.5 explains the CESS proposal;
- Section 10.6 explains the F Factor proposal;
- Section 10.7 explains the DMIS and DMIA proposal;
- Section 10.8 sets out AusNet Services' position on the transitional benchmarks to apply for the incentive schemes in 2016; and
- Finally, Section 10.9 lists the support material for the chapter.

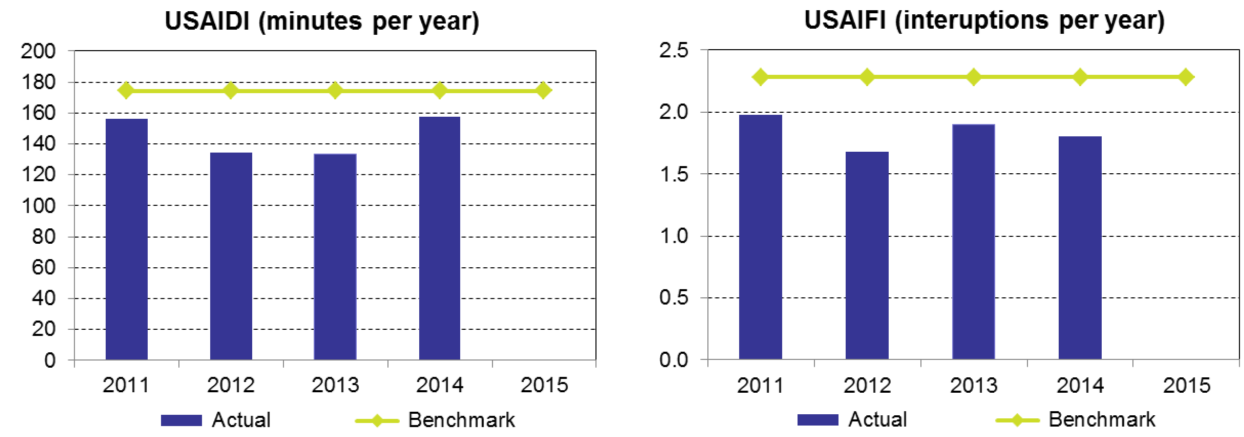
10.2 Operating Environment

AusNet Services strongly supports the AER's incentive regime. The framework's constituent schemes align the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

This has been practically demonstrated by AusNet Services' performance under the current period's various incentive schemes.

In the current period, significant capex investment, over $38 million, was incurred to improve the network's reliability performance. This investment has been funded upfront by the company with customers only paying if actual reliability improvements have been delivered. As a result, the network's underlying reliability has been improved by around 15%.

Figure 10.1: Network SAIDI and SAIFI performance, 2010–14



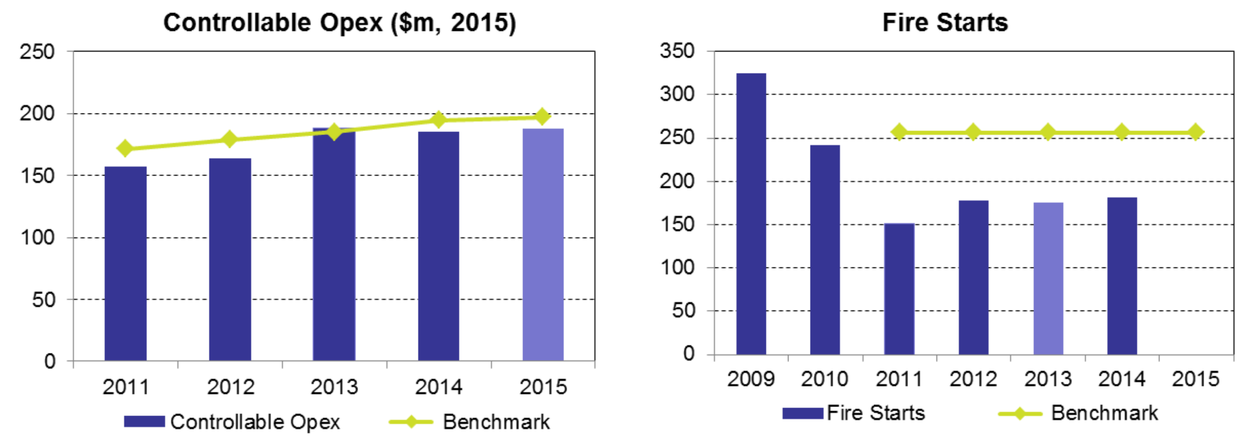
Source: AusNet Services

This improvement has largely been delivered through investments in innovation, including a new advanced network management system and distribution feeder automation (DFA) schemes. The DFA project uses 'smart' switches to divide the network into self-healing units significantly reducing the number of customers affected by any given outage. This fault isolation happens automatically with-in seconds but requires substantial upgraded protection and IT system support.

Similarly, AusNet Services has responded to the existing EBSS scheme, outperforming the operating allowance by 5% over the period (see figure below).

Finally, the large increases in safety expenditure are delivering improved safety outcomes for the community. Targeted under the jurisdictional F factor incentive scheme, the number of actual fire starts, caused by AusNet Services' assets have fallen since 2009 (see figure below).

Figure 10.2: Opex efficiency and F Factor performance, 2011–14

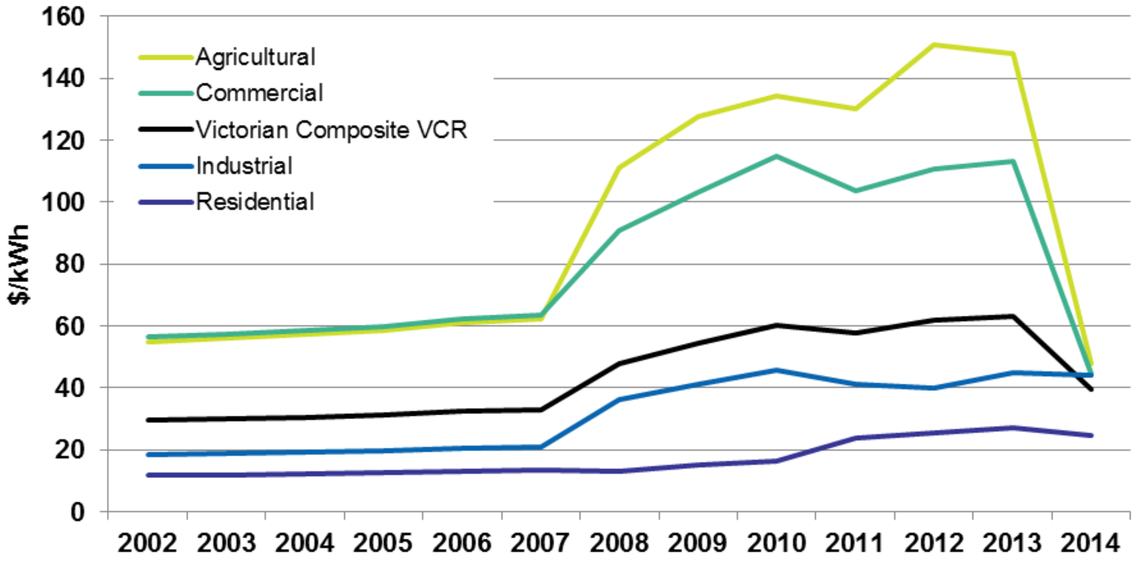


Source: AusNet Services

10.2.1 Value of Customer Reliability

In Victoria, the Australian Energy Market Operator (AEMO) has undertaken detailed studies to set the value the community places on a reliable electricity supply. This is referred to the as the Value of Customer Reliability (VCR). This value is an important input into both the reliability component of the STPIS and a network's assessment of a potential investment to improve reliability. An increase in the VCR, indicates the community places a higher value on reliability and, therefore, will be prepared to pay more for improved reliability. Historically, the VCR has tended to rise over time; however, the most recent study has resulted in a reduction in the VCR.

Figure 10.3: The value of the Victorian VCR over time



Source: AusNet Services

This reduced VCR changes the balance between expenditure proposed and reliability outcomes from a maintain case to one where expenditure will be deferred, thereby reducing costs, and reliability will be allowed to decline marginally. A more detailed discussion on the VCR is contained in Chapter 7.

The AER indicated in the *Final Framework and Approach for the Victorian Electricity Distributors* (Framework and Approach) that it intends to apply the new, lower VCR in the STPIS to apply to the upcoming regulatory control period.[1] AusNet Services endorses this approach.

10.2.2 Customer Engagement

AusNet Services undertook several engagement activities aimed at gauging our customers' attitudes to different aspects network reliability. These were not an attempt to substitute for the extensive surveys undertaken as part of AEMO's most recent VCR study, rather they were helpful in putting context around AEMO's findings as applied to AusNet Services' network.

Engagement Activities

Initially, AusNet Services undertook a broad based survey of 2,400 customers to gain an underlying baseline for further customer engagement.

This was followed by a series of community forums and technical workshops with advocacy groups where some of the reliability cost trade-offs used in AusNet Services' network planning were explained.

[1] *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016*, p. 97.

Finally, specific meetings were held with some large customers that dealt with local reliability and quality problems.

Findings

Generally, customers expressed a strong preference for current reliability levels. This satisfaction with current reliability levels was shared across customer groups. In the focus groups, in particular, there was recognition that reliability was generally very good, outside of storms, and that reliability had improved over the last 10 years. There were nonetheless, instances where localised reliability issues caused considerable customer inconvenience and complaint. This was exacerbated where communications with our customers had failed or were considered to be unsatisfactory.

There was a strong resistance to pay for either further reliability improvement or allowing reliability to decline for lower prices in the future. This was expressed in general terms in answer to questions such as "Do you think lowering the value of a reliable energy supply reflects community views?" and when confronted with the specific detailed trade-offs under consideration for this regulatory proposal.

Customers also did not want to pay more for improved performance during extreme weather events or to ensure localised problems were addressed. In particular, customers appeared forgiving of unplanned outages during extreme weather events and considered AusNet Services' network crews used best endeavours to restore supply quickly and efficiently.

Finally, customers were strongly resistant to paying more for reduced planned outages or for the company to receive payments under an incentive scheme to reduce them. This reflected both an understanding of the necessity for these outages, particularly in rural areas where preparing the network for the fire season received strong support, and a general feeling that these outages created little inconvenience if communicated well in advance.

The was general support for continued investment in innovation (as opposed to large network investments) that resulted in reliability benefits, allowed improved planning of outages or improved customer communications.

Customers considered investing in innovation was good business practice providing benefits to the business as well as the community. They were concerned that they do not pay twice where benefits pay for themselves. Innovation was more strongly supported when delivering benefits to the broad customer base, such as improvements in reliability

A $7 million increase in the Demand Management Innovation Allowance (DMIA) proposed by AusNet Services was tested in focus groups and received positive support.

How customer engagement findings were incorporated into our proposal

Initially, with respect to reliability, it was planned to propose:

- A lower ongoing reliability as result of incorporating the lower VCR into network planning;
- A planned outage incentive scheme;
- Expenditure on an improved customer service and communication, in particular a Customer Relationship Management system; and
- A new STIPS exemption for demand management contracts.

As a result of the strong customer feedback on planned outages, plans to introduce an incentive scheme to minimise planned outages are not being pursued. Network programs have also been costed without substantial live line work (which are more expensive but reduce planned outages).

However, customers and advocacy groups have been supportive of investment in innovation and improved customer service particularly where that can be substituted for network costs. Therefore, AusNet Services' proposal contains IT expenditure to support and enhance current network management capability, better customer communication and management, and an increase to the innovation allowance supporting research and development in demand management. This is particularly important where the major benefits accrue to the community rather than AusNet Services.

Another important component of the framework in the current period was the DMIA. This has allowed research and development to be undertaken where benefits to customers have been uncertain or long term. Without this component of the incentive framework, longer term research is discouraged even where long term benefits have the potential to be large or, as stated above, where the major benefits accrue to the community rather than AusNet Services.

Therefore, AusNet Services is proposing to expand from $3 million to $10 million this valuable component of the incentive framework for the 2016-20 period, with a focus on supporting research into how households can use storage to support the grid and reduce future energy bills.

Finally, AusNet Services has proposed an extensive and cutting edge demand management program. This program is particularly effective given the improved spatial demand forecasting that is possible as result of innovation spending during the current period. AusNet Services believes the program is particularly effective during a time of uncertainty around investing further in long term assets when energy consumption is falling and embedded generation and off network energy solutions are becoming more viable. Demand management ensures reliability can be maintained without locking customers into paying for long-term network costs.

10.3 Service Target Performance Incentive Scheme

The national distribution STPIS provides a financial incentive to distributors to maintain and improve service performance. The STPIS ensures that cost efficiencies encouraged under our expenditure schemes are not at the expense of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

10.3.1 Regulatory Requirements

The default STPIS, as it will be applied in Victoria is defined in the following three documents:

- Electricity Distribution Network Service Providers Service Target Performance Scheme Guidelines, released in November 2009 (STPIS Guidelines);
- Victorian Electricity Distribution Code as it pertains to Guaranteed Service Level (GSLs) payments; and
- The AER's Framework and Approach.

NER S6.1.3(4) requires that a regulatory proposal must contain a description of how the DNSP proposes the STPIS should apply for the relevant regulatory control period.

Modifications to default positions set out in the STPIS Guidelines can be proposed under Clause 2.2 of those guidelines, which requires that the DNSP must:

- Include the reasons for and an explanation of the proposed variation;
- Demonstrate how the proposed variation is consistent with the objectives in Clause 1.5; and
- If appropriate, include the calculations and/or methodology which differ to that provided for under this scheme.

The AER's Framework and Approach and Clause 23 of the RIN similarly provides for proposed modifications to the STPIS.

10.3.2 Proposed Application of the STPIS Scheme

The AER's proposed approach is to continue to apply the national STPIS to the five Victorian electricity distributors in the next regulatory control period. AusNet Services endorses this approach.

Revenue at Risk

The AER's proposed approach is to set revenue at risk for each distributor within a range of ±5 per cent. AusNet Services currently has ±7% of its revenue at risk but is comfortable returning to the standard ±5 per cent for the forthcoming regulatory control period. Therefore, it endorses the AER's position.

Exclusion Threshold

The AER's proposed approach to calculating the exclusion or major event day (MED) threshold is to apply the methodology indicated in the national STPIS Guideline. The Framework and Approach does not make clear whether this implies a uniform 2.5β threshold applied all Victorian distributors or whether current thresholds, which are differentiated between urban and rural distributors, will apply.

AusNet Services currently applies a 2.8β and is proposing this will also apply for the forthcoming regulatory control period. With this clarification, the AER's approach is endorsed.

Exclusions

AusNet Services proposes a variation to clause 3.3 Exclusions of the STPIS Guidelines to include an additional exclusion event as permitted under clause 2.2 of the STPIS Guidelines. The proposed inclusion would involve the addition of a new clause 3.3(a)(8) that reads:

> *(8) load shedding or load interruption due to the failure of a new contracted non-network solution entered into in the current regulatory control period.*

AusNet Services proposed a similar exclusion at the time of the last price review, however, this was rejected by the AER in the Final Determination. The new exclusion proposed is different, insomuch that it is limited only to new demand management contracts entered into during the 2016-20 regulatory control period. Outage events associated with existing demand management contracts will not constitute an exclusion event. This is more aligned with the intent behind the original exclusion proposition that the exemption would be transitory in nature.

Satisfying the National Electricity Objective and STPIS Objectives

The introduction of this clause better meets the AER objectives for this scheme as set out in Clause 1.5 and, in particular, clause 1.5(b)(7) as it ameliorates the possible effects of the STPIS on incentives for the implementation of new non-network alternatives. New non-network alternatives are often:

- R&D in nature or are being trialled for wider application; or
- Are proposed by immature counterparties that are unable to take on the appropriate reliability risk on to their own balance sheet either due to size (venture capital start-ups) or nature (for example government bodies such as the CSIRO), leaving the risk with the DNSP.

The addition of this exclusion is necessary to allow AusNet Services to better manage the risk that may result from a non-network solution failing to meet expected reliability requirements. The risks include the reliability penalties as a result of the failure of the contracted non-network solution. Without this exclusion, the (unproven) reliability risk would be included in the full economic cost of non-network solutions resulting in them being significantly less likely to be adopted, eroding the incentives to implement non-network solutions under clause 6.6.3 of the NER.

In conclusion, AusNet Services does not consider placing insurmountable barriers in the way of such trials, is to the long term benefit of electricity consumers and is, therefore, not consistent with the NEO.

Conclusion

The addition of a new clause 3.3(a)(8) aligns with both the NEO and the objectives of the STPIS outlined in section 1.5 of the STPIS Guidelines.

Therefore, the exclusion of load shedding and load interruptions due to the failure of a contracted non-network solution should be applied as an exclusion criteria of the STPIS for the regulatory control period 1 January 2016 to 31 December 2020.

Measures

The AER proposes to set applicable parameters for:

- Reliability of supply (system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and momentary average interruption duration index or MAIFI); and
- Customer service (telephone answering).

AusNet Services endorses this approach.

The AER proposes to continue to segment the network according to feeder categories (CBD, urban, short rural and long rural as appropriate for each distributor) in the Victorian jurisdictional distribution licence conditions. AusNet Services endorses this approach.

The AER proposes to set performance targets based on the distributor's average performance over the past five regulatory years. AusNet Services supports this approach as the foundation for calculating future targets, however, observes that application of the new VCR will result in further modifications.

GSLs

The AER will not apply the GSL component as the five Victorian electricity distributors are subject to a jurisdictional GSL scheme. In the Framework and Approach, the AER proposes to apply the existing Victorian jurisdictional GSL scheme under the Electricity Distribution Code and the Public Lighting Code. This position is endorsed by the Department of Economic Development, Jobs, Transport and Resources. AusNet Services also endorses this approach.

10.3.3 Proposed Targets

Reliability of Supply Measures

AusNet Services proposes that the targets for the forthcoming regulatory control period be based on the five year historic averages from 2010 to 2014. These are then modified for the effects of the new VCR. The table below shows the historic annual and average performance on the network segments for each reliability measure.

Table 10.1: Historic Performance, 2010–14 (2.8β)

Measure	2010	2011	2012	2013	2014	Average
USAIDI						
Urban	81.514	78.459	61.862	86.162	101.300	**81.859**
Rural Short	236.218	196.095	162.883	165.105	182.220	**188.504**
Rural long	303.816	236.669	207.813	178.565	246.121	**234.597**
USAIFI						
Urban	0.969	1.029	0.919	1.377	1.229	**1.105**
Rural Short	2.801	2.406	1.960	2.233	2.094	**2.299**
Rural long	3.461	3.143	2.492	2.454	2.640	**2.838**
MAIFI						
Urban	2.906	3.148	2.697	2.785	2.458	**2.799**
Rural Short	6.135	5.668	5.740	5.659	5.950	**5.830**
Rural long	12.168	12.168	10.580	9.925	12.059	**11.380**

Source: AusNet Services

Modifications to Average Historic Performance

As explained above, the introduction of the new VCR has impacts on both the expenditure proposed and the expected reliability relative to the historic average over the forthcoming regulatory control period. As outlined in Chapter 7, AusNet Services will defer over $140 million ($2014) of capital expenditure as a result of the applying the new VCR in its planning and risk assessments. This deferral will result in an average decline on historic reliability performance of 3.24 minutes on SAIDI and 0.09 interruptions of SAIFI annually, at a network level. A more detailed breakdown, by network segment is presented below.

Final Proposed Targets and Incentive Rates

As per clause S6.1.3(4) of the NER, AusNet Services' proposed targets and incentive rates are shown in table below. The incentive rates are calculated as per clause 3.2 of the STPIS Guideline using the new VCR.

Table 10.2: Proposed Targets and Incentive Rates for 2016–20

Measure	Average Historic Performance	Modification	Proposed Targets	Proposed Incentive Rates
USAIDI				**(%/minute)**
Urban	81.859	0.773	82.632	0.0161%
Rural Short	188.504	4.143	192.647	0.0128%
Rural long	234.597	7.557	242.154	0.0058%
USAIFI				**(%/0.01 Interruptions)**
Urban	1.105	0.021	1.126	1.3878%
Rural Short	2.299	0.117	2.416	1.2173%
Rural long	2.838	0.213	3.051	0.5748%
MAIFI				**(%/0.01 Interruptions)**
Urban	2.799	-	2.799	0.1110%
Rural Short	5.830	-	5.830	0.0974%
Rural long	11.380	-	11.380	0.0460%

Source: AusNet Services

The movement in the implied VCR for each of the different feeder categories is presented in the table below. This has been calculated by multiplying the AEMO VCRs by the proportion of energy delivered to customers in each segment (residential, commercial, etc.) on each feeder classification.

Table 10.3: Changes in VCR at the feeder classification level

Feeder Classification	Old VCR	New VCR	% reduction
Urban	$71.10	$37.01	48%
Rural Short	$62.87	$35.67	43%
Rural long	$76.76	$37.32	51%

Source: AusNet Services

10.3.4 Customer Service Measures

The customer service parameter places incentives on DNSPs to maintain and improve their call centre fault lines performance.

Consistent with the Framework and Approach, AusNet Services proposes that the targets for the forthcoming regulatory control period be based on the five year historic averages from 2010 to 2014. The table below shows the historic annual and average performance for the customer service measure, once the impact of MEDs has been removed.

Table 10.4: Historic Performance, 2010–14

Measure	2010	2011	2012	2013	2014	Average
% of Total Calls Answered within 30 Seconds	76.4%	82.4%	81.3%	78.3%	83.2%	80.3%

Source: AusNet Services

Final Proposed Targets and Incentive Rates

As per clause S6.1.3(4) of the NER, AusNet Service's proposed targets and incentive rates are shown in the table below. The incentive rates are as stated in clause 5.3.2 (a)(1) of the STPIS Guidelines.

Table 10.5: Proposed Target and Incentive Rate for 2016–20

Measure	Annual Target	Incentive Rate
% of Total Calls Answered within 30 Seconds	80.3%	-0.040% per unit

Source: AusNet Services

Revenue at Risk

Consistent with the STPIS Guidelines, AusNet Services proposes to continue the application of the STPIS customer service parameter cap of +/-0.5% revenue at risk.

10.3.5 Guaranteed Service Level Measures

The GSL scheme sets threshold levels of service for DNSPs to achieve, and requires direct payments to customers who experience service below the pre-determined level.

Consistent with the Framework and Approach, AusNet Services proposes that the targets for the forthcoming regulatory control period be based on the five year historic averages from 2010 to 2014. In accordance with clause S6.1.3(4) of the NER, AusNet Services' proposed GSL targets are shown in the table below.

Table 10.6: Proposed GSL Targets and Allowance for 2016–20

(Number Incurred)	2016	2017	2018	2019	2020
Customers experiencing more than 10 interruptions	6,672	6,672	6,672	6,672	6,672
Customers experiencing more than 15 interruptions	1,413	1,413	1,413	1,413	1,413
Customers experiencing more than 30 interruptions	0	0	0	0	0
Customers experiencing more than 20 hours of interruptions	13,919	13,919	13,919	13,919	13,919
Customers experiencing more than 30 hours of interruptions	10,545	10,545	10,545	10,545	10,545

(Number Incurred)	2016	2017	2018	2019	2020
Customers experiencing more than 60 hours of interruptions	2,003	2,003	2,003	2,003	2,003
Customers experiencing more than 24 momentary interruptions	18,594	18,594	18,594	18,594	18,594
Customers experiencing more than 36 momentary interruptions	4,990	4,990	4,990	4,990	4,990
Distributor being more than 15 minutes late for an appointment	0	0	0	0	0
Connections not made on agreed date (total)	321	321	321	321	321
Connections not made – 1-4 day delay	244	244	244	244	244
Connections not made 5+ day delay	78	78	78	78	78
Not repairing streetlights within two days	701	701	701	701	701
Total Payments (Real 2015 $)	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**

Source: AusNet Services

10.3.6 Transitional Matters

Final close out of the ESCV's 2006-10 S-Factor scheme

In the 2010 EDPR Decision, the AER developed a methodology to close out the ESCV S factor scheme, by replicating the intended benefits or penalties accrued under the scheme. It went to state:

> *"In the 2016–20 distribution determination, the AER will perform a final reconciliation to account for actual 2010 performance under the ESCV S factor scheme."* [2]

The methodology used to close out the ESCV S factor scheme is set out in section 15.6.6 of the 2010 EDPR Decision. AusNet Services has followed the instructions, substituting actual 2010 performance for the estimated performance embedded in its current determination. This recalculation results in revenue that is $19.4 million ($2015) lower than originally estimated and recovered.

Therefore, this number has been subtracted from the forecast revenue for the forthcoming regulatory control period by including the adjustment in the 'revenue adjustments' row of the PTRM.

Correction of 2011 customer service target result

In 2011, due to confusion over the definition of the telephone answering customer service target, AusNet Services supplied and the AER approved an incorrect telephone answering result of 93.37% in the 2011 STPIS outcome. Under the correct definition, the result should in fact have been 82.41%.

2 *Final Decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. LI.

It was subsequently agreed with the AER that the correction to revenue should be made in the current EDPR process.

The incorrect data resulted in a benefit of $2.2 million ($2015) additional revenue in 2013.

Therefore, this number has been subtracted from the forecast revenue for the forthcoming regulatory control period by including the adjustment in the 'revenue adjustments' row of the PTRM.

Application of the old VCR to existing investments

In the Framework and Approach, the AER proposes to:

- *"apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates to past investments*
- *apply the methodology as indicated in our national STPIS to the calculation of incentive rates to new investments and, if practicable, amend the value of customer reliability (VCR) values applicable to future investments consistent with values determined from the most recent AEMO review of VCR values."*[3]

AusNet Services endorses the AER position.

The simplest way to achieve this transition is to apply the old incentive when calculating the STPIS revenue outcomes for the 2016 and 2017 years as these will reflect investments and decision made in the 2014 and 2015 years respectively. The new incentive rates determined from the revised VCR should be applied to revenue outcomes from 2018 onwards.

10.4 Efficiency Benefit Sharing Scheme

This section sets out AusNet Services' proposal with respect to the application of the efficiency benefit sharing scheme (EBSS). It sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period; and
- AusNet Services' views on the operation of the EBSS in the next period.

10.4.1 The current period carry over amount

AusNet Services has calculated the efficiency carryover amount to be recovered during the forthcoming regulatory control period in accordance with the AER's final decision and determination on the application of the EBSS for the 2011-2015 period.

This calculation involved the following steps:

- Determining controllable opex from 2011-2014, which is equal to total opex (including provisions adjustments4 and debt raising costs) less costs considered uncontrollable by the AER:
    - GSL payments;
    - Self-insurance losses;
    - Debt raising costs;
    - DMIA opex;
    - Superannuation defined benefits scheme costs; and
    - Pass through event costs incurred to implement the recommendations of the VBRC.

3 *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016*, p. 97.

4 The provisions adjustment involves the replacement of movements in provisions with actual use of provisions, consistent with the AER's treatment of provisions in its recent TasNetworks and TransGrid reviews.

- Determining controllable opex for 2015 by adding the efficient benchmark increase approved by the AER to 2014 controllable opex;
- Adjusting the 2011-2015 regulatory allowances to reflect actual and revised forecast growth in the following cost drivers, which collectively make up the output growth model applied by the AER for the current period:
    - Line length;
    - The number of distribution transformers; and
    - Zone substation capacity.
- Calculating the efficiency carryover amount by comparing 2011-2015 controllable opex with the adjusted regulatory allowances.

While the Reset RIN lists non-network alternatives costs as an excluded cost category, these costs have not been removed from AusNet Services' total opex for the purposes of calculating controllable opex because they were:

- Included in the controllable opex allowance determined by the AER for the current period; and
- Not listed as an excluded cost category in the AER's 2011-2015 final determination.[5]

No adjustment has been made to actual opex for capitalisation policy changes because no changes have been made to AusNet Services' capitalisation policy during the current period.

The following table sets out the above steps, which result in a proposed efficiency carryover amount of $24 million. Note that the 2011 incremental efficiency gain/loss has been calculated in accordance with the final regulator year adjustment set out in the AER's EBSS for the current period.[6] It is noted that the $0.9 million difference between the carryover amount shown in the table below and provided in the RIN templates is due to different half year inflation adjustment approaches.

[5] AER, *SPI Electricity Determination 2011-2015*, p. 21.

[6] AER, 2008, Electricity distribution network service providers, Efficiency benefit sharing scheme, June 2008, p. 6.

Table 10.7: Calculation of efficiency carryover amount ($m, end 2015)

	2011	2012	2013	2014	2015	Total
O&M expenditure	162.3	171.2	197.1	198.1		
Debt raising costs	4.0	3.7	3.8	3.6		
Total opex	**166.3**	**174.9**	**200.9**	**201.7**		
Less: Debt raising costs	4.0	3.7	3.8	3.6		
Less: Self-insurance losses	0.0	0.7	0.8	1.4		
Less: Superannuation defined benefit schemes	0.7	0.3	-0.5	0.2		
Less: DMIA costs	0.0	0.1	0.2	0.1		
Less: Pass through event costs	0.3	0.4	2.0	3.1		
Less: GSL payments	4.0	7.2	5.3	6.6		
Less: Movements in provisions	0.3	-1.0	0.9	1.2		
Controllable opex	**157.0**	**163.5**	**188.5**	**185.5**	**188.0**	**882.5**
Approved allowance	**172.0**	**179.6**	**186.2**	**196.0**	**198.7**	**932.4**
Adjustment for actual growth	-0.3	-0.6	-0.9	-1.2	-1.6	**-4.7**
Adjusted allowance	**171.6**	**179.0**	**185.2**	**194.7**	**197.2**	**927.8**
Incremental efficiency gain/loss	28.9	0.9	-18.8	12.4	0.0	
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Carryover of efficiency gain/loss made in:						
2011	28.9					**28.9**
2012	0.9	0.9				**1.8**
2013	-18.8	-18.8	-18.8			**-56.3**
2014	12.4	12.4	12.4	12.4		**49.8**
2015	0.0	0.0	0.0	0.0	0.0	**0.0**
Efficiency carryover amount	**23.5**	**-5.4**	**-6.3**	**12.4**	**0.0**	**24.2**

Source: AusNet Services

10.4.2 The 2016-20 regulatory control period

In the Framework and Approach, the AER proposes to apply its new EBSS in Victoria. This version of the EBSS is largely unchanged from the scheme that applied during the current regulatory period. In contrast to that scheme, however, the AER has proposed to not exclude costs from the EBSS on the grounds of uncontrollability. AusNet Services endorses the AER position subject to the exception outlined below. Despite these exceptions, AusNet Services considers its proposed application of the EBSS is consistent with the Framework and Approach.

Proposed exclusions

The AER has limited discretion to remove those categories of opex not forecast using a single year revealed cost approach in the following period. GSL payments are one such category, where the amount forecast is based on a five year average. AusNet Services considers that GSL payments should be excluded from both the allowance and the actuals when assessing the efficiency benefit under the EBSS Guideline. If GSL payments are not excluded this results in an incentive payment on an incentive payment which changes, unintentionally, the underlying jurisdictional GSL incentive which were developed after an assessment of customers' willingness to pay and the balance between the service incentives and efficiency incentives generally.

The DMIA is also specifically designed to be a "use it or lose it" research allowance and should continue to be excluded from EBSS calculations.

Therefore, excluding these costs better achieves the requirements of clause 6.5.8 of the NER and the NEO.

The forecast of the costs to be excluded are provided in section 8.3.5 of the opex chapter.

Treatment of debt raising costs

AusNet Services draws the AER's attention to the fact that it is seeking a debt raising cost opex allowance which is consistent with a single year revealed cost approach, and therefore, is not seeking to exclude debt raising costs from the EBSS. Should the AER instead seek to set debt raising costs using its current benchmark methodology, which embeds a benchmark significantly below actual costs, then debt raising costs must also be excluded from the EBSS calculation. To do otherwise results in a continuous never ending penalty for the distributor which would clearly be inconsistent with both the requirements of clause 6.5.8 of the NER and the NEO.

10.5 Capital Efficiency Sharing Scheme

In the Framework and Approach, the AER proposes to apply the CESS as set out in the capital incentive guideline in Victoria. AusNet Services endorses the AER position.

10.6 F Factor Scheme

In the Framework and Approach, the AER's preliminary position is that, given the limited experience operating under the scheme, the existing incentive rates and targets be maintained and monitored. AusNet Services endorses the AER preliminary position and is proposing to adopt the exiting targets for the forthcoming regulatory control period.

It is also noted that the Department of Economic Development, Jobs, Transport and Resources has advised that it will review the scheme during 2015. If that review results in changes to the scheme, AusNet Services will submit revised information as required.

Table 10.8: Proposed Target and Incentive Rate for 2016–20

Measure	Annual Target	Incentive Rate
Fire start target	256.8	($ nominal) 25,000/start

Source: AusNet Services

10.7 Demand Management Incentive Scheme and Allowance

In the Framework and Approach, the AER proposes to apply the DMIA component of the DMIS in Victoria while noting the COAG Energy Council is considering a number of rule changes proposed by the AEMC in its Power of Choice review. AusNet Services endorses the AER position.

AusNet Services is proposing to increase the DMIA that applies during the upcoming regulatory control period. AusNet Services' DMIA proposal is set out in detail in the demand management chapter (Chapter 9).

10.8 Transitional Incentive Scheme Benchmarks

AusNet Services reiterates its position put in its submission to the *Framework and Approach Position Paper* that the targets that will ultimately apply in the 2016 transitional year should be those settled in the Final Decision. This includes the benchmarks, revenue at risk, exclusion threshold, and any other relevant parameters. While these will not be known with certainty for the first 4 months of 2016, it is expected that the preliminary determination will contain enough information for DNSPs to make an accurate assessment of the marginal incentives that they are likely to face.

10.9 Support Documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Spreadsheet entitled "*AST VCR Impact.xls"* showing the calculation of the adjustment to the STPIS reliability targets for the lower VCR;
- Spreadsheet entitled "*AST VCR by Feeder Class.xls"* showing the calculation of the adjustment by feeder;
- Spreadsheet entitled "*AST Incentive Rates Calculation.xls*";
- Spreadsheet entitled "*AST S-factor true up.xls*" showing the calculation of the final close out of the ESCV's 2006-10 S-Factor scheme;
- Spreadsheet entitled "*AST 2011 Call Centre.xls*" showing the calculation of the correction of 2011 customer service target result; and
- Spreadsheet entitled "AusNet Services - 2016-20 EDPR EBSS Model.xlsx".

11 Cost Pass Through

This chapter sets out AusNet Services' proposed nominated cost pass through events for the 2016-20 regulatory control period.

11.1 Summary

AusNet Services proposes the following nominated cost pass through events in addition to the events prescribed in the NER:

- Insurance cap event;
- Natural disaster event;
- Terrorism event; and
- Power of Choice event.

The proposed definitions for these events are set out in section 11.4.

In considering whether to nominate an event as a pass through event, AusNet Services has been guided by the NEO. Generally, these events are unpredictable as to occurrence, cost and/or timing. For this reason, the long-term benefit to consumers of including the costs associated with a specific event in its total capex or opex forecasts (as appropriate) compared to excluding those costs and using the cost pass through mechanisms has been considered. In general, where the accuracy and efficiency of its forecasts is improved by recovering those costs (if and to the extent they arise) through a pass through mechanism rather than via its approved expenditure allowance, AusNet Services has elected to nominate a pass through event. AusNet Services believes this approach promotes the achievement of the NEO. AusNet Services' approach to identifying nominated cost pass through events in explained in greater detail in section 11.2 below.

AusNet Services also considers that the acceptance of its proposed nominated pass through events is consistent with the Revenue and Pricing Principles. In particular, section 7A(2) requires the AER to provide AusNet Services with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services. The absence of the above pass through events would not provide AusNet Services with such an opportunity because the costs associated with these events have not been accounted for elsewhere in its Proposal.

11.2 Approach to Developing Cost Pass Through Events

By allowing DNSPs to pass through material costs associated with events outside of their control, the cost pass through provisions in the NER provide a key mechanism to deal with the risks presented by uncertainty. These provisions are intended to ensure:

- DNSPs have a reasonable opportunity to recover at least their efficient costs;
- DNSPs face an incentive to manage risk effectively; and
- Expenditure forecasts and approved allowances best reflect the prudent and efficient costs incurred by DNSPs.

In addition to cost pass through arrangements, DNSPs may address risk through a number of other mechanisms. These include:

- Including costs directly in opex and capex allowances;
- Utilising insurance and/or self-insurance; and
- Proposing contingent projects.

Without these mechanisms, there is a risk that the uncertainty associated with an event will create unfunded material expenditure that results in a DNSP's actual expenditure exceeding its approved regulatory allowances for a given regulatory control period. In these circumstances, the DNSP may be forced to either defer or redirect expenditure from other projects where doing so in the long-term interests of customers. Where these options are not available, such an event may threaten the financial sustainability of the DNSP to the extent that it is unable to raise the capital required to maintain and operate its network in order to deliver network services.

Cost pass-through provisions are most appropriate for risks that cannot be dealt with through the above mechanisms. These risks are typically associated with high consequence, low probability events, or where there is substantial uncertainty with respect to the cost impact of an event known to be occurring over a future regulatory period. The cost impact of these events cannot be predicted with sufficient certainty to include in expenditure allowances, while insurance and self-insurance is not likely to be available on a cost effective basis.

Contingent projects are typically relied upon when a DNSP is able to clearly identify the scope and cost impact of an event, but uncertainty exists with respect to the trigger that would require it to incur costs (e.g. demand exceeding a certain threshold). Accordingly, contingent projects are not considered a useful risk management tool for events with unpredictable cost impacts.

The pass through events prescribed in the NER cover a range of scenarios, which are:

"(1) a regulatory change event;

(2) a service standard event;

(3) a tax change event;

(4) a retailer insolvency event; and

(5) any other event specified in a distribution determination as a pass through event for the determination."[1]

AusNet Services has identified three events that do not presently satisfy any of the five prescribed pass through events: an insurance cap event, a natural disaster event and a terrorism event. AusNet Services has also identified the Power of Choice (PoC) reforms as an event that may be covered by the regulatory change cost pass through event set out in the NER. However, the materiality threshold applying to pass through events[2] may prevent AusNet Services from passing through costs resulting from the PoC review because of the separate, but interconnected, nature of the reforms. While PoC changes may collectively increase costs in excess of the materiality threshold specified in the NER, individual changes may not. Accordingly, AusNet Services is proposing a PoC cost pass through event. These four events are discussed further in section 11.4.

Clause 6.5.10(a) allows DNSPs to nominate additional pass through events to those prescribed in the NER:

"A building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the nominated pass through event considerations."[3]

In accordance with this clause, AusNet Services is proposing these events as nominated pass through events for the forthcoming regulatory control period. The matters the AER must consider when assessing proposed nominated events, known as the nominated pass through event considerations, are defined in the NER as follows:

"(a) whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to (4) (in the case of a distribution determination) or clause 6A.7.3(a1)(1) to(4) (in the case of a transmission determination);

(b) whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;

1 NER, Clause 6.6.1(1a).

2 The materiality threshold set out in the NER is equal to 1 per cent of the DNSP's annual revenue requirement for that regulatory year.

3 NER, Clause 6.5.10(a).

(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;

(d) whether the relevant service provider could insure against the event, having regard to:

(1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or

(2) whether the event can be self-insured on the basis that:

(i) it is possible to calculate the self-insurance premium; and

(ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services; and.

(e) any other matter the AER considers relevant and which the AER has notified Network Service Providers is a nominated pass through event consideration."[4]

AusNet Services has identified three further events where considerable uncertainty exists with respect to cost impacts, but is not proposing these as nominated cost pass through events because they are covered by the regulatory change event. These are a Rapid Earth Fault Current Neutraliser (REFCL) event, a Critical Infrastructure Declaration Event and a Codified Area Event. These three events are discussed further in section 11.3.

AusNet Services approach to identifying cost pass through events has broadly involved:

- Identifying potential changes to its operating environment and regulatory and legislative framework that may create risk over the forthcoming period;
- Assessing the certainty, likelihood and consequence of each risk to determine whether risks can be accounted for in expenditure forecasts or in the case of low consequence risks, absorbed internally;
- Reviewing the available risk management measures that may be used to mitigate or prevent risks, including:
    - Opex;
    - Capex;
    - Insurance;
    - Self-insurance;
    - WACC; and
    - Prescribed pass through events in the NER.

Through this approach, AusNet Services has been able to identify a number of risks that are best managed through the nominated pass through arrangements. Nominating a risk as a cost pass through event is the most appropriate treatment for low likelihood, high consequence risks that cannot be efficiently managed using alternative measures, or for risks with a high likelihood of occurrence but where substantial uncertainty exists with respect to cost impacts and timing (e.g. PoC reforms).

For the latter category of risks, AusNet Services emphasises that its preferred approach is to use pass through arrangements, rather than expenditure allowances. This approach ensures that the forecasts of the prudent and efficient costs associated with these risks, which are recovered through tariffs, are based on accurate and reliable information and data, therefore aligning with AusNet Services' commitment to providing electricity services in a way that is in the long term interest of consumers.

4 NER, Chapter 10.

11.3 Other Events

As noted above, AusNet Services has identified three events where considerable uncertainty exists with respect to cost impacts, but is not proposing these as nominated cost pass through events because they are covered by the regulatory change event. These are:

- A Rapid Earth Fault Current Limiter (REFCL) event;
- A Critical Infrastructure event; and
- A Codified Area event.

While AusNet Services expects the costs associated with a REFCL event to exceed the materiality threshold set out in the NER, there is a reasonable likelihood that the cost impacts of the Critical Infrastructure and Codified Area events will not. In the long-term interests of its customers, AusNet Services has elected not to include the potential costs of these events within its expenditure forecasts because of the degree of uncertainty surrounding these costs at the time of this Proposal. While the appropriate treatment of this uncertainty will be reassessed at the time of its Revised Proposal, AusNet Services invites the AER to discuss this matter prior to making its draft determination.

The remainder of this section provides further information regarding the REFCL, Critical Infrastructure and Codified Area events.

11.3.1 Rapid Earth Fault Current Limiter event

Following the Black Saturday Bushfires which occurred on 7 February 2009, the subsequent 2009 Victorian Bushfire Royal Commission (VBRC) made a number of recommendations relating to electricity network assets. Due to technical complexities, the VBRC recommended that Recommendations 27 and 32, which related to the replacement of SWER power lines and 22 kV feeders and the operation of automatic circuit reclosers during peak bushfire season, be further investigated by an expert taskforce.

The Victorian Government subsequently established the Powerline Bushfire Safety Taskforce which provided its recommendations on 30 September 2011. The Government provided its response to these recommendations in December 2011 which included acceptance of the proposal to install Rapid Earth Fault Current Limiter (REFCL) electrical protection devices over a ten year period in order to minimise the risk of fire ignitions from electricity network assets. The recommendation was for distribution businesses to include within their Bushfire Mitigation Plans the locations and timing for roll out of the devices.

Prior to the roll out of this technology, the Victorian Electricity Supply Industry (VESI), together with Energy Safe Victoria (ESV) participated in the Department of Economic Development, Jobs, Transport and Resources' (DEDJTR) program to trial the REFCL technology. The purpose of the trials are to confirm the electrical operating parameters of the technology and its ability to restrict energy, delivered through network faults, to levels that are unlikely to initiate ground fires.

AusNet Services is an active participant in the DEDJTR's program with REFCLs being installed at Woori Yallock and Kilmore South zone substations. In October 2012, the AER approved an expenditure allowance of $12.8 million ($2012) for the Woori Yallock REFCL[5]. The cost of the Kilmore South REFCL was not sought in any expenditure allowance.

The DEDJTR published findings from trials conducted at Frankston zone substation (on United Energy's distribution network) in late 2014 that essentially confirmed the effectiveness of the technology in minimising the risk of fire ignition associated with phase to ground faults on multiphase high voltage networks for a number of scenarios.[6] Whilst further trials are scheduled to commence at

[5] AER, Final Decision, *SP AusNet cost pass through application of 31 July 2012 for Costs arising for the Victorian Bushfire Royal Commission (Confidential version)*, 19 October 2012, p. 26.

[6] RECFL Trial Report, http://www.energyandresources.vic.gov.au/energy/safety-and-emergencies/powerline-bushfire-safety-program/refcl-trial-report

Kilmore South in mid-2015, the DEDJTR is proposing to establish legislation in late 2015 that would prescribe network electrical performance criteria. To facilitate the establishment of the proposed legislation, the DEDJTR has initiated the process of undertaking a Regulatory Impact Statement (RIS).

Although expenditure to roll out the technology is likely to been needed in the 2016-20 period, significant uncertainty exists over the scope and cost of the program that will be required. Completion of the RIS should establish locations and timing for the roll out of electrical protection technology by distribution businesses to achieve the Government's objective of minimising bushfire risk in Victoria.

Rather than seek to pre-empt the legislative requirement, it is appropriate to use the pass through framework within the NER to ensure the right program is delivered and that the expenditure allowance is based on a reasonable estimate of the cost of that program, which will only be possible once further details of the roll out program are confirmed.

Depending on the timeframe for the legislation, AusNet Services may be in a position to develop a full expenditure proposal before the finalisation of the AER's 2016-20 electricity distribution determination for AusNet Services. However, at the time of this Proposal, AusNet Services considers that the uncertainty surrounding REFCLs should be treated using the regulatory change event prescribed in the NER.

11.3.2 Critical Infrastructure Declaration event

In December 2014, the Victorian Government released its *Critical Infrastructure Resilience Interim Strategy* (Interim Strategy), setting out the Government's approach to improving the resilience of the state's critical infrastructure. A key part of the Interim Strategy is the amendment of the Victorian *Emergency Management Act 2013*. Unless proclaimed earlier, the amendments made by the *Emergency Management Amendment (Critical Infrastructure Resilience) Act 2014* will take effect on 1 July 2015, changing the way critical infrastructure is assessed and introducing mandatory requirements for operators of "vital" critical infrastructure.

AusNet Services understands that the amendments aim to implement a model that identifies individual assets as being critical to one which declares the criticality of the functionality of any asset of state significance, with any essential services required to operate that asset declared at the same level of criticality.

For example, if a hospital is 'declared' then the providers of essential services to the asset, such as electricity, water or gas, may be 'declared' as well. This may include AusNet Services' electricity distribution network where it supports vital infrastructure, which would mean assets (e.g. zone substations) that were previously not considered critical infrastructure will be classified as such, requiring improvements to security protection to meet a higher standard than what is currently deployed.

- The current security arrangements at assets such as zone substations are typically limited to secure fencing with conventional door locks on buildings. The declaration of an asset may require additional security deployment, which could include some or all of the following measures:
- Electronic Access Control to perimeter entry points and buildings;
- Electric fence affixed to chain mesh fence;
- Remote control lighting;
- Mobile security patrols;
- Closed Circuit Television (CCTV); and
- Monitored alarm system.

At the time of this Proposal, the new model for critical infrastructure declaration is yet to be finalised, making it difficult to predict how many distribution assets may fall in to this category, or the precise nature of the security upgrades that would be required at each asset.

Because of this uncertainty, AusNet Services has elected not to include the potential cost of its assets being identified as critical in its expenditure forecasts. While there is a risk that these costs will not exceed the materiality threshold, this approach is preferable as it promotes the long-term interests of customers.

Depending on the timing of the implementation of the new critical infrastructure model, it may be possible to forecast the relevant expenditure prior to the finalisation of the AER's 2016-20 electricity distribution determination for AusNet Services. However, at the time of this Proposal, AusNet Services considers that the uncertainty surrounding the declaration of critical infrastructure should be treated using the cost pass through events prescribed in the NER.

11.3.3 Codified Area event

In response to the recommendations of the VBRC, the Victorian Government allocated $200 million in funding for the replacement of existing bare wire, high voltage and private overhead electric lines (POELs) in the highest bushfire consequence areas (HBCAs). However, this program will not be sufficient to address all overhead powerlines within HBCAs.

Accordingly, the Victorian Government has stated its intention to continue to focus power line replacement activities in HBCAs by declaring these as "codified areas". Powerline replacement in codified areas is expected to yield the greatest net benefit for the community through reduction of bushfire risk.

Within a codified area, specific powerline design and maintenance standards will apply to each DNSP through its electricity safety management schemes (ESMS). These standards will set out requirements in relation to, among other things, the replacement of bare high voltage powerlines with insulated technologies that offer greatly reduced risk of bushfire ignition, but are substantially more costly. This will result in the replacement of existing high voltage powerlines with underground cable, aerial bundled cable or spacer cable. These technologies, which are significantly more costly than bare powerlines, will also be deployed for all new high voltage powerlines, including for both new customer connections and augmentation works.

At the time of this Proposal, considerable uncertainty exists as to how codified areas will be applied, including which areas will be codified, when decisions as to codification will be made, and the trigger to replace conductor that has reached end of life. If a codified area is declared in AusNet Services' network area, it is likely to have a substantial impact on replacement and/or connection and augmentation expenditure over forthcoming regulatory control period. The magnitude of the impact will depend on the nature of the powerline design and maintenance standards to apply within a codified area, as well as the size and number of codified areas.

ESV will be required to prepare a Regulatory Impact Statement (RIS) before the necessary changes to existing electricity safety legislation can be made. Preparation of this RIS, which AusNet Services understands has not commenced at the time of this Proposal, is anticipated to involve considerable community consultation because of the potential cost impacts on customers residing within codified areas. For example, the cost of new connections within a codified area will significantly increase because of the higher safety standards that must be met. This consultation process will have important implications for the scope and timing of the scheme.

Because of the uncertainty existing at the time of this Proposal with respect to the codification of areas, AusNet Services has elected not to include the potential costs of this event. While there is a risk that these costs will not exceed the materiality threshold, AusNet Services considers that this approach is in the long long-term interests of its customers.

Depending on the timing of the necessary legislative changes, it may be possible to forecast the relevant expenditure prior to the finalisation of the AER's 2016-20 electricity distribution determination for AusNet Services. However, at the time of this Proposal, AusNet Services considers that the uncertainty surrounding the codification of areas should be treated using the cost pass through events prescribed in the NER.

11.4 Proposed Cost Pass Through Events

In addition to the prescribed pass through events defined in the NER, AusNet Services proposes a number of nominated pass through events for the forthcoming regulatory control period. These cost pass through events, which have been developed in accordance with the approach set out in section 11.2, are:

- An insurance cap event;
- A natural disaster event;
- A terrorism event; and
- A Power of Choice event.

Each of these events is discussed below.

11.4.1 Insurance cap event

Background

AusNet Services maintains a level of insurance cover that is commensurate with the scale and size of its operations, the risks assessed to be associated with its operations and industry standards and practices. According to Aon, AusNet Services "purchases the single highest bushfire limit of Aon's largest utility clients in Australia and globally and certainly has the highest limit of any utility company in Australia."[7] The premiums associated with this insurance cover have been incorporated into AusNet Services' proposed opex forecast.

AusNet Services' opex forecast also includes self-insurance costs that relate to liability losses falling below its deductible. AusNet Services' proposed self-insurance forecast explicitly excludes losses from liability that exceeds the limit, or cap, of its insurance policies. This approach has been adopted because of:

- The complexity associated with developing credible self-insured risk quantifications for very low probability events, such as those that are above existing liability caps is such that the risk quantifications would likely be inaccurate; and
- If such an event did occur, it is likely that it would be catastrophic in nature, thus requiring substantial self-insurance premiums, which is unlikely to be in the long-term interests of consumers.

Accordingly, AusNet Services is exposed to the risk that it incurs liability losses that exceed its insurance caps. AusNet Services considers that nominating an 'insurance cap event' as a cost pass through event is a prudent and efficient way to mitigate this risk.

While AusNet Services' insurance cap is substantial, recent no liability settlements in relation to the Black Saturday bushfires demonstrate the significant liability losses the company's liability insurance policy absorbs. These settlements include the:

- $378.6 million settlement of the Kilmore East Bushfire Class Action approved by the Supreme Court of Victoria on 23 December 2014;[8]
- $260.9 million settlement of the Murrindindi Bushfire Class Action in February 2015 (which is subject to court approval); [9] and

[7] Aon, *Insurance Premium Forecast*, p. 8.

[8] ASX and SGX-T Release, Court Approves the Settlement of Kilmore East Bushfire Class Action, 23 December 2014.

[9] ASX and SGX-T Release, Settlement of Murrindindi Bushfire Class Action (Subject to Court Approval), 6 February 2015.

- $19.7 million settlement of the Beechworth Bushfire Class Action, approved by the Court on 16 May 2012.[10]

AusNet Services considers that its insurance cap event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. This is because:

- The insurance cap event is not covered by any of the prescribed cost pass through events set out in the NER;
- The nature and type of an insurance cap event can be clearly identified at the time of the AER's final determination;
- AusNet Services' ability to prevent or limit an insurance cap event on a cost-effective and efficient basis is limited. That said:
    - The protection of communities within its area of operations is of critical importance of AusNet Services, and it has developed a sophisticated approach to managing network safety; and
    - The substantial deductible payable on AusNet Services' bushfire liability policy creates a strong financial incentive for it to prevent or mitigate the risk of such events from occurring in the first place; and
- AusNet Services has exhausted cost effective market capacity for bushfire liability insurance in recent years;[11] and
- As explained above, it is not possible to calculate robust self-insurance premiums for liability losses that exceed the policy cap.

AusNet Services also considers that accepting the insurance cap event is consistent with the Revenue and Pricing Principles. In particular, section 7A(2) of the NEL requires AusNet Services to be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services. The absence of such a pass through event would preclude AusNet Services from receiving such an opportunity because the costs of an insurance cap event have not been accounted for elsewhere in this proposal.

Proposed definition

AusNet Services notes that in its draft decisions for the NSW DNSPs, the AER accepted an insurance cap event as a nominated pass through event but amended the proposed definition to "clarify some factors to which [it] will have regard when assessing a claim."[12] The amendments included the addition of a paragraph stating:

> *"Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application … the AER will have regard to:…*
>
> *i. the insurance policy for the event; and [*sic*]*
>
> *ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event*
>
> *iii. the extent to which a prudent provider could reasonably mitigate the impact of the event."*[13]

AusNet Services expects the AER will amend its definition of an insurance cap event to include equivalent text. Based on that expectation, AusNet Services makes the following comments.

10 ASX and SGX-T Release, Court Approves the Settlement of Beechworth Bushfire Class Action, 16 May 2012.

11 Aon, *Insurance Premium Forecast*, p. 8.

12 AER, AusGrid *draft decision | Attachment 15: Pass through events*, p. 11.

13 AER, AusGrid *draft decision | Attachment 15: Pass through events*, p. 14.

AusNet Services considers paragraph (iii) of the AER's amendment is unnecessary. The factors listed in NER 6.6.1(j) which the AER must have regard to in making a cost pass through determination permit the AER to consider "any other factors that the AER considers relevant."[14] In AusNet Services' opinion, this clearly encompasses considerations about the extent to which a prudent operator could reasonably mitigate the impact of the pass through event.

Moreover paragraph (iii) is potentially ambiguous. For example:

- Does it require a DNSP to acquire exorbitantly priced insurance (with the cost recovered through its regulated revenue)?
- Does it eliminate any prospect of recovery if there has been negligence (which is the exact cover that is being provided by liability insurance)?
- Does it require self-insurance (again with the cost recovered through its regulated revenue)?

AusNet Services considers that both customers and DNSPS desire clarity around this critical definition to avoid confusion in the pass-through application process. Clarity is provided by linking the nature and terms of the pass-through protection to that provided in the relevant insurance policy that has been exceeded.

Accordingly, AusNet Services' proposed definition of an insurance cap event makes the following refinements to the definition adopted in the NSW draft decisions:

- paragraph (i) is amended to insert the word 'relevant' to be consistent with the use of 'relevant insurance policy' which a defined term; and
- paragraph (iii) is deleted.

If the AER is minded to retain paragraph (iii), AusNet Services requests that the AER consider amending the drafting to remove any potential conflict arising from the application of NER 6.6.1(j)(3). That clause requires the AER to take into account:

> *"[I]n the case of a positive change event, the efficiency of the Distribution Network Service Provider's decisions and actions in relation to the risk of the positive change event, including whether the Distribution Network Service Provider has failed to take any action that could reasonably be taken to reduce the* ***magnitude of the eligible pass through amount*** *in respect of that positive change event and whether the Distribution Network Service Provider has taken or omitted to take any action where such action or omission has* ***increased the magnitude of the amount*** *in respect of that positive change event;"* (emphasis added)

The emphasised text reflects that the AER's task under this clause is to consider how AusNet Services' actions (or failure to act) affected the "magnitude" of the eligible pass through amount, i.e. the quantum of the amount. In contrast, the AER's paragraph (iii) calls into focus a much broader range of conduct and consequences.

If the intention of paragraph (iii) is to expressly acknowledge that the AER will compare AusNet Services' conduct with what a prudent DNSP would have done, the drafting of the paragraph should mirror NER 6.6.1(j)(3). Therefore, if the AER retains paragraph (iii) in its existing or in an amended form, AusNet Services requests that it explain how it intends to take this matter into account, and how it sees this paragraph operating in conjunction with the factors in NER 6.6.1(j).

AusNet Services proposed definition of an insurance cap event is as follows:

> *"An insurance cap event occurs if:*
>
> 1. *AusNet Services makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
> 2. *AusNet Services incurs costs beyond the relevant policy limit, and*

[14] NER, clause 6.6.1(j)(8).

3. *the costs beyond the relevant policy limit materially increase the costs to AusNet Services in providing direct control services.*

For this insurance cap event:

4. *the relevant policy limit is the greater of:*

   a. *AusNet Services actual policy limit at the time of the event that gives, or would have given rise to a claim, and*

   b. *the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.*

5. *A relevant insurance policy is an insurance policy held during the 2015-19 regulatory control period or a previous regulatory control period in which AusNet Services was regulated.*

Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to:

i. *the relevant insurance policy for the event, and*

ii. *the level of insurance that an efficient and prudent NSP would obtain in respect of the event."*

11.4.2 Natural disaster event

Background

As was demonstrated by the Black Saturday bushfires, the cost impact of a natural disaster on AusNet Services' network assets can be potentially significant. Possible natural disasters that could cause significant property damage include, but are not limited to, bushfires, earthquakes, storms and floods.

As discussed in Aon's insurance report at Appendix 8A, AusNet Services' insurance coverage provides some protection against property damage caused by natural disasters. Because this coverage does not extend to poles and wires assets, AusNet Services has also proposed a self-insurance allowance as part of its opex forecast for damage to these assets. However, the cost impact of a natural disaster could materially exceed the coverage provided by these measures.

Further, while the insurance cap event provides a cost recovery mechanism in the event of a natural disaster, the AER has acknowledged the need for both pass through events "because the NSP may incur costs which an insurance policy would not ordinarily cover."[15]

For these reasons, AusNet Services proposes a 'natural disaster event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with a natural disaster event will be net of insurance and self-insurance cover and any amounts recovered through an insurance cap event claim. AusNet Services considers that this pass through event satisfies the nominated pass through event considerations and should be accepted by the AER.

AusNet Services considers that including 'natural disaster event' as a nominated pass through event represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in AusNet Services' costs. This position is supported by the nominated pass through event considerations:

- Natural disaster is not covered by any of the prescribed cost pass through events set out in the NER;
- The nature and type of event can be clearly identified at the time that the AER makes its determination for AusNet Services;

[15] AER, *AusGrid draft decision | Attachment 15: Pass through events*, p. 13.

- The extent to which AusNet Services can reasonably prevent a natural disaster event from occurring and/or can substantially mitigate the cost impacts of such an event is limited;
- AusNet Services' insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage caused by a natural disaster. However, the cost impact of a natural disaster could materially exceed the coverage provided by this insurance. Any pass through amount claimed in association with a natural disaster event will be net of insurance cover; and
- The relative infrequency and potentially very high costs of a natural disaster creates significant practical challenges for self-insurance of such events. A pass though mechanism provides a more appropriate arrangement for managing the cost impacts in the unlikely circumstances that a natural disaster event occurs and causes a material increase in AusNet Services' costs. AusNet Services considers that managing costs in this way is in the long-term interest of consumers.

Proposed definition

AusNet Services notes that the AER accepted a natural disaster event in its draft decisions for the NSW DNSPs. However, to avoid creating an incentive for DNSPs to underinsure against natural disasters and instead manage this risk instead through pass through arrangements, the AER amended the definition proposed by the DNSPs. These amendments included the addition of a paragraph stating that the AER will have regard to "the extent to which a prudent provider could reasonably mitigate the impact of the event."[16] For the reasons in the above discussion of the insurance cap event, AusNet Services submits this paragraph should be removed.

AusNet Services' proposed definition of a natural disaster event is therefore as follows:

> *"A natural disaster event occurs if:*
>
> *Any major fire, flood, earthquake or other natural disaster occurs during the 2016-20 regulatory control period and materially increases the costs to AusNet Services in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider.*
>
> *The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP's annual revenue requirement for that regulatory year).*
>
> *Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:*
>
> *i. whether AusNet Services has insurance against the event,*
>
> *ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and*
>
> *iii. whether a relevant government authority has made a declaration that a natural disaster has occurred."*

11.4.3 Terrorism event

Background

The cost impacts of an act of terrorism, such as a cyber-attack on AusNet Services' IT and network operations systems, could potentially be significant. AusNet Services' insurance coverage provides some protection against losses caused by terrorism, however the cost impact of such an event could materially exceed the coverage provided by these measures.

16 AER, *AusGrid draft decision | Attachment 15: Pass through events*, p. 15.

Further, while the insurance cap event provides a cost recovery mechanism in the event of an act of terrorism, the AER has acknowledged the need for both pass through events "because the NSP may incur costs which an insurance policy would not ordinarily cover."[17]

For these reasons, AusNet Services proposes a 'terrorism event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with a terrorism event will be net of insurance cover and any amounts recovered through an insurance cap event claim.

AusNet Services considers that including 'terrorism event' as a nominated pass through event represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in AusNet Services' costs. This position is consistent with the nominated pass through event considerations:

- Terrorism event is not covered by any of the prescribed cost pass through events set out in the NER;
- The nature and type of event can be clearly identified at the time that the AER makes its determination for AusNet Services;
- The extent to which AusNet Services can reasonably prevent a terrorism event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, AusNet Services has a range of measures in place which are intended to prevent acts of terrorism, and mitigate the cost impact of such an event should one occur;
- AusNet Services' insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage caused by a terrorism event. However, the cost impact of such an event could materially exceed the coverage provided by this insurance. Any pass through amount claimed in association with a terrorism event will be net of insurance cover; and
- The relative infrequency and potentially very high costs of terrorism events creates significant practical challenges for self-insuring such events. A pass though mechanism provides a more appropriate arrangement for managing the cost impacts in the unlikely circumstances that a terrorism event occurs and causes a material increase in AusNet Services' costs. AusNet Services considers that managing costs in this way is in the long-term interest of consumers.

Proposed definition

AusNet Services notes that the AER approved a terrorism event in its draft decisions for the NSW DNSPs. However, to avoid creating an incentive for DNSPs to underinsure against such events and manage this risk instead through pass through arrangements, the AER amended the definition proposed by the DNSPs. These amendments included the addition of a paragraph stating that the AER will have regard to "the extent to which a prudent provider could reasonably mitigate the impact of the event."[18]

For the reasons explained in the above discussion of the insurance cap event, AusNet Services submits this part of the amendment should be removed.

AusNet Services' proposed definition of a terrorism event is therefore as follows:

> *"A terrorism event occurs if:*
>
> *An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any*

[17] AER, *AusGrid draft decision | Attachment 15: Pass through events*, p. 13.

[18] AER, *AusGrid draft decision | Attachment 15: Pass through events*, p. 15.

section of the public, in fear) and which materially increases the costs to AusNet Services in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

i. whether AusNet Services has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event,

iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred, and

11.4.4 Power of Choice event

Background

On 30 November 2012, the AEMC released its final report and implementation plan with respect to its review of demand side participation in the NEM, titled *Power of Choice – giving consumers options in the way they use electricity*. In response to this report, the Council of Australian Governments (COAG) and the COAG Energy Council agreed to implement a suite of energy market reforms that relate to:

- Improving pricing and incentives by providing customers with clear signals about the cost of their energy consumption;
- Providing customers and demand side providers with information that allows them to choose efficient demand options; and
- Implementing a range of technologies, skills and supporting frameworks to support pricing information and demand management options.[19]

The implementation of the Power of Choice (PoC) reforms will require changes to the NER. Accordingly, multiple rule change requests have been submitted to the AEMC by the COAG Energy Council. These rule changes will have a number of implications for the operation of the electricity market, some of which are likely to affect the cost of providing direct control services.

For example, the AEMC's draft rule determination regarding a rule change request to establish arrangements that would promote competition in the provision of metering and related services in the NEM was published on 26 March 2015.[20] This determination set out the AEMC's preliminary views on the establishment of these arrangements. However, AusNet Services considers that the rule change effective date could fall anywhere in the first few years of the forthcoming period.

It is anticipated that a number of ICT system changes will be required to respond to metering contestability, including changes to Network Billing Systems, Customer Information System (CIS), Meter Data Management System (MDMS), and the Meter Management System (MMS). While the costs of these system changes are likely to be substantive, the level of uncertainty with respect to the cost impacts and timing of the changes precludes AusNet Services from developing an accurate expenditure forecast at this stage.

In addition to metering contestability, a number of other PoC related rule change requests create considerable uncertainty for AusNet Services over the forthcoming regulatory control period. For example, the "multiple trading relationships" rule change request[21] introduces settlement points as the NMI, without the necessary changes to the arrangements set out in the NER. Implementing this change is expected to require significant architectural changes to both AusNet Services' AMI and

[19] COAG Energy Council rule change request.

[20] AEMC, *Draft Rule Determination - National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 and National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 March 2015.

[21] AEMO, *Rule Change Request – Multiple Trading Relationships*, 17 December 2014. Available at http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships.

non-AMI systems (e.g. CIS, MDMS, network billing systems). Further, the “embedded networks” rule change request[22] introduces a new Market Participant Role and obligation changes that are likely to require moderate changes to both AMI and non-AMI systems.

The table below, which summarises the status of PoC-related rule change requests, demonstrates the scope of the review and the immature stage that many key reforms are presently at.

Table 11.1: Status of Power of Choice rule change requests

Rule Change Request	Status
Distribution network pricing arrangements	Final determination published 27 November 2014
Expanding competition in metering and related services	Preparation of draft determination
Customer access to information about their electricity consumption	Final determination published 6 November 2014
Improving demand side participation information provided to AEMO by registered participants	Draft determination published 18 December 2014
Reform of the demand management and embedded generation connection incentive scheme	Request received. Expected to commence consultation in early 2015
Demand response mechanism – option for demand side resources to participate in the wholesale electricity market	COAG Energy Council officials developing rule change request
Multiple trading relationships	Request received
Embedded Networks	Requested received

Source: http://www.aemc.gov.au/Major-Pages/Power-of-choice.

This section demonstrates that there is a large degree of uncertainty with respect to the timing and quantum of PoC related cost impacts, limiting AusNet Services’ ability to accurately account for these impacts in its expenditure forecasts.

While a PoC event may be covered by the regulatory change cost pass through events set out in the NER, the materiality threshold applying to prescribed events may prevent AusNet Services from passing through costs resulting from the PoC review because of the separate, but interconnected, nature of the reforms. While PoC changes may collectively increase costs in excess of the materiality threshold specified in the NER, individual changes may not. This creates a risk that AusNet Services will incur costs not accounted for in its approved expenditure allowances should the AEMC determine rule changes that materially increase its costs over the forthcoming period.

Accordingly, AusNet Services is proposing a pass through event in relation to PoC. AusNet Services considers its Power of Choice nominated pass through event is consistent with the nominated pass through event considerations for the following reasons:

- The implications of some rule change requests associated with the PoC review are currently unclear due to the early stage of the AEMC’s review. For example, the AEMC is yet to commence its review of the multiple trading relationships and embedded generation rule change requests. However, the potential consequences of the PoC rule change requests are set out in the relevant rule change requests. This means that while the specific implications of some rule change requests are not yet known, the nature and type of the event(s) – NER changes resulting

[22] AEMO, *Rule change Request – Embedded Networks*, 1 October 2014. Available at http://www.aemc.gov.au/Rule-Changes/Embedded-Networks.

in new or changed obligations – can reasonably identified by the AER at the time it makes a determination for AusNet Services;

- By changing the regulatory framework DNSPs operate within, the rules changes arising from the PoC review will create new regulatory obligations and requirements which AusNet Services cannot reasonably prevent or mitigate the cost impacts of; and
- Insurance and self-insurance are not appropriate mechanisms to manage the uncertainties associated with the PoC review.

AusNet Services considers that the cost pass through provisions in the NER were designed with events such as the PoC review in mind. The significant uncertainty that exists with respect to the cost impacts and timing of PoC mean that it is in the long-term interests of customers for AusNet Services to recover the prudent and efficient costs of the event through pass through arrangements, rather than ex ante expenditure forecasts. This approach is being proposed despite the strong likelihood that the PoC reforms will be implemented over the forthcoming period. Consequently, AusNet Services would welcome the AER's views on the most appropriate treatment of the uncertainty created by the Power of Choice reforms prior to its draft determination.

Proposed definition

AusNet Services' proposed definition of a Power of Choice event is as follows:

A Power of Choice event occurs if:

1. The AEMC publishes notice of the making of a rule under sections 96A, 102 or 102A of the National Electricity Law; and

2. The rule is:

(a) The National Electricity Amendment (Improving demand side participation information provided to AEMO by registered participants) Rule 2015 No. 4; or

(b) The National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9; or

(c) The National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014 No. 7; or

(d) The final rule made in determination of Rule change proposal ERC0169 Expanding competition in metering and related services; or

(e) The final rule made in determination of the rule change request submitted by AEMO on 2 October 2014 which is identified by the AEMC as ERC0179 Embedded Networks; or

(f) The final rule made in determination of the rule change request submitted by AEMO on 17 December2014 which is identified by the AEMC as ERC0181 Embedded Networks; or

(g) Any other final rule made in determination of a rule change proposal which reflects, in whole or in part, one or more of the recommendations made by the AEMC in Power of choice review – giving consumers options in the way they use electricity, Final Report dated 30 November 2012; and

3. At the date notice under paragraph 1 is given, implementing or complying with that rule and each rule in paragraph 2 made earlier in time, individually or in aggregate and in any combination, materially increases the cost of providing direct control services.

If, at the time the Power of Choice event occurs:

4. The AEMC has not published notice of the making of one or more of the rules in paragraph 2; and

5. AusNet Services cannot provide evidence of the actual or likely increase in costs that it will or is likely to incur in providing direct control services as a result of the making of that rule or rules,

AusNet Services may seek the approval of the AER later in the regulatory control period to pass through those amounts on the basis that the materiality threshold is met.

11.5 Application of Pass Through Arrangements to Alternative Control Services

AusNet Services' nominated events should apply to all direct control services, namely standard control services and alternative control services on the basis that the costs of providing alternative control services are also permitted to be considered as part of the cost pass through framework in Rule 6.6.1.

12 Return on Capital

12.1 Overview

12.1.1 Introduction

Electricity distribution networks are capital intensive with long lived assets and therefore a key aspect of the Australian Energy Regulator's (AER) distribution determination is the allowed rate of return on the capital invested in AusNet Services' business. Rule 6.12.1 of the National Electricity Rules (the Rules)[1] provides that two of the constituent decisions that form part of the overall determination are:

- A decision on the allowed rate of return for each regulatory year of the regulatory control period in accordance with Rule 6.5.2 of the Rules[2]; and
- A decision on whether the return on debt is to be estimated using a methodology in which the allowance is potentially different for different regulatory years in the regulatory control period and, if that is the case, the formula that is to be applied in accordance with Rule 6.5.2(i) of the Rules[3].

Where there is uncertainty, expert evidence explains how the expected costs for electricity consumers of setting too low an allowance for the return on capital are greater than the expected costs of setting the allowance too high[4].

An efficient allowed rate of return is particularly important. If the rate of return is inflated, customer network charges will be higher than necessary. Equally, if the rate of return is below a fair market return, network businesses will be unable to attract investment capital necessary to promote efficient investment in electricity services in the long-term interests of consumers.

As a result of reforms adopted by the Australian Energy Market Commission (AEMC) in 2012, the Rules governing the AER's allowed rate of return decisions set out in Rule 6.5.2 of the Rules have been re-written. A range of previous policy considerations have now been encapsulated in an explicit guiding principle for the AER's decision concerning the rate of return in the following rate of return objective:

> *"…that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider …."*[5]

The new rules require the AER to have regard to all the relevant models and other available inputs6, not just the sub-set of material that the rules previously required. With respect to equity, the new rules require[7] the allowance to be set having regard to the prevailing conditions in the market for equity funds. With respect to debt, the AER has alternatives[8]. One alternative is the "on-the-day" method (which takes a focus on the prevailing conditions in the market for debt funding) and another permits a broader timeframe to be considered which the AER could do by adopting a trailing average method.

1 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), p. 716.

2 AEMC; *National Electricity Rules Version 71*, Rule 6.5.2, pp. 662 – 665.

3 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), page 716 and Rule 6.5.2(i), p. 663.

4 Oxera 2015, "Aiming high in setting the WACC: framework or guesswork?". This is also an important reason why the revenue and pricing principle in section 7(2) of the NEL is consistent with the NEO.

5 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), page 716 and Rule 6.5.2(c), pp. 662 – 663.

6 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), page 716 and Rule 6.5.2(e)(1), p. 663.

7 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), page 716 and Rule 6.5.2(g), p. 663.

8 AEMC; *National Electricity Rules Version 71*, Rule 6.12.1(5), page 716 and Rule 6.5.2(i), p. 663.

The new rules do not alter the requirements the National Electricity Law (NEL)[9] that provide that in making the determination in accordance with the Rules the AER must exercise its network regulatory functions:

- In a manner that contributes to the achievement of the National Electricity Objective (NEO) (including the promotion of efficient investments for the long term interests of end users of electricity); and
- Taking into account the revenue and pricing principles which specifically include the principle that network businesses should be provided with a reasonable opportunity to recover at least their efficient costs in providing the regulatory services and complying with their regulatory obligations.

The same AEMC rule reform removed the tightly specified requirements for the AER to adopt the SL-CAPM for establishing the permitted return on equity and the "on-the-day" method for determining the allowance for debt. Further, the previous requirement for there to be persuasive evidence before the AER departed from its previous choice of model parameters has been removed. Instead the AER is required to consider all the available models and evidence in reaching its decision.

A key undercurrent driving the need for rule reform was the inability of the pre-existing tightly specified SL-CAPM to adapt to prevailing market conditions and deliver market reflective rates of return.

As required by the Rules, the AER has issued Rate of Return Guideline[10] (**the Guideline**) concerning its intended approach to applying the new rules. The AER has issued draft decisions in relation to AusNet Services' NSW and ACT electricity distribution counter-parts and concurrently issued draft decisions relating to certain other electricity transmission and gas distribution network businesses.

With respect to equity, AusNet Services is concerned that the AER's approach set out in the Guideline and draft determinations does not conform to the new rules and would not provide a sufficient allowed rate of return for capital. As detailed in this chapter, despite reviewing a great deal of expert analysis concerning a broader range of models and other inputs, in substance the approach adopted delivers outcomes that are barely distinguishable from, and could have been produced by, the previous regulatory regime. Further, the approach is delivering returns on equity that are well below the prevailing market conditions. The AER continues to apply the SL-CAPM as its foundation model which acts as a filter through which all the other material must pass before it is given any weight.

In a manner that is very closely aligned to the pre-reform approach, the most recent regulatory determinations[11], the AER calculates a 40 (equity); 60 (debt) blended rate of return by applying the AER's own "Ibbotson" inspired specification of the SL-CAPM with a significantly lower "beta" than ever before. Applying this recent approach of the AER to current market data would not result in an efficient rate of return. The distinguishing feature of the Ibbotson approach to measuring the historical market risk premium (MRP) for use in the SL-CAPM (**the Ibbotson Approach**) is that its estimates for the rate of return track the risk free rate in perfect parallel. This means that the estimates for the return on equity have plummeted one-for-one as the Commonwealth Government Security (CGS) yields have fallen.

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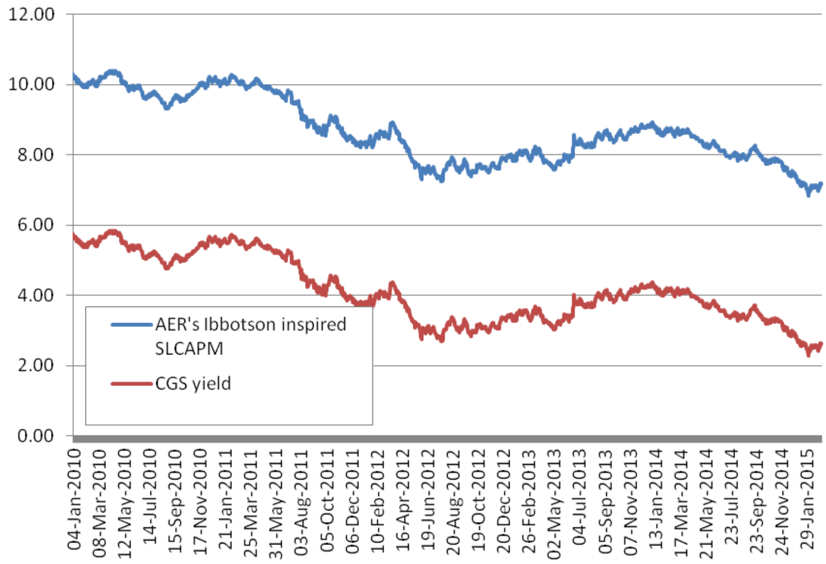
9 The National Electricity Law, a Schedule to the National Electricity (South Australia) Act 1996; (**the National Electricity Law**) Schedule 2, Part 3; sections 16(1)(a) and (2)(a), pp. 44 – 45.

10 As part of the Better Regulation reform program, the AER released its *Better Regulation | Rate of Return Guideline*; December 2013 on 17 December 2013 (**the Guideline**) (pdf version).

11 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, pp. 8 & 21 (pdf version).

Figure 12.1: Impact of changes in CGS yields on the AER's application of the SL-CAPM



Source: AusNet Services

There are a number of ways in which AER regulatory determinations concerning the equity allowance have changed over the last five years[12]. Nevertheless, when assessing whether the current approach is sensible and robust, it is informative to consider what rates of return allowances the method would have delivered if it had been employed over a number of years. The above graph illustrates how the AER's current approach to setting the allowed rate of return is directly related to CGS yields. The red line shows the yields on CGS and the blue line shows the estimated returns using the AER's method[13]. The fundamental problem with this approach is that there is no reason to suppose that investors' required rates of return have dropped in line with CGS yields and the AER's allowed rate of return for equity. To ensure that the allowed rate of return is commensurate with market returns, the AER must broaden the estimation methods it takes into account and give them real weight.

In fact the drop in permitted returns is considerably larger because the AER has also lowered the beta to record low levels. Compared with previous determinations the AER's current approach to the model inputs, and the resulting rate of return for equity, is as follows:

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12 For instance, for the 2011-2015 period the AER's determination employed a 6.0% market risk premium (compared with 6.5% today) and an 0.8 beta compared with a beta of 0.7 today.

13 I.e. allowed rate of return = risk free rate + beta x market risk premium = CGS yield + 0.7 x 6.5. The CGS yields are sourced from statistics available from the RBA's website.

Table 12.1: AusNet Services' historic regulatory rates of return

	Last ESC determination (2005)	First Victorian DB AER determination (Oct 2010)	Current draft AER determination for NSW DBs (Oct 2014)
Risk free rate	2.64% (Real)	5.14% (Nominal)	3.55% (Nominal)
Beta	1.0	0.8	0.7
MRP	6.0%	6.5%	6.5%
Nominal return on equity	11.42%	10.34%	8.10%
Real return on equity	8.64%	7.58%	5.46%

Source: AusNet Services

As discussed in this chapter, AusNet Services' principal objections to the way in which the AER's Guidelines and recent draft determinations set allowances for equity are that:

- The AER should not give any model, least of all the SL-CAPM, a central or "foundation model" role in setting an allowed rate of return for equity and, instead, all the four relevant models should be used and a weighted average of the four models should be used as the Rules require;
- The SL-CAPM relies on just three inputs (the risk free rate, a beta value and a value for the market risk premium) and the AER has made significant errors in relation to two of these and as such the rate of return objective cannot be met and is contrary to the revenue and pricing principles;
- Further, the AER's favoured SL-CAPM model is known to be significantly downwardly biased when estimating returns for stocks assigned a beta of less than 1.0 and there is no basis to conclude that the AER's approach of selecting beta and MRP from the upper ends of its ranges will compensate for that bias which also undermines the achievement of the rate of return objective and is contrary to the revenue and pricing principles; and
- When applying the SL-CAPM, the Ibbotson and Wright approaches to establishing the key "market risk premium" parameter are equally valid and each should be used when the SL-CAPM estimate is derived and, as such, the AER fails to correctly have regard to the Wright approach to setting the MRP.

With respect to setting the allowance for debt, the AER accepts that in practice prudent businesses ensure that debt matures on a staggered basis. Progressively over a 10 year period the AER would adopt a trailing average for debt and this should mean that the volatility in the debt allowance in absolute terms, and also the volatility in differences between the regulatory allowance and the actual costs of debt, should be substantially reduced.

However, for the duration of the regulatory period, under its transitional arrangements, the AER proposes to continue to predominantly using the "on-the-day" approach that applied under the previous regulatory regime. Although AusNet Services does not object to the concept of ultimately adopting a trailing average approach, nor to the appropriateness of an appropriately designed transition to reflect the AER's factual findings concerning the efficient financing practices of a regulated business, AusNet Services does not accept the AER's proposed transition is appropriately designed.

As such, the combined effect of the AER's allowed rate of return for debt has also fallen substantially over the last five years even though the AER acknowledges that a benchmark firm in AusNet Services' position will have a significant historic cost to AusNet Services' debt costs.

Further, the AER's adoption of an overly optimistic BBB+ credit rating for a 60% leveraged benchmark firm depresses the permitted rates of return below a truly market reflective return which should be based on a BBB credit rating.

The following table illustrates how the opening debt allowance would drop under the AER's proposed transition methodology.

Table 12.2: AusNet Services' historic rate of return under AER's transition methodology

	Last ESC determination (2005)	First Victorian DB AER determination (October 2010)	Current draft AER determination for NSW DBs (Oct 2014)
Risk free rate	2.64% (Real)	5.14% (Nominal)	3.55% (Nominal)
Credit rating	BBB+	BBB+	BBB+
Debt risk premium	1.425%	4.22%	2.96%
Nominal return on debt	6.73%	9.19%	6.51%
Real return on debt	4.07%	6.45%	3.91%

The AER's post tax revenue model (PTRM) applies the allowed rate of return to the asset base to deliver an allowance in pecuniary terms. An important additional variable in the PTRM used for establishing the second and subsequent years allowance is the expected rate of inflation. There has not been a detailed examination of the way in which inflation is estimated since 2008 and there are some indications that the factual circumstances upon which the current approach is based may have changed. During the course of the regulatory determination process, AusNet Services will monitor this issue and if necessary put forward further analysis on whether the current approach still meets the requirements of the Rules.

12.1.2 Summary table: Departures of this regulatory proposal from the Guideline

The Rules require that AusNet Services' proposal identify proposed departures from the Guideline and the following table summarises these.

Table 12.3: Departures of this regulatory proposal from the Guideline: Equity

Guideline	Regulatory Proposal	Rationale
Which models should be used in setting the allowance:		
Of the four models that the AER accepts are relevant, it only uses the SL-CAPM, Black CAPM and the Dividend Growth Model and not the Fama-French Three Factor Model.	Diverges because AusNet Services would use all four models.	The Fama-French Three Factor Model provides valuable insights and corrects for well-documented biases that are not explicitly considered by other models. (See 12.2.1 and 12.2.7(a)).
How the information gleaned from the models should be synthesised: The SL-CAPM, implemented in the way the AER has in the past, should (continue) to play the central role. Any other information should take a secondary role, at most being used to inform the estimate of one of the SL-CAPM parameters. In many instances, the information is simply being used to guide the choice of a parameter estimate from within a narrow range of values, rather than to contribute to a full, quantitative evaluation of that parameter estimate.	All the relevant information (i.e. all four models including the two principal ways to approach the SL-CAPM) should contribute directly to the allowed rate of return for equity as an average weighted according to the specific contributions each model can make.	There is no correct basis for the AER's Ibbotson inspired implementation of the SL-CAPM to be given the greatest weight, or for it to constrain the extent to which other inputs can affect the computation of the allowed rate of return for equity. (See 12.2.2 and 12.2.3).
Implementing the SL-CAPM: The SL-CAPM should be implemented using a current risk free rate, a beta of 0.7 and a long term market risk premium of 6.5% that is largely guided by historical estimates.	The beta should be a minimum of 0.8 and equal weighting should be given to the Ibbotson and Wright approaches to estimating the MRP. When implementing the Ibbotson approach, the market risk premium should be the arithmetic average for the longest available series – that is 6.56%. The appropriate role for the DGM is as a model to be employed directly in delivering an estimate for the return on equity rather than as an input to estimating the MRP for the SL-CAPM.	Network businesses have greater systematic risk than the AER assumes and the SL-CAPM is downwardly biased for low beta stocks and for stocks with a high book-to-market ratio. The Ibbotson and Wright approaches for estimating MRP are based on the same historical data but different methodologies return different results – and as such regard should be given to both. When seeking to employ the Ibbotson approach, the AER identifies a historic MRP range of 5.1% to 6.5%. The low end of this range is flawed in that it relies on an incorrectly adjusted yield series and irrelevant geometric averages. (See 12.2.3 pages 44/94 – 66/94).

The table presented below provides a summary of departures from the Guideline, but does not seek to discuss components of the cost of debt that were omitted from the Guideline altogether. By way of example, the new issue premium, optimal hedging ratios, and swap transaction costs are issues that were not properly considered by the AER when it prepared the Guideline. There is no reference to these components in the table below, however any premium or transaction cost that is payable by the benchmark efficient entity is discussed and evaluated in the regulatory proposal, and supporting documents.

Table 12.4: Departures of this regulatory proposal from the Guideline: Debt

Guideline	Regulatory Proposal	Rationale
Credit rating from Standard and Poor's: BBB+	 BBB	 In both cases the credit rating is established on the basis of a median of a group of comparators but AusNet Services would exclude ourselves from the group on the basis that it is majority government owned. (See 12.3.4, pp. 83/94 – 86/94).
Form of the transition to a trailing average cost of debt: There would be a transition towards the trailing average over two five year regulatory periods. In the first year of the first regulatory period the "on-the-day" approach would be accorded a 100% weighting. For each of the next 10 years, a weighted average would be calculated in which the weight accorded to the "on-the-day" approach would reduce by 10% compared with the year before. In the second year and subsequent years, 10% of the weighted average would be drawn from the prevailing cost of debt in that year and this figure would then contribute a 10% weighting in each of the next nine years until in year 10, there would be 10% weighting assigned to each of the 10 most recent years.	 A hybrid approach has been adopted. This makes use of an historical average approach to the measurement of the spread over swap. In addition, swap rates are measured during the averaging period. Swap rates for different tenors are combined.	 The hybrid approach has been developed to correspond with the debt-raising and hedging practices of privately-owned, regulated distribution businesses. (See 12.3.3).
Nomination of averaging periods for the cost of debt. The AER requires averaging periods to be nominated for each of the constituent years of the regulatory period. Specifically: The period must be specified prior to the commencement of the regulatory control period: • At the time the period is nominated, all dates in the averaging period must take place in the future. • The averaging period should be as close as practical to the commencement of each regulatory year in a regulatory control period. A period needs to be specified for each regulatory year within a regulatory control period.	 Averaging periods will be nominated in advance. Some averaging periods lie at the start or in the middle of the regulatory years, and are therefore not always "as close as is practical to the commencement of each regulatory year in a regulatory control period".	 Chosen to align with the likely timing of debt issuance to allow AusNet Services to adopt the financing practices that the AER considers efficient under the trailing average portfolio approach to setting the regulatory allowance. (See 12.3.5).

12.1.3 Chapter outline

This chapter is structured as follows:

- **Allowed rate of return for equity:** establishing the allowance for the return on equity (section 12.2);
- **Allowed rate of return for debt:** establishing the allowance for the return on debt (section 12.3);
- **Inflation expectations:** the expected inflation rate (section 12.4); and
- **Conclusion:** an illustrative calculation establishing a rate of return using data from the period 2 to 30 January 2015 (section 12.5).

12.2 Allowed Rate of Return on Equity

Since it is assumed that a benchmark firm in AusNet Services' position would be efficiently financed using 40% equity and 60% debt, the AER needs to set an allowed rate of return to reflect the costs of equity capital employed in the business. Stock markets (and equity markets more generally) are notoriously volatile and unpredictable and finance market experts have developed models to assist in the task of establishing benchmark rates of return.

The two main ways that this is done are either through capital asset pricing models or dividend growth models. In the past, Australian regulators have used capital asset pricing models and US regulators have tended to use dividend growth models.

As noted in the introduction to this chapter, the Rules require the AER to have regard to the relevant models and other inputs that are available when setting the allowed rate of return for equity. As explained in detail in this section 12.2.3, AusNet Services is concerned that the AER's approach as set out in its Guideline and recent draft decisions to evaluating and using the available material is deeply flawed and that a very different approach is needed.

In the past, the AER has always used the SL-CAPM for setting rates of return for electricity distribution businesses but there is now a vast array of evidence that shows the significant shortcomings of the SL-CAPM and the superior usefulness of other models. The shortcomings of the SL-CAPM are significantly exacerbated when it is implemented using current low government bond yields and a market risk premium based on a long term average. Indeed the SL-CAPM is very poor at explaining the movement in returns over time and produces estimates that are systematically biased downwards for assets with betas of less than one and for assets with high book-to-market ratios – such as the benchmark entity.

The SL-CAPM's downward bias is considerably exacerbated in the current times of low official interest rates if the model is implemented using current Commonwealth Government Bond yields with a long term market risk premium.

Under old Rule 6.5.2, the AER was required to implement the SL-CAPM in a narrowly defined way which would have essentially required the AER to combine current very low CGS bond yields with a long term market risk premium and, therefore, it would have been difficult to achieve a rate of return that is commensurate with the prevailing cost of equity funds without making compensating adjustments. However, according to Rule 6.5.2 of the Rules, the AER has a broader degree of discretion as to which models and other inputs to use and it can exercise this discretion to give significant weight to methods that do not suffer from the flaws of the SL-CAPM implemented using current CGS yields and a long run risk premium.

However, in the AER's Guideline and recent draft decisions the AER's approach that continues to give primary weight to the SL-CAPM and deviates from the requirements of the new rules that regard be had to a broader range of inputs in reaching a decision that is in line with the prevailing efficient cost of equity. While the AER's documents record that there is a detailed process of examining the submissions put by interested parties, very little of this material is actually used to calculate the allowed rate of return save the SL-CAPM. All the other information is either given no weight or is used in a highly constrained way so that it contributes very little to the final result.

AusNet Services is concerned that the AER's approach does not comply with its statutory obligations by:

- Continuing to put the worst performing of the available models (i.e. the SL-CAPM) centre stage by employing it as the foundation model;
- Having insufficient regard to much of the material presented by:
  - in some cases expressly assigning zero weight to the material (i.e. Fama-French Three Factor Model); or
  - in other cases, adopting an approach that highly constrains the ability of relevant information to contribute to the "bottom line" rate of return for equity (i.e. the limited and indirect role assigned to the DGM and Black CAPM);
- Using the SL-CAPM as a filter through which all other information must first pass before it can have any bearing on the permitted rate of return. This approach significantly curtails the manner and degree to which the other information can contribute to the allowed rate of return; and
- Making errors in applying the SL-CAPM.

This section explores these issues in detail as follows:

- Section 12.2.1 introduces the models that are relevant in estimating the return on equity;
- Section 12.2.2 summarises the approach in the Guideline;
- Section 12.2.3 identifies the key reasons why the approach in the guideline is delivering an unacceptably low return on equity and does not comply with the requirements of the Rules;
- Section 12.2.4 sets out AusNet Services' proposed approach to the return on equity; and
- Section 12.2.5 provides an illustrative calculation using current market data.

12.2.1 Identify and compare the relevant models and any other relevant evidence

As noted by the AEMC, there is no single model that is preferable, being free of weaknesses or capturing all of the strengths of the others[14] and consequently the AEMC decided that Rule 6.5.2(e) of the Rules should require the AER to have regard to all the relevant models, financial methods, market data and other evidence available.

Because the requirement to have regard to all the relevant models and other inputs is new, as well as considering the issue from first principles, it is also informative to consider how the same exercise occurs in the United States. In 1944, the US Supreme Court established the equivalent of the AEMC's rate of return objective and, indeed, indirectly this is the source of the language used in the AEMC's objective:

> *"the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks."*[15]

The US Supreme Court also explained how this should be applied in order to meet broader policy concepts that in the Australian system appear in the NEO and the Revenue and Pricing Principles:

> *"That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, as to maintain its credit and to attract capital."*[16]

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[14] AEMC; *Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*; August 2012, p. 48 (AEMC Draft Rule Determination).

[15] *FRC v Hope Natural Gas Co*., 320 U.S.591 (1944) at [603] p. 5.

[16] *FRC v Hope Natural Gas Co*., 320 U.S.591 (1944) at [603] p. 5.

Since that time the predominant model used in the United States applying the above requirements has been the Dividend Discount Model but each of the following models have also been used and AusNet Services agrees with the conclusions of the Guideline that these are the relevant financial models today:

- SL-CAPM;
- Black-CAPM;
- Fama-French Three Factor model;[17] and
- Dividend Discount Model.

SFG Consulting provides a good summary as to why these four models constitute the relevant field of techniques for estimating a market based return on equity:[18]

> *"In our view, these four models all provide evidence that is relevant to the estimation of the required return on equity for the benchmark efficient entity. We reach this conclusion for the following reasons:*
>
> *a)* ***All four models have a sound theoretical basis.*** *The Sharpe-Lintner CAPM, Black CAPM and Fama-French model are all based on the notion that the expected return on any asset is equal to a linear combination of the returns on an efficient portfolio and its zero covariance portfolio. This basic theoretical framework is the same for all three models, which differ only according to the way the efficient portfolio and the zero-covariance portfolio are determined. For example, under the Fama-French model the efficient portfolio is formed by combining three factor portfolios, whereas under the Sharpe-Lintner CAPM and Black CAPM the market portfolio (proxied by a stock market index) is assumed to be efficient. The Sharpe-Lintner CAPM further assumes that investors can borrow and lend as much as they like at the risk-free rate. The dividend discount model is based on the notion that the current stock price is equal to the present value of expected future cash flows (dividends).*
>
> *b)* ***All four models have the purpose of estimating the required return on equity as part of the estimation of the cost of capital.*** *This point is not weakened by the fact that the models can be used to inform other decisions as well. For example, the Sharpe-Lintner CAPM and the Fama-French model can also be used to compute "alpha" for the purpose of mutual fund performance evaluation.*
>
> *c)* ***All four models can be implemented in practice.*** *For all four models, there is a long history and rich literature concerning the estimation of model parameters. This literature has developed empirical techniques, constructed relevant data sets, and considered issues such as the trade-off between comparability and statistical reliability.*
>
> *d)* ***All four models are commonly used in practice.*** *Some form of CAPM is commonly used in corporate practice and by independent expert valuation practitioners. The Black CAPM is commonly used in rate of return regulation cases in other jurisdictions (where it is known as the "empirical CAPM"). The dividend discount model is also commonly used in rate of return regulation cases in other jurisdictions (where it is known as the "discounted cash flow" approach). The Fama-French model has become the standard method for estimating the required return on equity in peer-reviewed academic papers and its use to estimate the required return on equity is required knowledge in professional accreditation programs."*

Other information such as expert reports prepared in the context of assessing whether corporate takeover offers are "fair" and surveys of practitioners could be used provided the quality is dependable and regard is had for the different context for which that other material may have been prepared. To the extent that these other sources are of any use, their values is in terms of illustrating how the above models are implemented and combined in practice to deliver timely estimates of value or return.

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17 AER; *Better Regulation | Rate of Return Guideline*; December 2013.

18 SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks*; 6 June 2014, p. 3.

Along with a number of other energy network businesses, AusNet Services has commissioned a series of detailed reports from a number of leading experts to explore the strong and weak characteristics of each model. The first set of relevant reports was provided by the Energy Networks Association as part of the consultation process on the Guideline[19].

Since the publication of the Guideline, SFG Consulting has prepared a suite of reports, which explore in detail a series of issues raised in the Explanatory Statement that accompanied the Guideline. A report prepared by SFG Consulting dated 12 May 2014[20] addresses the issues raised in connection with the equity beta in the context of the SL-CAPM. Another three reports[21] [22] [23] focus on the issues raised in relation to each of the other financial models and a fifth report[24] addresses how to set a single allowed rate of return figure for equity using the above inputs. In February 2015, SFG Consulting has written further reports on each of the above topics in response to the suite of draft determinations that the AER issued in late 2014[25] [26] [27].

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[19] (a) NERA Economic Consulting; *Review of cost of equity models, A report for the Energy Networks Association*; June 2013.

(b) NERA Economic Consulting; *Estimates of the [Black CAPM] zero beta premium, A report for the Energy Networks Association*; June 2013.

(c) NERA Economic Consulting; *The market, size and value premiums, A report for the Energy Networks Association*; June 2013.

(d) NERA Economic Consulting; *The Fama-French Three-Factor Model, A report for the Energy Networks Association*; October 2013.

(e) NERA Economic Consulting; *The Market Risk Premium: Analysis in Response to the AER's Draft Rate of Return Guidelines, A report for the Energy Networks Association*; October 2013.

(f) CEG Competition Economists Group; *Estimating the return on the market*; June 2013.

(g) CEG Competition Economists Group; *Estimating E[Rm] [expected return on the market] in the context of regulatory debate*; June 2013.

(h) CEG Competition Economists Group; *Information on equity beta from US companies*; June 2013.

(i) CEG Competition Economists Group; *AER equity beta issues paper: International comparators*; October 2013.

(j) SFG Consulting; *Dividend discount model estimates of the cost of equity*; 19 June 2013.

(k) SFG Consulting; *Evidence on the required return on equity from independent expert reports, Report for the Energy Networks Association*; 24 June 2013.

(l) SFG Consulting; *Regression-based estimates of risk parameters for the benchmark firm*; 24 June 2013.

(m) SFG Consulting; *The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model*; 17 June 2013.

(n) SFG Consulting and Monash University; *Comparison of OLS and LAD regression techniques for estimating beta*; 26 June 2013.

(o) SFG Consulting and Monash University; *Assessing the reliability of regression-based estimates of risk*; 17 June 2013.

(p) SFG Consulting; *Reconciliation of dividend discount model estimates with those compiled by the AER*; 10 October 2013.

(q) SFG Consulting; *Letter: Water utility beta estimation*; October 2013.

(r) Incenta Economic Consulting; *Report for the Energy Networks Association Term of the risk free rate for the cost of equity*; June 2013.

[20] SFG Consulting; *Equity beta, Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014.

[21] SFG Consulting; *Cost of equity in the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks*; 22 May 2014.

[22] SFG Consulting; *The Fama-French model; Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid, and SA PowerNetworks*; 13 May 2014.

[23] SFG Consulting; *Alternative versions of the dividend discount model and the implied cost of equity; Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid*; 15 May 2014.

[24] SFG Consulting; *The required return on equity for the benchmark efficient entity*; *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy*; 25 February 2015 (attached as Appendix 12A).

[25] SFG Consulting; *Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL Electricity, APA, Ausgrid, Ausnet Services, CitiPower, Endeavour, Energex, Ergon, Essential Energy, Powercor, SA PowerNetworks and United Energy*; 18 February 2015 (attached as Appendix 12B).

NERA has also prepared reports that provide important insights into the empirical performance of the SL-CAPM, the AER's variation on the SL-CAPM and the Black CAPM[28] and into historical estimates of the market risk premium[29].

Incenta has provided two reports, one prepared for submission to the AER as part of the first group of decisions to be made under the new rules released in late 2014 and another in response to those draft decisions.

Grant Samuel has extensive experience undertaking valuations in the context of stock market acquisitions and it has provided its views on the AER's approach, and specifically the AER's mischaracterisation of its independent expert report for Envestra[30].

The key characteristics of the models are as follows:

SL-CAPM

The SL-CAPM is the model with which Australian economic regulators are most familiar and it has been required since the beginning of the NEM. This model estimates a return on equity by adding a margin for risk to the risk free rate. For the investment in question (i.e. in this case the benchmark efficient firm) the risk margin is the product of a generalised estimate of the average reward for risk that investors expect on a fully diversified portfolio (that is the "market risk premium") and the "beta" which is a measure of the extent to which the investment in question carries non-diversifiable risk.

It is also commonly used in most other infrastructure revenue regulatory frameworks. SIRCA states:

> "With regard to the CAPM, its efficacy comes from the test of time. This model has been around for in excess of half a century and has become the standard workhorse model of modern finance both in theory and practice. The CAPM's place as the foundation model is justifiable in terms of its simple theoretical underpinnings and relative ease of application. The competing alternatives, which build upon the CAPM, serve to add a level of complexity to the analysis. It remains that case that the majority of international regulators currently base their decisions primarily on the CAPM framework.[31]"

However, the model has theoretical weaknesses – most notably the unrealistic assumption that investors can borrow and lend at the risk free rate in the quantities they wish. Further, empirical studies have consistently found the performance of this model to be poor. As SFG Consulting explains:

> *"In particular, stocks with low beta estimates earn higher returns than predicted by the Sharpe-Lintner CAPM, and stocks with high beta estimates earn lower returns than predicted by the Sharpe-Lintner CAPM. This empirical result has been documented in literature over 50 years … . The poor empirical performance of the Sharpe-Lintner CAPM likely occurs for two reasons. First, risks other than systematic risk are incorporated into share prices (in particular, stocks with a high book-to-market ratio persistently earn higher returns than stocks with a low book- to-market ratio).*

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26 SFG Consulting; *Using the Fama-French model to estimate the required return on equity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; 13 February 2015 (attached as Appendix 12C).

27 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; 13 February 2015 (attached as Appendix 12D).

28 NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM, A Report Jemena Gasworks, Jemena Electricity Networks, ActewAGL, AusNet Services, Citipower, Energex, Ergon Energy, Powercor, SAPower Networks and United Energy*; February 2015 (attached as Appendix 12E).

29 NERA; *Historical Estimates of the Market Risk Premium, A report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, AusNet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; February 2015 (attached as Appendix 12F).

30 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015.

31 McKenzie M and G Partington; *Report to the AER, Part A: Return on Equity, The Securities Industry Research Centre of Asia-Pacific (SIRCA) Limited*; October 2014, p. 9.

Second, the common measurement of systematic risk – the regression coefficient of excess stock returns on market returns – is an imprecise measure of risk.[3233]"

And NERA explains:

"The model tends to underestimate the mean returns to low-beta assets, value stocks and, in the US and some other countries, low-cap stocks. A value stock is a stock that has a high book value relative to its market value or, identically, a low market value relative to its book value. A growth stock is a stock that has a low book value relative to its market value or, identically, a high market value relative to its book value.[34]*"*

NERA Economic Consulting, which investigated this issue in detail comparing the empirical performance of the SL-CAPM and the Black CAPM models, produced results which corresponded with those of SFG. NERA uses two types of tests and in relation to in-sample tests, the findings were:[35]

"The data indicate that there is a negative rather than a positive relation between returns and estimates of beta. As a result, the evidence indicates that the SL CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL CAPM underestimates returns to low-beta portfolios is both statistically and economically significant.

*As an example, we estimate that the lowest-beta portfolio of the 10 portfolios that we construct to have a beta of 0.54 – marginally below the midpoint of the AER's range for the equity beta of a regulated energy utility of 0.4 to 0.7. Our in-sample results suggest that the SL CAPM underestimates the return to the portfolio by **4.90 per cent per annum.**" (Emphasis added)*

Similar findings arise from NERA's out-of-sample tests.

A further estimation problem arises during periods of particularly high official interest rates or low official interest rates when this model is implemented in the way that the AER has used it for many years by using a current Commonwealth Government Bond yield to estimate the risk free rate in combination with a very long run average of historical excess returns to estimate the MRP. The AER's approach (whose market risk premium is inspired by Ibbotson) behaves as if investors' expectations moved in perfect parallel with yields on the Commonwealth Government Bonds and there is no solid basis for this assumption.

There are alternatives to establishing the market risk premium for use in the SL-CAPM to the Ibbotson inspired approach adopted by the AER. One is known as the Wright approach in which the historical average is used in conjunction with a current expectation of inflation (discussed further below) but this approach is not a panacea for the flaws in the Ibbotson approach and it does nothing to address the downwardly biased returns for low beta stocks that arise due to the unrealistic assumption concerning the ability of investors to borrow and lend at the risk free rate.

The Black CAPM

The Black CAPM is a "next generation" model in that it builds on the SL-CAPM by incorporating additional flexibility. It is related to the SL-CAPM in the following way:

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32 SFG Consulting; *Cost of equity in the Black Capital Asset Pricing Model; Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks*; 22 May 2014, p. 2.

33 Also SFG Consulting; *Equity Beta; Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, pp. 6-7.

34 NERA; *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA PowerNetworks, and United Energy*; March 2015, page 9 (attached as Appendix 12G).

35 NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM, A Report Jemena Gasworks, Jemena Electricity Networks, ActewAGL, AusNet Services, Citipower, Energex, Ergon Energy, Powercor, SAPower Networks and United Energy*; February 2015, page 54.

"[T]he Sharpe-Lintner CAPM remains a specific application of the more general model, the Black CAPM.[36]"

"The Black CAPM does not rely upon the assumption that all investors can borrow at the risk-free rate of interest.[37]"

The Black CAPM has been demonstrated to provide a significantly better empirical fit to the data than the SL-CAPM:

"Using the 10 portfolios formed on the basis of past estimates of beta and monthly data from January 1979 to December 2013, we find:

…

little evidence of bias in the Black CAPM[38]"

Although the AER has accepted that the Black CAPM's theoretical insights are relevant to its determinations, it does not directly use the Black CAPM to estimate the required rate of return on equity. Rather, this model's theoretical insights are used by the AER via the "back door" as one of the rationales for adopting a beta estimate at the high end of the AER's constraining beta range.

The AER's approach is not the way in which the Black CAPM is usually used for regulatory purposes. Despite the AER's protestations that the model is unusable because a zero beta portfolio is allegedly hard to estimate, as identified in the following table, the Black CAPM (also referred to as "empirical" or the "Zero Beta" CAPM) has been used extensively in US regulation cases particularly when adopting a beta materially less than one.

Table 12.5: Use made by regulators of the Black, Zero-Beta and Empirical CAPM[39]

Regulator	Industry	Application	Citation	Date
New York Public Service Commission	Electricity distribution	50/50 weighting. "Traditional" CAPM/zero-beta CAPM paragraph 56.	*Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers* 2009 N.Y. PUC LEXIS 507[40].	2009
New York Public Service Commission	Gas distribution	50/50 weighting. Average of traditional CAPM result and zero beta CAPM result paragraph 20.	*Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas*	2007

36 SFG Consulting; *Cost of Equity in the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks*; 22 May 2014, p. 15.

37 SFG Consulting; *Cost of Equity in the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Network*; 22 May 2014, p. 2.

38 NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM, A Report Jemena Gasworks, Jemena Electricity Networks, ActewAGL, AusNet Services, Citipower, Energex, Ergon Energy, Powercor, SAPower Networks and United Energy*; February 2015, p. 54.

39 The data in this table is drawn from consultation of reports of the various applicable regulators.

40 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers* 2009 N.Y. PUC LEXIS 507.

Regulator	Industry	Application	Citation	Date
			Service 2007 N.Y. PUC LEXIS 449; 262 P.U.R.4th 233[41].	
New York Public Service Commission	Gas and electricity distribution	50/50 weighting. Average of traditional CAPM result and zero beta CAPM result paragraph 19. NB; this decision changed the weighting from 75/25 to 50/50, the previously accepted weighting following the approach in the Generic Finance case.	*Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service* 2006 N.Y. PUC LEXIS 227; 251 P.U.R.4th 20[42].	2006
Oregon Public Utility Commission	Electricity distribution	Zero-beta is used to identify contrast with S-L "*as beta decreases, the cost of equity decreases by less than the Sharpe-Lintner CAPM model suggests…….as beta decreases, the cost of equity decreases by less than the Sharpe-Lintner CAPM model suggests. This is important, …, because it means the costs of equity for utilities with betas of less than 1 are closer to the cost of equity for an average risk stock than is shown by the Sharpe-Lintner CAPM model. Under this model, the required return for the risk-free asset is expected to be higher than the return on Treasury bills.*" Paragraph 20. *"While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of*	*In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149.* 2001 Ore. PUC LEXIS 418; 212 P.U.R.4th 379[43].	2001

41 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service* 2007 N.Y. PUC LEXIS 449; 262 P.U.R.4th 233.

42 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service* 2006 N.Y. PUC LEXIS 227; 251 P.U.R.4th 20.

43 *In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*. 2001 Ore. PUC LEXIS 418; 212 P.U.R.4th 379.

Regulator	Industry	Application	Citation	Date
		equity." Paragraph 23. CAPM given no weight, DCF preferred.		

Further, even if the Black CAPM does not perfectly model the relationships in question SFG Consulting notes that:

> *"because the Black CAPM is more general in that it allows flexibility in a parameter input (r_z versus r_f) it gives some chance of aligning with historical stock returns.[44]"*

While empirical studies have consistently found that this model performs better than the SL-CAPM, the Black CAPM is known to have a downward bias for value stocks:

> *"[S]tocks with above-average book-to-market ratios would be expected to have returns above that predicted by the Black CAPM and a zero beta premium of 3.34%. If the risks associated with high book-to-market stocks are not incorporated elsewhere, and the Black CAPM alone is used to estimate the cost of equity with a zero beta premium of 3.34%, the cost of equity will be understated.[45]"*

The same implementation problem arises as with the SL-CAPM when the current returns on central bank debt are used as the estimate of the risk-free rate and this value is added to an essentially constant long run average estimate of MRP.

The Fama-French Three Factor Model

This model, provides separately for an additional return on value stocks and empirical studies in the US and Australia have confirmed that:

> *"The Fama-French model has the advantage of providing an unambiguously better fit to the data than the Sharpe-Lintner CAPM.[46]"*

This model in relation to which a Nobel prize[47] has been awarded, is newer than the other two CAPM models. Despite being the newer model, since the turn of the century the Fama-French Three Factor model has been part of the evidence in a number of state regulatory proceedings in the United States, including:

1. Before the Massachusetts Department of Telecommunications[48], Mr Moul (an expert witness) cites the Fama-French study as demonstrating the relationship between company size and stock returns.
2. Before the California Public Utilities Commission[49], Mr Hunt (an expert witness), used the FFM and calculated a cost of equity of 14.0 percent in September 2005; using the CAPM, Mr

44 SFG Consulting; *Cost of Equity in the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks*; 22 May 2014, p. 15.

45 SFG Consulting; *Cost of Equity in the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks*; 22 May 2014, p. 38.

46 SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks*; 6 June 2014, p. 9.

47 "Eugene F. Fama - Facts". *Nobelprize.org*. Nobel Media AB 2014. Web. 15 Mar 2015. <http://www.nobelprize.org/nobel_prizes/economic-sciences/laureates/2013/fama-facts.html>

48 Moul, Paul R., 'Direct Testimony of Paul R. Moul, Managing Consultant, P. Moul & Associates, Concerning Cost of Equity,' Commonwealth of Massachusetts Department of Telecommunications and Energy, October 17, 2005 p. 50.

49 *Application of Pacific Gas and Electric Company for Authority to Establish Its Authorized Rate of Return on Common Equity for Electric Utility Generation and Distribution Operations and Gas Distribution for Test Year 2006. (U 39 M); Application of Southern California Edison Company (U 338-E) for Authorized Capital Structure, Rate of Return on Common Equity, Embedded Cost of Debt and Preferred Stock, and Overall Rate of Return for Utility Operations for 2006; Application of San Diego Gas & Electric Company (U 902-M) for Authority to: (i) Increase its Authorized Return on Common Equity, (ii) Adjust its Authorized Capital Structure, (iii) Adjust its*

Hunt calculated a cost of equity of 12.55 percent. The FFM returned a result that was 16945 (basis) points above that from the CAPM.

3. Before the Delaware Public Service Commission[50], Artesian Water Company led evidence that included Fama-French data[51]. The Commission accepted that evidence without reservation.

4. Mr Ronald Knecht (an expert witness for the Nevada Public Utilities Commission)[52] proposed a return on equity of 10.28 per cent which was calculated as an arithmetic mean of four components. He applied two discounted cash flow (DCF) estimates, a 2CAPM/FF3F model average, and one risk premium estimate. A hearing was held before the Public Utilities Commission of Nevada in April 2006. Mr Knecht stated that this approach was superior to relying only on the average of DCF models, because the CAPM, FF3F, and "capital appreciation and income" (CA + I risk premium) methods used basic cost of capital input data differently from the DCF models. The overall result for the 2CAPM/FF3F was reported to be 10.13 per cent. The outcome of 10.13 per cent was comprised of a result from the CAPM with a "Value Line" beta of 10.45 per cent, a result from the CAPM using an Ibbotson beta (with size adjustment) of 8.25 per cent, and a result from the Fama-French Three Factor model of 11.63 per cent. The evidence was considered by the Public Utilities Commission of Nevada in April 2006.

5. On a separate occasion, in July 2007, Mr Knecht acted on behalf of the Nevada Public Utilities Commission[53] and again used the Fama-French Three Factor Model to assess the rate of return on equity. He obtained a result for an average energy utility of 11.39 per cent. The average of two CAPM methods and the FF3F model was 11.13 per cent. On both of these occasions the Nevada Public Utilities Commission accepted Mr Knecht's Fama-French evidence without reservation[54].

6. On another occasion in December 2014, Mr Knecht gave expert evidence (evidence that contained Fama-French data) before the California Public Utilities Commission. Whilst the Commission observed that the Fama-French model had previously been rejected by the California Public Utilities Commission[55], the Commission recognised that the Fama-French model has "gained great currency in investment practice"[56].

7. Mr Hayes (an expert from San Diego Gas & Electric) used the FFM model in his testimony before the California Public Utilities Commission in May 2007[57]. Hayes calculated a return on

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Authorized Embedded Costs of Debt and Preferred Stock, (iv) Increase its Overall Rate of Return, and (v) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief 2005 Cal. PUC LEXIS 537; 245 P.U.R.4th 442.

50 *In the matter of the application of Artesian Water Company, Inc., for an increase in water rates* 2003 Del. PSC LEXIS 51.

51 *In the matter of the application of Artesian Water Company, Inc., for an increase in water rates* 2003 Del. PSC LEXIS 51 at [8]-[11].

52 *Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Sierra Pacific Power Company for approval of new and revised depreciation rates for electric operations based on its 2005 depreciation study,* 2006 Nev. PUC LEXIS 91 at [63].

53 *Application of NEVADA POWER COMPANY for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.* 2007 WL 2171450 (Nev.P.U.C.).

54 See *Application of NEVADA POWER COMPANY for authority to increase its annual revenue requimrent for general rates charged to all classes of electric customers and for relief properly thereto.* 2007 WL 2171450 (Nev.P.U.C.) at [102]; and see *Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Sierra Pacific Power Company for approval of new and revised depreciation rates for electric operations based on its 2005 depreciation study,* 2006 Nev. PUC LEXIS 91 at [63].

55 *Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism* 2014 Cal. PUC LEXIS 622 at [7], citing *Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008; and Related Matters* 2007 Cal. PUC LEXIS 593 at [5.2.5].

56 *Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism* 2014 Cal. PUC LEXIS 622 at [15].

57 Testimony of Gary G Hayes on behalf of San Diego Gas and Electric before the California Public Utilities Commission 2007, p. 19.

equity of 13.89 per cent using the FFM, with a value of 11.73 per cent obtained using the CAPM.

In his testimony before the Californian Public Utilities Commission Gary Hayes notes:

"[T]he California Public Utilities Commissioner Bohn stated after the January 2007 cost-of-capital workshop: The commission should remain open to receiving evidence from new additional models should parties wish to provide such. We should always welcome new and better tools and ways of tackling problems."

…

"First, the FF model is not a new, untested formula dropping in from academia. It has behind it a solid track record of research and has been the topic of extensive debate...Nowadays, the FF model is used routinely by financial economists as they research investments, returns, and relative performance, as it is a useful tool with which to interpret return data on a wide number of asset types… Use of the FF model is not limited to just the halls of the academy; it has expanded into the investing world as well. …. Other professional practitioners have begun to utilize the FF model. Valuation experts now add FF results to fairness opinions issued in mergers-and-acquisitions transactions. Noteworthy is the Delaware courts' acceptance – and in one case, utilization – of FF evidence in asset-valuation disputes…. From the perspective of the everyday ROE analyst, the FF model is very accessible….Aside from its three California appearances, the FF method has also made its debut in Massachusetts and Nevada....The Commissioner asked [the witness] whether FF is more accurate or useful than old standards. Accuracy, when measured as an equation's ability to predict returns (called R^2 by statisticians) is improved by the FF factors…Therein lies the model's usefulness as a cross check on it sibling, the CAPM.[58]*"*

The Guideline, however, takes the approach that although the Fama-French model is "relevant" it should play no part whatsoever in the establishment of the allowed rate of return. In AusNet Services' view this is wholly unacceptable.

If the Fama-French Three Factor model is wholly excluded from the analysis, there is no other model that specifically addresses the downward bias for value stocks. As SFG Consulting notes:

"Our view is that if the Fama-French model is not given any consideration by the AER, the estimated cost of equity will be understated. If we were to rely solely upon the Sharpe-Lintner CAPM, populated with a regression-based estimate of beta, we would adopt a second-best solution, because we would ignore the empirical evidence that the HML factor proxies for risk.[59]*"*

Section 12.2.3 below discusses in more detail the concerns AusNet Services has about the manner in which this evidence has been treated in the Guideline and the recent draft determinations.

58 Testimony of Gary G Hayes on behalf of San Diego Gas and Electric before the California Public Utilities Commission 2007, pp. 12-15.

59 SFG Consulting; *The Fama-French model*; *Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid, and SA PowerNetworks;* 13 May 2014, p. 3.

The Dividend Discount Model

The Dividend Discount Model is also referred to as the Discounted Cash Flow (**DCF**) Model. The Federal Energy Regulatory Commission of the United States of America noted that:

> *"The DCF model is a well established method of determining the equity cost of capital, (See Illinois Bell Telephone Co. v FCC, 988 F.2d 1254, 1259 n. 6 (D.C.Cir 1993)"*[60]

and

> *"The DCF method 'has become the most popular technique of estimating the cost of equity, and it is generally accepted by most commissions.* ***Virtually all cost of capital witnesses use this method, and most of them consider it their primary technique."*** *Quoting J. Bonbright et al., Principles of Public Utility Regulation and other methods such as the risk premium model have not been used by the Commission for almost two decades."*(Emphasis added)

The DCF model or DGM approaches the task of estimating the required rate of return in a different way:

> *"The dividend discount model approach has the advantage of not requiring any assumptions about what factors drive required returns – it simply equates the present value of future dividends to the current stock price. It is also commonly used in industry and regulatory practice. Whereas the Guideline materials identify some concerns with the dividend discount approach, the specification adopted in this report addresses most of those concerns. Consequently, our view is that the dividend discount estimate of the required return is relevant evidence and some regard should be given to it.*[61]*"*

This model performs well provided a robust method is used for forecasting future dividends. SFG Consulting has reviewed a range of ways in which this model can be implemented, considering the techniques produced by or for the AER during the Guideline consultation process and methods described in other publications. The principal issues include the length of the period over which dividend growth reverts to an assumed long run growth rate, whether that progression is linear or otherwise and how long term dividend growth is assumed to be related to assumptions about over-all economic growth.

The AER has rejected the DDM/DCF approach to estimating the required return on equity for the benchmark entity and instead uses it only to inform the estimate of the market-wide MRP. This is wholly inconsistent with the US approach, which relies primarily on DCF estimates directly in establishing the permitted returns of the firm being regulated.

12.2.2 The approach in the Guideline

The most straight forward approach (that was rejected in for the Guideline) would be to estimate all the relevant models and determining what weight they should have in contributing to an over-all rate of return[62]. This was essentially Option 3 considered by the AER as part of the Guideline development process. It was rejected on the following basis:

[60] United States of America Federal Energy Regulatory Commission *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity* 123 FERC ¶ 61,048 at [53].

[61] SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks;* 6 June 2014, p. 9.

[62] Which would be consistent with the regulatory precedent from the US in, for example, the two Nevada PUC cases cited at 50 and 51 above.

> *"(3) Use several primary models with quantitative but non–complicated fixed weighting. For example, this might entail the choice of two models with broad, simple weightings (such as 70:30).*
>
> *…*
>
> *This may reduce the significance of weaknesses in any one model or source of information. The limitations of this approach, however, is that it may be complex to implement (given multiple models must be estimated), and may not provide an appropriate level of predictability. A multiple model approach may also lead to inappropriate consideration being given to relevant material. These limitations are discussed in detail in section 5.3.10."*[63]

Importantly, the criterion of "predictability" is regarded as being desirable for investors:

> *"As noted in our consultation paper, and in stakeholder submissions, the guideline should provide certainty and predictability to assist investors in making their investment decisions."*[64]

These three reasons for rejecting the straight forward approach of giving all the models an explicit weight in determining the rate of return for equity have been misapplied:

- As discussed above, the criterion of "complexity" is irrelevant to the rate of return objective, NEO and revenue and pricing principles but, in any event, it is quite incredible to regard the approach of specifying each of the models and taking a weighted average can be more complex than the six step foundation model, an abridged version of which is quoted below.
- In fact taking a weighted average delivers more predictable outcomes in that any "surprises" or variations that occur only in one model have little impact upon the weighted average while any version of a "primary model" is highly sensitive to any changes in the parameters used in that primary model. In any event, the businesses must be in a better position than the AER to assess whether investors perceive a multi-model approach to lack predictability when compared with the SL-CAPM because it is AusNet Services' own shareholders and potential shareholders who are the investors in question. AusNet Services is not aware of any businesses (nor any potential investors) who provided a submission or any evidence to the AER to support its conclusion in this respect. Indeed, all network business and investor submissions of which we are aware supported the multi-model approach.
- Section 5.3.10 of the Explanatory Statement explains that the third consideration concerning the inappropriate consideration being given to relevant material is simply a summary of all the criticisms that the AER makes in relation to the Fama-French, Black CAPM and DGM and this consideration would fall away on the basis that the AER's criticisms of these models are incorrect for the reasons discussed in this chapter of AusNet Services' submission.

Instead, the AER's Guideline adopts a "foundation model" approach consisting of the following steps:

> *"Step one: identify relevant material*
>
> *…*
>
> *We will, in accordance with the rules, have regard to all relevant material. However, this does not require us to use all of that material to inform our estimate of the return on equity.*
>
> *…*
>
> *Step two: determine role*
>
> *…*
>
> *Specifically, we may use relevant material in one of four different ways:*
>
> *As the foundation model:*

[63] AER; *Better Regulation | Explanatory Statement | Rate of Return Guideline* (**Explanatory Statement**); December 2013, page 54 (pdf version).

[64] AER; *Explanatory Statement*; p. 102.

…

To inform where within the return on equity range (set by the foundation model) our 'final' return on equity point estimate should fall:

…

Not used to estimate the return on equity:

…

Step three: implement foundation model

[W]e propose to implement the Sharpe–Lintner CAPM as follows:

[Except in the manner identified as follows, the Explanatory Statement then summarises the way in which the AER has approached the SL-CAPM confirming that this will continue. In particular the Ibbotson inspired implementation of the SL-CAPM will be used to establish the MRP.]

The MRP range will be estimated with regard to theoretical and empirical evidence—based on evidence such as historical excess returns, survey evidence, financial market indicators, estimates from other regulators, and DGM estimates.

The MRP point estimate will be determined based on regulatory judgement, taking into account estimates from each of those sources of evidence … .

The range and point estimate for the return on equity will be calculated based on the range and point estimates from the corresponding input parameters. For example, the lower bound of the return on equity range would be calculated by applying the point estimate for the risk free rate and the lower bound estimates for the equity beta and MRP.

….

Step four: other information

Under step four, other information that may inform our final return on equity point estimate is considered. …

The manner in which we may use other information, however, may differ for each alternative source. Specifically, some of the other information may provide a range (at a point in time) for the return on equity, while others may provide only directional information. … Alternatively, the Wright approach, and other regulators and brokers provide more direct estimates of the expected return on equity for service providers.

Table 5.3: Form of other information

Additional information	*Form of information*
Wright approach	*Point in time*
Other regulators' return on equity estimates	*Point in time*
Brokers' return on equity estimates	*Point in time and directional*
Takeover and valuation reports	*Directional*

Comparison with return on debt	*Relative*

Source: AER analysis.

Step five: evaluate information set

This step requires the evaluation of the full set of material that we propose to use to inform, in some way, the estimation of the expected return on equity. This includes assessing the foundation model range and point estimate alongside the other information from step four.

In evaluating the full information set, the consistency (or otherwise) of the information is expected to be important. That is, circumstances where most of the other information suggests the return on equity should be above the foundation model estimate is likely to be more persuasive than if only a single estimate suggests an alternative value. The strengths and limitations of each source of additional information, however, will also be an important factor guiding the informative value of the available material.

Step six: distil a point estimate of the expected return on equity

Our approach requires the determination of a single point estimate for the return on equity. As outlined in section 5.2 our starting point for estimating the return on equity will be the foundation model point estimate. Moreover, the final point estimate is expected to be selected from within the foundation model range.

…

The use of regulatory judgement may also result in a final estimate of the return on equity that is outside the foundation model range. This recognises that, ultimately, our rate of return must meet the allowed rate of return objective. In these circumstances, we may reconsider the foundation model input parameter estimates, or more fundamentally, we may also reconsider the foundation model itself. That said, we consider it reasonable to expect our final return on equity estimate, in most market circumstances, to fall within the foundation model range. ...

Further, under our approach, if the foundation model point estimate is not adopted the final estimate of the return on equity will be determined as a multiple of 25 basis points. This recognises the limited precision that the return on equity can be estimated. …"

The reasons why the AER favours the above "foundation model" approach are as follows. The foundation model is one of the variants of implementing a "primary model" approach. In relation to primary model approaches the AER states:

"The key benefit of using a primary model is that it provides greater predictability of outcomes."

Again, this claim of predictability is unsupported, particularly as regards the effect it has on investor appetites and must be rejected as a proper "key benefit" of adopting the "foundation model".

In addition to the "key benefit" the AER has also identified the following considerations concerning the foundation approach:

Table 12.6: AusNet Services' comments on the AER's foundation approach

AER comment (pp. 79 & 80 of Explanatory Statement)	AusNet Services' comment
Using the foundation model and other information informatively (as opposed to determinately) to estimate the expected return on equity is consistent with the approaches adopted by market practitioners.	The AER has not cited any examples of market practitioners using a six step foundation model or anything that resembles it. AusNet Services is unaware of any practitioners who do so and would be most surprised if there were.
Using the foundation model and other information informatively acknowledges the inherent uncertainty in estimating the expected return on equity. That is, it recognises that all models are incomplete and that some approaches provide greater insight than others.	As discussed below, all the models are complete in the sense that they provide independent estimates for the return on equity and compared with all three of the other models, the model that provides the least insights is the SL-CAPM chosen by the AER to be the foundation model.
Using the foundation model and other information informatively acknowledges the need for regulatory judgement in estimating the expected return on equity. Given the breadth of material and range of values that may represent reasonable estimates of the expected return on equity, the use of judgement is unavoidable.	While regulatory judgement is required, the approach of the AER involves qualitative and quantitative judgements of a wide variety of forms at every step of the process. This undermines predictability and transparency.
Using a foundation model approach is relatively simple to implement (particularly in comparison to combining different estimates of multiple models). For example, the foundation model—the Sharpe–Lintner CAPM—is a model that stakeholders are familiar with already (given its widespread use amongst market practitioners and other regulators).	AusNet Services does not understand how the foundation model can be described as simple to implement when compared with the weighted average approach. For example, that approach can be distilled to a simple mathematic or logical formula whereas most aspects of the foundation model is incapable of expression in that form. The way in which the information is categorised and combined is extremely complex and often not transparent.
Using a foundation model approach may allow stakeholders to make reasonable estimates of the returns expected to be determined in advance of a determination. AusNet Services considers that its proposed approach provides more guidance than the alternative of separately estimating and combining different models. As noted in stakeholder submissions, the guideline should provide certainty and predictability to assist investors in making their investment decisions.	AusNet Services does not agree. The AER has made value judgements at each of the six steps of the foundation model process that are all open to extensive debate and difficult to rationalise. Consequently these points undermine certainty considerably. Adopting the foundation approach makes the resulting rate of return highly sensitive to changes in the results emerging from the AER's specification of the SL-CAPM whereas a weighted average varies less as any one of its contributing parts moves.
Using a foundation model, and drawing on other information to determine a final estimate of the expected return on equity, provides an appropriate balance between a relatively replicable and transparent process and providing flexibility in changing market circumstances. Such a process provides scope for engaging with the openness and flexibility of the Rules within a broad structure.	The foundation model has delivered lower and lower allowed rates of return on equity as the yield on CGS has fallen even though the prevailing cost of equity has not fallen nearly to the same extent. Consequently, a better characterisation of the model is that it adjusts in a manner that is inconsistent with the change in equity markets. The process is also not easy to replicate due to the significant number instances in which "regulatory judgement" is exercised without an explanation of how the "judgement" has lead to the adoption of a particular value.

AER comment (pp. 79 & 80 of Explanatory Statement)	AusNet Services' comment
Using a foundation model and other information informatively, and selecting a final estimate of the return on equity that is a multiple of 25 basis points (if departing from the foundation model estimate), disavows the pursuit of false precision.	In fact the other information (e.g. the Wright approach) strongly suggests that the foundation model is delivering an incorrect range and that a departure should have occurred. In fact there are no departures of a precise or approximate nature where there should be.
Using the Sharpe–Lintner CAPM as the foundation model reflects our assessment of the model against our criteria. Specifically, we consider it is superior to alternative models (for the purposes of estimating the return on equity for the benchmark efficient entity).	AusNet Services does not agree that the criteria are relevant or (even if they were relevant) that they have been correctly applied. The SL-CAPM cannot be regarded as superior on any relevant metric.
Our approach has also been developed in consultation with a range of stakeholders, including service providers and their industry associations, investors, and consumer groups.	Certainly there was an extensive opportunity for stakeholders to provide submissions but very little account was taken in the foundation model to any of the concerns raised by the businesses.

Further, the concept of selecting a primary model implicitly assumes that one of the available models must be superior to all the other models and introduced a hierarchy but this assumption is without any support and is contrary to the views of AEMC when the new rules were adopted.

12.2.3 Flaws with the AER's approach to estimating the allowed return on equity

The AER's approach to estimating the allowed return on equity is flawed and contrary to law in several critical respects:

- The AER brings a skewed perspective to the evaluation of the strengths and weaknesses of the models;
- The AER's extra-legislative criteria distort the evaluation of the merits of the available inputs;
- The Guideline does not give real weight to all the relevant inputs as required;
- The AER has improperly laboured over maintaining one model as preeminent with the consequent improper constraints inherent in using a "foundation model" instead of devoting its efforts to specifying all of the available models and giving to each one a weight which is proportionate or deserved;
- Even when implementing the foundation model approach, the AER has made a flawed selection of the Ibbotson inspired approach to implementing the SL-CAPM as the foundation model;
- The AER's incorrect selection of a beta of 0.7;
- The AER's incorrect selection of a market risk premium of 6.5;
- The AER's inconsistent treatment of imputation adjustments; and
- The AER's flawed use of independent expert reports.

These are each discussed below.

A skewed perspective on the strengths and weaknesses of the available models

AusNet Services is concerned that the assessment by the AER is not being undertaken on an even handed basis. AusNet Services has observed that the reasoning in the AER's Guideline and recent draft decisions:

- Does not make "like for like" criticisms – criticisms that apply equally to the SL-CAPM are only levelled against the Black-CAPM or Fama-French model;
- Inadequate recognition is accorded to significant weaknesses of the SL-CAPM and other models do not suffer these weaknesses; and
- Relatively minor implementation challenges with implementing the other models (or challenges that are equivalent in nature to that which apply when implementing the SL-CAPM are exaggerated and portrayed as major weaknesses rather than approaching these challenges with a problem solving mindset.

For example, despite the superior empirical performance of the Black CAPM discussed above[65], the AER relegates this model to a secondary status on the following basis:

> *"the model is not empirically reliable"*
>
> *and*
>
> *"the model is not widely used to estimate the return on equity by equity investors, academics or regulators."*[66]

The AER elaborates on the first criticism, stating that the return on the zero beta asset is unobservable and that the methods for estimating it are unreliable. Both the AER and McKenzie and Partington appear to reach that conclusion by observing differences between the reports lodged by the businesses on this question. The AER makes a further apparent criticism that:

> *"While we consider SFG's latest estimate of the zero beta premium appears more plausible, we believe that the large range of zero beta estimates by consultants for the NSPs indicates the model is unsuitable to use to estimate the RoE of our benchmark efficient entity.*[67]*"*

However, the AER is in effect undermining its own approach. This is because the estimation of beta and the MRP for use in the AER's primary model, the SL-CAPM, can be undertaken in a broad range of plausible and implausible ways and are not observable. For example, the AER's own consultants produce beta results that range from 0.3 to 0.8 and results for the MRP that are a full percentage point apart. With the NSP's studies included, the ranges are somewhat wider again. Therefore, the yard-stick used to exclude the Black-CAPM could also be put forward as a basis upon which to exclude the results from the SL-CAPM.

Similarly, with respect to the (arguably irrelevant) consideration of whether the model is widely used, SFG notes that:

> *"[I]t is common for U.S. regulatory cases to use what is known as "the empirical CAPM." This is an implementation of the CAPM formula with an intercept above the contemporaneous risk free rate – to be consistent with the Black CAPM and the empirical evidence that supports it. The AER's contention that the Black CAPM is not widely used in practice relies only on the label of the model, and not on its substance.*[68]*"*

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65 See *National Electricity Law*, section 12.2.1.

66 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 18 February, 2015, p. 18.

67 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, p. 183 (pdf version).

68 SFG Consulting, *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 18 February, 2015, page 21.

In its letter, Grant Samuel shares its views more broadly concerning the AER's model selection choices:

> *"In this case, it seems that the AER's approach has been to avoid changing its existing (single) formula "foundation model" and proceed on the basis that as long as it can show that the model is widely used and the individual inputs can be justified, there is no need to concern itself with whether or not the final output is commercially realistic.[69]"*

Similarly, despite conceding that the model is useful indirectly to estimate the market risk premium for use in the foundation model, the AER decided not to use the Dividend Discount Model directly in estimating the allowed return on equity.

One reason put forward is that:

> *"[W]e do not consider that the … level of data exists to form robust dividend yield estimates for Australian energy service providers. For example, there are only five sample Australian service providers for which dividend yield data is available[70]. Further, the time series for when these estimates are available are both variable and short.[71]"*

However, exactly the same five companies' data is used by the AER as the primary basis for establishing the beta range of 0.4 to 0.7 for use in the SL-CAPM.

Another reason put forward by the AER for its approach is that it considers that its results of the DGM are too sensitive to the input assumptions that are used[72]:

> *"The sensitivity of DGMs to input assumptions limits the ability to use DGMs as the foundation model."*

However, the AER does not give even handed acknowledgement to the same criticisms apply to the CAPM. In Grant Samuel's words:

> *"The DGM, in its simplest form, has only two components to estimate – current dividend yield and the long term growth rate for dividends. The current yield is a parameter that can be estimated with a reasonably high level of accuracy, particularly in industries such as infrastructure and utilities. We accept that the question of the long term dividend growth rate becomes the central issue and is subject to a much higher level of uncertainty (including potential bias from sources such as analysts) and we do not dispute the comments by Handley on page 3-61.*
>
> *However, there is no way in which the issues, uncertainties and sensitivity of outcome are any greater for the DGM than they are with the CAPM which involves two variables subject to significant measurement issues (beta and MRP). The uncertainties attached to MRP estimates in particular are widely known yet are glossed over in the AER's analysis of the relative merits. Section D of Attachment 3 of the Draft Decision contains almost 40 pages discussing the most esoteric aspects of methodologies for calculating beta but in the end the AER's choice of 0.7 is, in reality, an arbitrary selection rather than a direct outcome of the evidence. Moreover:*
>
> - *the plausible beta range nominated by the AER (0.4-0.7) creates a 2 percentage point swing factor for the CAPM-based cost of equity. Its own expert nominated an even wider range (0.3-0.8);*
> - *the 40 pages contain little meaningful discussion of issues such as standard errors or stability over time (as opposed to different time periods). Data on these aspects would be important to properly evaluate the overall reliability of the statistics; and*
> - *the publication of only averages for individual companies and not the range hides the underlying level of variability in these measures.*
>
> *In short, the claim of superiority for the CAPM is unfounded."*[73]

69 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015.

70 The relevant businesses are the APA Group, DUET, Envestra, Spark Infrastructure and SP AusNet.

71 For example, dividend yield estimates for Envestra are available from 2001, and from 2006 for Spark Infrastructure.

72 AER; *Better Regulation | Explanatory Statement (appendices) | Rate of Return guideline* (**Explanatory Statement (appendices)**); December 2013, p. 15 (pdf version).

The Grant Samuel letter adds:

> *"It is also difficult to fathom why the AER states that the DGM is highly sensitive to interest rates but makes no mention of the sensitivity of CAPM to interest rates."*[74]

The AER also suggests that the perpetual time-frame[75] over which the DGM is specified is inappropriate for regulatory purposes but SFG Consulting[76] note:

> *"We do not really have useful information about whether there is a term structure for equity. We are attempting to estimate the cost of equity from share prices to obtain a timely estimate of required returns. It might be the case that the cost of equity from year 10 onwards is different to the cost of equity for years 1 to 10, and it might be the case that the cost of equity is the same for all years.''*

And Grant Samuel points out:

> *"The AER also seeks to distinguish discount rates for valuations from discount rates for regulatory purposes by the fact that valuations have a perpetuity timeframe (and must reflect expectations of investors over that timeframe) while the regulator sets the return on equity only for the length of that regulatory period (typically five years). We do not believe this distinction is valid. For a start, the AER adopts a 10 year term for its overall rate of return (page 3-25) including a 10 year risk free year rate so if the five year timeframe of the Draft Decision was paramount then its own methodology is inconsistent with the return objective. In any event, it is our view that the relevant period is always a perpetuity, even in the context of a five year regulatory period. The rate of return over the five year period can only be realised if the capital value is sustained at the end of the period. The sustainability of the capital value at the end of year five is in turn dependent on cash flows beyond year five (i.e. the cash flows in perpetuity)."*[77]

Grant Samuel also disputes the notion that the DGM is not used in practice:

> *"In our opinion, in examining the CAPM and comparing it to the DGM, the AER has unfairly accentuated the failings of the DGM while, at the same time, it has ignored many real shortcomings in the CAPM.*[78]*"*

The AER's treatment of the Fama-French Three Factor model provides the most concrete illustration of the double-standards that have been applied because the AER has excluded the results from the model from consideration altogether. SFG Consulting's repudiation of the AER's criticisms also illustrate that criticisms (a) and (b) shown below, apply equally to the SL-CAPM while criticisms (c) and (d) are incorrect – yet the Fama-French Three Factor model, and not the SL-CAPM model, is excluded on this basis:

> *"In our view, the reasons that the AER provides for dismissing the Fama-French model are without basis:*
>
> *(a) Sensitivity to different estimation periods and methodologies.*
>
> *The AER states that the estimates from the Fama-French model can vary across different estimation periods and techniques. In response, we note that this applies to all models that require the estimation of parameters. For instance the AER's own estimates for beta vary materially over time and across estimation methods. Moreover, the fact that some estimates of the Fama-French model might produce inconsistent results is not a basis for dismissing all estimates. A better approach would be to consider the relative quality and reliability of estimates.*
>
> *(b) Estimation of ex ante required returns.*

[73] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 3.

[74] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 3.

[75] AER; *Draft decision, Jemena Gas Networks, 2015-20, Attachment 3: Rate of Return,* November 2014, p. 277 (pdf version).

[76] SFG Consulting; *Alternative versions of the dividend discount model and the implied cost of equity, Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid;* 15 May 2014, paragraph 74 on p. 17.

[77] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 5.

[78] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 2.

The purpose of the Fama-French model is the same as the purpose of the Sharpe-Lintner CAPM – to explain the cross-section of stock returns. That is, the purpose of these models is to identify the features of stocks that can be used to predict what average returns they are likely to generate in the future. The key difference is that the predictions from the Fama-French model have been shown to be more closely associated with stock returns. It is theoretically possible that the superior empirical performance of recent decades might not continue into the future, but that should not be the basis for dismissing the Fama-French model.

(c) Lack of a theoretical foundation.

We note that the Fama-French model was originally motivated by the poor empirical performance of the Sharpe-Lintner CAPM. Fama and French identified that the Sharpe-Lintner CAPM did not work and set about developing a model that did. Since that time, theoretical justifications for the Fama-French factors have been developed, in a way that is quite standard for scientific progression. In our view it would be illogical to reject the Fama-French model in favour of the Sharpe-Lintner CAPM on the basis that its original motivation was the poor performance of the very model that is to be adopted in its stead.

(d) Complex to implement.

The Fama-French model is not complex to implement. It requires the estimation of factor returns and factor sensitivities (betas). There are simply three factors instead of one. In any event, a superior model should not be rejected in favour of an inferior one on the grounds of simplicity."[79]

In summary, AusNet Services is concerned that the AER has approached all aspects of the evaluation of the various models in a way that is pre-disposed to favour the SL-CAPM and reject the other models or assign the other models to a highly constrained role. Specifically, AusNet Services supports the view of SFG Consulting that:

"In our view, what the Rules require is an identification of all estimation methods, financial models and other evidence that may be relevant to estimating the return on equity. Following that identification, and assuming that there is more than one information source that is relevant, some weight will need to be ascribed to the information sources or they will somehow need to be combined to produce a point estimate. The Rules do not specify that the Sharpe-Lintner CAPM is to be used unless a model about which there is no debate or potential weaknesses is identified. Each of the information sources, including the Sharpe-Lintner CAPM must be fairly assessed if the estimate of the return on equity is to be arrived at on a reasonable basis and be the best forecast or estimate possible in the circumstances. The evidence supports a finding that the best forecast or estimate is one that is properly informed by estimates from a range of evidence, including the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French model."[80]

Extra-legislative criteria distort the evaluation of the merits of the available inputs

Instead of directly applying the rate of return objective, the National Electricity Objective (NEO) and the Revenue and Pricing Principles (RPP), the Guideline applies a set of extra-legislative criteria[81] that do not appear in the NER or the NEL.

Although the criteria appear on their face to constitute a reasonably common sense or at least innocuous set of considerations, they have been instrumental in contributing to several of the significant errors in the formation and implementation of the foundation model approach. Because each of these criteria is initially introduced in abstract terms, it is not immediately obvious how or why the application of the criteria when applied when evaluating the relevant evidence leads to error.

Indeed as explained below, the AER's application of these criteria has incorporated irrelevant considerations, contrary to the requirements of the Rules. For example, estimation methods and

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79 SFG Consulting; *Using the Fama-French model to estimate the required return on equity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, p. 2.

80 SFG Consulting; *The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks, and United Energy;* 27 March 2015, pages 22 – 23 (attached as Appendix 12H).

81 AER; *Explanatory Statement*; p. 24.

financial models are required to be consistent with "well accepted economic and finance principles" and promote "simple over complex approaches"[82].

When the AEMC adopted the current common rate of return rules to apply to AusNet Services' business and equally to gas network businesses, it explicitly repealed the words "well accepted" financial model from the former gas rules because the AEMC considered that it lead to excessive conservatism. To explain this point further, recall that the current rules are common to both electricity and gas and they are the product of a repeal of three sets of rules, none of which the AEMC considered to be performing adequately. Unlike the former electricity rules, former gas rules 87(1) and (2) permitted the AER to adopt a financial model other than the SL-CAPM but the model selected had to be a "well accepted" model "such as the CAPM". The AEMC's adoption of a common set of rules for electricity and gas consciously repealed the "well accepted" criterion because it inappropriately narrowed regulatory decisions:

> *"In [two previous gas] cases, the Tribunal reached identical conclusions on the application of rule 87(1) and rule 87(2). The Tribunal considered that since the CAPM is a "well accepted financial model" under the provisions of rule 87(2), provided that the inputs to this model are appropriate, the output from this model will necessarily lead to an outcome in accordance with the objective specified in rule 87(1). Therefore, under the Tribunal's interpretation of the NGR, using only the CAPM to estimate the return on equity was sufficient to satisfy the objective in rule 87(1).[83]"*

> *"[R]ules 87(1) and (2) as interpreted by the Tribunal, could be applied in such a way as to reduce the range of information that can be used in estimating the rate of return. Such application could lead to the adoption of relatively formulaic approaches to determining the rate of return rather than focussing on whether the overall estimate of the rate of return meets the overall objective.[84]"*

> *"The rate of return estimation should not be formulaic and be driven by a single financial model or estimation method.[85]"*

> *"An example of an estimation process that has become formulaic is the mandatory use of the CAPM under the NER and the view that appears to be adopted in practice that CAPM is the only "well accepted" model under the NGR, despite the flexibility to consider other models.[86]"*

The way in which the AER uses the "well accepted" criterion in its Guideline is exactly the sort of excessively conservative outcome that the AEMC sought to avoid by repealing that phrase from the gas rules and choosing not to adopt the phrase in the electricity rules.

There are a number of other ways that this excessive conservatism manifests itself and causes decision making error. For example, a key report upon which the AER relies on in support of the foundation model framework was prepared by Associate Professor Handley of the University of Melbourne.[87] He was not asked what the best way of achieving the rate of return objective was. Rather he was asked whether the AER's approach was capable of meeting the objective and, importantly:

> *"[Do] you consider any material in the regulatory proposals from the service providers and the three consulting reports, provide* ***<u>compelling reason to depart from the core framework</u>*** *underpinning the foundation model approach as outlined in Figure 5.1 on page 12 of the Guideline?"* (Emphasis added)[88].

[82] AER; *Explanatory Statement*; pp. 24 – 28.

[83] AEMC; *Draft Rule Determination;* p. 42.

[84] AEMC; *Draft Rule Determination;* p. 42.

[85] AEMC; *Draft Rule Determination;* p. 47.

[86] AEMC; *Draft Rule Determination;* p. 47.

[87] Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, pp. 3 & 6.

[88] Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, p. 6.

This question illustrates two forms of conservatism: inertia around the SL-CAPM when making the Guideline and inertia around the Guideline when making regulatory determinations. The latter is directly contrary to the AEMC's rule determination which repealed the Rules that required there to be "persuasive evidence" before the AER was permitted to depart from its Statement of Regulatory Intent. The AEMC's reasoning was as follows:

> *"[T]he persuasive evidence test is problematic. Although regulatory certainty is desirable, it should not be attained at the expense of limiting the regulator's ability to make the highest-quality rate of return estimate at any particular time.*[89]*"*

> *"In its draft rule determination, the Commission took the view that inclusion of an inertia principle would undermine the strength of its proposed rate of return framework. The Commission further noted that its proposed non-binding rate of return guidelines would safeguard the framework against the problems of an overly-rigid prescriptive approach that cannot accommodate changes in market conditions. Instead, sufficient flexibility would be preserved by having the allowed rate of return always reflecting the current benchmark efficient financing costs.*[90]*"*

Returning to the inertia the AER gives to the SL-CAPM, the primary basis for the Securities Industry Research Centre of Asia-Pacific (SIRCA) Limited's McKenzie and Partington to endorse the use of the CAPM is simply that it is the model with the earliest birthday and a misplaced assumption that it is the "standard workhorse":

> *"With regard to the CAPM, its efficacy comes from the test of time. This model has been around for in excess of half a century and has become the standard workhorse model of modern finance both in theory and practice.*[91]*"*

This conservatism has been a significant contributor to the decision to adopt the SL-CAPM as the foundation model, with secondary weight being given to the DGM and the Black-CAPM only in the limited role of informing certain parameter estimates used within the SL-CAPM, and no weight at all being given to the Fama-French three factor Model which is of a substantially younger vintage than the SL-CAPM. This conservatism runs directly counter to the intention of the AEMC[92] that the Rules do away with the incumbency of the SL-CAPM and open the decision making to the inclusion of all the relevant models and other inputs:

> *"In the Commission's view, achieving the NEO, the NGO, and the RPP requires the best possible estimate of the benchmark efficient financing costs. This can only be achieved by ensuring that the estimation process is of the highest possible quality. It means that a range of estimation methods, financial models, market data and other evidence should be considered, with the regulator having discretion to give appropriate weight to all the evidence and analytical techniques considered."*

In referring to the decision of the Tribunal in which it concluded that the use of well-accepted financial models effectively guaranteed that the resulting estimate of the required return on equity was reasonable and commensurate with the prevailing conditions in the market, the AEMC stated:

> *"The Commission considered that this conclusion presupposes the ability of a single model, by itself, to achieve all that is required by the objective. The Commission is of the view that any relevant evidence on estimation methods, including that from a range of financial models, should be considered to determine whether the overall rate of return objective is satisfied*[93] *and The Commission considered that no one method can be relied upon in isolation to estimate an allowed return on capital that best reflects benchmark efficient financing costs.*[94]*"*

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89 AEMC; *Economic Regulation of Network Service Providers Rule Change Final Determination* (**AEMC Rule Determination**); November 2012, p. 41.

90 AEMC; *Rule Determination;* p. 46.

91 McKenzie M and G Partington; *Report to the AER, Part A: Return on Equity, The Securities Industry Research Centre of Asia-Pacific (SIRCA) Limited*; October 2014, p. 9.

92 AEMC; *Draft Rule Determination*; p. 46.

93 AEMC; *Rule Determination*; p. 48.

94 AEMC; *Rule Determination*; p. 49.

Models chosen on the basis of being simple can easily fall into error by excluding a proper consideration of the full range of factors affecting the prevailing return on equity.

There is overwhelming evidence that the SL-CAPM's dominant role should cease. The model has a poor empirical performance and it is demonstrably producing downwardly biased results - particularly for firms such as the benchmark efficient entity and in market conditions that are currently being experienced. The Black CAPM avoids the low-beta bias but further empirical improvements are possible by using the Fama-French Three Factor model to address the value bias. The DGM has been used for many years in the US and it provides an independent, alternative basis for setting a rate of return that is also free of the flaws in the SL-CAPM but the AER dismisses the possibility that all these other models should play a material role in the AER's estimation process.

If an existing model is shown to be flawed in ways that newer models are not, then collective inertia and simplicity are not proper decision making constraints upon giving the newer model(s) real weight according to the substantive contributions they can make. It cannot be the case that by removing any reference within the Rules to the incumbency of the SL-CAPM, the AEMC intended a "chicken and egg" situation that prevents the regulator from moving to adopt a new model until another regulator has.

The criterion that the choice of inputs should "promote the simple over the complex where appropriate[95]" also leads the decision making process astray. The explicit requirement in Rule 6.5.2(e) of the Rules is to consider all the relevant inputs and no mention is made of the exclusion or devaluation of inputs on the basis that they are complex. Although simplicity is intuitively appealing, it is eminently possible (as illustrated below) that a certain degree of complexity is required to properly estimate the prevailing return on equity for an efficient benchmark business.

The preference for the simple over the complex has been instrumental in the selection of the SL-CAPM as the "foundation model" but the expert theoretical and empirical evidence demonstrates that the exclusion of additional detail (which the AER refers to as complexity) is required to avoid downward biases for stocks with betas of less than one (i.e. Black CAPM) or otherwise incorrect results for "value stocks" (i.e. Fama-French Three Factor model).

This criterion is also inconsistently applied. For instance, the AER's own foundation model concept is a good deal more complex than any of the SL-CAPM, Black CAPM and DGM taken individually and the aggregate result is clearly more complex than simply estimating the Fama-French Three Factor model. It is also a good deal more complicated than simply estimating all the models and taking a (weighted) average of the results.

The "fit for purpose" criterion, when implemented by the AER, is also problematic. That criterion imports the notion that each relevant model should be employed in a manner that is "consistent with the original purpose for which it was compiled"[96]. There is no logical basis to apply this constraint upon the use of the models. By analogy, medicines are commonly initially identified and marketed for one purpose (e.g. Aspirin as a pain killer) but are found to be very useful for other purposes (e.g. the use of Aspirin to ameliorate high blood pressure).

The AER has also adopted the criterion for consideration: "where applicable, reflective of economic and finance principles and market information". The AER reveals its intent through its written deliberations, and it appears that the theoretical pedigree of the model is one of the key considerations as to whether the criterion is met or not:

95 AER; *Better Regulation | Rate of Return Guideline*; December 2013, p. 6.

96 AER; *Explanatory Statement*; p. 24.

> *"We consider economic and finance theory provides important insights into the conditions for achieving economic efficiency, including for the setting of revenue and prices for natural monopoly service providers. Economic theory also suggests economically efficient outcomes are in the long-term interests of consumers. This criterion is intended to draw on these theoretical insights to maximise the likelihood that regulatory outcomes would promote economic efficiency, and thus would achieve the allowed rate of return objective and the (national electricity and gas) objectives.*[97]*"*

Expressed in that way, the criterion appears unobjectionable but the AER has in fact used it as a criterion of inclusion *and exclusion* – as well as "ruling in" a model the AER considers has a strong theoretical foundation despite its dubious empirical credentials (i.e. the SL-CAPM), the AER's draft explanatory statement for the Guideline used this as one significant basis for "ruling out" the Fama-French Three Factor Model. The Explanatory Statement to accompany the Guideline as promulgated gave greater emphasis to other considerations but it still noted that:

> *"[W]e consider the statement by McKenzie and Partington—that there is no clear theoretical foundation to identify the risk factors, if any, that the model captures—to be informative.*[98]*"*

In fact, the model's theoretical underpinning is strong[99] [100] and more importantly its empirical credentials are strong and on this basis alone – regardless of whether it has a strong theoretical foundation – require that significant weight be accorded to the model.

Excluding models on this basis is likely to frustrate the achievement of the rate of return objective. To illustrate the point, consider by analogy what would have happened if the AER's criteria were to have been applied to the discovery of the magnetic compass which was used for extensively for approximately 500 years from about 1100 before a theory was developed in 1600 to explain why it worked (i.e. the idea that the earth itself was magnetic and that a magnetic needle will align with the earth's magnetic field).

The Guideline does not give real weight to all the relevant inputs as required

The approach to establishing the return on equity set out in the Guideline is not consistent with the NER and is not the best possible estimate of the required rate of return for equity that progresses the NEO. In particular, the Guideline does not meet the requirements of Rule 6.5.2(e) of the Rules that regard must be had to "relevant estimation methods, financial models, market data and other evidence". It is recognised that "an expression such as "have regard to" is capable of conveying different meanings depending on its statutory context.[101] [102]" And in the absence of a definition of relevant, it is to be given its ordinary meaning in the context[103]. In this regard, it was noted by the AEMC in its draft rule determination[104] and final rule determination:

> *"The final rule provides the regulator with sufficient discretion on the methodology for estimating the required return on equity and debt components but also* ***requires the consideration of a range of estimation methods, financial models, market data and other information so that the best estimate of the rate of return can be obtained overall that achieves the allowed rate of return objective****.*[105]*" (Emphasis added)*

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97 AER; *Explanatory Statement*; p. 27.

98 AER; *Explanatory Statement (appendices)*; p. 21.

99 NERA Economic Consulting; *The Fama-French Three-Factor Model, A report for the Energy Networks Association*; October 2013, pp 8-10.

100 NERA; *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA PowerNetworks, and United Energy;* March 2015, pages 17 - 21.

101 *Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231, paragraph 55.

102 *Project Blue Sky v Australian Broadcasting Authority* (1998) 194 CLR 355.

103 *Project Blue Sky v Australian Broadcasting Authority* (1998) 194 CLR 355.

104 AEMC; *Draft Rule Determination*; pp. 9 -10.

105 AEMC; *Rule Determination*; p. 8.

Nor can it be adequate to elevate a single model as the foundation model and limit the role of all other models to the secondary status of estimating parameters within that foundation model unless there is a proper basis for concluding that they are unsuitable for contributing directly to the return on equity or that the return on equity cannot lie outside those constraints and that the "right answer" must fall within the range of outputs that the foundation model could deliver.

Further, it is relevant to consider the context of the overall regulatory structure into which this new rule has been inserted. The same language requiring "regard" to be had to the full range of relevant inputs now appears in both the new NER and NGR and should be similarly applied:

National Electricity Rules:

> *"In determining the allowed rate of return, regard must be had to:*
>
> *(1) relevant estimation methods, financial models, market data and other evidence; …*[106]*"*

National Gas Rules:

> *"In determining the allowed rate of return, regard must be had to:*
>
> *(a) relevant estimation methods, financial models, market data and other evidence;…*[107]*"*

The meaning of these words needs to be understood as both a reform to previous regulatory practice in electricity and to the previous regulatory practice in gas. In this regard, two points from the gas industry are important:

- The AER was permitted under the previous gas rules to depart from solely using the SL-CAPM and it could have chosen to use alternatives for setting the return on equity. Network providers had previously proposed other methodologies that the AER had considered but had either rejected outright or else had consigned to a secondary role as a "cross check". The AEMC recognised that this approach needed reform to remove consequent constraints that concepts such as "well accepted" had placed on the AER, in the sense of accommodating broader range of inputs and the AEMC considered that the new rules would achieve their stated aim; and
- The NGR is the successor to the Gas Code and much of the language is inherited from that document. The use of the term "have regard" in the Gas Code has been the subject of extensive litigation and the courts construed the term within the context of that document as imposing a requirement on the regulator to give "real weight"[108] to the material and that it was inadequate to consider and give no weight to relevant information. Given the prominence of that litigation in the history of the development of the current NGR it is difficult to accept that the AEMC envisaged that it would be sufficient for the AER to consider all the relevant inputs and then give certain of those inputs no probative weight or only a constrained or secondary form of weighting.

The Guideline does not adhere to the requirement to give real weight:

- To the Fama-French Three Factor model because it is not used at all (specifically given no role)[109] in the establishment of the return on equity; and
- Although some limited role[110] may be given to the other two relevant models (the Black CAPM and DDM), these other models are each only used to inform one single parameter of the SL-CAPM. Even when used to inform a parameter of the SL-CAPM, they are used as secondary evidence that is disregarded to the extent that it is inconsistent with the primary range that is established using a different subset of the available evidence. Limiting their

106 AEMC; *National Electricity Rules Version* 71; Rule 6.5.2(e), p. 663.

107 AEMC; *National Gas Rules Version 25, Part 9 Price and Revenue Regulations*; Rule 87(5), p. 61.

108 *RE Dr Ken Michael AM; ExParte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231 at [54 – 6].

109 AER; *Better Regulation | Rate of Return Guideline*; p. 13.

110 AER; *Better Regulation | Rate of Return Guideline*; p. 13.

use this way severely constrains their ability to improve the quality of the return on equity estimate. In fact these models are not used in the standard way to estimate at all, which is to calculate the required return on equity for the benchmark efficient firm as is the approach adopted by other regulators including in the United States (see section 12.2.1.2 above).

The Guideline Explanatory Statement describes the foundation model as follows:

> *"Use one primary model with reasonableness checks. Generally, it would be expected that the output from the primary model would be adopted as our estimate of the expected return on equity (as per option one). However, where the reasonableness checks suggested the output from the primary model was not reasonable, the expected return on equity would be* ***determined based on regulatory judgement*** *(informative use of primary model)."*[111] (Emphasis added)

In any event, even if it were correct to hold significant reservations about the models other than SL CAPM, the deficiencies with the SL CAPM discussed in section 12.2.1.1 are demonstrably so significant that there is no choice but to reconsider the other models and give them significant weight to offset the significant flaws that could arise from giving the SL-CAPM primary weight.

The more detailed specification in the NSW draft decisions[112] [113] [114] [115] [116] [117] provide additional insight into the AER's approach of how the foundation model is to be applied, providing examples of the "cross check" and "regulatory judgement" – each of which have been problematic concepts in energy regulation. With respect to "cross-checking" it is easy to decide what to do when all the evidence is mutually corroborative. However, there is a problem when the secondary cross check material contradicts the primary material (and usually there is no concrete explanation by the regulator of what would happen). Where there is a conflict, either the initial estimate is to be preferred regardless of what the cross check suggests or the secondary material is used to displace the initial estimate. In either case, one piece of information is in effect being given determinative weight and the other information is being given no weight.

The only "circuit breaker" is to suggest that in the event of a conflict regulatory judgement will prevail. The problem with this concept is that it is generally the term used when a regulator selects a value from within a list of conflicting factors without providing the reasoning as to how the particular value was chosen. In other words, this term is usually used when there is no reasoning provided, and in that sense the decision is unreasonable. In this circumstance, it is impossible to know whether real weight was given to all the relevant material. This is not consistent with the Rules which require reasons to be given at both the draft determination stage[118] and the final determination stage[119].

[111] AER; *Explanatory Statement*; page 54.

[112] AER; *Draft decision for Ausgrid distribution determination 2015-16 to 2018-19, Overview;* November 2014, pp. 43 – 44 (pdf version).

[113] AER; *Draft decision for Directlink determination 2015-16 to 2019-10, Overview;* November 2014, pp. 33 – 34 (pdf version).

[114] AER; *Draft decision for Endeavour Energy distribution determination 2015-16 to 2018-19, Overview;* November 2014, pp. 41 – 42 (pdf version).

[115] AER; *Draft decision for Essential Energy distribution determination 2015-16 to 2018-19, Overview;* November 2014, pp. 41 – 42 (pdf version).

[116] AER; *Draft decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview;* November 2014, pp. 37 – 38 (pdf version).

[117] AER; *Draft decision for Transgrid transmission determination 2015-16 to 2018-19, Overview;* November 2014, pp. 39 – 40 (pdf version).

[118] AEMC; *National Electricity Rules Version* 71; Rule 6.10.2(3), p. 711.

[119] AEMC; *National Electricity Rules Version* 71; Rule 6.11.2(3), p. 714.

For example, the AER uses regulatory judgement in selecting a beta at the high end of its depressed range of 0.4 to 0.7 but there is no positive rationale expressed about why the 0.7 figure was selected. This means that if (as AusNet Services contends) the range is incorrect, it is not possible to discern whether the 0.7 number is then also incorrect. The AER may consider that, unencumbered by the depressed range, the number would be higher. An alternative approach is to find an empirical method or unique rationale which directly supports the particular number.

The draft determinations identify a number of matters that have not been the basis of selecting the 0.7 number but the closest that the regulator comes to an articulation of why the 0.7 number has been chosen is when the AER has read all of the materials submitted to it and has reached a "balanced outcome" by using "regulatory judgement" that results in it being "satisfied" as to the furtherance of the rate of return objective:

> *"After taking these considerations into account, we adopt an equity beta point estimate of 0.7 for this draft decision, consistent with the Guideline. We consider this approach is reflective of the available evidence, and has the advantage of providing a certain and predictable outcome for investors and other stakeholders. We recognise the other information we consider does not specifically indicate an equity beta at the very top of our range. However, a point estimate of 0.7 is consistent with these sources of information and is a modest step down from our previous regulatory determinations. It also recognises the uncertainty inherent in estimating unobservable parameters, such as the equity beta for a benchmark efficient entity."*[120]

And[121]:

> *"We consider an equity beta of 0.7 for the benchmark efficient entity is **reflective of the systematic risk** a benchmark efficient entity is exposed to in providing regulated services. In determining this point estimate, we applied our regulatory judgement while having regard to all sources of relevant material. **We do not rely** solely on empirical evidence and we do not make a specific adjustment to equity beta to correct for any perceived biases in the SLCAPM. **We also do not rely** on empirical evidence from the Black CAPM, FFM or SFG's construction of the DGM (see appendix A and C). **We do not consider** our use of the SLCAPM as the foundation model will result in a downward biased estimate of the return on equity for a benchmark efficient entity (see appendix A.2.1).*
>
> *Our equity beta point estimate provides a balanced outcome, given the submissions by stakeholders and services providers. Figure 3-6 shows our equity beta point estimate and range in comparison with other reports and submissions. **We are satisfied** this outcome is likely to contribute to a rate of return estimate that achieves the allowed rate of return objective, and is consistent with the NEO and RPP. We provide a detailed analysis of technical issues and responses to Ausgrid's proposal in appendix D."* (Emphasis added).
>
> *"We consider an equity beta of 0.7 for the benchmark efficient entity is reflective of the systematic risk of a benchmark efficient entity is exposed to in providing regulated services. In determining this point estimate, we applied our regulatory judgement while having regard to all sources of relevant material. **We do not rely** solely on empirical evidence and we do not make a specific adjustment to equity beta to correct for any perceived biases in the SLCAPM. We also do not rely on empirical evidence from the Black CAPM, FFM or SFG's construction of the DGM (see appendix A and C). **We do not consider** our use of the SLCAPM as the foundation model will result in a downward biased estimate of the return on equity for a benchmark efficient entity (see appendix A.2.1). Our equity beta point estimate **provides a balanced outcome**, given the submissions by stakeholders and services providers. Figure 3-6 shows our equity beta point estimate and range in comparison with other reports and submissions. We are satisfied this outcome is likely to contribute to a rate of return estimate that achieves the allowed rate of return objective, and is consistent with the NEO and RPP".*[122] (Emphasis added).

[120] AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 82 (pdf version).

[121] AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 83 (pdf version).

[122] AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 83 (pdf version).

And finally:

> *"We note McKenzie and Partington have now indicated the Black CAPM (of itself) does not justify any uplift to the estimated equity beta to be used in the SLCAPM. Nevertheless, we consider the model does theoretically demonstrate that market imperfections* ***could lead to the SLCAPM generating RoE estimates that are too high or too low. We have taken this into account in exercising our regulatory judgment*** *in choosing to use an equity beta of 0.7 in the SLCAPM. This is the equity beta we indicated we would use at the time we published the Guideline.*
>
> *We also acknowledge an equity beta of 0.7 is well above the fixed weight portfolio and average of individual firm equity beta estimates in Henry's 2014 report. However, in using an equity beta of 0.7 in applying the SLCAPM, we have exercised our regulatory judgment taking into account a range of information beyond the empirical beta estimates. We have selected an equity beta point estimate of 0.7 because we consider will this lead [sic] to a RoR that meets the RoR objective and best advances the RoR objective. We consider this is appropriate in all the circumstances."* [123] (Emphasis added).

While the decision discloses a series of matters that were <u>not</u> the reason for the 0.7 figure, from what has been written, it is simply not possible to understand in any positive way how the figure of 0.7 was reached and in the absence of a rational explanation, it is not possible to hold the decision to account. Related to the inadequacy of the explanation for the adoption of a value of 0.7 is the failure of the AER to explain why this figure has been significantly reduced since the AER's 2009 determination when essentially the same information was considered (other than information which now points to a higher beta). SFG Consulting explains this in more detail in paragraphs 89 to 92 of its 25 February 2015 report on "The required return on equity for the benchmark efficient entity"[124].

Both of these problems are illustrated in the AER's draft NSW determinations. For example, when selecting a beta range of 0.4 to 0.7 the AER relies on a small (and potentially unrepresentative) set of partly dated data for domestic firms which are dwindling in number rather rapidly. The AER purports to apply a "cross check" comparison with international data from the UK and US but the US material, and the average of the combined material, when properly considered delivers results above the 0.7 level[125]. To resolve the inconsistency, the AER adheres to the initial range, effectively rendering the international cross check nugatory.

The same problem arises in relation to the "cross checking" that is said to occur in respect of the Ibbotson inspired AER approach to specifying the SL-CAPM using the Wright approach. SFG Consulting states:

> *"This highlights the problem of using one subset of relevant evidence when estimating the original MRP parameter while relegating another subset of the relevant evidence to the role of "cross checks." Having determined that the Wright approach for estimating the MRP is relevant evidence, and having obtained a Wright estimate of the return on equity that is materially inconsistent with the AER's proposed estimate, there are two possible courses of action. Either:*
>
> *(a) The AER would retain its original estimate – in which case the cross check has no effect and there seems to be no point in performing it; or*
>
> *(b) The AER would revise its original estimate to make it consistent with the cross-check estimate – in which case the original evidence has effectively been discarded in favour of the cross check evidence."*[126]

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[123] AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, p. 172 (pdf version).

[124] SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, pp. 19 – 20.

[125] SFG; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, paragraphs 40-56, pp. 10 – 16.

[126] SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, paragraph 151, p. 32.

The improper search for a preeminent model and improper constraints inherent in using a "foundation" model

An assumption underpinning the Guideline is that it is possible to identify a single superior model and to accord that model "single foundation" status which in practice means setting outer limits on the range of possible values for the return on equity from the high and low point estimates that model delivers.

The first flaw with this aspect of the Guideline is that there is no evidence to support the assumption that there is a superior model. The concept of a foundation model does not appear in the NER or the NEL. Indeed, when adopting the Rules, the AEMC notes with disapproval that:

> *"The AER has strongly rejected any approach other than the CAPM in its submission. The AER's view is that it is unlikely that there would be a justifiable departure from the CAPM over the medium to long term.[127]"*

A key purpose of the Rule change was clearly to prevent the AER from retaining the SL-CAPM as a preeminent model. The AEMC's rejoinder to the AER's emphatic preference for the SL-CAPM was as follows:

> *"Most of the financial models that exist in the finance field are based on academic work.* ***All of the models appear to have some weaknesses.*** *All the models that have been advanced have been criticised for either the underlying assumptions required or lack of correlation of modelling results with empirical tests. Even the CAPM has been criticised in academic literature. For example, some of the identified limitations of the CAPM are:*
>
> - *it is based on unrealistic assumptions;*
> - *it is difficult to test the validity of the CAPM; and*
> - *the Beta estimate does not remain stable over time.*
>
> *Two of the most prominent academics in this field, Eugene Fama and Kenneth French, make the following statement on the CAPM:*
>
> > *'The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model.'*
>
> *An illustration of the issues associated with just relying on the CAPM to estimating return on equity has also been highlighted by the LMR Panel. In its stage one report, the LMR Panel noted that 'binding regulatory decisions hand and foot to a financial model with known defects does not immediately commend itself as an approach that will advance the NEO and NGO'.*
>
> *There are a number of other financial models that have varying degrees of weaknesses. Some of the financial models that have gained some prominence include the Fama-French three-factor model, the Black CAPM, and the dividend growth model. Weaknesses in a model do not necessarily invalidate the usefulness of the model. Ultimately it is important to keep in mind that all these financial models are based on certain theoretical assumptions and* ***no one model can be said to provide the <u>right</u> answer****.[128]"* (Emphasis added).

SFG states:

> *"Because all the models have different strengths and weaknesses along different dimensions, it is impossible to identify one superior model that alone would out-perform the combined evidence of all of the relevant models.[129]"*

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[127] AEMC; *Draft Rule Determination*; p. 47.

[128] AEMC; *Draft Rule Determination*; pp. 47 – 48.

[129] SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks;* 6 June 2014, paragraph 370, p. 89.

Neither of the AER's experts were explicitly asked whether the SL-CAPM model is superior to the others or whether the SL CAPM is more likely to produce the best estimate of the required return on equity, relative to an approach that considers all of the relevant models. Rather they were asked whether the foundation model was capable of delivering an allowance that met the rate of return objective or whether there was a "compelling reason" to depart from the SL-CAPM. Even their reports demonstrate that there are strengths of the other models and weaknesses of the SL-CAPM, the inevitable conclusion of which is that the SL-CAPM is not necessarily preferable:

> *"An apparent weakness of the Sharpe-CAPM is the empirical finding, for example by Black, Jensen and Scholes (1972) and Fama and French (2004), that the relation between beta and average stock returns is too flat compared to what would otherwise be predicted by the Sharpe-CAPM – a result often referred to as the low beta bias. In considering the relevance of this evidence, however, it is important to recognize that the current objective is to determine the fair rate of return given the risk of the benchmark efficient entity rather than to identify the model which best explains past stock returns.*[130]*"*

> *"The AER's proposal for estimating the expected return on equity using the S–L CAPM as a 'foundation model' provides a starting point, which is firmly based in a mature and well accepted theoretical and empirical literature. As no framework is perfect, the foundation model has its weaknesses, but these are well-documented and in many cases can either be diagnosed or perhaps compensated for in empirical practice. The final estimate of the expected return on equity may have regard to a broad range of relevant material including a range of multifactor models such as the Fama and French (1993) and the APT of Ross (1976), inter alia. Many of these competing models nest this foundation model and so potentially make more use of available information. In that sense, they may prove to be useful in validating this foundation model estimate.*[131]*"*

As discussed in the next section, there are strong reasons why the SL-CAPM is not the best of the available models. However, even if it were the best of the available models, using it in the way that the AER has done constrains, and in some cases prevents, insights from the other models from being employed. Further, adopting a single foundation model is inconsistent with practices of other regulators who draw on a number of models to inform their decisions[132].

Elevating any one model to the "foundation" status necessarily gives that model primary weight and all the other models less weight. Given the significant downward bias of this model for low beta stocks and the over-all empirical shortcomings of the SL-CAPM, the AER's approach gives undue primary weight to the foundation model and, contrary to the requirement to take into account all the available information, the AER's framework improperly constrains the regard the AER can effectively give to those other models.

There is substantial evidence[133] that the SL-CAPM produces a downwardly biased estimate of the return on equity for low beta firms and value stocks – both characteristics apply to the benchmark efficient entity. Recent NERA work, for example, concludes as follows with respect to its in-sample tests of the SL-CAPM:

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130 Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, p. 5.

131 McKenzie M and G Partington; *Report to the AER, Part A: Return on Equity, The Securities Industry Research Centre of Asia-Pacific (SIRCA) Limited*; October 2014, p. 9.

132 (a) *Application of Southwest Gas Corporation for authority to increased its rates and charges for natural gas service for all classes of customers in Southern and Northern Nevada.* 2009 Nev. PUC LEXIS 265 at p. 7.

(b) *Application of Southwest Gas Corporation for authority to increase its rate and charges for natural gas service for all classes of customers in Southern and Northern Nevada.* 2009 Nev. PUC LEXIS 237; 277 P.U.R. 4th 182 at p. 4.

(c) *Application of Sierra Pacific Power Company for authority to begin to recover the costs of constructing the new Tracy Combined Cycle Unit and other plant additions and costs of service through an increase of its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.* 2008 Nev. PUC LEXIS 288 at p. 7.

133 SFG Consulting, in referring to the extensive empirical research in this respect, such as the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973) in SFG Consulting; *Cost of equity in the Black Capital Asset Pricing Model*, *Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks;* 22 May 2014, pp. 6- 10.

> *"The data indicate that there is a negative rather than a positive relation between returns and estimates of beta. As a result, the evidence indicates that the SL CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL CAPM underestimates the returns to low-beta portfolios is both statistically and economically significant."*[134]

Further, using current data, SFG calculates returns using the various models, which illustrates that the SL-CAPM delivers a lower result than any other model, particularly when the SL-CAPM is estimated in the way the AER proposes via placing primary reliance on a sub-set of the relevant evidence.

An important basis for the AER's exclusion of the Fama-French Model was that the AER considered there to be no clear theoretical foundation to identify risk factors. This is an improper basis upon which to exclude a model that in fact performs well empirically in explaining stock market returns. Indeed, there is a lot to be said for giving primacy to empirical performance over theories as, until they are tested robustly, theories are simply one idea as to reality.

There is no reason to suppose that selecting from the upper range of possible outcomes for SL-CAPM parameters will correct for these biases. Indeed by selecting from ranges set using a downwardly biased model there is logically a significant risk that the true or unbiased return on equity will lay outside that range.

The AER has acknowledged that the DDM, Black-CAPM and survey evidence can also be informative in addressing some of the limitations of the AER's application of the SL-CAPM. However, under the AER's framework, the inputs from this evidence are only taken into account within an upper limit selected from an application of the SL-CAPM that has not corrected for those biases. There is, therefore, every reason to suppose that the results do not accord with prevailing (unbiased) equity returns.

Moreover, the AER's method does not conform to the regulator's own "fit for purpose" criterion[135] which is that regard should be had to the limitations of the model's original purpose. The SL-CAPM was not originally implemented by drawing parameter estimates from competing models, and nor were the competing models developed for the purpose of estimating parameters to be used in the SL-CAPM. In implementing its convoluted foundation model approach, the AER is not being true to any model and is not implementing any model in the way that was intended.

Flawed selection of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model

Even if the Rules did allow a foundation model to constrain the ways in which other relevant data can contribute to the allowed rate of return, there is no basis to conclude that the Ibbotson inspired SL-CAPM is "*.. superior to other models we have considered. We therefore employ the SLCAPM as our foundation model*"[136].

There are two aspects to the AER's flawed specification of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model (a) the selection of the SL-CAPM; and (b) specifying it in the manner the AER does.

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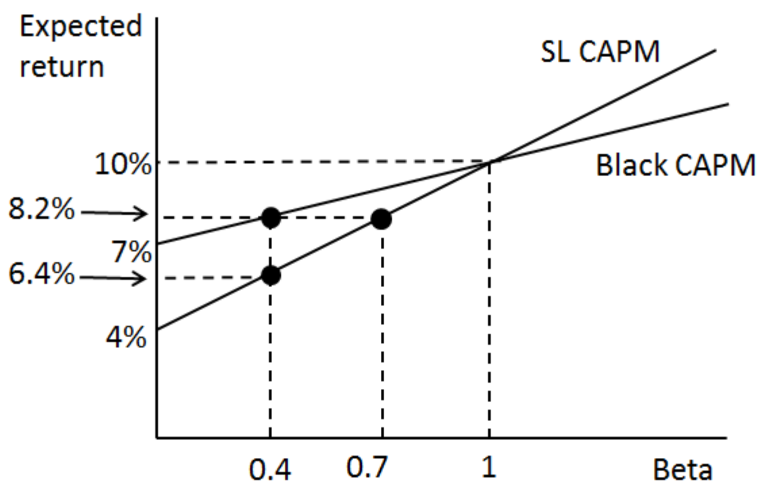
[134] NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM*, *A Report Jemena Gasworks, Jemena Electricity Networks, ActewAGL, AusNet Services, Citipower, Energex, Ergon Energy, Powercor, SA Power Networks and United Energy*; February 2015, page 54. Similar results arise from out-of-sample tests.

[135] As noted above, we consider this criterion to be a distraction that is likely to lead the AER away from the attainment of the rate of return objective. However, even it were a relevant criterion, there is a failure to apply the criterion properly.

[136] AER; Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return; November 2014, p. 27 (pdf version).

The SL-CAPM is flawed both because it has very weak explanatory power (i.e. there is at best a very weak association between observed returns and betas) and there is a downward bias for stocks with a beta of less than one due to the assumption of the Sharpe-CAPM that there is a risk free asset and investors are assumed to be able to borrow or lend freely at the risk free rate. The Black CAPM does not suffer this flaw. In graphic terms[137]:

Figure 2: SL and Black CAPM



The size of the bias is very substantial when compared with previous Australian Competition Tribunal cases. For example, in ActewAGL the Tribunal corrected a decision arising from the selection of the source of debt by 53 basis points. Adjusting this using the 60:40 leveraging assumption, this is equivalent to approximately 80 basis points. By contrast, NERA has estimated that at about the mid-point of the AER's 0.4 to 0.7 range for beta, the downward bias is approximately 490 basis points.

As detailed in the discussion below, the AER does not explain clearly what it has done to address this bias but it appears that a substantial contributing factor in selecting a beta at the higher end of the AER's 0.4 to 0.7 range for beta is in recognition of this bias. The problem with this approach is that there is no reason to suppose that this adjustment is sufficient to address the low-beta bias. A much safer way to proceed would be to avoid selecting the SL-CAPM as the foundation model or, indeed, not to elevate any model to the foundation model status.

The low beta bias is not the only flaw of the SL-CAPM and there are others that independently, and together, are sufficient to disqualify the SL-CAPM from contention as the foundation model. Indeed, SFG Consulting is of the view that not only is it necessary to relax the assumption that investors are assumed to be able to borrow or lend freely at the risk free rate (as the Black CAPM does) to overcome the bias but to improve the over-all fit of the data to the model it is also necessary to take into account the insights from Fama-French's work:

> *"The AER adopts a model that does not fully account for factors that are associated with stock returns. The AER's use of the Sharpe-Lintner CAPM, without giving consideration to the Fama-French model, means that is places sole reliance on a model that has been shown to have less ability to explain stock returns."*[138]

[137] SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks*; 6 June 2014, p. 93.

[138] SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy*; 25 February 2015, paragraph 42, p. 10.

All the above models are forms of capital asset pricing models which, in the US, are generally regarded as flawed when compared with the DGM. For example, the Maine Public Utilities Commission states that:

> *"The theoretical weaknesses of the CAPM spelled out in the Bench Analysis causes us to rely more heavily on the DCF analysis in our decision making. In this particular case, the lack of a true forward looking beta is a large obstacle given that a pure T&D-utility industry does not exist at this point in time."*[139]

With models that do not suffer from the flaws of the SL-CAPM, any of them would be preferable to select as a foundation model (if the Rules required or permitted such a foundation model).

It is not surprising, therefore that, at present, all the other models provide a mutually corroborating cluster of benchmark returns on equity for benchmark energy network businesses. These returns are in the vicinity of 9.93% to 10.32% while the SL-CAPM falls well below that cluster at 9.3% when estimated by SFG Consulting[140], and orders of magnitude lower when estimated using the AER's Ibbotson inspired implementation at approximately 8.1%[141]. If the AER's method of applying the SL-CAPM were used with risk-free rate data from the January 2015 averaging period, the same time interval that was used for the SFG computations, then the resulting post-tax nominal return on equity would be 7.19%.

These figures also highlight the significance of choosing between different approaches to implementing the SL-CAPM when using it as a foundation model.

Having chosen to adopt the SL-CAPM as the foundation model, the AER is confronted with two approaches for using historical stock return data to estimate MRP: the Ibbotson and Wright approaches. The AER elects to adopt the "status quo" which is to primarily rely on the "Ibbotson Approach", to measuring the historical MRP. The AER combines its estimate of the historical MRP with an "on-the-day" risk free rate. The AER, has quite elaborately chosen to constrict itself to the Ibbotson approach, paying no more than lip service to the notion of the Wright approach by adopting "cross checking" of the sort described above that gives the secondary material nugatory weight.

In the current economic conditions, the AER's approach of combining a contemporaneous measure of the risk free rate with an essentially constant market risk premium delivers values that are necessarily materially lower than prevailing market returns.

Experts explain that there is no one-to-one relationship between movements in the risk free rate and the risk adjusted returns that investors require. In fact the market risk premium tends to fluctuate in the reverse direction from risk free rates[142].

Although the expert work is informative at an aggregate level, there are also occasions when this concept is readily apparent. For example, shortly after the collapse of Lehman Brothers two key propositions were inescapably prominent to finance market practitioners and the general business community alike – at the same time that investors became nervous and were demanding significantly

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139 (a) *PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design* 1998 Me. PUC LEXIS 603 at [42].

(b) (see also *PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design* 1999 Me. PUC LEXIS 259 at [41]).

Note: these cases predate decisions in which an equal weighting between the Black CAPM and the SL CAPM models have been adopted.

140 SFG Consulting; *The required return on equity for the benchmark efficient entity*; *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy*; 25 February 2015, page 35.

141 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, page 34 (pdf version).

142 Incenta Economic Consulting; *Further update on the required return on equity from Independent expert reports - Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, AusNet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA PowerNetworks, and United Energy;* February 2015, p. 1, second bullet point (attached as Appendix 12I).

increased returns, central banks were significantly reducing wholesale interest rates to try and stimulate the economy. This is a stark example of what the expert evidence shows is generally the case: the market risk premium and risk free rates tend to move in opposite directions.

This means that adding a long run average (essentially constant) market risk premium to a contemporaneous risk free rate will deliver downwardly biased results when risk free rates are low and upwardly biased results when risk free rates are high. In the current environment of record low risk free rates, a simple addition of a very long term market risk premium with a current risk free rate is almost bound to significantly under compensate equity investors.

Indeed, the approach in the draft determinations delivers a nominal post tax return on equity of just 8.1% which is very substantially lower than five years previously which provided for a return on equity of, in Ausgrid's case 11.82%, and similar figures for other businesses. More than two percentage points of that drop can be attributed to the fall in the underlying risk free rate. While the risk free rate has dropped in this way, there is simply no evidence available from which to conclude that equity investors' required rates have fallen in exact proportion to the fall in the risk free rate.

Exactly the same question confronted the AER's US counterpart in its 28 January 2014 decision concerning the New York Independent System Operator. In that case FERC decided as follows:

> *"We find that NYISO's proposed ROE value of 12.5 percent is adequately supported by substantial evidence. NYISO argues that unique* ***current conditions in financial markets created a downward bias in the CAPM results, necessitating a calibration adjustment of 1.21 percent to the calculated return on equity of 11.29 percent****. Specifically, NYISO argues that the result yielded by the CAPM analysis "appeared potentially too low relative to regulated rates of return and as the CAPM is subject to bias at times during the interest rate cycle" because of the potential impact on the historic relationship between the market returns for government debt and common equities. Given the recent trends of near-historic low yields for long-term U.S. Treasury bond rates, the CAPM's input for the "risk-free" rate, we find that it is a reasonable assumption that the current equity risk premium (which is added to the risk-free rate to calculate the cost of equity data point that determines the slope of the CAPM curve) exceeds the 86-year historical average used as the consultants' CAPM input.* ***The current low treasury bond rate environment creates a need to adjust the CAPM results, consistent with the financial theory that the equity risk premium exceeds the long-term average when long-term U.S. Treasury bond rates are lower than average, and vice-versa.****"*[143]

Even in Continental Europe, where NERA notes there is a significant problem mismatching long term market risk premia with short term risk free rates that is already leading to under-investment, it is remarkable to note what those countries regard as a "short term" averaging period for the risk free rate[144]:

- In Austria a *five year* averaging period is combined with a 110 year market risk premium;
- In the Netherlands a *three year* averaging period is combined with a 110 year market risk premium;
- In France a *one to two year* averaging period is combined with a 110 year market risk premium; and
- In Norway a *long term* risk free rate is combined with long term market risk premium.

On this issue, the AER is clearly out of step with all its major peers.

It might be tempting to jump to the conclusion that under-compensating investors at this time is of little concern if, once the economic cycle turns, the current under-compensation could be off-set by future over-compensation but this is not the case. If there is a mismatch in either direction between

143 Federal Energy Regulatory Commission (28 January 2014): "*Order accepting tariff filing subject to condition and denying waiver",* Docket No. ER14-500-000, p. 36.

144 NERA; *European Regulators' WACC Decisions Risk Undermining Investment Decisions*; 2015, page 4. The table also reports on Denmark which has a 6 month averaging period and Germany with an unspecified "short term" averaging period. Across the Channel in the UK there is a "long and short term" averaging period for the risk free rate.

prevailing rates and regulatory allowances, inefficiencies will arise. Firstly, there are costs for the businesses of absorbing inter-temporal fluctuations in returns through explicitly or implicitly carrying a balance sheet provision for such a mismatch. Secondly, at times of under-compensation timely investments are discouraged or delayed and at times of over-compensation the opposite effect applies and there is an incentive to invest earlier than required. Neither is efficient, nor in the interests of customers. Note also that these effects are pro-cyclical which means that the direction of the mismatch encourages businesses to reduce capital expenditures at times when input costs are likely to be low and to increase capital expenditures at times when input costs are likely to be high.

It is appropriate, therefore, that the Rules require (as they do) that each determination provides for a regulatory allowance that is commensurate with the prevailing efficient costs for a benchmark firm at the time. In the AEMC's words:

> *"If the allowed rate of return is not determined with regard to the prevailing market conditions, it will either be above or below the return that is required by capital market investors at the time of the determination. The Commission was of the view that neither of these outcomes is efficient nor in the long term interest of energy consumers."*[145]

In other words, unless the AER has a proper basis to conclude that the investors' expectations move in parallel with the risk free rate, placing effectively sole reliance on the Ibbotson inspired implementation of the SL-CAPM as it does, prevents its MRP estimate from adjusting to produce an allowed rate of return that can accommodate the prevailing expectations of equity investors.

Errors in the AER's selection of the beta

Equity beta is the key input into the SL-CAPM representing the AER's view as to the risks associated with the operation of an energy network business relative to benchmark efficient businesses. The AER has indicated that it intends to adopt an "equity beta" of 0.7; its lowest level ever in Australian regulatory decision making. The equity beta has progressively been down-graded from 1.0 for most of the period since the NEM began[146] to 0.8 and is now proposed to be 0.7 (including in NSW).

The AER's decision to significantly downgrade the beta value is based on a general review of risk by Frontier Economics and on domestic empirical estimates. The Frontier report sets the scene in a broad qualitative sense, suggesting that electricity businesses are comparatively safe – even with high levels of leverage. In AusNet Services' view, that report fails to properly assess the risks facing the business as noted by SFG[147]. Specifically, the Frontier report only deals with operational risks that are relevant to the asset beta. The Frontier report does not consider whether the higher-than-average leverage offsets the lower-than-average asset beta, and therefore never makes any recommendation about whether the equity beta is likely to be above or below 1. AusNet Services submits that the AER has clearly misinterpreted and misrepresented the findings of that report.

Further, it precedes in the face of firm evidence that electricity network businesses are becoming more risky over time compared with a balanced market portfolio. By contrast, as detailed in this chapter, there is significant evidence to conclude that electricity network businesses are experiencing significant increases in risk. Debates can be had as to whether these risks are best included in the beta or elsewhere but presently these increases are accommodated neither in the equity beta nor in any other part of the regulatory framework.

When it comes to making a quantitative estimate, it would be surprising if all parties did not agree with the following proposition:

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145 AEMC; *Rule Determination*; p. 44.

146 Note that in South Australia the figure was 0.9.

147 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; 13 February 2015, paragraph 39, p. 12.

"In an ideal world there would be a very large number of domestic comparators and there may be no need to consider international comparators at all."[148]

Unfortunately the current situation could not be further from the ideal world because the number of domestic firms has dwindled to an unworkably small number with current data available for only four domestic comparators. When the US Federal Energy Regulatory Commission was confronted with the same problem (i.e. a comparator set that shrank below 10 or so) in relation to interstate gas pipeline businesses, it broadened the sample:

"[S]tructural changes have strained the Commission's prior approach towards proxy group composition to breaking point. As a result of mergers, acquisitions, and other changes in the natural gas industry, fewer and fewer interstate natural gas companies have satisfied our prior requirements for proxy group composition.

Our policy change was born out of a practical recognition that the size of the proxy group used under our prior approach had shrunk dramatically."[149]

However, the AER continues to rely on an ever narrowing set of current data supplemented by ever more dated observations that cannot any longer be assumed to represent the prevailing cost of equity funds as required by Rule 6.5.2(g) of the Rules. As SFG Consulting explains:

"The AER adopts a set of nine domestic comparator firms, only four of which remain listed. Two of the firms have not been listed since 2006 and one has not been listed since 2007. The AER's approach is to maintain the beta estimates for these firms in its sample, even though those estimates become progressively more dated with the passage of time. That is, the beta estimate at the time a firm delists becomes a permanently determinative observation in the AER's sample. By the time the current Guideline expires, three of the nine beta estimates will be more than 10 years out of date. These estimates will, by definition, not reflect anything that has transpired in financial markets for over a decade."[150]

In the Guideline process[151], the AER drew from this scarce dataset several results that appear to be mutually corroborative but which are in fact averages drawn from substantially over-lapping datasets or the same data-sets reworked using two different statistical techniques. This delivered a range of 0.4 to 0.7. The principal analysis that was intended to inform the estimate was a report by Henry which was not delivered until five months after the Guideline was issued.

In this report from Professor Henry of the University of Liverpool Management School[152], the AER's brief tightly specified the data he was to use ("nine specified Australian gas/electricity firms", "short term Australian Government debt" and the "ASX 300 Accum") and precisely what work was to be done. He was instructed to use 100% Australian data, weekly returns, value weights, no Blume adjustment, no Vasicek adjustment, the Dimson thin trading adjustment, the ordinary least squares regression model and to report his answers at the 95% confidence interval. Indeed there are only two aspects of the project in which Henry was explicitly permitted to exercise his judgement: in relation to the regression equation he was permitted to use *"[E]ither raw returns or excess returns (but not both*)[153]" and with respect to the stability and robustness tests he was permitted to adopt "consultants choice". In other words, Professor Henry's work does not set out his expert opinion as to the level of beta at large and instead he has undertaken a highly constrained process of employing inputs provided by the AER in a manner specified by the AER and the results are a product of the AER's views concerning each of the relevant inputs.

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148 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, paragraph 38, p. 12.

149 Federal Energy Regulatory Commission of the United States of America, Statement of Chairman Joseph T. Kelliher, 17 April 2008.

150 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, paragraphs 28 – 29, p. 10.

151 AER; *Explanatory Statement (appendices)*; Appendix C, pp. 53 – 55.

152 Henry O, University of Liverpool Management School; *Estimating β: An update*; April 2014.

153 Henry O, University of Liverpool Management School; *Estimating β: An update*; April 2014, p. 4.

Within that constrained framework, Henry's report states:

> *"The consultant is of the opinion that the most reliable evidence about the magnitude of β is provided in Tables 2, 14 and 16 using individual assets and fixed weight portfolios."*
>
> *"In the opinion of the consultant, the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate for β lies in the range **0.3 to 0.8**."[154] (emphasis added).*

Indeed if the nine firms that Henry was instructed to consider, in Henry's Table 2, two of the beta estimates significantly exceed 0.8 (Alinta at 0.8795 and Hastings at 1.0305). The report states that:

> *"[T]aken together, the evidence from Table 2 suggests that the point estimates of equity beta lie in the range 0.21 to 1.04".[155]*

The range reported by Henry is narrower than the 0.21 and 1.04 due to the instructions that the AER placed upon him as to how he was to establish a range.

In other words, even using the AER's tightly constrained set of instructions, its own consultant states that the range is 0.3 to 0.8, not 0.4 to 0.7 as published in the AER's Guideline, and when unconstrained by the strictures imposed in the AER's instructions, the analysis delivers beta estimates that vary even further in an upward and downward direction.

Despite this December 2014 evidence demonstrating the 0.4 to 0.7 range published in the 2013 Guideline to be in error, the AER has failed to retract and correct the document. Instead, in the draft determinations the approach is to delve into the report and assert that the majority of the beta figures fall within the AER's narrower range even though the narrower range is not consistent with the instructions the AER itself provided to Henry.

The AER sought to bolster the domestic data with one set of international comparators for the Guideline and another in the NSW draft determinations. SFG Consulting has examined all that material and concluded that in relation to the first set of data relied upon, all the contemporaneous estimates are above 0.7.

In relation to the latter data, the analysis has been undertaken with insufficient rigor. For example, the AER has relied upon the following:

> *"Alberta Utilities Commission (2013). This report documents submissions to the regulator in relation to equity beta – it does not present any estimates of beta. Unsurprisingly, user groups such as the Canadian Association of Petroleum Producers (CAPP) submitted that a low equity beta should be used. The report provides no information at all about the basis for the equity beta submissions. There is no information about how many, or which comparator firms were used. There is no information about what statistical techniques were employed or how the range of resulting estimates was distilled into a point estimate or range.[156]"*

It is also important to note that the beta used in Alberta is the starting point for the analysis and after which an assessment is made of whether "adders" are required to increase the returns to meet the required returns.

SFG Consulting has identified significant flaws in the use of the following report:

> *"PWC (2013) In its recent draft decisions the AER summarises the evidence from the PWC report for the NZCC as follows:*
>
>> *'PwC's June 2014 report presents the following raw equity beta estimates for New Zealand energy network firms as at 31 December 2013: 0.6 for the average of the individual firm estimates.'*

154 Henry O, University of Liverpool Management School; ***Estimating β: An update***; April 2014, p. 63.

155 Henry O, University of Liverpool Management School; ***Estimating β: An update***; April 2014, p. 17.

156 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, paragraph 56(c), p. 15.

The AER implies that this estimate of 0.6 can be compared with its allowed equity beta of 0.7. However, such a comparison would be an error for the reasons set out below. First, the 0.6 estimate does not appear anywhere in the PWC report. The beta estimates set out in the "Utilities" section of the report are set out in the table below.

Table 1. PwC beta estimates for the NZCC

Company	*Raw beta*	*Leverage*	*Regeared beta*
Contact	*0.9*	*0.27*	*1.64*
Horizon	***0.5***	***0.31***	***0.86***
NZ Windfarms	*0.5*	*0.33*	*0.84*
NZ Refining	*0.8*	*0.17*	*1.66*
TrustPower	*0.5*	*0.36*	*0.80*
Vector	***0.7***	***0.50***	***0.88***

The AER's estimate of 0.6 is the average of the raw beta estimates for Horizon and Vector, which are considered to be the firms most comparable to the benchmark efficient entity. The average of the regeared estimates for these two firms is 0.87.[157]*"*

In summary, the AER's range for beta of 0.4 to 0.7 is erroneous and inconsistent with the evidence before it. This is a key reason why the 0.7 figure chosen by the AER is also in error and the discussion now progresses to discuss that issue.

Although Appendix C of the Rate of Return Guideline Explanatory Statement is replete with criticisms and rejections of the point estimates proposed by user groups and businesses alike, exactly how the AER chooses to adopt the upper 0.7 value from its (excessively) constrained range of 0.4 to 0.7 is unclear. The closest that Appendix C comes to an explicit statement is as follows:

"[O]ur proposed point estimate of 0.7 is not inconsistent with our consultants' advice.[158]*"*

"Adopting a point estimate around the mid-point would be more reasonable if our intention was to base the allowed return on equity on the Sharpe–Lintner CAPM and empirical estimates alone. However, the rules require us to have regard to relevant estimation method, financial models, market data and other evidence when determining the allowed rate of return. When this information is taken into account, we consider it reasonable to select a point estimate from the upper end of the range of empirical equity beta estimates.[159]*"*

The best inference from the totality of the AER's document appears to be that the selection is primarily chosen as an apology for the downward biases of the SL-CAPM (discussed above).

The problem is, even if the range of 0.4 to 0.7 is appropriate (which is clearly incorrect according to the AER's own consultant's domestic stock analysis and an even handed international comparison), the AER has not demonstrated that taking the upper end of that range is an adequate correction for the downward biases. Appendix C of the Guideline[160] provides a discussion of this issue but in such heavily qualified terms that it is clear the AER cannot be satisfied of the adequacy of this correction factor. That is, there is no basis to support the conclusion that selecting the upper bound of the AER's assessment of the range supported by the sample of four current and five former domestic comparators will be exactly sufficient to redress all the known biases in the SL-CAPM. A better approach would be to simply estimate the models that have been developed to redress the well-documented problems with the SL-CAPM.

157 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015, paragraph 50(d), p. 16.

158 Ibid, p. 76.

159 Ibid, pp. 76 – 77.

160 Ibid, pp. 69 – 73.

The flaws in the AER's implementation of the Ibbotson approach to measuring the historical MRP for use in the SL-CAPM

The AER considers that the reasonable range for MRP is from 5.1 (which is 20 basis points above the geometric means of various cuts of the data going back to 1883) to 7.8 (which is drawn from the high-point of the AER's DGM). As well as the historic means and DGM analysis, the AER considers certain other information as set out below.

The AER has not explicitly explained how its 6.5 point estimate is drawn from the range.

> *"We propose to estimate the MRP point estimate based on our regulatory judgement, taking into account estimates from each of those sources of evidence and considering their strengths and limitations."*[161]

The information considered by the AER is as follows[162]:

- Historic long run average MRPs;
- Dividend growth models;
- Survey evidence;
- Conditioning variables; and
- Other regulators' determinations.

Below, AusNet Services' discuss each of these in turn.

(a) Historic long run average MRPs

The AER has stated that it places the greatest weight upon the historic long run average MRP. Specifically, the AER Guideline Explanatory Statement:

> *"Both the arithmetic and geometric averages are relevant to consider when estimating a 10 year forward looking MRP using historical annual excess returns. The Tribunal has found no error with this approach. The best estimate of historical excess returns over a 10 year period is therefore likely to be* ***somewhere between the geometric average and the arithmetic average of annual excess returns****."*[163]

The low point of the range is established as follows. In the Guideline process the AER states:

> *"The geometric mean historical excess return currently provides the lowest estimate of the MRP with a range of 3.6 to 4.8 per cent. However, as we discuss in more detail in appendix D, there are concerns with using the geometric mean as a forward looking estimate. Therefore, we consider a reasonable estimate of the lower bound will be above the geometric average. However, we give some weight to geometric mean estimates. Therefore, we consider a lower bound estimate of 5.0 per cent appropriate."*[164]

In other words, the low end of the range is established form the high end of the geometric mean estimates (i.e. 4.8) to which 20 basis points is added.

The Guideline process used data up to 2012 for the above analysis. In the NSW draft determination[165] the above figure of 4.8 is updated and is now 4.9 using the additional data available for 2013. The data that was current as at the time of the NSW draft determinations[166] is as follows:

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161 AER; *Explanatory Statement*; p. 90.

162 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, pp. 194 – 205 (pdf version).

163 AER; *Explanatory Statement (appendices)*; p. 83.

164 AER; *Explanatory Statement*; p. 93.

165 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, footnote 774, p. 194 (pdf version).

166 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, p. 195 (pdf version).

Table 12.7: Historical excess returns assuming a theta of 0.6 (per cent)

Sampling period	Arithmetic mean	Geometric mean
1883 – 2013	6.3	4.9
1937 – 2013	6.0	4.1
1958 – 2013	6.5	4.0
1980 – 2013	6.4	4.0
1988 – 2013	5.9	4.1

Source: AER

The above material is erroneous in the following respects:

- Geometric means are irrelevant because they are only appropriate in the context of compounding but the AER's revenue model is a non-compounding model.
- The first three time periods reported are derived from wrongly adjusted data by using a 0.75 adjustment figure to the Lamberton yield series instead of NERA's adjustment factor that various over time.
- It gives no weight to the Wright approach in which historic estimates compare returns with the expected inflation rate.

Further, historic market risk premium estimates are notoriously volatile and unless there is a concrete reason to curtail the period over which it is estimated, the longest possible period should be adopted. This is the approach of international experts (e.g. Dimson, Marsh and Staunton) and as such only the 1883 to 2013 arithmetic figure should be used. When that is adjusted to overcome the erroneous adjustment of the Lamberton yield series, the correct historic average market risk premium is 6.56 or 6.6 when expressed to two significant figures.

Each of these issues is discussed below.

NERA has undertaken further analysis of the historical MRP estimates relied upon by the AER and reported above and found them to be wanting in two further respects[167].

NERA's first concern is that the AER insists on using geometric means on the basis of advice from McKenzie and Partington in 2011 and 2012 to the effect that an arithmetic mean would be upwardly biased where WACC estimates are compounded[168]. However, both the AER's own consultant, Lally[169], and NERA have more than once pointed out that the regulatory arrangements do not provide for compounding. Since the regulatory arrangements do not involve compounding, the reverse is true and the use of a geometric mean is downwardly biased as has been noted by the Maine Public Utilities Commission: *"….[W]we agree with the Company that it is improper to use a geometric mean in the CAPM model…*[170]"

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167 NERA; *Historical Estimates of the Market Risk Premium, A report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, AusNet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* February 2015.

168 Ibid, p. 12.

169 Ibid, pp. 12 – 13.

170 *PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design* 1998 Me. PUC LEXIS 603 at [41] and *PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design* 1999 Me. PUC LEXIS 259 at [42].

NERA's second concern is that the AER continues to adopt a paper authored by Brailsford, Handley and Maheswaran, first published in 2008 and updated in 2011 and again in 2012 reaching a value for the market risk premium (for identifying a value for the market risk premium used in the SL-CAPM)[171,172]. The AER continues to take this approach despite the reliability of the data underlying the article has being brought into question repeatedly.

In fact it is misleading to state that: *"The ASX, which we consider to be a credible source, provided and adjusted the earlier data.*[173]*"*

The original source of the adjusted data is identified in the footnote 13 and 16 in Brailsford et al[174] 2013 as emails received from the ASX on 11 April 2003 and 26 May 2004. Within one full page of those footnotes, the authors had already described these emails, asserting that "staff carefully considered the issue and ultimately decided on an adjustment factor of 0.75.[175]"

By the time the process of "Chinese whispers" was complete, the AER had effectively (falsely) invested the adjustment with the ASX corporate endorsement and created the impression that the adjustment carries the ASX's corporate approval. In this way, the AER is creating an apparently indisputable ground for its position.

Further, the AER has given weight to the notion that the Brailsford et al[176] article has been published in a "peer reviewed academic review" without making inquiries to understand what that peer review entailed. Certainly, the review did not require the source and context of the email correspondence to be set out in the published paper. By contrast, the later NERA work was prepared according to the Federal Court's Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia – Practice Note CM7 including disclosing all sources upon which they rely. The fact that a paper has been published in a peer reviewed journal does not mean that it should be permanently determinative even after errors or inaccuracies in its data source have been identified. This is especially the case where the peer review process does not extend to any examination of the source data.

Accordingly, NERA's adjustment factor based on 7 years (compared to Brailsford et al's comparison of just one year) must be preferred.

171 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, p. 40 (pdf version).

172 AER; *Explanatory Statement (appendices)*; pp. 84 & 103.

173 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, pp. 3 – 197 (pdf version).

174 Brailsford, T., J Handley and K. Maheswaren; *Re-examination of the historical equity risk premium in Australia;* Accounting and Finance 48, 2008.

175 Ibid, p. 80.

176 Ibid.

(b) Dividend Growth Models

Although it is the historic MRP data that the AER gives the most weight, it has had next most regard to the outcome of the DGM and in particular the data in the following table:

Table 12.8: MRP Estimates under Dividend Growth Models, 0.6 theta (per cent)

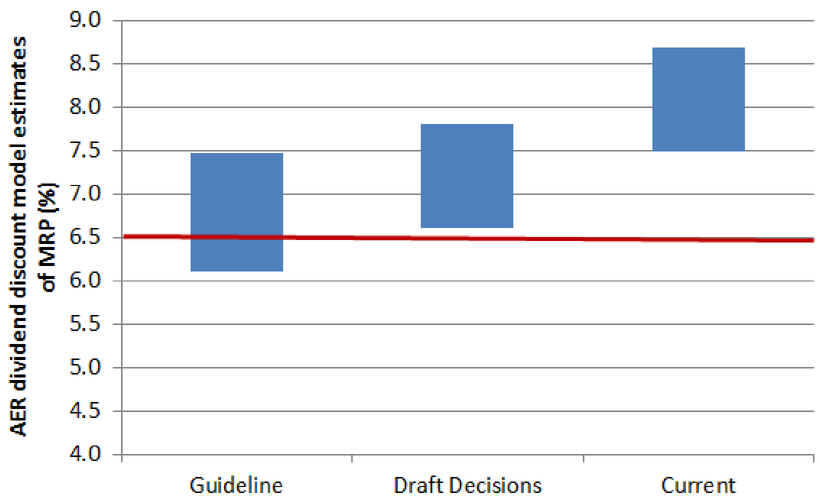
Growth rate[177]	2-stage model	3-stage model
4.0	6.6	7.0
4.6	7.2	7.4
5.1	7.7	7.8

Source: AER, AusGrid Draft Decision, Table 3-40.

SFG Consulting[178] has advised that the 7.8 figure in the above table should, on the latest available data, be 8.71.

As depicted by the image below, "the AER's own estimates of the contemporaneous MRP have risen materially since the publication of the Guideline. The AER's estimates of the contemporaneous MRP were uniformly above the allowed 6.5% at the time of the draft decisions and are even more materially above the 6.5% allowance now. In our view, there is no logic to an approach that would simply maintain a fixed 6.5% allowance that reflects the long-run historical average conditions (over the long-run historical period that was used to estimate it) in the face of the mounting evidence from the AER's own estimates of the MRP in the prevailing market conditions. To do so would be an error.[179]"

Figure 3: Range of AER dividend discount model estimates of MRP



[177] AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, p. 201 (pdf version).

[178] SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, table 4 at paragraph 115.

[179] Ibid.

(c) Survey evidence

The AER also has regard in the Explanatory Statement accompanying its Guideline to the following Dividend Growth Model data:

Table 12.9: Key findings from recent MRP surveys

Survey[180]	Responses	Mean (%)	Median (%)	Mode (%)
Fernandez (2013)	73	5.9	6.0	-
KPMG (2013)	19	-	6.0	6.0
Fernandez (2013)	17	6.8	5.8	-
Asher & Hickling (2013)	46	4.8	5.0	6.0
Fernandez (2014)	93	5.9	6.0	-

Source: AER

There are a number of significant problems with this data. Surveys can be extremely unreliable and the surveys in question in this case do not appear to have been undertaken applying the appropriate protections such as those set out in the Federal Court guidelines for conducting surveys. Certainly AusNet Services was not accorded the opportunity to be consulted on the questions before they were administered to the participants. As such, they should not be accorded any weight – particularly when there is an extensive range of more reliable evidence available.

(d) Other Regulators

Table 12.10: Recent regulatory decisions

Regulator	Decision date	Sector	MRP
QCA	Aug 2014	General / Policy	6.5
IPART	Jul 2014	Rail	Midpoint WACC using 5.5-6.5 (LR), 7.6-8.7 (Current)
Utilities Commission	Apr 2014	Electricity	6.0
IPART	Jun 2014	Water	Midpoint WACC using 5.5-6.5 (10 year), 7.2-8.6 (40 day end 12 May 2014)
ERA	Jul 2013	Rail	6.0
ESC	Jun 2013	Water	6.0
IPART	Jun 2013	Water	Midpoint WACC using 5.5-6.5 (LR), 7.6 (SR)
ESCOSA	May 2013	Water	6.0

180 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, pp. 205 – 206 (pdf version).

Regulator	Decision date	Sector	MRP
IPART	May 2013	Water	Midpoint WACC using 5.5-6.5 (LR), 7.4 (SR)
QCA	Apr 2013	Water	6.0
ERA	Mar 2013	Water	6.0
ERA	Nov 2013	Electricity	6.0
ESC	Jun 2012	Rail	6.0
IPART	Jun 2012	Water	5.5-6.5
IPART	Jun 2012	Water	5.5-6.5

Source: AER

The above regulators' views cannot rise to be of any higher value than the strength of the underlying evidence and the current energy network regulatory process has thoroughly investigated this material. A not insignificant minority of that material has indeed been prepared after the regulatory determinations and therefore cannot have been taken into account by the regulators in question when they made their determinations.

Further, AusNet Services would caution that many of the judgements exercised by those regulators contain errors and should not be adopted.

The AER's flawed use of expert reports

The AER performs a "cross check" for its beta estimates against expert reports (reports prepared for the purpose of stock market valuations in the context of takeovers). It is relevant to note that the question posed to these experts is whether a specific takeover offer is "fair" – i.e. *sufficient* to be fair. This is not the same question that the AER is required to answer.

Incenta has examined the AER's reasoning and found it to be significantly wanting.

The first issue concerns whether the Ibbotson inspired approach reflects current equity market expectations. In this regard, Incenta reports the following:

> *"The AER has compared the risk premium over the "spot" risk free rate that independent experts have applied to the risk premium over the spot risk free rate that it applies, and so implicitly assumed the risk premium that experts apply has remained (and will remain) constant in the face of large changes in the risk free rate. However, this masks the actual behaviour of independent experts, with almost 90 per cent having adjusted the risk free rate and / or the market risk premium in response to changes in the risk free rate."*[181]

The AER gives particular attention to the Grant Samuel report concerning APA's unsuccessful takeover of Envestra. Grant Samuel itself has expressed serious reservations about how its report has been interpreted and used by the AER, both in relation to the market risk premium and other issues such as the beta adopted and whether in fact experts use the SL-CAPM.

[181] Incenta Economic Consulting; *Further update on the required return on equity from Independent expert reports - Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, AusNet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA PowerNetworks, and United Energy*; February 2015, p. 1.

In essence, the AER sought to gain support from the report for the use of the CAPM to the exclusion of other approaches. Grant Samuel states:

> *"[O]ur approach … is to form an overall judgement as to a reasonable discount rate rather than mechanistically applying a formula. The fact is that, particularly in some market circumstances, the CAPM produces a result that is not commercially realistic. When this occurs it is necessary and appropriate to step away from the methodology and use alternative sources of information to provide insight as to what is, after all, an unobservable number that can only be inferred. In our view, Envestra was clearly a case in point.*
>
> *In using the Envestra report, the AER seems to be to trying to co-opt the parameters that we used for calculating the initial CAPM based rate to bolster its own case while trying to find ways to justify not having to recognise the fact that for the valuation of Envestra Limited's assets, we actually selected a different rate (i.e. 6.5-7.0% or, more correctly 6.5-8.0%, rather than 5.9-6.5%)."*[182]

The AER expresses concerns about the transparency of Grant Samuel's methodology but Grant Samuel responds as follows:

> *"In view of the apparent importance of the Envestra Report in supporting the AER's findings we are surprised that, if there were such transparency issues, the AER did not approach us for clarification. To our knowledge, we have never been approached to discuss any aspects of our discount rate or other valuation approaches."*[183]

The AER asserts that:

> *"[T]he return on equity and equity risk premium estimates contained in Table 3 - 20 are the final values used in the independent valuation report and reflect any uplifts applied."*[184]

However, Grant Samuel disavows that assertion:

> *"This statement is simply not true as the table, at least in the case of Grant Samuel's reports for Envestra Limited, DUET Group and Hastings Diversified Utilities Fund, only reflects the calculated post tax WACCs ignoring the uplifts and adopts midpoints for post tax WACC and return on equity, an approach which Grant Samuel considers inappropriate."*[185]

And in a similar vein:

> *"the AER claims that the implied adjusted equity risk premium range in three of the four uplift scenarios referred to by Grant Samuel in Appendix 3 of the Envestra Report justifying its uplift is consistent with its foundation model premium of 4.55%. We do not know how the AER determined this but our calculations indicate that in fact the 4.55% is well in the range in only one of the scenarios, is right at the bottom of the range in one other scenario and is outside the range in the other two"*[186]

Indeed, Incenta reaches the following conclusions with respect to the AER's whole approach to expert reports:

> *"Taken together, our findings indicate strongly that were the AER to continue to apply the same mechanistic SL-CAPM approach that was applied in its draft decision, with JGN's current averaging period risk free rate at 2.64 per cent, the resulting estimated rate of return on equity will fall materially short of the required rate of return in the market that is implied by a consideration of independent expert reports, and not be commensurate with the efficient financing costs a benchmark entity will face over the access arrangement period."*

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182 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, pp. 4 - 5.

183 Ibid, p. 6.

184 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; November 2014, p. 93 (pdf version).

185 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, pp. 6-7.

186 Ibid, p. 7.

Inconsistent treatment of the imputation adjustment

In the accompanying chapter, AusNet Services discusses its approach to the valuation of imputation credits (i.e. the gamma). However, it is important to recognise that there is an inter-relationship between the regulatory estimates of the required return on equity and gamma. This relationship is most apparent in the AER's post-tax revenue model (PTRM). The PTRM requires the regulator's estimate of the with-imputation required return on equity. It then removes the regulator's assumed value of imputation credits, leaving an estimate of the ex-imputation required return on equity. Allowed revenues are then based on this ex-imputation required return. The idea is that the firm requires sufficient revenue to provide investors with their ex-imputation required return, which is supplemented by imputation credits to provide them with their total required return.

The first step in this process requires an estimate of the with-imputation required return on equity. The AER's approach to this task is to "gross up" its estimates of MRP to include the AER's assumed value of imputation credits. For example, when implementing its DGM approach for estimating MRP, the AER grosses-up forecast future dividends to include its estimate of the value of the imputation credits that will be attached to those dividends.

That is, adjustments for imputation credits are made in two places in the AER's estimation process:

1. The assumed value of imputation credits is added to produce an estimate of the with-imputation required return on equity; and then
2. The assumed value of imputation credits is subtracted to produce an estimate of the ex-imputation required return on equity.

Internal inconsistency problems arise when the assumed value that is added in step 1 is different from the assumed value that is subtracted in step 2. In the AER's recent draft decisions, the value that is added in step 1 is materially lower than the value that is subtracted in step 2 – creating a downward bias to the allowed return on equity. On this point AusNet Services simply submits that the AER should ensure that the same adjustment for imputation credits should be applied in both steps of the AER's estimation approach.

A simple check for internal inconsistency can be performed as follows. First note that the AER's two-step approach (set out above) ultimately produces an estimate of the ex-imputation required return on equity. There is another way to produce an estimate of the ex-imputation required return on equity – simply avoid grossing-up the MRP estimate for imputation credits. That is, an ex-imputation estimate of MRP will produce an ex-imputation estimate of the required return. If this direct estimate of the ex-imputation required return on equity is materially different from the estimate obtained by the AER's two-step process, there is an internal inconsistency problem to be resolved.

Summary

The AER's approach to establishing an allowed return on equity is ill conceived in almost every respect. Consequently AusNet Services departs from the Guideline in all respects other than the identification of the relevant models. AusNet Services' approach is described in the next section.

12.2.4 Rate of Return Allowance Proposed in Place of the AER Guideline

For all the above reasons, AusNet Services considers that the approach in the Guideline cannot appropriately be remedied through adjustments correcting isolated errors and instead a new ground-up assessment of each of the inputs and how they are combined needs to be undertaken. SFG has conducted such an evaluation including with the assistance of work undertaken by other experts. AusNet Services' proposal, described in the next section, is based on that work.

Instead of the approach adopted in the Guideline, AusNet Services proposes to establish a rate of return giving real weight to all the relevant models and inputs by:

- Identifying the relevant rate of return models (which are, in fact, the same as those identified by the AER);
- Identifying the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;

- Estimating model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- Separately estimating the required return on equity using each of the relevant models; and
- Synthesising the modelling results as a weighted average of the individual estimates with weights that avoid double-weighting any of the key conceptual elements of the models.

12.2.5 Estimate the parameters for use within each of the four models

Between them, the four relevant financial models require estimates of the following parameters:

- A risk free rate of return;
- A required rate of return on the market portfolio (or an MRP to combine with the risk free rate);
- An equity beta (for the two CAPM models);
- A zero-beta return (for the Black-CAPM), or zero-beta risk premium;
- market exposure, size and book to market factor risk premiums and sensitivities (Fama-French Model only); and
- A risk premium for comparable firms (for use with the DDM only).

The proposed source of each of these parameters is discussed below.

(a) Risk Free Rate Averaging Period

AusNet Services accepts the approach to setting the risk free rate proposed in the Guideline which is for the AER to select a minimum of 20 business day averaging period as close as practically possible to the commencement of the regulatory period. For illustrative purposes, the figures presented in this proposal are calculated using a 20 business day period ending on 30 January 2015.

(b) Required return on the market portfolio (or its corollary, the market risk premium)

A number of the four models include a MRP which is simply the required return on the market portfolio less the risk free rate. In the past the AER has adopted the approach of using long run average excess returns (i.e. the returns of a representative portfolio above the risk free rate) as Ibbotson calculates an MRP. It is noted that there are other ways to estimate an MRP including historical data using an approach championed by Wright, the estimates derived from a dividend growth model, and estimates from independent experts and surveys. Wright did not develop an alternative implementation of the SL-CAPM. Wright simply proposed an alternative method of estimating the MRP from historical stock return data for use in the SL-CAPM – as the difference between (a) the historical average real market return adjusted to reflect current expected inflation, and (b) the current risk free rate – on the basis that real market returns may be more stable over time than excess returns.

SFG note that the Ibbotson approach involves adding an effectively constant MRP to the contemporaneous risk-free rate to produce an estimate of the required return on equity that varies one-for-one with changes in the risk-free rate:

> *"the Ibbotson approach implies that equity is more expensive than average during economic expansions and bull markets (the late 1990s and mid 2000s) and cheaper than average during financial crises (the pronounced reduction in 2008)."*[187]

It is counter-intuitive that the required return on equity should be lower during financial crises than during periods of economic expansion. This should be taken into account when the AER considers how to best employ historical stock return data to inform estimates of MRP. In the Guideline, the

[187] SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks;* 6 June 2014, paragraph 224, p. 56.

AER uses historical stock return data only via the Ibbotson approach (which leads to these counter-intuitive results) and places no weight on the Wright method for processing the historical stock return data. By contrast, SFG recommend that both methods provide relevant evidence in which case both should be given regard.

The Guideline proposes that the AER would consider all this material and determine an MRP using "regulatory judgment". The Guideline provides a worked example as at December 2013 but the AER would not necessarily exercise judgment in the same way in AusNet Services' regulatory proposal. AusNet Services considers that there are a number of flaws in the worked example as detailed by SFG Consulting. The detailed analysis is summarised as follows:

> *"[I]n some places the Guideline relies on dated evidence that has now been updated, in other places it relies on inaccurate data that has since been corrected, and in other places it makes improper comparisons (e.g., where estimates that include the benefit of imputation credits and estimates that exclude the benefit are compared as equals).*[188]*"*

AusNet Services' proposal adopts SFG Consulting's view as to the appropriate manner in which the AER should exercise judgment establishing the MRP. To a significant extent it relies on similar information, although certain information (such as inherently unreliable surveys) were not used. There are, however, other important differences in the details of how the other sources would be used to address flaws that SFG Consulting have identified above. SFG Consulting notes:

> *"[SFG Consulting would] have regard to the following evidence:*
>
> *a) First, we note that historical returns can be processed in two ways – by assuming that MRP is constant in all market conditions (Ibbotson approach or by assuming that real required returns are constant in all market conditions (Wright approach). We apply equal weight to each of these approaches, producing an estimate of MRP from historical returns of 7.11%;*
>
> *b) The estimate of MRP from dividend discount models of 7.31%; and*
>
> *c) The estimate of MRP from independent expert reports of 7.08%.*[189]*"*

SFG Consulting's report for the 2 to 30 January 2015 averaging period[190] illustrates why the outcome is not sensitive to the weightings given to the three sources. The relevant evidence is discussed in detail both reports. In summary it comprises the following (each grossed up for a theta estimate of 0.35):

- A historical average of excess returns above the contemporaneous risk free rate from 1883 to 2013 (which delivers an average of 6.56%) added to the current risk free rate (i.e., 2.64%) to deliver an estimate of 9.20%;
- A historical average market return using the Wright approach to deliver an estimate of 11.64%;
- A DDM estimate to deliver an estimate of 11.37%; and
- Independent expert valuation reports to deliver an estimate of 9.57%.

SFG Consulting synthesises this information to provide a single point estimate of 10.81% as the mid-point between the first two of the above historical estimates, which is also a figure that is very similar to the other two estimates.

188 SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks;* 6 June 2014, paragraph 157, p. 44.

189 Ibid, paragraph 340, p. 82.

190 SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, p. 33.

The other inputs suggested in the Guideline are not used because there are no reliable surveys upon which to rely and recycling past regulatory decisions does not provide any additional insight to prevailing market conditions.

(c) Equity beta

AusNet Services considers the reduction of the equity beta from 0.8 to 0.7 proposed by the Guideline to be incorrect on the basis of the following considerations emerging from work undertaken by SFG Consulting:

> *"a) The estimate of 0.7 is the outcome of a convoluted multi-stage approach whereby:*
>
> > *i) a sub-set of the relevant evidence … is used to constrain the range of possible estimates to 0.4 to 0.7;*
> >
> > *ii) the other relevant evidence that is considered in the Guideline … all supports an estimate above 0.7, but the first stage of the process constrains the maximum estimate to be 0.7; and*
> >
> > *iii) there is relevant evidence that is not considered in the Guideline …;*
>
> *b) The subset of evidence that is used to produce the constraining range of 0.4 to 0.7 is not sufficiently reliable to be used for that purpose because: the beta estimates vary wildly … across firms;… over time; … depending on which sampling frequency is used;… depending on which regression specification is used; and …depending on the day of the week and month on which they are computed;*
>
> *c) The evidence from international comparable firms suggests an equity beta materially above 0.7;*
>
> *d) To the extent that the 0.7 estimate has been influenced by the AER's conceptual analysis, it is wrong. The AER concludes that the conceptual analysis supports an equity beta materially below 1, but it does not. In this regard:*
>
> > *i) The Frontier Economics (2013) report does not support an equity beta below 1 … ; and*
> >
> > *ii) The McKenzie and Partington (2012) report sets out two pieces of empirical evidence. One suggests that energy networks have equity betas materially above one, and the other suggests that finance risk is the primary component of beta for utilities;*
>
> *e) To the extent that the 0.7 estimate has been set to match the equity beta that the ACCC uses for water utilities, it is wrong. Regulatory estimates of beta for water utilities are based on regulatory estimates of beta for energy networks (which introduces circularity) and on international water utilities … ."*[191]

Additionally, the modelling of the equity beta is flawed in that the sample is too small and the estimate too variable in response to the choice of statistical method. Further, irrelevant water utility data is included instead of relevant international data on the energy network sector.

AusNet Services, based on SFG Consulting's expert opinion[192], submit that the most appropriate estimate for the equity beta is 0.82 on the following basis:

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191 SFG Consulting; *Equity beta*, *Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, paragraph 10, pp. 3 - 4.

192 SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 18 February 2015, page 32 and SFG Consulting; *Equity beta*, *Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, paragraph 195, p. 42.

> *"One way of having regard to the range of relevant models and evidence is to estimate the required return on equity under each of the relevant approaches and then to determine an allowed return on equity after having regard to the relative strengths and weaknesses of each approach. Under such a multi-model approach, we would adopt a Sharpe-Lintner CAPM beta of 0.82 – the raw estimate of beta that does not reflect any evidence other than the historical statistical relationship between stock returns and market returns for the relevant set of comparable firms.*[193]*"*

The AER's consultant concludes: "*In the opinion of the consultant, the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate for β lies in the range 0.3 to 0.8*."[194] Adopting 0.7 is not supported by any empirical evidence.

(d) Return on a zero beta asset

SFG Consulting have estimated the return on a zero beta asset by adding a 3.34% zero beta premium to the risk free rate of 2.64% to give an estimated return on a zero beta asset of 5.98%.

This is within the reasonable range in the Guideline[195] and for that reason this issue does not warrant a detailed treatment in this document.

(e) Fama-French Model market exposure, SMB and HML factors

Because the Guideline does not use the Fama-French Model, there is no relevant departure from the Guideline in relation to these factors.

Recent regressions conducted by SFG Consulting have concluded that the best estimates for the three relevant Fama-French Model factors are:

- Market exposure: 5.04%;
- Size exposure: -0.19%; and
- Book to market exposure: 1.15%.

SFG Consulting's reports fully substantiate these figures[196].

(f) Risk premium for use in the DDM

SFG Consulting has estimated the risk premium for relevant comparable firms at 94% of the over-all market returns.

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193 SFG Consulting; *Equity beta*, *Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, paragraph 195, p. 42.

194 Henry O, University of Liverpool Management School; ***Estimating β: An update***; April 2014, p. 63.

195 AER; *Explanatory Statement*; p. 15.

196 SFG Consulting; *The Fama-French Model, Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid, and SA PowerNetworks*; 13 May 2014, and SFG Consulting; *Using the Fama-French model to estimate the required return on equity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; 13 February 2015.

12.2.6 Separately estimate the required return on equity using each of the relevant models

Using the above parameter estimates, SFG Consulting[197] estimates for the four models using an indicative averaging period spanning the 20 days to 30 January 2015:

- SL-CAPM: 9.32%;
- Black-CAPM: 9.93%[198];
- Fama-French Three Factor model: 9.93%; and
- DDM: 10.32%.

On the basis of the above the return on equity for AusNet Services is 9.87%.

12.2.7 Weighted average of all four models

It is the firm position of AusNet Services that the approach to establishing the return on equity set out in the Guideline is not consistent with the NER and is not the best possible estimate of the required rate of return for equity. In particular, AusNet Services is concerned that the approach set out in the Guideline does not meet the requirements of the new Rules that regard must be had to “relevant estimation methods, financial models, market data and other evidence”.

Accordingly, AusNet Services does not agree with the approach in the Guideline that an estimate for the return on equity in compliance with the NER can be generated using the SL-CAPM as a “foundation model” (or indeed any foundation model). AusNet Services submits that there are three preferable approaches to the AER’s foundation model approach consistent with the NER including:

1. Applying differing weightings to the four models;
2. Applying an even weighting to the four models; or
3. Correctly identifying the parameters for use in the SL-CAPM.

Weighting the four relevant equity return models

(a) Equal weighting to each model

AusNet Services does not accept that using the SL-CAPM to constrain the estimate of equity returns enables proper regard to be had to the point estimates delivered by the Black-CAPM and the DDM. Nor should the three factor insights of the Fama-French Model be disregarded when establishing single point estimate for the return on equity.

AusNet Services’ preferred approach is to weight all four estimates equally. This is because all four models have strengths and weaknesses and there does not appear to be a clear basis to distinguish one model over another in a way which would contribute towards achieving the rate of return objective. AusNet Services also notes that this approach is consistent with the simple average that the AER has applied when estimating the return on debt using the two available third party data series, on the basis that neither curve is clearly superior to the other[199].

On that basis and drawing on SFG Consulting’s data[200], the single point estimate for the required return on equity would currently be 9.87%.

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197 SFG Consulting; *The required return on equity for the benchmark efficient entity*, *Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, p. 35.

198 The Black CAPM estimate of 8.56% in SFG Consulting; *Beta and the Black Capital Asset Pricing Model* February 2015 report applies the AER’s MRP of 6.5%. The estimate of 9.93% reflects SFG Consulting’s preferred MRP estimate of 8.17%.

199 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* November 2014, p. 135 (pdf version).

200 SFG Consulting; *The required return on equity for regulated gas and electricity network business, Report for Jemena Gas Networks, ActewAGL, Distribution, Ergon, Transend and SA Power Networks;* 6 June 2014, paragraph 26, p. 9.

(b) Specific weighting to each model

SFG Consulting[201] points out that:

- The two CAPM estimates rely on common theoretical elements and to give them each the same weighting as the other two models could be viewed as according the common theoretical elements double weighting.
- The two CAPM differ, however, in that the Black-CAPM delivers an estimate of the intercept while the SL-CAPM delivers a lower bound.

Accordingly, AusNet Services submits that an alternative way to have regard to all the relevant information is to establish a weighted average of the four estimates that takes into account these matters identified by SFG Consulting[202].

SFG Consulting recommends[203] using the following specific weights:

- 25% to the DDM and 75% to the three asset pricing models;
- Half of the 75% should be accorded to the Fama-French Model (i.e., 37.5%);
- The remaining 37.5% assigned to the capital asset pricing models should be divided two thirds to the Black-CAPM (which provides an estimate of the intercept – i.e., 25%) and one third to the SL-CAPM (which provides a lower bound to the intercept – i.e., 12.5%).

On that basis and drawing on SFG Consulting's data[204], the single point estimate for the required return on equity would currently be 9.95%.

Use of parameters within the SL-CAPM

As noted elsewhere in this chapter[205], SFG Consulting[206] has identified at least two significant flaws in the SL-CAPM, being that it is downwardly biased for both low beta assets and value assets. SFG Consulting has separately estimated three CAPM[207] equity betas using each of the other models to correct for these biases. The Black-CAPM in particular addresses the issue of the bias for low beta assets, the Fama-French Three Factor model addresses the issue of the bias for value assets and the DGM uses contemporaneous evidence.

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201 SFG Consulting; *The required return on equity for the benchmark efficient entity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, p. 35.

202 SFG Consulting; *The required return on equity for the benchmark efficient entity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, p. 35.

203 SFG Consulting; *The required return on equity for the benchmark efficient entity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, table 6, p. 35.

204 SFG Consulting; *The required return on equity for the benchmark efficient entity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, APA AusNet Services, Australian Gas Networks, CitiPower, Endeavour Enery, Energex, Ergon, Essential Energy, Powercor, SA Power Network and United Energy;* 25 February 2015, table 6, p. 35.

205 See section 12.2.3.2 in this chapter.

206 SFG Consulting, in referring to the extensive empirical research in this respect, such as the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973) in SFG Consulting; *Cost of equity in the Black Capital Asset Pricing Model Report for Jemena Gas Networks, ActewAGL, Networks NSW, Transend, Ergon and SA Power Networks;* 22 May 2014, pp. 6- 10.

207 (a) SFG Consulting; *Using the Fama-French model to estimate the required return on equity, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015.

(b) SFG Consulting; *Beta and the Black Capital Asset Pricing Model, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, Ausnet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy;* 13 February 2015.

(c) NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM*, *A Report Jemena Gasworks, Jemena Electricity Networks, ActewAGL, AusNet Services, Citipower, Energex, Ergon Energy, Powercor, SAPower Networks and United Energy*; February 2015.

AusNet Services thereby submits that if the employment of the SL-CAPM as a foundation model is pursued, the correct parameters as estimated by SFG Consulting over the 2nd to 30th January 2015 averaging period are:

- The simple average of the four betas is 0.89208; and
- The required return on the market to be 10.81%.

Accordingly, for a risk-free rate of 2.64%, an asset with a beta of 0.89, and an over-all required rate of return for the market of 10.81%, the required return on equity within the SL-CAPM model is 9.87%.

12.3 Allowed Rate of Return on Debt

As described below, the benchmark efficient entity facing this level of risk and a 60:40 leveraging ratio would have a credit rating of no higher than BBB. Further, AusNet Services' submission regarding return on equity explains how the AER's approach delivers a substantially below market return on equity. In that situation, it would put further downward pressure on the effective benchmark credit rating.

This part of our proposal discussed the relevant aspects of establishing an allowed rate of return for debt as follows:

- Establish the tenor of the benchmark debt (section 12.3.1);
- Establish, in section 12.3.2, whether it is ultimately preferable to set the benchmark efficient debt management strategy on the basis that the benchmark entity:
    - Refinances all debt at the beginning of each regulatory period (the "on-the-day" method);
    - Maintains a staggered debt portfolio with no interest rate swap overlay (the trailing average method); or
    - Maintains a staggered debt portfolio with an interest rate swap overlay; the effect of which is to reset some portion "x%" of the benchmark entity's base rate of interest at the beginning of each regulatory period (the hybrid debt management strategy);
- Determine what transition (if any) should apply (section 12.3.3);
- Set out the proposed estimation procedure (section 12.3.4);
- Select averaging periods (section 12.3.5);
- Assess debt raising costs (section 12.3.6);
- Assess the cost of the new issue premium (section 12.3.7); and
- Set out the proposed annual update formula (section 12.3.8);

Each of these aspects is discussed below. The first set of relevant reports provided as part of the consultation on the Guideline provide a helpful background to the matters discussed below[209].

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208 Calculated as the average of the risk premia in each of the three models divided by the current market risk premium of 8.17% as estimated by SFG Consulting.

209 (a) Kanangra Ratings Advisory Services, Howell, D; *Credit ratings for regulated energy network services businesses;* June 2013.

(b) CEG Competition Economists Group, Hird, T; *Debt strategies of utility businesses*; June 2013.

(c) CEG Competition Economists Group, Hird, T; *Estimating the debt risk premium;* June 2013.

(d) PricewaterhouseCoopers Australia, Balchin, J. et al; *Energy Networks Association: Debt financing costs*; June 2013.

(e) PricewaterhouseCoopers Australia, Balchin, J. et al; *Energy Networks Association: Benchmark term of debt assumption;* June 2013.

(f) PricewaterhouseCoopers Australia, Balchin, J. et al; *Energy Networks Association: Potential impact of the ERA's DRP methodology*; June 2013.

12.3.1 Tenor of the benchmark debt instrument

The Guideline[210] adopts a 10 year tenor for the debt portfolio of the benchmark efficient entity based on a review undertaken by the AER of actual debt portfolios of comparable businesses and this is accepted by AusNet Services.

However, in its recent NSW draft determinations[211] [212] [213] [214] [215] [216] (**the NSW draft decisions**) the AER states that "*if anything, this assumption is more likely to overstate than understate the debt term of a benchmark efficient entity*"[217]. The draft decisions go on to state that the AER will monitor the average debt term at issuance of regulated network service providers against the benchmark term and that the AER may consider the information in the context of debt transaction cost assessments or any proposed adjustment to the "foundation model" estimate of the return on equity.

We do not accept the caveats upon the 10 year tenor.

Benchmark efficient finance practices are to raise debt with a long-term tenor to control refinancing risk within the useful lives of long-run network capital investments[218] [219] [220] [221]. This principle can be seen played out in practice: in the Guideline development process the data presented to the AER showed that the simple/weighted average term at issue for debt, including bank debt, was 11.0/10.7 years for privately owned businesses regulated by the AER[222].

The AER modified CEG's calculations by:

(a) assuming some callable debt had a maturity at its first call date;

(b) ignoring cash and cash equivalents; and

(c) including debt issued by: 100% government SPIAA (parent of Jemena) and Dampier to Bunbury Pipeline (which was not originally included by CEG as it was not regulated by the AER).

(g) PricewaterhouseCoopers Australia, Balchin, J. et al; *Responding to AER's criticism of PwC's report on the benchmark term of debt*; 2 October 2013.

(h) CEG Competition Economists Group, Hird, T & Wilton, A; *Mechanistic cost of debt extrapolation from 7 to 10 years;* October 2013.

(i) CEG Competition Economists Group, Hird, T; *Review of Lally and Chairmont Reports*; October 2013.

(j) CEG Competition Economists Group, Hird, T; *Transition to a trailing average approach*; October 2013.

(k) Diamond, N & Brooks, R.B.; *A review of measures of Australian corporate credit spreads published by the Reserve Bank of Australia, Esquant Statistical Consulting*; 19 May 2014.

210 AER; *Better Regulation | Rate of Return Guideline*; December 2013, section 6.3.1, p. 19.

211 AER; *Draft decision for Ausgrid distribution determination 2015-16 to 2018-19, Overview;* November 2014 (pdf version).

212 AER; *Draft decision for Directlink determination 2015-16 to 2019-10, Overview;* November 2014 (pdf version).

213 AER*; Draft decision for Endeavour Energy distribution determination 2015-16 to 2018-19, Overview*; November 2014 (pdf version).

214 AER; *Draft decision for Essential Energy distribution determination 2015-16 to 2018-19, Overview*; November 2014 (pdf version).

215 AER; *Draft decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview*; November 2014 (pdf version).

216 AER; *Draft decision for Transgrid transmission determination 2015-16 to 2018-19, Overview*; November 2014 (pdf version).

217 For example AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, page 129 (pdf version).

218 Witness statement of Gregory Damien Meredith; 31 January 2009.

219 Witness statement of Sim Buek Khim; undated.

220 Witness statement of Alistair Watson; 30 January 2009.

221 Witness statement of Andrew Noble; undated.

222 Letter from Dr Tom Hird (Director of CEG) to Mr Warwick Anderson (GM Network Regulation Branch of the AER) dated 11 November 2013.

Based on these amendments the AER estimated an 8.7 year weighted average term of debt (the AER did not report the simple average which CEG consistently estimated to be higher than the weighted average).

In terms of the maturity of bonds issued, the AER estimated bonds issued by the privately owned businesses these had an average term of 9.7 for bonds issued off-shore and 9.6 for Australian issued bonds and this is as close to the 10 year benchmark as is practicable when dealing with a small sample with lumpy debt raising requirements facing a range of practical constraints[223] [224] [225] [226] on when debt can be issued.

While bank debt is raised at somewhat shorter terms (i.e. 4.3 years according to the data collected for the Guideline process), bank debt forms a relatively small proportion of the total debt raised by the private businesses bank debt should not be, or should not fully be, included in establishing an average tenor for benchmark regulatory purposes. As explained by CEG, short-term bank debt is used to fund, at least in part, cash and cash equivalent assets which act as liquid funds for working capital and are necessary for efficient operation of a firm. Working capital is an asset above and beyond the regulated asset base which has no provision for working capital. The Explanatory Statement to the Guideline discusses this issue, however, the discussion involves a series of non-sequiturs:

> *"We do not agree with CEG's submission that a portion of short-term debt (bank debt and commercial paper) may be excluded as negative cash. We consider that a cash balance will reflect a number of items, including receivables and the proceeds of asset sales, which are not debt transfers. We understand that short-term debt is primarily used by the businesses to fund new capital expenditure, until such time as a marketable parcel (approximately $500 million) is accumulated that may be refinanced by issuing longer-term (bond) debt. We also understand that businesses try to have enough residual bank debt drawn to maintain competition between a pool of banks in order to provide competitively priced capex facilities. We therefore do not consider that it is appropriate to discount short-term debt by an amount equal to cash and cash equivalents."*[227]

Here the AER is, in essence, repeating CEG's view that cash and cash–equivalents are in the nature of working capital. But rather than drawing CEG's conclusion that the term of debt used to fund working capital should not be included in an estimate of the term of debt used to fund the Regulated Asset Base (RAB) the AER reaches the opposite conclusion.

Consistent with CEG's advice, it is unreasonable to include debt used to fund short term working capital requirements in the estimation of the average term of debt used to fund the long-term assets included in the RAB. Were the AER to do so it should, as a matter of consistency, expand the definition of the RAB to include working capital. In any event, even with this debt included, the average tenor is well above 5 years and substantially closer to 10 years than to 5.

Any consideration of the transaction costs component of our costs should similarly be consistent with the principle established above (that debt is raised on a long-term basis) and that the principal source of debt financing for use in funding the regulated asset base is through bond issues with tenors very close to the 10 year benchmark adopted in the Guideline.

The NSW draft decisions do not explain how there is a conceptual linkage between the tenor for debt and the foundation model for equity (or for any adjustments to it). As such, it would be wholly unacceptable if the issue of the tenor for debt were reopened by the AER as an attempt to claw back any adjustments to the flawed "foundation model" for equity.

223 Witness statement of Gregory Damien Meredith; 31 January 2009.

224 Witness statement of Sim Buek Khim; undated.

225 Witness statement of Alistair Watson; 30 January 2009.

226 Witness statement of Andrew Noble; undated.

227 AER; *Explanatory Statement*; p. 145.

12.3.2 Trailing average portfolio approach

The trailing average portfolio approach recognises that in practice the benchmark efficient entity's actual return on debt will be determined by historical rates at the time of debt issue. In addition, it recognises that energy networks do not raise all their capital at one time and instead have staggered debt maturities. In practice, electricity distribution network businesses need to balance a number of considerations when determining how much debt to refinance and at what times, including:

- Diversification of debt instruments and maturities;
- Liquidity management;
- Changes in the aggregate capital required as new investments are made contributing to a growth in the RAB and as ageing assets are depreciated;
- Credit metrics; and
- Market conditions, including access to foreign and domestic markets and the ability to hedge interest rate movements.

For this reason, entities will have different amounts of debt maturing at different points in time. It is not the case as the AER has asserted in current NSW draft distribution decisions that a benchmark efficient entity would hold an evenly staggered portfolio of long-term (10 year) debt where exactly 10 per cent of the debt is refinanced each year[228]. Due to the considerations set out above, a benchmark efficient entity would make decisions as to the amount of debt to be refinanced in any given year to minimise its debt financing costs and these amounts may vary each year.

Nevertheless, the trailing average portfolio approach is likely to more closely align with the staggered approach to refinancing a debt portfolio than the "on-the-day" method, noting that the trailing average method is a substantial simplification of what actually occurs. The trailing average portfolio approach significantly reduces the risk that the allowed return on debt might be higher or lower than the actual return on debt simply because the "on-the-day" rate for their particular service provider occurred at a high or low point in interest rate movements.

AusNet Services therefore accepts the 10 year trailing average portfolio approach set out in the Guideline provided that certain transitional and implementation issues are addressed.

12.3.3 Transitional Arrangements

The Guideline proposes that the new trailing average method be introduced gradually[229]. In the first year, the rate for debt would be set in the manner that applied in the previous determination for AusNet Services in 2010 (i.e. the "on-the-day" method). In the second regulatory year of the control period, a weighted average will be calculated with 90% weight accorded to the figure determined at the outset of the regulatory period and 10% weight given to the prevailing interest rate at the time of the second regulatory year[230]. In the third year, the weighted average will be calculated with an 80% weight accorded to the figure determined at the outset of the regulatory period, 10% in the second year of the regulatory period and 10% at the time of the third year and so on.

After a 10 year transition period (i.e. by the end of the second regulatory control period) the rate for debt would be set using a weighted average in which the current year and each of the preceding nine years would each have a 10% weighting.

AusNet Services does not consider the transition in the Guideline meets the requirements of the Rules.

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[228] See AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 39 (pdf version).

[229] AER; *Better Regulation | Rate of Return Guideline*; December 2013, section 6.3.2, pp. 19 – 20.

[230] A proxy for the prevailing interest rate in any regulatory year will be taken by measuring the return on debt over an averaging period in the prior year.

Rule 6.5.2(j) provides that the allowance for debt may be determined using the "on-the-day" method, on the basis of an average of the costs of debt raised over a historical period prior to the determination or a combination of the two. Rule 6.5.2(k) provides that the allowance would take account of any impacts on the benchmark efficient entity arising from a change in methodology.

Under the previous regulatory arrangements, the benchmark efficient entity would have had to manage as best it could:

- Refinancing risk (i.e. the risk that it may not be possible or economic to refinance a business's entire debt portfolio at one time or a substantial part of it); and
- The risk of disparities between interest rates between the averaging period used for the "on-the-day" methodology and the interest rates prevailing at the time debt was actually raised.

The first of these two considerations effectively required that a benchmark efficient entity raise debt progressively over time even though the regulatory framework established a return on debt each five years shortly before the regulatory determination.

The benchmark efficient business would then control interest rate risk as best it could by purchasing hedging instruments (the simplest of which is an interest rate swap) to manage the risk of disparities between the regulatory allowance and the actual time the debt was raised.

In 2009, as part of consultation on the AER's WACC parameter reset determination, the corporate treasurers of the Envestra (at paragraphs 5.16, 5.17, 6.4 and 6.5)[231], Jemena (at paragraph 5.19, 5.23 and 5.25)[232], SP AusNet (at paragraphs 4.9 to 4.15 and 5.1 to 5.9)[233] and Citipower and Powercor (at paragraphs 5.2, 5.4, 7.1 and 7.2)[234] each provided the AER with witness statements explaining how under the previous form of the rules no business would prudently raise all its debt in the "on-the-day" averaging period. Rather all businesses sought to stager their maturities to avoid refinancing risk and then generally undertook hedging transactions to control their exposures to interest rate movements as well as they reasonably could.

Although there is an actively traded market for interest rate swaps referenced to the prevailing yields on short-term highly rated bank debt, there is no equivalent for generic BBB debt and therefore it is not possible to hedge movements in the debt risk premium. Indeed an ability to better manage volatility in the debt risk premium is one of the principal advantages of ultimately moving to the trailing average method. This has been acknowledged by the AER:

> *"For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP."*[235]

The AER has argued that this is how an efficient benchmark entity would have managed its debt portfolio at that time:

> *"Given the observed practices of regulated network businesses and the definition of the benchmark efficient entity, we consider that the following practice is likely to constitute **an efficient debt financing practice of the benchmark efficient entity** under the current 'on the day' approach:*
>
> - *holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period…"*[236]

The above finding was restated in other parts of the Explanatory Statement[237] in the draft decision for Jemena Gas Networks NSW[238] and in the other regulatory decisions being made concurrently.

231 Witness statement of Gregory Damien Meredith, 31 January 2009.

232 Witness statement of Sim Buek Khim; undated.

233 Witness statement of Alistair Watson, 30 January 2009.

234 Witness statement of Andrew Noble; undated.

235 AER; *Explanatory Statement*; p. 122.

236 Ibid, p. 107.

Under the previous rules, the "on-the-day" methodology was mandatory and the flexibility concerning whether and how the AER might recompense the businesses for their efficient costs was constrained.

Under the new rules, however, the AER has greater flexibility in setting the returns on debt. However:

- It is mandatory under Rules 6.5.2(a) and (b) of the Rules to determine the debt allowance consistently with the allowed rate of return objective which requires that the rate of return to be commensurate with the efficient financing costs of the of a benchmark efficient entity; and
- Where there is discretion to be exercised that it be done in accordance with the revenue and pricing principles of the NEL including providing network businesses with a reasonable opportunity to recover at least its efficient costs239.

Having made the factual finding that it is efficient under the previous rules for a business to raise debt on a staggered basis and hedge to the averaging period, it would be an error not to establish the rate of return on a basis that enables the businesses to recover the efficient costs of doing so.

The transition path in the guidelines is not established on that basis and will fail to comply with Rule 6.5.2(b) of the Rules and section 16 of the NEL unless the transition path in the guideline provides *at least* as high a return as a transition path that is explicitly calculated on the basis of the costs of a business with a portfolio of debt with staggered maturities and hedging.

It is clear that an approach consistent with the NEL would be for the AER to make a determination that directly employs its finding concerning the efficient debt portfolio of a benchmark efficient business and for that reason this proposal establishes costs on the basis set out above.

This means that the benchmark efficient firm would enter the 2016-2020 Victorian distribution regulatory period with:

- A trailing average DRP; and
- A floating rate exposure for the proportion of its portfolio base rate of interest that it was efficient to hedge.

Therefore in making its decisions for AusNet Services, the AER should not adopt the Guideline position on transitional arrangements for the return on debt. Rather, the AER should adopt a position that is consistent with the new analysis it has undertaken and the expert advice it has received on this issue.

In light of the AER's findings in the NSW draft decisions, a "hybrid" transitional arrangement would be more appropriate. That is:

- For the proportion of the portfolio that it is assumed the benchmark efficient entity would have, using interest rate swaps, hedged to the beginning of the regulatory period there should be a ten-year transition to a trailing average plus the transaction costs of the associated interest rate swaps; and
- There should be no transition for:
    - The debt margin (or debt risk premium) component. That is, the AER should immediately move to a trailing average estimation of the debt risk premium component. This means that for the first year of the forthcoming regulatory period, the debt risk premium would be estimated as a ten-year trailing average, and this trailing average estimate would be updated in each subsequent year; and

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237 AER; *Explanatory Statement*; pp. 121 – 122.

238 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, see for example, p. 115 (pdf version) .

239 The National Electricity Law; Schedule 2, Part 3; section 16.2.

- That proportion of the portfolio that it is assumed the benchmark efficient entity would not have hedged to the beginning of the regulatory period.

This approach would provide for an estimate of the return on debt which reflects the required return on debt for the benchmark efficient entity. As noted above, under the efficient financing strategy identified by the AER in the NSW draft decisions, 100% of the base interest rate component of the benchmark efficient entity's actual return on debt would have been matched with the regulatory allowance set using an "on-the-day" rate, but the debt risk premium component each year would have reflected the historical (or trailing) average of the debt risk premiums over the previous ten years. Under this approach, 100% of the base rate of interest would be subject to a transition and only the DRP would be set immediately consistent with a trailing average.

Accordingly, AusNet Services submits that, consistent with its own definition of the benchmark efficient entity's historical debt management strategy, the AER should not adopt the Guideline position on transitional arrangements for the return on debt. Rather, the AER should adopt the hybrid transitional arrangement described above. Moreover, AusNet Services notes that the above quote from the AER's explanatory statement and the logic as set out in the NSW draft decisions proceeds on the basis that it is appropriate to define the efficient financing costs of a benchmark efficient entity on the assumption that they are regulated and as a function of the type of regulation that they are/have been subject to. For example, consistent with the previous AER quote, the AER states:

> *"Based on the above, we consider a staggered debt portfolio with interest rate swaps was an efficient financing practice of the benchmark efficient entity* ***under the on-the-day approach****.*[240]*"* (Emphasis added.)

It is not obvious that such a construction of the allowed rate of return objective (ARORO) is correct. There is, inevitably, an element of circularity in this construction – with the efficient debt management strategy depending on the regulatory policy rather than the regulatory policy depending on the efficient debt management strategy. Dr Hird has made this "circularity" point previously[241].

However, even if the benchmark efficient debt management strategy can be conceived of as the one that most efficiently matched past regulatory practice, it does not follow that this involves hedging 100% of the base rate of interest using interest rate swaps. This is only correct if the level of the prevailing DRP was independent of the level of the prevailing swap rates. If the prevailing DRP and the prevailing swap rates tend to be inversely related (just as the prevailing MRP and risk free rates tend to be) then leaving some portion of the debt portfolio unhedged would have more efficiently matched the benchmark efficient entity's cost of debt to the on-the-day allowance.

12.3.4 Estimation Procedure

Benchmark credit rating

The Guideline considers that the benchmark credit rating should be BBB+[242]. Further, the AER has rejected CEG's position with respect to the appropriate credit rating for a benchmark efficient entity in its NSW draft decisions[243]. CEG found that each year from 2009 to late 2013, the median credit rating of energy network service providers was BBB, amid a clear trend of downgrades in the industry.

The AER repeated CEG's analysis for 31 December 2013, and found that at that moment in time, the median had risen to BBB+. However, AusNet Services considers that with such a very small sample of comparators, it is not reasonable to take an "on-the-day" credit rating which can oscillate

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240 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 115 (pdf version).

241 CEG Competition Economists Group, Hird, T; *Efficiency of staggered debt issuance*, February 2013, pp. 29-32.

242 AER; *Better Regulation | Rate of Return Guideline*; December 2013, Section 6.3.3, pp. 21 – 22.

243 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 296 (pdf version).

considerably in response to a ratings change for a single firm and instead the credit rating needs to be established over a reasonable period such as that used by CEG.

Over that timeframe (i.e. over approximately five years) the information before the AER clearly provides sufficient weight to warrant a departure from the Guideline and a reduction in the median credit rating relied on.

In relation to the comparator group used to determine the median credit rating, while the AER has deleted Ergon Energy Corp Ltd from its comparator group on the basis that its credit rating is obviously influenced by government ownership, the AER has taken the view that its comparator set should include both AusNet Services and SGSP Australia Assets Pty Ltd, even though clear evidence exists that Singaporean Government ownership in these businesses has significant effect on the consideration of their credit ratings by credit rating agencies. For example both companies were placed on negative watch when the Singapore Government proposed to dilute its ownership in 2013[244].

The AER has also taken the view that even if it were to consider Singapore Government ownership in AusNet Service and SGSP, some time has passed since the dilution of Singapore Government ownership (which is evidence of the effect of the ownership on the rating), and it therefore considers that credit rating agencies have had time to revise their credit ratings[245]. This statement seems to misunderstand the issue that the continuing effect of Singapore Government ownership is to provide greater comfort to credit rating agencies as to key issues relevant to their consideration of the appropriate credit rating, such that the credit rating applied to these companies is not one that would be applied to a pure play, regulated energy network business operating within Australia (which is defined as the benchmark efficient entity in the Guideline). Evidence of dilution of government ownership having a negative effect on a credit rating agency's views of the risk of a downgrade in a credit rating serves to support this proposition[246].

Further the AER appears to take comfort in the fact that the credit rating of SGSP has changed since the dilution to assert that government ownership has not been sufficient to maintain an A- credit rating.[247] The issue however is that government ownership has maintained the credit rating at a higher level that it would otherwise been over this period, and therefore the credit rating of this business is not reflective of the credit rating of an efficient private service provider which is the standard that informs the definition of a benchmark efficient firm[248].

Over a five year period the data for the corrected comparators is illustrated in the following table.

244 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, see for example, p. 295 (pdf version).

245 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 296 (pdf version).

246 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 296 (pdf version).

247 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 297 (pdf version).

248 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, p. 296 (pdf version).

Table 12.11: Credit Ratings of Corrected Comparator Firms

End of year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	MEDIAN over all years	Median over last 5 years
APT Pipelines								BBB	BBB	BBB	BBB	BBB	BBB	**BBB**	**BBB**
ATCO Gas Australian LP										BBB	BBB	A-	A-	**BBB**	**BBB+**
DBNGP Trust			BBB	BBB	BBB	BBB	BBB	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	**BBB**	**BBB-**
DUET Group		BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-			**BBB-**	**BBB-**
ElectraNet Pty Ltd	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB	BBB	BBB	BBB	BBB	BBB+	**BBB+**	**BBB**
Energy Partnership (Gas) Pty Ltd		BBB	BBB	BBB	BBB	BBB	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	**BBB-/BBB**	**BBB-**
Envestra Ltd	BBB	BBB	BBB	BBB	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-	BBB	BBB+	**BBB-**	**BBB-**
ETSA Utilities	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	**A-**	**A-**
Powercor Utilities	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	BBB+	BBB+	**A-**	**A-**
SP AusNet Group	A	A	A	A	A	A	A-	A-	A-	A-	A-	A-	A-	**A**	**A-**
SPI (Australia) Assets Pty Ltd							A-	A-	A-	A-	A-	BBB+	BBB+	**A-**	**A-**
The CitiPower Trust	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	BBB+	BBB+	**A-**	**A-**
United Energy Distrib. Pty Ltd	A-	BBB	BBB	BBB	BBB	BBB	BBB	BBB	BBB	BBB	BBB	BBB	BBB	**BBB**	**BBB**
Median	**A-**	BBB+	BBB/BBB+	BBB/BBB+	BBB/BBB+	BBB/BBB+	BBB+	BBB	BBB	BBB	BBB	BBB/BBB+	BBB+	**BBB**	**BBB**

It can be seen that, with the exception of 2014, 2002 and 2003, the median credit rating has been below BBB+. The median credit rating has been BBB across all firms for the longest time period examined and for the last 5 years. While the median credit rating in 2014 was BBB+ by including all of the firms that the AER seeks to include, but once the firms with sovereign government ownership are excluded (i.e. SP AusNet (A rated), SPI (A- rated) and Electranet (BBB+ rated)), the mean credit rating is BBB/BBB+.

Moreover, historical credit ratings do not reflect the extremely low equity buffer that would result if the AER's proposed approach to compensation for the cost of equity is implemented in current market circumstances. Our concern is that the AER's methodology for establishing the return on equity delivers a depressed return in circumstances in which CGS yields are at historically low levels (because the AER's foundation model passes through falls in CGS yields on a 'one of one' basis to its allowed rate of return on equity). The result is that the regulatory arrangements provide a lower equity buffer than a benchmark efficient firm would have and consequently debt holders are exposed to additional risk. Similarly, the AER's proposed transition to a trailing average cost of debt will, at prevailing debt risk premiums, under-compensate the benchmark efficient entity who will have to pay the higher trailing average debt risk premium on its efficiently issued staggered debt portfolio. This under-compensation will further compress cash-flow buffers for the benchmark efficient entity.

Separately, ActewAGL presented analysis by CEG of cash-flow metrics implied by the AER's draft decision for that company[249]. The methodology was based on that set out in Moody's 2014 guide: Rating methodology for Regulated Electric and Gas Networks. CEG estimated that credit metrics for ActewAGL were BBB- even if all of the AER's assumptions about efficient costs were considered to be accurate and achievable. However, if the AER's assumption about the cost of debt was replaced by a trailing average then the credit metrics fell to sub investment grade BB+.

CEG also applied Moody's qualitative rating framework to arrive at an overall credit rating. This tended to lift the credit rating above that implied by the metrics alone. On the other hand, CEG's conclusion was that, even if all of the AER's assumptions about efficient costs, including debt costs were achievable, the overall credit rating would be BBB. Further, if a trailing average cost of debt were assumed to be efficient the overall credit rating fell to BBB-.

AusNet Services considers that the AER should review the appropriate criteria for businesses to be included in its comparator set and remove those businesses who do not reflect the risk profile of a benchmark efficient firm due to government ownership (full or partial) or other relevant factors such as implicit support from parent companies which improves subsidiary individual credit ratings. The AER should also establish its credit rating over a longer period than a simple "on-the-day" rating established when the regulatory determination happens to be made and have regard to CEG's "first principles" analysis. Taken together, all this material supports a BBB not BBB+ credit rating.

Source of data

The Guideline did not express a definitive proposal as to the source of the data for the benchmark return on debt and as such it is not a matter of accepting the guideline or proposing a departure. The AER has noted that the use of independent third party estimates may be less controversial where the published source is already available and not explicitly constructed for the regulatory process[250].

There are currently two principal options for independently published BBB yield estimates under consideration. Namely, the Bloomberg BBB BVAL curve and the RBA published aggregate measure of 10 year Australian BBB corporate debt[251].

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249 CEG Competition Economists Group, Hird, T; *Efficient debt financing costs - A report for ActewAGL*; 19 January 2015.

250 AER; *Explanatory Statement*; p. 127.

251 Reserve Bank of Australia; *Aggregate Measures of Australian Corporate Bond Spreads and Yields - F3*. http://www.rba.gov.au/statistics/tables/

The RBA's daily reported measure of the cost of debt is actually a combination of components some of which are daily and some of which are established from interpolation between month end statistics. Specifically, the AER interpolates the spread to CGS at the 10 year target tenor and adds to this the 10 year CGS yield on each day in order to get the yield on each day. It then calculates a daily spread to swap by subtracting the swap rate from its estimated yield and it then extrapolates this spread to swap from 10 year target tenor to 10 year actual tenor. It is not clear why the RBA uses CGS rather than swaps but that is the method it has chosen to adopt.

That approach is not supported by any statistical analysis. An analysis by ESQUANT, using an ARIMA model, in May 2014[252], showed that interpolation between the end of month figures in this way is not an accurate method of estimating the cost of debt for the intervening days of the month. We will be exploring whether and how this issue can best be addressed as the revenue reset consultation proceeds.

Although neither curve publishes an estimate for 10 year debt, the Bloomberg service produces a 7 year fair value estimate, and the RBA's publication provides a fair value estimate for a "target tenor" of 10 years but, because most bonds in its sample are less than 10 years, this is generally associated with a published "effective tenor" of less than 10 years. Extrapolation can be used to arrive at a 10 year figure for both published yield estimates.

The AER's recent NSW draft decisions take the simple average of the extrapolated results from these two services. Consistent with the AER's approach in the recent NSW draft decisions, our regulatory proposal gives a 50% weighting to each of the Bloomberg BBB BVAL and RBA published series (but, as discussed below, with each extrapolated out to a 10 year tenor using the SAPN extrapolation method rather than the AER method).

CEG[253] has reviewed two methods for extrapolation (which it calls the AER and SAPN methods). AusNet Services' proposal adopts the SAPN methodology for all future years of the regulatory period.

The most desirable extrapolation approach is that which best fits the underlying bond yield data for a particular period. This can vary over time. For example, CEG finds that the estimate of the trailing average DRP is not sensitive to the extrapolation method used. However, in the placeholder averaging period applied in this proposal (2 to 30 January 2015) the choice of extrapolation methodology is significant. The SAPN methodology best fits the data in this instance[254].

Given that the AER does not propose to test which extrapolation is most appropriate for each averaging period within the regulatory control period, an extrapolation methodology must be selected despite there not being one superior approach. Given the SAPN methodology fits the data in the most recent averaging period better than the AER's method, AusNet Services proposes to adopt the SAPN methodology going forward.

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[252] Esquant Consulting, Diamond, N & Brooks, R; *A review of measures of Australian corporate credit spreads published by the Reserve Bank of Australia – Submission to the Issues Paper (Return on Debt: Choice of third party data service provider) released by the Australian Energy Regulator (April 2014)*; 19 May 2014.

[253] CEG Competition Economists Group, Hird, T; *Critique of the AER's JGN draft decision on the cost of debt*; April 2015, page 44–46 and Appendix B (attached as Appendix 12J).

[254] CEG Competition Economists Group, Hird, T; *Critique of the AER's JGN draft decision on the cost of debt*; April 2015, page 62–63 and Appendix B.

The extrapolation formula is as follows:

For each service provider the average slope of the DRP with respect to changes in maturity at each point on the published yield curve at or above 1 year maturity is estimated as the slope coefficient using ordinary least squares (OLS) regression on observations of fair value DRP against maturity with an intercept term. That is, the formula below:

Average slope = $\frac{\sum_{i=1}^{n}(DRP_i - \overline{DRP})(M_i - \bar{M})}{\sum_{i=1}^{n}(M_i - \bar{M})^2}$; where

DRP_i = published yield at target maturity of "i" years less the swap rate at maturity "i" based on data published by the relevant service provider;

$\overline{DRP}$ = the mean of all DRP_i for "i" greater than or equal to 1;

M_i = is the maturity of "i" years associated with DRP_i (in the context of the RBA publication this is effective maturity);

$\overline{M}$ = the mean of all M_i for "i" greater than or equal to 1;

n = the number of observations of fair value DRPs with maturity greater than or equal to 1.

If i_{max} is a value less than 10 years, the extrapolated DRP at 10 years is given by:

$DRP_{10} = DRP_{i_{max}}$ + (Average slope)×(10 - i_{max})

Where i_{max} is the longest maturity associated with a published yield.

If i_{max} is a value greater than 10 years is then DRP_{10} is determined by linear interpolation between the published DRP_i for the i that is closest to, but less than, 10 years and the DRP_i for the i that is closest to, but greater than 10 years.

The extrapolated yield at 10 years is given by:

Extrapolated yield = 10 year swap rate + DRP_{10}

The RBA publishes the DRP to swap at each maturity and the yield at each maturity, so the implied swap rate at each maturity to be used for RBA data can be calculated as:

$$Swap_i = Yield_i - DRP_i$$

Bloomberg publishes swap rates that can be sourced through the ADSWAP fields within the Bloomberg environment. For example, "ADSWAP1 Index" is the field for Australian swap rates with 1 year to maturity.

AusNet Services is aware, however, that other businesses are actively investigating and debating whether there are more appropriate ways to select between, or combine, benchmarks drawn from the two services and we will monitor this debate as the regulatory process moves forward.

12.3.5 Averaging period

Accompanying this regulatory proposal and forming part of it is a confidential letter proposing details of the averaging periods for each year of the regulatory period (attached as confidential Appendix 12K).

The Guideline states that one of the criteria for the selection of an averaging period should be that "*The averaging period should be as close as practical to the commencement of each regulatory year in a regulatory control period*.[255]" That consideration may have been relevant under the old, pre-2012, rules, in which there was an attempt to select a benchmark debt allowance as close to the commencement of the regulatory period that would then endure for the following five years.

However, where the trailing average approach is selected under the new rules, it assumes that debt will be raised on staggered basis drawn from 10 approximately evenly spaced periods. Where businesses have existing staggered portfolios with existing instruments that mature at the beginning of the year, enforcing an "end of the year" averaging period would require such businesses to inefficiently engage in bridge financing or hedging, if they are to align their actual debt raising practices with the regulatory trailing average benchmark.

One of the key rationales for adopting the trailing average portfolio approach was to allow service providers to align actual debt financing costs with the regulatory debt allowance:

> *"In other words, the trailing average portfolio approach allows a service provider—and therefore also the benchmark efficient entity—to manage interest rate risk arising from a potential mismatch between the regulatory return on debt allowance and the expected return on debt of a service provider without exposing itself to substantial refinancing risk.*
>
> *Thus, we consider that holding a (fixed rate) debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt allowance is likely to be an efficient debt financing practice of the benchmark efficient entity under the trailing average portfolio approach."*[256]

As it was not necessarily efficient to issue debt in the latter half of the regulatory year under the previous (on-the-day) debt approach, there is no reason why components of a benchmark efficient firm's staggered debt portfolio would expire in the latter half of the regulatory year going forward.

Therefore, to align actual debt practices with the trailing average approach, it is necessary to align the timing of debt issuance with the timing of the averaging periods used to estimate the regulated return on debt. If the timings do not align, a benchmark efficient entity will be unable to adopt the financing practices considered by the AER to be "efficient" (see above) without risking a mismatch between the regulatory return on debt allowance and its actual return on debt.

AusNet Services understands that the AER is also concerned about the potential for averaging periods to overlap, which could result in a "double-counting" of debt costs over a specific time period. As AusNet Services has nominated the averaging periods to apply for each year of the 2016-20 regulatory period and these do not overlap, then it does not consider this concern is valid.

There is no conceptual reason why it should be presumed that raising debt towards the end of the calendar year is preferable to the beginning of the year. On that basis, we have departed from the Guideline in that our averaging periods may be chosen in the early, middle or late part of each relevant year.

12.3.6 Debt raising costs

AusNet Services' opex chapter includes an analysis of debt raising costs. If for any reason debt raising costs are not allowed for as part of opex, the AER should include these costs as part of the allowed return on capital.

255 AER; *Better Regulation | Rate of Return Guideline*; December 2013, section 6.3.1, p. 15.

256 AER; *Explanatory Statement*; pp. 108-109.

12.3.7 New issue premium

The proposed sources of debt data (i.e. the RBA and Bloomberg series) are observations of the secondary debt market – that is the market in which debt issued in the past, but which has not yet reached maturity, is sold from one bond holder to another. Alternatives to the RBA and Bloomberg series were identified in the AEMC Rule change[257] and Guideline[258] processes but these sources are also derived from the secondary market.

By contrast, when network businesses raise debt it is by issuing new bonds to bond holders. This is known as the primary bond market. There are a number of differences between the primary and secondary bond markets. For example, the quantum of debt that is the subject of an issue is much greater than the later secondary trade in bonds with only a small proportion (if any) re-traded each business day.

The difference between the costs facing a business issuing bonds into the primary debt market and trading in the secondary debt market is commonly referred to as the "new issue premium". It is accepted that this premium is, on average, positive – due to reasons identified in the literature including market liquidity constraints asymmetric information held between borrowers and lenders.

CEG has prepared a report detailing its views on the extent of the new issue premium[259]. The new issue premium is measured as the change in yields from issue relative to changes in yields of a bond market index. Both the Bloomberg BBB BVAL fair value curve and the RBA BBB fair value curve are calculated based on Bloomberg indicative yields.

CEG's report notes that economic logic suggests that compensation for the return on debt should be based on the cost of issuing debt into primary (issuance) markets. This is because this is the market which determines the actual yield paid by an issuer on debt raised. Further, the Rules are consistent with this conclusion. The allowed rate of return objective states:

"The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).[260]"

CEG finds that the best estimate of the new issue premium that is relevant to a benchmark debt management strategy of issuing 10 year BBB rated debt is 27 basis points.[261]

Although we consider the new issue premium to be a cost we face, we do not propose to include an explicit allowance for it at this time. Consequently, our proposed debt allowance is a conservative allowance which means that it is all the more important that the AER approves other aspects of our regulatory proposal in full.

The Guideline did not explicitly determine whether or not a new issue premium should be include in the cost of capital allowance and, on one view, to now consider and include an additional allowance to account of the new issue premium is not a departure from any explicit provision of the Guideline. On the other hand, it could be argued that to provide an additional increment for the new issue premium is a departure by addition and to the extent that this is the case, our proposal departs from the Guideline.

12.3.8 Annual Update Formula

Rule 6.5.2(l) of the Rules requires that if the debt allowance is to differ within the revenue period from one year to the next:

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[257] For example, see SFG Consulting; *Rule change proposals relating to the debt component of the regulated rate of return, Report for the AEMC;* 21 August 2012, Table 2, p. 13.

[258] AER; *Explanatory Statement*; p. 126.

[259] CEG Competition Economists Group, Hird, T; *New Issue Premium*; October 2014 (attached as Appendix 12L).

[260] AEMC; *National Electricity Rules Version 71*, Rule 6.5.2(c).

[261] CEG Competition Economists Group, Hird, T; *New Issue Premium;* October 2014, p. 54.

"… then a resulting change to the Distribution Network Service Provider's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination."[262]

For each of the four years 2016-2020, the annual revenue requirement will be updated by adjusting the return on capital building block for that year as follows:

ΔRocBlockt = Δcod × 60% × *oRABt*

Where:

ΔRocBlockt is the Adjustment to the return on capital building block in regulatory year t;

Δcod is the change in the trailing average cost of debt in regulatory year t determined in accordance with the process set out in this section 4 of the proposal relative to the cost of debt for that year applied by the AER in making its distribution determination; and

oRABt is the opening RAB in year t set out in the distribution determination.

Note: The 60% represents the gearing ratio assumed for the benchmark firm.

For clarity, in addition to the formula required under Rule 6.5.2(l) of the Rules, we have also included other formulae to describe other aspects of our proposal. Above we have provided the formula for extrapolation of the services. The formula to then be used for each of years of the regulatory period is as follows:

262 AEMC; *National Electricity Rules Version 71*, Rule 6.5.2.

The return on debt for each Regulatory Year of the Revenue Period is to be calculated as follows:

For Regulatory Year 2016: $kd_{2016} = T_{2016} + swap_{;}$

For Regulatory Year 2017: $kd_{2017} = (0.9 \times T_{2017}) + (0.1 \times R_{2017}) + swap_{;}$

For Regulatory Year 2018: $kd_{2018} = (0.8 \times T_{2018}) + (0.1 \times R_{2017}) + (0.1 \times R_{2018}) + swap_{;}$

For Regulatory Year 2019: $kd_{2019} = (0.7 \times T_{2019}) + (0.1 \times R_{2017}) + (0.1 \times R_{2018}) + (0.1 \times R_{2019}) + swap_{;}$

For Regulatory Year 2020: $kd_{2020} = (0.6 \times T_{2020}) + (0.1 \times R_{2017}) + (0.1 \times R_{2018}) + (0.1 \times R_{2019}) + (0.1 \times R_{2020}) + swap,$

where:

- k_{dt} is the return on debt for Regulatory Year t of the Regulatory Period;
- T_{20XX} is the cost of debt that feeds into the calculation of kd_{2016} *and* is not yet matured in 20XX;
- R_t is the annual return on debt observation for each Calendar Year t of the regulatory period (other than Calendar Year 2016) calculated according to the methodology set out above including the data must be annualized consistent with section 6.3.3 of the Guideline; and
- *swap* is the estimate of transaction costs.

12.3.9 Proposed Return on Debt

Applying AusNet Services' proposed approach to estimating the return on debt yields 5.39% over the placeholder averaging period of 2nd to 30th January 2015. This is made up of the following components:

- Trailing average DRP of 2.40% plus average of 1 to 10 year swap rates of 2.69% provides a cost of debt of 5.09% on a semi-annual basis, annualised to 5.17%; plus
- Swap transaction costs of 0.23%.

The detail underpinning this calculation is set out in the attached CEG report dated April 2015[263].

12.4 Expected Inflation

Rule 6.4.1 of the Rules requires that the AER prepares and published a post-tax revenue model (PTRM), which is used to establish the revenue allowance each year during the regulatory period. Under Rule 6.4.2(b)(1) of the Rules, the post tax revenue model must include:

> *"…a method that the AER determines is likely to result in the best estimates of expected inflation."*

The Guideline does not explain how the AER proposed to determine the rate of inflation, instead leaving that question to be determined in each individual revenue determination.

[263] CEG Competition Economists Group, Hird, T; *Critique of the AER's JGN draft decision on the cost of debt*; April 2015.

Since the SP AusNet transmission determination in 2009, the AER has established the expected inflation rate by taking a simple average of the RBA forecasts of short-term inflation extending out to two years and the mid-point of the RBA's target inflation band for the remaining years in the 10 year period. At the time of that determination, the AER noted that it would monitor the situation to see if the reasons for adopting the change might reverse.

Presently, AusNet Services does not oppose the AER's current approach to determining the expected rate of inflation. However, AusNet Services notes that very recently in Australia and globally, expectations concerning inflation (or in fact fears of significant deflation) appear to be volatile and it may be that the best method for estimating inflation may evolve during the period that our revenue proposal is being considered.

Using the AER's method, the relevant inflation rate would be 2.52%.

12.5 Conclusion

Using the indicative averaging period spanning the 20 days to 30 January 2015, our proposed allowed rate of return on equity for each regulatory year of the regulatory period, based on the SFG Consulting approach outlined above would be calculated as follows:

Table 12.12: Proposed return on equity based on indicative averaging period

Model	Risk free component	Risk premium	Weight	Return on equity
Sharpe-Lintner Capital Asset Pricing Model	2.64%	6.68%	25%	9.32%
Black Capital Asset Pricing Model	2.64%	7.29%	25%	9.93%
Fama and French Model	2.64%	7.29%	25%	9.93%
Dividend discount model	2.64%	7.68%	25%	10.32%
Overall return on equity	**2.64%**	**7.31%**	**100.00%**	**9.87%**

Combined with the proposed return on debt outlined in section 12.3.8 and the gamma value proposed in Chapter 13, AusNet Services' proposed rate of return for each regulatory year of the regulatory period is shown in the table below.

Table 12.13: Proposed rate of return based on indicative averaging period

Input	Rate
Overall return on equity	9.9%
Overall return on debt	5.39%
Gamma	0.25
Rate of Return	**7.19%**

Note – The return on equity has been rounded to one decimal place, in accordance with the Guideline.

As we have explained, we do not consider that the foundation model is appropriate to use to estimate the return on equity. However, if it were to be used in the manner re-specified as per SFG Consulting's advice, the beta for use in the SL-CAPM as a foundation model should be:

Table 12.14: Implied SL-CAPM foundation model beta

Model	Implied SL beta
Sharpe-Lintner Capital Asset Pricing Model	0.82
Black Capital Asset Pricing Model	0.89
Fama and French Model	0.89
Dividend discount model	0.94
Weighted average beta	**0.89**

If this approach were adopted, using the indicative averaging period spanning the 2 to 30 January 2015, our proposed allowed rate of return and based on the SFG Consulting data outlined in section 12.2.7 above the overall rate of return would be calculated as follows:

Table 12.15: Implied SL-CAPM foundation model rate of return based on indicative averaging period

Input	Rate
Overall return on equity	9.9%
Overall return on debt	5.39%
Gamma	0.25
Rate of return	**7.19%**

12.6 Supporting Documents

The following documentation supporting this chapter are provided as Appendices to this revenue proposal:

- Appendix 12A – SFG Consulting; The required return on equity for the benchmark efficient entity; February 2015.
- Appendix 12B – SFG Consulting; Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network; February 2015.
- Appendix 12C – SFG Consulting; Using the Fama-French model to estimate the required return on equity; February 2015.
- Appendix 12D – SFG Consulting; Beta and the Black Capital Asset Pricing Model; February 2015.
- Appendix 12E – NERA; Empirical Performance of the Sharpe-Lintner and Black CAPM; February 2015.
- Appendix 12F – NERA; Historical Estimates of the Market Risk Premium; February 2015.
- Appendix 12G – NERA; Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model; March 2015.
- Appendix 12H – SFG Consulting; The foundation model approach of the Australian Energy Regulator to estimating the cost of equity; 27 March 2015.
- Appendix 12I – Incenta Economic Consulting; Further update on the required return on equity from Independent expert reports; February 2015.
- Appendix 12J – CEG; Critique of the AER's JGN draft decision on the cost of debt; April 2015.
- Appendix 12K – Averaging Period Letter (Confidential).
- Appendix 12L – CEG; New Issue Premium; October 2014.

In addition, documents footnoted in this chapter will be submitted to the AER on a USB with the revenue proposal.

13 The Value of Imputation Credits

13.1 Overview

13.1.1 Introduction

The National Electricity Rules (NER) require an estimate of "*the value of imputation credits*"[1] (also referred to as "gamma") as an input to the calculation of the corporate income tax building block. In order to promote the National Electricity Objective (NEO),[2] the estimate of gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate). This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role in determining returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on them, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity distribution for the long term interests of consumers.

13.1.2 Summary of Proposal

The estimation method that AusNet Services proposes to adopt will result in an estimate of gamma that reflects the value equity-holders place on imputation credits. In particular, AusNet Services proposes to calculate gamma in the orthodox manner with the Monkhouse formula,[3] as the product of:

- The distribution rate (i.e. the extent to which imputation credits that are created when companies pay tax, are distributed to investors) using ATO data; and
- The value of distributed imputation credits to investors who receive them (theta) based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis).

AusNet Services proposes the observed distribution rate (0.70), which is consistent with both the AER's rate of return guideline, explanatory statement (appendices)[4] and findings of the Australian Competition Tribunal (the Tribunal).[5] AusNet Services proposes that the distribution rate be combined with the best estimate of theta from market value studies (0.35) which leads to an estimate for gamma of 0.25. AusNet Services' proposal is consistent with the expert advice of both Professor Gray (of SFG Consulting)[6] and Simon Wheatley (of NERA)[7] attached as Appendices 13A and 13B respectively.

AusNet Services considers that the AER's recent[8,9,10,11,12,13] approaches fail to estimate gamma reflecting the value equity-holders place on imputation credit as the AER:

1 Australian Energy Market Commission, National Electricity Rules Version 69, cl 6.5.3, p. 661 (pdf version).

2 The National Electricity Law, A Schedule to the National Electricity (South Australia) Act 1996, (the NEL), Schedule 2, Part 3, section 8.

3 Monkhouse, P. H.L. (1996), The valuation of projects under the dividend imputation tax system, Accounting & Finance, 36: pp. 185-212.

4 AER, Better Regulation, Explanatory Statement Rate of Return Guideline (Appendices) (Guideline Appendices), December 2013, pp. 136-180 (pdf version).

5 ACT, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3)(2010)ATPR 42-333; [2010] ACompt9.

6 SFG Consulting, Estimating gamma for regulatory purposes, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy, February 2015, paragraph 22, p. 4.

7 NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Powercor, SA PowerNetworks and United Energy, March 2015.

8 AER, Draft decision for Ausgrid distribution determination 2015-16 to 2018-19, Overview, November 2014 (pdf version).

9 AER, Draft decision for Directlink determination 2015-16 to 2019-10, Overview, November 2014 (pdf version).

10 AER, Draft decision for Endeavour Energy distribution determination 2015-16 to 2018-19, Overview, November 2014 (pdf version).

- proposes to revise the definition of theta to exclude the effect of certain factors on the value of imputation credits. AusNet Services considers that this is conceptually incorrect and inconsistent with the requirements of the NER;
- uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value;
- the AER incorrectly proposes to use equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors;
- has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with evidence;
- has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors;
- the AER has erred in its interpretation of market value studies. The AER considered market value studies in a very general manner and found that some criticisms can be made of some studies, rather than considering the merits of the particular market value estimates from the studies we propose. Based on these generalised observations, the AER discounts the contribution that all market studies make to the AER's analysis – even studies to which the generalised criticisms do not apply. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;
- has reported a higher estimate of the distribution rate for listed equity only inconsistent with the AER's stated position that a benchmark efficient network service provider is not defined as a large, stock market listed network service provider.[14] Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample; and
- reaches an ultimate conclusion as to the value for gamma is inconsistent with evidence, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER overestimated the value of imputation credits.

13.1.3 Chapter Structure

This chapter in structured as follows:

- The requirements of the NER and the NEL are described (Section 13.2);
- AusNet Services' proposal is set out, and the reasons why AusNet Services proposes departing from the Guideline value of gamma are explained (Section 13.3); and
- AusNet Services' proposed approach to estimating gamma is described (Section 13.4).

11 AER, Draft decision for Essential Energy distribution determination 2015-16 to 2018-19, Overview, November 2014 (pdf version).

12 AER, Draft decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview; November 2014 (pdf version).

13 AER, Draft decision for Transgrid transmission determination 2015-16 to 2018-19, Overview, November 2014 (pdf version).

14 AER, Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters, May 2009, p. 105.

13.2 Requirements of the Rules and Law

The key aspects of the NER and National Electricity Law (NEL) relating to gamma are:

- Clause 6.5.3 of the NER requires an estimate of γ (gamma), being "*the value of imputation credits*";
- Clause 6.5.2 of the NER, which relates to the rate of return, requires consistency between the approaches to estimating the rate of return and the value of imputation credits;
- As with all of its economic regulatory functions and powers, when assessing AusNet Services' proposal under the NER and NEL, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the NEO;
- To the extent the AER's decision on the value to be adopted for gamma involves the exercise of discretion, the AER must take into account the revenue and pricing principles in section 7A of the NEL.[15] The revenue and pricing principles include that a service provider should be provided with a reasonable opportunity to recover at least its efficient costs and a price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates;
- AusNet Services considers that it is clear that what is required under the NER is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the NER to determine total revenue by reference to the various specified building blocks, as well as being consistent with past regulatory practice, and previous decisions of the Tribunal;
- This is the interpretation that best achieves the NEO, as it ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or *potential* value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is commensurate to promoting efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

13.3 Proposal

AusNet Services proposes a gamma of 0.25, combining a distribution rate of 0.7 with a theta estimate of 0.35. This proposal is consistent with the expert advice of Professor Gray[16,17] and previous Tribunal findings.

The correct approach to estimating gamma, which is the approach adopted by AusNet Services in this proposal, is as follows:

- Gamma is estimated as the product of the distribution rate and the value of distributed imputation credits (theta), consistent with the requirements of the NER and NEL;
- The distribution rate is observed from ATO data, which shows the proportion of imputation credits that are distributed over time. It is widely accepted that this data shows that the economy-wide distribution rate is 0.7;
- Theta is the value of distributed imputation credits to investors, consistent with the requirements of the NER, and is estimated as using the best available market value study. Market value studies indicate the value of imputation credits to investors, as reflected in share price movements. The best estimate of theta from market value studies is 0.35;

15 NEL s 16(2)(a)(i).

16 SFG, *Estimating gamma for regulatory purposes*, February 2015, paragraph 22, p. 4.

17 NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA PowerNetworks and United Energy*, March 2015.

- Equity ownership rates and credit redemption rates can only be used to indicate the upper bound for theta, and provide a check on the final point estimate – i.e. to confirm that the point estimate is not too high. These measures indicate that the upper bound for theta is 0.43, and thus confirm that the estimate of theta from market value studies is not too high.

AusNet Services considers that its approach to determining gamma – which is fundamentally based on estimating the value of imputation credits to investors in the business – will better achieve the NEO. This approach ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or potential value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

The reason why AusNet Services is proposing a value for theta that is different to the value in the Guideline include:

- AusNet Services does not agree with the 'conceptual framework' adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence. The AER's approach is not consistent with the NEO. It does not measure the required return for the purposes of promoting efficient investment, and would lead to under investment;
- In order to provide an acceptable overall return to equity holders, theta must be estimated as the value of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment;
- There needs to be consistency in the way the parameters of the weighted average cost of capital are computed and the way gamma is computed which requires the application of relevant empirical methods to the relevant market data;
- The value for theta proposed by AusNet Services accords with what one would expect to be the additional benefit conferred by the system of imputation credits. The value of theta proposed in the Guideline does not;
- There are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the Guideline. They are, and are well recognised to be, simply unreliable. Further, a key piece of evidence used by the AER (Handley and Maheswaran (2008))[18] is not an empirical study at all (because the data was not available), but merely involves an assumption of full utilisation by domestic investors; any reliance upon it involves obvious error;
- The Tribunal has earlier concluded that redemption rates cannot be used to estimate theta (as the value of distributed credits) and that these can be used only as an upper bound check on estimates of theta obtained from the analysis of market prices;
- The only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors' valuation of imputation credits. The conceptual goalposts approach referred to by the AER provides no relevant information on the actual value of credits; and
- The best estimate of investors' valuation of imputation credits from market value studies is 0.35.

[18] John C Handley and Krishnan Maheswaran, 'A Measure of the Efficacy of the Australian Imputation Tax System', *The Economic Record*, Vol 84, No 264, March 2008.

13.4 Approach

As noted above, gamma is defined in the NER as the value of imputation credits. The initial theory upon which the NER is based was developed by Officer and the AER has asserted that its particular conceptual framework for gamma was developed by Officer but this is not in fact the case. As explained in NERA's paper[19] his 1994 paper, Officer provided two different definitions for gamma which, as a result of extensive further expert work predominantly undertaken for stakeholders and the regulators, we now know diverge from each other:

- the proportion of credits created that are redeemed; and
- the value of a dollar of tax credits created to a representative shareholder.

It is important to remember that when Officer originally published his paper with these two inconsistent definitions, the detailed market studies and tax statistic studies we have access to today had not been undertaken and he did not have any occasion to consider whether or why the two above concepts might diverge from each other.[20]

To the extent that there is any utility in trying to imagine which formulation Officer would have favoured in 1994 if he had known then what we know today, AusNet Services points out that the most obvious way to read the two together was that he was seeking the second definition (ie a value of a dollar of tax credits created to a representative shareholder) and assumed without having the detailed data and reasoning to hand, that the first concept was a means to estimate the second. More importantly, the approach that is appropriate to adopt today should take full account of the extensive expert material that has been prepared since and, as NERA explains, it is only the "value of a dollar of tax credits created to a representative shareholder" that is consistent with the way in which the equity allowance is calculated, which is to draw on market data for market parameters such as the market risk premium used when estimating the SL-CAPM.

As noted above, the relevant valuation is arrived at by taking the product of the distribution rate and the value of distributed imputation credits (theta). While the AER has taken an economy wide distribution rate in the past and in the absence of an energy network specific metric, we consider the 0.7 value to be acceptable, NERA explains[21] that this parameter can vary on a firm specific basis because it concerns the individual choices that a company may make concerning a range of factors concerning how it manages its inflow and outflow of required capital. On the other hand, the theta must be a market-wide valuation because through trading shares on a cum- or ex-dividend basis there is in effect the ability to trade distributed credits. Each of these is discussed further below.

13.4.1 Estimating the Distribution rate

The Guideline states the AER that it would apply a distribution rate (or payout ratio) of 0.7.[22] Recent empirical evidence also continues to support a distribution rate of 0.7.[23] Further the Tribunal has recently adopted a distribution rate of 0.7.[24]

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[19] NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA PowerNetworks and United Energy*, March 2015, p. i.

[20] Today we know the reasons and these are summarised in the diagrams in Figures 13.1 and 13.2 below.

[21] NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA PowerNetworks and United Energy, March 2015, p. ii.

[22] The payout ratio would be estimated using the cumulative payout ratio approach. The cumulative payout ratio is an estimate of the average payout rate from 1987, when the imputation system began, to the latest year for which tax data is available. Based on current evidence, this leads to an estimate of 0.7. AER, Better Regulation: Rate of Return Guideline, December 2013, p. 23 (pdf version).

[23] NERA, The payout ratio, June 2013.

[24] Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

Recently the AER has referred to two estimates of the distribution rate:[25]

- A market-wide distribution rate (including listed and unlisted equity) of 0.7; and
- A distribution rate for listed equity only of 0.8.

In contrast, AusNet Services considers that there are two acceptable means to reach a distribution rate: to date the AER has adopted an economy wide rate which delivers a distribution rate of 0.7 and, indeed, without knowing specifically what would drive the behaviour of a benchmark firm, this is an appropriate starting assumption. On the other hand, NERA explains that the distribution rate might better be thought of as a firm specific parameter which, on its estimates, also delivers a figure of approximately 0.7.

What would be unacceptable (as explained by NERA[26]), however, would be to take a half-way house of a subset of the firms in the economy (i.e. listed firms) without a proper basis to conclude that this subset of firms is a good proxy for the benchmark efficient firm and, indeed, such a measure would result in a distribution rate of 0.8 which diverges from the 0.7 figure established on the above two bases.

AusNet Services considers that it is neither necessary nor appropriate to separately identify a distribution rate for a limited set of listed businesses only, particularly mostly large ASX listed companies. AusNet Services notes that the distribution rate is a firm specific parameter meaning that the AER must determine the distribution rate for a benchmark efficient entity which may differ from the distribution rate for the market as a whole. As noted by NERA,[27] in determining the distribution rate, "significant weight should be placed on estimates of the rate for companies that are not large ASX-listed companies"*.*

The AER, in its 2009 WACC Review Final Decision, provides an analysis of the characteristics of a benchmark efficient entity and states that "…the AER does not agree that a benchmark efficient NSP be defined as a large, stock market listed NSP"[28].

Associate Professor Lally, in a report, states that he favours the inclusion of listed and unlisted firms in the dataset for measuring market parameters where possible.[29]

It is true that some other parameters are estimated using data for listed equity only – for example theta, the MRP and beta are all measured using data for listed equity only. However as noted by Lally, this is only done as a matter of practicality – data is more widely available for listed firms, and in some cases the relevant data for unlisted firms is either unavailable or inadequate.[30]

In the case of the distribution rate however, there is objective and reliable data on the proportion of credits distributed for both listed and unlisted businesses.[31]

The AER's definition of the benchmark efficient entity is also not confined to listed entities only. The AER's conceptual definition of the benchmark entity is a pure play, regulated energy network business operating within Australia.[32] Therefore there is no conceptual basis to confine the dataset for estimating the distribution rate to listed equity. In fact, in its 2009 WACC Review Final Decision, the AER stated that it "does not agree with that a benchmark efficient NSP be defined as a large,

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[25] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, pp. 14 – 15 (pdf version).

[26] NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Powercor, SA PowerNetworks and United Energy, March 2015, pp. 12-20.

[27] Ibid, pp. 12-13.

[28] AER, Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameter, May 2009, p. 105.

[29] M Lally, Review of submissions to the QCA on the MRP, risk-free rate and gamma, 12 March 2014, p. 34.

[30] Ibid.

[31] While there are some concerns as to the reliability of the ATO data in relation to imputation credit redemption, the ATO data on distribution of credits is reliable, and produces stable estimates of the distribution rate over time.

[32] AER, Better Regulation: Rate of Return Guideline, December 2013, p. 7.

stock market listed NSP".[33] Therefore, there is no reason why consideration should be restricted to listed equity only.

Professor Gray further notes that even if the dataset were to be limited to listed entities, the AER's estimate of 0.80 is likely to be overstated to the extent that foreign-sourced income enables large listed companies to distribute a higher proportion of imputation credits (compared to the benchmark efficient entity, which is assumed to have no access to foreign-sourced income). Professor Gray concludes that there is no reasonable basis to adopt a distribution rate of 0.80, even if the data is restricted to listed firms only.[34] SFG Consulting estimates the distribution rate:

- for a public company to be 0.75;
- for public companies that are not top-20 ASX listed to be 0.70; and
- for private companies to be 0.50.

Accordingly, the market-wide distribution rate of 0.70 should be applied. It would be an error to apply a higher distribution rate based on data from a limited set of businesses.

13.4.2 Value of distributed credits (theta)

(a) Definition of theta

AusNet Services notes that the AER has recently adopted a different definition of theta to that adopted in the Rate of Return Guideline.

In the Guideline, the AER defined theta as:

> *"…the extent to which investors can use the imputation credits they receive to reduce their personal tax."*[35]

This approach implies that gamma would only measure the proportion of total company tax payments accounted for by imputation credits that are redeemed (or that can be redeemed) by investors. Such an approach would have been contrary to the requirements of the NER and a departure from conventional regulatory practice which is to define gamma as the *value* of imputation credits to investors.

The AER appears to recognise that theta should reflect the value of imputation credits to investors, not just the proportion of credits that are redeemed or that can be redeemed by investors. The AER defines theta as:

> *"the utilisation value to investors in the market per dollar of imputation credits distributed."*[36]

The "utilisation value" definition is consistent with the advice provided to the AER by Associate Professor Handley. Handley's report states (under the heading *Interpretation of the 'Second Parameter'*):

> *"It is clear from Monkhouse (1996) that the second parameter refers to the utilisation value of a distributed imputation credit. This parameter is commonly denoted and called theta θ. It is also clear from the post-tax basis of the regulatory framework (and the Officer and Monkhouse WACC frameworks) that the item of interest is more precisely described as the after-company-before-personal-tax utilisation value of a distributed imputation credit."*[37]

33 AER, Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters, May 2009, p. 105.

34 SFG, Estimating gamma for regulatory purposes, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy, February 2015, paragraph 224, p. 47.

35 AER, Better Regulation: Explanatory Statement Rate of Return Guideline, December 2013, p. 159 (pdf version).

36 See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 17 (pdf version).

37 John C Handley, Advice on the Value of Imputation Credits, 29 September 2014, p. 17.

Handley also observes that:[38]

> *"Implicit in Officer's WACC framework (and the standard classical WACC framework) is the notion of market value and so the relevant measure of utilisation value is that value as determined by the market."*

However, the AER qualifies this definition by noting that, consistent with the building block framework, theta should reflect the *before-personal-tax and before-personal-costs value* of imputation credits to investors.[39] The AER then says that this qualified version of its definition of theta is practically equivalent to the definition adopted in its Guideline, because once the effects of personal tax and personal costs are excluded, an investor that is eligible to fully utilise imputation credits should value each dollar of imputation credits received at one dollar.[40] There are two difficulties with this. The first is that, as discussed below, there are good reasons why investors will not value each dollar of imputation credits received at one dollar. The second is that there is no proper basis for excluding the effects of personal tax and costs.

The AER's new qualified definition of theta is novel. AusNet Services is not aware of theta previously being defined as the *before-personal-tax and before-personal-costs value* of imputation credits to investors. It is certainly true that theta must reflect the value of imputation credits to investors. However, it is unusual for theta to be defined in a way that excludes the effect of certain factors that may impact on value (and which will be reflected in market value measures), such as personal costs.

AusNet Services does not agree with the AER's revised definition of theta (i.e. the qualified version which ignores the effects of personal costs and taxation). While AusNet Services agrees that theta must reflect the value of distributed imputation credits, we do not agree that this value should be assessed before the effects of personal costs and taxation.

As stated in the expert report of Professor Gray, gamma (and therefore theta) must reflect the value of imputation credits to investors. AusNet Services considers that this is clear from the words of the NER themselves, which refer to the "value of imputation credits". Further, this approach to estimating gamma (and theta) will best promote the NGO, as it provides for overall returns which promote efficient investment.

As noted by Professor Gray:[41]

> *"Under the building block approach, the regulator makes an estimate of gamma and then reduces the return that is available to investors from dividends and capital gains from the firm accordingly. In my view, it is clear that this is consistent with a value interpretation. If the value of foregone dividends and capital gains is greater than the value of received imputation credits, the investors will be left under-compensated, and vice versa."*

If the value of imputation credits is assessed before personal costs and taxation (i.e. ignoring these costs to investors), the overall return to equity-holders will be less than what is required to promote efficient investment. Quite simply, there will be certain costs incurred by investors – such as transactions costs involved in redeeming credits – which are not accounted for.

The value of imputation credits to investors will necessarily reflect (and will be net of) any transactions costs or other personal costs incurred in redeeming credits. Such costs cannot simply be assumed away. If such costs are assumed away, then the resulting estimate of theta (and therefore gamma) will overstate the true value of imputation credits to investors.

38 Ibid, p. 9.

39 See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 36. (pdf version).

40 Ibid.

41 SFG Consulting, Estimating gamma for regulatory purposes, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy, February 2015, paragraph 12, p. 2.

Therefore, AusNet Services proposes that the estimate of theta must simply reflect the value of imputation credits to investors. It would be an error to seek to estimate theta as a hypothetical before-personal-tax and before-personal-costs value.

(b) Types of evidence relied on by the AER to estimate theta

There are three types of evidence relied on by the AER in relation to theta. These are, in order of weight given by the AER:

- Equity ownership rates (i.e. the share of Australian equity held by domestic investors);
- Redemption rates from tax statistics; and
- Market value studies.

The AER no longer relies on the 'conceptual goalposts' method, which is referred to in the Rate of Return Guideline. Associate Professor Handley advises that the conceptual goalposts approach is not a reasonable approach. [42]

This section will address the relevance of each of the forms of evidence relied on by the AER recently, in terms of their relevance to the task of estimating the value of imputation credits to investors.

(i) Equity ownership rates

The AER relies on the equity ownership approach as direct evidence of the value of distributed imputation credits. The AER states that its estimate of the value of distributed imputation credits "primarily reflects" the evidence from the equity ownership approach. [43]

In relying on equity ownership rates as direct evidence of the value of distributed imputation credits, the AER at least implicitly assumes that:

- All domestic investors are eligible to utilise imputation credits, while foreign investors are not (**Assumption 1**); and
- Eligible investors (i.e. domestic investors) value imputation credits at their full face value because each dollar of imputation credits received can be fully returned to them in the form of a reduction in tax payable (**Assumption 2**). [44]

Both of these assumptions are incorrect.

Assumption 1 is known to be incorrect due to certain tax rules which prevent redemption of credits by domestic investors in some circumstances. In particular, as has been acknowledged by the AER, the 45-day holding rule affects the eligibility of short-term investors to claim imputation credits.[45]

The AER has sought to dismiss the impact of tax rules affecting eligibility of domestic investors to redeem imputation credits by saying that:[46]

> *"…we do not consider that there is clear evidence as to effect that these rules have or should be expected to have."*

Even if this statement was correct (which it is not), AusNet Services does not consider that there must be "clear evidence" as to the effect of particular tax rules in order for these to render equity ownership an inappropriate measure. The fact is that these rules exist and they will affect the

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[42] John C Handley, Advice on the Value of Imputation Credits, 29 September 2014, p. 31.

[43] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 13 (pdf version).

[44] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 18. (pdf version).

45 Ibid, p. 53 (pdf version).

46 Ibid, p. 53 (pdf version).

eligibility of certain domestic investors to redeem imputation credits, and therefore mean that theta cannot be equated to the rate of domestic ownership.

In any event, the fact that the redemption rate indicated by tax statistics is significantly below the domestic equity ownership rate strongly indicates that these tax rules (and possibly other factors as discussed below) are affecting domestic investors' ability to redeem imputation credits. The redemption rate indicated by tax statistics is approximately 0.43, which is well below the domestic equity ownership rate for all equity.

As for Assumption 2, there are a number of reasons why even eligible investors will not value imputation credits at their full face value. These include transactions costs associated with the redemption of imputation credits and portfolio effects (discussed below).

Given that neither of these assumptions hold, equity ownership rates cannot be used as direct evidence of the value of distributed imputation credits. Equity ownership rates will only indicate the maximum set of investors who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on imputation credits. Certainly theta cannot be higher than the domestic equity ownership rate, since foreign investors cannot place any value on imputation credits. However the domestic equity ownership rate cannot be used as direct evidence of the value of imputation credits, because it does not account for the fact that:

- some domestic investors may be ineligible to redeem imputation credits; and
- even eligible investors will not value imputation credits at their full face value.

Therefore, concluding that equity ownership rates are direct evidence of the value of imputation credits (or evidence from which a value can be inferred) and in giving these measures the primary role in the determination of a point estimate for theta would be erroneous.

(ii) Tax statistics

The AER also appears to have relied on redemption rates from tax statistics as direct evidence of the value of distributed imputation credits. In particular that it has placed "some reliance" on tax statistics in estimating theta, but less reliance than is placed on equity ownership rates.[47]

Redemption rates from tax statistics will be closer to the true value of imputation credits than domestic equity ownership rates. This is because redemption rates account for certain factors impacting on the value of imputation credits which are not accounted for in the domestic equity ownership rate – for example, redemption rates will reflect the fact that some domestic investors are not eligible to redeem credits due to the 45-day holding rule, and that some investors face costs and other barriers that deter them from utilising imputation credits.

However, redemption rates from tax statistics also cannot be used as direct evidence of the value of distributed imputation credits, because redemption rates do not take into account the fact that investors may value redeemed credits at less than their full face value. There are a number of reasons why investors will not value imputation credits at their full face value, including:

- Transactions costs. Transactions costs associated with redemption of credits may include requirements to keep records and follow administrative processes. This can be contrasted with realisation of cash dividends, which are paid directly into bank accounts. The transactions costs associated with redemption of imputation credits will tend to reduce their value to investors (meaning that the value of credits redeemed will be less than their face value) and may also dissuade some investors from redeeming credits (thus reducing the redemption rate);
- Time value of money. There will typically be a significant delay (which can be years) between credit distribution and the investor obtaining a tax credit. This may be a period of

47 See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 17 (pdf version).

several years in some cases, for example where credits are distributed through other companies or trusts, or where the ultimate investor is initially in a tax loss position. Over this period, the value of the imputation credit to the investor may be expected to diminish, due to the time value of money;

- Portfolio effects. Portfolio effects refer to the impact of shifting the investor's portfolio away from the optimal construction (including overseas investments) in order to take advantage of imputation. An investor who would otherwise invest overseas (to get a better return from the overall portfolio) might choose instead to make that investment in Australia to obtain the benefit of an imputation credit. This reallocation of portfolio investment would tend to continue with the relevant imputation credit having less and less marginal value until an equilibrium is reached with the credit having no additional value: that is, on average, the value of the imputation credits will be less than the face value. To the extent that an investor reduces the value of their overall portfolio simply to increase the extent to which they can redeem imputation credits, this lost value will be reflected in a lower valuation of the imputation credits. These portfolio effects are further explained in the expert report of Professor Stephen Gray.

Redemption rates from tax statistics can only indicate the upper bound for theta. Theta clearly cannot be higher than the proportion of credits that are redeemed by investors, since credits that will never be redeemed have no value. However, theta may be (and for reasons referred to above, is likely to be) less than the redemption rate.

Therefore giving redemption rates a direct role in the determination of a point estimate for theta would be in error.

(iii) Market value studies

The AER places 'less weight' on market value studies, as it considers that these studies have a number of limitations.

The limitations identified by the AER recently are:[48]

- The results of these studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the utilisation rate;
- These studies can produce nonsensical estimates of the utilisation rate – that is, greater than one or less than zero;
- The results of these studies might not be reflective of the value of imputation credits to investors in the market as a whole;
- These studies can be data intensive and employ complex and sometimes problematic estimation methodologies; and
- Regarding dividend drop off studies, it is only the value of the combined package of dividends and imputation credits that can be observed in the market, and there is no consensus among experts on how to separate the value to the market of dividends from the value to the market of imputation credits (this is referred to as the 'allocation problem').

In effect, the AER is raising two concerns in relation to market value studies:

A. Whether market value studies are measuring the right thing (reflected in the first point above); and

B. Whether the methodology employed in dividend drop-off studies is sufficiently robust such that these studies will accurately measure that thing (reflected in the other four points).

Each of these concerns is addressed below.

[48] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 22 (pdf version).

A. Are market value studies measuring the right thing?

The first concern flows from the AER's conceptual definition of theta, which seeks to exclude the effects of personal taxes and personal costs. Since market values will reflect the impact of personal costs and taxation, the AER considers that a market value approach may not be compatible with its revised definition of theta.

As noted above, AusNet Services does not agree with the AER's revised definition of theta (i.e. the qualified version which ignores the effects of personal costs and taxation). Theta must reflect the value of distributed imputation credits to investors, which will necessarily reflect (and will be net of) any transactions costs or other personal costs incurred in redeeming credits.

If the conventional definition of theta is adopted – i.e. defining theta as the value of distributed imputation credits to investors – then use of market value studies is entirely compatible with this definition. Market value studies will reflect the value of imputation credits to investors, as reflected in market prices for traded securities.

Indeed, of the three approaches that have been identified by the AER to estimate theta, an approach based on market value studies is the only approach that is entirely compatible with a definition of theta that is consistent with the NER. As discussed above, both equity ownership rates and redemption rates from tax statistics will overstate the true value of theta, since they will not reflect certain factors which affect the value of imputation credits to investors.

Use of market value studies – and more generally, the adoption of a market value measure – is also consistent with how other rate of return parameters are estimated.[49] Other rate of return parameters such as the market risk premium and debt risk premium are estimated based on the return required by investors as reflected in market prices. The market value measures of these parameters are not adjusted to account for personal costs or other factors which may be reflected in market prices.

B. Do market value studies accurately measure that thing?

The AER has listed several methodological concerns with dividend drop-off studies, several of which are not relevant to the particular study relied on by AusNet Services.

In particular, the AER's concern about 'nonsensical results' clearly does not apply to Professor Gray's dividend drop-off study. Professor Gray's study produces a theta estimate of 0.35, which is an entirely sensible result given that:

- It is within the theoretical bounds for theta (i.e. it is between zero and one);
- It is below the domestic equity ownership rate for both listed equity (0.44) and all equity (0.59). As noted above, the domestic equity ownership rate indicates the maximum set of investors who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on imputation credits, and therefore it may be expected that the value for theta would be below this figure;
- It is also below the redemption rate indicated by tax statistics (0.43). Again, this may be expected given that redemption rates will indicate the upper bound for theta and do not capture certain factors affecting value, such as the time value of money, transaction costs and portfolio effects.

Indeed, the result of the SFG study is consistent with the other evidence and a result that is to be expected in light of that evidence.

Similarly, the AER's concern about 'problematic estimation methodologies' may apply to ***some*** market value studies but does not apply to the particular study relied on by AusNet Services. The methodology used in Professor Gray's study is the product of a consultative development process involving the AER and several regulated businesses and overseen by the Tribunal in the *Energex* review. The methodology used in Professor Gray's study was designed specifically to overcome

49 As noted above, the NER requires the rate of return and the value of imputation credits to be *measured* on a consistent basis (NER, clause 6.5.2(d)(2)).

methodological shortcomings of previous studies (e.g. shortcomings in the methodology employed by Beggs and Skeels (2006), which were identified by the Tribunal in the *Energex* review). In accepting the conclusions of Professor Gray's study, the Tribunal expressed confidence in those conclusions in light of the careful scrutiny to which the methodology had been subjected, and the way in which it had been designed to overcome shortcomings of previous studies.[50]

Professor Gray notes that the dividend drop-off literature has evolved over time, and that the SFG studies use current state-of-the-art techniques. Professor Gray explains:[51]

> *"In relation to dividend drop-off studies, I first note that the dividend drop-off literature has evolved over time, as do all areas of scientific investigation. This evolution has seen the development of different variations of the econometric specification, different variations of regression analysis, and different types of sensitivity and stability analyses. It has also seen material growth in the available data. The SFG studies use the latest available data, and they apply a range of econometric specifications, regression analysis and sensitivity and stability analyses that have been developed in the literature. The SFG estimate of 0.35 is based on this comprehensive analysis. It is not as though the SFG studies use one of the reasonable approaches and other studies use different reasonable approaches. The SFG studies are comprehensive state-of-the-art studies."*

Box 1 below outlines the process by which the methodology used in Professor Gray's study was developed, and the conclusions of the Tribunal in relation to that methodology. In light of this, it cannot be said that Professor Gray's study shares the same methodological issues as previous market value studies. Rather, this study was specifically designed to overcome the shortcomings of previous studies.

[50] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [22].

[51] SFG, Estimating gamma for regulatory purposes, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy, February 2015, paragraph 177, p. 36.

Box 1: Key conclusions of the Tribunal in *Energex* in relation to the SFG methodology

In *Application by Energex Limited (No 2)* [2010] ACompT 7, the Tribunal had before it two market value studies which produced different estimates of theta – a study by Beggs and Skeels (2006) and a study by SFG (2010) which sought to replicate the Beggs and Skeels (2006) methodology. The Tribunal identified shortcomings in the methodology used in both studies and observed that the results of both studies should be treated with caution.

The Tribunal therefore sought a new "state-of-the-art" dividend drop-off study.[52] To this end, the Tribunal directed that the AER seek a re-estimation by SFG of theta using the dividend drop-off method, but without the constraint that the study replicates the Beggs and Skeels (2006) study. The Tribunal encouraged the AER to seek expert statistical or econometric advice to review the approach prior to the estimation proceeding and to consider any possible enhancements to the dataset. It was said that the new study should employ the approach that is agreed upon by SFG and the AER as best in the circumstances.

The terms of reference for the new study were settled between the AER and the businesses involved in the Energex review (Energex, Ergon and ETSA Utilities), with oversight from the Tribunal. The AER and the businesses also had the opportunity to comment on a draft of the report, and SFG's responses to those comments are incorporated in the final report.

In submissions to the Tribunal, the AER raised eight "compliance" issues with the final SFG (2011) study – these were perceived issues of non-compliance by SFG with the agreed terms of reference. The Tribunal was not concerned by any of these issues and considered that they raised no important or significant questions of principle. The Tribunal concluded that any departures from the agreed terms of reference were justified, or even necessary and observed that calling them "major compliance issues" was unnecessarily pejorative.[53]

The Tribunal was ultimately satisfied that the procedures used by SFG (2011) to select and filter the data were appropriate and did not give rise to any significant bias in the results obtained from the analysis. It was also not suggested by the AER that the data selection and filtering techniques had given rise to any bias.[54]

In relation to the model specification and estimation procedure, the Tribunal concluded:[55]

> *"In respect of the model specification and estimation procedure, the Tribunal is persuaded by SFG's reasoning in reaching its conclusions. Indeed, the careful scrutiny to which SFG's report has been subjected, and SFG's comprehensive response, gives the Tribunal confidence in those conclusions. In that context, the Tribunal notes that in commissioning such a study, it hoped that the results would provide the best possible estimates of theta and gamma from a dividend drop-off study. The terms of reference were developed with the intention of redressing the shortcomings and limitations of earlier studies as far as possible."*

Ultimately, the Tribunal was satisfied that the SFG (2011) study was the best study available at that time for the purposes of estimating gamma in accordance with the Rules.[56] The Tribunal did not accept the submission of the AER that either minor issues in the construction of the database or econometric issues would justify giving the SFG study less weight and earlier studies some weight.

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52 Application by Energex Limited (No 2) [2010] ACompT 7, [146]-[147].

53 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [18].

54 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [19].

55 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [22].

56 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [29].

The other two issues that have been identified by the AER – the allocation problem, and the possibility that results of these studies might not be reflective of the value of credits to investors in the market as a whole – have previously been considered and addressed by Professor Gray. These issues are again addressed in Professor Gray's most recent report[57] are in relation to:

- Whether estimates reflect the value of credits to investors in the market as a whole, and whether there may be some impact on the theta estimate from 'abnormal trading' around ex-dividend day, Professor Gray notes that to the extent this effect is material it would result in the dividend drop-off (and therefore the theta estimate) being higher than it otherwise would be.[58] This is because any increase in trading around ex-dividend day would be driven by a subset of investors who trade shares to capture the dividend and imputation credit and who are therefore likely to value imputation credits highly (i.e. higher than the average investor). These investors tend to buy shares shortly before payout of dividends (which pushes up the share price) and tend to sell shortly after (which pushes down the share price), the overall effect of which is to increase the size of the price drop-off;
- The allocation issue, Professor Gray notes that empirical evidence provides a very clear and consistent view of the combined value of cash and imputation credits.[59] This evidence indicates that the combined value is one dollar. The relevant evidence includes the recent studies by SFG (2011 and 2013) and Vo et al (2013). Allocation can be made based on this clear evidence as to combined value of the cash/credit package.

In summary, the general set of 'limitations' referred to by the AER do not provide a justification for placing limited weight on the particular market value study relied on by AusNet Services. Several of the general limitations do not apply to the SFG study that is relied on by AusNet Services, and the other concerns have been comprehensively addressed by Professor Gray.[60]

The AER's approach to considering market value studies – which involves simply identifying limitations which ***may*** apply to these studies in general, without considering whether those limitations apply to the particular study relied on by AusNet Services – is illogical and unreasonable. Without considering whether the potential limitations it has identified actually apply to the SFG study, the AER cannot reasonably form a view that this study is unreliable or should be given limited weight.

Accordingly, be placing only limited weight on all market value studies in estimating theta the AER will have erred and AusNet Services considers that approach to be incorrect. Market value studies that are methodologically robust – in particular the SFG study – can and should be used as direct evidence of the value of imputation credits.

13.4.3 Estimates of theta

(a) Estimates for equity ownership rate relied on by the AER

The AER has recently relied on ranges, AusNet Services considers that the AER has erred in its construction of these ranges and continued application of this process would be a mistake.

The AER has recently concluded that a reasonable estimate of the equity ownership rate is between:

- 0.55 and 0.7, if all equity is considered; and

57 SFG, Estimating gamma for regulatory purposes, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy, February 2015, paragraph 185, p. 38.

58 SFG, An appropriate regulatory estimate of gamma, Report for Jemena Gas Networks, ActewAGL, APA, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), ENERGEX, Ergon, Transend, TransGrid and SA Power Networks, May 2014, paragraphs 150-153, pp. 31-32.

59 SFG, An appropriate regulatory estimate of gamma, Report for Jemena Gas Networks, ActewAGL, APA, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), ENERGEX, Ergon, Transend, TransGrid and SA Power Networks, May 2014, paragraphs 158-163, pp. 32-33.

60 SFG, An appropriate regulatory estimate of gamma, Report for Jemena Gas Networks, ActewAGL, APA, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), ENERGEX, Ergon, Transend, TransGrid and SA Power Networks, May 2014, paragraphs 150-153, pp. 31-32.

- 0.4 and 0.6, if only listed equity is considered.

However, these ranges were not supported by the AER's analysis of equity ownership statistics. The AER's analysis – based on a refinement of the ABS dataset to focus on types of equity considered most relevant to the benchmark entity – indicates:[61]

- The equity ownership rate for listed equity is currently around 0.44[62], and it has averaged approximately 0.43 over the past five years. At no time since June 1988 (the period covered by the ABS dataset) has the equity ownership rate for listed equity reached 0.60, and for most of that period it has remained below 0.50. In other words, there is no support for the upper end of the AER's 0.4 to 0.6 range and the 0.6 must be reduced even adopting the data sources for which AER advocates; and
- The equity ownership rate for listed and unlisted equity is currently around 0.59, and it has averaged approximately 0.57 over the past five years. At no time since June 1988 (the period covered by the ABS dataset) has the equity ownership rate for all equity reached 0.70, and on only a few occasions has it exceeded 0.60. Again there is insufficient evidence to support an upper bound to the range as high as 0.70.

The table below shows the domestic equity ownership rate as at September 2014 (the most recent period for which data is available) and at the same time in each of the previous four years. This shows the proportion of the equity stock held by domestic investors at the relevant points in time, for listed and all equity respectively. These calculations are based on the AER's refined methodology, as recently described.[63]

Table 13.12: Domestic equity ownership rate, based on AER refined methodology

	Listed equity	All equity
September 2010	0.45	0.57
September 2011	0.39	0.55
September 2012	0.40	0.56
September 2013	0.44	0.59
September 2014	0.44	0.59

Source: ABS, Australian National Accounts: Finance and Wealth, September 2014 (Cat no. 5232.0), table 47, 48.

To the extent that equity ownership rates are relevant at all to the estimation of theta, the only relevant measure is the current domestic equity ownership rate – that is, the proportion of the equity stock currently held by domestic investors. The current equity ownership rate indicates the maximum proportion of current investors in the benchmark business who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on those credits. Historical equity ownership rates are of no relevance in the context of considering the eligibility of current investors to redeem imputation credits.

It is not appropriate to simply refer to a wide range of estimates for the equity ownership rate based on historical data, in circumstances where the current rate is clearly observable. Such an approach would be in error.

[61] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 57 (pdf version).

[62] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 59, footnote 197 (pdf version).

[63] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 56 (pdf version).

If equity ownership rates are to be used, a current point estimate must be observed from the ABS dataset. As noted above, the AER's analysis indicates that the current domestic equity ownership rate is 0.44 for listed equity and 0.59 for all equity.

(b) Estimate from tax statistics

As explained above, tax statistics can provide an upper bound to the theta value but not a point estimate. The AER has observed that the redemption rate from tax statistics is 0.43, based on analysis by Hathaway. However the AER also states that tax statistics "*support an estimate of the utilisation rate between 0.4 and 0.6*".[64]

As is clear from the analysis of the AER, and from the Hathaway paper referred to by the AER, tax statistics clearly support a point estimate for the redemption rate of 0.43 (paired with a distribution rate of 0.7). Given the AER's adoption of a distribution rate of 0.7, the only redemption rate estimate that would be consistent with this is 0.43.

It would be an error to adopt a redemption rate any higher than 0.43, based on either the Handley and Maheswaran (2008) study or Hathaway's alternative estimate of 0.61. This is because:

- The Handley and Maheswaran (2008) study cannot be relied on for an empirical estimate of the redemption rate for the post-2000 period. As is clear from that study, for the period 2001-2004 (the period for which the AER has previously relied on this study), the authors do not provide any empirical estimate of the redemption rate. Rather, Handley and Maheswaran simply make an assumption that all credits received by individuals and funds will be used. Therefore, the Handley and Maheswaran study **is not an empirical measure of redemption rates for the relevant period**. This has been pointed out to the AER since the *Energex* proceedings, and the AER should desist from erroneously using Handley and Maheswaran for this purpose;[65]
- Hathaway's alternative estimate of 0.61 corresponds to a distribution rate of around 0.5, whereas the AER adopts a distribution rate of 0.7.[66]

AusNet Services is concerned by the use of redemption rates from tax statistics, for the purposes of estimating theta, including because the redemption rate is necessarily an upper bound for theta rather than a measurement of theta. Redemption rates from tax statistics cannot be used as direct evidence of the value of distributed imputation credits, because redemption rates do not take into account the fact that investors may value redeemed credits at less than their full face value.

However, if redemption rates from tax statistics are to be used to indicate an upper bound for theta, the appropriate point estimate for the redemption rate is 0.43.

(c) Estimates from market value studies

The AER has recently considered that market value studies support a range for theta of between zero and one.[67]

Underpinning this position appears to be a view that all market value studies should be given equal (or similar) weight, regardless of:

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[64] See for example, AER, Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, November 2014, p. 56 (pdf version).

[65] John C Handley and Krishnan Maheswaran, 'A Measure of the Efficacy of the Australian Imputation Tax System', The Economic Record, Vol 84, No 264, March 2008, pp. 82-94. The authors note, at pp. 86-87, that for resident individuals and resident funds they have assumed zero Excess Credits (i.e. 100% usage of credits received) for the years 2001-2004, "consistent with investor rationality". This is reflected in Table 4, where the utilisation rate for resident individuals and resident funds is set to 1.00 for each of the years 2001-2004.

[66] See for example, AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, November 2014, p. 59 (pdf version). As noted in the AER Draft decision, Hathaway's calculations actually suggest estimates of the utilisation rate of 0.44 and 0.62 and corresponding estimates of the distribution rate of 0.69 and 0.49, respectively. However, the AER rounds these distribution rate estimates up to 0.7 and 0.5, which implies slightly higher amounts of credits distributed and therefore slightly lower utilisation rates of 0.43 and 0.61.

[67] See for example, AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, November 2014, p. 56 (pdf version).

- The time period for estimation (including whether the study relates to the period before or after changes to the tax law in 2000);
- Robustness of the methodology; and
- Quality of data and filtering techniques.

This is an erroneous and unreasonable approach to consideration of market value studies. AusNet Services proposes a specific value for theta based on a particular study, and this is not just any study, for the reasons set out above. It is not sufficient for the AER to consider a wide range of estimates produced by market value studies, without considering the relative merits of the various studies (and in particular, the merits of the SFG study relied on by AusNet Services).

As the AER is aware, many of the earlier market value studies have methodological shortcomings and rely on very old data. As explained above, the SFG study relied on by AusNet Services was specifically designed to overcome the shortcomings of previous studies. In particular, the methodology used in the SFG study:

- Was designed, at the request of the Tribunal, to overcome shortcomings in previous studies (particularly the Beggs and Skeels (2006) study);
- Was the product of a consultative process involving the AER; and
- Relies on more recent data than previous studies.

In effect, the SFG study was designed to supersede previous studies, both in terms of its methodology and the currency of the underlying data.

As noted above, the SFG study was found by the Tribunal (at the time of its May 2011 decision in *Energex*) to be "*the best dividend drop-off study currently available*".[68] The Tribunal also did not accept the submission of the AER that either minor issues in the construction of the database or econometric issues justified giving the SFG study less weight and earlier studies (particularly the previous Beggs and Skeels (2006) study) some weight. The Tribunal observed that "*the Beggs and Skeels study, despite not being subjected to anything like the same level scrutiny [sic], is known to suffer by comparison with the SFG study on those and other grounds*".[69]

AusNet Services is not aware of any more recent study (apart from Professor Gray's updated study, using the same methodology) which is more robust or is more likely to provide a better estimate of theta.[70]

Unlike the Tribunal in *Energex*, the AER in its Draft Decision gives no consideration to the relative strengths and weaknesses of the available market value studies. Rather, the AER has simply grouped all market value studies together and referred to a range of estimates emerging from this broad group.

It would be unreasonable for the AER to simply adopt a wide range of estimates from market value studies and to criticise such studies as a group, without having regard to the relative strengths and weaknesses of each study. In considering the appropriate estimate for theta from market value studies, the AER must consider which of these studies are most appropriate having regard to factors such as the robustness of their methodology and currency of data.

[68] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [29].

[69] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [29].

[70] There is one other more recent study by Vo et al, Estimating the market value of franking credits: Empirical evidence Australia, April 2013. This study adopts a methodology similar to SFG (2011) and SFG (2013), except that additional methodological permutations are run, including to exclude the standard market adjustment (as explained by SFG, the standard market adjustment is a simple adjustment made in most dividend drop-off studies to remove the effect of movements in the broader market). The results of the Vo et al (2013) study with the standard market adjustment are consistent with those reported by SFG, while the result without the standard adjustment is higher. However, as previously explained, the results without the adjustment will be biased due to exogenous factors which may be driving the broader market over the ex-dividend day.

AusNet Services maintains its view that the best estimate of theta from market value studies is 0.35. This reflects the output of the best dividend drop-off study currently available.

Lally / Handley adjustment to estimates from dividend drop-off studies

The AER has recently referred to the adjustment to dividend drop-off estimates of theta proposed by Associate Professor Lally and referred to by Handley. This adjustment is said to account for factors such as personal taxes and risk which mean that cash (and by implication credits) will be valued at less than face value.

This adjustment to dividend drop-off estimates of theta is unnecessary and inappropriate. As explained above, in valuing imputation credits, personal costs which may affect the value investors place on imputation credits cannot be ignored or assumed away. Accordingly, any adjustment to exclude the impact of these factors would be inappropriate and would lead to overestimation of the true value of imputation credits to investors.

The AER's recent draft decisions (depicted in the table below) have recently concluded that a reasonable estimate of the value of imputation credits is in the range 0.30 to 0.50, and that a reasonable point estimate for gamma is 0.40.

Table 13.2: Draft decision estimates of gamma based on redemption rate re-definition of theta

Estimation Approach	Theta	F	Gamma
Equity ownership (all equity)	0.55 – 0.70	0.70	0.39 – 0.49
Tax statistics (all equity)	0.43	0.70	0.30
Equity ownership (listed equity)	0.40 – 0.60	0.80	0.32 – 0.48

Given the values adopted by the AER for the distribution rate this implies:

- For listed equity, a theta estimate of 0.50 (i.e. 0.40 divided by 0.80); and
- For all equity, a theta estimate of 0.57 (i.e. 0.40 divided by 0.70).

This conclusion is clearly inconsistent with the evidence presented recently to the AER, including the AER's own analysis of the empirical data.

The evidence presented recently demonstrates that:

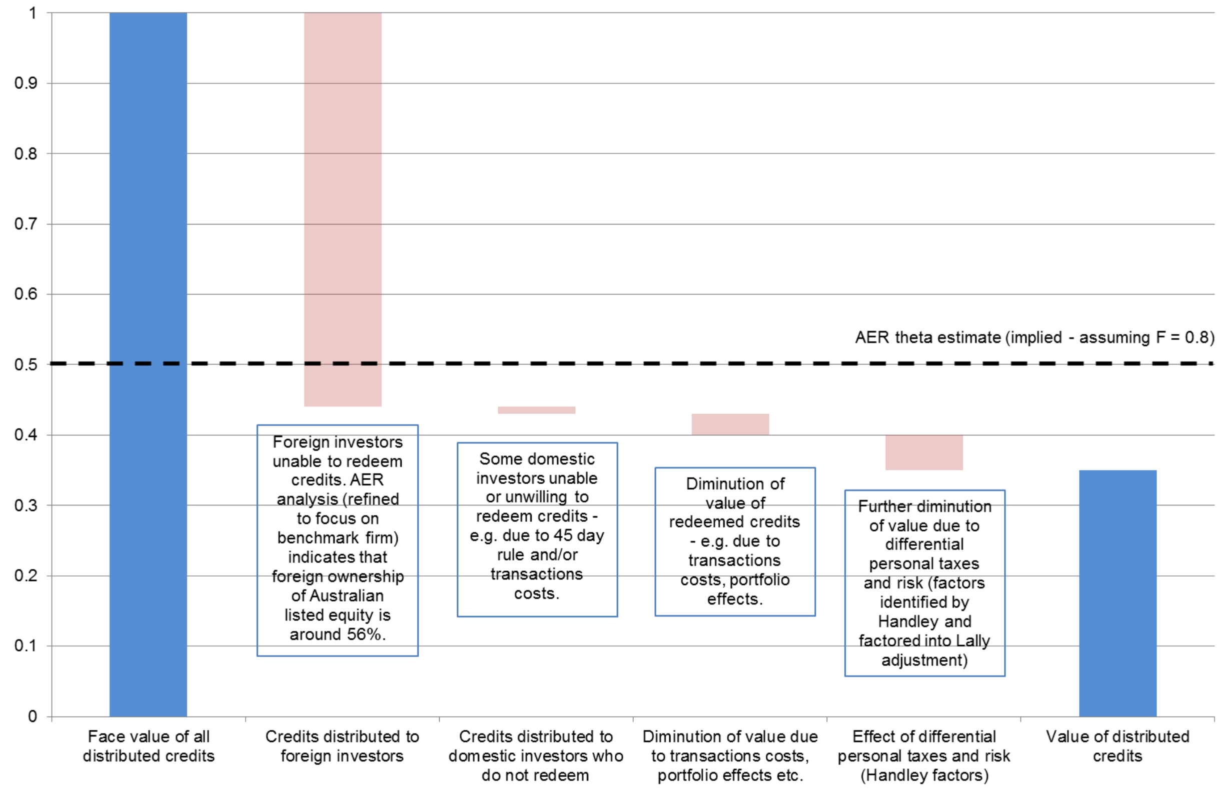
- The current domestic equity ownership rate is 0.44 for listed equity and 0.59 for all equity. This means that the maximum set of investors who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on imputation credits is 44% of listed equity investors and 59% of all equity investors. This implies that a theta a value of 0.5 for listed equity cannot be correct – theta cannot be higher than 0.44 for listed equity and will in fact be lower than this for the reasons explained above;
- The redemption rate estimate using tax statistics is 0.43 for all equity consistent with a distribution rate of 0.7. While tax statistics do not show the redemption rate for listed equity only, it is likely that this will be lower than 0.43, due to higher foreign ownership of listed equity. This means that the upper bound for theta is 0.43 (corresponding to a distribution rate of 0.7), and will likely be lower for listed equity. This implies that a theta value of 0.5 for listed equity and 0.57 for all equity cannot be correct;
- The value of imputation credits to investors – as indicated by market value studies – is in fact 0.35.

In order to illustrate the key implications of the empirical evidence, AusNet Services proposes an analysis of the data for listed equity (see figure below) reflecting the AER's updated approach. This reflects the data for listed equity, including:

- A domestic equity ownership rate of 0.44;
- A redemption rate of 0.43 (although as noted above, the redemption rate for listed equity investors is likely to be lower than 0.43, due to higher foreign ownership);
- A market value estimate excluding the effects of differential personal taxes and risk (i.e. with the Handley / Lally adjustment) of 0.40; and
- A market value for imputation credits of 0.35.

This shows that the AER's implied theta estimate for listed equity (0.57) is well above any possible measure of the value of distributed imputation credits.

Figure 13.1: Illustrative impact on value of imputation credits – listed equity



Note:

(1) the proportion of credits distributed to foreign investors is set equal to 0.56, based on the current foreign equity ownership rate (as at September 2014), calculated using the AER's refined methodology (refer to Table 13.1);

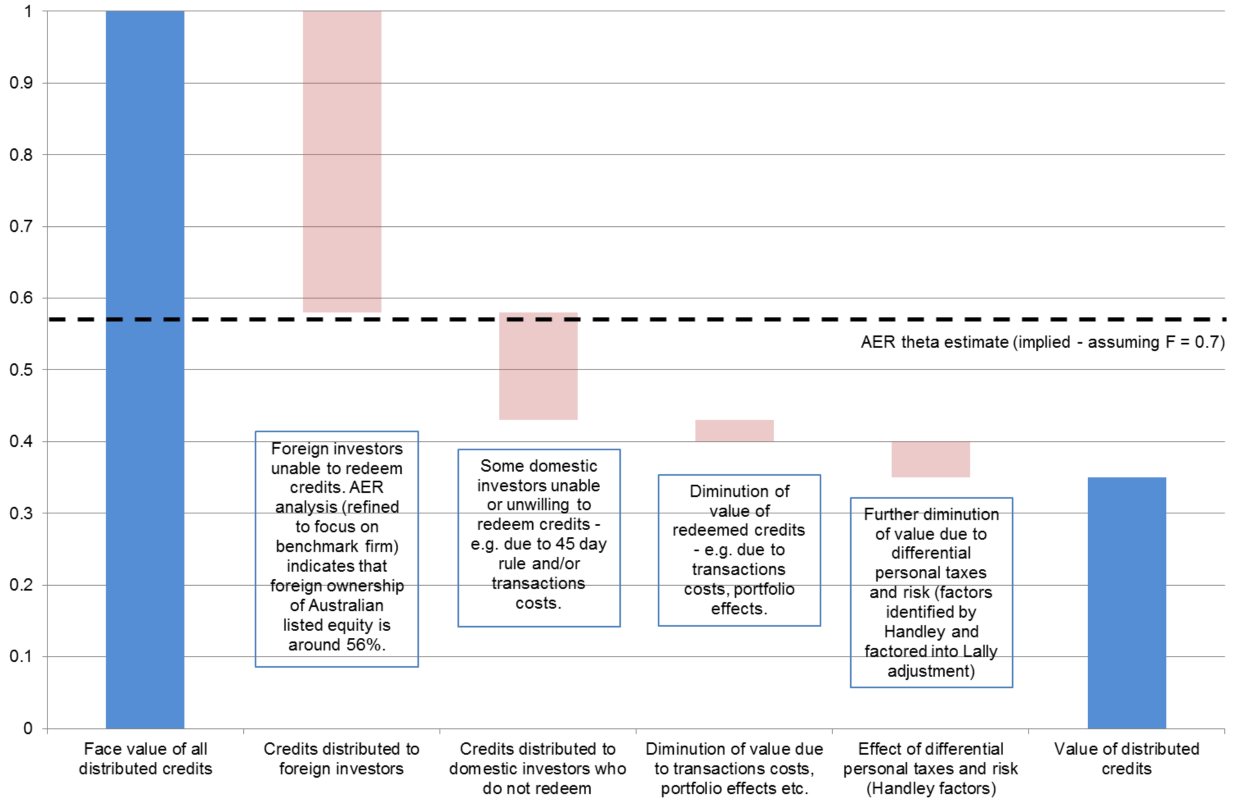
(2) the proportion of domestic investors unable or unwilling to redeem credits is set equal to the difference between the domestic equity ownership rate (0.44) and the observed redemption rate (0.43) – this is likely to be an under-estimate of the proportion of domestic investors in listed equity that are unable or unwilling to redeem credits because (as discussed above) 0.43 will likely overstate the redemption rate for listed equity;

(3) the diminution of value of redeemed credits due to factors such as transactions costs is calculated as the difference between the redemption rate (0.43) and the value of distributed credits estimated by Professor Gray, adjusted for the effects of differential personal taxes and risk, as proposed by Handley (0.40);

(4) the further diminution of value due to differential personal taxes and risk is the difference between the Handley-adjusted estimate of the value of distributed credits (0.40) and Professor Gray's unadjusted estimate (0.35).

Similarly, for all equity, the AER's implied theta estimate (0.57) is only marginally below the domestic equity ownership rate, and is well above the observed redemption rate and the market value of distributed credits (see figure below).

Figure 13.2: Illustrative impact on value of imputation credits – all equity



Note:

(1) the proportion of credits distributed to foreign investors is set equal to 0.42, based on the current foreign equity ownership rate (as at September 2014), calculated using the AER's refined methodology (refer to Table 13.1);

(2) the proportion of domestic investors unable or unwilling to redeem credits is set equal to the difference between the domestic equity ownership rate (0.59) and the observed redemption rate (0.43);

(3) the diminution of value of redeemed credits due to factors such as transactions costs is calculated as the difference between the redemption rate (0.43) and the value of distributed credits estimated by Professor Gray, adjusted for the effects of differential personal taxes and risk, as proposed by Handley (0.40);

(4) the further diminution of value due to differential personal taxes and risk is the difference between the Handley-adjusted estimate of the value of distributed credits (0.40) and Professor Gray's unadjusted estimate (0.35).

The AER's recent approach of a value for gamma of 0.4 is not consistent with evidence. This value is well above even the upper bound values indicated by the equity ownership approach and tax statistics.

The evidence indicates:

- Gamma can be no higher than 0.31 (combining a distribution rate of 0.7 with the upper bound for theta of 0.45);
- Even if the AER's new conceptual definition of theta were to be accepted, which is clearly inappropriate, this would imply a gamma point estimate of 0.28 (applying the Lally adjustment to Professor Gray's estimates to exclude the effect of factors such as differential personal taxes and risk); and
- If the correct definition of theta were to be accepted, consistent with the requirements of the NER, this would imply a gamma point estimate of 0.25.

As demonstrated above, the AER's recent approach to adopting a value for gamma is based on several errors of fact and reasoning. These include errors in the use of certain measures as direct evidence of the value of imputation credits, and errors in the interpretation of empirical data.

On a proper interpretation of the empirical evidence a value of 0.25 for gamma is clearly correct. The AER's approach in recent draft decisions overestimates gamma and consequently underestimates the overall return required by investors. Accordingly, the AER's recent approach will not contribute to the achievement of the NEO whereas 0.25 for gamma is clearly correct.

13.5 Supporting Documents

The following documentation supporting this chapter are provided as Appendices to this revenue proposal:

- Appendix 13A – SFG, Estimating gamma for regulatory purposes; February 2015; and
- Appendix 13B – NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, March 2015.

In addition, documents footnoted in this chapter will be submitted to the AER on a USB with the revenue proposal.

14 Opening Regulatory Asset Base

14.1 Overview

This chapter sets out the calculation of the opening RAB and its roll forward for the forthcoming regulatory period. The RAB calculation is highly relevant to the calculation of the return on capital and depreciation elements of the building block proposal. The RAB calculation presented in this chapter complies with the requirements of the NER and the AER's roll forward model.

AusNet Services is including some asset costs in the forthcoming regulatory control period that were previously recovered outside the price cap in the current period. Specifically, for the asset base associated with upgrades to core distribution systems as result of the AMI smart meter program (such as the billing system), as opposed to dedicated metering systems, it is now appropriate to subsume them into the standard control distribution service.

14.2 Establishing the Opening RAB at 1 January 2011

The opening RAB at 1 January 2011 is sourced from the 2011 Final Decision Roll Forward Model approved by the AER at the last reset. The value of the nominal opening RAB is $2,093 million including opening RAB adjustments associated with nominal roll forward for final year of the previous regulatory control period. These opening RAB adjustments are consistent with the requirements of clause S6.2.1(c)(2) of the NER, which specifies that a reconciliation includes adjustments to remove any benefit or penalty on the returns associated with any difference between the forecast and actual capex values for the final regulatory year of the previous regulatory control period.

14.3 Rolling Forward the RAB to 1 January 2016

AusNet Services has rolled forward the RAB consistent with NER Clauses S6.2.1(e) and (f) which establish the methodology for the roll forward. AusNet Services has utilised the AER's roll forward model (RFM) to derive the opening RAB at 1 January 2016 which incorporates both actual and forecast Net Capex up to the end of the current period. Depreciation of the RAB in the current period has been applied on a straight line basis in accordance with the methodology contained in the RFM. Further details on AusNet Services' depreciation allowance are contained in Chapter 15 of this proposal.

14.3.1 Actual and Forecast Net Capex, 2011 to 2015

To establish the opening RAB at 1 January 2016 AusNet Services has used the AER's roll forward which contains opening RAB at 1 January 2011 (including opening RAB adjustments) and rolled the RAB forward using a combination of actual and forecast information. Specifically, actual additions (net of disposals) from 2011 to 2014 have been input plus forecast additions (net of disposals) for 2015, as shown in table 14.1 below. Actual additions and disposals reconcile with the nominal values reported in the annual regulatory accounts. It is assumed that the 2015 forecast additions will be updated in AusNet Services' response to the AER's Draft Decision and be subsequently reflected in the AER's Final Decision.

Table 14.1: Net Capex, 2011 to 2015

(Nominal $M)	2011	2012	2013	2014	2015
Capex	261.2	306.4	363.5	383.6	351.1
Disposals	-0.1	-4.5	-5.6	-0.5	-1.2
Net Capex	**261.1**	**301.9**	**357.9**	**383.1**	**349.9**
Net Capex recognised in RAB[1]	**273.8**	**317.8**	**373.9**	**400.5**	**366.1**

14.3.2 Actual and Forecast Economic Depreciation, 2011 to 2015

Consistent with current AER modelling practice, AusNet Services has used economic depreciation when rolling forward the asset base over the current regulatory control period. Economic depreciation is calculated by determining the nominal depreciation, and offsetting the CPI indexation for each asset class. The calculation of each of these elements is set out below.

14.3.3 Actual and forecast straight line depreciation, 2011 to 2015

AusNet Services has adopted the AER's approach to calculating depreciation for the current regulatory period on an actuals basis through the use of the AER's roll forward model. AusNet Services acknowledges that this approach differs to the methodology for depreciation in the previous regulatory period (2006-10) where the RAB was reduced by the inflation-adjusted depreciation allowance contained in that determination.

The amount of nominal depreciation for the current regulatory period as per the AER's RFM is shown in the table below.

Table 14.2: Nominal Depreciation, 2011 to 2015

(Nominal $M)	2011	2012	2013	2014	2015
Nominal Depreciation	142.8	113.6	135.1	140.7	145.6

Actual and forecast indexation, 2011 to 2015

Clause 6.5.1(e)(3) of the NER requires that the established opening asset base, be adjusted for actual inflation consistently with the method used for indexation of the control mechanism. AusNet Services has applied the following definition of CPI to escalate the RAB for the current period:

> *"CPI for a particular calendar year means:*
>
> a) *the Consumer Price Index: All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter immediately preceding the start of the relevant calendar year*
>
> *divided by*
>
> b) *the Consumer Price Index: All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter immediately preceding the September Quarter referred to in paragraph (a).*
>
> *minus one."*[2]

[1] Net Capex recognised in RAB includes a half-nominal WACC allowance.

[2] ESCV, *EDPR 2006-10, Final Decision Volume 2*, October 2006, p.70. (Consistent with the EDPR 2011-15 Determination)

The CPI and escalation factors applied within the AER's roll forward model are shown in the following table.

Table 14.3: Escalator for the RAB, 2011 to 2015

	2011	2012	2013	2014	2015
Sept CPI (old base) $_{(t-1)}$	173.3	179.4			
Sept CPI (rebased) $_{(t-1)}$			101.8	104.0	106.4
Sept CPI (old base) $_{(t-2)}$	168.6	173.3			
Sept CPI (rebased) $_{(t-2)}$			99.8	101.8	104.0
Escalator	**0.0279**	**0.0352**	**0.0200**	**0.0216**	**0.0231**

Consistent with current AER modelling practice and the indexation methodology used in the 2011 EDPR Determination, AusNet Services has applied the indexation to the actual RAB. The table below shows this indexation.

Table 14.4: Indexation, 2011 to 2015

(Nominal $M)	2011	2012	2013	2014	2015
Indexation	58.4	80.4	51.4	61.8	73.4

Economic depreciation, 2011 to 2015

The calculation of economic depreciation (nominal straight line depreciation net of RAB indexation) for the current period is shown in the table below.

Table 14.5: Economic Depreciation, 2011 to 2015

(Nominal $M)	2011	2012	2013	2014	2015
Nominal Depreciation	142.8	113.6	135.1	140.7	145.6
RAB Indexation	-58.4	-80.4	-51.4	-61.8	-73.4
Economic Depreciation	**84.5**	**33.3**	**83.6**	**78.9**	**72.2**

14.4 AMI IT & Comms Assets Roll Forward

Consistent with AusNet Services' approved cost allocation methodology (CAM) and long standing practice, metering charges for the forthcoming regulatory control period will calculated on an incremental costs basis.

Practically, this means that many distribution business systems, as opposed to dedicated metering systems, that were upgraded as part of the AMI project will now be subsumed into the distribution service. Examples include billing and B2B (data to market) systems that are required to fulfil distribution services and would exist even in the absence of a metering service.

Specifically, AusNet Services has included all opex on systems and assets that are required for the standard control network service, and particularly the Local Network Service Provider (LNSP) function outlined in the current Rules, in its distribution use of system charges.

The new allocation results in the following additions to the opening RAB for 1 January 2016:

- The addition of the 31 December 2015 closing AMI communications RAB; and
- The addition of the 31 December 2015 closing AMI IT (ex-MMS) RAB.

The costs are shown in the table below.

Table 14.6: AMI IT (ex-MMS) & Communications, 2015 Closing RAB

(Nominal $M)	2015
AMI communications	33.2
AMI IT (ex-MMS)	42.1
Closing RAB	**75.3**

14.5 Summary

The nominal written-down value of the rolled forward RAB as at 1 January 2016 is $3,545 million which includes the EDPR RAB roll forward value of $3,470 million plus AMI IT (ex-MMS) & Comms opening RAB at 1 January 2016 of $75 million.

The roll-forward calculation is summarised in the table below.

Table 14.7: Asset Base Roll Forward, 2011 to 2015

(Nominal $M)	2011	2012	2013	2014	2015
Opening RAB	2,093.4	2,281.8	2,567.3	2,857.5	3,179.1
Net Capex	272.8	317.8	373.9	400.5	366.1
Economic Depreciation	-84.5	-33.3	-83.6	-78.9	-72.2
Interim Closing RAB	2,282.8	2,567.3	2,857.5	3,179.1	3,473.0
Foregone return (2010)					-1.1
EDPR RAB at 1 Jan 2016					**3,471.9**
AMI IT & Comms RAB roll-in					75.3
Closing RAB (Total)					**3,547.2**

In compliance with Clause S6.1.3(7) of the NER, a roll-forward model illustrating the details, amounts, calculations and other inputs used to establish the RAB for each regulatory year of the relevant regulatory control period will be submitted to the AER in support of this Proposal.

AusNet Services' RAB for the forthcoming regulatory period has been calculated in accordance with the requirements of Clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capex forecasts set out in Chapter 7 of this proposal and is consistent with the RAB roll forward information contained within AusNet Services' submitted Post Tax Revenue Model (PTRM).

The table below shows a summary of AusNet Services' RAB roll forward for the forthcoming regulatory control period.

Table 14.8: Regulatory Asset Base for the Forthcoming Regulatory Control Period

(Nominal $M)	2016	2017	2018	2019	2020
Opening RAB	3,547.2	3,814.6	4,084.8	4,343.2	4,641.5
Net Capex	393.4	362.5	365.3	377.0	368.5
Economic Depreciation	-126.0	-92.3	-106.9	-78.7	-74.4
Closing RAB	**3,814.6**	**4,084.8**	**4,343.2**	**4,641.5**	**4,935.6**

14.6 Support Documentation

In addition to the PTRM, RFM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Spreadsheet entitled "*AMI Comms & IT RAB model.xls*".

15 Depreciation

15.1 Overview

15.1.1 Introduction

This chapter sets out the depreciation elements of AusNet Services' building block proposal.

The depreciation building block reflects the gradual return of the capital used to build the network, over a timeframe that reflects the life of the assets. The life can be determined either by how long the asset is expected to physically last (engineering life) or by how long the asset is expected to be utilised by customers (economic life).

The depreciation building block is determined in accordance with the NER.

15.1.2 Operating Environment

The rate of depreciation is an important determinant of intergenerational equity, for example, if an asset will provide an effective service for 50 years it is important that future generations contribute to the cost of the initial investment. Conversely, future customers should not pay for assets that have been previously retired and no longer provide a service.

For AusNet Services, the appropriate timing for the return of its capital in the current environment of large, costly, investments in community bushfire safety, falling per capita energy consumption and increasingly viable off-grid energy solutions is particularly important. Long term sustainable prices can be more easily achieved if the regulated asset base (RAB) per customer is stabilised by recovering a greater proportion of the value of investment over a shorter time period, from the customers who are deriving economic value from the assets, and before off-grid solutions become economic. This reduction of asset standing risk also increases the likelihood that customers remaining on-grid in future continue to face sustainable prices even as some customers choose to disconnect, helping avoid initiating the 'death spiral' effect.

AusNet Services has replaced and will continue replacing very large proportions of some asset classes as a result of its safety programs. For example, by 2020 it will have replaced:

- 49% of cross arms;
- 54% of EDO fuses; and
- 14% of steel conductor.

Therefore, AusNet Services is proposing that the remaining asset value associated with the assets removed from service be written off over the forthcoming regulatory control period. This approach best serves the long-term interests of customers by ensuring that future generations do not pay for assets that no longer provide services, while also paying for the new, safer assets which have been installed.

15.1.3 Consumer Engagement

AusNet Services has explained the accelerated depreciation of assets replaced as part of its safety improvement programs and the associated revenue effects in its customer forums and workshops with customer advocacy groups.

This part of the proposal did not elicit significant positive or negative feedback.

15.1.4 Chapter Structure

The remainder of the chapter sets out the depreciation methodology used and the specific approach to calculating the accelerated depreciation for asset classes where substantial retirements have occurred.

15.2 Depreciation Methodology

AusNet Services has calculated its depreciation schedules using a straight line depreciation methodology utilising the remaining and standard lives as outlined below.

This methodology is consistent with the approach undertaken in the current period.

15.2.1 Opening RAB

To establish the opening RAB at 1 January 2016, AusNet Services has used the AER's roll forward model which contains the opening RAB at 1 January 2011 (including opening RAB adjustments) and rolled the RAB forward using a combination of actual and forecast information. Specifically, actual additions (net of disposals) from 2011 to 2014 have been input plus forecast additions (net of disposals) for 2015. Actual additions and disposals reconcile with the nominal values reported in the annual regulatory accounts. The 2015 forecast additions will be updated in AusNet Services' response to the AER's Draft Decision.

Further discussion of the opening RAB is contained in chapter 14 of this proposal.

15.2.2 Standard Lives and Remaining Lives

The standard asset lives to be applied to additions in the forthcoming regulatory control period are consistent with those used in the current period. Section 15.2.3 below, provides further details on the standard lives to be adopted in the forthcoming period.

The remaining lives associated with the opening RAB at 1 January 2016 are based on the remaining lives calculated within the AER's roll forward model.

Additional asset classes have been established in the PTRM to accommodate the accelerated depreciation adjustments which form part of AusNet Services' proposal. These additional asset classes and their respective remaining lives are provided in the table below:

Table 15.1: Additional Asset Classes

Asset Class	Remaining Life
Accelerated Depr Opening RAB Adj – Subtr	1
Accelerated Depr Opening RAB Adj – Distr	1
Accelerated Depr – Subtr (forecast period)	5
Accelerated Depr – Distr (forecast period)	5

Source: AusNet Services

Further discussion on AusNet Services' proposed accelerated depreciation is contained below, in section 15.3.

15.2.3 New Additions

New assets will be created by the proposed capex program during the forthcoming regulatory control period. Standard asset lives must be determined for these assets to allow depreciation schedules to be calculated.

AusNet Services is adopting the standard lives contained in the table below for new assets created on or after 1 January 2016. These standard lives are consistent with those used in the current regulatory period except for SCADA & Comms assets which are proposed to be increased and Equity Raising costs which are calculated within the AER's PTRM.

Table 15.2: Proposed Standard Lives

Asset Class	Standard Life
Sub-transmission	45
Distribution	50
SCADA & Comms	10
Non System – IT	5
Non System – General	5
Equity Raising costs	46.9

Source: AusNet Services

As explained in section 7.2.3, AusNet Services will be rolling SCADA IT capex into general IT from 2016 onwards.

The 5 year standard life applied to the SCADA and Communications asset category has historically reflected the fact that it only captured SCADA IT and Communications capex, for which a 5 year asset life is appropriate.

However, AusNet Services now proposes to report network SCADA under the SCADA and Communications category. As such, it is appropriate for the standard asset life to be applied to SCADA & Communications assets to be increased from 5 to 10 years. This asset life will be applied only to new additions from 2016 onwards.

15.3 Accelerated Depreciation

Based on analysis of its capital replacement programs in both the current and forthcoming regulatory control periods, AusNet Services has identified several network asset classes within the regulated asset base which have been, or are planned to be, removed from service. AusNet Services proposes that accelerated depreciation be applied to the value for these assets calculated to be remaining in the RAB at the commencement of the forthcoming period. This depreciation amount would thereby form part of the depreciation building block requirement for 2016-20.

AusNet Services' analysis reveals $110 million of remaining asset value across a range of assets, as shown in Table 15.3 below (see section 15.3.3). This represents 3.1% of the total opening RAB value at 1 January 2016.

15.3.1 Proposal Justification

The relevant clause 6.5.5(b)(1) of the NER requires that "the schedules 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 the present case, the nature of the assets and asset classes is such they have been or will be replaced ahead of the end of their expected economic and/or technical lives. AusNet Services' proposal to apply accelerated depreciation to these assets accurately reflects change in the remaining economic lives of those assets. Accordingly, AusNet Services' proposal conforms to the requirement in clause 6.5.5(b)(1).

Importantly, AusNet Services' proposed approach also contributes to the achievement of the NEO by delivering an outcome which best serves the long-term interests of its network customers. Accelerated depreciation slows RAB growth per customer, which is ultimately reflected in a reduction in required revenue. This contributes to medium and long term sustainability of distribution service prices.

AusNet Services has also considered the risk that accelerated depreciation represents to asset stranding from increasing near-term prices. The value of assets subject to accelerated depreciation in this proposal is small relative to both the size of the opening RAB and forecast additions for 2016-20, and is not considered likely to encourage customers to disconnect from the network.

Conversely, the alternate approach to allow customers to fund the return of capital over the remaining standard lives of the asset class (i.e., in the absence of accelerated depreciation) would not contribute to the achievement of the NEO and would be likely to deliver outcomes which are detrimental to customers' interests. Specifically, it would mean that future generations continue to pay for assets no longer providing distribution services while, at the same time, also paying for the new safer assets that replaced them.

15.3.2 Drivers for Replacement

The key drivers for early retirement and/or replacement of the identified assets, as noted in Table 15.3 below, are either condition or safety based, or both. Examples include:

- The pre-emptive replacement of steel and copper conductors in high risk areas due to early deterioration / corrosion of conductors; and
- The replacement of EDO fuses with alternative fuse technologies (such as Boric acid or Fault tamer fuses) that are associated with lower risk of fire ignition.

The safety related replacement programs undertaken by AusNet Services' form part of its Electricity Safety Management Scheme (ESMS) to eliminate assets in poor condition and to install assets with lower risk profiles in high bushfire risk areas of the network. AusNet Services' ESMS is accepted by Energy Safety Victoria (ESV) in accordance with the *Electricity Safety Act 1998*.

15.3.3 Methodology

AusNet Services used the following methodology to determine the proposed accelerated depreciation:

1. Identify assets that:
    a) were removed in the current regulatory control period; or
    b) are to be removed in the forthcoming period.
2. Estimate RAB value of relevant asset classes.
3. Determine portion of asset class to be accelerated (i.e. proportion removed from asset base).

The table below shows the proposed RAB value that is to be accelerated by asset class. The method for determining each aspect of the proposal is described in more detail below.

Table 15.3: Accelerated Depreciation Proposal by Asset Class

Replacement program	Program primary driver	Asset Class (% of RAB)	Current period (2011-15)		Forecast Period (2016-20)	
			Retired (% of asset group)	Estimated RAB value ($M)	Retired (% of asset group)	Estimated RAB value ($M)
Cross-arms (wood)	Condition & Safety	6.4%	24.9%	$30.9	24.3%	$52.0
Conductor – Steel	Condition & Safety	2.0%	8.0%	$3.1	6.3%	$4.3
Services	Condition	1.6%	4.8%	$1.5	4.6%	$2.5
OCR's	Safety	0.3%	96.7%	$6.5	3.3%	$0.4
HV ABC conductor	Safety	1.0%	5.6%	$1.1	4.3%	$1.5
EDO fuses – (excluding fuse tube replacements)	Safety & Technology	0.5%	36.4%	$3.2	17.3%	$2.6
Total				**$46.4**		**$63.3**

Source: RAB Accelerated Depr Analysis

Step 1 – Identify assets

Assets were identified for inclusion in the accelerate depreciation proposal where either:

- A significant portion of an asset class was or is being removed or replaced with updated technology;
- The entire fleet of a particular type of asset was or is being removed;
- The assets being removed have significant value in the RAB.

The full list of assets considered in AusNet Services' accelerated depreciation proposal is as follows:-

- Steel Conductor;
- Copper Conductor;
- Wooden Cross-arms;
- Services (including Neutral Screened Services);
- Oil Circuit Reclosers (OCR's);
- High Voltage Aerial Bundled Cable (ABC) Conductor;
- Expulsion Drop-Out (EDO) Fuses.

Step 2 – Estimate RAB value of identified asset class

AusNet Services' RAB is aggregated at a high level (e.g. Sub-transmission Assets, Distribution Assets) and it is not possible to identify the value associated with individual assets or asset classes. Hence, the remaining RAB value for each of the identified asset classes must be estimated.

AusNet Services has relied on data within its Repex Model[1] to establish each asset class's share of the total RAB value. The Repex model contains Electricity Distribution system assets including Network SCADA assets and does not contain IT or Non Network assets. The proportion obtained from the Repex model for each asset class was then separately applied to the 2011 and 2016 opening RAB values (excluding assets not modelled in the Repex model, such as IT assets) to derive estimated opening RAB values for each asset class. A worked example is provided below.

Step 3 – Determine proportion of identified RAB value to be depreciated

The portion of the asset class that is to be included in the accelerated depreciation proposal is calculated based on replacement volumes completed in the current regulatory control period and expected to be completed in the forthcoming period in accordance with AusNet Services' replacement programs, as a share of the total volume of assets in the identified asset class.

The replacement volumes in the current period are consistent with those reported in the annual regulatory accounts in relation to Safety program initiatives. Projected volumes for 2015 are consistent with volumes set out in the ESMS. The replacement volumes expected in the forecast period are based on the units proposed in AusNet Services' Capex proposal for 2016-20.

In the case of Copper conductors, whilst AusNet Services expects to have replaced 24% of its Copper Conductor fleet by 2020, no RAB value was attributed to these assets due to this asset class being fully written down in the Repex model. This asset class therefore does not form part of the accelerated depreciation proposal.

Worked example

An example is provided below explaining the calculation of accelerated depreciation for wooden cross-arms.

According to the Repex model, the "total remaining value" of all wooden cross-arms as a proportion of the closing 2012 total asset base value was 6.4%.

This proportional RAB factor was then applied to the opening RAB at 1 January 2011 of $1,950 million (excluding assets not modelled in the Repex model) to establish an estimated opening RAB value of $124 million for the total population of wooden cross arms. Using combined volume of actual and forecast wooden cross-arm replacements in the current period (totalling 46,785 units), representing 24.9% of the total population of wooden cross-arms, this equates to $31 million of RAB value identified for accelerated depreciation. This value is shown in table 15.3 above under column 'Estimated RAB value' relating to current period replacements.

Similarly, by applying the proportional RAB factor of 6.4% to 1 January 2016 opening RAB of $3,365 million (excluding assets not modelled in the Repex model) this equates to $215 million estimated opening RAB for wooden cross-arms. Based on forecast replacement of 45,645 wooden cross-arms to be completed in the forecast period, representing 24.2% of the total population of wooden cross-arms, this equates to $52 million of RAB value identified for accelerated depreciation. This value is shown in Table 15.3 above under column 'Estimated RAB value' relating to forecast period replacements.

[1] 2012 Repex Model owned and maintained by the Regulatory & Network Strategy team within AusNet Services. This model supports data reported in the AER's Historical Category Benchmarking RIN (2009-13).

15.3.4 Timing of Accelerated Depreciation

As shown in Table 15.3 above, the total estimated RAB value relating to replacements in the current period is $46 million which represents 2.4% of the 2011 Opening RAB value of $1,950 million (excluding assets not modelled in the Repex model). Since the remaining asset value of $46 million that is proposed for accelerated depreciation is associated with assets that have been removed from the network in the current period (replaced with new assets prior to 2016), this asset value is proposed to be accelerated fully in 2016. The effect of this proposal on the depreciation building block requirement is shown below in Table 15.4 – 'Nominal Economic Depreciation, 2016 to 2020' within section 15.4.

The total estimated RAB value relating to replacements in the forthcoming regulatory control period is $63 million which represents 1.5% of the 2016 Opening RAB value of $3,365 million (excluding assets not modelled in the Repex model). As the physical asset replacements will occur in stages over the forecast period (2016-20) the write-off of the remaining asset values will be smoothed over the period.

Separate asset classes have been established within the PTRM to cater for current period replacements (i.e., immediate write-off in 2016) and forecast period replacements. Refer to Table 15.1 in section 15.2.2 for the list of new asset classes.

15.4 Depreciation Proposal

AusNet Services' proposed depreciation for the regulatory period from 1 January 2016 to 31 December 2016 is shown in the table below.

The portion of proposed depreciation relating to accelerated depreciation is $110 million representing 23.0% of the total depreciation allowance.

Table 15.4: Nominal Economic Depreciation, 2016 to 2020

(Nominal $M)	2016	2017	2018	2019	2020	Total
Accelerated Depreciation	57.7	12.0	12.6	13.3	14.0	109.6
RAB roll forward Depreciation	68.2	80.3	94.3	65.4	60.4	368.7
Total Depreciation	**126.0**	**92.3**	**106.9**	**78.7**	**74.4**	**478.3**

15.5 Support Documentation

In addition to the PTRM, RFM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Spreadsheet entitled "*RAB Accelerated Depr Analysis.xls*".

16 Corporate Income Tax

16.1 Overview

The corporate income tax allowance is an input into AusNet Services' revenue requirement, allowing AusNet Services to recover an estimate of the corporate tax liability an efficient Distribution Network Service Provider (DNSP) would incur as a result of the provision of standard control services.

The AER's post-tax revenue model (PTRM) calculates a DNSP's tax allowance in accordance with clause 6.5.3 of the National Electricity Rules (NER). Specifically, the PTRM calculates the tax allowance (or the tax building block) by:

1. Deducting tax expenses (opex, interest payments on debt and total tax depreciation for all assets) from required revenue (including income from customer contributions) to arrive at the DNSP's taxable income; and
2. Multiplying taxable income by the corporate income tax rate, then again by one minus the utilisation of imputation credits (gamma).

This calculation is represented by the following equation in clause 6.5.3:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that *regulatory year* that would be earned by a benchmark efficient entity as a result of the provision of *standard control services* if such an entity, rather than the *Distribution Network Service Provider*, operated the business of the *Distribution Network Service Provider*, such estimate being determined in accordance with the *post-tax revenue model*;

r_t is the expected statutory income tax rate for that *regulatory year* as determined by the AER; and

γ is the value of imputation credits.

This chapter sets out AusNet Services' proposed approach to this calculation and consequently its proposed corporate tax allowance for the 2016-20 regulatory control period.

16.2 Proposed Approach

16.2.1 Overview

In accordance with clause 11.17.2, AusNet Services' corporate tax allowance for the current regulatory control period was calculated using an approach established by the Essential Services Commission (ESC). This approach calculated depreciation expenses using the reducing-balance method.

For the forthcoming period, AusNet Services proposes to calculate its tax allowance using the straight-line method of tax depreciation applied in the PTRM.

This methodology requires the following inputs:

- Opening tax asset base (TAB) as at 1 January 2016;
- Remaining tax lives;
- Standard tax lives;
- The value of gamma; and
- The corporate income tax rate.

This section sets out AusNet Services' proposed approach to the calculation of the first three of these inputs. The value of gamma, which is estimated at 0.25, is discussed in detail in Chapter 13. The corporate income tax rate is expected to remain at 30 per cent.

16.2.2 Opening TAB as at 1 January 2016

In determining its opening TAB as at 1 January 2016, AusNet Services used the AER's RFM to roll forward the approved opening TAB as at 1 January 2011.

The approved opening TAB was based on a combination of actual and forecast expenditure and depreciation figures. AusNet Services used actual 2010 capex and depreciation in place of the forecast values used at the last determination to calculate a revised opening TAB as at 1 January 2011. The following table compares the two TAB values.

Table 16.1: Approved and revised TAB as at 1 January 2011 ($m, nominal)

As at 1 January 2011	Value
Approved TAB	$1,260
Revised TAB	$1,279
Difference	$19

Source: AusNet Services

The $19 million difference between the approved and revised TAB is because of lower than forecast capex and depreciation in 2010.

The following table shows the roll forward of the revised TAB using actual and forecast net capex and forecast depreciation from 2011-2015 to determine the opening TAB as at 1 January 2016.

Table 16.2: AusNet Services' TAB roll forward ($m, nominal)

	2011	2012	2013	2014	2015
Opening TAB	$1,279	$1,445	$1,624	$1,833	$2,041
Net capex	$125	$152	$178	$220	$210
Less: tax depreciation	$291	$331	$386	$428	$388
Closing TAB	$1,445	$1,624	$1,833	$2,041	$2,218

Source: AusNet Services

16.2.3 Standard lives

Because AusNet Services used the reducing-balance method of depreciation during the current regulatory period, the AER did not approve standard tax lives for this period. AusNet Services has therefore been required to calculate standard tax lives, which are used to determine depreciation charges for new assets during the forthcoming regulatory control period.

AusNet Services adopted the standard tax lives set out in ATO Tax Ruling 2014/4 (TR 2014/4) to assign standard lives to each tax asset class. This process resulted in the standard tax lives shown in the table below.

Table 16.3: AusNet Services' proposed standard tax lives

Tax asset class	Standard tax life (years)
Subtransmission	43
Distribution system assets	46
Standard metering	n/a
Public lighting	n/a
SCADA/Network control	10
Non-network general assets – IT	4
Non-network general assets – other	12
Equity raising costs	n/a

Source: AusNet Services

In its draft decision for Ausgrid's proposed corporate tax allowance for the 2015-16 to 2018-19 distribution determination, the AER accepted the majority of Ausgrid's proposed standard tax lives on the basis that they were:[1]

- Broadly consistent with the values prescribed by the Commissioner for taxation in tax ruling 2014/4; and
- The same as those approved standard tax asset lives for the 2009–14 regulatory control period.

While AusNet Services has no approved standard tax lives for the current regulatory period with which to compare its proposed standard tax lives, the lives it proposes are appropriate because they closely reflect the lives prescribed by the ATO in TR2014/14.

For example, the values prescribed by the Tax Commissioner for zone substations and overhead assets (33kV and above) are 40 and 47.5 years, respectively.[2] These standard tax lives have been used by AusNet to establish a standard tax life for subtransmission assets of 43 years.

Appendix 16A provides further information on the method used to assign standard lives from TR/2014/4.

[1] AER (2014) *Draft Decision, Ausgrid distribution determination 2015-16 to 2018-19, Attachment 8: corporate income tax*, November 2014, p. 16.

[2] ATO Tax Ruling 2014/4, p. 164.

16.2.4 Remaining Tax Lives

AusNet Services was also required to estimate remaining tax lives to apply to the forthcoming period that reflect the expected life of its TAB.

The approach applied by AusNet Services to estimating remaining tax lives involved:

6. Dividing RAB remaining lives by RAB standard lives to calculate remaining lives as a proportion of standard lives for assets in the RAB; and
7. Multiplying these proportions by the tax standard lives shown above in Table 16.3.

This approach to calculating remaining tax lives was approved by the AER in its draft decision for Ausgrid's proposed corporate tax allowance. In approving this approach, the AER stated that:[3]

> *"We reviewed Ausgrid's proposed approach against alternative methods to establish the remaining tax asset lives as at 1 July 2014. We found Ausgrid's proposed approach provides reasonable estimates of remaining tax asset lives for the majority of Ausgrid's asset classes. We consider that Ausgrid's proposed approach aligns the cash flows associated with the estimate of tax depreciation with the expected life of the network. This is because for the majority of asset classes the standard asset lives for Ausgrid's RAB are comparable to the standard tax asset lives. We are therefore satisfied that the proposed approach results in an estimate of tax depreciation consistent with the tax expenses used to estimate the annual taxable income of a benchmark efficient entity over the 2014–19 period."*

The table below shows the remaining lives determined using AusNet Services' proposed approach.

Table 16.4: AusNet Services' proposed remaining tax lives

Tax asset class	Remaining tax life (years)
Subtransmission	34
Distribution system assets	31.7
Standard metering	n/a
Public lighting	n/a
SCADA / Network control	6.9
Non-network general assets – IT	2.6
Non-network general assets – other	8.2
Equity raising costs	n/a

Source: AusNet Services

[3] AER (2014) Draft Decision, Ausgrid distribution determination 2015-16 to 2018-19, Attachment 8: corporate income tax, November 2014, p. 17.

16.3 Proposed Corporate Tax Allowance

Based on the PTRM inputs described above, and the values proposed for other revenue building blocks and gamma, AusNet Services estimates its cost of corporate tax for the forthcoming regulatory control period at $244 million.

Table 16.5: AusNet Services' proposed corporate tax allowance ($m, $2015)

	2016	2017	2018	2019	2020	Total
Tax allowance	60	45	50	48	41	**244**

Source: AusNet Services

Note: Individual numbers may not add to total due to rounding.

16.4 Support Documentation

In addition to the PTRM, RFM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 16A – Calculation of Proposed Tax Standard Lives; and
- Spreadsheet entitled "*AMI Comms & IT TAB model.xls*".

Part III –
Alternative Control Services

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17 Metering Services

17.1 Overview

17.1.1 Introduction

The Victorian roll-out of smart metering infrastructure has been subject to alternative regulatory arrangements to those that apply to other electricity distribution services. These arrangements were intended to cover the accelerated roll-out of advanced metering infrastructure (AMI). From 1 January 2016, metering expenditure will form part of the overall expenditure proposal of the EDPR.

This chapter adopts the AER's classification and, therefore, sets out charges for the following alternative control metering services:

- Regulated smart metering service (type 5 and 6);
- Type 7 metering service;
- Meter exit and restoration services; and
- Auxiliary metering services.

It outlines:

- The prices or unit rates that AusNet Services proposes to apply to its alternative control metering services in 2016; and
- The mechanism that will be utilised to control individual prices / unit rates for Alternative Control Services throughout the forthcoming regulatory control period.

17.1.2 Background and assumptions

Government mandated roll out of smart meters

In 2005, the ESC mandated a roll-out of manually read interval meters (30-minute interval) by distribution businesses for selected electricity customers in Victoria from 1 January 2006. The meters were intended to provide detailed consumer information to assist in monitoring and responding to electricity demand.

In 2006, the Victorian Government announced a halt to the ESC mandate and announced its decision to roll out advanced remotely read interval meters to all Victorian electricity customers. Throughout the 2006 to 2008 period, the Victorian Government worked with distributors, retailers and consumer groups to establish the requirements of the roll-out.

The Victorian Government established a range of requirements for the programme, including technology functionalities, performance and service levels, as well as a framework for the regulated recovery of costs associated with the programme. The requirements are documented in the *AMI Cost Recovery Order in Council* (CROIC), the *Minimum AMI Service Levels Specification Victoria* (September 2008) and the *Minimum AMI Functionality Specification Victoria* (September 2013).

The AMI CROIC

The AMI CROIC establishes a building block cost pass-through regime for the setting of the prices for the regulated metering services and provided for exit and restoration charges to be paid to the distribution business by retailers. This allows AusNet Services to recover all investments in the programme in full that are within budget, contingencies and scope, even if competitive activities were to occur and retailers supplied their own meters in the future.

The AMI CROIC required AusNet Services to install in excess of 680,000 interval meters together with appropriate communications and information technology systems by 31 December 2013.

The Victorian Government undertook a review of the arrangements for the AMI roll-out in 2011 and announced on 14 December 2011 that the AMI roll-out would continue to existing timelines. The Victorian Government flagged a number of changes to the rollout milestones in the AMI CROIC, focusing on promoting the benefits to customers through devices such as in-home displays, and tightening the cost recovery mechanism on distribution businesses.

Since this announcement, the Victorian Government has amended the AMI CROIC (Government Gazette G 51 on 22 December 2011) removing the interim roll-out targets, whilst leaving the target for completion of the rollout of 31 December 2013 unchanged. The amendments to the AMI CROIC also tighten the cost recovery process for AusNet Services by removing the 10% project budget contingency, and shift the onus to AusNet Services to prove that budgeted costs are prudent.

On 29 November 2013, the further amendments to the AMI CROIC were made comprised of three policy positions:

- distribution businesses will be required to continue the installation of smart meters after 31 December 2013;
- distribution businesses will be required to pay a rebate to customers where they have not attempted to install a smart meter by 30 June 2014; and
- distribution businesses will be able to consider recovering the costs of running a separate metering service from customers who refuse the installation of a smart meter after 1 March 2015.

The above amendments to the CROIC were gazetted in 2014.

Contestability

Under the current Victorian framework DNSPs are exclusively responsible for metering services for small customers (<160KWh). This jurisdictional derogation from the national arrangements is due to expire on 31 December 2016.

The AEMC's 2014 Power of Choice review identified opportunities for customers to make more informed choices about the way they use electricity through better information, education and technology. The AEMC recommended the introduction of a framework that provides for competition in metering services. This framework would unbundle the provision of metering services, giving consumers choice in metering capability.

It is uncertain when the national framework will be implemented and if it will be applied to Victoria given the mandated smart meter rollout.

What is clear, is that DNSPs will be faced with the possibility of contestability in metering services during the forthcoming regulatory control period. In light of this, the EDPR needs to have the right mechanisms in place to ensure that if, and when contestability in metering is introduced, DNSPs can recover the efficient costs of metering and that effective competition can be established in an orderly manner.

For the purposes of this Regulatory Proposal, AusNet Services has assumed that contestability will not be introduced during the forthcoming regulatory control period. This is consistent with the position the company has recommended to the Victorian Government in order to preserve the benefits from the initial decision to mandate the roll out.

Transition to AER Regulation under the NER

The Victorian Government has mandated (Clause 11.17.6(b) of the NER) that the AER regulate smart meters and associated equipment in the next regulatory control period on the same basis as the AMI CROIC and classify the service these meters provide as an alternative control service.

Although smart meters are, technically speaking, a type 4 meter under the NER definitions, they were deemed by a jusrisdictional derogation contained in clause 9.9C of the NER to be type 5-6. Therefore, to aid it in this task, the AER has introduced a new term 'smart meter'.

The five Victorian electricity distributors are the monopoly providers of 'smart meters' until the jurisdictional derogation from the national arrangements is due to expire on 31 December 2016.

Therefore the AER has created two classifications for the smart meter service:

- Metering types 5 and 6 and smart meters – regulated service pre expiry of derogation – alternative control
- Metering types 5 and 6 and smart meters – unregulated service post expiry of derogation – unclassified.

AusNet Services endorses these classifications.

WiMAX

In previous AMI budget decisions, the AER has expressed concerns with AusNet Services' decision to proceed with WiMAX communications technology, which, when compared to the Mesh technology rolled out by other Victorian Distribution Businesses was appraised to be considerably more costly.

In its October 2011 AMI budget decision, the AER disallowed $106.5M of AusNet Services' forecast AMI costs for the AMI budget period 2012 to 2015. The decision to disallow the majority of costs was based on the AER belief that the decision to proceed with WiMAX was imprudent and therefore, the AER substituted the cost of an equivalent mesh 'benchmark'.

A subsequent appeal to the Australian Competition Tribunal (the Tribunal) overturned $17.5M (real $2011) of cuts to foreign exchange management and project management. However, the reductions associated with the WiMAX solution were upheld in this and subsequent appeals.

The expenditure excess incurred in 2014 and 2015, as well as future expenditure from 2016, will be considered by the AER in light of these decisions under the AMI CROIC regulatory framework.

AMI system stabilisation

AusNet Services encountered periods of significant instability in its AMI systems' performance as the number of smart meters connected to its AMI systems increased. In light of these issues, AusNet Services undertook a technical review of its AMI systems to address that instability. The technical review was completed during 2014, and a plan has been put in place to stabilise the existing end-to-end metering systems and to complete the network coverage. Stabilisation will commence in 2015 and full completion and implementation of the AMI program is estimated to be achieved by the end of 2016.

Interaction with 2014 and 2015 excess expenditure processes

As set out above, AusNet Services is establishing a stabilisation project to address the issues with its metering communication and IT systems. Until these issues are resolved, business as usual metering costs will remain above the current approved budget for 2014 and 2015.

Therefore, both the stabilisation and recurrent business as usual costs will be the subject of excess expenditure applications under the AMI CROIC regulatory framework.

For the purposes of this Regulatory Proposal, only recurrent business as usual metering costs and replacement costs are included in the charges calculations. As discussions with the AER on the excess expenditure applications progress, the proposal will be modified accordingly. The excess expenditure application for 2014 is to be submitted by 31 August 2015 and a determination is due to be made by the AER by 31 December 2015. The timeframe of the excess expenditure application is after the release of the AER's Draft Determination on this Regulatory Proposal.

17.1.3 Consumer engagement

The AMI roll-out has dominated customer complaints over the current regulatory control period. These complaints have been varied but cost, compulsion and health concerns have comprised the majority.

Most recently, customers' concerns have centred on the relatively high costs of AusNet Services' metering charges and genuine frustration with the much publicised problems AusNet Services is having with its smart meter communication systems.

In particular, the inability to see their own consumption data on AusNet Services' *MyHomeEnergy* web portal and access remote services were consistent issues raised during our public forums.

Unfortunately, as the stabilisation plan was not finalised, AusNet Services was not in position to canvass forecast metering charges as part of its engagement process.

However, when provided with examples of network benefits generated from smart meter data, customers were impressed. Section 17.2.1 below provides examples of these network benefits.

17.1.4 Chapter structure

The remainder of the chapter is structured as follows:

- Section 17.2 summarises AusNet Services' approach to alternative control metering services;
- Section 17.3 summarises AusNet Services' alternative control metering charges;
- Section 17.5 summarises AusNet Services' metering exit charges; and
- Section 17.6 summarises AusNet Services' alternative control auxiliary metering charges.

17.2 AusNet Services' Approach to Metering Services

The AER has set out its proposed metering service classifications in the *Final Framework and Approach for the Victorian Electricity Distributors*. As stated above, AusNet Services endorses the AER's metering services classifications.

The table below outlines AusNet Services' proposed alternative control metering services for the forthcoming regulatory control period.

Table 17.1: Proposed Alternative Control Metering Services

Service	Description
Type 5 and 6 and smart metering services – regulated service (i.e. metering provision not subject to competition)	This includes installation (including on site connection of a meter at a customer's premises, and on site connection of an upgraded meter at a customer's premises where the upgrade was initiated by the customer), provision, maintenance, reading and data services. Meter provision refers to the capital cost of purchasing the metering equipment to be installed. Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services involve the collection, processing, storage, delivery and management of metering data.
Meter exit services	A meter exit fee is to be paid by a retailer to AusNet Services where: (a) that retailer becomes the responsible person in respect of a metering installation for a customer with annual electricity consumption of 160MWh or less which, immediately prior to that time, included a revenue meter that is a remotely read interval meter which complies with the AMI Specifications and that has been previously installed by AusNet Services; and (b) the responsible person in respect of that metering installation immediately prior to that time was AusNet Services.
Meter restoration services	A meter restoration fee is to be paid by a retailer to AusNet Services where: (a) that retailer ceases to be the responsible person in respect of a metering installation for a customer with annual electricity consumption of 160MWh or less which, immediately prior to that time, included a revenue meter that is a remotely read interval meter which complies with the AMI Specifications and that has been previously installed by AusNet Services; and (b) AusNet Services becomes the responsible person in respect of that metering installation. For the purposes of this Regulatory Proposal, AusNet Services has assumed that contestability will not be introduced during the forthcoming regulatory control period. Therefore, AusNet Services is not proposing a meter restoration fee in this Regulatory Proposal as AusNet Services is currently the responsible person in respect of all metering installations for customers with annual electricity consumption of 160MWh or less.
Metering type 7	A type 7 metering service does not measure the flow of electricity and are unmetered connections. Rather, a type 7 'metering' service establishes energy data suitable for market settlement in accordance with the AEMO metrology procedure for type 7 installations such as public lights or traffic lights. Usage of electricity by type 7 meter connections is estimated using formulae and standard data.
Auxiliary metering services	Distributors also provide a range of metering related services to customers on request. Examples include remote connection / disconnection, customer requested meter tests, additional meter reads or equipment alterations.

Source: AusNet Services

17.2.1 The network benefits of smart meters

The smart meter roll out has transformed the availability of data for network management and planning, and created opportunities to translate this data potentially into real benefits for customers.

The smart meter network is already extensively used by AusNet Services for the following functions:

- **Better investment planning** – more informed and, therefore, less conservative augmentation, based on improved long term spatial demand forecasts (see chapter 7).
- **Demand management** – improving the integration of demand management activities into network planning (see chapter 9).
- **Improved efficiency** – more efficient operating and capital expenditure as a result of more informed decision making. For example, using smart meter data to allow phase balancing or transformer tap adjustment to solve local network stresses avoiding network augmentation.
- **Improved community safety –** using smart meter data to identify and prevent shocks from a failed neutral in the service lines and identifying unsafe and unauthorised network connections.
- **Short term operational benefits –** from timely and accurate short term demand forecasts (see case study in chapter 4).
- **Improved forecasting capability** – using smart meter data to better understand consumer behaviour (see chapter 4) including:
    - temperature-energy correlations, which can now be calculated with a significantly higher degree of accuracy due to interval data, rather than using quarterly billing data;
    - energy profiles for houses built at different times, which illustrates the impact of energy efficiency;
    - energy profiles for solar versus non-solar customers, which quantifies the impact of energy savings from solar installations and impact of solar at times of peak demand; and
    - the impact of different price structures on different customers.
- **Building an Australian leading solar uptake model** – The objective of this study was to provide AusNet Services with a model to understand and predict demand for market uptake of distributed solar power based on consumer behaviour (see chapter 9). The spreadsheet model and associated descriptive material has provided AusNet Services with:
    - Improved robustness of solar uptake forecasting as an input to allow more targeted and informed demand management strategies and projects to be developed;
    - An improved understanding of factors driving solar uptake, especially customer-driven factors; and
    - Exposure to other methods of modelling, including statistical analysis techniques, with the potential to incorporate these methods in future projects including non-solar modelling.
- **Data provision to the community –** the ability to provide customers, customer groups and government agencies with data that imparts insights they have not had access to before (see chapter 4). Recent examples include:
    - The provision of energy consumption data to agencies such as the Northern Alliance for Greenhouse Action and the South Gippsland Shire Council;
    - The provision of interval data from smart meters to better inform the Victorian Government's My Power Planner website; and

- Presenting energy and demand insights during AusNet Services' 2016-20 EDPR customer consultation.

For many of the above examples, AusNet Services is the only distributor in Australia systematically achieving these benefits.

Potential future network benefits could be even more impressive and include:

- **Load control (voluntary)** – developing the ability to control air-conditioners remotely would allow AusNet Services to reduce residential peak loads at source with minimal impact on customers' behaviour and comfort;
- **Low voltage network modelling** – deployment of residential focussed demand management and the need to handle increasing levels of customer-driven distributed energy will require support from increased network modelling capabilities and toolsets to analyse the performance of the low voltage network (from 230V single phase supplies up to the 22kV side of distribution transformers) as an essential pre-requisite; and
- **Automatic supply restoration –** ability to automatically restore supply to customers after restoring normal supply conditions.

A more comprehensive list of network management functionality is provided in Appendix 17A.

This discussion illustrates that AusNet Services has begun to significantly integrate the smart meter network and data into its broader network management. This integration will only become deeper through the forthcoming regulatory control period. Therefore, maintenance of an effective functioning population of smart meters and their associated communication network is an indispensable part of the distribution service regardless and independent of the metering services themselves.

Importantly, the current communication and system problems that are affecting the metering service largely do not impact the realisation of network benefits accruing to the network service. Noting the AER has not allowed the full cost recovery of the current smart meter investment based on the metering service it is providing; fair recompense for the significant network benefits from the same investment must be assessed for the forthcoming regulatory control period on its own merits.

As the network benefits from smart meters increase these also have implications for the appropriate allocation of costs. This is addressed in the following section.

17.2.2 Allocation of costs between network and metering services

Consistent with AusNet Services' approved cost allocation methodology (CAM) and long standing business practice, metering charges for the forthcoming regulatory control period will be calculated on an incremental costs basis.

Practically, this means that many distribution business systems (as opposed to dedicated metering systems) that were upgraded as part of the AMI project will now be subsumed into the distribution service. Examples include billing and B2B (data to market) systems that are required to fulfil distribution services and would exist even in the absence of a metering service.

As explained above, the AMI communications network now provides numerous network management services with many additional services identified for future implementation. These network services would be utilised in the future, independent of the existence of a metering service.

Specifically, AusNet Services has included all systems and assets that are required for the standard control network service, and particularly the Local Network Service Provider (LNSP) function outlined in the current Rules, in its distribution use of system charges. This results in the following allocation of assets and operating expenditure post 31 December 2015:

- Existing metering assets and future metering expenditure (including meters and communication cards) are included in the alternative control metering charges;
- Existing assets and future expenditure on the meter management systems (MMS) are included in the alternative control metering charges;

- Existing communication assets and future communications backbone expenditure (including communication towers and asset management systems) are included in the standard control network charges; and
- Existing assets and future expenditure on the following IT systems; billing, B2B, customer information system (CIS) and meter data management system (MDMS) are included in the standard control network charges.

This allocation results in the following modifications to the calculation of standard control network charges:

- The addition of the 31 December 2015 closing AMI communications RAB to the opening 1 January 2016 Distribution Asset Class RAB in the PTRM (see section 14.4 of Chapter 14);
- The addition of the 31 December 2015 closing AMI IT (excluding MMS) RAB to the opening 1 January 2016 IT Asset Class RAB in the PTRM (see section 14.4 of Chapter 14);
- The inclusion of forecast communication and IT (excluding MMS) capex in the standard control IT capex (see section 7.4.6 of Chapter 7);
- The inclusion of forecast communication and IT (excluding MMS) opex in the standard control IT opex (see section 8.3.6 of Chapter 8); and
- Overheads that were previously being allocated into the AMI project now being recovered in the core distribution network service (see section 8.3.6 of Chapter 8).

17.3 Metering Charges

17.3.1 Type 5-6 metering installations (including smart meters)

Given the allocation of costs above, the smart metering charges consist of:

- The return on and of capital associated with the sunk metering RAB and continued capex associated with new customers and replacement of existing meters;
- The return on and of capital associated with the sunk MMS system RAB and continued capex associated with maintaining and renewing that system;
- The opex associated with maintenance, meter reading and data services. Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services involve the collection, processing, storage, delivery and management of metering data; and
- any tax liability that arises over the period.

These building blocks are set out below.

The over/under recoveries of metering charges from 2014 and 2015 governed under the AMI CROIC framework have been included in the metering charges from 2016.

Proposed metering capex

Meters in-service will require further investment in order to continue to provide the metering service. This includes capex to meet customer growth and to maintain the metering service as current technologies become obsolete or technically unsupported over the period. In particular, the forecast includes capex:

- To manage the obsolescence of the communications network in the forthcoming regulatory control period; and
- Investment in new meter management IT systems.

The proposed metering capex is set out in the table below.

Table 17.2: Proposed Metering Capex

Real $2015 ($M)	2016	2017	2018	2019	2020
Meters	24.7	25.5	25.4	25.1	25.0
IT (MMS)	5.0	1.6	3.6	3.6	3.6
Total	**29.7**	**27.1**	**29.0**	**28.7**	**28.6**

Source: AusNet Services

Detailed support for the forecast capex is provided in the supporting materials.

Proposed metering opex

Likewise the meters will require continued operating and maintenance expenditure to continue functioning. In particular, the forecast includes opex:

- to read remaining refusals and smart meters where the communications are uneconomic to install;
- for meter data management and ongoing maintenance of the meters; and
- management of the metering business, including asset management of the meters and the meter management IT system.

Importantly, despite incurring significant costs, AusNet Services is not seeking opex for the manual reading of meters where they have not been logically converted to allow remote meter reading.

The proposed metering opex is set out in the table below.

Table 17.3: Proposed Metering Opex

Real $2015 ($M)	2016	2017	2018	2019	2020
Meter reading	1.4	1.4	0.8	0.8	0.8
Meter data management	4.2	3.4	3.6	3.8	3.9
Meter maintenance	2.5	2.3	2.0	2.0	2.0
Metering management	0.3	0.3	0.3	0.3	0.3
IT and communications infrastructure maintenance and support	3.4	3.5	3.5	3.5	3.5
Total	**11.8**	**10.9**	**10.2**	**10.4**	**10.5**

Source: AusNet Services

Detailed support for the forecast opex is provided in the supporting materials.

Metering RAB

AusNet Services has not sought to modify the asset lives established under the AMI CROIC for depreciation purposes. In line with the AER's building block model, there is no depreciation in the first year and capital expenditure is inflated by a half year WACC, with this inflated amount depreciated over the useful life of the asset. Therefore, including forecast capex and depreciation, the proposed metering RAB is set out in the table below.

Table 17.4: Proposed Metering RAB

Real $2015 ($M)	2016	2017	2018	2019	2020
Opening RAB	351.9	354.6	352	349.3	343.9
Net Capex	30.4	27.7	29.6	29.3	29.2
Economic Depreciation	-27.7	-30.2	-32.3	-34.7	-37.1
Closing RAB	354.6	352.1	349.3	343.9	336.0

Source: AusNet Services

Return on capital

AusNet Services is proposing the same WACC and gamma values for the metering service as for the standard control network service set out in chapters 12 and 13.

Proposed charges

To generate the proposed charges the above parameters have been entered into the AER Metering Model. The final charges are shown in the table below.

Table 17.5: Proposed Alternative Control Metering Services Charges (nominal)

	2016	2017	2018	2019	2020
Single phase single element	$103.66	$74.36	$76.28	$79.86	$83.23
Single phase two element with contactor	$119.12	$85.45	$87.66	$91.76	$95.64
Multiphase	$143.91	$103.24	$105.91	$110.87	$115.55
Multiphase with contactor	$159.64	$114.52	$117.48	$122.98	$128.17
Multiphase CT connected	$205.49	$147.41	$151.22	$158.30	$164.98

Source: AusNet Services

17.3.2 Type 7 metering installations

AusNet Services provides Type 7 Meter data services to Public Lighting Customers as an Alternative Control Service. The service involves the establishment of 30 minute metering data for public lights connected to the AusNet Services distribution network where there is no physical meter provided. The 30 minute data streams are calculated in accordance with the requirements for unmetered supplies as set out in the AEMO metrology procedure for Type 7 meters. The charges for the provision of the service are in two parts, a charge in respect of each NMI for which the data stream is calculated and a charge for each light that is recorded on the Inventory table of lights for each public lighting customer. Consistent with historical practice, AusNet Services proposes that the charges for both parts be adjusted by the CPI each year. The following table sets out the charges for the regulatory period.

Table 17.6: Proposed Type 7 metering charges (nominal)

Charge Element	2016	2017	2018	2019	2020
Per NMI	$308.00	$316.00	$324.00	$332.00	$340.00
Per Light	$1.6073	$1.6479	$1.6895	$1.7321	$1.7758

Source: AusNet Services

17.4 Price control mechanism that will be adopted for Alternative Control Services

In its Framework and Approach paper, the AER states that it will apply[1]:

- A revenue cap to the type 5 and 6 and smart metering service - not subject to competition.
- Apply caps on the prices of individual services in the next regulatory control period to alternative control services.

AusNet Services accepts the formula the AER proposes to apply to the type 5, 6 and smart metering – regulated service. This formula was[2]:

(1) $$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $$MAR_t = AR_t + T_t + B_t$$

(3) $$AR_t = AR_{t-1}(1+CPI_t)(1-X_t)$$

Where:

MAR_t is the maximum allowable revenue in year t.

p_t^{ij} is the price of component i of tariff j in year t.

q_t^{ij} is the forecast quantity of component i of tariff j in year t.

AR_t is the annual revenue requirement for year t.

AR_{t-1} in 2016 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2016 year in 2015 dollar value. After 2016 this is the AR_t from the previous year.

T_t is the adjustments in year t for true-ups relating to the AMI-OIC.

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1 AER, *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 89.

2 Ibid, pp. 92-93.

B_t is the sum of annual adjustment factors in year t for the overs and unders account.

CPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_t is the X-factor in real terms in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final decision.

AusNet Services accepts the formula the AER proposes to apply to Alternative Control Services. This formula was[3]:

$$\bar{p}_i^t \geq p_i^t \qquad i=1,...,n \text{ and } t=1,2,3,4$$

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1+CPI_t)(1-X_i^t)$$

Where:

$\bar{p}_i^t$ is the cap on the price of service i in year t

p_i^t is the price of service i in year t. The initial value is to be decided in the final decision.

CPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_i^t is the X-factor for service i in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final decision.

17.5 Exit Fee

17.5.1 Overview of proposed exit fee

The current CROIC provides for the AER to determine an exit fee (in accordance with the requirements set out in the CROIC) that would be paid by a retailer to the distributor where:

- That retailer becomes the responsible person in respect of a metering installation for a customer with annual electricity consumption of 160MWh or less which, immediately prior to that time, included:
  - A revenue meter that is a remotely read interval meter which complies with the Specifications and that has been previously installed by a distributor; and
  - The responsible person in respect of that metering installation immediately prior to that time was the distributor.

This section:

- Outlines AusNet Services' understanding of the regulatory requirements contained in the CROIC pertaining to the derivation of its meter exit fees;
- Compares the CROIC's requirements with the requirements of the broader regulatory framework;
- Describes the model that AusNet Services has used to derive its proposed exit fees;
- Describes the other, non-meter costs, associated with removing a metering installation that AusNet Services has reflected in its exit fee; and

[3] AER, *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 92-93.

- Summarises AusNet Services' proposed exit fees for the forthcoming regulatory control period.

17.5.2 Requirements of the CROIC

Clause 7.1 of the CROIC states that:

"An exit fee, determined by the Commission in accordance with this clause must (except as otherwise agreed by the relevant distributor) be paid by a retailer to the distributor where:

(a) that retailer becomes the responsible person in respect of a metering installation for a customer with annual electricity consumption of 160MWh or less which, immediately prior to that time, included a revenue meter that is a remotely read interval meter which complies with the Specifications and that has been previously installed by a distributor and

(b) the responsible person in respect of that metering installation immediately prior to that time was the distributor."[4]

Clause 7.2 of the CROIC states that:

"The Commission must determine an exit fee payable to each distributor as referred to in clause 7.1 in such a way that the exit fee enables the distributor to recover in a lump sum which is payable upon the change in responsible person referred to in clause 7.1:

(a) the reasonable and efficient costs of removing the metering installation for which the distributor was the responsible person; and

(b) the unavoidable costs (fixed and variable) that a prudent distributor has incurred or would incur as a result of the metering installation for which it was the responsible person being removed prior to the expiry of the life of that metering installation including:

(i) the written down value of the meter (assuming that depreciation is calculated on a straight line basis);

(ii) the proportion referable to that metering installation of the written down value of commissioned telecommunications and information technology systems; and

(iii) a reasonable rate of return on the written down values determined under paragraphs (i) and (ii), calculated using the applicable WACC."[5]

Clause 3.2 (b) states that:

(a) "Metering services that are regulated under the AMI Order in Council are not, while so regulated, subject to regulation under a distribution determination but, on cessation of regulation under the AMI Order in Council, are liable to regulation under a distribution determination.

(b) However, for a relevant regulatory control period, services to which exit fees under clause 7, or restoration fees under clause 8, of the AMI Order in Council applied are to be classified as alternative control services and are to be regulated by the AER on the same basis as applied under the AMI Order in Council.

(c) For paragraph (b), a relevant regulatory control period is a regulatory control period commencing on or after 1 January 2016 and before 1 January 2021."[6]

Having regard to the above requirements, AusNet Services' interpretation of the CROIC is that it:

- Clearly provides for AusNet Services to levy an exit fee on **any** remotely read interval meter (that is churned) that it has installed at the premises of a customer who consumes under 160MWh per annum. This means that the exit fee:
  - Is not just applicable to the remotely read interval meters that it has installed prior to a certain date (e.g. before December 2013); and

4 Vic. Gov. Gazette No. G51 22 December 2011 – Amend CROIC ensuring cost efficiency.

5 Ibid.

6 Ibid.

  - May include future expenditure (that the AER accepts as being prudent and efficient as part of its broader assessment of this regulatory proposal) that AusNet Services will be required to spend on purchasing and installing new remotely read interval meters for customers consuming under 160MWh, or alternatively, in order to support the on-going operation of existing remotely read interval meters;

- Provides for the:
  - Recovery of the written down value of that meter **as part of the exit fee**; and
  - The reasonable and efficient costs of removing the metering installation **as part of the exit fee**;

- Applies throughout the entire forthcoming regulatory control period, which, taken together, requires that:
  - The AER must make an exit fee determination that is ***consistent with the principles outlined in the CROIC***; and
  - This determination will apply to all remotely read interval meters where a retailer becomes the responsible person in respect of that metering installation over **the entire forthcoming regulatory control period**.

17.5.3 Comparing the requirements of the CROIC to the broader regulatory framework

The methodology used to determine the exit fee charged by the incumbent metering provider has implications for the likely breadth and scope of competition in metering, as well as the risks borne by different parties operating in the energy market, including, in particular, electricity distribution businesses.

Given the importance of the exit fee, AusNet Services considers it worthwhile to explore whether or not the methodology prescribed in the CROIC would differ materially, if it were to be developed under the broader regulatory framework, notwithstanding the fact that the AER is constrained in its review of AusNet Services' proposed exit fees to assessing whether or not they comply with the CROIC requirements. The broader regulatory framework includes, but is not limited to the:

- Principles outlined in the National Electricity Objective (NEO);
- Revenue and pricing principles (National Electricity Law, section 7A); and
- Distribution pricing rules (NER, 6.18).

Generally, the principles outlined in the NEL and the NERs reflect economic concepts. For example, the NEO, which states that the "*the objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to — (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system*", reflects the three components of economic efficiency:

- **Productive Efficiency**: ('promote efficient investment in') Tariffs for regulated services should, in totality, only recover the 'efficient costs' of investing in regulated services;
- **Allocative Efficiency**: ('efficient … use of, electricity services') Tariffs for regulated services should be reflective of the forward looking costs of providing those services (cost reflective), so that consumption only occurs where the benefit to the consumer outweighs the cost to the society of providing those services; and
- **Dynamic Efficiency**: ('for the long term interests of consumers of electricity with respect to … price') Regulated businesses should be incentivised to seek to make efficiency investments in the long-term, including seeking out efficiency gains over time and improving performance where the benefits exceed the costs, such that efficiency is promoted in the long-term.

The following table highlights the issues that AusNet Services considers would be fundamental to the development of an exit fee under the broader regulatory framework.

Table 17.7: Summary of issues relevant to the exit fee design

Issue impacted by the design of the exit fee	Description
Influences whether competition will lead to the efficient allocation of resources (allocative efficiency)	The exit fee is the key price signal that will guide investment in the metering market. This price signal will materially influence which meters will be changed over (churned) and which meters will not be churned upon the opening up of the metering market to competition. If the exit fee is set below efficient levels (i.e., it does not reflect the economic cost to the incumbent distribution business stemming from the removal of that meter), everything else being equal: • A meter may be churned, even though the private benefits accruing from that transaction may be less than the economic cost to society from that transaction occurring, and • Too many meters will be churned, relative to efficient levels, thus leading to inefficient expenditure on installing new meters. Conversely, if the exit fee is set above efficient levels (too high), too few meters will be churned (i.e., some meters will not be churned, even though the private benefits accruing from that transaction would have exceeded the economic cost to society stemming from that transaction occurring). The key, therefore, is to consider: (a) what the economic benefits and costs of any meter changeover are, and (b) ensure that the criteria used to guide the development of any exit fee allows for the value of these benefits and costs to be included in the exit fee. For completeness, the benefits and costs can in theory extend beyond the direct value of the meter itself, for example, if the changeover of a meter deprives a distribution business (or makes it more expensive for them to obtain) a certain network benefit that would have otherwise been facilitated as a result of the on-going retention of that meter in-situ, then that is a cost to the electricity market of changing over that meter, which should in turn be reflected in the exit fee price signal.
Impacts on the long term incentive for businesses to make investments in the metering market, and the energy market more broadly (dynamic efficiency)	If the methodology used to derive the exit fee leads to an inappropriate allocation of risk, for example, the transfer of technological or market risk to the Victorian distribution businesses for decisions that were effectively outside of their control (as a result of the mandated nature of the AMI program), then this inappropriate allocation of risk is likely to impact on dynamic efficiency.
Impacts on the broader market for electricity network services (allocative efficiency)	If the exit fee methodology prescribes that the recovery of the exit fee should be borne by a party other than the new metering coordinator (previously the Responsible Person), then this could impact upon the efficiency of the market from which those costs are recovered (not just the metering market itself). For example, if the recovery of the exit fee in Victoria were to occur via an increase in distribution ('DUoS') tariffs, then this could in theory impact upon the efficiency of distribution services, as the DUoS price

Issue impacted by the design of the exit fee	Description
	signal (inclusive of the exit fee) will influence whether existing customers choose to maintain their existing electricity connection, or revert to an alternative source of energy (e.g., go off-grid), or for that matter, whether new customers will choose to connect to a distribution business' network.

Source: AusNet Services

Having regard to the above, AusNet Services is of the opinion that the requirements of the CROIC will lead to the development of exit fees that are generally consistent with the requirements of the broader regulatory framework – in particular the National Electricity Objective (NEO). Firstly, the CROIC provides for the written down value (WDV) (as a proxy for the remaining economic value) of the meter to be recovered via the exit fee, not smeared across the broader customer base – which AusNet Services believes is clearly consistent with the NEO, as it allows the remaining economic value of meter to be signalled through the exit fee price to prospective entrants into the metering market. That said, the CROIC does not prescribe the level of granularity at which the WDV calculation should be undertaken (e.g., whether it should be a single WDV that covers all remotely read interval meters that comply with the Specifications; whether separate WDVs should be calculated for each category of meter; whether separate WDVs should be calculated for each category of meter, by the year of installation). AusNet Services has chosen to calculate WDVs by meter category, but not by installation year. AusNet Services' rationale for adopting this approach is as follows:

- Disaggregating the exit fee by the category of meter will provide a more accurate price signal to the market, relative to if one (average) exit fee was to be calculated based on one (average) WDV calculation. Everything else being equal, this should improve allocative efficiency (and therefore, be consistent with the NEO, as the price signals seen by potential entrants into the metering market will be much more cost reflective than they otherwise would be). AusNet Services is also of the view that there is unlikely to be any (a) material increase in the administrative costs of calculating or communicating this more granular exit fee, nor (b) adverse effect on potential entrants in the market as a result of them not being able to understand or respond to this slightly more disaggregated price signal. In relation to the latter, AusNet Services is of the view that most customers who are considering changing their Metering Coordinator are likely to be able to provide enough information to their prospective Metering Coordinator to allow them to ascertain what type of meter that customer currently has, and therefore, the relevant exit fee that will be applied if that meter is churned, and
- The decision to not disaggregate the exit fee price signal by installation year was made as this was considered likely to increase the costs of developing such a fee, and more importantly, the costs of administering such a fee as neither the customer nor a prospective party entering into the metering market is likely to know what year the meter being churned was installed. The uncertainty that this creates may limit activity in the broader metering market, therefore, AusNet Services considers it more efficient to simply average the exit fee across installation years (but as stated previously, not meter category).

In addition to the WDV, the CROIC provides for the 'reasonable and efficient costs of removing the metering installation' to also be recovered via the exit fee. AusNet Services considers this to be a legitimate economic cost that will be borne by the incumbent distribution business as a result of their remotely read interval meter churning, therefore this rightly needs to be signalled to the market so as to ensure that efficient levels of meter churn occur.

However, AusNet Services considers the CROIC to be deficient in one area, and that is that it does not appear to consider the possibility that if a distribution business has one of its meters churned, they (on behalf of their customers) may incur other economic costs, over and above simply 'removing the metering installation'. These potential economic costs relate to the network benefits that the distribution business may have otherwise received from the retention of that meter in situ in the future, but which upon removal, will either diminish or be more costly to achieve (e.g. via purchase from the new metering coordinator, infill communication). This is part of the broader opportunity cost to the distribution business of having that meter churned, which, from an economic perspective, should be factored into the exit fee, otherwise, the price signal that competitor sees in the market will lead to over-investment in new meters.

17.5.4 Description of the model AusNet Services has used to derive its proposed exit fees

In simple terms, the model that AusNet Services has used to calculate its proposed exit fee:

- Requires historical and forecast capital expenditure (by meter category, and for IT and communications) to be inputted in nominal terms,
- Converts these nominal expenditures into end 2015 dollars based on inputted escalation factors that are consistent with those that have been used throughout other parts of this regulatory proposal;
- Depreciates this end of 2015 dollar capital expenditure using one of two methods:
    - The method that underpins the AMI Charges Model (which, sees a ½ year of depreciation in the first year, and a ½ year of depreciation in the final year), and
    - The method that underpins the AER's building block model (which provides for no depreciation in the first year, but for capital expenditure to be inflated by a half year WACC, with this inflated amount depreciated over the useful life of the asset),
- Calculates the average WDV in each year, by meter category, based on the average of the start and end year WDVs for that meter category, with the end year WDV figure based on the:
    - The starting WDV for that year (in end 2015 dollars),
    - *Plus* the capital expenditure incurred in that year (in end 2015 dollars, inflated by a half year WACC if that expenditure is forecast to occur from 2016 onwards),
    - *Less* one of the two depreciation methodologies outlined above (with the decision dependent on whether or not the asset was constructed prior to 2016), and
- *Divides* the average WDV of each meter category in each year, by the average number of meters in that meter category that were (or are expected to be) in situ in that year,
- *Adds* the average WDV of IT and communications based on the same methodology as outlined above (except that the denominator in the calculation is the average number of meters in in total that were, or are expected to be, in situ in that year), and
- *Adds* in other costs such as, but not limited to, administration and removal costs, and tax costs, to determine the final exit fee per meter (by meter category).

The key inputs into the model are therefore:

- **Historical capital expenditure** (by meter category): The total dollar amount is based on the AMI charges that have been previously approved by the AER. However, these costs have been split into meter categories for the purposes of modelling the exit fee, as opposed to the broader capital expenditure category of 'remotely read interval meter' that is used as part of the AMI charges application process.
- **Forecast capital expenditure** (by meter category): This is based on the forecast costs included in other parts of this regulatory proposal that have been allocated to the provision of metering services to customers less than 160MWh. Again, these costs have been split out by meter category.

- **Depreciation lives**: These have been sourced from the AMI charges models, but generally, the capital and installation costs of the meters have been depreciated over 15 years, whilst the communications and IT costs have been depreciated over 7 years.
- **Real Vanilla WACC**: This figure is 4.56%, consistent with the parameters and methodology described in chapter 12 of this submission.
- **Escalation factors**: These are consistent with the escalation rates outlined in section 8.3.4 of this submission.
- **Tax treatment**: Whilst theoretically, the levying of an exit fee may lead to a distribution business incurring a tax liability, for the purposes of calculating its exit fee, AusNet Services has not included any allowance for tax, as it is forecasting to have carry-forward tax losses for its metering services over the forthcoming regulatory control period.
- **Other costs** associated with the removal of the metering installation. These are discussed in more detail in the following section.

17.5.5 Other costs associated with the removal of the metering installation

As has been stated previously, the CROIC entitles distribution businesses to reflect in the exit fee, the 'reasonable and efficient costs of removing the metering installation for which the distributor was the responsible person'.

To this end, AusNet Services has developed a generic process for removing the metering installation. It has then estimated the incremental cost that it will incur as a result of having to complete this process.

The following table identifies the key steps in this process, and the basis for costing up this process.

Table 17.8: Process for removing the metering installation

Step	Description	Costing Methodology
1	Back office processing, final read and billing activities	Reviewed back office tasks and the associated time required to perform those tasks. Only labour costs are involved.
2	Removal of meter and return of meter to store	Reviewed the tasks associated with removing the meter and returning it to the store, and the associated time required to perform those tasks. Only labour costs are involved.

The cost per meter (in end 2015 dollars) attributable to removing the metering installation is $21.80.

17.5.6 Summary of AusNet Services' proposed exit fees

The following table summarises AusNet Services' proposed exit fees for each of its relevant meter categories, for each year of the forthcoming regulatory control period.

Table 17.9: Proposed exit fee by meter type (nominal)

Meter type	2016	2017	2018	2019	2020
Single phase single element	$538.30	$536.99	$532.34	$526.33	$517.24
Single phase two element with contactor	$562.53	$554.14	$541.87	$527.98	$510.76
Multiphase	$583.48	$575.00	$558.50	$535.93	$505.26
Multiphase with contactor	$570.04	$574.98	$576.01	$575.44	$571.69
Multiphase current transformer connected	$659.44	$668.52	$672.80	$674.41	$671.88

17.6 Auxiliary Metering Charges

The AER has set out its proposed auxiliary metering service classifications in the *Final Framework and Approach for the Victorian Electricity Distributors*. As stated above, AusNet Services endorses the AER's metering services classifications.

The table below outlines AusNet Services' proposed alternative control auxiliary metering services for the forthcoming regulatory control period.

Table 17.10: Proposed Alternative Control Auxiliary Metering Services

Service	Description
Remote Special Meter Reading	An actual meter read performed outside of the usual reading cycle for the meter.
Remote Re-energisation	This refers to the use of the AMI/smart metering infrastructure communications system to control a supply contactor inside the meter such that the customer is connected to AusNet Services' network.
Remote De-energisation	This refers to the use of the AMI/smart metering infrastructure communications system to control a supply contactor inside the meter such that the customer is disconnected from AusNet Services' network.
Remote Meter Reconfiguration	This is a change to the software in the meter that enables changes to parameters for specific meter function. Examples of meter reconfigurations include: • Changing the switching times for controlled loads; and • Changes associated with the installation of embedded generation and/or the feed in tariff.

Source: AusNet Services

The remote services are available as part of the AMI meter rollout. The provision of these services will provide consumer benefits to those consumers who have a logically converted AMI meter.

AusNet Services is anticipating having these auxiliary metering services available after the AMI system stabilisation is achieved by the end of 2016. Although these services will still be performed manually in 2016, AusNet Services will charge customers a remote fee for these services.

AusNet Services has undertaken a comprehensive bottom-up costing exercise to determine the estimated costs of providing auxiliary metering services. AusNet Services has estimated the expected volumes of eligible Service Orders based on an analysis on the current Service Orders and the number of retailers with an approved Memorandum of Understanding (MOU) by Energy Safe Victoria (ESV). In cases where a retailer has no MOU, the service will have to be performed manually and a manual charge will apply.

Due to the interconnected nature of AusNet Services' system architecture and the system stabilisation currently being undertaken, AusNet Services conservatively expects a large proportion of eligible Service Orders will be processed remotely without further manual processing. As the IT system matures, the number of exceptions, and subsequently the level of manual intervention, is expected to fall.

No material costs are required in the provision of auxiliary metering services and in accordance with AusNet Services' CAM, there are no overheads applied in the provision of these services.

17.6.1 Alternative control auxiliary metering services charges

The following tables lists the key assumptions used to calculate the alternative control auxiliary metering services charge:

Table 17.11: Remote special meter reading assumptions

Assumptions	
Service Orders meeting the eligibility criteria for remote special meter read	17,571 per annum
Manual validation for remote special meter read (5 minutes)	4% of eligible Service Orders
System timeout intervention for remote special meter read (5 minutes)	5% of eligible Service Orders
Hourly cost for manual intervention (10 minutes)	$49 per hour
Service Orders successfully performed remotely (88% of eligible Service Orders)	15,814 per annum

Source: AusNet Services

The following table lists the key assumptions used to calculate the remote re-energisation charge:

Table 17.12: Remote re-energisation assumptions

Assumptions	
Service Orders meeting the eligibility criteria for remote re-energisation	59,498 per annum
Manual validation for remote re-energisation (5 minutes)	10% of eligible Service Orders
System timeout intervention for remote re-energisation (5 minutes)	5% of eligible Service Orders
Hourly cost for manual intervention (15 minutes)	$49 per hour
Service Orders successfully performed remotely (70% of eligible Service Orders)	41,649 per annum

Source: AusNet Services

The following table lists the key assumptions used to calculate the remote de-energisation charge:

Table 17.13: Remote de-energisation assumptions

Assumptions	
Service Orders meeting the eligibility criteria for remote re-energisation	34,757 per annum
Manual validation for remote re-energisation (5 minutes)	10% of eligible Service Orders
System timeout intervention for remote re-energisation (5 minutes)	5% of eligible Service Orders
Hourly cost for manual intervention (15 minutes)	$49 per hour
Service Orders successfully performed remotely (70% of eligible Service Orders)	24,330 per annum

Source: AusNet Services

The following table lists the key assumptions used to calculate the remote meter reconfiguration charge.

Table 17.14: Remote meter reconfiguration assumptions

Assumptions	
Service Orders for remote meter reconfiguration received	6,305 per annum
Manual validation for remote meter reconfiguration (12 minutes)	100% of Service Orders received
Service Orders meeting the eligibility criteria for remote meter reconfiguration	4,098 per annum
System timeout intervention for remote meter reconfiguration (5 minutes)	10% of eligible Service Orders
Hourly cost for manual intervention (15 minutes)	$49 per hour
Service Orders successfully performed remotely (70% of eligible Service Orders)	2,869 per annum

Source: AusNet Services

AusNet Services proposes the following charges to apply from 1 January 2016 and it is also proposed that the charges be adjusted by the CPI each year. The following table sets out the charges for the regulatory period.

Table 17.15: Proposed Auxiliary Metering Services Charges (nominal)

Name of service	2016	2017	2018	2019	2020
Remote Special Meter Read	$1.35	$1.38	$1.42	$1.46	$1.49
Remote Re-energisation	$6.24	$6.40	$6.56	$6.73	$6.90
Remote De-energisation	$6.24	$6.40	$6.56	$6.73	$6.90
Remote Meter Reconfiguration	$27.75	$28.45	$29.17	$29.91	$30.66

Source: AusNet Services

17.7 Supporting Documentation

In addition to the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- 17A – Distribution network benefits from AMI meters;
- Metering Asset Management Strategy;
- Metering cost model;
- Alternative control metering services charges model;
- Exit fee model; and
- Remote services model.

18 Alternative Control and Negotiated Services

18.1 Overview

18.1.1 Introduction

Alternative Control Services are services that are provided by means of or in connection with a distribution system. Alternative control services are customer specific or customer requested services. A number of these services may also have the potential to be provided on a competitive basis rather than by the local distributor.

Negotiated services require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services. Distributors and customers are able to negotiate prices according to a framework established by the rules. The AER is available to arbitrate if necessary.

Alternative Control and Negotiated Services costs are not recovered through revenue earned from distribution use of system tariffs. Rather they are recovered, via regulated or negotiated fees, directly from the customer requesting the service.

AusNet Services endorses the AER's classification of services set out in the Framework and Approach.

The chapter outlines:

- The prices and unit rates that AusNet Services proposes to apply to its Alternative Control Services in 2016;
- The mechanism that will be utilised to control individual prices / unit rates for Alternative Control Services throughout the forthcoming regulatory control period; and
- The services that AusNet Services proposes to classify as negotiated services.

18.1.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 18.2 outlines AusNet Services' proposed fee based Connection Services, the basis for developing the fees for those services, and the proposed fees;
- Section 18.3 outlines AusNet Services' proposed fee based Ancillary Network Services, the basis for determining the fees, and the proposed fees;
- Section 18.4 outlines the Alternative Control Services that AusNet Services proposes to be determined based on quoted rates, the basis for determining those quoted rates, and the proposed quoted rates;
- Section 18.5 outlines the basis upon which AusNet Services has developed its proposed fees for Public Lighting, as well as the proposed fees;
- Section 18.6 outlines the price control mechanism that AusNet Services proposes to adopt for Alternative Control Services during the forthcoming regulatory control period; and
- Section 18.7 sets out the support documentation for the chapter.

18.2 Fee Based Connection Services

The Framework and Approach paper simplifies and codifies existing practice for Victorian connection services. All connection (and disconnection) services that are non-routine in nature are classified as standard control and regulated under Victorian Electricity Industry Guidelines 14, *Provision of services by electricity distributor,* and 15, *Connection of embedded generation*. These Guidelines include the methodology to be used for the calculation of the customer contribution. These services include:

- New connections requiring augmentation (including a supply enhancement or modification at customer request);
- Customer initiated undergrounding and/or rearrangement of distribution assets serving that customer;
- Routine supply abolishments (<100 amps); and
- Operation and maintenance of connection assets (captured as network services).

Routine connection services to customers making connection of a new premise to the network are classified as alternative control services.

18.2.1 AusNet Services' proposed fee based Connection Services

The table below outlines the fee based[1] connection services that AusNet Services proposes to provide over the forthcoming regulatory control period.

Table 18.1: AusNet Services' proposed fee based Connection Services

Service	Description
Routine connection of new premises – customers up to 100 amps	Connection services to customers making connection of a new premise to the network. This service includes the provision of a service cable in areas with overhead supply and making a connection in a pit for customers in underground supply areas or where a customer requests an underground connection in an overhead supply area.
Temporary connections and disconnections	Distributors provide temporary connection and/or disconnection services to specific customers on request. This is most commonly used for construction sites, although other examples include blood bank vans and community fetes.
Remote energisation and de-energisation	Remote energisation and de-energisation services are the connection or disconnection of electricity remotely when a customer moves in or vacates premises or the service is disconnected for other reasons such as safety or at the request of retailer for non-payment of accounts.
Pre-approval of a PV or small generator installation	This services involves AusNet Services assessing whether or not the connection of a PV or small generator installation at a particular site will have any technical implications for its upstream distribution network.

1 Connection Services that are to be based on quoted rates are discussed in later sections.

Service	Description
Meter exchange upon installation of a small scale renewable energy generation system	This services covers the situation where a meter is required to be changed at a site as a result of the installation of a renewable energy installation such as solar generation.
Meter reconfiguration upon installation of a small scale renewable energy generation system	This service covers the situation where an existing meter is required to be reconfigured at a site as a result of the installation of a renewable energy installation such as solar generation.

Source: AusNet Services

18.2.2 A summary of AusNet Services' methodology for deriving fee based Connection Fees

AusNet Services provides connection services to customers across three broad geographic regions, being:

- **Central region**: this region covers those predominately urban and semi urban areas in and around AusNet Services' north and east growth corridors (e.g., Beaconsfield, South Morang),
- **North Region**: this region covers those predominately rural and semi-rural towns and regions in the northern part of AusNet Services' service territory, and
- **East Region**: this region covers those predominately rural and semi-rural towns and regions in the eastern part of AusNet Services' service territory.

AusNet Services periodically goes to market for the provision of the majority of its connection services in its Central Region, therefore, these rates are market tested, which in turn means it is reasonable to assume that those rates represent the efficient cost associated with providing those services in the Central region. However:

- AusNet Services does not outsource the provision of these services in its Northern and Eastern regions, nor does it separately capture the direct costs associated with providing those services in these regions in its financial system; and
- The (market tested) rates in the Central region do not include the costs of any materials.

Therefore, to estimate the efficient cost of providing these services in its Northern and Eastern regions, AusNet Services has first scaled up the direct market tested contractor costs incurred in the Central Region, to account for the lower customer densities (and therefore longer travel times) in the Northern and Eastern Regions.

The scaling factor used took into account, amongst other things:

- The average time required to travel to site in each region with this based on the estimated travel time to each postcode within each of the regions from the nearest located depot (using publically available information, and assuming no traffic congestion), with this weighted by the number of customers in each of those postcodes;
- Calculating the cost per minute to conduct a task in the Central region (based on the above methodology, plus the estimated time required on-site to complete each service), and multiplying this cost per minute by the number of minutes required to travel to site and undertake the same task in the Northern and Eastern Regions (based on the above methodology); and
- Multiplying these costs (for each of the Central, Northern and Eastern Regions) by the estimated proportion of customers in each of the three regions, to derive an AusNet Services wide figure.

This allowed AusNet Services to derive a starting 2016 figure (excluding materials). AusNet Services then applied its real labour cost escalator forecasts (as described in earlier sections of this submission) to the starting 2016 prices, to calculate real unit rates for each of the remaining years of this regulatory control period. These figures were discounted back, and divided by a discounted volume, to determine a starting 2016 figure that was inclusive of future real labour cost escalators (in lieu of providing an allowance for these forecast real labour cost increases through an annual price adjustment in the price control formula). AusNet Services then also included the estimated cost of materials associated with each connection type. This has been based on a bottom up build of the cost of materials required to complete each connection type. No escalation has been applied to materials for the purposes of developing these fees.

The benefit of adopting this methodology is that it has allowed AusNet Services to both leverage off the market rates that have been revealed in the Central region, whilst also providing a reasonable allowance for the difference in time required to travel to site in its different regions.

The methodologies AusNet Services has used to derive its proposed prices for other connection services are as follows:

- Temporary connections and disconnections – this is based on the costs of providing a service truck visit. This is discussed in more detail in other sections of this submission.
- Remote re-energisation and de-energisation – this is discussed in Chapter 17 of this Proposal.
- Pre-approval of PV & small generator installation – this is based on the time required for an appropriately qualified AusNet Services employee to undertake a desktop assessment of the technical implications stemming from the connection of a PV & small generator installation at that location. The estimated time required to undertake these reviews has been based on information provided by AusNet Services' internal subject matter experts. The time required (and skills of the AusNet Services employee undertaking the review) differ depending on the size of the installation – with larger installations (above 15kW) taking more time, and requiring a design engineer, not just a technician, because of the greater complexity of the assessment process. AusNet Services is not proposing to apply a fee for systems that are below 4.6kW.[2]
- Meter exchange upon installation of a small scale renewable energy generation system – AusNet Services proposes that this fee be based on the summation of the published service truck visit rate applicable in the year the service is requested by a customer, and the Exit Fee applicable to the type of meter that is being removed in the year the service is requested. Each of these components are discussed in more detail in other sections of this submission.
- Meter reconfiguration upon installation of a small scale renewable energy generation system – AusNet Services proposes that this fee be based on the cost of undertaking a remote meter re-configuration. This is discussed in other sections of this submission.

The detailed calculations and assumptions supporting AusNet Services' proposed connection fees are contained in spreadsheets accompanying this submission.

[2] This threshold is slightly lower than what was outlined in the Framework and Approach Paper. This threshold reflects the fact that on parts of AusNet Services' network (for example areas supplied by Single Wire Earth Return systems) there is a significant probability that the connection of installations larger than 4.6kW may adversely impact upon AusNet Services' upstream distribution network.

18.2.3 AusNet Services' proposed fee based Connection Services

The following table outlines the fees that AusNet Services proposes to charge for its fee based Connection Services.

Table 18.2: Proposed Alternative Control Connection Services Fees

Service	Business Hours	After Hours
Routine new connections — customers<100amps		
Single Ø Overhead	$403.69	$487.89
Single Ø Underground	$210.30	$269.59
Multi Ø Overhead — Direct Connected Meter	$430.05	$519.74
Multi Ø Overhead — CT Connected Meter	$578.36	$698.98
Multi Ø Underground — Direct Connected Meter	$313.23	$389.01
Multi Ø Underground — CT Connected Meter	$452.53	$562.02
Install 95mm Overhead Service from LVABC	$709.41	$837.23
Other fee based connection services		
Temporary supply connection and with co-incident disconnection	$368.80	$437.00
Remote re-energisation and de-energisation	Provided in Chapter 17	Provided in Chapter 17
Pre-approval of PV & small generator installation - <4.6kW	$0	Not applicable
Pre-approval of PV & small generator installation – >4.6kW to 15kW	$147.79	Not applicable
Pre-approval of PV & small generator installation – >15kW to 30KW	$195.91	Not applicable
Meter exchange upon solar connection	Applicable Exit Fee plus Service Truck Visit in the year the service is requested	Applicable Exit Fee plus Service Truck Visit in the year the service is requested
Meter reconfiguration upon solar connection	$27.07	Not applicable

Source: AusNet Services

18.3 Fee Based Ancillary Network Services

Ancillary network services share the common characteristic of being non-routine services provided to individual customers on an 'as needs' basis. Ancillary network services involve work on, or in relation to, parts of the Victorian distributor's distribution network. Therefore, as with network services, only the distributor can perform these services.

The table below outlines AusNet Services' proposed fee based ancillary network services for the forthcoming regulatory control period.

Table 18.3: Proposed fee based Ancillary Network Services

Service	Description
Field Officer Visit	Field Officer visits are provided to customers, retailers and other parties seeking the following range of Services: (a) Reconnection (Fuse Insertion New Customer); (b) Customer Transfer; (c) Fuse Removal (for any purpose as requested by the customer, the customer's retailer, or electrical contractor); and (d) General information on the nature of a customer's usage (eg: residential, small commercial).
Service truck visits	DNSP attendance by a 1 or 2 man service crew required to carry out electrical trades work on customer's electrical interface to the network where the work on site may take up to 60 minutes.
Wasted Truck Visit – not AusNet Services' fault	Where a service truck visit is requested and the truck arrives to find the site is not ready for work to be carried out then a Wasted Truck Visit charge will apply.
Meter equipment test	Where metering data is in dispute, AusNet Services will conduct an "in situ" test of the meter. Where the meter is found to be faulty, the prepaid charge will be refunded and a replacement meter installed at no charge to the customer.

Source: AusNet Services

18.3.1 A summary of AusNet Services' methodology for deriving fee based Ancillary Network Services

AusNet Services has utilised a number of approaches to develop prices for its proposed fee based Ancillary Network Services, with the approach adopted reflecting:

- Whether market tested cost information was available to support the derivation of fees for those services;
- Whether robust historical cost information was available in relation to the provision of those specific services; and
- The size of the market for those services.

More specifically, for service truck visits, AusNet Services used a similar methodology as it undertook for connection services, namely, reliance was placed on the market tested rates in AusNet Services' Central region, with adjustments made for travel time and the cost of materials. These fees have also been used to price the establishment of a temporary supply connection.

For field officer visits conducted during normal business hours, AusNet Services extracted from its financial system the direct costs associated with providing these services over the current regulatory control period. AusNet Services used this information to establish its starting 2016 unit price – specifically, AusNet Services:

- divided the total actual cost of providing these services during business hours in 2014, by the total volume of field officer visits conducted in that year during business hours;
- applied labour escalation rates (as set out in other parts of this regulatory submission) to the labour portion of that cost (~83%), to determine unit rates in each future year of the forthcoming regulatory period in real terms; and then
- discounted back these future real unit rates, and then divided this figure by a discounted volume figure (assuming no change in the number of field officer visits provided over the regulatory period).

This has allowed AusNet Services to derive a starting 2016 figure that is inclusive of future labour cost escalators, without over-recovering costs over the overall regulatory period. AusNet Services notes that this approach is conservative in that it makes no allowance for the impact that the deployment of the AMI system (which will allow many of these tasks to be completed remotely) will have on the density (and therefore unit cost) of field officer visits.

AusNet Services' after-hours field officer visit fee is based on the market tested rates it is charged by its contractor to undertake an after-hours fuse insertion in the Central Region, adjusted for the different travel times in each of the three regions that AusNet Services serves, and weighted by the number of customers in each of those regions. AusNet Services has not included any materials cost in this fee.

For meter equipment tests conducted during business hours (for which AusNet Services only provides a relative small number in any one year, and for which the costs are not captured separately in its financial system), AusNet Services has applied its proposed quoted services hourly rate for a 'Technician' to the:

- estimated time on-site to complete a meter equipment test – which differs between single phase and multi phase meters; plus
- estimated time required to get to and from[3] site in each of AusNet Services' three service regions (with this based on the same analysis as was described above for connection services).

Separate costs are calculated for single phase and multi phase meters. The costs that are calculated for each of AusNet Services' three service regions are then weighted by the estimated proportion of customers in each of those regions, to derive an AusNet Services wide rate.

AusNet Services has also created two additional fees that will be applied in circumstances whereby any additional single phase or multi phase meters are tested at the same site on the same visit. These additional meter fees are simply based on the hourly rate of a technician multiplied by the estimated additional time the technician will need to spend on site to conduct those tests.

The detailed calculations supporting AusNet Services' proposed fee based Ancillary Network Services are contained in spreadsheets accompanying this submission.

[3] AusNet Services considers it reasonable to include in its proposed meter equipment test price, the opportunity cost of travelling both to and from site, as AusNet Services completes relatively few of these tasks each year, and the skills required to complete these tests are not those of a field service officer. Collectively, this means that the specialised technician completing the task will not be in a position to undertake a number of meter equipment tests on the same day in the same general vicinity – rather, they will likely have to travel to and from site to undertake a test.

18.3.2 AusNet Services' proposed fee based Ancillary Network Services

The following table outlines the fees that AusNet Services proposes to charge for its fee based Ancillary Network Services.

Table 18.4: Proposed Ancillary Services (Fee Based)

Service	Business Hours	After Hours
Field officer visits	$18.46	$340.98
Service truck visits	$368.80	$437.00
Wasted Truck Visit	$195.80	$283.08
Meter equipment test – Single Phase	$158.67	Not applicable
Meter equipment test – Single Phase Each Additional Meter at same site	$59.11	Not applicable
Meter equipment test – Multi Phase	$188.23	Not applicable
Meter equipment test – Multi Phase Each Additional Meter at same site	$88.67	Not applicable

Source: AusNet Services

18.4 Quoted ancillary network services

Quoted services are not heavily utilised by customers, indeed some services have not been used during the period. A customer's final charge consists of a regulated charge per hour for each labour type used plus any materials and any vehicle costs (otherwise not reflected in the underlying hourly rate). AusNet Services' financial systems track the revenues generated by way of quoted services, however they do not track costs.

18.4.1 Proposed services that will be based on quoted rates

The table below outlines the Alternative Control Services that AusNet Services proposes to use quoted rates for to derive the final charge to customers over the forthcoming regulatory control period.

Table 18.5: Proposed services whose prices will be derived based on quoted rates

Service	Description
Reserve feeder maintenance	Maintaining network assets that provide an alternative supply to a customer's premise by reserving capacity for use by the customer in emergency situations.
Routine connections – customers above 100 amps	Connection services to customers making connection of a new premise to the network – where that customer is above 100 amps. This service includes the provision of a service cable in areas with overhead supply and making a connection in a pit for customers in underground supply areas or where a customer requests an underground connection in an overhead supply area.
Rearrangement of network assets at customer request, excluding alteration and relocation of public lighting assets	Works associated with any rearrangement of the network at the request of a third party. Examples may include a single pole relocation, a re-alignment of line of poles for road construction works, or relocation of a substation to enable a redevelopment of a site.
Auditing design and construction	Carrying out inspection and testing of works being constructed by third parties to be vested to the DNSP to ensure compliance with standards and specifications.
Specification and design enquiry fees	Provision of design standards and specifications for works to be constructed by third parties and vested to the DNSP.
Elective undergrounding where above ground service currently exists	Provision of underground services to customers in Overhead Supply areas where requested to do so by the customer. This service involves installing cable down an appropriate pole, trenching to a suitable location for an underground pit, and installing an underground pit.
Damage to overhead service cables caused by high load vehicles	The re-instatement of overhead lines that are pulled down by high loads. Where the party responsible for the damage is identified, AusNet Services will recover the costs to re-instate the line from the party concerned.
High load escorts – lifting overhead lines	Escorting high load transportation through areas where lines may need to be temporarily lifted or removed to allow passage of the high load.
Covering of low voltage lines for safety reasons	The provision of temporary covers for mains and services to ensure a safe working environment for those required to work in close proximity to overhead power lines.
After hours truck by appointment	DNSP attendance by service crews as required outside normal working hours to carry out electrical trades work on customer's electrical interface to the network.

Source: AusNet Services

18.4.2 A summary of AusNet Services' methodology for deriving its quoted rates

AusNet Services has taken a base year trend approach to calculating its quoted rates for the forthcoming regulatory control period. More specifically, this involved:

- Determining actual rates per hour for each labour category from the 2014 base year, with this information sourced from AusNet Services' internal estimating system.
- Escalating these hourly rates by the labour escalators discussed in other parts of this submission to obtain a starting 2016 rate.
- Factoring into that starting 2016 price, real labour cost escalators that are forecast for the remaining years of the regulatory period (consistent with those discussed in prior sections of this submission), so that in NPV terms, AusNet Services recovers future real cost increases upfront (in lieu of providing for this through an annual price adjustment in the price control formula).

The resultant charges for 2016 are presented in the tables below.

Table 18.6: Quoted Alternative Control Services Charge-out Rates for 2016

Labour category	Service description	$/hour rate – BH	$/hour rate – AH
Labour—wages	Construction Overhead Install	$113.95	$138.40
Labour—wages	Construction Underground Install	$111.30	$135.17
Labour—wages	Construction Substation Install	$111.30	$135.17
Labour—wages	Electrical Tester Including Vehicle & Equipment	$198.98	$224.34
Labour—wages	Planner Including Vehicle	$152.97	Not applicable
Labour—wages	Supervisor Including Vehicle	$152.97	Not applicable
Labour—design	Design	$130.61	$158.63
Labour—design	Drafting	$100.36	$121.89
Labour—design	Survey	$118.23	$143.59
Labour—design	Tech Officer	$118.23	$143.59
Labour—design	Line Inspector	$113.95	$138.40
Labour—design	Contract Supervision	$118.23	$143.59
Labour—design	Protection Engineer	$130.61	$158.63
Labour—design	Maintenance Planner	$118.23	$143.59

Source: AusNet Services

Where a quoted service requires materials and / or vehicles, these would be charged at actual cost.

18.4.3 Negotiated ancillary network services

AusNet Services provides reserve feeder construction as a negotiated service under the Negotiating Framework published in Appendix 18A.

18.5 Public Lighting

AusNet Services provides Public Lighting services to local councils and other authorities such as Vic Roads. These services are provided in accordance with Victorian Public Lighting Code which is available on the Essential Services Commission web site, www.esc.vic.gov.au. The services provided are:

- Operation, maintenance, repair and replacement of shared public lighting assets;
- Operation, Maintenance and Repair – dedicated public lighting assets;
- Replacement – Dedicated public lighting assets;
- New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites); and
- Alteration and relocation of public lighting assets.

Consistent with the classification in the Framework and Approach, the table below outlines AusNet Services' proposed alternative control public lighting services for the forthcoming regulatory control period.

Table 18.7: Classification of public lighting services

Public Lighting Service	Classification
Operation, maintenance, repair and replacement – shared public lighting assets	Alternative control (fee-based)
Operation, maintenance and Repair – dedicated public lighting assets	Negotiated
Replacement – Dedicated public lighting assets	Negotiated
New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites)	Negotiated
Alteration and relocation of public lighting assets	Negotiated

Source: AER Final Framework & Approach for the Victorian Electricity Distributors.

18.5.1 Fee based public lighting services

AusNet Services has used the AER's Public Lighting model to determine the fee based charges to apply to the shared public lighting assets, these rates apply to all public lighting installations that are owned by AusNet Services and utilise either wholly or in part the shared distribution network assets in the provision of the lighting service. Shared distribution network assets include lights mounted on AusNet Services' distribution poles, lights serviced directly off the overhead distribution network whether on a distribution pole or a public lighting pole, and lights serviced from the underground distribution network whether on a distribution pole or a public lighting pole.

AusNet Services has separate pricing structures for the Central Region and for the North and East Regions. These price structures take account of the higher costs associated with the provision of the services in these regions due to the higher costs of servicing lights in lower light density areas and greater distances travelled by contractors and service agents. The table below sets out the prices for fee-based services for the regulatory period.

Table 18.8: Operation, Maintenance Fee Based

Central					
Light Type	**2016**	**2017**	**2018**	**2019**	**2020**
Mercury Vapour 80W	$43.71	$46.97	$50.22	$53.44	$56.61
HP Sodium 150W	$100.31	$105.19	$110.09	$115.00	$119.87
HP Sodium 250W	$101.25	$106.18	$111.13	$116.08	$121.00
Mercury Vapour 50W	$66.88	$71.86	$76.83	$81.76	$86.61
Mercury Vapour 125W	$64.26	$69.04	$73.82	$78.55	$83.21
Mercury Vapour 250W	$106.31	$111.49	$116.69	$121.89	$127.05
Mercury Vapour 400W	$110.36	$115.73	$121.13	$126.53	$131.89
HP Sodium 100W	$107.33	$112.55	$117.80	$123.05	$128.27
HP Sodium 400W	$143.78	$150.77	$157.81	$164.84	$171.82
T5 2X14W	$48.92	$49.02	$49.79	$50.95	$52.35
T5 2X24W	$53.53	$53.49	$54.20	$55.34	$56.75
North & East					
Mercury Vapour 80W	$49.43	$53.07	$56.72	$60.35	$63.94
HP Sodium 150W	$113.93	$119.39	$124.89	$130.41	$135.91
HP Sodium 250W	$112.69	$118.13	$123.61	$129.10	$134.58
Mercury Vapour 50W	$73.16	$78.54	$83.94	$89.32	$94.63
Mercury Vapour 125W	$73.16	$78.54	$83.94	$89.32	$94.63
Mercury Vapour 250W	$117.20	$122.85	$128.55	$134.27	$139.96
Mercury Vapour 400W	$120.58	$126.40	$132.26	$138.14	$144.00
HP Sodium 100W	$121.90	$127.74	$133.63	$139.54	$145.43
HP Sodium 400W	$160.03	$167.74	$175.52	$183.33	$191.10
T5 2X14W	$54.53	$54.91	$55.99	$57.47	$59.20
T5 2X24W	$59.25	$59.50	$60.51	$61.98	$63.72

Source: AusNet Services

18.5.2 Negotiated public lighting services

AusNet Services provides operation, maintenance, repair and replacement of the following additional light types as a negotiated service:

- Metal Halide 70W;
- Metal Halide 100W;
- Metal Halide 150W;
- Mercury Vapour 700W;
- LED 18W;
- Compact Fluorescent 32W; and
- Compact Fluorescent 42W.

The following negotiated services are provided under the Negotiating Framework published in Appendix 18A.

- Replacement – dedicated public lighting assets;
- New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites);
- Alteration and relocation of public lighting assets.

18.6 Form of Control

In its Framework and Approach paper, the AER states that it will apply:[4]

- A revenue cap to the type 5 and 6 and smart metering service – not subject to competition.
- Apply caps on the prices of individual services in the next regulatory control period to alternative control services.

AusNet Services accepts the formula the AER proposes to apply to Alternative Control Services. This formula is:[5]

$$\bar{p}_i^t \geq p_i^t$$

i=1,...,n and t=1,2,3,4

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1+CPI_t)(1-X_i^t)$$

Where:

$\bar{p}_i^t$ is the cap on the price of service i in year t

p_i^t is the price of service i in year t. The initial value is to be decided in the final decision.

CPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_i^t is the X-factor for service i in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

4 AER, *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 89.

5 Ibid, pp. 92-93.

18.7 Support Documentation

In addition to the Public Lighting Model and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Appendix 18A – Proposed Negotiating Framework;
- Spreadsheet entitled *"AST ACS_Build up of prices (Confidential).xls"* showing the calculation of the prices and charges outlined in the chapter;
- Spreadsheet entitled "*AST RIN Information.xls"* showing selected time series as required by the RIN; and
- Spreadsheet entitled "*AST Travel Times.xls*" setting out how travel adjustments for our regional areas were calculated.

Part IV –
Tariffs and Prices

19 Tariffs for Standard Control Services

19.1 Overview

19.1.1 Introduction

Standard control services are services that are central to the supply of electricity and therefore relied on by most (if not all) customers. These services cover activities such as building and maintaining the shared distribution network.

The AER regulates these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs of providing standard control services are recovered through revenue earned from distribution use of system tariffs.

This chapter outlines:

- The indicative prices that AusNet Services proposes to charge for its standard control services in CY2016 and for the remainder of the regulatory control period;
- The basis, rationale and underlying regulatory requirements underpinning the development of those prices; and
- AusNet Services' broad approach to developing its prices for standard control services for CY2017 onwards.

19.1.2 Background

The revenue requirement determined by the AER for standard control services is recovered from customers in accordance with the DNSPs pricing approach, which must be approved by the AER. Customers are assigned to tariffs, which describe the unit price the customer pays for the use of the network.

Historically the unit price for use of the network, for small customers, has been based on an energy parameter (kWh), measuring the accumulation of electricity use over time. However, the electricity demand parameter (kW), which represents the point in time use of electricity, is the primary driver of network costs. Installed metering technology has not previously enabled this parameter to be measured for small customers. This has changed with the introduction of smart meters in Victoria, and pricing structures which will lead to more 'cost-reflective' tariffs and efficient allocation of network costs is possible.

In parallel with the implementation of smart metering the AEMC has concluded a review of pricing arrangements and resulting changes to the Rules facilitate greater cost reflectivity. Pricing in accordance with the new Rules commences in 2017, the second year of the regulatory period subject to this revenue determination by the AER.

Improving cost reflectivity has the potential to reduce cross-subsidies between customers, which can lead to inefficient investment by both customers and the DNSP. Cross-subsidies will exist between users of the network, where the basis for charging and the main cost drivers are not aligned. For example, customers who have a very high demand for electricity at the time when the network is most constrained, but make average use of electricity most of the time, will cause network investment. Unless charged on a demand basis, this customer will not contribute more than the average customer to the network augmentation costs.

The new cost reflective pricing arrangements also seek to encourage locational signalling of future investment costs. The principle is that in locations where network constraints are foreshadowed and network investment will become necessary this should be presented to the customers facing the network constraint as a 'price signal' representing the cost of investment to relieve it. This should encourage the customers to respond in a way which will ensure electricity needs are most efficiently delivered, which may include network usage reduction strategies, or indeed, recognition of the impending need for network investment.

The introduction of geographic differentiation in pricing is a sensitive matter, and AusNet Services initial engagement with customers on the concepts has not indicated support for this approach. Since differentiation is inherent in the intent of the revised Rules, AusNet Services will continue to engage with all stakeholders on this aspect whilst it develops its tariff structures to comply when these commence in 2017.

19.1.3 Customer engagement

Findings

With respect to how revenue is collected from customers through tariffs rather than the revenue itself, several cost reflective concepts were tested with customers in focus groups. The concepts were only tested at a ‘principle’ level, and were largely not supported.

AusNet Services considers that efficient price signals are an important ingredient in keeping long term network prices at sustainable levels. The network is largely rural, requiring significant safety investment in predominantly low density rural areas. We therefore sought customer views on the merits of introducing locational cost allocation, which would be aimed to avoid inefficient connection that imposes increasing costs on the rest of the customer base, and to incentivise off-grid solutions where these would be cost efficient.

Locational cost to serve price signals were rejected, even, somewhat surprisingly, by focus groups chosen exclusively of urban customers who would benefit from the unwinding of the urban rural cross subsidy. This reflected views that the cost of safety expenditure, which had been previously linked to increasing prices, be spread across the community and that this tariff design penalised customers for sunk decisions on where they had chosen to live. Regional customers expressed a strong view that all customers were entitled to a reliable supply of electricity at a reasonable cost, regardless of where they live.

When asked about consumption based tariffs, the concept of peak usage in late afternoon is well understood. However, this is generally thought of in terms of electricity consumption rather than grid capacity. While peak pricing signals were more acceptable than locational signals, it was also clear that consumers do not distinguish between the network and energy consumption elements of their electricity bill and, therefore, already consider themselves to be paying more for using more during peak times.

Paying fixed charges to cover sunk network capacity was also rejected as it was considered unfair that there was no reward for cutting consumption.

During one of the face-to-face meetings arranged with large customers, one customer expressed a level of dissatisfaction with the existing design of their tariff.

How they were incorporated into our proposal

The tariffs proposed for the first year of the new regulatory control period retain AusNet Services’ existing tariff structures. These do not incorporate locational attributes for small customer tariffs. During the course of developing tariffs for the subsequent years of the regulatory control period, to be submitted via the Tariff Structures Statement in September, we propose to consult extensively with stakeholders to refine the appropriate tariff structures for the AusNet Services network.

19.1.4 Chapter structure

The remainder of this chapter is structured as follows:

- Section 19.2 provides background to AusNet Services' discussion of its proposed prices for standard control services;
- Section 19.3 outlines the regulatory requirements that AusNet Services has had regard for when developing the prices it proposes to charge for its standard control services;
- Section 19.4 outlines the indicative prices that AusNet Services proposes to charge for its standard control services in CY2016 and the remainder of the regulatory control period;
- Section 19.5 outlines how AusNet Services has sought to comply with the regulatory requirements, including the results of its stand alone, avoidable cost and long run marginal cost modelling;
- Section 19.6 discusses AusNet Services' approach to developing its prices for standard control services from CY2017 onwards;
- Section 19.7 outlines AusNet Services' proposed tariff reassignment procedures;
- Section 19.8 outlines AusNet Services' proposed approach to developing tariffs for the recovery of transmission charges;
- Section 19.9 outlines AusNet Services' proposed Control Mechanism for Standard Control Services; and
- Section 19.10 outlines the support documentation for the chapter.

19.2 Background to the Development of AusNet Services' Prices

AusNet Services has a number of distribution use of system tariffs that are available to its customers. A customer's eligibility for a particular tariff will generally depend upon, amongst other things:

- Their customer type (e.g., residential, small commercial);
- The voltage level that they are connected to;
- The amount of energy that they consume; and
- The distance that they are from the transmission terminal station by which they are served (for some very large customers who take supply at greater than 22,000 volts and are more than 20kms from a terminal station).

AusNet Services' current mix of distribution tariffs include multiple components (being the parameters that are used as the basis for charging the customer). These include, but are not limited to:

- Daily fixed charge ($/day): This tariff component is calculated based on the number of days a customer has been connected to AusNet Services' network over the billing period;
- Usage charges ($ / kWh): This tariff component is calculated based on the amount of energy that a customer has consumed over the billing period:
  - At certain times of the day ('Time of Use tariffs' or 'Two-rate tariffs');
  - At certain times of the year (Seasonal time of use tariffs or multi-rate tariffs); or
  - Above and below a certain pre-determined level of usage (e.g., 1020kWh) over a 90 day period ('block tariffs').
- Capacity charge ($/kVA): This tariff component is calculated based on a customer's installed connection asset/s, for example the:
  - Nameplate rating of the transformer supplying the customer's installation; or
  - Rating of the cabling and switchgear that makes the customer connection point; and

- Critical peak demand charges ($/kVA per annum): This tariff component is based on an average of the customer's 30 minute peak demand measured in the 4 hour critical period on 5 nominated days.

Over the current regulatory control period, AusNet Services has introduced a number of new, cost reflective distribution use of system tariffs. AusNet Services received regulatory approval for the introduction of a cost reflective Seasonal Time of Use tariff at the commencement of the current regulatory control period. This was not implemented, in response to community concerns and became subject to the Victorian moratorium on new tariff structures relating to AMI metering data. In 2013, in support of the Victorian Government's introduction of flexible pricing, AusNet Services introduced a new multi rate time of use tariff (NGT26) that reflected the tariff structure nominated by the Victorian Government in its “Introduction of Flexible Pricing – Position Paper”. The previously approved AusNet Services' cost reflective tariff structures are also now available to residential and small customers with logically converted AMI meters as an option to the existing tariff structures and the government introduced alternative structures.

In addition to these two initiatives, in 2011, AusNet Services become the first distribution network in Australia to introduce a dynamic, cost reflective, critical peak demand tariff to apply to its large industrial customers. This price signal was designed to reflect the future cost to AusNet Services of meeting increased utilisation of its network during times of peak loading. This cost reflective price signal was designed to incentivise industrial customers to reduce their load during those peak periods, where the benefit to them (via lower network charges) exceeded the cost to them of doing so. This has been a highly successful tariff, contributing to an estimated 60MW reduction in peak demand per annum since its inception. This has led to the more efficient use of AusNet Services' distribution network, lower costs to participating customers who have responded to the price signal, and lower costs to all consumers in the long-run via lower augmentation related capital expenditure.

19.3 Regulatory Requirements Governing the Design of Network Tariffs

There have been a number of recent changes to the Rules that underpin how distribution businesses set prices for their standard control services. In particular, in November 2014, the Australian Energy Market Commission (AEMC) made a Rule Determination titled: *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, which codified a number of important changes to the Rules related to the development of tariffs for standard control services.

The key features of this Rule Determination were that:

- A network pricing objective was codified in the Rules, requiring each network tariff to reflect the efficient costs of providing network services to the consumers assigned to the tariff.
- DNSPs must base their tariffs on the Long Run Marginal Costs (LRMC) of supply.
- DNSPs must recover their allowed revenue in a way that minimises distortions to the price signals for efficient usage provided by LRMC based prices.
- DNSPs must (a) manage the impact of annual changes in network prices on consumers, and (b) set network prices which consumers are reasonably capable of understanding.
- DNSPs must develop a Tariff Structure Statement (TSS) that sets out their network price structures. The TSS is to be approved by the AER as part of the regulatory determination process and applies for the five year regulatory control period. Price levels are still approved by the AER on an annual basis.
- DNSPs are required to describe how they have consulted with retailers and consumers on the design of network prices and sought to address their concerns.
- Binding timeframes have been included so that network prices are generally approved at least six weeks before they commence, except in the first year of a regulatory period.

Notwithstanding the above, a number of important transitional arrangements have been outlined in the final Rule Determination. These include that:

- Victorian DNSPs are able to submit their initial proposed TSS to the AER by 25 September 2015, five months after submission of the Regulatory Proposal.
- Tariff structures based on the new set of pricing principles are required from 1 January 2017, such that compliance with the pre-existing principles is applicable for the first year of the Regulatory Control Period, and is provided for in the Rules transitional provisions.

The key features of the pre-existing principles include, but are not limited, to requiring that:[1]

"(a) For each tariff class, the revenue expected to be recovered should lie on or between:

(1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and

(2) a lower bound representing the avoidable cost of not serving those retail customers.

(b) A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:

(1) must take into account the long run marginal cost for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates; and

(2) must be determined having regard to:

(i) transaction costs associated with the tariff or each charging parameter; and

(ii) whether retail customers of the relevant tariff class are able or likely to respond to price signals.

(c) If, however, as a result of the operation of paragraph (b), the Distribution Network Service Provider may not recover the expected revenue, the provider must adjust its tariffs so as to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption."

AusNet Services has had regard to these principles when developing its CY2016 indicative prices for standard control services.

19.4 Indicative tariffs for CY2016 and the remainder of the regulatory control period

The following table outlines AusNet Services' indicative tariffs and tariff levels for its main tariffs for CY2016 as well as for the remainder of the regulatory control period. A list of all tariffs and tariff levels is contained in the PTRM that has been submitted in conjunction with this Proposal. The indicative prices outlined in the table below reflect the:

- Costs and revenue levels outlined in this Proposal, which may change depending on the AER's Final Decision; and
- Application of the existing Rules regarding the development of prices for standard control services, consistent with the transitional arrangements as outlined in the Distribution Network Pricing Arrangements Rule Determination.

AusNet Services is not proposing to make any major change to the structure of its network tariffs in CY2016. Tariffs for CY2017 and beyond may change as a result of AusNet Services' compliance with the new Distribution Network Pricing Arrangements Rule Determination, which will come into effect from CY2017. Revised indicative price structures and levels to be applied from 2017 onwards will be advised in the TSS, which is to be submitted to the AER in September 2015.

[1] NER Version 65

Table 19.1: AusNet Services' Indicative Prices for CY2016 and the remainder of the regulatory control period

Tariff	Tariff Component	Units	2016	2017	2018	2019	2020
NEE11	Standing Charge	$/Yr	51.48	52.78	54.11	55.48	56.88
	Block 1 Energy	c/kWh	8.1653	8.3714	8.5827	8.7993	9.0214
	Block 2 Energy	c/kWh	14.8876	15.2634	15.6487	16.0436	16.4486
NEE20	Standing Charge	$/Yr	67.84	69.55	71.31	73.11	74.96
	Peak Energy	c/kWh	18.4332	18.8985	19.3755	19.8645	20.3659
	Off Peak Energy	c/kWh	3.1991	3.2798	3.3626	3.4475	3.5345
NGT26	Standing Charge	$/Yr	67.84	69.55	71.31	73.11	74.96
	Peak Energy	c/kWh	13.9601	14.3125	14.6737	15.0441	15.4238
	Shoulder Energy	c/kWh	9.1602	9.3914	9.6285	9.8715	10.1207
	Off Peak Energy	c/kWh	2.4435	2.5052	2.5684	2.6332	2.6997
NEE21	Standing charge	$/Yr	57.35	58.80	60.28	61.80	63.36
	Peak Energy	c/kWh	16.7724	17.1958	17.6298	18.0747	18.5310
	Off Peak Energy	c/kWh	3.4281	3.5146	3.6033	3.6942	3.7875
NSP56	Standing Charge	$/Yr	2,330.38	2,389.20	2,449.50	2,511.33	2,574.71
	Peak Energy	c/kWh	11.4397	11.7285	12.0245	12.3280	12.6392
	Shoulder Energy	c/kWh	8.3300	8.5402	8.7558	8.9768	9.2034
	Off Peak Energy	c/kWh	3.9096	4.0083	4.1095	4.2132	4.3195
	Capacity kVA	$/kVA/Yr	20.53	21.05	21.58	22.12	22.68
	Critical Peak kVA	$/kVA/Yr	34.17	35.03	35.92	36.82	37.75
NSP76	Standing Charge	$/Yr	5,156.86	5,287.02	5,420.47	5,557.28	5,697.54
	Peak Energy	c/kWh	3.9839	4.0844	4.1875	4.2932	4.4016
	Shoulder Energy	c/kWh	2.7204	2.7891	2.8595	2.9316	3.0056
	Off Peak Energy	c/kWh	2.4370	2.4985	2.5615	2.6262	2.6925
	Capacity kVA	$/kVA/Yr	54.25	55.62	57.02	58.46	59.94

Tariff	Tariff Component	Units	2016	2017	2018	2019	2020
	Critical Peak kVA	$/kVA/Yr	90.37	92.65	94.99	97.39	99.85
NSP81	Standing Charge	$/Yr	5,156.86	5,287.02	5,420.47	5,557.28	5,697.54
	Peak Energy	c/kWh	0.5442	0.5580	0.5720	0.5865	0.6013
	Off Peak Energy	c/kWh	0.2202	0.2257	0.2314	0.2373	0.2433
	Capacity kVA	$/kVA/Yr	41.66	42.71	43.79	44.89	46.03
	Critical Peak kVA	$/kVA/Yr	69.39	71.14	72.94	74.78	76.66

Source: AusNet Services

19.5 AusNet Services' compliance with the Regulatory Requirements

The following sections outline how AusNet Services has sought to comply with the current regulatory requirements, including the results of its stand alone, avoidable cost and long run marginal cost modelling, as well as its compliance with other factors outlined in the Rules.

19.5.1 Stand alone cost

The existing Rules require that for each tariff class, the revenue expected to be recovered should lie on or between:

- an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and
- a lower bound representing the avoidable cost of not serving those retail customers.

The rationale for this test is to ensure that inefficient connection and disconnection decisions are not made by users, or prospective users of AusNet Services' distribution network.

Therefore, for a tariff to be deemed to be efficient under the Rules, it must deliver a stream of revenue from a customer, or as a proxy, a class of customers, that is between this upper and lower bound. This is commonly known as the 'efficient pricing band'. The reason why a price within this 'band' is deemed to be efficient is for two reasons:

- Greater than the avoidable cost: If the revenue expected to be recovered from a customer / customer class does not exceed the cost that the business would avoid if they did not provide them with electricity services, that customer is (a) being subsidised by AusNet Services' remaining customer base, and (b) would be over-consuming electricity services, relative to efficient levels (assuming that the customer or customer class' demand curve is not perfectly inelastic); and
- Less than the stand alone cost: Breaching this upper bound may result in that customer (or group of customers) being incentivised to inefficiently by-pass AusNet Services' existing distribution network in order to avoid paying AusNet Services' tariffs, despite the fact that the incremental cost to AusNet Services of providing these services to that customer (or group of customers) may be less than the alternative (by-pass) option.

AusNet Services' considers that the costs that it would be guaranteed to avoid if an individual customer disconnected from its network would be the costs that it would have incurred in transporting energy[2] through its distribution network to that customer in that location. Given this, AusNet Services has used it off-peak distribution use of system tariffs, which have been designed to broadly reflect its incremental operating and maintenance expenditure per kWh, as a proxy for this avoided cost.

However, AusNet Services notes that there are a number of methodologies that can be utilised to estimate the stand alone cost of servicing a customer, or group of customers. In determining which approach should be used to calculate the stand alone cost for each individual customer, or each group of customers, AusNet Services has considered a number of practical and theoretical issues. In particular, AusNet Services has considered the extent to which the adoption of a theoretical stand alone cost to serve a group of customers may be inconsistent with the decisions that will be made by individual customers – particularly:

- If it is individual customers that are likely to cease to obtain supply from the existing system, not groups of customers; and
- In new developments, where they will virtually all contain a mixture of customer groups (e.g., both residential and small commercial customers).

As a result, AusNet Services has adopted an approach that focuses on the potential for an individual customer to by-pass its network, as opposed to the potential for an entire customer class to by-pass its network. AusNet Services considers this to be a more practical, and robust application of the underlying economic principle that underpins the Rules, as it is likely to be individual customer's that make the decision to by-pass networks, not customer classes.

AusNet Services has further split this analysis into two categories, reflecting the likely alternative servicing solution that would be taken up by an individual customer:

- Large Customers: AusNet Services has estimated the total network cost of connecting a customer to the existing electricity transmission network, and compared this to AusNet Services' existing distribution use of system charges; and
- Small Customers: Assessing the cost per kWH of installing, operating and maintaining a stand alone power system (where this is required to obtain an equivalent level of reliability to AusNet Services' distribution network), and comparing this to the average retail bill that customers would avoid (inclusive of AusNet Services' proposed network use of system tariffs for that class of customer) if they by-passed the grid.

The former focuses on the fact that it is the location of a large customer to another potential alternative source of electricity that will be the predominant driver of by-pass. Further, this acknowledges that the larger the customer, the less economic it is likely to be to utilise non-network sources of electricity (e.g., embedded generation).

The latter recognises that it will be likely to be individual customers that seek to by-pass its existing network to avoid having to pay their all-in retail charges. Moreover, it reflects the fact that given the size of residential and small commercial customers, it will not be a network solution that is utilised to by-pass the network, rather it may be through the use of an alternate fuel source, including non-network sources of electricity.

The results of the analyses are contained in the table below. For completeness, the 'Average All-in Retail Bill' reflects the average retail bills for the two customer classes for which AusNet Services has assumed the adoption of a stand alone power system. As stated previously, the avoided distribution costs are based on the off-peak tariffs that AusNet Services is proposing to charge customers for the provision of energy in those off-peak period.

[2] AusNet Services notes that depending on the particular circumstances of the customer disconnecting from the grid, the actual avoided costs may be higher in practice. These circumstances might include whether or not that customer consumes energy during peak demand periods (and therefore contributes to future augmentation requirements), or whether they are part of a broader group of customers within a particular region disconnecting from the network. In relation to the latter, if a group of customers were to disconnect from a part of AusNet Services' network that was forecast to require significant capital expenditure to upgrade / replace parts of that network, the avoidable cost could also reflect these avoided capital costs, however this would be dependent on the number of customers within a particular area leaving the grid (i.e., the loss of customer density within that particular area), which is difficult to predict and model.

Table 19.2: Results of Stand alone / Avoidable cost test

Tariff Class	Stand alone Cost ($/kWh)	Average All-in Retail Bill Avoided ($/kWh)	Avoided Distribution Costs	Average DUoS Bill
Residential	$0.84/kWh	$0.273/kWh	$0.021/kWh	$0.110/kWh
Small I & C	$0.60/kWh	$0.252/kWh	$0.051/kWh	$0.124/kWh
Large I & C	$1.13/kWh	Not applicable	$0.015/kWh	$0.071/kWh
High Voltage	$0.388/kWh	Not applicable	$0.003/kWh	$0.033 /kWh
Sub Transmission	$0.019/kWh	Not applicable	$0.0004/kWh	$0.005/kWh

Source: AusNet Services

19.5.2 Long Run Marginal Cost

The applicable pricing principles require that in developing tariffs, AusNet Services must take into account the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.

The requirement to take into account the LRMC reflects a fundamental economic concept - namely allocative efficiency. Allocative efficient outcomes will be promoted if customers consume electricity up to the point where the marginal benefit to them of consuming an additional unit of energy (kWh, kW or kVa, depending on the cost driver being priced) equals the marginal cost of providing that extra unit of energy to that customer.

When price deviates from the marginal cost of supply – in this case, the LRMC - customers will consume either:

- too much of the service attribute, which will occur if the marginal price is less than its true cost (i.e., some customers will consume electricity services, despite the fact that the cost of providing them with an additional unit of that service attribute exceeds the benefit that they receive from consuming that service attribute), or
- not enough of the service attribute, which will occur if the marginal price is greater than its cost of supply (i.e., some customers will NOT consume electricity services, despite the fact that the cost of providing them with an incremental unit of that service attribute is less than the incremental benefit that they would receive from consuming that additional unit).

The LRMC for a network service can be calculated in a number of different ways. These include the Average Incremental Cost (AIC) approach, which is underpinned by a business' forecast of its future costs (numerator) that will change as a result of its forecast change in demand (denominator), with both the numerator and denominator discounted back to create a Net Present Value (NPV). An alternative approach is to use the perturbation approach, which in practical terms, seeks to ascertain how a business' expected future costs would change (in NPV terms) if there was an incremental increase (or decrease) in the future levels of demand for its services. This approach is generally considered to be more suited to wholesale supply systems where there is lumpy capital investment required to augment the system. A number of other approaches have also been mentioned in the broader literature on this topic, including the common distribution charging methodology (CDCM) introduced by OFGEM in 2011, which involves estimating the incremental costs of a hypothetical 500 MW increment in capacity.

Whilst AusNet Services will investigate all of these alternative models in more detail as part of its future tariff strategy, it has chosen to adopt the AIC approach for the purposes of calculating the LRMC outlined in this submission. AusNet Services has adopted this approach for a number of reasons, including, but not limited to:

- It ensures that if AusNet Services' underlying demand and cost forecasts eventuate, the NPV of revenue that AusNet Services' generates over the evaluation period via the adoption of a cost reflective price based on the calculated LRMC, will exactly equal the NPV of the costs that it incurs – that is, growth is 'self-funding'. This means that not only can it be said with some certainty that this tariff is cost reflective in those circumstances, it ensures that there is no cross-subsidisation between those customers causing the growth to occur, and those that are not causing that growth to occur,
- It is commonly used by distribution networks, as it is generally considered to be well suited to situations where there is fairly consistent profile of investment over time to service growth in demand, and
- Forecast of growth in the demand for AusNet Services' services is consistent with forecasts that underpin other components of this regulatory submission.

The AIC approach to determining the LRMC utilises the following formula:

$$LRMC = \frac{\sum NPV(Forecast\ Capex + Forecast\ Opex)}{\sum NPV\ (Forecast\ Growth\ in\ outputs)}$$

For the purposes of this exercise, AusNet Services has adopted two key assumptions to derive its LRMC:

- Only the 'costs' that are able to be mitigated by the broader customer base, if they were to respond to the price signal derived by the LRMC, are included in the model. Put another way, if the broader customer base were to respond to a particular price signal, and that response did not lead to a reduction in a particular cost item, then that cost item has not be included in the LRMC calculation that is used to set variable prices. In general, this means that only 'shared network assets' that will vary with changes in future demand (and any associated opex) have been included; and
- The proposed price that is compared to the calculated LRMC is the distribution use of system 'peak period' price, as almost all capital expenditure that could change with a change in demand is required to alleviate capacity constraints during peak periods.

The results of the LRMC analysis are contained in the following table.

Table 19.3: Results of LRMC

Tariff Class	Voltage Level	Proposed Peak Period Price ($/kWh)	LRMC ($/kVA)	LRMC ($/kWh)[3]
Residential	Low Voltage	$0.110	$88.70	$0.115
Small I & C	Low Voltage	$0.130	$88.70	$0.044
Large I & C	Low Voltage	$0.082	$88.70	$0.042
High Voltage	High Voltage	$0.033	$24.58	$0.011
Sub Transmission	Sub transmission	$0.005	$16.08	$0.007

Source: AusNet Services

19.5.3 Other factors

The Rules also require that tariffs be determined having regard to:

- The transaction costs associated with the tariff or each charging parameter; and
- Whether retail customers of the relevant tariff class are able or likely to respond to price signals.

As AusNet Services is not proposing to make any material change to its tariff structures in CY2016, it does not consider there to be any material increase in transaction costs associated with its proposed tariff structure for CY2016, relative to previous years, nor does it consider there to be any risk that customers may be unlikely to be able to respond to the price signals, particularly given evidence from the current regulatory control period that customers (albeit larger customers) have been able to respond to the Critical Peak Demand tariff.

As discussed in more detail below, any change to tariffs made in 2017 and beyond will be subject to the TSS review process.

19.6 The development of AusNet Services' tariff for 2017 and beyond

As outlined earlier in this chapter, there has been a recent change to the Rules regarding how network businesses develop the tariffs they will charge for standard control services. As a result, AusNet Services is reviewing its entire suite of tariffs to ensure that tariffs will accord with the requirements of the new Rules that will take effect from 2017 onwards.

In undertaking this review, AusNet Services will be investigating (but will not necessarily adopt) a number of potential features, including:

- Using the functionality of its AMI meters to include a demand component in the tariffs for small customers, for which the level would be based on the LRMC of supply. AusNet Services will investigate tariff structure options that align a 'demand' tariff with its underlying cost drivers (and hence, comply with the recent Rule Determination). Options may include charging customers based on their anytime maximum demand, their maximum demand within a small pre-determined period of time, their average demand over small pre-determined period of time, or a combination of the above.

[3] Translating the LRMC – which is measured in $/kVA – to a $/kWh unit, reflects a number of assumptions, each of which may vary across tariff classes. These assumptions include, but are not limited to: (a) the period covered by the peak price, (b) the average load factor of a customer within that tariff class over that peak period, (c) the average power factor of a customer within that tariff class.

- Adopting some form of geographic differentiation to reflect the differing LRMC of supply of providing services to different parts of AusNet Services' network region.
- Recovering its residual revenue[4] in a way that least distorts customer's marginal consumption and connection decisions.

The transitional provisions of the Rules require AusNet Services to set out proposed tariff structures and indicative prices for the remainder of the regulatory period in a TSS, to be submitted by 25 September 2015. The transitional provisions also require that the proposed TSS must be accompanied by an overview paper which includes a description of how AusNet Services has engaged with retail customers and retailers in developing the proposed TSS and has sought to address any relevant concerns identified as a result of that engagement. To be clear, AusNet Services will consult thoroughly with customers and retailers in formulating new tariff structures to be included in the TSS.

19.7 Tariff Reassignment

This section outlines AusNet Services' position on:

- defining tariff classes for all residential and small commercial customers in existence as at the commencement of the forthcoming regulatory period;
- defining how new customers will be assigned to tariffs; and
- the process for implementing New Tariffs for an Existing Tariff Class.

19.7.1 Regulatory Requirements

In developing its position on the aforementioned issues, AusNet Services has had regard to the requirements of Clause 6.12.1(17) and Clause 6.18.4 of the Rules. Clause 6.12.1(17) requires that the AER make the following decision as part of its distribution determination:

> *"…a decision on the policies and procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another (including any applicable restrictions);"*[5]

Moreover, Clause 6.18.4 of the NER states that:

> *"(a) In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles:*
>
> > *(1) retail customers should be assigned to tariff classes on the basis of one or more of the following factors:*
> >
> > > *(i) the nature and extent of their usage;*
> > >
> > > *(ii) the nature of their connection to the network;*
> > >
> > > *(iii) whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;*
> >
> > *(2) retail customers with a similar connection and usage profile should be treated on an equal basis;*
> >
> > *(3) however, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile;*

4 Residual revenue is the additional revenue that AusNet Services needs to recover, over and above what it recovers via the application of its LRMC based variable component of its tariffs, to ensure it recovers its overall revenue requirement.

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> (4) *a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.*

> (b) *If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged."*[6]

19.7.2 Defining tariff classes for existing residential and small commercial customers

Each customer who continues to be a customer of AusNet Services as at 1 January 2016, will be taken to be "assigned" to the tariff class that AusNet Services was charging that customer immediately prior to 1 January 2016.

19.7.3 Defining how new customers will be assigned to tariffs

In developing any new tariffs – whether to apply to new customers, or whether to apply to existing customers – AusNet Services will comply with the requirements of Clause 6.18.4 of the Rules, along with the rebalancing constraint outlined in the Rules and its overall Revenue Cap, as determined in accordance with this determination. AusNet Services proposes to utilise the annual Pricing Proposal to illustrate its compliance to the AER with all relevant Rules pertaining to the development of new distribution tariffs.

19.7.4 Assessment and Review Process

As stated previously, Clause 6.18.4 of the Rules requires that:

> *"…a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review".*[7]

In accordance with the above, AusNet Services proposes to notify a customer's retailer in writing (including via email) of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring. The notice will include advice that the customer may request further information from AusNet Services, or that they may object to the proposed assignment or reassignment. If the customer objects to the proposed assignment or reassignment and that objection is not resolved to the satisfaction of the customer, the customer has access to dispute resolution arrangements. If, as part of any dispute resolution process, AusNet Services receives a request for further information from a customer, AusNet Services will provide such information. AusNet Services will not provide the customer with any information that it deems to be of a confidential nature, unless required to under any relevant Law, Code or Regulation. AusNet Services will adjust any tariff assignment or reassignment in accordance with any decision made by a valid dispute resolution mechanism (e.g. EWOV).

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[6] NER Version 65

[7] Ibid.

19.8 Recovery of Transmission Charges

This section outlines why AusNet Services proposes to separate out and communicate its transmission charges to customers, and how it proposes to set those charges.

19.8.1 Regulatory Requirements

Clause 6.20.1 (d) of the NER states Distribution Network Service Providers must:

> *"(1) calculate transmission service charges and distribution service charges for all connection points in their distribution network; and*
>
> *(2) pay to Transmission Network Service Providers the transmission service charges incurred in respect of use of a transmission network at each connection point on the relevant transmission network."*[8]

Part M of Chapter 6 of the Rules requires separate disclosure of transmission and distribution charges for customers with loads greater than 10MW or 40GWh per annum or with metering equipment capable of capturing relevant transmission and distribution system usage data.

Effectively these rules require Victorian distribution companies with AMI meters installed throughout the network to disclose transmission and distribution charges separately to all customers. AusNet Services publishes its transmission tariffs separately to its distribution tariffs in order to comply with this obligation. Furthermore, where a large customer requires the information as set out in Clause 6.20.1 (d), AusNet Services will provide a statement detailing the charges.

19.8.2 Tariff Design

Historically, AusNet Services has set its transmission charges as common rates across the network. This approach has ensured that the charges fully recover the actual costs incurred through payments for Transmission Connection, Transmission Use of System, Embedded Generator network support where that support is a transmission substitute, net inter-distribution business connection charges and Avoided Transmission Use of System payments made to all complying embedded generators. AusNet Services recovers these costs through peak and off peak charges to customers.

The methodology for recovering the charges beyond 2017 will be considered within the scope of the TSS due to be submitted in September 2015.

19.9 Control Mechanisms

19.9.1 Overview

This section outlines how AusNet Services propose to adjust prices for each year in the 2016 regulatory period and how tariffs comply with the requirements of the National Electricity Rules that relate to setting prices.

- Compliance with the relevant control mechanisms [cl. 6.12.1(13)];
- Reporting and compliance with designated pricing proposal charges [cl. 6.12.1(19)];
- Reporting and compliance with jurisdictional scheme amounts [cl. 6.12.1(20)].

AusNet Services agrees with the positions taken in the Australian Energy Regulator's Framework and Approach Paper and proposes further clarification on the treatment of some items that have been identified as requiring resolution during the review process.

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19.9.2 Control mechanisms

To ensure AusNet Services sets prices in accordance with the regulatory regime the Australian Energy Regulator (AER)'s Framework and Approach (F&A) outlines mechanisms under which it controls the way prices are set.

By adopting the formulae outlined in this attachment, AusNet Services considers it will meet the requirement of Cl. 6.12.1(13) to demonstrate compliance with the relevant control mechanism.

19.9.3 Price control mechanism – Direct Control Services

The AER's framework and approach paper sets out the price control mechanism that AusNet Services applies to direct control service tariffs for each of its services offered in the 2016 regulatory period and adjusted annually via an annual pricing proposal. We will submit an initial pricing proposal following the AER's first final determination on this regulatory proposal and then by 30 September of each remaining year in the regulatory period.

The AER's price control mechanisms include:

- a revenue cap for standard control services refer 19.9.4.1;
- a revenue cap for type 5, type 6 and smart regulated metering for 'installation, operation, repair & maintenance, and replacement' and 'collection of meter data, processing and storage of meter data, and provision of access to meter data' services (refer Chapter 17);
- price caps for each individual service for alternative control services (refer Chapter 18).

19.9.4 Revenue cap for standard control services

A revenue cap on standard control services means that AusNet Services has no scope to recover more or less from our tariffs than the total revenue allowed by the AER. Where tariff levels and actual demand levels result in an under- or over-recovery of revenue in any one year (year t-2), it must be adjusted in the next year's (year t) tariffs to correct this.

Control mechanism for standard control services

$$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^{t*}$$ i=1,...,n and j=1,...,m and t=1,...,5

(1) $$MAR_t = AAR_t + I_t + T_t + B_t$$ t = 1,2,…,5

Where:

(2) $$AAR_1 = AR_1(1 + S_t'')$$ t = 1

(3) $$AAR_t = AAR_{t-1}(1 + CPI_t)(1 - X_t)(1 + S_t)$$ t = 2,3,4,5

Where:

MAR_t is the maximum allowable revenue in year t.

p_{ij}^t is the price of component i of tariff j in year t.

q_{ij}^{*t}	is the forecast quantity of component i of tariff j in year t.
AR_t	is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t. Adjusted as necessary to account for any difference between actual inflation and estimated inflation.
AAR_t	is the adjusted annual smoothed revenue requirement for year t.
I_t	is the sum of incentive scheme adjustments in year t. To be decided in the final decision.
T_t	is the sum of end-of-period adjustments in year t. Likely to incorporate but not limited to adjustments from the initial regulatory control period. To be decided in the final decision.
B_t	is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account. To be decided in the final decision.
CPI_t	is the percentage increase in the consumer price index. To be decided in the final decision.
X_t	is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing average return on debt where necessary. To be decided in the final decision.
S_t'''	is the sum of the s-factors for all parameters after application of the s-bank adjusted for the change in the annual revenue requirement between the last year of the 2011-2015 regulatory control period to 2016.
S_t	is the s-factor for regulatory year t.

AusNet Services has adopted the control mechanism as set out in the AER's Framework and Approach paper. This mechanism allows for the modification of elements in the formula as they are identified during the price reset consultation phase.

19.9.5 Items to be decided in the final decision – Standard Control Services

'I' Term

AusNet Services notes there are number of incentive schemes in the 2016 regulatory period however only proposes including the State Government's f-factor scheme active in the 2016 regulatory period in the 'I' Term.

Previous regulatory period adjustments, 'T' Term

AusNet Services proposes one component be included in the transitional adjustment factor ('T' term) to account for adjusts from the 2006 and 2011 regulatory periods.

The Demand Management Incentive Scheme (DMIS) from 2011-15 requires the return unspent funds to customers by adjusting future revenue. There is also a requirement to offset any revenue not recovered as a result of initiatives delivered under the DMIS. To achieve this objective, we propose adjusting revenue in the 2017 year in accordance with the DMIS process, see below.

AusNet Services does not propose to claim any foregone revenue, permissible under Cl. 3.2.5, attributed to the DMIS scheme noting that is making a contribution to the development of demand management initiatives for the long term interests of customers.

Adjustments for DMIS (Section 3.1.5 adjustments)

Annual adjustment amounts

(1) $$C_t = C_{t-1} - \left[\frac{R_t - A_t}{\left(1+i\right)^t} \times (1+i)^5 (1+i^*)^2 \right]$$

Where:

Rt	ex-ante revenue allowance under the DMIS for regulatory year 't' (t = 1,2,…,5)
At	expenditure approved ex-post under the DMIS for regulatory year 't' (t = 1,2,…,5)
i	nominal vanilla WACC as set in the distribution determination for the forthcoming regulatory control period
*i**	nominal vanilla WACC as set in the distribution determination for the forthcoming regulatory control period

NPV amount ($, 2015) to be adjusted in 2017

(2)

$$NPV = \frac{(R_1 - A_1)}{(1+i)} + \frac{(R_2 - A_2)}{(1+i)^2} + \frac{(R_3 - A_3)}{(1+i)^3} + \frac{(R_4 - A_4)}{(1+i)^4} + \frac{(R_5 - A_5)}{(1+i)^5} + \frac{C_5}{(1+i)^5(1+i^*)^2} = 0$$

Where:

Rt ex-ante revenue allowance under the DMIS for regulatory year 't' (t = 1,2,…,5)

At	expenditure approved ex-post under the DMIS for regulatory year 't' (t = 1,2,…,5)
i	nominal vanilla WACC as set in the distribution determination for the forthcoming regulatory control period
i*	nominal vanilla WACC as set in the distribution determination for the forthcoming regulatory control period

Annual adjustments, 'B' Term

License fees charges by the Victorian Essential Service Commission were recovered through the L-factor during the 2011-15 price reset period. With a change in the form of price control towards a revenue cap and the consequential changes in price control formulae, the recovery of these fees can best be achieved through the B_t term rather than continuing the use of the L-factor mechanism.

AusNet Services proposes to include a true-up for the net present value of under or over recovery of revenue in the t-2 year. The method to achieve this is to create the present value of actual revenue equal to the present value of revenue allowable.

AusNet Services does not propose to include any other adjustments under this term.

Calculation of CPI

In various price control formula, CPI is used to escalate revenues and prices to nominal dollars. In the framework and approach paper, the AER indicated it would advise the method for determining CPI as a part of the final determination

AusNet Services proposes the method for determining this escalator inset below. This is consistent with the approach followed in the previous regulatory control period using the September quarter data from the Australian Bureau of Statistics (ABS). AusNet Services proposes to balance the most recent actual escalation data with the submission timelines required under the National Electricity Rules (NER) requirements for tariff and revenue submissions.

Method for determining CPIt

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year t;

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year t-1;

minus one.

Adjusting X-factor for the trailing average return on debt

The X-Factor is determined by the Post Tax Revenue Model (PTRM). The value of X-Factor is to be amended annually to adjust for the trailing average return on debt.

19.10 Support Documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- Spreadsheet entitled "AST *LRMC Model.xls"* showing the calculation of the LRMC underlying tariff calculations;
- Spreadsheet entitled "*AST Convert kVA LRMC into dollar kWh.xls*" which converts the LRMC in kVA terms into kWh terms;
- Spreadsheet entitled "*AST Large Customer By Pass.xls"* setting out the avoided cost calculation for large customers.; and
- Spreadsheet entitled "*AST Off-grid system options- present value analysis.xls*" setting out the avoided cost calculation for small customers.

20 Prices and Bills

20.1 Overview

Throughout this submission, we have returned to the theme of sustainable prices. The effect of investing $1.25 billion over 10 years to improve distribution network safety, at a time when per capita energy consumption is falling and alternative technologies to traditional electricity supply via networks and large scale generation are emerging, is creating an increased risk of precipitating the so-called 'death spiral'. Higher network prices mean that more people are likely to leave the grid, leaving fewer customers to pay for the sunk asset cost.

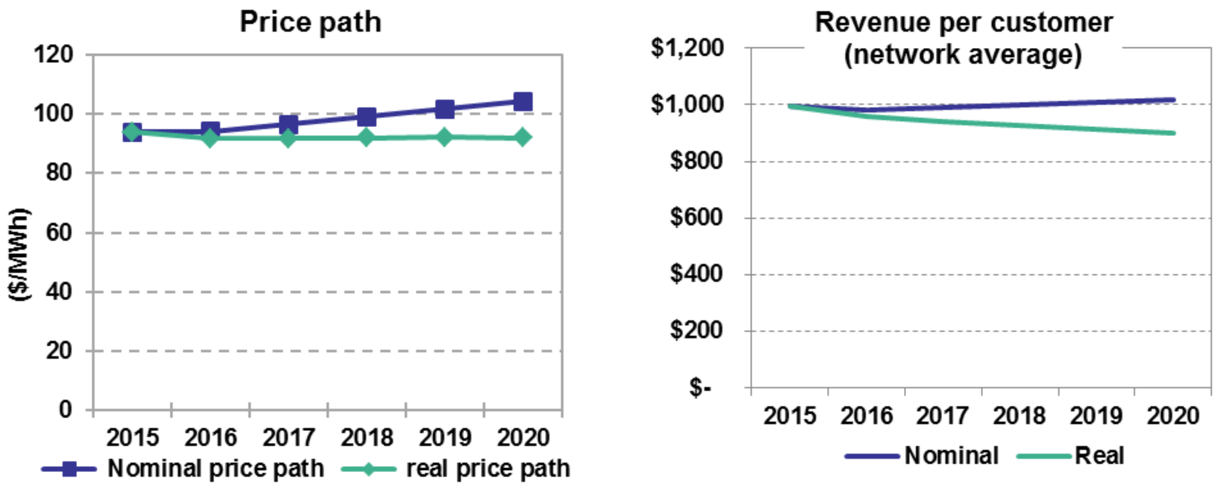
These are vexed issues, and are ones we cannot hope to completely address in this submission alone. For instance, the question of what is an appropriate funding mechanism for safety investment is a jurisdictional one, rather than one to be resolved by the AER. In many respects, the significant fall in the rate of return will help shield customers from some of the underlying tensions of the operation of the distribution network.

AusNet Services' revenue proposal continues to invest significant network capital to meet customers' expectations for their network service, and particularly, to improve community safety.

A number of charges that were formerly separate have been merged into the one distribution charge (known as the DUOS charge). These includes smart metering related upgrades to core distribution systems such as billing, that for the last 5 years have been included in the metering charge, and the costs of a large network support contract at Bairnsdale.

On a like-for-like basis, over the next five years, the average price impact on customers will be small. Nominal prices, measured in $/MWh, are proposed to increase by an annual average of 2.1%. The distribution component of customer bills, the total charge per year, will increase by an annual average of 0.4% in nominal terms. In real terms, both prices and bills will fall (by 0.4% and 2.0% per annum respectively).

Figure 20.1: Network average impact on prices from AusNet Services



Source: AusNet Services
Note: 2015 revenue and prices are presented on a like-for-like basis with forecasts (inclusive of smart metering related upgrades and Bairnsdale network support contract) so they do not match PTRM outputs; excludes metering charges.

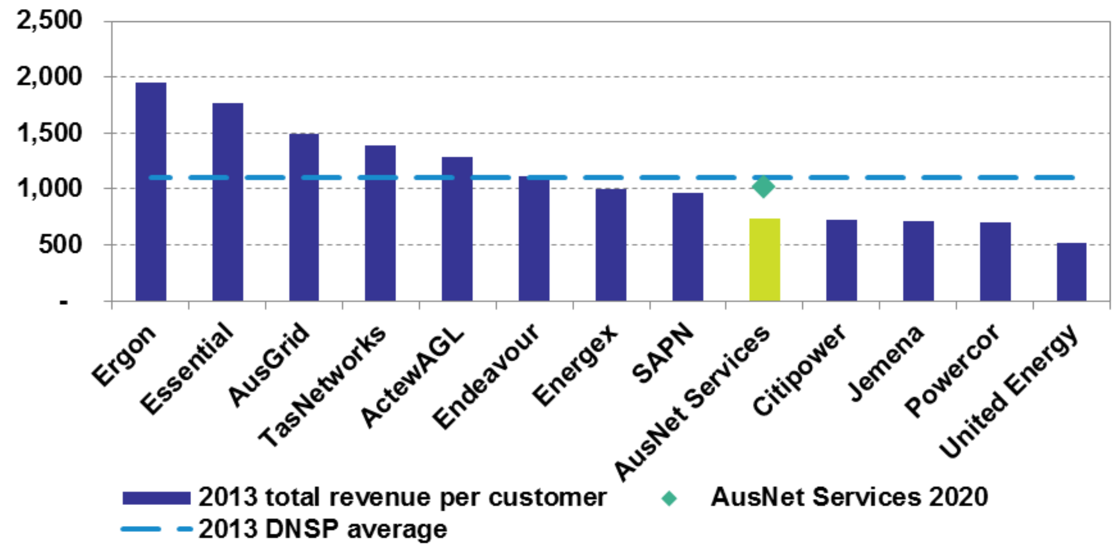
Including metering charges, residential network customer bills will fall by 10.4% in 2016, before remaining largely flat until 2020. Between 2015 and 2020, residential network customer bills will decrease, on average, by 2.3% per year.

The reason that prices rise while distribution bills (revenue per customer) stay relatively flat is that most customers are expected to use less energy than they do today.[518]

While AusNet Services' prices have increased rapidly in the current regulatory period, based on the latest available data, the average customer on our network pays less for distribution network services than the average National Electricity Market (NEM) customer. In 2013, the NEM average distribution network charge (average revenue per customer) was $1,107 (nominal), whereas the average charge on AusNet Services' network was $740. For residential customers, AusNet Services' charge was almost one-third lower than the NEM average.

As the figure below, which shows AusNet Services' average charge for 2020 and 2013 compared to other distributors' 2013 average charges, illustrates, AusNet Services' proposed prices will remain below the average 2013 price for distribution services in Australia's National Electricity Market through to 2020. This is true for residential customers as well as for the network average.

Figure 20.2: Comparison of NEM distribution charges in 2013 ($ nominal)



Source: 2013 Economic Benchmarking data

The proposed prices are sustainable in the short term. Steps are being taken to ensure prices remain sustainable in the longer term. However, the investment requirements for the network will see prices continue to diverge from the Victorian DNSPs with predominantly urban network areas.

20.2 Background

This section provides the background required to understand the financial impact of AusNet Services' proposal on our customers.

Typical distribution bills on AusNet Services' network

Chapter 19 Tariffs for Standard Control Services set out the background to how AusNet Services' distribution prices are set, including how costs are allocated across different customer groups.

The table below shows the average distribution charges on AusNet Services' network for the major customer types. This year, the average residential customer will pay $507. When other charges distribution charges that are proposed to be rolled into DUOS are added in, this comes to $582.

[518] The indicative bill model in the AER's Reset RIN fails to account for the annual change to per capita electricity consumption. The model assumes that customers consume the same volume of energy each year which is inconsistent with the total energy volumes used to generate prices.

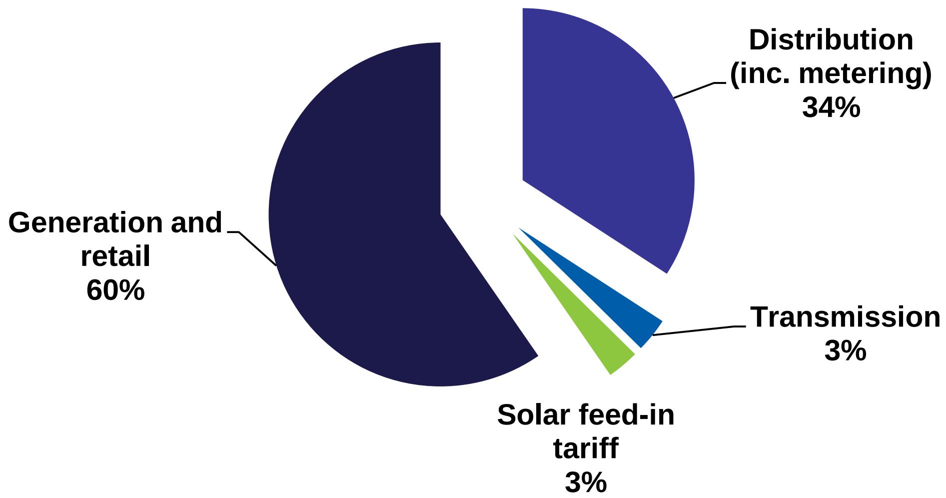
Table 20.1: Average distribution charges by customer type in 2015

Customer type	Distribution charge (DUoS)
Residential	$507
Industrial and Commercial	
Small	$2,155
Medium	$11,225
Large (LV)	$73,066
Large (HV)	$173,152
Large (subtransmission)	$199,614

Source: AusNet Services analysis, PTRM (not like-for-like with forecast)

Distribution networks do not charge their customers directly. Rather, network fees make up a part of the total electricity bill that customers receive from their retailer. While the composition of an electricity bill varies by customer type, by retailer and by tariff, the figure below shows that for a typical residential customer on AusNet Services' distribution network, the distribution component makes up around one third of their annual electricity bill.

Figure 20.3: Composition of an AusNet Services' residential customer electricity bill in 2014



Source: AusNet Services analysis, based on standing offer for Energy Australia.

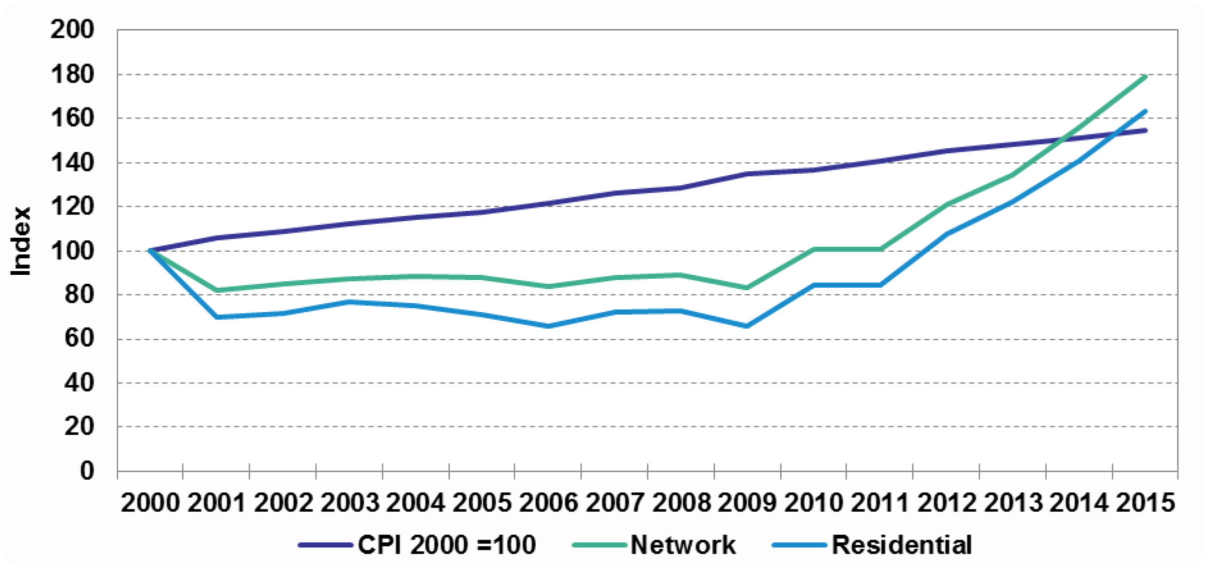
Historic price levels and trends

To understand the question of whether distribution charges are sustainable, this section considers the long term trends for distribution prices, the contribution of distribution charges to overall electricity charges, and how AusNet Services' current prices compare to other distribution networks.

The figure below shows that across AusNet Services' distribution network, prices fell in real terms from 2000 to 2009. Since then, prices have been rising.

Rising prices explain recent pressure being felt by customers. Yet, over the course of 15 years, AusNet Services' distribution prices have grown only marginally above the general level of price growth in the economy (as measured by the CPI).

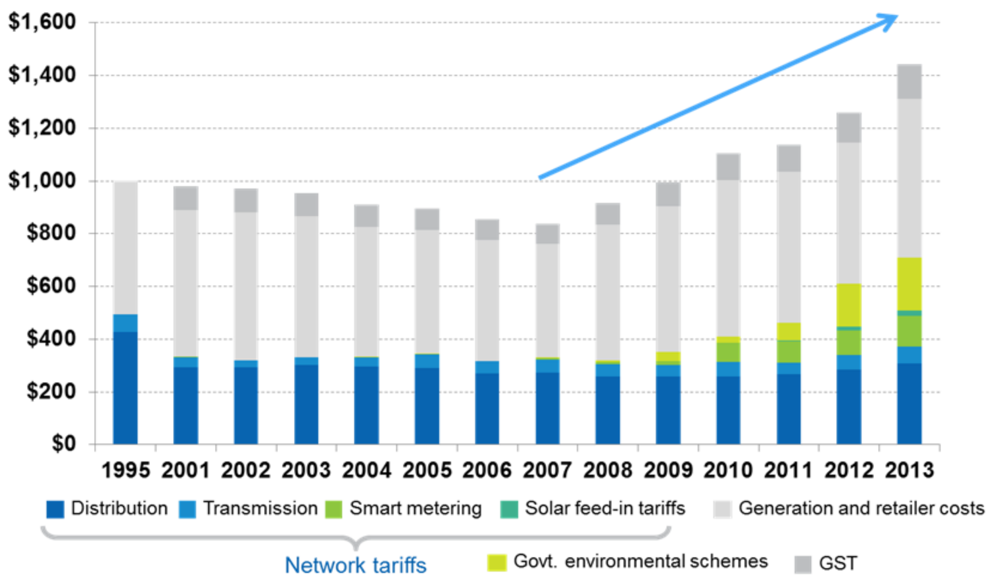
Figure 20.4: Distribution price movement, network average and residential



Source: AusNet Services

The figure below, which shows data for all of Victoria, shows that it is not just the network component of electricity bills that has increased in recent years. The retail and wholesale component of the bill has increased sharply since 2007.

Figure 20.5: Composition of the average Victorian residential electricity bill without electric off-peak hot water, using 4,000 kWh, FY 2001 thru FY 2012 (2012 dollars)



Source: Oakley Greenwood, 2013

Relationship between electricity consumption, distribution prices and bills

The distribution component of most customers' electricity bills has a fixed component and a component that is based on the amount of electricity that is consumed. The price for the variable component is a rate specified as the dollars charged per kilowatt hour of electricity consumed. Because the variable component of distribution charges is the larger component of the total charge, typically it is the movement in this charge that is the focus of discussion of 'electricity prices'.

Most costs for distribution networks are fixed or slow to change, so falling electricity consumption means that electricity prices (the dollars charged per kilowatt hour consumed) have to increase in order to collect the same amount of revenue.

The evidence presented above illustrates that there have been large increases to distribution prices in recent years and that AusNet Services' prices are higher that other Victorian DNSPs. This has put recent pressure on AusNet Services' customers. However, when prices are compared over the last two decades, or to the current distribution prices in other jurisdictions, AusNet Services' prices remain reasonable.

20.3 Consumer Attitudes and Expectations

Relevant findings

Customers expressed concern about rising energy bills in an environment where many households and businesses were 'doing it tough'.

With regards to overall price levels there was strong expectation that the distributor should plan its investments and operating costs in a manner that keeps prices level over time and, in particular, avoid large short term increases.

Customers saw the operation of our network in safe manner as non-negotiable and were very supportive of investment that improved community safety, particularly where it reduced the risk of fire ignition from electricity assets. They also strongly supported continued improvement. This support remained even when presented with the significant costs of proposed programs.

Customers expressed a strong preference for current reliability levels. This satisfaction with was shared across different customer groups. There was a strong resistance either to pay for further reliability improvement or allowing reliability to decline in exchange for lower prices in the future.

Customer focus groups were not concerned about removing cross-subsidies of new customer connection, seeing their removal as fair. This was notable because there was strong resistance to removing other cross subsidies (for example, low fire risk areas subsidising high fire risk areas).

How they were incorporated into this proposal

In formulating the proposal, AusNet Services has incorporated many features aimed at delivering sustainable long term network prices including:

- Absorbing operational cost step changes that have been identified and not included these in the forecast revenue requirement;
- Continued investment in demand management and innovation to provide future alternatives to capital investment;
- The removal of any uncertain expenditure from the proposal, to be replaced by pass-through mechanisms, so customers do not pay for investment that may not eventuate. For example, uncertain costs associated with the introduction of 'power of choice' and research and development being undertaken in conjunction with the State Government on protection systems that may reduce bushfire ignition from electricity assets;
- Accelerated depreciation of the remaining asset value associated with assets that have been or will be removed from the network as a result of the large safety programs. This is fair to ensure future generations do not continue to pay for assets that no longer provide services while also paying for the new safer assets installed; and
- A low augmentation expenditure, reflecting a low demand growth forecast and lower value of customer reliability. AusNet Services' development of forecasting capability in the current period has provided greater confidence to defer network upgrades (a less conservative approach to network planning taking advantage of greater forecasting accuracy).

20.4 Prices and Bills

This section sets out the impact of AusNet Services' regulatory proposal on our customers' network bills, which include both distribution and metering charges. Final electricity bills include other costs such as the wholesale electricity costs (the cost of generating the electricity) and the retail margin, which are not controlled by AusNet Services.

Distribution prices (in $/MWh) are proposed to fall by 0.1% (nominal) in 2016 on a like for like basis. Following that, prices will increase at around 2.6% per annum.

The average bill (revenue per customer) across the network is expected to initially fall by 1.6% per annum on a like-for-like basis, then grow by 1.0% per annum in nominal terms. In real terms this means AusNet Services customers' bills will fall over the next five years, with average revenue per customer falling by two percent per year.

Table 20.2: Average distribution charges by customer type in 2016-20 ($, nominal)

	Distribution charge (DUoS)				
Customer type	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	540	544	548	551	557
Industrial and Commercial					
Small	2,321	2,352	2,377	2,402	2,427
Medium	12,811	13,856	15,104	16,648	18,557
Large (LV)	80,027	82,430	84,754	87,076	89,410
Large (HV)	185,280	185,635	185,847	186,112	186,448
Large (subtransmission)	216,537	220,898	225,103	229,345	233,658
Network Average	**981**	**991**	**1,000**	**1,008**	**1,020**

Source: AusNet Services

Residential customers' bills will fall in the next regulatory period. The average residential customer will pay $42 less in 2016 than 2015, with 2020 charges still forecast to be below 2015 levels.

Metering charges (for single phase single element meters) will more than halve in 2016, from $206 in 2015 (not shown in the below table) to $104.

Table 20.3: Proposed Alternative Control Metering Services Charges ($, nominal)

Meter type	**2016**	**2017**	**2018**	**2019**	**2020**
Single phase single element	104	74	76	80	83
Single phase two element with contactor	119	85	88	92	96
Multiphase	144	103	106	111	116
Multiphase with contactor	160	115	117	123	128
Multiphase CT connected	205	147	151	158	165

Source: AusNet Services

Including metering charges, residential network customer bills will fall by 10.4% in 2016, before remaining largely flat until 2020. Between 2015 and 2020, residential network customer bills will decrease, on average, by 2.3% per year.

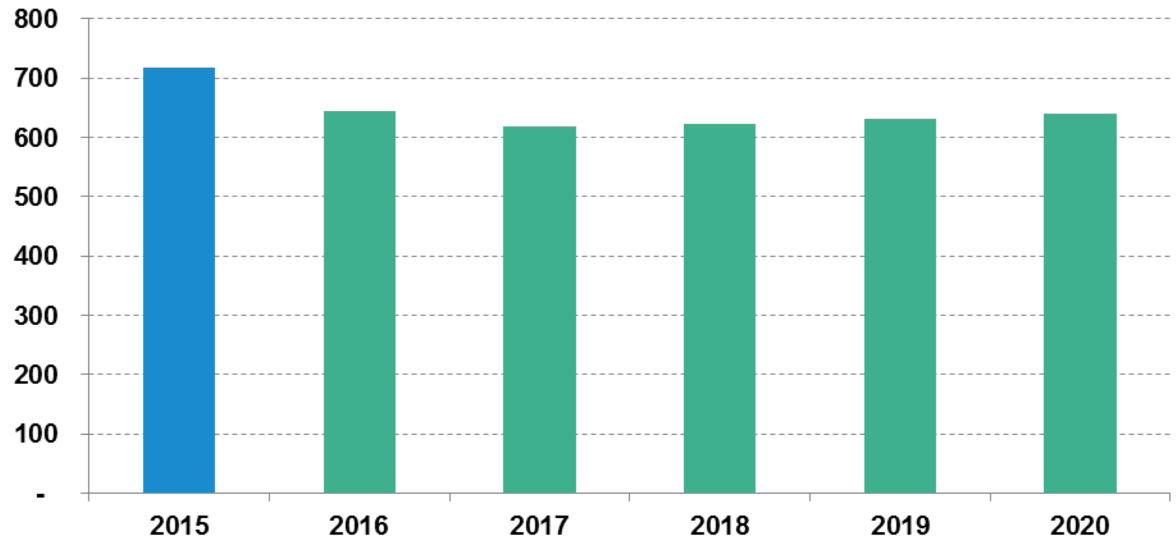
Table 20.4: Average residential customer network bill ($, nominal)

	2015	2016	2017	2018	2019	2020
Residential network bill	719	644	618	624	631	640

Source: AusNet Services

The figure below compares the average residential customer network bill (including metering charges) in 2015 with proposed bills across the forthcoming regulatory control period.

Figure 20.6: Average residential customer network bill ($, nominal)



Source: AusNet Services