# AusNet Transmission Group Pty Ltd

## Transmission Revenue Review 2017-2022

**Submitted: 30 October 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


## Contact

This document is the responsibility of the Asset Management division of AusNet Services. Please contact the indicated owner of the document below with any inquiries.

Charlotte Coster
AusNet Services
Level 31, 2 Southbank Boulevard
Melbourne Victoria 3006
Ph: (03) 9695 6000

## Table of Contents

# Glossary

| Abbreviation | Full Name |
|---|---|
| AARR | Aggregate annual revenue requirement |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AMS | Asset Management System |
| APS | Anglesea Power Station |
| ASIC | Australian Securities and Investments Commission |
| ASRR | Annual Service Revenue Requirement |
| BAU | Business-as-usual |
| BLTS | Brooklyn Terminal Station |
| CBD | Central Business District |
| CAM | Cost Allocation Methodology |
| capex | Capital Expenditure |
| CCP | Consumer Challenge Panel |
| CESS | Capital Efficiency Sharing Scheme |
| CGS | Commonwealth Government Security |
| DC | Direct Current |
| DCF | Discounted Cash Flow |
| DGM | Dividend Growth Model |
| DI | Dispatch Intervals |
| DNSP | Distribution Network Service Provider |
| EAM | Enterprise Asset and Works Management |
| EBSS | Efficiency Benefit Sharing Scheme |
| EGTS | East Geelong Terminal Station |
| EGWWS | Electricity, Gas, Water and Waste Services |

| Abbreviation | Full Name |
|---|---|
| EMLO | Emergency Management Liaison Officer |
| EMV | Emergency Management Victoria |
| EPA | Environment Protection Authority |
| ERP | Enterprise Resource Planning Platform |
| ESC | Essential Services Commission |
| ESMS | Electricity Safety Management Scheme |
| ESV | Energy Safe Victoria |
| EUAA | Energy Users Association of Australia |
| EWL | East West Link |
| FBTS | Fisherman's Bend Terminal Station |
| FMECA | Failure Mode Effect Criticality Analysis |
| GDP | Gross Domestic Product |
| GFC | Global Financial Crisis |
| GIS | Gas Insulated Switchgear |
| GST | Goods and Services Tax |
| GTS | Geelong Terminal Station |
| HTS | Heatherton Terminal Station |
| HWPS | Hazelwood Power Station |
| HYTS | Heywood Terminal Station |
| IAP2 | International Association of Public Participation |
| ICT | Information and Communication Technology |
| IT | Information Technology |
| ITOMS | International Transmission Operations Maintenance Study |
| KPIs | Key Performance Indicators |
| LMA | Linking Melbourne Authority |
| MAR | Maximum Allowed Revenue |

| Abbreviation | Full Name |
| --- | --- |
| MIC | Market Impact Component |
| MPS | Morwell Power Station |
| MTFP | Multilateral Total Factor Productivity |
| MVA | Mega Volt Amps |
| NCC | Network Capability Component |
| NCIPAP | Network Capability Incentive Parameter Action Plan |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NGO | Non-Government Organisation |
| NIST-CSFCI | National Institute of Standards and Technology Cyber Security Framework for Critical Infrastructure |
| NPV | Net Present Value |
| NSP | Network Service Provider |
| OH&S | Occupational Health and Safety |
| Opex | Operating and Maintenance Expenditure |
| PCRs | Protection & Control Requirements |
| PPIs | Partial Performance Indicators |
| PTH | Point Henry |
| PTRM | Post Tax Revenue Model |
| PV | Present Value |
| RAB | Regulatory Asset Base |
| RCM | Reliability Centred Maintenance |
| repex | Replacement expenditure |
| RIN | Regulatory Information Notice |
| RPP | Revenue and Pricing Principles |

| Abbreviation | Full Name |
|---|---|
| RTS | Richmond Terminal Station |
| ROTS | Rowville Terminal Station |
| RWTS | Ringwood Terminal Station |
| SAIP | Smart Aerial Image Processing |
| SAUR | Shared Asset Unregulated Revenues |
| SCADA | Supervisory Control and Data Acquisition |
| SCC | State Control Centre |
| SCO | Synchronous condenser |
| SMTS | South Morang Terminal Station |
| STPIS | Service Target Performance Incentive Scheme |
| SVTS | Springvale Terminal Station |
| TDM | Transformer Dependability Model |
| TNIs | Transmission Node Identifiers |
| TNSP | Transmission Network Service Provider |
| TSTS | Templestowe Terminal Station |
| TTS | Thomastown Terminal Station |
| TUOS | Transmission Use of System |
| VCR | Value of Customer Reliability |
| WMTS | West Melbourne Terminal Station |
| WPI | Wage Price Index |

# Highlights

| | |
|---|---|
| **We will continue to provide Victorian customers with efficient and low cost transmission services** | Transmission prices in Victoria will continue to be low and flat. AusNet Services has the lowest total cost per customer of all transmission networks in the NEM. This reflects AusNet Services' continued commitment to efficient asset management approaches. |
| **We have reduced network capex as an efficient response to changing energy market conditions** | AusNet Services has re-evaluated capital projects in response to lower network demand and the lower value placed on reliability by consumers, as demonstrated by AEMO's revised estimate of the Value of Customer Reliability. Consumers will benefit from these savings in the forthcoming regulatory period. |
| **Our proposal increases inter-generational efficiency and equity in response to emerging energy market trends** | This proposal includes a modest acceleration in depreciation for new investments. This better matches revenue recovery with network usage and, therefore, delivers fairer and more efficient outcomes. |
| **Incentive regulation works** | AusNet Services strongly supports incentive regulation and welcomes the application of the stronger capital efficiency incentive in the coming regulatory period. We will continue to drive efficiency and performance improvements under the AER's expenditure and service performance incentive schemes. |
| **We have listened to stakeholder views** | We have captured and responded to feedback from our stakeholders to develop our revenue proposal. This has helped validate that the revenue proposal reflects the long-term interests of consumers. We have highlighted where we have incorporated feedback and, where we have not, we have explained why. |
| **Customers will benefit from lower interest rates and debt costs** | AusNet Services is proposing a fair return on its assets, by balancing the interests of both network users and investors. Our proposed cost of capital is below that which has applied in the current period.<br><br>We intend to pass on to customers the fall in interest rates through our approach to setting the cost of debt. We have set aside the AER's Guideline approach to estimating the cost of equity because, in the current environment, it does not deliver a return to equity holders which reflects market realities. |
| **Current trends are recent changes are reflected in every building block** | Changing energy market trends such as declining consumption and emerging technologies make it prudent to reduce capital investment and accelerate depreciation. The deferral of capital works has a consequential impact on reliability.<br><br>The interactions between the proposed building blocks have been carefully considered to propose the lowest overall present value cost for consumers. |

# Executive Summary

AusNet Services[1] (formerly SP AusNet) owns and operates Victoria's shared electricity transmission network.

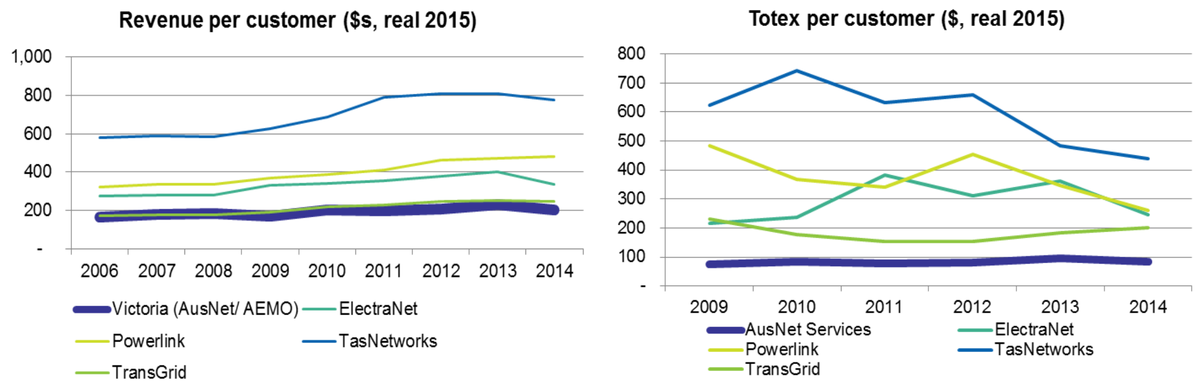
This proposal sets out AusNet Services' expenditure plans for the electricity transmission network for the five years from 1 April 2017, and the associated revenue requirements. The proposal excludes augmentation plans for the shared network, which are the responsibility of AEMO.

Some of the key features of the proposal are set out below.

## AusNet Services will Continue to Deliver Low Cost Transmission Services

Over the next five years AusNet Services will continue to provide a reliable, low cost electricity supply for Victorian consumers. AusNet Services has the lowest cost per customer of all transmission networks in the NEM and this is not expected to change over the next regulatory period.

**We have the lowest cost per customer of all transmission networks in the NEM**




*Source: Benchmarking data, 2014 Electricity Transmission Benchmarking Report Excludes Easement Land Tax for AusNet Services.*

This revenue proposal has been developed with the price impact in mind. AusNet Services has responded to stakeholder feedback by focusing on keeping prices low. However, given our reliability and safety compliance obligations, we have balanced cost reductions with the need to replace and maintain ageing assets.

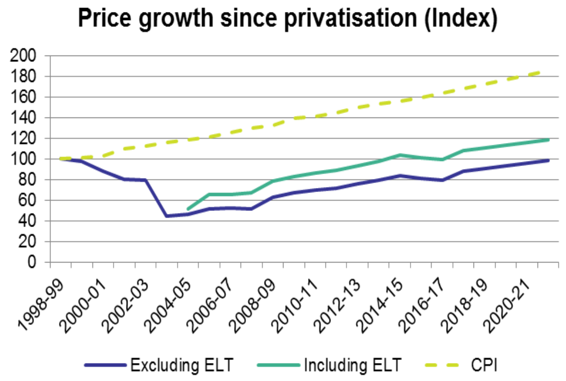
Transmission prices are forecast to increase by an average of 1.8% per annum in real terms over the 2017-22 regulatory period. Easing price pressure as a result of a reduction in capital expenditure and relatively low and stable financing costs are offset by:

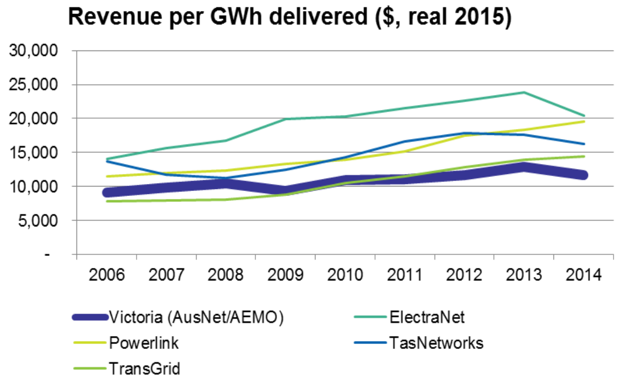
- An increase in forecast depreciation (an additional $30m per annum, or 5% of average annual revenues) driven by asset base growth and a modest acceleration in the rate of depreciation for new investments;
- Asset base growth driven by new investments together with AEMO's augmentation decisions in the current period, providing an additional $27m per annum return on capital invested, or 5% of average annual revenues;

[1] The relevant licenced entity is AusNet Services Transmission Group Pty Ltd (ABN 78 079 798 173).

- A modest increase in opex (an additional $19m per annum, or 3% of average annual revenues); and
- An increase in the proposed tax allowance as a result of a decline in the value of imputation credits (an additional $19m per annum, or 3% of average annual revenues).

**Despite this, Victorian transmission prices will continue to be low and stable…**

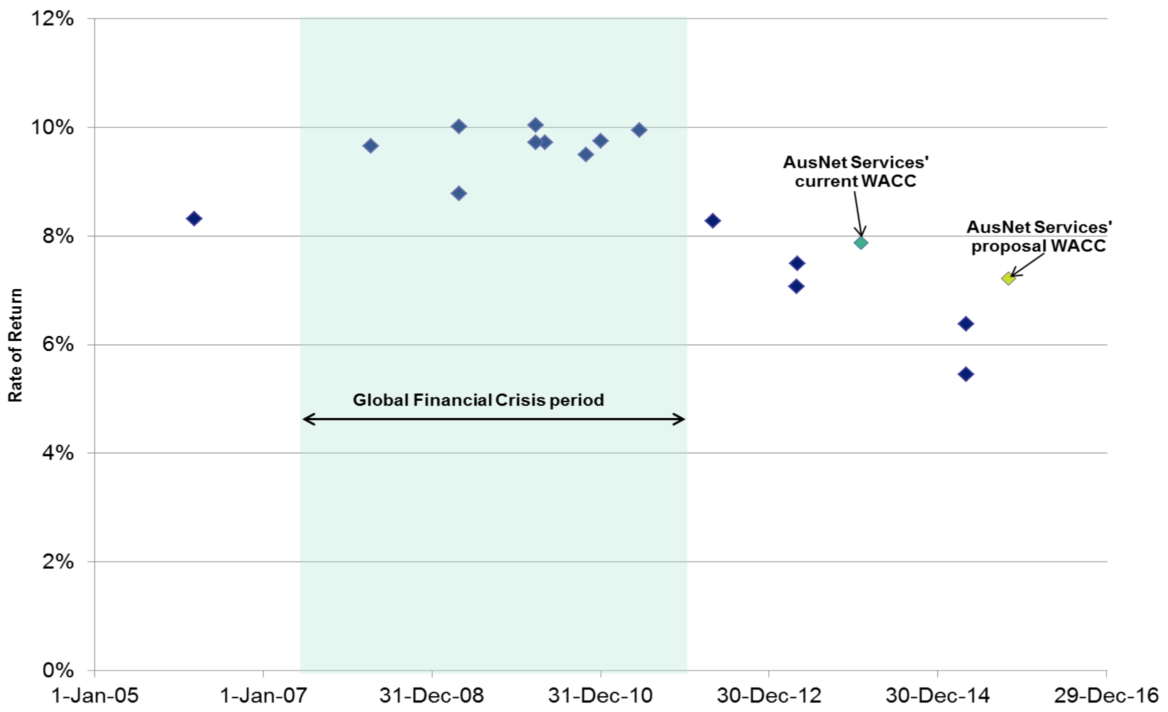



*Source: Huegin Consulting, AER RIN data, AusNet Services*

In recent regulatory reviews, many network service providers have proposed real price reductions, following a period of particularly high growth in electricity prices in some jurisdictions. The proposed reductions are partly due to lower financing costs as the impact of the Global Financial Crisis (GFC) dissipates. In contrast to other network companies, AusNet Services' current determination was made less than two years ago, which means that the benefits of the reduction in financing costs post-GFC are already reflected in current prices. Therefore, much of the impact of the GFC is already reflected in the transmission prices charged by AusNet Services, and there is less flexibility to further reduce Victorian transmission prices as a consequence.

**AusNet Services' financing costs already reflect post-GFC conditions**

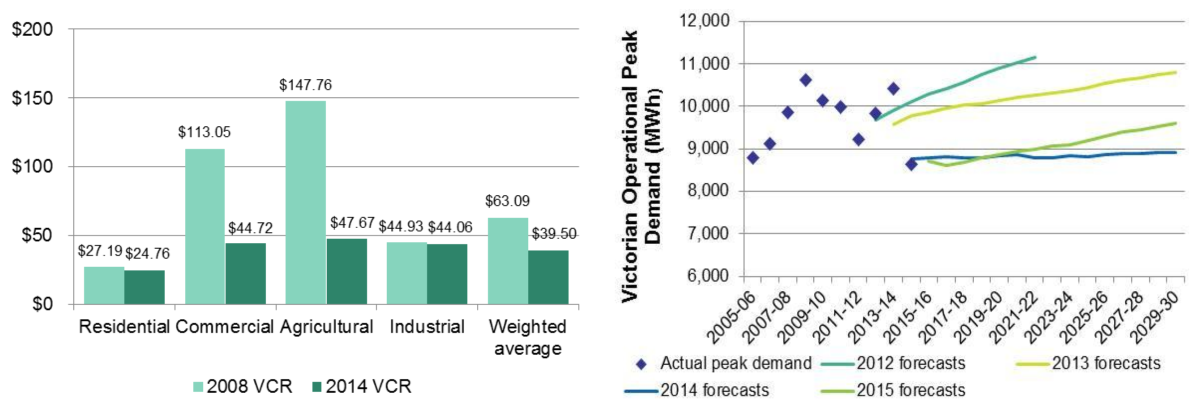



*Source: AER, AusNet Services analysis*

## AusNet Services is Efficiently Responding to Change

Since AusNet Services' previous transmission revenue determination there have been two exogenous changes that have required AusNet Services to revisit its capital expenditure plans. These changes are reduced growth in network demand and AEMO's downward revision in the estimated Value of Customer Reliability (VCR).

**Forecast demand and the Value of Customer Reliability (VCR) have declined**




*Source: AEMO*

The need for investment in new and replacement transmission infrastructure is reduced as the energy sector embarks on a period of potentially significant transformation. This is apparent from a reduction in forecast demand seen over the last few years (except for a slight reversal in 2015). Customers do not place as high a value on reliability as previously, as evidenced in the lower value ascribed to VCR in AEMO's latest review. These impacts, and the increased level of uncertainty in relation to the longer term need for some transmission assets, means that AusNet Services' latest capital works program is reduced compared to previous requirements. Similarly augmentation programs planned by AEMO are reduced for the next regulatory period. As already noted, AEMO-directed augmentation of the shared network is outside of the scope of these capex forecasts.

This reduction in capital investment means that existing assets will remain in place for longer than originally planned. This will result in an overall cost saving to customers. However, as there is a trade-off between price and reliability, there will be a gradual decline in reliability. This has been reflected in AusNet Services' performance incentive scheme proposal, which includes adjustments to targets measuring the number of loss of supply events.

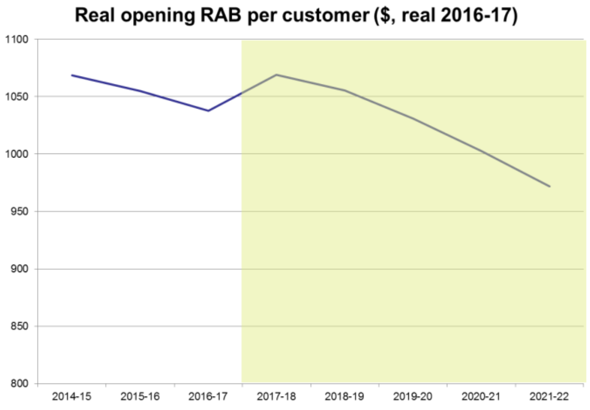
In addition to expected savings due to major project deferrals, the planned rebuild of West Melbourne Terminal Station has been re-scoped following the increase in land availability at the site. This has enabled a significantly cheaper Air Insulated Switchgear replacement project to proceed, saving customers approximately $90m.

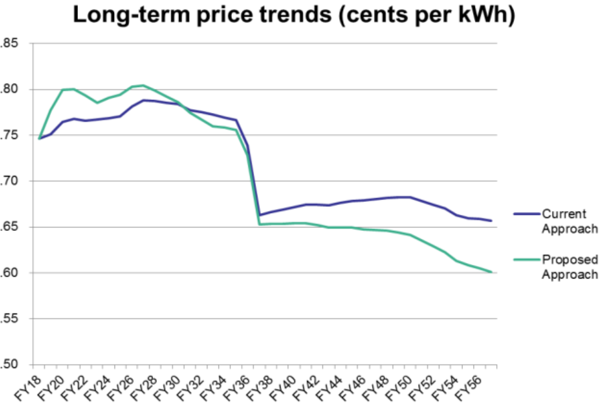
## Improving the Sustainability of our Network Investment

Technological advancements are transforming the energy industry, changing the generation mix and creating opportunities for customer participation in producing and consuming electricity. These changes have begun to impact the transmission network but, at this time, the longer-term impacts of these developments are unclear.

AusNet Services' revenue proposal addresses these changes through balancing the interests of current and future network users. Given that network utilisation per customer is likely to reduce in the future, it is both efficient and equitable to recover a slightly higher proportion of investment costs from current, rather than future, network users. For this reason a small acceleration in the depreciation of new network assets is proposed. The current environment of low financing costs and reduced capital expenditure provide an opportunity for this approach to have minimal impact on transmission prices.

**RAB per customer and transmission prices are forecast to decline, in line with expected utilisation trends**




*Source: AusNet Services analysis*

The majority of stakeholder feedback received strongly opposed accelerated depreciation. This has been factored into the development of our proposal, as AusNet Services has limited the application of accelerated depreciation to new investments.

While stakeholders' feedback is acknowledged, AusNet Services remains convinced there is merit to this approach. The NEO requires the 'long-term' interests of customers to be considered. Engagement has been conducted with stakeholders substantially representing current consumers, rather than future consumers. It is therefore necessary for a network service provider to extrapolate to some degree, to provide a reasonable assessment of the long-term interests of future consumers (including the future interests of existing consumers).

AusNet Services considers that it will be neither equitable nor efficient for future consumers to pay the same capital costs as current customers if future network utilisation is substantially lower. As noted above, it is likely that future network utilisation will decrease over time and, therefore, the proposal to accelerate depreciation is retained as a reasonable approach to addressing this asymmetry. For this reason, we have retained our proposal to accelerate depreciation but moderated it to address stakeholder concerns.

## We have Listened to Stakeholder Preferences

The strong reliance of the Value of Customer Reliability (determined by AEMO) in our capital expenditure forecasting methodology ensures that customers' preferences are directly reflected in this revenue proposal. In relation to the price-reliability trade-off, we have implemented what consumers have decided, reaching the highest level of engagement under the International Association of Public Participation's Engagement Spectrum.

AusNet Services has also undertaken a stakeholder engagement program which has centred around three sequential forums, through which we have captured stakeholder feedback on key aspects of the revenue proposal. We have modified our plans where appropriate and where we have chosen to depart from stakeholder views we explain why we have done so.

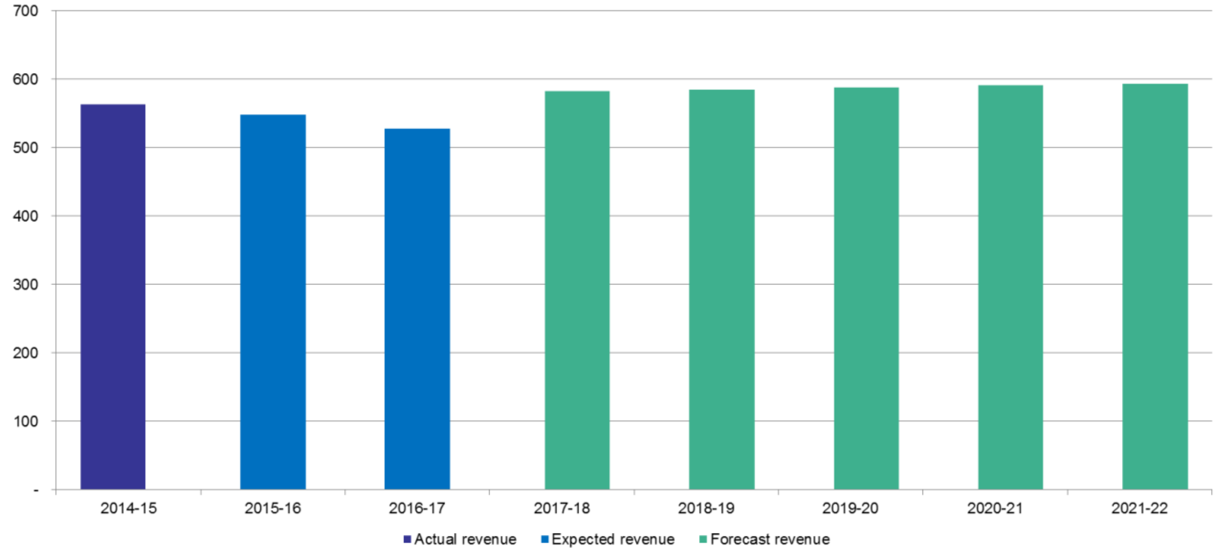
## More Detail on our Revenue Proposal

### Forecast Revenue and Prices

As a result of 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 manages the price impact on consumers without compromising investment incentives or the quality, safety, security or reliability of AusNet Services' electricity services. It therefore balances the conflicting objectives of the National Electricity Objective in a way that AusNet Services considers is equitable and reasonable.

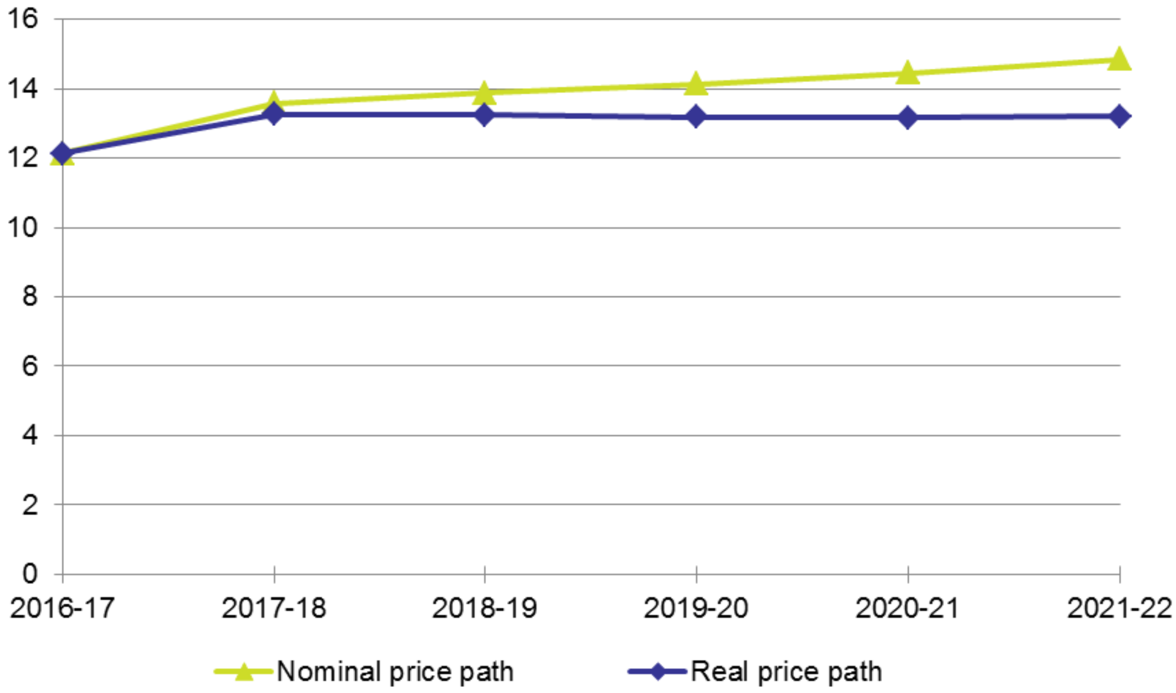
AusNet Services' total revenue requirement over the 2017-22 regulatory period is $2,945.3m (smoothed, real 2016-17). This represents an 8% increase compared to average allowed revenue for the 2014-17 regulatory period.

**Figure ES1: Total Revenue Requirement ($m, real 2016-17)**




The proposed price path represents an average increase of 1.8% per annum in real terms over the forecast period. The proposed price path is calculated as proposed revenue, divided by forecast Victorian electricity consumption. As there is a small increase in proposed revenues, and growth in forecast electricity consumption is very low, the resulting price path is relatively flat.

**Figure ES2: Indicative Price Path ($ per MWh)**




*Source: AusNet Services' PTRM*

This price outcome is considered to be in the long term interests of electricity consumers, given that the individual components of the revenue proposal have been developed with the interests of current and future consumers in mind, including through the use of the VCR in forecasting the capital expenditure requirement and by incorporating feedback received through the stakeholder engagement process. Benchmarking metrics confirm that AusNet Services has delivered low-cost and efficient transmission services and the proposed price path is a continuation of that trend.

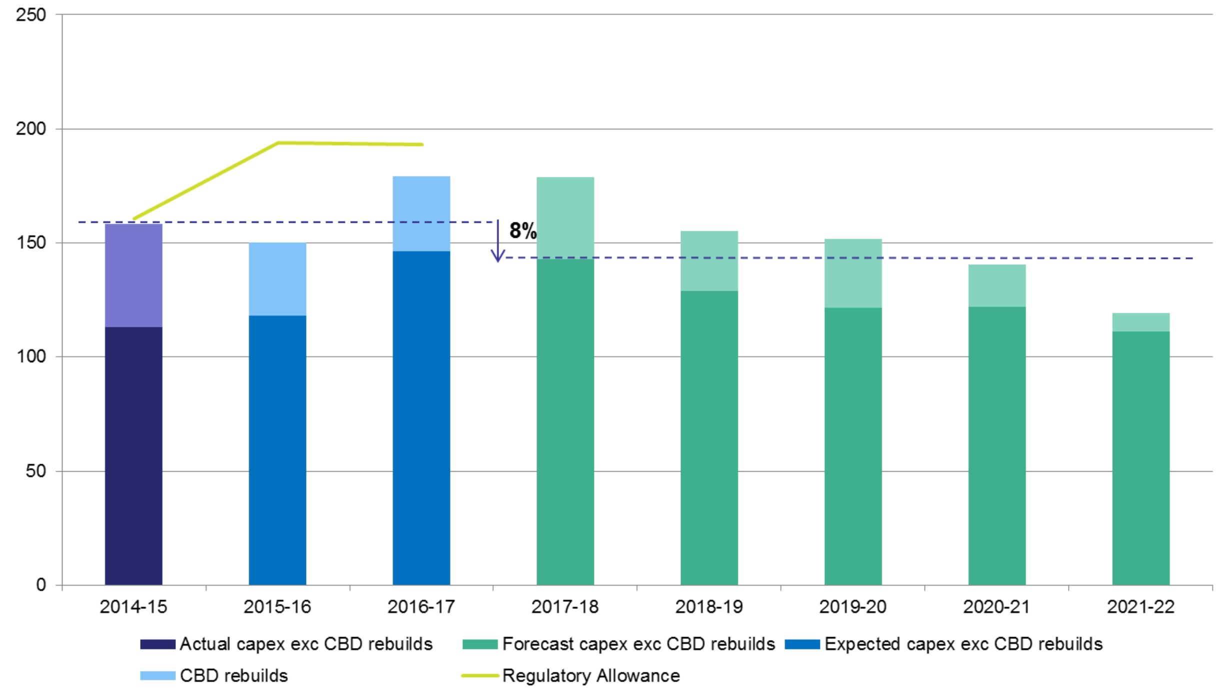
A high-level overview of the components of forecast revenue is provided below. More detail on each is contained in the following chapters of this revenue proposal.

### Capital Expenditure Requirements

AusNet Services' capex forecast is driven by targeted asset replacement based on asset condition. AusNet Services' rigorous asset management practices work to minimise the total life cycle cost. Through this approach, an optimal balance is struck between the costs of asset replacement and maintenance on the one hand, and the risk and cost of deteriorating asset performance on the other. Changing utilisation patterns are also taken into consideration.

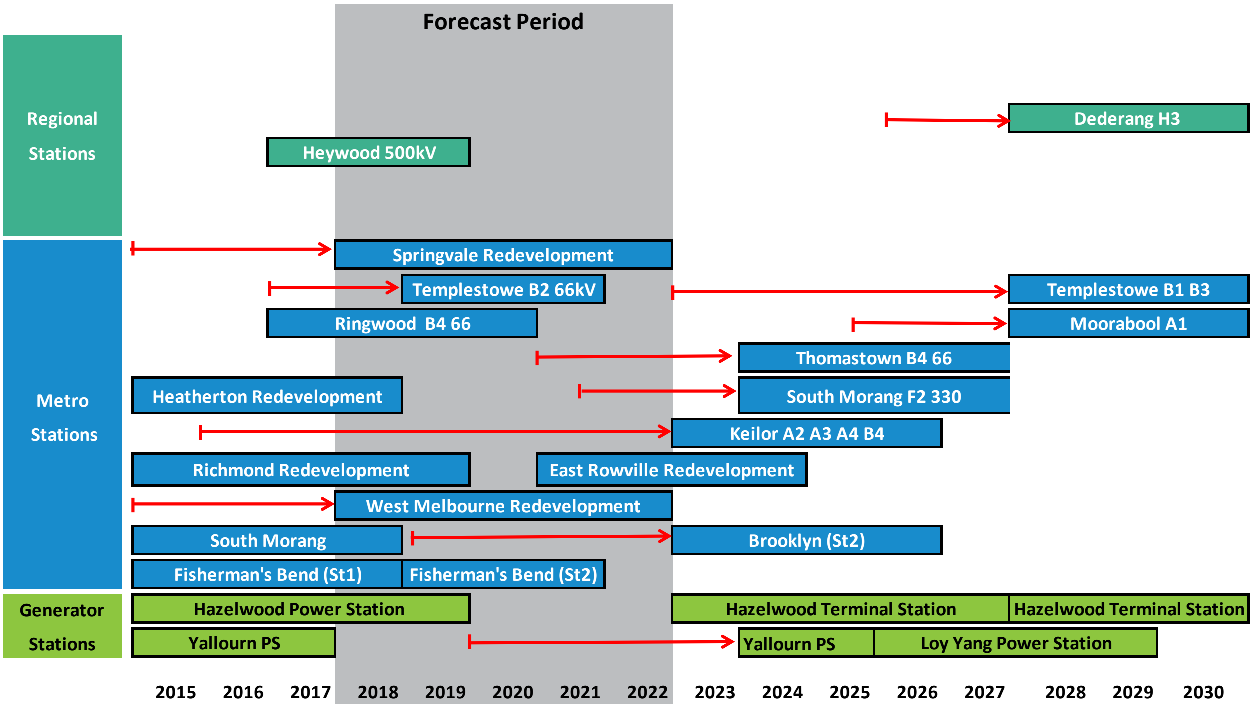
AusNet Services' total forecast capital expenditure for 2017-22 is $745.6m (real 2016-17). This forecast represents an 8% reduction in total capex compared to current period actual and forecast expenditure.

### Figure ES3: Actual and forecast capex ($m, real 2016-17)




As already noted, the decline in forecast demand and the VCR have resulted in significant deferrals to the economic timing of major projects, with approximately $145m (or 19% of capex proposed) deferred beyond the 2017-22 regulatory period. The latest expected timing of major station replacement projects to be delivered is shown below.

### Figure ES4: Indicative Major Projects Timing




Note: *Projects that were previously expected to be undertaken before 2030 but have been deferred beyond this date are not represented in the above figure.*

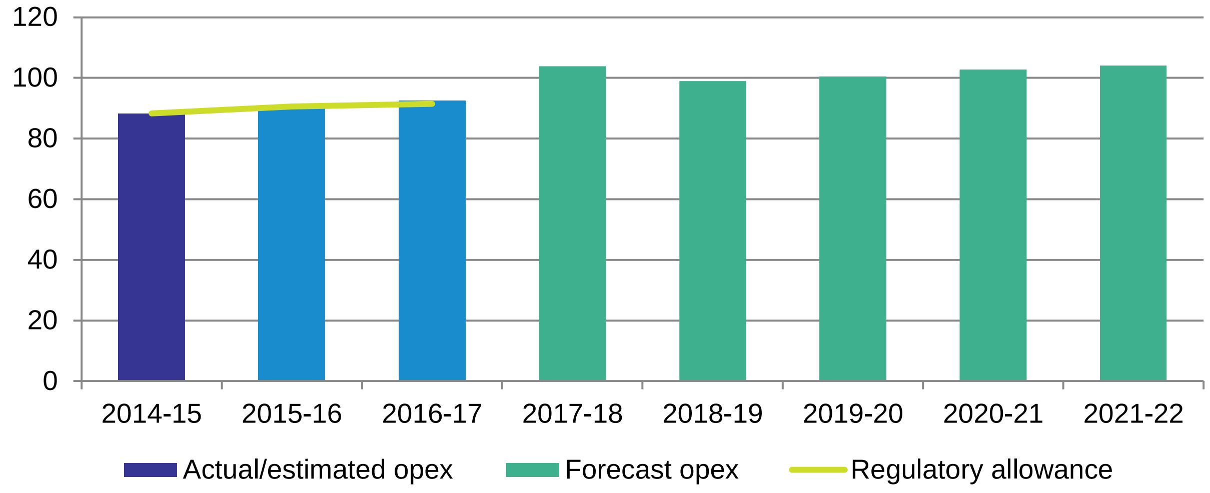
AusNet Services welcomes the introduction of the capex incentive schemes in the forthcoming period. AusNet Services will be the first network to be subject to the AER's ex post capex review, as an efficiency assessment of its capital expenditure for the 2014-15 year will be part of this review.

## Operating Expenditure Requirements

Forecast operating expenditure is based on current expenditure levels and expected increases for network growth and labour costs. These are slightly offset by a reduction to account for expected productivity improvements over the period.

AusNet Services has also identified a small number of step changes driven by asset retirements, capex-opex trade-offs and regulatory changes.

**Figure ES5: Actual and forecast controllable opex ($m, real 2106-17)**

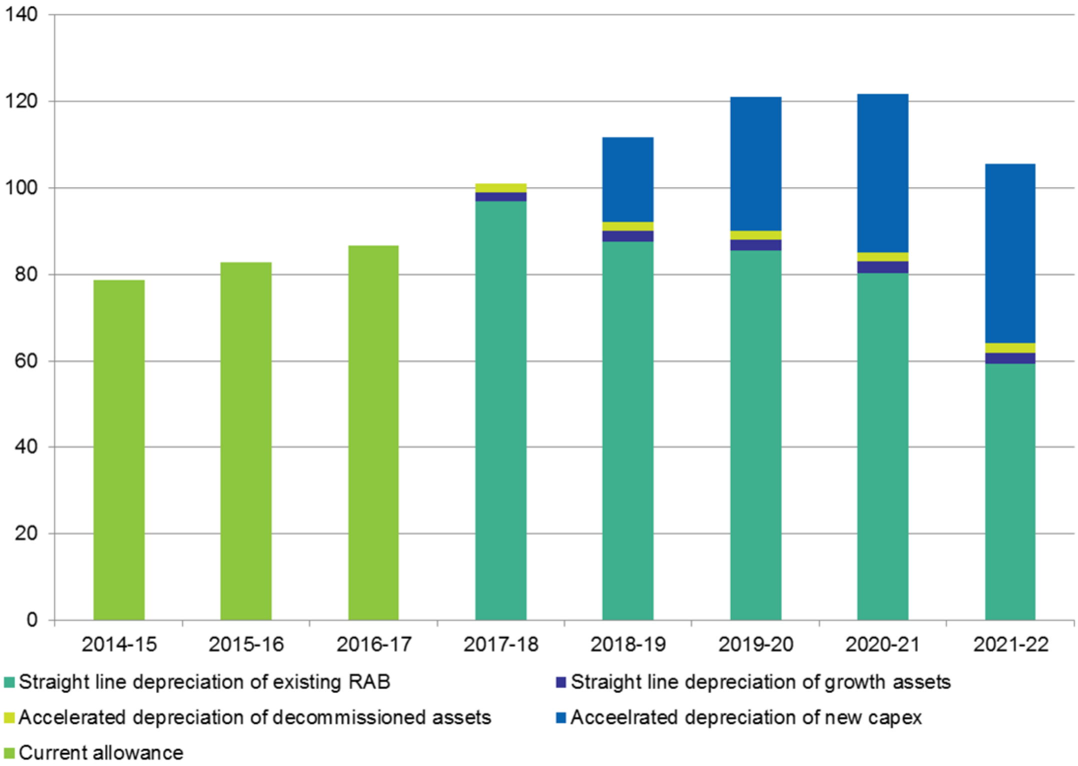



Performance under the opex efficiency incentive scheme has continued to be strong over the current period and AusNet Services will continue to respond to efficiency incentives in the next regulatory period.

## Return of Capital (Depreciation)

AusNet Services is proposing to accelerate depreciation for new investment in the forthcoming regulatory period. To manage the price impact on today's consumers, only a moderate rate of acceleration is proposed. This moderate increase is shown in the figure below.

**Figure ES6: Accelerated vs Straight Line Depreciation ($m, real 2016-17)**




This proposal does not change the present value of the investment costs recovered from consumers. However, it does change the profile of cost recovery. A higher proportion of the cost of new investments will be recovered from current consumers, and a lower proportion of cost will be recovered from future consumers. This is consistent with the expected trend in network utilisation, which is likely to fall over time.

This acceleration in the depreciation allowance is an appropriate means to address the increased utilisation risk that networks are currently facing. This is a risk that is not compensated for elsewhere in the regulatory framework, including through the rate of return.

### Return on Capital

It is essential that the rate of return is set at an adequate level to allow the level of financing required to enable networks to undertake investment.

AusNet Services is proposing a fair return on its assets from both the perspective of customers and investors, thus balancing the objectives reflected in the National Electricity Objective. In particular, the relatively significant fall in interest rates and debt costs experienced in worldwide markets are being passed back to customers. However, AusNet Services considers that, in a 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 proposing to set aside the AER's approach, AusNet Services' proposed a rate of return 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 GFC, 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. In short, it is submitted that the inclusion of alternative models better achieve the outcomes of the national electricity objective.

### Service Standards Proposal

AusNet Services and AEMO have agreed to close the Availability Incentive Scheme (AIS). This legacy scheme provided incentives which duplicated or conflicted with those provided by the AER's Service Target Performance Incentive Scheme (STPIS). The effective date of closure of the AIS has not yet been confirmed; however AusNet Services has proposed that it ceases from 1 April 2016. This will enable AusNet Services to pass back $2.3m to customers in the 2016-17 regulatory year. We are currently awaiting a decision from AEMO on whether it supports this timing.

AusNet Services was the first network to participate in Network Capability Component of the STPIS. This has delivered consumer benefits in the current regulatory period and will continue to do so beyond the end of the period.

AusNet Services will be the first TNSP to be subject to the new version of the STPIS (v5) and proposes targets which will appropriately drive and reward service performance improvements at a level consistent with the signals provided by the reduction in the VCR.

## Conclusion

AusNet Services' regulatory proposal properly serves the long-term interests of its customers. The proposal meets the immediate needs of the network and delivers a longer term vision for the network that sees the network continuing to provide efficient transmission services in a safe and reliable manner.

AusNet Services has carefully balanced current and future consumers' interests, while addressing the need to attract and retain long-term investment to provide assurance that its electricity transmission business remains viable and sustainable, and capable of delivering safe and reliable transmission network services, into the future.

# 1 Introduction

## 1.1 Purpose of this Document

AusNet Services owns and operates Victoria's electricity transmission network. The network serves Victoria, covering an area of approximately 227,600 square kilometres and serving a population of over 5.9 million people, or more than 2.1 million households and businesses. AusNet Services' organisational structure, internal processes and governance arrangements are all focused on delivering safe and reliable network services to transmission customers at an efficient cost, consistent with the NEO.

This Revenue Proposal sets out the expenditure plans and revenue requirements for the Victorian electricity transmission system owned and operated by AusNet Services (formerly SP AusNet). It covers the five year period from 1 April 2017 to 31 March 2022, and relates to the following transmission services:

- Prescribed transmission use of system services and prescribed common services, both of which are provided "in bulk" to Australian Energy Market Operator (AEMO). These services refer to the use of the transmission network for the supply of electricity;
- Prescribed entry (connection) services, which are provided to generators. These services enable generators to export electricity into the transmission network; and
- Prescribed exit (connection) services, which are provided to distributors and directly connected customers. These services enable distributors and directly connected customers to draw electricity from the transmission network.

Under the Victorian transmission planning arrangements, AusNet Services does not have responsibility for planning augmentations to the Victorian transmission system. In contrast to other Transmission Network Service Providers (TNSPs) which participate in the NEM, therefore, this Revenue Proposal does not consider future transmission network and transmission connection augmentations. This is discussed further in section 1.3 below.

The revenue proposal has been developed in accordance with AusNet Services' approved Cost Allocation Methodology (Appendix 1A) and Related Party Arrangements (Appendix 1B). Accordingly, the expenditure forecasts reflect arm's length terms and do not contain any related party margins.

The Introduction is structured as follows:

- Section 1.2 outlines the regulatory developments that have occurred since AusNet Services' previous determination;
- Section 1.3 describes the responsibilities of different parties in relation to the Victorian transmission network;
- Section 1.4 provides an overview of AusNet Services' transmission network; and
- Section 1.5 sets out the structure of this regulatory proposal.

The Revenue Proposal must address all of the relevant matters set out in the NER and the Reset RIN. In this regard, Compliance Checklists have been provided to identify the location within the Revenue Proposal and supporting documents of information provided in accordance with each relevant clause of the NER and the Reset RIN.

## 1.2 Regulatory Developments – Better Regulation

At the time of AusNet Services' 2014 transmission determination, important changes to the NER were being implemented through the AER's Better Regulation reform program. To facilitate a quicker transition to the new arrangements, the current determination applies for three years, instead of the typical five year duration.

In broad terms, the Better Regulation reform program focused on the following changes to regulatory process:

- Consumer engagement – to ensure that consumers have genuine input to the regulatory process.
- AER guidelines – to explain the AER's approach to regulation under the new Rules.
- Benchmarking – to provide an appropriate role for benchmarking in regulatory decision-making.

AusNet Services supports the new regulatory arrangements, including the increased focus on consumer engagement and benchmarking. Price-service-risk preferences are best understood by engaging with consumers on the available options.

Some useful observations on the drivers of relative efficiency can be made from the benchmarking measures. However, it is important to recognise that benchmarking is less informative for transmission companies compared to distributors. This is driven partly by the comparatively small number of TNSPs and the diversity in their operating environments and network design. Therefore, benchmarking is better suited to assessing productivity performance over time rather than relative efficiency.

In the context of the Better Regulation reform program, the key objective for this Revenue Proposal is to satisfy the regulatory requirements and objectives set out in the NER and the AER's Guidelines. AusNet Services recognises that the AER's approval of a revenue proposal is contingent upon, amongst other things, the AER being satisfied that consumer input has been properly taken into account in the company's expenditure plans.

## 1.3 Transmission Arrangements in Victoria

After the disaggregation and privatisation of the Victorian electricity industry during the 1990s, responsibility for Victoria's transmission network was split between:

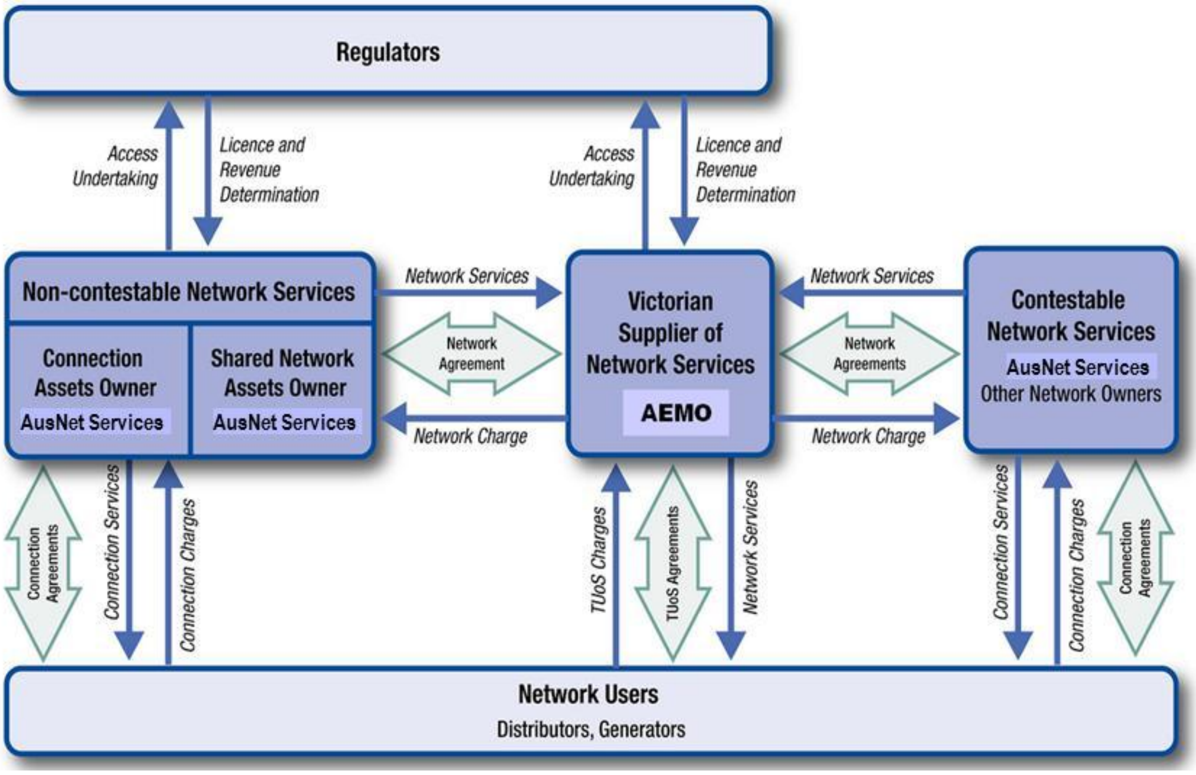
- AEMO (then the Victorian Power Exchange) – responsible for planning the shared network and procuring network support and shared network augmentations;
- AusNet Services (then PowerNet Victoria) – the asset owner, responsible for operating and maintaining the network; and
- Transmission customers – responsible for planning and directing the augmentation of their respective transmission connection facilities.

The formal responsibilities of the parties are set out in Victorian legislation, the licences, guidelines and codes administered by the Essential Services Commission (ESC) and the National Electricity Law (NEL). Together these instruments describe the model for the planning, procurement and provision of electricity transmission services in Victoria.

As noted previously, the transmission network planning functions in Victoria are separated from network ownership and operation. These arrangements differ from those in other NEM jurisdictions, where planning and responsibility for augmentation is not separated from the incumbent transmission company (although independent planning oversight occurs in South Australia).

The relationships between the parties listed above and the regulators are shown in the figure below. These arrangements have implications for the definition of AusNet Services' prescribed transmission services, which are subject to the revenue cap proposed in this document.

**Figure 1.1: Institutional Arrangements for Victorian Transmission**




*Source: AusNet Services*

Further details of the Victorian arrangements, including the planning roles of AEMO and connected parties, are summarised below.

### 1.3.1 Australian Energy Market Operator (AEMO)

AEMO is a non-profit organisation responsible for planning and procuring augmentation of the Victorian shared transmission network under applicable Victorian regulatory instruments, as well as derogations in the NER.

AEMO's planning objective for Victoria is to ensure that the network will, over the long term, optimise the total delivered cost of electricity to consumers, while maintaining a safe a reliable supply of electricity. To achieve this objective, AEMO adopts a probabilistic planning approach in which the transmission network is augmented when the economic benefits of the augmentation, arising through avoidance of unserved energy or congestion, equal or exceed the costs of implementing the augmentation.

The value of avoided unserved energy is estimated using the Value of Customer Reliability (VCR). The VCR values are derived from surveys of consumers, which are undertaken every 5 years and indexed annually. AEMO accepts that some level of network congestion or unserved energy is economic.

Urgent or unforeseen circumstances may necessitate augmentation of the Victorian transmission network without AEMO conducting a probabilistic cost-benefit analysis. AEMO notes that these circumstances may include[2]:

---

2 AEMO, *Economic Planning Criteria – Victoria*, October 2011, p. 4.

- A change in government policy requiring or directing an urgent augmentation;
- Actual demand is found to be significantly different to forecast; and
- Natural disaster or other emergencies.

In accordance with section 50F of the NEL, AusNet Services must not augment the Victorian shared network, unless:

- AEMO authorises or directs it to carry out the augmentation; or
- AusNet Services is selected through a competitive tender conducted by AEMO to carry out the augmentation; or
- The augmentation is authorised by the Rules.

AEMO determines whether an augmentation is to be classified as 'contestable', and subject to a competitive tender, even if it is an augmentation to the shared network. It is important to note that contestable network services are excluded from this Revenue Proposal, as the revenues are determined by competition rather than regulation.

AEMO defines a transmission network augmentation as contestable if the capital cost is reasonably expected to exceed $10m and it can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable)[3]. The Rules provide for AEMO to classify an augmentation as non-contestable if[4]:

- The delay in implementation as a contestable augmentation would unduly prejudice system security; or
- It is not economical or practicable to treat the augmentation as a contestable augmentation.

Non-contestable augmentations are 'rolled' into the regulatory asset base, as explained in section 1.3.3.

#### *Asset Retirement Decisions*

Recently it has become apparent that the Victorian split in responsibilities does not comprehensively deal with the situation where network assets are no longer required. While Section 50F of the NEL clearly states that AEMO can direct the *augmentation* of the transmission network, there are no equivalent provisions for network *contraction*, through asset retirement and potentially removal.

The assessment process and supporting information required to make decisions to augment the network is very similar to that to reduce the capacity of the network. It may be logical that AEMO, as network planner, is able to both direct capacity increases and make decisions on capacity reductions, with input from AusNet Services.

AusNet Services and AEMO are working together to consider the appropriate regulatory arrangements for network contraction decisions. Going forward, there may be an increased need to retire shared network assets compared to previous years, due to softening network demand.

### 1.3.2 Connected Parties

In Victoria, parties connected to the transmission network are responsible for the planning and augmentation of their connection assets. Therefore, the five Victorian distribution businesses are responsible for planning and directing the augmentation of those facilities that connect their distribution systems to the shared transmission network. The Victorian distributors plan and

3 AEMO, *2014 Victorian Annual Planning Report*, June 2014, p. 86.

4 Clause 8.11.6(b).

direct the augmentation in a way that minimises costs to customers, taking into account distribution losses and losses that occur within the transmission connection facilities.

Other connected parties (major consumers or generators) are responsible for their own connection planning, although they can choose to delegate this task to a distributor.

In the event that a new connection or an augmentation of an existing connection is required, the connected parties must consult with and meet the reasonable technical requirements of AEMO, AusNet Services and other affected parties. Each year the Victorian distributors publish the Transmission Connection Planning Report, which sets out their planning criteria, and assesses the risks of lost load and options for meeting forecast demand.

In planning network replacements, AusNet Services consults with AEMO and the Victorian distributors in relation to future network and transmission connection augmentations. This ensures that asset replacement and capacity augmentation works are optimised, and all opportunities for cost synergies are identified and, where possible, network augmentation is avoided using alternative solutions, including the adoption of innovative technology.

### 1.3.3 Augmentation of the Shared Network: Group 3 assets

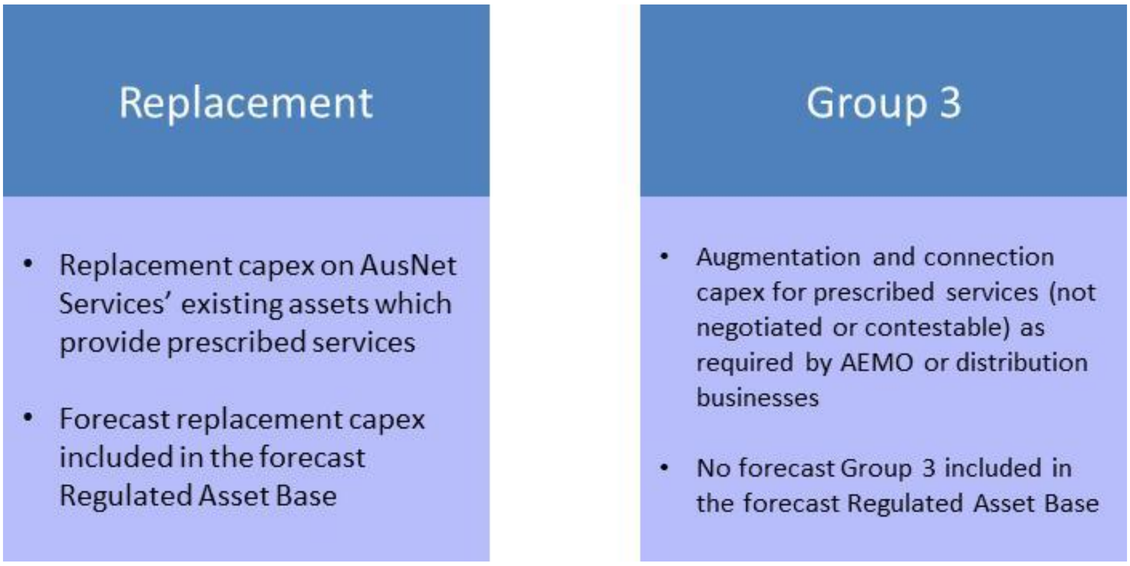
During any regulatory control period, AEMO or a distribution business may request AusNet Services to augment the transmission network or distribution connection services. These capital expenditure works are not contestable and AusNet Services undertakes them at the direction of the responsible planner (AEMO for transmission, and the Distribution Network Service Provider (DNSP) for distribution-transmission connection). Although these assets provide prescribed transmission services, they sit outside the regulatory asset base and are governed by commercial contracts until the subsequent revenue determination, when they are rolled into the regulatory asset base if they satisfy the relevant criteria for being included in the regulatory asset base. AusNet Services and AEMO refer to the assets that provide these services as ‘Group 3 assets’.

At each revenue reset, a number of Group 3 assets commissioned since the last revenue reset are rolled into the regulatory asset base for the first time. The purpose of this process is to recognise those investments undertaken in the previous regulatory control period, and ensure that AusNet Services earns an appropriate regulated return in respect of these assets. These new additions to the regulatory asset base are subject to the same rules regarding depreciation and escalation as other assets that provide prescribed transmission services. The regulatory arrangements governing the roll-in of these assets are set out in NER 11.6.21(c).

Given the roll-in process, the forthcoming Revenue Proposal will relate only to the provision of prescribed services as at 31 December 2014, being the practical cut-off date for the roll-in of existing Group 3 assets. Accordingly, the expected costs and revenues associated with the provision of any prescribed services commissioned after 31 December 2014 will be excluded from the forthcoming revenue cap.

The figure below shows the different regulatory approach to replacement capital expenditure and Group 3 assets. Specifically, AusNet Services’ forecast replacement capital expenditure is included in the regulatory asset base and remunerated through the revenue cap. As explained above, however, Group 3 assets are remunerated through commercial contracts initially and then can be rolled into the regulatory asset base at the next revenue reset.

**Figure 1.2: Replacement and Group 3 assets**




*Source: AusNet Services*

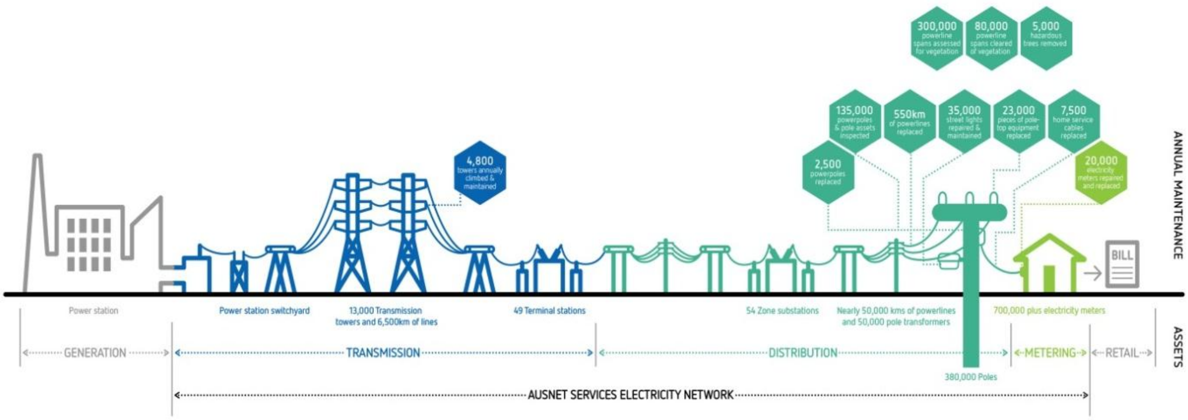
The periodic 'roll-in' of Group 3 assets increases the volume of regulated assets. As a consequence, the operating expenditure allowance must increase to manage the higher volume of assets that must be inspected, condition assessed and maintained. Details of AusNet Services' operating expenditure requirements are set out in Chapter 5.

In addition to replacing network assets, AusNet Services also incurs non-network capital expenditure associated with the new network assets, relating to buildings and property, vehicles, and IT. These assets provide essential support to the business, and AusNet Services' expenditure plans therefore also include non-network requirements. AusNet Services' capital expenditure requirements for the forthcoming regulatory period are explained in chapter 4.

## 1.4 Overview of AusNet Services' Transmission System

AusNet Services' transmission system operates at 500 kV, 330 kV, 275 kV, 220 kV and 66 kV, and generally includes those assets between the 'point of connection' with generators and distribution companies, as illustrated in the figure below.

**Figure 1.3: Facilities and Assets in the Victorian Electricity System**




*Source: AusNet Services*

AusNet Services' electricity transmission network includes more than 6,500 kilometres of transmission lines that transport electricity from power stations to electricity distributors and large customers. The highest recorded operational demand during summer 2013–14 was 10,313 MW, which was significantly higher than the previous summer's maximum operational demand (9,774 MW).[5]

The network is centrally located among Australia's five eastern states that form the National Energy Market (NEM), and provides key connections between South Australia, New South Wales and Tasmania's electricity transmission networks. The NEM interconnections on AusNet Services' transmission network include:

- Two 330 kV lines from Dederang Terminal Station, to the Murray Switching Station (NSW);
- One 330 kV line from Wodonga Terminal Station to Jindera (NSW);
- One 220 kV line from Red Cliffs Terminal Station to Buronga (NSW);
- Two 275 kV lines from Heywood Terminal Station to South East Substation (SA);
- One 220 kV circuit from Red Cliffs Terminal Station to Berri (SA); and
- One 500 kV circuit from Loy Yang Power Station to the 400 kV HVDC circuit between Loy Yang and Bell Bay (TAS).

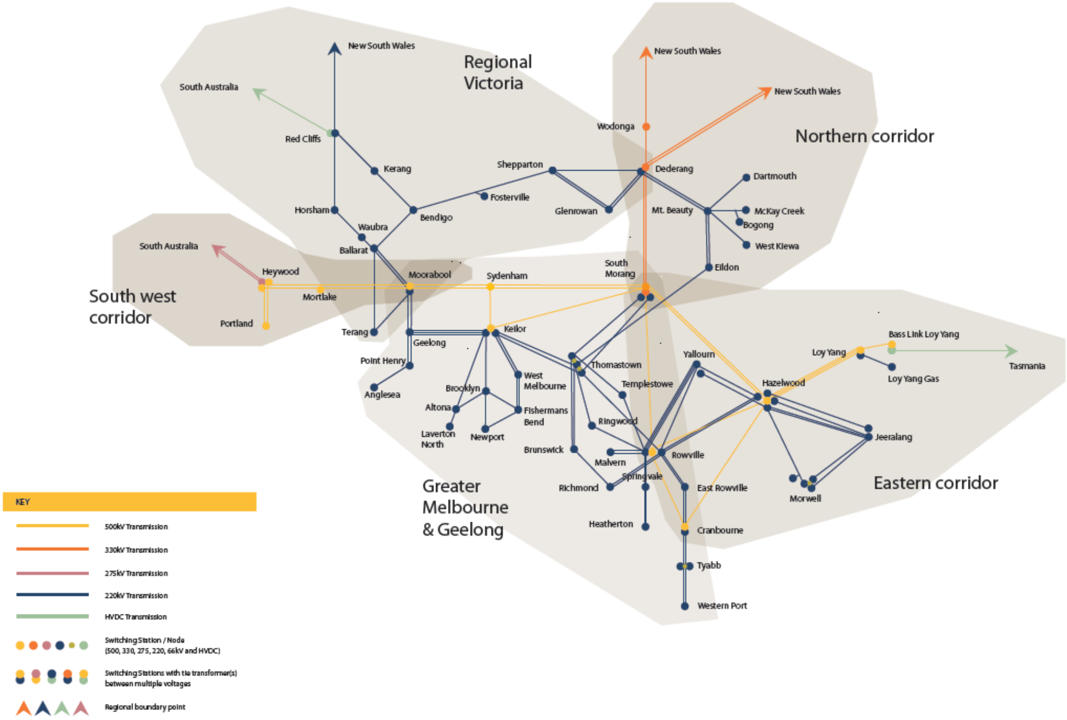
The transmission network consists of a 500 kV backbone, running from the Latrobe Valley, through Melbourne and across south-west Victoria to Heywood. The backbone serves the major load centres and is reinforced by:

- A 220 kV ring around Melbourne supplying 220 kV / 66 kV / 22 kV terminal stations;
- Inner and outer rings of 220 kV / 66 kV / 22 kV terminal stations in country Victoria supplying the regional centres; and
- Interconnections with New South Wales, South Australia and Tasmania.

The transmission system location, configuration and voltages are illustrated in the figure below.

5 AEMO, *2014 Victorian Annual Planning Report* 2014, June 2014, p. 3.

**Figure 1.4: Victorian Electricity Transmission System**

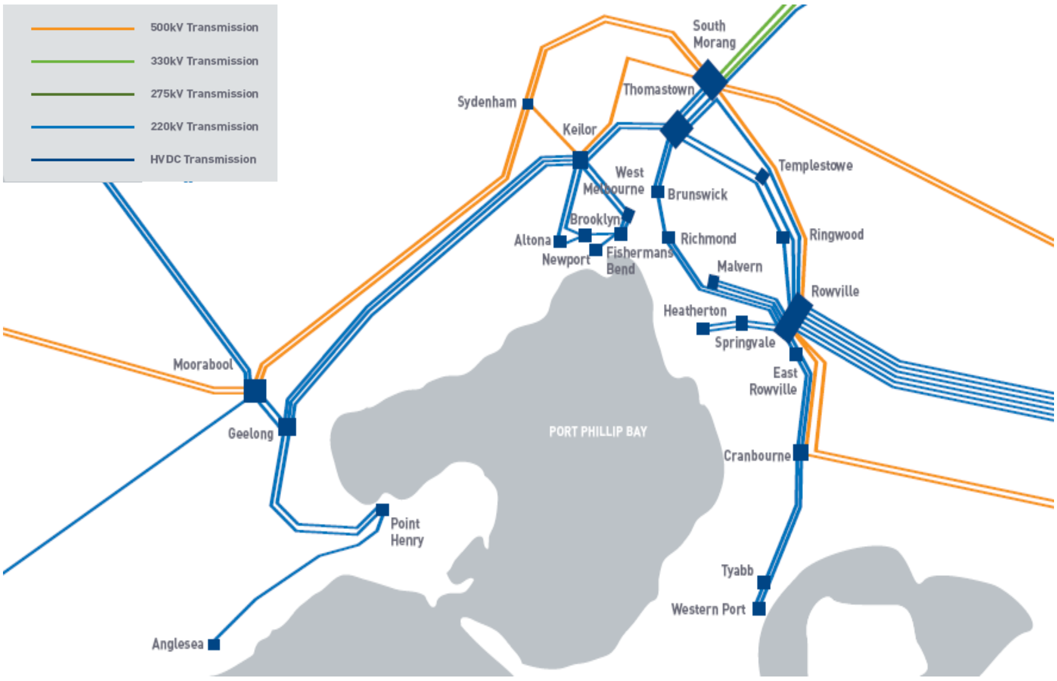



*Source: AusNet Services Asset Management Strategy*

Metropolitan Melbourne is served by 500 kV and 220 kV networks which receive power from major generators in the Latrobe Valley, the Victorian hydro-electric power stations, the gas-fired Newport power station and the interstate links.

The configuration of the metropolitan transmission system is shown in the figure below.

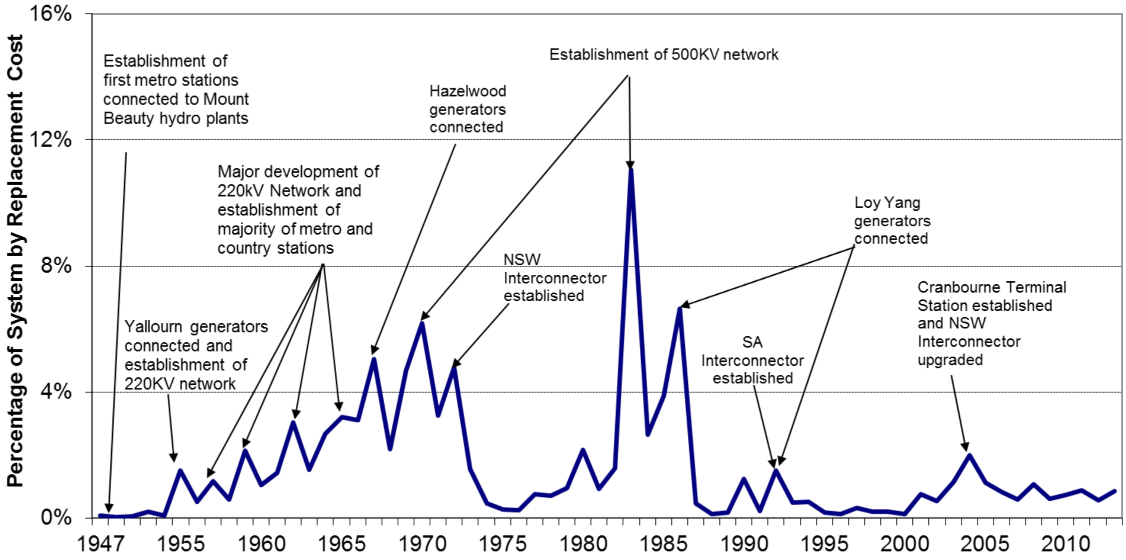
**Figure 1.5: Metropolitan Melbourne Electricity Transmission System**




*Source: AusNet Services*

The historic development of AusNet Services' transmission system is shown in the figure below. The major development milestones are highlighted.

**Figure 1.6: Historical development of AusNet Services' transmission system**




*Source: AusNet Services*

The figure above shows the relatively large amount of expansion investment that took place in the 1960s through to the early 1970s. A high volume of the assets installed over this period are displaying signs of deterioration as they approach the end of their technical lives. This has led to an increasing requirement for asset replacement expenditure, which will continue over the next decade and beyond. AusNet Services has in place a prudent asset replacement program, aimed at ensuring that the reliability of the Victorian transmission system is maintained, in accordance with the NEO.

## 1.5 Structure of this Revenue Proposal

The remainder of this document is structured as follows:

**Chapter 2** provides context for this Revenue Proposal by describing AusNet Services' operating environment and its key challenges for the forthcoming regulatory control period.

**Chapter 3** provides an overview of the customer engagement we have undertaken to better understand the needs and preferences of customers, and to inform this Revenue Proposal.

**Chapter 4** explains AusNet Services' capital expenditure proposal.

**Chapter 5** explains AusNet Services' operating expenditure proposal.

**Chapter 6** presents information relating to shared assets.

**Chapter 7** shows the derivation of the efficiency incentive payments that result from the operation of the Efficiency Benefit Sharing Scheme (EBSS) during the current regulatory control period. The chapter also presents information on the service performance and efficiency incentive schemes that will apply over the forthcoming regulatory control period.

**Chapter 8** provides an overview of the calculations underpinning the opening regulatory asset base (RAB) at the start of the forthcoming regulatory period, and the forecast RAB for that period.

**Chapter 9** sets out the depreciation allowance for the forthcoming regulatory control period.

**Chapter 10** outlines AusNet Services' proposed return on capital.

**Chapter 11** explains AusNet Services' proposed taxation allowances.

**Chapter 12** presents information on proposed cost pass-through arrangements.

**Chapter 13** presents AusNet Services' total revenue requirement for the forthcoming regulatory control period and the resulting average price path.

**Chapter 14** sets out AusNet Services' proposed pricing methodology for the forthcoming regulatory control period.

**Chapter 15** describes and explains AusNet Services' proposed negotiating framework for the forthcoming regulatory control period.

All monetary values presented in this proposal exclude GST. Unless otherwise stated, all monetary values are expressed in March 2017 Australian dollars.

## 1.6 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 1A – Cost Allocation Methodology
- Appendix 1B – Related Party Arrangements

# 2 Operating Environment and Asset Management Approach

## 2.1 Introduction and Overview

This chapter provides background information on the changes that are occurring in AusNet Services' operating environment and how it is managing the risks associated with these changes. It also describes AusNet Services' approach to asset management which enables the company to deliver efficient, safe and reliable transmission services to its customers.

The chapter is structured as follows:

- Section 2.2 outlines how AusNet Services is responding to emerging energy market trends;
- Section 2.3 outlines AusNet Services' asset management practices, and the regulatory, legal and technical obligations with which AusNet Services must comply to ensure the delivery of safe and reliable transmission services; and
- Section 2.4 lists the supporting documents provided that relate to this chapter.

## 2.2 Responding to Emerging Energy Trends

Transmission networks play an essential role in the delivery of electricity to end users. Australia's electricity transmission networks are often referred to as the 'backbone' of the National Electricity Market (NEM). They enable a competitive market across interconnected regions for the electricity produced by generators to reach consumers no matter where they are located in the NEM. This allows the cheapest generation to be used to meet consumers' needs at all times which, over time, minimises the overall cost of electricity.

However, in recent years the electricity market has changed significantly. These changes include:

- A decline in electricity consumption from historically high levels and minimal growth is forecast in the foreseeable future. Peak demand for electricity is forecast to continue to grow, but at a slower rate than in the past;
- The increased prominence of distributed and renewable generation at both the consumer end of the supply chain (for example, residential solar panels) and in the wholesale generation market (for example, wind farms); and
- The introduction of other technologies that enable consumers to generate and store their own electricity.

These changes follow a long period of a relatively stable energy market characterised by steady consumption and demand growth. The longer-term impacts of these developments on the future role of the transmission network are currently unclear.

AusNet Services continues to actively participate in energy market developments, and continually reviews and updates its asset management strategies and investment plans to ensure that they recognise these changes and are adaptable to change. However, the safe and reliable operation of the network remains a non-negotiable requirement and cannot be compromised in the short-term despite this longer-term uncertainty.

In response to future uncertainties, AusNet Services has sought to retain optionality by:

- Reassessing the economic timing of key investment programs to reflect changes in the operating environment, and to take account of future uncertainty. Some of these changes have been reflected in key planning assumptions. Operating expenditure solutions have been considered as an alternative to investing in long-lived assets, particularly where it is assessed that the long term requirement for a capital asset based solution is very uncertain.

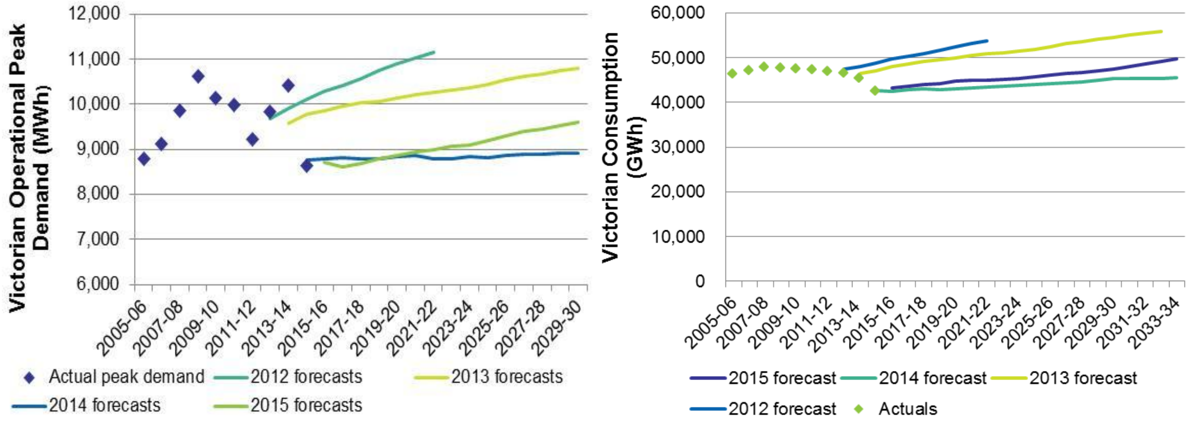
- Implementing advanced condition monitoring techniques to obtain more accurate information on conductor condition. This will enable the replacement of ageing conductor to be better aligned with asset condition which demonstrates the greatest deterioration and/or is at risk of failure. A large proportion of AusNet Services' conductor fleet will reach the end of their useful lives over the next 15 to 30 years, and it is expected that the longer-term requirement will become clearer in this timeframe. As a consequence, the medium- to longer-term benefits of this highly targeted investment approach is likely to be substantial.
- Where investment is unavoidable to meet mandatory obligations or to maintain required levels of reliability, proposing to accelerate the depreciation allowance. This proposal maintains the flexibility for AusNet Services to more efficiently recover its sunk investment in future years, while not increasing the cost to consumers over the long-term as a direct consequence of this proposal. This is particularly important to avoid an inefficient reduction in grid-sourced electricity should disruptive technology become more cost-competitive with electricity network services.

More detail on the impact of these emerging trends on network utilisation, and how AusNet Services is managing utilisation risk, is outlined below.

### 2.2.1 Reduced demand and consumption growth

Until recent times, the electricity market was characterised by steadily increasing electricity consumption and peak demand. However, in recent years the growth in both electricity consumption and peak demand has fallen, as shown below.

**Figure 2.1: Trends in Electricity Peak Demand and Consumption**




*Source: AEMO*

These trends can be explained by a number of factors including:

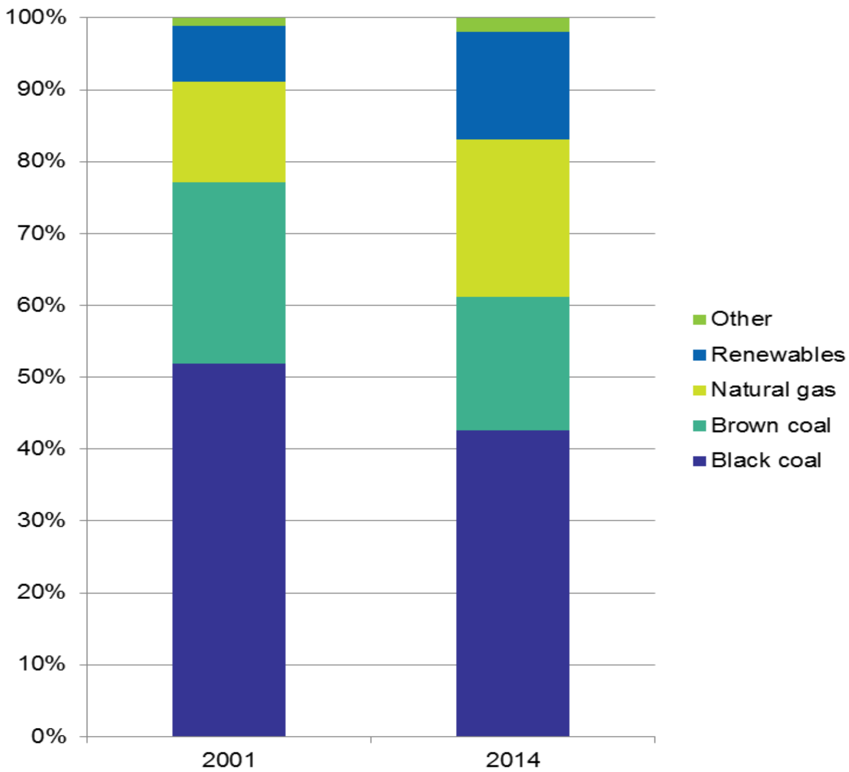
- The relationship between GDP growth and growth in electricity consumption is not as strong as it has been historically. Structural changes in the Australian economy have resulted in a shift from more traditional, energy-intensive activities (such as manufacturing) towards more service-based activities which generally use less energy. The closure of Alcoa's aluminium smelter at Point Henry is one outcome of this shift.
- The increased penetration of distributed generation such as solar PV has reduced the consumption of electricity sourced from the grid. This has been encouraged by Government policies such as solar feed-in tariffs in some jurisdictions.
- Increasing electricity prices have resulted in electricity consumers reducing their consumption due to a heightened awareness of cost.
- Improvements in energy efficiency. This is due to the use of more modern equipment driven by new technologies and increased awareness and concern about climate change.

The increased participation of consumers in the energy sector has also consequentially increased the importance of stakeholder engagement. It is critical that distribution and transmission network service providers ensure that the network services provided meet the needs of consumers, including in regard to the costs of the services. Therefore stakeholder engagement has been given a high level of importance in developing this revenue proposal. The approach taken and key findings are outlined in Chapter 3.

### 2.2.2 Changes in the generation mix

Changes in the generation mix are also impacting the energy market. Over the last decade, electricity from renewable sources has made up a growing component of generation. These sources include solar, wind and hydro.

**Figure 2.2: Changes in the generation mix in Australia between 2001 and 2014**




*Source: Department of Industry and Science*

Renewable generation may be connected to the distribution network (e.g. solar PV on residential homes) or the transmission network (e.g. large scale wind farms). AusNet Services has connected several wind farms to its transmission network over the past decade which enables the supply of renewable energy to end users.

There are plausible future scenarios where there is an increasing number of large-scale renewable generation sources connected to the transmission network. These would most likely be concentrated in regional areas, and will require the continued operation and maintenance of transmission network assets in these areas. However, in other parts of the network, changing generation patterns may lead to assets no longer being required. The brown coal generators located in the Latrobe Valley are an example of an energy source which may decline as a consequence community's awareness of environmental impacts of brown coal, and carbon abatement measures. This means replacement decisions for transmission network assets that serve these generators are particularly challenging.

The future pattern of generation is uncertain. In the face of that uncertainty AusNet Services must continue to meet its obligations to provide a safe and reliable electricity supply in the short term while focusing on asset management strategies and practices that contemplate the longer term reduction in the utilisation of these assets. A key measure that is being increasingly used is valuing maintaining optionality and taking it into account in asset management decisions.

### 2.2.3 Managing utilisation risk

The emerging energy market trends outlined above have led to a debate about whether the transmission network will continue to be required to provide the same level of service in future years. The risk that the network will be under-utilised, which may lead to specific assets becoming stranded, is referred to as utilisation risk.

Utilisation risk has only recently been identified as a potential concern for network businesses, as electricity consumption in Victoria rose steadily for a long period of time prior to 2008-09. Utilisation risk can be split into two separate types:

- The physical stranding of assets that serve particular customers or locations and are no longer required. AusNet Services has experienced this in the 2014-17 regulatory period, including due to the closure of Morwell Power Station and Alcoa’s Point Henry facility. These closures have been successfully managed, with minimal impact on other electricity consumers.
- A general reduction in utilisation of the transmission network as a whole not related to the actions of an individual customer or customers.

These are discussed below.

#### *Physical stranding of specific assets*

As AusNet Services does not plan the transmission network, it does not decide whether to augment the network, including for third party connections. The risk of future stranding of these assets should be considered by AEMO and the connecting parties when planning the network. Indeed, since 2006, AusNet Services’ contracts with connecting parties explicitly protect consumers from standing risk.

AusNet Services is responsible for managing existing assets, including deciding if and when it is economic to replace these assets. These assets have lives of up to 50 to 70 years, and, as the costs of replacing electricity transmission assets are high, it is important to consider the likely future need for the assets as part of the replacement decision.

To inform these decisions, AusNet Services takes into account forecast demand at the relevant terminal station. These forecasts indicate the extent to which the assets are expected to be required over the 10 to 20 year timeframe. Beyond this, electricity demand and consumption trends are very uncertain.

AusNet Services must balance the future uncertainty of the network with the requirement to meet its obligations to provide a safe and reliable supply of electricity. To do this, AusNet Services only invests in asset replacements where the risks (including to reliability and safety) exceed the costs of the investment. This approach is outlined in more detail in the following section, and in Chapter 4 – Capital Expenditure.

#### *Reduction in utilisation across the network as a whole*

It is also possible that demand on the electricity networks will decline as a result of a dispersed energy use decline, for example across the entire Melbourne metropolitan area. While assets may physically continue to be used, declining asset utilisation increases the price per unit of electricity supplied faced by connected parties. This is because allowed revenue will be recovered across a diminishing amount of electricity supplied. The increase in price per unit may encourage a further reduction in electricity consumption, encouraging further reductions in network utilisation, and so on. This situation is colloquially known as the ‘death spiral’, and, while often perceived to be a higher risk for distribution networks, declining utilisation also presents challenges for transmission. To manage utilisation risk due to increasing prices over time, which may inefficiently reduce electricity consumption from the network, AusNet Services has proposed to accelerate the depreciation of new investments (see Chapter 9).

This revenue proposal has been prepared under NER version 74. The NER allows an NSP to isolate itself from financial asset stranding risk, through the specification of the Regulatory Asset Base roll forward methodology, which does not include re-optimisation or re-valuation provisions. This is a critical feature of the current regulatory framework and has implications on other parts of the revenue determination including through reducing the allowed rate of return, as the risk of financial asset stranding is not borne by the network businesses. The AER confirms this is the case:

> *'the business risk for the benchmark efficient entity will be very low for the following reasons:*
>
> - *…*
> - *The structure of the regulatory regime insulates service providers from systematic risk. For example,… protection of sunk investment through rolling forward the regulatory asset base (RAB).'*[6]

If the protection for the continued cost recovery of sunk investments were to be removed, the rate of return would need to be adjusted upwards to compensate for the corresponding increase in the systemic risk faced by efficient network businesses. It is critical for the AER to allow efficient investment in transmission networks, to continue to attract the right levels of investment in existing networks and required augmentations, and to approach stranding in a manner that does not unduly and negatively impact the viability of NSPs. There are already mechanisms built into the NER to deter uneconomic and inappropriate network expansions, and it is therefore submitted that an appropriate approach to the potential of stranded transmission network assets is imperative to achieve the NEO of promoting efficient investment in the transmission system.

## 2.3 Efficient Delivery of Safe and Reliable Transmission Services

As stated previously, despite the future uncertainty, current obligations to plan and operate a safe, reliable and secure transmission service remain paramount. This revenue proposal sets out how AusNet Services plans to continue to deliver safe and reliable transmission services in the forthcoming regulatory control period.

- Section 2.3.1 describes AusNet Services' recent achievements and ongoing challenges;
- Section 2.3.2 outlines AusNet Services' approach to asset management;
- Section 2.3.3 sets out the obligations that AusNet Services must meet; and
- Section 2.3.4 contains some high-level benchmarking indicators which demonstrate AusNet Services' ability to provide efficient, low cost transmission services.

### 2.3.1 Recent Achievements and Ongoing Challenges

#### *Key Achievements*

This section highlights AusNet Services' key achievements since the previous determination.

***Continued Delivery of the Richmond Terminal Station Rebuild***

Richmond Terminal Station supplies the eastern CBD and inner east and south-east suburbs of Melbourne. The redevelopment of the terminal station to reduce the risk of failure of ageing assets commenced in 2012. Despite the project's complexity due to space constraints, the need to maintain secure supply to Melbourne's CBD during the brownfield construction and the

6 SA Power Networks preliminary decision: Attachment 3: Rate of return, pp. 3 – 364.

location of the site in a high density residential area, delivery has progressed extremely well, with construction meeting all major milestones to date. The project is due to be completed at the start of the next regulatory period and will have significantly reduced the supply risk to the CBD.

#### *Responded Quickly to Changes in Key Planning Assumptions*

The combined impact of the softening of AEMO's demand forecasts (published each June) and the reduction in the Value of Customer Reliability (published by AEMO in November 2014) have led to a re-evaluation of the economic timing of AusNet Services' capital works program, which has resulted in significant changes. We have been quick to respond to these changes and have deferred the delivery of major stations projects even where AusNet Services' management's approval had been received and the project was well advanced in the design phase. These project deferrals result in lower costs to consumers through a reduction in the value of the regulatory asset base.

The most notable project deferral has been the West Melbourne Terminal Station rebuild. This project has also been re-scoped, with a cheaper solution identified, due to easing space constraints at the site. This further reduces to cost to consumers.

#### *Removal of the Bulk Oil Circuit Breakers from the Network*

Bulk oil circuit breakers pose significant safety, reliability and environmental risks. They do not meet the requirements of the EPA and are no longer manufactured or supported. By the end of the current regulatory period, AusNet Services will have retired all remaining 220kV bulk oil circuit breakers, except for at Hazelwood Terminal Station where a project will be underway to remove the final circuit breakers. This will significantly reduce safety and environmental risks on the network.

#### *Achieved ISO 55001 Accreditation*

ISO 55001 is the internationally recognised standard for the optimised management of physical infrastructure assets to achieve a desired and sustainable outcome. In early 2014 AusNet Services was one of the first Australian businesses to achieve certification to ISO 55001.

Accreditation demonstrates robust and transparent asset management policies, processes, procedures and practices, and a sustainable performance framework. Accreditation demonstrates that AusNet Services remains an effective, efficient and competent asset manager, which has in place an industry-leading approach to asset management.

#### *Built a Network of Regulatory Stakeholders*

The stakeholder engagement undertaken as part of the development of this revenue proposal built on the engagement undertaken for the previous review. This time, a greater number of stakeholders was invited to participate, mainly through a series of forums and individual meetings. Through this process, AusNet Services has developed a network of stakeholders with a particular interest in transmission regulatory issues and developed an understanding of the perspectives of these stakeholders. This has informed the development of the revenue proposal, and, as the review process progresses, AusNet Services will continue to seek feedback from this existing network, as well as any other stakeholders.

#### *Delivered Network Capability Incentive Parameter Action Plan (NCIPAP) projects*

AusNet Services was the first TNSP to participate in the AER's Network Capability incentive, part of the Service Target Performance Incentive Scheme (STPIS). This requires AusNet Services to deliver a number of specified low cost projects, which will increase the capability of existing assets. AusNet Services is progressing well with the delivery of the agreed projects, with seven of the fourteen completed to date with estimated net benefits of \$34m achieved so far; this will rise to \$80m by the end of the regulatory period.

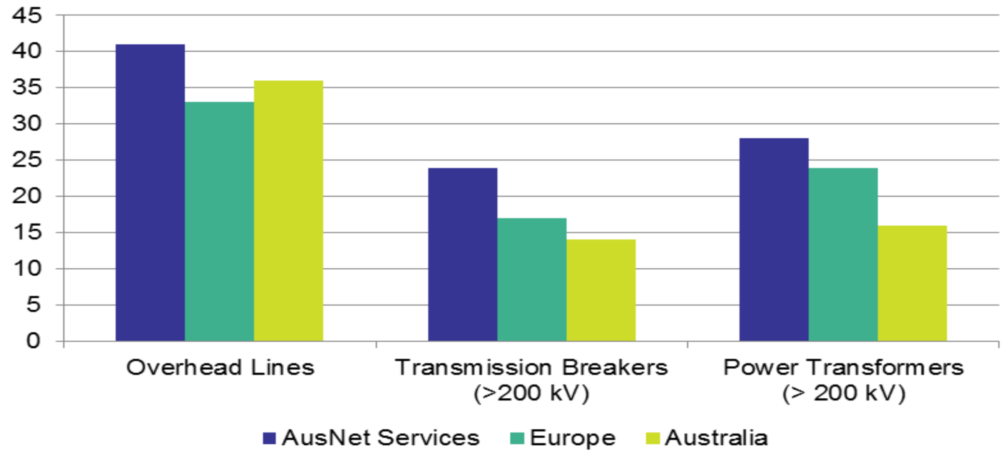
## Ongoing Challenges

This section outlines a few key challenges faced by AusNet Services.

### Ageing Assets

Victoria's use of probabilistic planning and AusNet Services' high quality asset management practices based on the consequence as well as probability of failure mean that its assets are relatively old compared to those of other TNSPs in both Australia and in overseas jurisdictions, for example Europe.

**Figure 2.3: Average age (in years) of major network assets compared to other TNSPs**




*Source: ITOMS 2013 Survey, AusNet Services*

In many locales the asset age is compounded by the physical environment in which the assets are located. In particular, AusNet Services' network covers a wide range of environments such as alpine regions, rural areas, forested areas and coastal areas. Some areas are exposed to high winds and salt deposition causing the condition of assets, particularly towers and conductors, in such locations to deteriorate at a faster rate than usual. In addition, Victoria is one of the highest bushfire risk areas in the world. These environmental characteristics affect both network performance and required expenditure.

Ageing assets create risk in terms of reliability performance and asset failure. An important challenge for the forthcoming regulatory period is to ensure that these risks are appropriately managed, through various asset management techniques including increased investment in improved condition monitoring, recognising the importance of also managing the costs to transmission customers. Achieving these goals is consistent with the elements of the NEO.

### Meeting the Community Expectations regarding Network Reliability

As existing assets age and their condition deteriorates, the risk of failures increase. This may result in supply interruptions. As mentioned above, due to recent reductions in AEMO's Value of Customer Reliability and forecast demand, a number of asset replacement projects have been deferred – which means that the network will be operating with higher risk of interruption than has previously been the case. While this is an efficient outcome, supported by AEMO's VCR estimate, there is a risk that the community will not accept the reduction in network performance. AusNet Services is not in a position to challenge this, and accepts the revised VCR estimate.

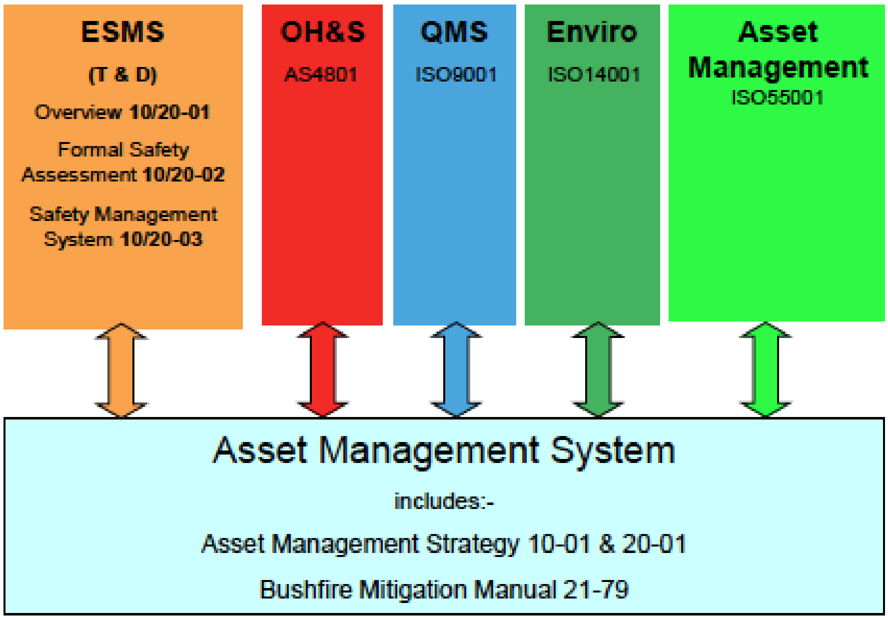
## 2.3.2 Asset Management Approach

AusNet Services maintains quality assurance over its Asset Management System through certification to:

- AS/NZS 4801 -- Occupational Health & Safety Management Systems;
- ISO9001 – Quality Management Systems;
- ISO14001 – Environmental Management System; and
- ISO55001 – Asset Management.

The figure below depicts these policies, processes, procedures and standards, which together with AusNet Services' ESMS define the company's strategic objective of providing customers with a safe and reliable electricity supply.

**Figure 2.4: Asset Management System Certification & Approval**




*Source: AusNet Services*

AusNet Services' asset management policies, processes, procedures and practices provide important context for the expenditure plans and forecasts for the forthcoming regulatory period. In particular, AusNet Services' Asset Management System (AMS) aims to stabilise the risks associated with the electricity transmission network. Asset risk relates to the probability of asset failure (determined using asset condition data) multiplied by the impact of that failure on network safety, reliability and availability. This approach to asset management establishes an economic basis for evaluating investment decisions.

AusNet Services was the first transmission company in Australia to obtain PAS 55 accreditation for its AMS. In early 2014, AusNet Services' asset management practices were certified to ISO 55001, the successor to PAS 55.

ISO 55001 is the internationally recognised standard for the optimised management of physical infrastructure assets to achieve a desired and sustainable outcome. It is applied where physical assets are a critical factor in achieving business objectives and effective service delivery, and permits organisations to assess their asset management systems in a similar manner to other management systems, such as ISO 9000 and ISO 14001. ISO 55001 implements a risk management focussed approach to asset management.

### 2.3.3 Obligations

#### *Safety Obligations*

AusNet Services is committed to providing a safe, efficient and reliable transmission network. The company's commitment to safety is underpinned by legal requirements to maintain a safe working environment for employees, and to minimise any risk to public safety presented by its operations. These requirements are set out in the following Acts:

- Occupational Health and Safety Act (2004), which this sets out requirements to protect the health and safety of AusNet Services' staff.
- Electricity Safety Act (1998), which sets out legal responsibilities to ensure public safety. The requirements of this Act are addressed in AusNet Services' Electricity Safety Management Scheme for its electricity transmission network.

AusNet Services is also subject to mandatory obligations set out in the NER and the transmission licence issued by the Victorian Essential Services Commission. The suite of key legal and regulatory obligations, which include operational requirements, are outlined in the figure below.

**Figure 2.5: Key Operational Legal and Regulatory Obligations**

| Electricity System Code (Vic) | Australian Standards | Electricity Safety Management Plan | National Electricity Rules (NER) |
|---|---|---|---|
| • Applicable through Victorian Licence<br>• System performance obligations | • AS/NZS 7000<br>• AS 62053 | • Approved by ESV<br>• Safety system operation | • System security obligations<br>• Connection obligations<br>• Metering obligations<br>• Economic regulation<br>• Regulatory Information Notices |

*Source: AusNet Services*

Section 98 of the Victorian Electricity Safety Act 1998 requires AusNet Services (as a major electricity company) to design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

- The hazards and risks to the safety of any person arising from the supply network; and
- The hazards and risks of damage to the property of any person arising from the supply network; and
- The bushfire danger arising from the supply network.

Electricity Safety (Management) Regulations 2009 (made under section 150 of the Act) set out the requirements for an Electricity Safety Management Scheme (ESMS). An ESMS is compulsory, and effectively covers all documentation, procedures, accreditation, monitoring and reporting of work on or for designing, installing, operating, maintaining and decommissioning network assets. The ESMS must be submitted to Energy Safe Victoria (ESV) every five years for acceptance, and is audited by ESV.

In Victoria, workplace health and safety is governed by the Occupational Health and Safety Act (Vic) 2004, which sets out the responsibilities of employers and workers to ensure that safety is maintained at work. Under this legislation, an employer must, so far as is reasonably practicable:

- Provide and maintain a safe working environment for employees;
- Provide or maintain safe plant or systems of work;
- Make arrangements for ensuring safety and the absence of risks in connection with the use, handling, storage or transport of plant or substances;
- Monitor workplace conditions; and

- Ensure persons other than employees are not exposed to risks arising from an employer's undertaking.

The Environment Protection Act 1970 empowers the Environment Protection Authority (EPA) to issue regulations and other compliance instruments relating to protection of the environment. Areas covered by the legislation include:

- Part V – Clean Water
- Part VI – Clean Air
- Part VII – Control of solid wastes and pollution of land
- Part VIII – Control of noise
- Part IXA – Transport of prescribed waste
- Part IXD – Environmental audits

The EPA has issued State Environment Protection Policy No. N-I, which deals with control of noise from industry, commerce and trade. This policy applies to all network assets.

Part 7A of the Victorian Emergency Management Act 2013 and the following unpinning instruments set out requirements for protecting critical assets from emergencies:

- Emergency Management (Critical Infrastructure Resilience) Regulations 2015;
- Critical Infrastructure Resilience Strategy.

The regulations referred to above refer to particular Australian Government guidance to be adhered to, including the Australian Emergency Management Handbook Series.

In summary, the obligations set out above have a substantial bearing on the expenditure that will be incurred by AusNet Services in the provision of prescribed transmission services over the forthcoming regulatory control period. Pursuant to NER 6A.6.7(2), AusNet Services' capital and operating expenditure forecasts include the costs of complying with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

### *Reliability Obligations*

AusNet Services is also responsible for ensuring that the reliability of its transmission network is maintained, subject to the planning decisions made by AEMO. Reliability obligations are set out in:

- The Victorian Electricity System Code (October 2000) which requires AusNet Services to undertake its activities as a Victorian transmission network service provider in a safe, efficient and reliable manner;
- Chapter 4 of the NER, which applies to system security obligations; and
- Chapter 5 of the NER, which prescribes connection obligations.

In addition to reliability obligations, AusNet Services must also comply with other obligations, including AEMO's system operation procedures for transmission businesses. As already noted, these obligations must be reflected in AusNet Services' expenditure plans.

While it does not specify reliability obligations, the AER's Service Target Performance Incentive Scheme (STPIS) provides incentives to improve reliability. The AER reviewed the STPIS and published an amended scheme (version 5) in September 2015. It consists of the following three components:

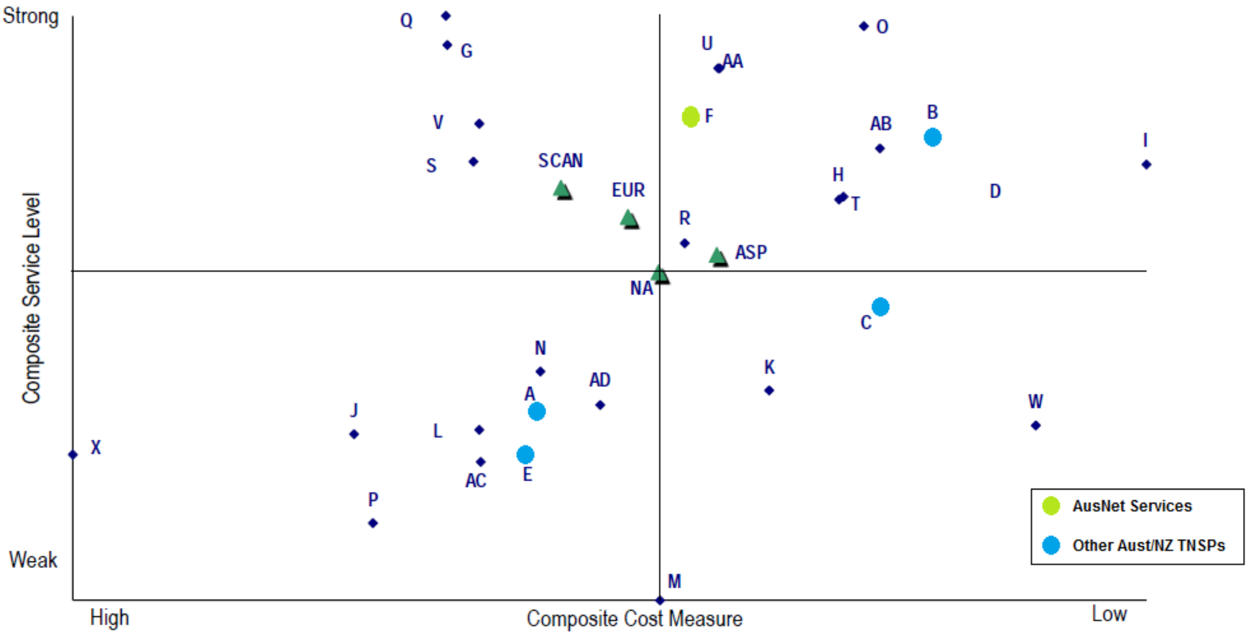
- Service Component – provides an incentive to reduce the occurrence of unplanned outages and to return the network to service promptly after unplanned outages that lead to an interruption to supply.

- Market Impact Component – provides an incentive to reduce the impact of planned and unplanned outages on wholesale market outcomes.
- Network Capability Component – provides an incentive to deliver benefits through increased network capability, availability or reliability through one-off projects.

### 2.3.4 Demonstrated Cost Efficiencies

The most recently available International Transmission Operations Maintenance Study (ITOMS) report from 2013 shows that AusNet Services ranks highly (in the top right quadrant) in overall benchmarked performance, in terms of transmission network service level and equivalent operating costs. This is a favourable ranking compared to other Australian and New Zealand transmission companies and the average performance in Europe and North America, as shown in the figure below.

**Figure 2.6: ITOMS Overall Composite Benchmark**




*Source: ITOMS 2013 Report*

AusNet Services also performs strongly across the suite of benchmarking indicators published by the AER. These are discussed in further detail in the relevant chapters of this revenue proposal.

The benchmarking evidence, together with the analysis of the company's performance against the regulatory allowances and service performance targets, demonstrate that AusNet Services' expenditure and service performance is efficient. The fact that AusNet Services is commencing the forthcoming regulatory period in circumstances where its costs and service performance compare well against its peers is important contextual information for assessing this revenue proposal.

## 2.4 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 2A – Asset Management Strategy.

# 3 Stakeholder Engagement

## 3.1 Key Points

- AusNet Services undertook an effective stakeholder engagement program to inform the development of its revenue proposal.
- AusNet Services delivered a pragmatic, low cost, stakeholder engagement program through:
  - Focusing on large customers and customer advocacy groups, rather than small (e.g. residential) customers, which was more appropriate and effective for a transmission business; and
  - Using AEMO's Value of Customer Reliability (VCR) estimate in asset replacement decisions, rather than commissioning large-scale surveys, for example, willingness to pay studies.
- The program focused on explaining how AusNet Services makes investment decisions, and sought feedback on key aspects of the revenue proposal particularly where there were significant changes to existing practice, such as accelerated depreciation and operating expenditure step changes.
- The forums held were well-received. However, interest in engaging in more detail through individual discussions was limited.
- In developing the revenue proposal, we have balanced stakeholder feedback with other influencing factors. This was a key part of the revenue proposal preparations and we gained valuable insights into stakeholder views.
- The most robust way in which stakeholder views are reflected in the revenue proposal is through the use of AEMO's VCR estimate in planning asset replacements. This value is determined by customers and is a direct input into establishing the economic timing of major stations projects.
- We have adopted stakeholder preferences where possible; where we have decided not to adopt these, we have explained why.
- AusNet Services welcomes further feedback on its stakeholder engagement approach and looks forward continuing engagement with stakeholders throughout the review process.

## 3.2 Introduction

With energy markets undergoing rapid changes, it is important that AusNet Services understands stakeholder views and preferences. In a future characterised by greater consumer choice, this will help ensure its electricity networks continue to provide services that are required by customers in the most economic manner. While transmission represents a relatively small component of most consumers' electricity bills, nonetheless a reliable and cost-effective transmission service is a vital part of the electricity network service experienced by all consumers.

While understanding and responding to stakeholder preferences is critical, there are many other factors that influence AusNet Services' activities, and hence the development of this revenue proposal. These include meeting compliance obligations to provide a safe and reliable supply of electricity. AusNet Services' role is to balance these influencing, and sometimes competing, factors. Where stakeholder's preferences have been unable to be incorporated, a clear explanation has been provided as to why this is the case.

As part of its previous transmission revenue review, a stakeholder engagement program was undertaken. While this review occurred prior to the publication of the AER's Consumer Engagement Guideline, this stakeholder engagement process was considered to be 'robust' and 'effective' by the AER and consumer groups[7]. The stakeholder engagement program for the 2017-22 revenue review has built on the previous engagement program.

An important factor that influenced the design of AusNet Services' stakeholder engagement program is the split in responsibilities for the transmission network in Victoria. Uniquely in Victoria, AEMO is the body responsible for planning augmentations of the shared transmission network, while customers, whether generators, directly connected large customers or distributors plan the augmentation of transmission connection points. Network augmentation is not included in AusNet Services' revenue proposal and therefore was not part of the scope of the engagement.

AusNet Services' use of AEMO's Value of Customer Reliability (VCR) estimate in planning the timing of asset replacements also influenced the program. As the VCR is an independently-derived and statistically robust means of capturing consumer preferences for price and reliability in our transmission investment plans, the purpose of the engagement was not to duplicate the extensive research carried out to inform the VCR estimate (e.g. through a large-scale and costly willingness to pay survey). Rather, the engagement program sought broader, qualitative input on parts of the proposal and tested whether the impact of the VCR on our plans was appropriate.

AusNet Services acknowledges that its stakeholder engagement practices are in a developmental phase. The company is committed to building the strengths it needs to implement broad based business-as-usual (BAU) stakeholder engagement. As such, each piece of stakeholder engagement work contributes to a process of continuous improvement.

This chapter describes the approach, activities and outcomes of the stakeholder engagement work undertaken by AusNet Services to inform this revenue proposal. It is structured as follows:

- Section 3.3 sets the context for AusNet Services' stakeholder engagement program;
- Section 3.4 discusses AusNet Services' approach to stakeholder engagement;
- Section 3.5 describes the stakeholder engagement activities that were undertaken for the TRR engagement program;
- Section 3.6 summarises stakeholder views;
- Section 3.7 explains how the TRR engagement program was consistent with AER's Consumer Engagement Guideline.
- Section 3.8 outlines AusNet Services' plans for ongoing transmission stakeholder engagement; and
- Section 3.9 references supporting documents provided for this chapter.

## 3.3 Context

A number of factors influenced the design of the stakeholder engagement program. These included:

- The requirements of the NER and the AER's Consumer Engagement Guideline;
- Existing engagement activities undertaken by AusNet Services;
- The split responsibilities for Victoria's transmission network;

[7] AER, *SP AusNet Final Determination 2014-17*, p. 176, EUAA, *Submission to the AER on SPI PowerNet Pty Ltd Electricity Transmission Revenue Proposal*, p. 6

- The use of AEMO’s VCR in the economic assessment of capital expenditure plans;
- Stakeholder capacity for involvement; and
- Providing value for money.

### 3.3.1 Requirements of the NER and the Consumer Engagement Guideline

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

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.

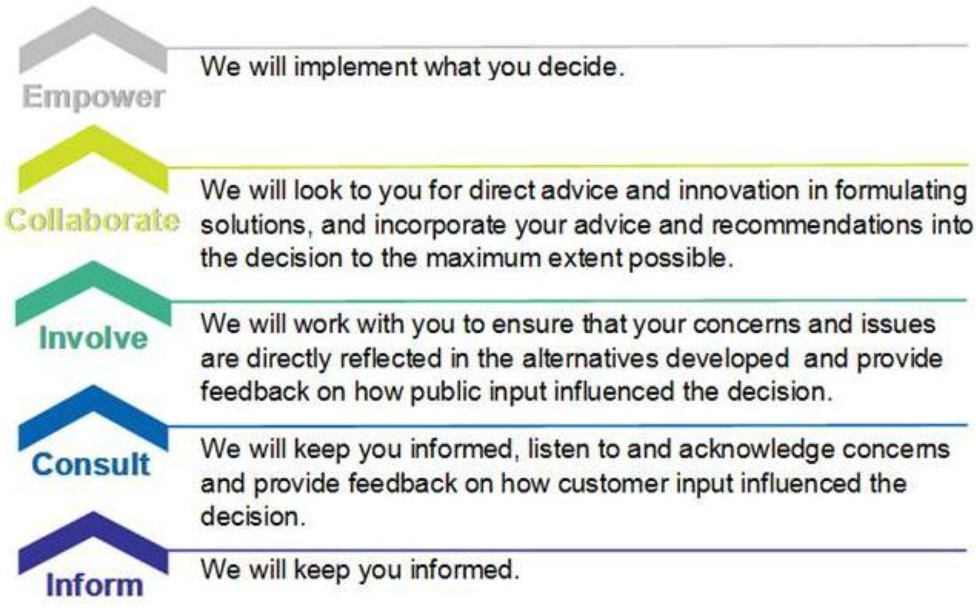
This guideline includes an expectation that consumer consultation is an ongoing BAU practice. The AER describes the Guideline as providing ‘a high level framework to integrate consumer engagement into [*network businesses’*] business-as-usual operations’.

In developing a customer engagement approach for the current review process AusNet Services was guided by the AER’s best practice Consumer Engagement Principles. These are:

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

The Guideline also includes a framework for best practice stakeholder engagement. The framework, the IAP2 Engagement Spectrum (shown in the figure below), was developed by the International Association of Public Participation (IAP2). The spectrum identifies five levels on which stakeholder views can be sought. It also acknowledges that plans will not always reflect stakeholder views. Use of the IAP2 guideline emphasised to stakeholders that AusNet Services’ engagement program was consistent with AER expectations.

**Figure 3.1: IAP2 Engagement Spectrum**




*Source: International Association of Public Participation*

As AEMO plans augmentations of the shared network, and connected parties (distribution businesses, generators and direct customers) plan connection asset augmentations, AusNet Services directly implements the decisions of other parties when augmenting the network, thus reaching the higher end of the spectrum (Collaborate and Empower). These arrangements differ from those in other jurisdictions. The direct use of the VCR in planning asset replacements (see Chapter 4 – Capital Expenditure) also falls into the higher levels of the spectrum. The VCR was estimated based on a large-scale survey of different consumer types. The result has directly influenced our capex plans – we have implemented what consumers have decided.

Aside from the use of the VCR, the majority of engagement activities undertaken to inform the development of the revenue proposal fell into the 'Inform' or 'Consult' categories, with some engagement targeted at 'Involve'. Accordingly, AusNet Services was mindful of managing stakeholder expectations around how much impact views expressed through this process could have on the proposal. Nonetheless, stakeholders 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.

### 3.3.2 Existing engagement activities – case study

In addition to the engagement program designed for the TRR proposal, AusNet Services undertakes a range of business-as-usual (BAU) engagement activities that are relevant to transmission stakeholders. These activities are described in more detail below.

- *Regular transmission stakeholder engagement* includes working with the Victorian distribution network service providers (DNSPs) and AEMO on joint network planning issues. This work typically involves quarterly joint planning meetings, AEMO-DNSP-TNSP operational meetings and joint planning meetings with Victorian DNSPs.
- *Project-specific activities* are undertaken with a range of stakeholder groups, including: city councils; planning bodies such as the Metropolitan Planning Authority (for projects and developments such as the Fishermans Bend precinct development or Deer Park development); developers (when transmission line easements, sites and future plans are discussed); major customers and new connections such as the desalination project; non-network proponents (mostly for the distribution network); generators (mostly project-related

but can also involve a network incident or planning issue); other TNSPs as part of Grid Australia and; regulators (for provision of data and planning reports or market reviews).

- *Engagement work related to other regulatory reviews and tariff reforms.* The stakeholder engagement programs run by AusNet Services as part of its electricity distribution regulatory proposal informed the design of TRR engagement program. In particular, the stakeholder engagement component of the 2016 Electricity Distribution Price Review established approaches, processes and internal skills that were applied to the 2017 TRR.
- *Connection-related engagement with generators and directly-connected customers.* As well as maintaining ongoing relationships with generators and directly connected transmission customers, AusNet Services has worked with AEMO, generators and directly connected customers on improving Victoria's connection processes[8]. To ensure we are aware of how the current connections process is working, AusNet Services is currently designing a survey for existing large generators and large load customers, AEMO and all Victorian DNSPs. The survey will gather feedback on the connection process, from the initial enquiry stage through to ongoing operations and maintenance. It will also measure attitudes towards AusNet Services as a TNSP. The aim of this project is to gain insights into transmission customer perceptions of the end-to-end connection experience. The results will be used to identify areas for improvement in both the connection process and ongoing transmission customer relations.
- *Engagement with local communities impacted by major projects.* AusNet Services runs community engagement programs in conjunction with major projects such as terminal station upgrades. These programs have evolved to reflect changing social expectations. The stakeholder engagement program summarised below was run as part of the Richmond Terminal Station (RTS) upgrade. It demonstrates AusNet Services' approach to major project community engagement. This approach, which is based on best practice principles and also reflects AusNet Services' experiences with other major projects, has proven highly effective in the case of RTS.

8 AEMO's Victorian connection review (tbc)

**Box 3.1 – Case Study – Richmond Terminal Station Community Consultation**

The Richmond Terminal Station is an integral part of Victoria’s electricity infrastructure. It is one of several high voltage electricity terminal stations that serve inner Melbourne. A local primary school is in close proximity to the facility.

The upgrade involves replacing existing ageing outdoor switchgear with more compact equipment housed in three new buildings. This will result in a more functional and compact design with less visual clutter.

A detailed stakeholder engagement program began prior to submission of the Planning Permit Application, based on the following principles;

- Provision of relevant useful information to communities and stakeholders impacted, or likely to be impacted, by works.
- Incorporating / taking into account community feedback received where possible.
- Building trust between community, stakeholders and AusNet Services.
- Ensuring the smoothest possible delivery of works on site. Minimise schedule disruption by encouraging community involvement.

As part of the process of community consultation that occurred before the planning permit was approved, a small group of objectors made submissions. Their concerns were dealt with individually by the community engagement team. A public information night, along with many individual resident discussions, was held as part of the pre-approval consultation.

The project was largely accepted by the community, enabling works to commence without community objection. Where possible, stakeholder feedback was incorporated into the design of the upgraded terminal station. Communication with stakeholders has continued throughout the upgrade works, and will continue for the life of the project.

The community consultation has been well-received. An example of the positive feedback received is provided below:

> *‘This is just a note of thanks for the excellent communications you have had with the local community during the upgrade.*
>
> *We are residents of Mary Street, and the advance notice, coupled with a friendly knock at the door to remind us to move our car for this weekends transformer delivery is appreciated. It's nice to have a considerate corporate neighbour.*
>
> *Often it's easy to complain about development and construction, so I thought I'd make the effort to give you some positive feedback.’*

### 3.3.3 The Split Responsibilities for Victoria’s Transmission Network

Due to the split in responsibilities of planning and operating Victoria’s transmission network, AusNet Services and AEMO worked to identify opportunities for both parties to engage with their common stakeholders simultaneously. AEMO staff responsible for planning the Victorian transmission network attended AusNet Services’ stakeholder forums. This enabled stakeholders to raise issues related to the Victorian transmission network, regardless of whether these issues involved AusNet Services or AEMO.

At the second forum, AEMO presented on its latest VCR survey.

### 3.3.4 The Use of AEMO’s Value of Customer Reliability (VCR) Estimate

AEMO’s 2014 VCR estimate was based on a survey of 2,930 residential, business and directly-connected customers across the national energy market, using a methodology that compared favourably with similar international studies. Therefore, the VCR provided a source of robust data related to consumer preferences on the value they place on a reliable supply of electricity.

Given the availability of this VCR estimate, AusNet Services did not consider it a prudent use of consumers' money to engage in a duplicate exercise.

By using the VCR as an input into planning asset replacements, AusNet Services has ensured that consumer preferences on reliability are reflected in its capex proposal in a robust manner. AusNet Services' revenue proposal also reflects stakeholder preferences by incorporating feedback from the stakeholder engagement program, although this feedback does not have the same statistical significance as the VCR data.

### 3.3.5 Stakeholder capacity for involvement

From the outset of the TRR, AusNet Services was mindful of the fact that stakeholder capacity and appetite to participate in the program could be impacted by a number of factors. These included:

- Availability of time and resources;
- Level of detailed knowledge of the complex regulatory framework;
- Recognition that AusNet Services' revenue proposal does not include expenditure associated with network expansion; and
- The materiality of the impact of transmission prices on end users' electricity bills.

These considerations led AusNet Services to develop a core stakeholder engagement program focused around three forums which were designed to highlight and seek feedback on key issues while keeping engagement costs low. However, throughout the program AusNet Services offered to hold detailed discussions with individual stakeholders on topics of interest. This approach recognised that different stakeholder groups had different preferences regarding topics and level of detail. For example, some topics, such as rate of return and service standards were not addressed in core engagement activities.

However, very few stakeholders expressed interest in participating in individual discussions. The low rate of uptake reinforced that the 'two tier' engagement approach was appropriate.

### 3.3.6 Providing value for money

AusNet Services sought to deliver a prudent stakeholder engagement program that sought input on material issues through forums. AusNet Services did not attempt to engage directly with residential consumers (although this customer group was not precluded from participating as the engagement program was accessible via AusNet Services' webpage), commission large-scale surveys or hold focus groups as, given the use of the VCR and the open discussion that occurred at forums, these approaches would have been unlikely to provide value for money.

## 3.4 Engagement Approach

### 3.4.1 Objectives

The objective of AusNet Services' stakeholder engagement program was to:

- Align the revenue proposal with stakeholder preferences where possible; and
- Ensure stakeholders understand how their preferences are reflected in the revenue proposal (including through the VCR). Where this is not possible, explain to stakeholders why this is the case.

### 3.4.2 Stakeholder identification

The TRR stakeholder engagement plan targets the following stakeholder groups:

- Directly connected and sub-transmission customers – these are the consumers with the highest proportion of their electricity bills allocated to transmission, and so are likely to be the group most directly impacted by the review.
- Consumer and industry advocacy groups – these bodies represent various end-user consumers and have historically been highly engaged in determination processes, including AusNet Services' previous transmission review and current distribution reset.

While AusNet Services proactively made contact with these key stakeholder groups, other stakeholder groups were identified. AusNet Services sought to promote awareness of the TRR process with these groups. These include:

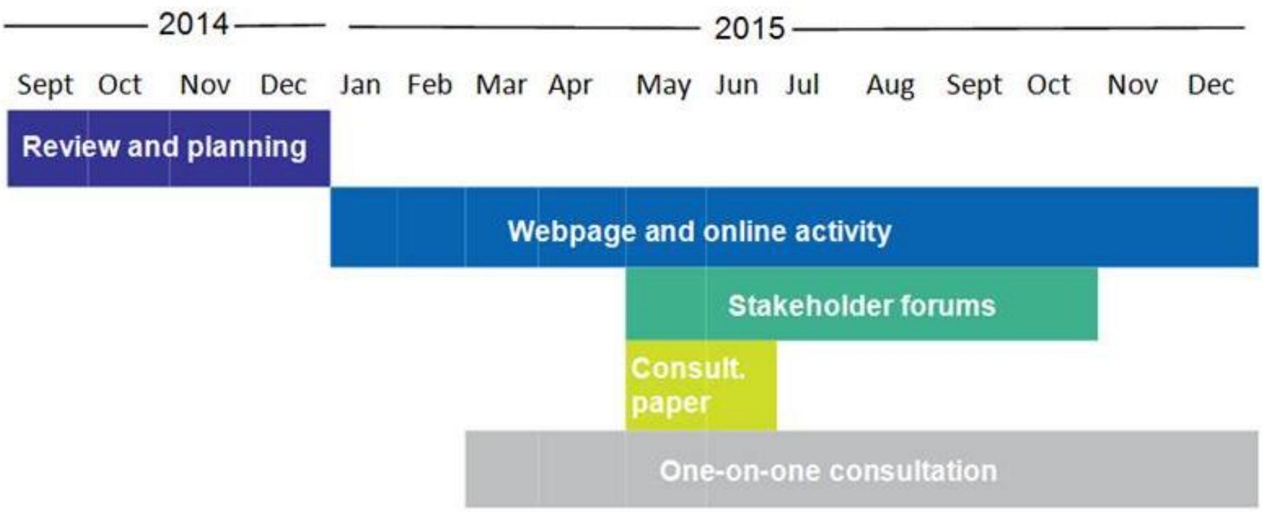
- Government representatives;
- Environmental groups; and
- Victorian distribution businesses.

The stakeholder groups listed above tend to be reasonably well-informed about the transmission network and the regulated revenue process. Most groups participating in AusNet Services' TRR engagement activities have previously participated in other revenue review processes, including AusNet Services' current distribution revenue review. Therefore, while background information was provided for less-informed participants, more emphasis was placed on providing details of AusNet Services' forecasting approaches and revenue proposal development. Stakeholder feedback validated this decision; stakeholders did not indicate a strong desire for a greater amount of background information.

## 3.5 Stakeholder Engagement Activities

This section describes specific stakeholder engagement activities undertaken for the TRR process, while other activities formed part of the company's broader stakeholder engagement work. Figure 3.2 shows the main stages of the engagement program, which is described in more detail below.

**Figure 3.2: TRR Stakeholder Engagement Timeline**




### 3.5.1 Review and planning

AusNet Services began this program with a detailed review of items such as stakeholder submissions to the previous TRR, conclusions related to consumer engagement from other Victorian electricity distributor's revenue proposals, AEMO surveys and AusNet Services' consumer segmentation research.

This process provided valuable insights into consumer views, while reducing the need for potentially costly activities, such as surveys, to generate data that had already been captured. In addition, commentary in the AER's recent decisions and CCP advice (both formal and informal), has indicated that they consider that directly engaging with small business and residential customers is not an efficient use of resources for transmission networks[9]. AusNet Services agrees with this.

In line with the Consumer Engagement Guideline, AusNet Services sought input from stakeholders on the design of the TRR stakeholder engagement program. A questionnaire was produced and distributed to approximately fifty stakeholders. Responses were received from four stakeholders. These responses confirmed that different stakeholders were interested in different types of engagement, with preferred models ranging from forums and online activities to one-on-one consultations. While AusNet Services did not place too much weight on the responses received due to the small number of responses received, some changes were made to the planned engagement program, including reducing the duration of planned forums.

### 3.5.2 Webpage

AusNet Services established a dedicated TRR webpage that served as a stakeholder information resource. This webpage allowed all stakeholders to access information about our engagement program. It also provided a point of contact via a dedicated TRR email address for queries or feedback. As at the 12 October, there had been 906 unique visits to the webpage, demonstrating that the webpage was a relatively popular means for stakeholders to obtain information on the TRR.

An interactive timeframe (see figure below) gave visitors to the webpage an effective summary of the progress of the TRR. The timeframe shows key dates and stages in the process with accessible links to relevant documents.

[9] See, for example, AER, *TransGrid Draft Decision*, Nov 14, pp. 7 – 57

**Figure 3.3: Timeline of Regulatory Review Process**

| Date | Activity |
|---|---|
| 31 Jul 14 | AusNet Services initiates framework and approach (F&A) |
| 28 Jan 15 | AER publishes F&A positions paper |
| 27 Feb 15 | AusNet Services submits response to F&A positions |
| 26 Mar 15 | First stakeholder forum \| Presentation \| Summary |
| 31 Mar 15 | AusNet Services submits forecasting methodology |
| 30 Apr 15 | AER publishes final F&A paper |
| 28 May 15 | Second stakeholder forum \| Presentation \| Summary |
| 12 Oct 15 | Third stakeholder forum |
| 31 Oct 15 | AusNet Services submits revenue proposal |
| Dec 15 | AER publishes issues paper and holds public forum |
| Feb 16 | Submissions on revenue proposal close |
| 30 Jun 16 | AER to publish draft revision |
| Jul 16 | AER to hold public forum on draft determination |
| Sept 16 | AusNet Services to submit revised revenue proposal to AER |
| Oct 16 | Submissions on draft determination and revised revenue proposal close |
| 31 Jan 17 | AER to publish transmission determination for next regulatory period |

During the course of the TRR, AusNet Services produced a small number of publications to build understanding among stakeholders. These included:

- Fact sheets, which explained the regulated revenue process and stakeholder engagement in the TRR;
- A consultation paper on accelerated depreciation of transmission assets (see section 3.5.4); and
- A plain language overview of the TRR proposal.

### 3.5.3 Stakeholder forums

Three stakeholder engagement forums formed the core of the TRR engagement activities. These were designed to provide sequential updates on the development of the revenue proposal, and seek feedback on key aspects at a time in the proposal's development which would enable this feedback to be taken into account.

Each forum consisted of an interactive presentation and a discussion. AusNet Services was mindful of the need to provide participants with an informed, independent perspective at these forums. Therefore, an independent consultant was engaged to attend the first two sessions, to facilitate discussion and ensure objectivity in answers to technical regulatory questions. Feedback provided indicated that this was viewed favourably by participants.

Participants were asked to complete feedback forms. All three forums were well-attended with participants proving informed and prepared to engage in discussions. A summary of each forum (including the feedback received) and the presentations were published shortly after the forum took place. These are attached.

An overview of each of the stakeholder forums is below. The forum summaries which were published shortly after the forums were held are attached (Appendix 3A).

### *Stakeholder forum 1*

The first forum was held in Melbourne CBD on 26 March 2015. The theme was 'Responding to Change.'

The purpose of this forum was to outline the context for developing the revenue proposal and to allow stakeholders an early opportunity to provide feedback on some specific topics, in line with TRR stakeholder engagement objective. This forum was attended by 16 external stakeholders, representing industry, consumer and government organisations.

Topics covered were:

- An introduction to AusNet Services;
- Approach to stakeholder engagement;
- Benchmarking performance;
- Responding to changes in the Value of Customer Reliability and forecast demand;
- Initial operating expenditure step changes; and
- An introduction to accelerated depreciation.

This forum set the context and parameters for the stakeholder engagement program and invited participant feedback on initial forecasts for capital and operating expenditures, including on specific opex step changes being considered. The discussion highlighted areas of interest for stakeholders.

Participants were asked via feedback forms to indicate topics or issues they would like to know more about. Discussion topics, questions, feedback and suggested improvements were taken into account when planning the second forum and developing the TRR proposal.

### *Stakeholder forum 2*

The second forum was held in Melbourne CBD on 28 May 2015. The title was 'Our Future Plans.' It was attended by 20 external stakeholders, representing industry, consumers and government organisations.

The purpose of the second forum was to provide more detail on specific inputs into the revenue proposal (including the Value of Customer Reliability and the proposed West Melbourne Terminal Station rebuild) and to seek robust feedback on costed options on the trade-off between price and reliability, and accelerated depreciation.

Topics covered were:

- Stakeholder engagement update;
- Value of Customer Reliability (presented by AEMO);
- West Melbourne Terminal Station – project update;
- The latest forecasts of revenue, price and expenditure; and
- Consultation on key issues: price vs reliability and accelerated depreciation.

In the deliberative part of the forum, discussion followed the presentation of costed options related to price / reliability trade-offs and accelerated depreciation. Participants had the opportunity for direct involvement in influencing AusNet Services' planning decisions in these areas.

#### *Stakeholder forum 3*

The third forum was held on 12 October 2015.

In this forum, the final TRR proposal was presented. Participants were shown how stakeholder feedback influenced this proposal. In cases where feedback did not influence the proposal, clear explanations were given.

The topics covered were:

- Emerging Energy Market Trends; and
- Overview of the Revenue Proposal – outlining the building blocks, the impact of stakeholder feedback and documentation which will be claimed as confidential.

A fourth TRR forum is planned to discuss key elements of the revised proposal with stakeholders. Feedback from the third and fourth forums will be incorporated into the revised revenue proposal.

### 3.5.4 Consultation paper on accelerated depreciation

AusNet Services is proposing to accelerate the depreciation of new transmission investments. To develop stakeholder understanding of its proposal, and ensure that stakeholder views were accurately understood and reflected in the proposal, AusNet Services published a consultation paper outlining the rationale for this approach. This is attached (Appendix 3B).

This paper provided detailed, accessible information about accelerated depreciation and invited stakeholders to make written submissions on the subject. These submissions would inform the TRR proposal.

AusNet Services received a single written submission on the consultation paper from another TNSP. Feedback was received that resource constraints impacted the ability of some stakeholders to provide written feedback on this document. Nonetheless, the paper provided detailed information that informed the robust discussion on accelerated depreciation that took place at the second forum (see above). The feedback received is outlined below.

### 3.5.5 One-on-one consultation

In addition to forums, participants were offered individual meetings to allow more detailed discussion on topics of particular interest to specific stakeholder groups.

Following this, AusNet Services presented to members of the Energy Users Association of Australia (EUAA) on the key transmission review issues which allowed more detailed discussion on key issues such as accelerated depreciation and the rate of return.

However, very few stakeholders expressed an interest in holding more detailed discussions on the TRR beyond the level of the forums. This suggests their preferred involvement was consistent with level one or two of the IAP2 Engagement Spectrum (*Inform* and *Consult*).

## 3.6 Summary of Stakeholder Views

From the initial stages of the TRR stakeholder engagement program, stakeholders were given opportunities to provide feedback and comments on key parts of the TRR proposal. As the program progressed, prevailing stakeholder views on certain topics became evident.

Following is a summary of typical stakeholder views by topic, along with the responses that have been included in the revenue proposal. AusNet Services has summarised these views in good faith, believing they accurately represent stakeholder attitudes on the respective aspects of the proposal. These views have been described in more detail and, where it has been possible, incorporated in relevant sections of the proposal.

### 3.6.1 Reliability and capital expenditure

In response to lower network demand and AEMO's revised estimate of the VCR, AusNet Services has deferred capital projects. This means that the network will be operating with a higher risk of interruption than has previously been the case.

#### *Stakeholder feedback*

The impact on both price and reliability of deferring capital projects was explained at the second stakeholder forum, using Springvale Terminal Station as an example. This was presented in the form of 'costed options'. A discussion was held, focussing on explaining the analysis presented. No strong support or resistance to the proposed reduction in reliability from capital project deferrals, based on the example presented.

However, some stakeholders asked questions about the expected impacts on reliability at specific terminal stations that supply the Melbourne CBD, such as West Melbourne. Concern was expressed about the impact of a supply interruption in this case.

Some stakeholders supported the recent lowering of the VCR, but questioned whether the application of the VCR at both the transmission and distribution networks was a duplicative assessment that resulted in excess capacity across the networks.

Stakeholders (particularly generators) were interested in the timing of planned replacement projects. This enables works and outages to be coordinated. We will keep interested parties informed about the timing of specific replacement projects as required, consistent with existing practices.

#### *Response in proposal*

AusNet Services has applied its economic planning approach to asset replacements, which uses AEMO's VCR to ensure that customer preferences related to the price/reliability trade-offs are robustly reflected in the proposal. While reliability risk is expected to increase slightly over the period, reflecting the reduction in the VCR, this deterioration is expected to be gradual and will be localised to specific areas where terminal station rebuilds have been deferred.

While an interruption in supply to Melbourne's CBD would have a severe impact, the completion of the RTS rebuild and the planned WMTS rebuild will reduce the supply risk to Melbourne's CBD.

AusNet Services is comfortable that its application the VCR in its replacement decisions does not result in duplicated or unnecessary redundancies in the electricity supply chain. The VCR is used at the connection point level when assessing whether to proceed with transmission asset replacements. AusNet Services works closely with the distributors in undertaking this assessment.

The reduction in reliability has also been acknowledged in AusNet Service' Service Target Performance Incentive Scheme (STPIS) proposal, by adjusting the targets for the loss of supply event frequency parameters to reflect the efficient decline in reliability expected.

### 3.6.2 Operating expenditure

AusNet Services has proposed a modest increase in operating expenditure. This is driven by:

- The application of the AER's Rate of Change approach, which reflects increased wage costs, output growth and expected productivity improvements (which will reduce required operating expenditure).

- Step changes related to changed regulatory obligations and capex-opex trade-offs.

### *Stakeholder feedback*

Participants queried whether opex step changes could be funded by 'doing less elsewhere.'

They also expressed interest in the AER's benchmarking analysis, and questioned whether AusNet Services' benchmarking data included AEMO's costs to present an accurate picture of Victorian transmission costs.

### *Response in proposal*

The proposal explains how step changes in operating expenditure can lead to reductions in total cost to customers through savings in capital expenditure, either now or in future regulatory periods. We have also identified savings in existing practices which will partially offset the magnitude of additional opex required. The proposal contributes to lower costs to customers in the long term.

The revenue proposal includes the results of the AER's benchmarking analysis updated to incorporate AEMO's costs. This helps facilitate a comparison of the efficiency of AusNet Services with other TNSPs on a like-for-like basis.

## 3.6.3 Accelerated depreciation

AusNet Services has proposed a modest acceleration in the depreciation allowance for new investments. This will better match revenue recovery with expected network usage over time.

The accelerated depreciation approach was consulted on through publishing a consultation paper and holding a discussion at a stakeholder forum.

Options that we considered and sought feedback on are described below.

Accelerating the depreciation of:

- Specific transmission assets;
- The transmission network as a whole; and
- New transmission assets.

Different ways of accelerating the depreciation include through:

- Reducing asset lives;
- Declining balance.

### *Stakeholder feedback*

Participants were strongly against the application of any type of accelerated depreciation. Specific feedback included questioning why they should bear any risk of asset stranding when, in a competitive environment, this risk is borne by the firms making the investment decisions. It was suggested that the regulated rate of return compensates for asset stranding risk and that accelerating the depreciation allowance is at odds with the notion that assets will be worked harder and made to last longer.

The one exception to this was written feedback provided by another TNSP, ElectraNet, which considered that 'alternative depreciation approaches described in the AusNet Services Consultation report need to be explored further[10]'.

10 ElectraNet, *Submission to AusNet Services' Accelerated Depreciation Consultation Paper*, 11 June 2015.

Stakeholders also questioned whether the application of accelerated depreciation to new capital investments would increase the incentive for AusNet Services to spend inefficiently high levels of capex to maximise the depreciation allowance it receives.

### *Response in proposal*

The proposal also explains the intentional separation between the regulatory depreciation allowance and the physical service lives of network assets. Nonetheless, in response to this feedback, we have selected an accelerated depreciation approach that does not shorten the regulatory life of the assets. While it is in consumers' best interests for the physical lives of assets to be extended, there are compelling reasons why the regulatory depreciation allowance should be accelerated. These reasons are explained in detail in Chapter 9 – Depreciation.

In response to stakeholders concerns about the price impact of accelerating the depreciation allowance, accelerated depreciation has been applied to a subset of assets, rather than the whole transmission network. Specifically, it is proposed that declining balance depreciation is applied to investments made from 1 April 2017. All investments made before this date will continue to be depreciated on a straight line basis. Stranding of particular assets at specific locations will continue to be managed to minimise the impact on the wider consumer base.

The application of accelerated depreciation to new investments does not increase AusNet Services' incentive to increase investment in the network. The economic assessments undertaken to justify the capex forecast are not impacted by the regulated depreciation allowance, and therefore the capex forecast is independent of the approach to accelerated depreciation. This is validated by the significant reduction (8%) in the average capex forecast per annum for the 2017-22 regulatory period, compared with actual and expected capex in 2014-17.

The proposal explains that under the NER, the value of the regulatory asset base is insulated from asset stranding. As a result of this, regulated rates of return have been lower historically, which have led to lower prices than would otherwise have been the case. The AER has confirmed that it does not take this risk into account when setting the regulated rate of return[11]. The proposal explains why the AER's approach to setting the regulated rate of return does not compensate for asset stranding risk (see Chapter 10 – Rate of Return).

## 3.7 Consistency with the Consumer Engagement Guideline

The TRR stakeholder engagement program was conducted in accordance with the best practice principles and IAP2 Framework included in the AER Consumer Engagement Guideline. The activities carried out are consistent with the best practice principles identified in the table below.

**Table 3.1: Assessment of engagement activities against Guideline principles**

| Activity | Purpose | Consumer Engagement Guideline:<br>Best Practice Principle |
|---|---|---|
| **Review and Planning** | Identify relevant existing information to gain insights into consumer views.<br>Gather stakeholder preferences related to design of TRR stakeholder engagement program. | Transparent<br>Clear, accurate and timely communication |
| **Webpage Engagement** | Enables all stakeholders to access information relevant to the TRR engagement program, | Clear, accurate and timely communication |

11 AER, *SA Power Networks preliminary decision,* April 2015, pp. 3 – 376

| Activity | Purpose | Consumer Engagement Guideline:<br>Best Practice Principle |
|---|---|---|
| | including event details and key publications.<br>Provide a channel for feedback. | Accessible and inclusive<br>Transparent |
| **Stakeholder Forums** | Provide a progressive series of updates and feedback opportunities on the development of the regulatory proposal.<br>Obtain consumer views and preferences on specific aspects of the proposal.<br>Address the AER / CCP focus on service providers presenting genuine 'costed options.'<br>Conduct feedback surveys.<br>Publish presentations and discussion summaries shortly after the event. | Clear, accurate and timely communication<br>Accessible and inclusive<br>Transparent<br>Measurable |
| **Consultation Paper: Accelerated Depreciation** | Establish a dedicated channel for the subject of accelerated depreciation.<br>Gather submissions to inform the proposed approach to accelerated depreciation. | Clear, accurate and timely communication<br>Accessible and inclusive<br>Transparent |
| **One-on-one consultations** | Provide stakeholders with an opportunity for engagement that is tailored to their specific information and time requirements. | Clear, accurate and timely communication<br>Accessible and inclusive<br>Transparent |

In the context of the IAP2 Engagement Spectrum shown above, the type of engagement undertaken in the TRR Stakeholder Engagement Program was consistent with the first, second and third levels; 'inform', 'consult' and 'involve', as described below.

- *Inform.* Most stakeholder engagement activities, including stakeholder forums, the TRR webpage, one-on-one interactions and publications such as fact sheets and a consultation paper, served to educate and inform stakeholders about the TRR proposal.
- *Consult.* In addition, the forums, one-on-one interactions and a consultation paper gave AusNet Services the opportunity to receive stakeholder feedback, acknowledge concerns and provide specific information on how stakeholder input influenced the revenue proposal.
- *Involve.* AusNet Services was mindful of the need to provide opportunities for stakeholders to have their views directly reflected in the TRR proposal. The second 'deliberative' stakeholder forum gave participants this opportunity, with the presentation of costed options on accelerated depreciation and capex-opex trade-offs.

However, the planning of network connections and shared network augmentations in Victoria is the responsibility of, respectively, the connecting parties and AEMO. In these instances, AusNet Services directly implements what stakeholders decide, consistent with the higher levels of the spectrum – *Collaborate* and *Empower.* The direct application of the VCR in AusNet Services' replacement plans is another example of reaching these levels.

AusNet Services envisages that, in future, more stakeholder engagement work could be conducted at these levels.

## 3.8 Ongoing Stakeholder Engagement

AusNet Services' customer strategy identified the following five outcomes to be achieved 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 streamlined customer facing processes.

While these outcomes apply to AusNet Services' energy delivery businesses in different ways, they emphasise the fact that, for the transmission business, stakeholder engagement must grow beyond that undertaken for regulatory proposals and major capital projects.

AusNet Services is currently developing a business-wide customer engagement model that includes policies, approaches and processes. The company is committed to building the strengths it needs to implement broad-based BAU stakeholder engagement across the business.

For transmission network stakeholders, AusNet Services is committed to continuing stakeholder engagement beyond the TRR. Specific ongoing activities include:

- Development of the webpage into a permanent transmission stakeholder resource.
- Continued consultation with key stakeholders though activities such as presentations tailored specifically to the information needs and expertise of those groups.

Given the current stakeholder appetite for involvement in the TRR, and considering the need to provide consumer value, AusNet Services believes its pragmatic approach to TRR stakeholder engagement was appropriate for the current regulatory review.

However, as customer engagement grows across the business, it is expected that stakeholder involvement will increase.

## 3.9 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 3A – Stakeholder Engagement Forums – Summaries
- Appendix 3B – Consultation Paper – Accelerated Depreciation

# 4 Capital Expenditure Forecast

## 4.1 Key Points

- Forecast capex totals $745.6m (real $2016-17) over the forthcoming regulatory period. This represents an average reduction of approximately 8% compared to actual and expected expenditure over the current period.
- The capex forecast has been developed based on AusNet Services' economic approach to planning. This aims to minimise the expected lifecycle cost of transmission assets. It has also been developed with regard to the changing energy market trends, with over 95% of the major stations capex forecast focused on key interconnector or metropolitan terminal stations.
- Changes in key planning assumptions including demand forecasts and AEMO's revised Value in Customer Reliability have been incorporated, which has enabled the deferral of key capex projects, including the West Melbourne Terminal Station (WMTS) Rebuild. It is estimated that the reduction in the capex forecast as a result of this change amounts to around $145m.
- A top-down assessment of the capex forecast has been carried out. As a result, a reduction of 0.89% has been applied to reflect expected efficiencies achieved at a portfolio level.

## 4.2 Introduction and Overview

### 4.2.1 Introduction

This chapter sets out AusNet Services' forecasts of the capital expenditure (capex) required to facilitate the efficient, on-going provision of prescribed transmission services for the forthcoming regulatory control period.

AusNet Services recognises the importance of providing value for money to its customers and end users. In preparing its capex forecast, AusNet Services has, therefore, sought to identify an overall program of capital work that will maintain the safety, quality, reliability and security of supply of prescribed network services[12] at an efficient level of long-run cost to customers while remaining cognisant that the long term utilisation of new investment is less certain than previously. This approach is consistent with the NEO and the capital expenditure objectives and criteria set out in the NER.

The capex forecast presented in this chapter is a product of AusNet Services' sound and prudent asset management practices, which deliver an optimal balance between total life cycle cost, quality, safety, reliability and security of electricity supply. Rigorous asset replacement planning – based on economic evaluation – is used to ensure the efficient timing of network investment. AusNet Services' prudent investment decision-making practices are supported by a robust project governance framework, which incorporates continuous improvement to ensure projects are delivered at an efficient cost.

AusNet Services' analysis indicates that the forecast detailed in this chapter will allow it to maintain the safety, quality, reliability and security of supply of prescribed transmission services. This is explained in more detail in AusNet Services' Asset Management Strategy 10-01 (Appendix 2A) and the Capital Expenditure Overview (Appendix 4A).

[12] As required by NER 6A6.7(a)(3).

The forecast capex program is expected to efficiently manage risk resulting from asset failure. Risks such as supply interruptions, injury and damage to equipment and the environment have been assessed for each major asset based on the probability of asset failure. These factors are all taken into account in assessing capital works.

Expressed in dollar terms, monetised reliability risk is expected to remain broadly constant over the period. However, consistent with the signals provided by the reduction in the Value of Customer Reliability (VCR) in 2014, there is expected to be a small but efficient decline in network reliability. This has been reflected in proposed adjustments to the targets under the AER's performance incentive scheme.

However, the expected decline in reliability will not compromise safety outcomes. AusNet Services must meet legislated safety requirements. Therefore, safety is the focus of ongoing investment in equipment, training and awareness. Forecast capex over the forthcoming regulatory period will make the Victorian transmission network safer both for the public and employees, through the replacement of assets with the highest risk of failure and through capex projects aimed at improving safety (or safety compliance).

AusNet Services' capex forecast only relates to the replacement of shared transmission network assets and transmission connection assets, and excludes any expenditure to augment the transmission system. As explained in Chapter 1 of this Revenue Proposal, AEMO is responsible for planning and procuring the augmentation of the shared transmission network, and the five Distribution Businesses have responsibility for planning the augmentation of transmission connections to their distribution networks. In planning network asset replacement, AusNet Services has consulted with AEMO and the Distribution Businesses in relation to future network and shared transmission connection augmentation proposals. This ensures that asset replacement and capacity augmentation works are optimised, and any opportunities for cost synergies are identified and incorporated.

As no augmentation is included in the plan, AEMO's National Transmission Network Development Plan is not directly relevant to this Revenue Proposal. However, AusNet Services and AEMO work together to integrate replacement and augmentation projects for the Victorian transmission network, to ensure any potential cost efficiencies are achieved.

### 4.2.2 Overview of the Capex Forecast

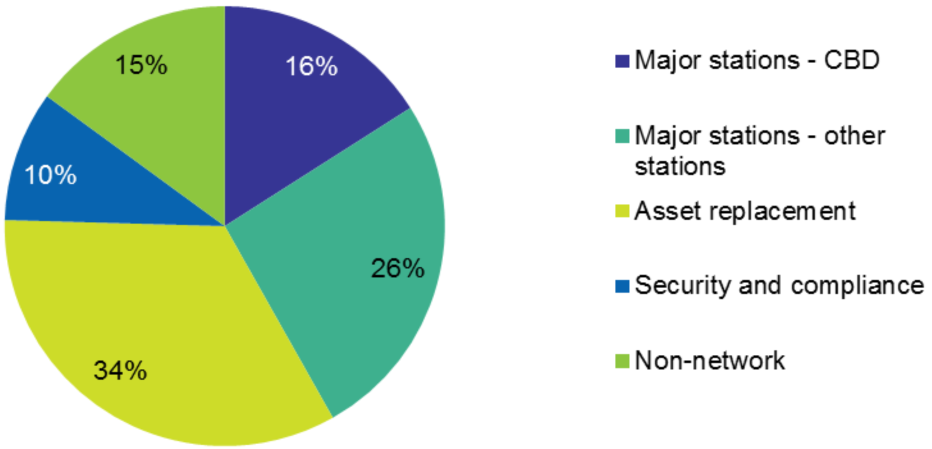
AusNet Services is forecasting total capex requirements of $745.6m (real 2016-17) for the forthcoming regulatory control period[13].

The capex forecast is driven by the need to replace assets that are reaching the end of their serviceable lives. The reduction in the VCR and demand forecasts have led to a reduction in the number of major stations rebuilds that are forecast to occur in the 2017-22 regulatory period. This has reduced the capex forecast compared to actual expenditure in the current period.

The majority of the capex forecast is related to network ($634.1m, or 85%) compared to non-network ($111.5m, or 15%). A significant part of the forecast (42%) is for major stations projects, including the re-scoped WMTS redevelopment.

[13] AusNet Services confirms that its forecasts of capex and opex are consistent with its capitalisation policy, which has not changed in the current regulatory control period.

**Figure 4.1: Breakdown of capex forecast into driver categories**




The figure below shows the annual capex for the previous and current regulatory periods and the forecast for the forthcoming period. Overall, the forecast capex for 2017-22 is, on average 8% lower per annum than actual and expected capex in the 2014-17 regulatory period. That data, and the explanatory information that follows are provided in accordance with NER S6A.1.1(7) and Schedule 1 clause 4 of the RIN.

**Figure 4.2: Historical and forecast capex ($m, real 2016-17)**

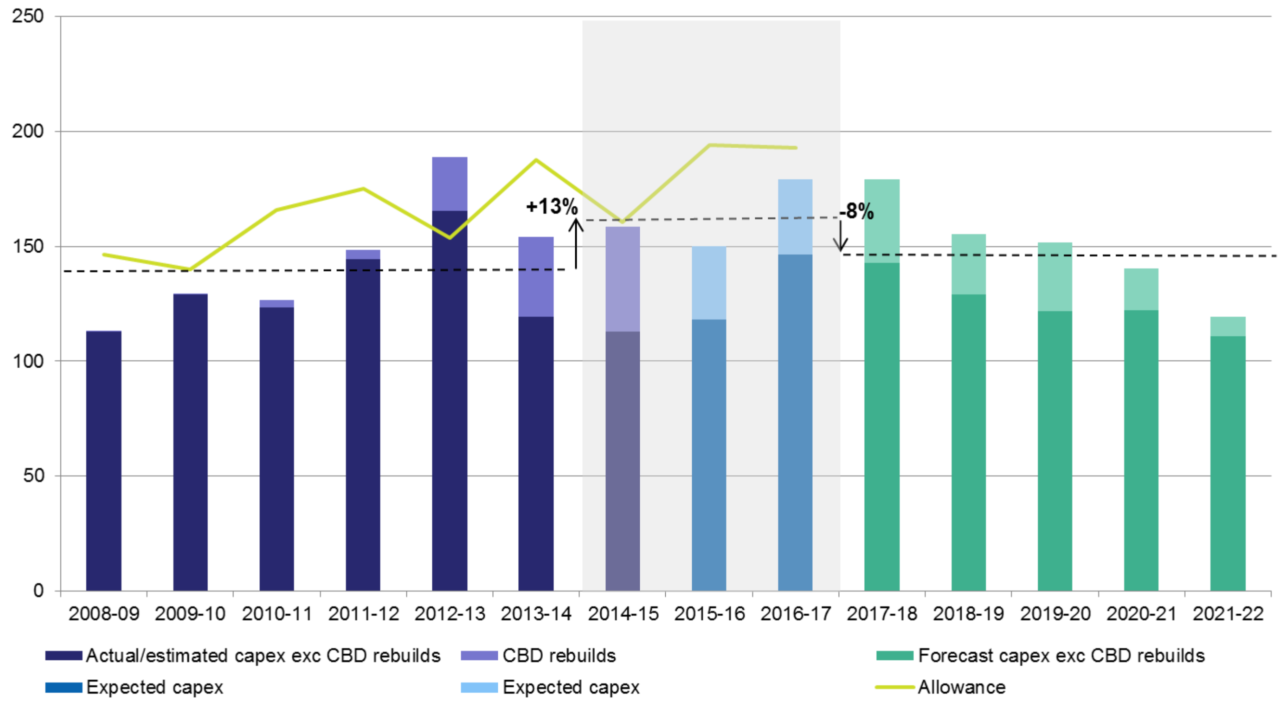
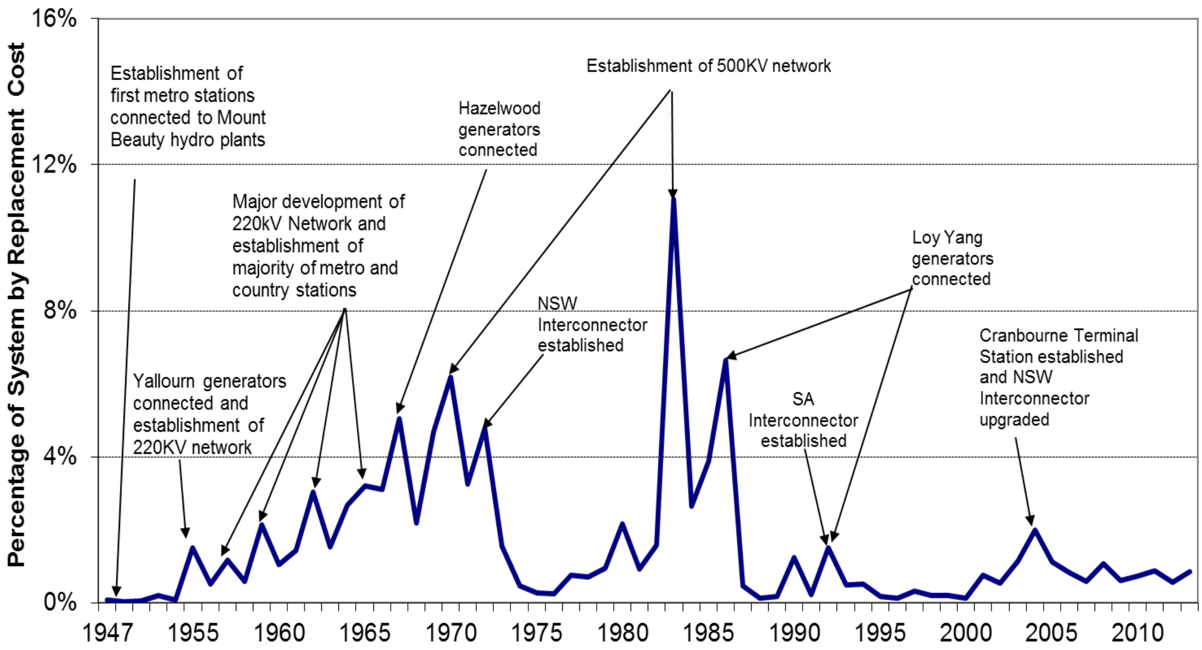



Figure 4.2 shows that over the previous regulatory period, capex gradually increased, peaking in the 2012-13 regulatory year. Since that year, capex has remained relatively high, largely due to the Richmond Terminal Station rebuild, which will be completed in 2018. Expenditure on the CBD rebuilds has averaged $36.8m per annum in the current regulatory period. In the upcoming period, expenditure on CBD rebuilds is forecast to average $23.8m per annum. While significant expenditure on WMTS is forecast for the beginning of the 2017-22 period, this reduces in the last two years as the redevelopment reaches completion. The CBD rebuilds replace ageing assets and are critical to secure supply to Melbourne's CBD.

While the average age of AusNet Services' assets has continued to increase, changes in key planning assumptions (being forecast demand and the VCR) have led to a reduction in forecast capex. These changes impacted AusNet Services' capex in the 2014-17 period, deferring the WMTS project and other major station rebuilds. It is estimated that, through the deferral of major projects, the combined effect of lower demand forecasts and the VCR is to reduce the 2017-22 capex forecast by around $145m.

As shown in the figure below, a significant portion of the transmission network was established between 1955 and 1970. As these assets reach the end of their useful lives over the next 20 to 30 years, and assuming that the services they provide continue to be required, there will be a substantial capex requirement to replace towers and rebuild major stations on the 220kV and 500kV network.

**Figure 4.3: Historical Development of AusNet Services' Transmission Network**




*Source: AusNet Services*

## 4.2.3 Drivers of capex

AusNet Services' capex forecast reflects the need for asset replacement given the historic pattern of development of the Victorian transmission network and the consequential age (and condition) profile of the asset base. The capital work planned for the forthcoming regulatory control period is driven by:

- The requirement to continue to meet our obligations to provide a safe and reliable supply of electricity, by replacing assets in poor condition;
- The age and condition of assets which influence the profile of asset replacement that is required;
- Key planning assumptions, including demand forecasts and the VCR; and
- Emerging electricity market trends, including reduced consumption and increase in utilisation risk.

Each of these drivers is outlined briefly below.

### *Requirement to continue to meet our Obligations*

AusNet Services must comply with its Transmission Licence conditions and national and state electricity industry legislation, rules, standards and regulations.

These obligations have a substantial bearing on the level of forecast capital expenditure that will be incurred by AusNet Services in the provision of prescribed transmission services over the forthcoming regulatory control period. Pursuant to NER 6A.6.7(a)(2), AusNet Services' capital expenditure forecast includes the forecast costs of complying with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

These requirements, which are summarised in section 4.4.1, are key inputs to the forecasting methodology.

### *Asset Age and Condition*

The timing of establishment of each element of the Victorian transmission network determines the age and condition of transmission assets today. Given that a significant proportion of the transmission network is at, or approaching, the end of its economic life, asset replacement due to condition continues to drive capex requirements.

However, AusNet Services does not expect that future replacement expenditure will perfectly mirror the original investment profile, in terms of timing and cost. This is because effective asset management, based on condition rather than age, enables AusNet Services to identify opportunities to efficiently defer the replacement of some assets. This maximises the service life of existing assets, and thus minimises long-run costs to customers.

### *Change in Key Planning Assumptions*

AusNet Services' economic analysis of its replacement plans incorporate forecast demand and the VCR as determined by AEMO. Since the previous determination there have been significant changes to both of these inputs. As a consequence, the revised capital expenditure forecast for network replacements is substantially lower than was previously the case.

AusNet Services' capex proposal for the 2014-17 regulatory period incorporated AEMO's demand forecasts published in 2012. Since then, both the magnitude and rate of growth of AEMO's demand forecasts have progressively declined (see Section 4.4.2). A reduction in forecast demand reduces the economic benefit of proposed asset replacement projects, as a lower volume of energy is assumed to be unserved following an asset failure. This reassessment of risk has enabled the timing of replacement projects to be deferred where there is no consequential diminution in safety.

In September 2014 AEMO published new VCR values following an extensive review which used choice modelling and a large-scale customer survey. Compared to the previous VCR values (set by VENCorp in 2008), these were much lower. This change has had a material impact on the economic assessment of the asset replacement program and has resulted in the economic deferral of several major station rebuilds. These deferrals are likely to result in a gradual decline in network reliability, as the change to the VCR indicates that consumers place a lower value on reliability than has been assumed in network planning to date. Consumers would prefer to pay lower prices for a lower level of reliability than has been supplied in the past. As outlined above, AusNet Services has satisfied itself that there would be no impact on safety to its staff or the wider community as a consequence of this decline in reliability.

Due to the expected decline in reliability, AusNet Services has proposed to adjust service performance targets that will apply. This is to ensure consistency across the different parts of the determination. If the adjustments to the targets are not approved, this will penalise AusNet Services for its economic planning approach which incorporates the VCR to efficiently reflect consumer preferences. These adjustments are described in section 7.3.2.

### *Emerging Energy Market Trends*

The capex forecast has been prepared in light of the recent trends in network utilisation, the increased uptake in distributed generation and the improving economics of storage technologies. Where possible, AusNet Services has sought to defer investments in long-lived assets and to adopt opex solutions as an alternative to additional network investment. This approach provides time to assess whether there is a continued, long-term requirement for specific assets in light of these changes, while balancing the ongoing requirement for AusNet Services to provide a safe and reliable supply of electricity.

Specifically, the forecast is a prudent response to these trends as it:

- Minimises investment in the parts of the network most at risk of future reductions in utilisation (such as the Latrobe Valley). Almost all (over 95%) of the major stations replacement projects are located in either wider metropolitan Melbourne or are linked to the interconnectors into NSW and South Australia.
- Includes minimal expenditure on towers and lines, despite the age and condition profile of these assets demonstrating that there will be a significant replacement requirement in the next 15 to 30 years. The use of advanced condition monitoring technologies such as SAIP will provide information to assist in potentially deferring these replacements.
- Adopts opex solutions as an alternative to capex solutions to retain optionality where feasible and cost effective to do so, through the application of AusNet Services' economic evaluation of replacement requirements.
- Incorporates the retirement of the synchronous condensers, assets at Morwell Power Station and the closure of Alcoa's Point Henry facility. An increase in the capital expenditure forecast would be necessary if these assets continued to be required.

## 4.2.4 Stakeholder feedback

Stakeholder views have been incorporated into the capex forecast in the following ways:

- Through the use of the VCR in the replacement planning approach. This is the most robust way in which stakeholder feedback has been incorporated into the revenue proposal. This is a key factor in determining whether each capex project has been assessed as being economic to proceed.
- The feedback received through the TRR stakeholder engagement activities. The following topics related to the capex forecast were presented and discussed at the stakeholder forums:
    - How capex projects are economically justified;
    - AEMO's Value of Customer Reliability review; and
    - West Melbourne Terminal Station (WMTS) – revised project.

Feedback received through this program, and AusNet Services' response to this feedback, is presented in the table below. Feedback related to specific components of the capex forecast is addressed in the relevant sections of this chapter. This is contained in boxes shaded in yellow.

### Table 4.1: Stakeholder Feedback on Capital Expenditure

| Stakeholder Feedback | Response |
|---|---|
| **AusNet Services should use existing assets for as long as it is safe to do so.** | AusNet Services agrees with this feedback and this sentiment underpins our approach to asset replacement.<br>The timing of asset replacement is determined to be where the expected benefits exceed the expected costs. A quantitative assessment is undertaken to establish the economic timing of rebuild projects. Where safety is not compromised, existing assets will remain in place for longer.<br>Section 4.3 sets out AusNet Services' economic approach to planning in further detail. |
| **Support capex-opex trade-offs where the overall cost to customers is lower** | AusNet Services' agrees with this statement. Its economic approach to planning considers both opex and capex solutions to an identified replacement need. The solution selected is that which addresses the need, and minimises the present value lifecycle cost to customers. |
| **Should AusNet Services invest in transmission reliability (including via the use of the VCR), given the majority of reliability losses occur on the distribution network?** | When planning transmission replacement projects AusNet Services applies the VCR to cost the additional reliability risk that would be put on the network. This is consistent with the approach used in planning the distribution network. In both cases the investment will only be justified if the benefits to end use customers, which include reliability and safety, exceed the cost of the investment. |
| **Does AusNet Services retain the revenue allowance associated with projects that were forecast to proceed in the current period by have been deferred (for example, West Melbourne)?** | AusNet Services will retain the forecast return on the capital expenditure forecast over the 2014-17 regulatory period. This is consistent with the incentives provided by the regulatory regime, which works to encourage efficient project deferrals. The benefit of the deferral will be shared with customers as the asset base at the beginning of the 2017-22 regulatory period will be roughly $50m lower than it would have been had AusNet Services progressed with the WMTS redevelopment project as forecast in the previous determination. |
| **Presented costed options regarding the expected impact on reliability due to the deferral of major projects. This included the impact on both price and reliability for different timings of major projects, using the planned Springvale Terminal Station redevelopment project as an example. No strong opposition was expressed in response to the small deterioration in reliability under the scenario which is reflected in the capex forecast.** | There was strong consumer support for the use of the VCR in asset replacement planning. Given this, AusNet Services has continued to forecast capex using its economic approach and the 2014 VCR and latest forecast demand as inputs. While this approach is likely to lead to an efficient gradual decline in reliability, in monetary terms (i.e. expected outage duration multiplied by the VCR) expected reliability will be broadly constant. |

### 4.2.5 How the capex forecast contributes to the NEO

AusNet Services' forecast total expenditure will deliver a capex program that best serves the long term interests of consumers. The forecast addresses the need for ongoing, efficient network investment which is required for the network assets to continue to provide safe and reliable electricity services. However, it also responds to falling demand forecasts and the reduction in the valuation placed by consumers on reliability (the VCR).

AusNet Services considers that the information presented in the Revenue Proposal and its accompanying appendices and other supporting documents demonstrates that the company's capex for the forthcoming regulatory control period reasonably reflects:

- The efficient costs of achieving the capital expenditure objectives set out in NER 6A.6.7(a);
- The costs that a prudent operator would require to achieve the capital expenditure objectives set out in NER 6A.6.7(a); and
- A realistic expectation of the demand forecasts and cost inputs required to achieve the capital expenditure objectives set out in NER 6A.6.7(a).

AusNet Services also considers that the capital expenditure forecast complies with the other requirements of the NER and is consistent with the NEO. Accordingly, pursuant to the provisions set out in NER 6A.6.7(c), the capex forecasts set out in this Revenue Proposal should be accepted by the AER.

A more detailed overview of the capital expenditure forecast is provided in Appendix 4A – Capital Expenditure Overview.

### 4.2.6 Structure of this chapter

The remainder of this chapter is structured as follows:

- Section 4.3 describes AusNet Services' forecasting methodology;
- Section 4.4 sets out the assumptions that underlie the forecasts;
- Section 4.5 explains how AusNet Services benchmarks against its peers;
- Section 4.6 sets out AusNet Services' capex forecast;
- Section 4.7 discusses how our forecast capex compares with historic expenditure;
- Sections 4.8 to 4.10 provide further details of the main components and key drivers of AusNet Services' network capex forecasts;
- Section 4.11 explains AusNet Services' non-network capex forecasts;
- Section 4.12 describes the expected benefits to customers of the proposed capex;
- Section 4.13 demonstrates the deliverability of the forecast capex;
- Section 4.14 outlines the links between the capital expenditure forecasts and the other building blocks; and
- Section 4.15 lists supporting documentation relevant to this Chapter.

## 4.3 Forecasting Methodology

### 4.3.1 Introduction and background

The capex forecasts have been prepared in accordance with the expenditure forecasting methodology document submitted to the AER on 31 March 2015. As noted in that document, AusNet Services' objective is to ensure that its capex forecast complies with the NER and promotes the NEO.

Accordingly, AusNet Services' forecasting methodology is focused on identifying an overall program of capital work that will prudently and efficiently maintain the safety, quality, reliability and security of supply of prescribed network services at optimum cost. This approach is consistent with the NEO and the capital expenditure objectives and criteria in the NER.

In broad terms, AusNet Services routinely implements the following robust planning and governance processes to drive capital expenditure forecasts that comply with the NER and the RIN requirements:

- Asset management practices, which deliver an optimal balance between total life cycle cost, quality, safety, reliability and security of electricity supply.
- Asset replacement planning – based on economic evaluation – is used to ensure the efficient timing of network investment.
- Investment decision-making practices are supported by a robust project governance framework, which incorporates continuous improvement to ensure projects are delivered at lowest efficient cost, and that replacements can be deferred where this is the most efficient risk-based outcome.

The capex forecast presented here has been developed in accordance with these processes.

The capital expenditure forecast has been subject to rigorous internal testing to ensure that it is analysed, reviewed and finalised appropriately. A due diligence process has been followed prior to sign-off of the submission. This process includes following a Submission Assurance Plan, which focuses on information management and internal quality assurance, including regulatory model review.

As explained in Chapter 1, AEMO is responsible for planning the augmentation of the shared transmission network in Victoria, and the five Victorian distribution businesses have responsibility for planning the augmentation of transmission connections to their distribution networks. Accordingly, AusNet Services' network capital expenditure forecast relates only to the replacement of shared transmission network assets and transmission connection assets, and excludes any expenditure to augment the transmission system.

In planning network replacements, AusNet Services consults with AEMO and the Victorian distributors in relation to future network and transmission connection augmentations, in order to ensure that asset replacement and capacity augmentation works are optimised, and all opportunities for cost synergies are identified.

### 4.3.2 Overview of forecasting methodology

#### *Categorisation of capital expenditure*

In terms of the categories adopted by the AER in the RIN, AusNet Services' capex forecast is comprised of two expenditure categories, namely:

- Replacement capex; and
- Non-network capex.

AusNet Services' approach to forecasting replacement capital expenditure has two stages:

- Stage 1: Project based evaluation (bottom up); and
- Stage 2: Aggregation and efficiencies (top down).

Each of these stages is outlined below.

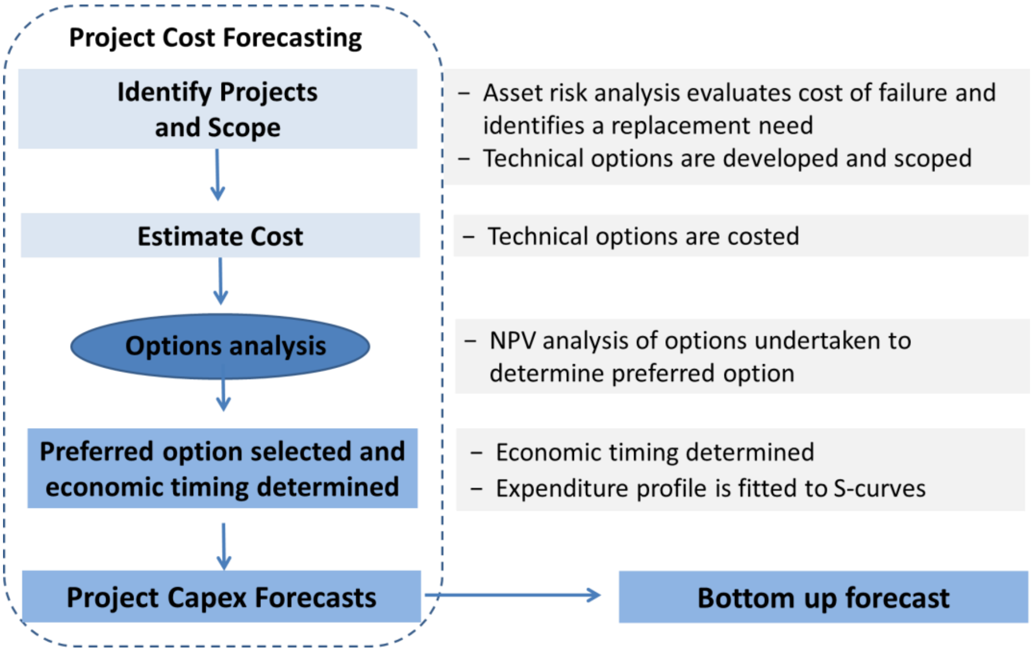
This section concludes with a description of AusNet Services' forecasting methodology for non-network capital expenditure.

### *Replacement capex forecasting – Project based evaluations*

AusNet Services seeks to deliver optimal electricity transmission network performance at efficient cost by ensuring that all decisions to replace or maintain network assets are economically justified and appropriately consider all relevant criteria. The relevant criteria include safety, demand for network services, performance and condition of network assets, reliability and security of supply, technological advancements, the changing nature of generation and demand, and the environmental impact of asset failure.

The figure below depicts the process for determining a project based replacement decision.

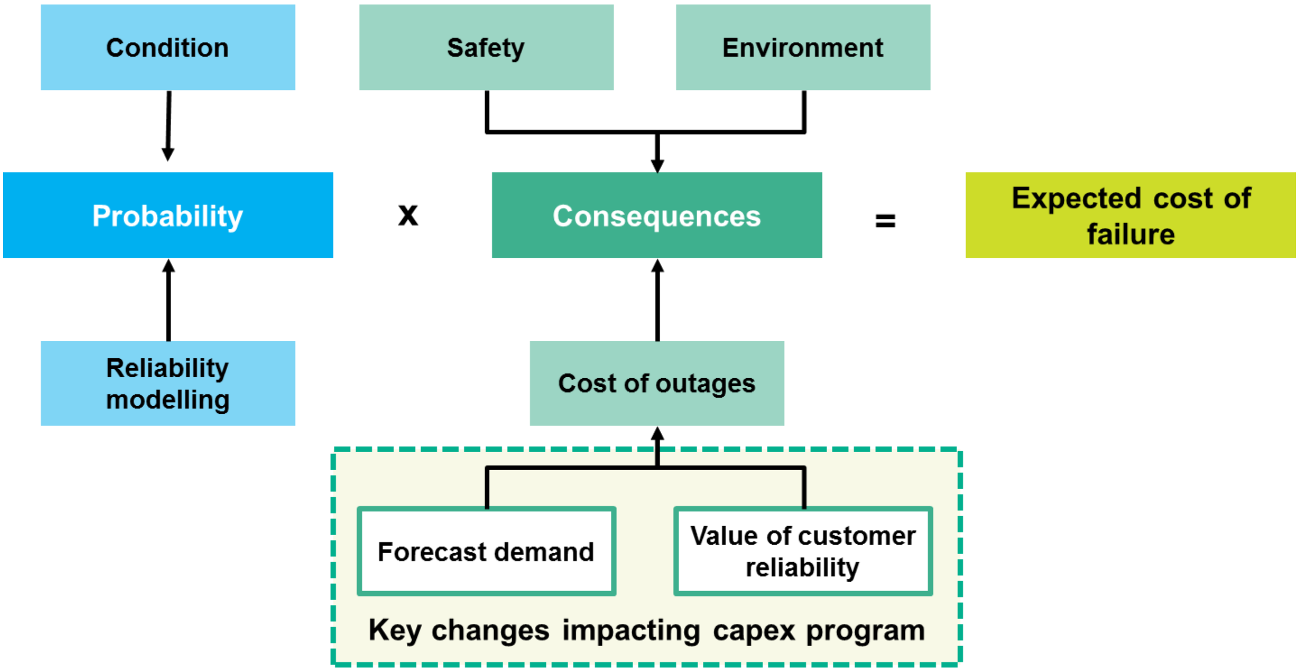
**Figure 4.4: Project Estimates and the Bottom Up Forecast**




*Source: AusNet Services*

The first step in the process is to evaluate the need for an asset replacement. This assessment is based on asset class modelling that identifies those assets that present the highest risk, based on asset condition and consequences of failure. This approach is an economic evaluation, which focuses on the expected cost of failure, as depicted in the figure below.

**Figure 4.5: Economic Evaluation Method**




*Source: AusNet Services*

The next step is to examine the technically feasible options to address the identified risk. The costs and benefits (in terms of avoiding the expected costs of asset failure) of each option are examined. The Value of Customer Reliability (VCR) and forecast demand are combined to forecast the cost of outages. While the VCR reflects customer preferences, any additional relevant feedback from stakeholders is also taken into account in the evaluation process. The option that delivers the maximum net benefit, in Net Present Value (NPV) terms, is the preferred option.

Once the preferred option has been selected a detailed project scope and detailed project cost can be estimated. AusNet Services employs a detailed technical scope of works (refined from the preferred option) and current unit costs for installing the assets. This resulting cost estimate is the most likely cost of the project and assumes the scope of work will not change during the detailed design and construction phases. The cost estimate does not capture likely changes in unit costs, but accounts for the expected cost of various project contingencies (estimated using Monte Carlo analysis). The basis for the contingencies is explained in Appendix 4E – Cost Estimation Methodology.

The economic timing of the preferred option is established by comparing the annualised total cost of the selected option with the annual incremental benefits. Under this evaluation approach, the economic timing is identified as the point in time at which the annual incremental benefits just exceed the annualised cost. S-curves of generic project types that are representative of the projects typically undertaken are then used to forecast the timing of the expenditure.

Sensitivity studies around the discount rate, asset failure rate, value of customer reliability and forecast demand scenarios are conducted to test the robustness of the economic evaluation. The forecasts from different demand scenarios for Victoria are used in the sensitivity analysis. This step ensures that the proposed replacement capital expenditure is economic under a range of reasonable scenarios.

### *Replacement capex forecasting – aggregation and efficiencies*

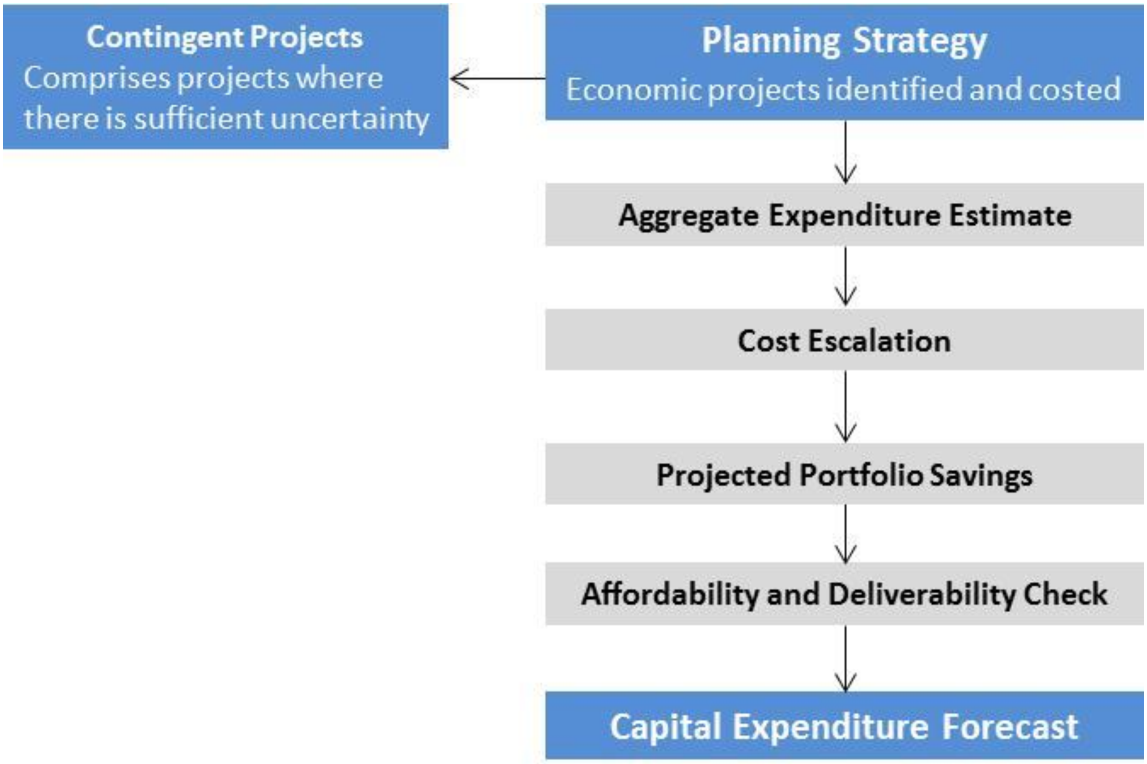
While project based evaluations underpin the replacement capital expenditure forecasts, a number of other factors must be taken into account in developing a forecast for total replacement expenditure. In particular, a number of synergies and savings may become apparent as bottom up forecasts are aggregated. For example:

- Minor replacement works may be included in a major replacement project to attain synergies in project design, project management and project establishment costs.
- Project based replacements may be combined with AEMO's shared network augmentation requirements or the distributors' connection augmentation needs.
- Large complex projects may be staged so that assets with the highest failure risks are replaced first, while lower risk assets may be replaced later in the project.

These expected savings are reflected in the total replacement capital expenditure forecast through adjustments to the affected projects.

The figure below shows how the economic projects identified and costed on a bottom up basis (from stage 1) are subject to a series of adjustments and checks to determine the total forecast replacement capital expenditure. These stages are discussed in more detail below.

**Figure 4.6: Capital Expenditure Forecasting Methodology**




### *Aggregate Expenditure Forecast Testing*

AusNet Services has considered the conclusions presented in the AER's 2014 Annual Benchmarking Report in assessing its aggregate capex forecast. However, given the relative infancy of benchmarking transmission networks in Australia, AusNet Services submits that the conclusions that can applied to the capex forecast are limited.

However, AusNet Services does draw the following insights from the total factor, or overall, productivity benchmarking:

- The overall productivity of the Australian transmission sector declined between 2006 and 2012; and
- AusNet Services' overall productivity increased between 2006 and 2012.

These statements provide a degree of assurance as to the efficiency of AusNet Services' practices, but there are more meaningful indicators that can be used to test this. Benchmarking is discussed in more detail in section 4.5.

Trend analysis can be more meaningful in some capex categories. There should be sound justifications for significant changes in the magnitude of capex over time. Forecast capex has been compared with outturns in current and prior regulatory periods. The results of this analysis are discussed in Section 4.7.

### *Projected Portfolio-level Savings*

To assess the projected portfolio-level savings, AusNet Services compared forecast and actual expenditure outcomes for recent completed transmission projects. This analysis concluded that an adjustment of 0.89% should be made to the total capex forecast to reflect cost savings that are expected to be achieved at a portfolio level. This adjustment is discussed further in Section 4.4.8 – Capex Efficiency.

### *Affordability and Deliverability*

AusNet Services has tested its provisional capital expenditure forecasts against affordability and deliverability considerations prior to finalising its forecasts. Specifically, AusNet Services has considered:

- The price impact for transmission customers and end-use consumers;
- The funding implications of the proposed capital expenditure in the context of its commitments in relation to AusNet Services' electricity and gas distribution businesses; and
- The deliverability of the proposed program, in terms of resource requirements and scheduling of works.

The affordability of the forecast capex program assumes that the AER will determine a rate of return commensurate with the risks faced by the benchmark business. This will secure investor financing to enable the program to be delivered. An appropriate balance of these outcomes is consistent with the elements of the NEO.

### *Non-network capital expenditure*

In addition to replacement capital expenditure, AusNet Services must also forecast its non-system capital expenditure requirements.

Non-network capex is made up of:

- Information technology (IT);
- Buildings and property;
- Vehicles; and
- Other (principally tools and equipment).

With the exception of corporate IT systems, capital expenditure on non-network assets is generally recurrent in nature, which reflects the economic life cycles of each asset type. IT capital expenditure is forecast based on AusNet Services' corporate IT strategy, which itself has been set in a manner consistent with the obligations of, and expectations placed upon, a prudent network service provider.

## 4.4 Assumptions and Inputs

Schedules S6A.1.1(4) requires a Revenue Proposal to provide information on the key assumptions that underlie the capital expenditure forecast. This information is set out below.

### 4.4.1 Compliance with Laws, Codes and Standards

AusNet Services must comply with all applicable regulatory and legislative requirements. A number of these requirements result in various significant secondary system capex requirements for AusNet Services. These include the requirements defined in Schedule S5 of the NER, along with the operational requirements set by AEMO in relation to system protection, communication and metering as well as the specific performance obligations regarding the provision of services to AEMO that are specified in the network arrangements for Victoria.

The key compliance drivers are outlined in the figure below.

**Figure 4.7: Applicable compliance instruments**

| Victorian Electricity System Code and Transmission Licence | Australian Standards | Electricity Safety Management Plan | National Electricity Rules |
|---|---|---|---|
| • System performance obligations | • AS/NZS 7000<br>• AS 62053 | • Approved by ESV<br>• Safety system operation | • System security obligations<br>• Connection obligations<br>• Metering obligations<br>• Economic regulation<br>• Regulatory Information Notices |

*Source: AusNet Services*

AusNet Services is also required to comply with health and safety, environmental and security obligations which impact on the design and operation of the network. These obligations and the related internal standards cover matters such as:

- Safe access for work on towers;
- Management of fire hazards;
- Changes to the Occupational Health and Safety Act 2004 requiring additional reviews of safety issues at the design stage of a project and additional liability (and therefore cost) for designers;
- Management of various pollutants and environmental effects (oil discharge, noise and greenhouse gas emissions); and
- Physical security, including counter terrorism defence due to the characterisation of the transmission network as critical infrastructure.

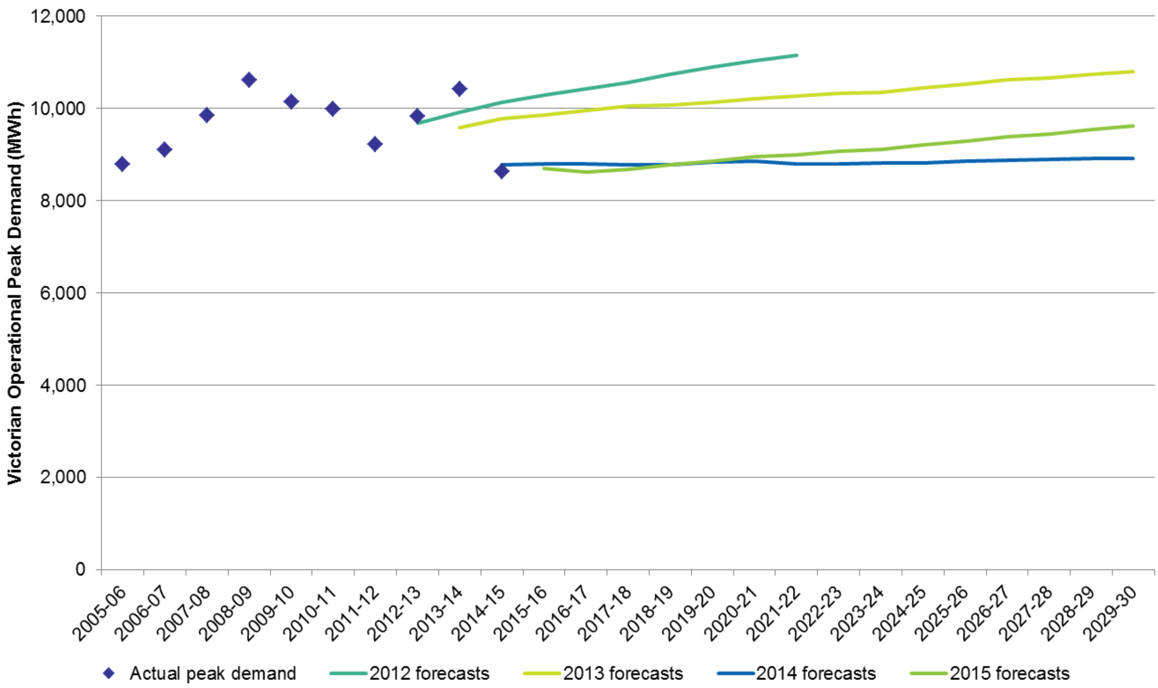
These compliance obligations have a substantial bearing on the level of forecast capital expenditure that will be incurred by AusNet Services in the provision of prescribed transmission services over the forthcoming regulatory control period. These compliance obligations must be met despite the changes in the operating environment described in Chapter 2. Pursuant to NER 6A.6.7(a)(2), AusNet Services' capital expenditure forecast includes the forecast costs of complying with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

### 4.4.2 Demand Forecasts

Although AusNet Services is not responsible for planning network augmentations, it uses demand forecasts for asset replacement planning purposes. Specifically, AusNet Services uses terminal station demand forecasts to assess load at risk under unplanned outage conditions. That assessment forms part of AusNet Services' economic evaluation of asset replacement decisions.

AusNet Services' capex proposal for the 2014-17 regulatory period incorporated AEMO's demand forecasts published in 2011. Since then, both the magnitude and rate of growth of AEMO's demand forecasts have progressively declined (except for a slight recovery in the growth rate in 2015), as shown in the figure below.

**Figure 4.8: Summer maximum demand for Victoria**




*Source: AEMO*

A reduction in forecast demand reduces the economic benefit of proposed asset replacement projects, as a lower volume of energy is assumed to be unserved following an asset failure. This enables replacement projects to be deferred.

Lower demand forecasts also affect the economic analysis of network augmentations. The 2015 Victorian Annual Planning Report produced by AEMO (as the network planner) identifies that four of the six emerging augmentation requirements have been deferred beyond its 10 year outlook period, as a result of reduced demand forecasts[14].

AusNet Services has used both the AEMO Transmission Connection Point Forecast and the DNSP Victorian Terminal Station Demand Forecasts (both published in September 2014) for asset failure risk assessments and asset replacement decisions[15]. These two demand forecasts are provided in Appendix 4B and Appendix 4C of this Revenue Proposal.

Sensitivity analysis of the economic timing of the project is carried out by comparing the results using the alternative forecasts.

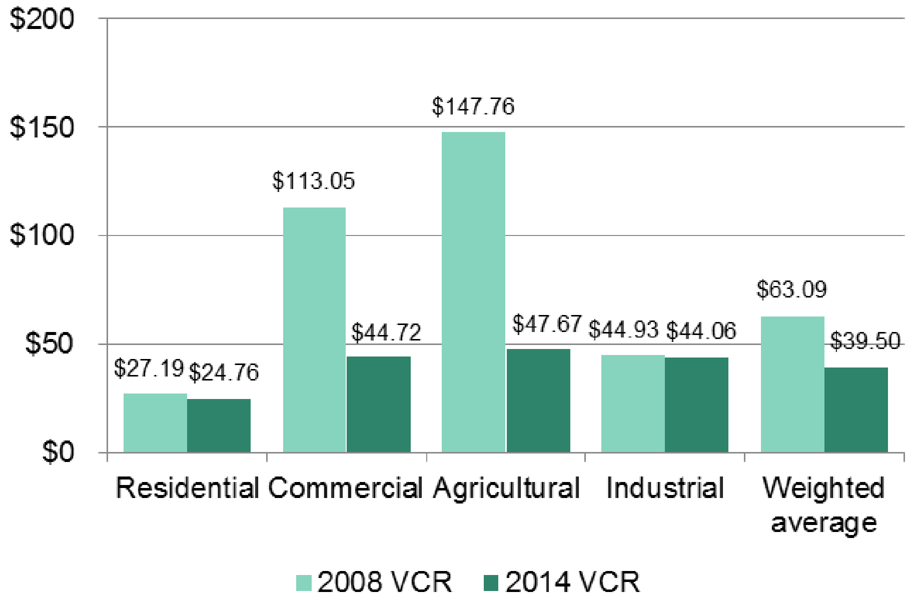
14 2015 Victorian Annual Planning Report, AEMO.

15 AEMO, *Victorian Terminal Station Demand Forecasts for 2014/15 to 2024/25,* September 2014.

### 4.4.3 Value of Customer Reliability

In September 2014 AEMO published new VCR values following an extensive review which used choice modelling and a large-scale customer survey. Different VCR values were published for different business sectors and for customers directly connected to the transmission network. Compared to the previous VCR values (set by VENCorp in 2008), these were much lower. The figure below shows the reduction in VCR values for the various sectors.

**Figure 4.9: Reduction in the VCR by Sector ($ per kWh)**




*Source: AEMO*

AusNet Services has adopted AEMO's lower 2014 VCR estimate in preparing its capex forecast.

This change has had a material impact on the economic assessment of our asset replacement program. Specifically, it has resulted in the economic deferral of several major station rebuilds. These deferrals are likely to result in a gradual decline in network reliability, as the change to the VCR indicates that consumers place a lower value on reliability than has been assumed in network planning to date. Consumers would prefer to pay lower prices for a lower level of reliability than has been supplied in the past. It is important to note that in assessing the viability of these deferrals, care has been taken to ensure that there is not a concomitant, unacceptable reduction in safety outcomes.

To express reliability risk in dollar terms (monetised reliability risk) the change in reliability can be valued using the VCR. Reliability will decline, but as a lower value is assigned to reliability than has been the case in the past, monetised reliability risk is expected to remain relatively stable. AusNet Services' revenue proposal therefore constitutes a 'maintain' case in terms of reliability as valued by consumers, despite an expected (efficient) reduction in network reliability.

Stakeholders asked whether the VCR should be used for transmission planning, given that generally distribution networks have a more direct impact on reliability. However, the VCR is used to quantify the expected unserved energy that would result from an asset failure. The probability of a failure is also an input into this calculation.

One stakeholder (a distributor) expressed concern about AusNet Services' use of the VCR in planning replacement capex on the basis that it is not required by the Rules. However, AusNet Services considers the use of the VCR in planning replacement is the most appropriate and robust means of capturing customers' valuations of the level of service provided by the asset. It is reasonable for AusNet Services to do so, and it is submitted that its incorporation into the model is consistent with attainment of the NEO.

### 4.4.4 Asset condition

Asset condition is an important input in developing the replacement capital expenditure forecasts.

AusNet Services measures asset condition with reference to an asset health index, on a scale of 1 to 5. The range of the index is consistent across all asset types and relates to the expected remaining asset life. The table below provides a simple explanation of the range of asset health assessments.

**Table 4.2: Asset health reporting**

| Health Index | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Description** | As new | Signs of wear | Starting to deteriorate | Deteriorating | Advanced deterioration |

*Source: AusNet Services*

Various techniques are used to measure the health of different types of assets. The table below provides an overview of the condition assessment methods used for major asset types.

**Table 4.3: Condition assessment methods**

| Asset type | Condition assessment methods |
|---|---|
| **Transformers** | Offline electrical testing<br>Dissolved Gas Analysis<br>$SF_6$ analysis |
| **Power Cables** | Visual inspection of cable joints for signs of corrosion |
| **Insulators** | Visual inspection for degradation |
| **Circuit Breakers** | Gas and oil sampling<br>Offline electrical testing<br>$SF_6$ analysis |
| **Switchgear** | Visual inspection for corrosion<br>Thermal imaging |
| **Conductors** | Visual inspection for corrosion |

*Source: AusNet Services*

In preparing the replacement capital expenditure forecasts, AusNet Services has relied on the asset condition assessments to determine the efficient capital expenditure requirements for the forthcoming regulatory period.

### 4.4.5 Failure risk ratings

Asset failure risk information flows from AusNet Services' Reliability Centred Maintenance (RCM) asset management techniques, which focus on asset condition (rather than age) to guide optimal replacement timing. This approach takes into account performance requirements and actual failure data to assign failure rates to individual network assets or classes of assets.

Failure Mode Effect Criticality Analysis (FMECA) based on historical asset performance data is undertaken to determine typical root causes of functional failures, and the resulting effects these causes have on key performance measures including network safety, reliability and asset availability. Asset condition data collected during scheduled maintenance tasks is used to determine dynamic time-based probability of failures and the remaining service potential of the asset in that lifecycle phase.

As noted in relation to asset condition assessments, AusNet Services relies on the accuracy of the failure risk ratings to determine the efficient capital expenditure requirements for the forthcoming regulatory period.

### 4.4.6 Unit Rates and Project Cost Estimation

The unit rates to derive project cost estimates have been established from internal standard costs, which will reflect the best available actual data. Forecast cost escalators have been applied to project estimates. Appendix 4D outlines the basis of the unit rates that are applied in deriving the capex forecast.

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 4E – 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 of the most likely cost of the project. AusNet Services' standard estimating procedures generate both P50 and P90 (which has a 90% confidence factor of not being exceeded by cost at project completion) estimates for projects, with P90 estimates used for internal planning and budgeting processes.

S-curves have been used to define the profile and timing of expenditure over the term of a major capital project. The S-curves applied by AusNet Services reflect actual historic experience.

### 4.4.7 Cost escalators

#### *Labour*

Cost escalators for internal and external labour have been applied in the development of project cost estimates. These are shown in the table below. The proportion of AusNet Services' total capex forecast due to labour escalation is approximately 2% (or $16m, real $2016/17) over the forthcoming regulatory period.

**Table 4.4: Labour cost escalators used in developing forecast capex (in real terms)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Labour (internal)** | 0.81% | 0.81% | 0.83% | 0.90% | 0.91% |
| **Labour (external)** | 1.04% | 1.04% | 1.01% | 1.09% | 1.12% |

*Source: CIE*

*Note – Numbers rounded to one decimal place.*

AusNet Services engaged CIE to Forecasts of growth in the wage price index (WPI) for all industries, construction and utilities, in Australia and Victoria (see Appendix 5E). The labour escalators applied to the capex forecast are based on a simple average of labour price forecasts produced by CIE and the forecasts presented in Deloitte Access Economics' (DAE) report for the AER, entitled *Forecast growth in labour costs in NEM regions of Australia*.[16] This methodology, which recognises that the average of two forecasts is likely to be more accurate than an individual forecast, aligns with the AER's approach in its recent reviews for other NSPs.

The same labour escalators have been used in developing the opex forecast. A more detailed discussion on labour cost escalation is contained in section 5.7.3 of this revenue proposal.

### *Materials*

In recent determinations, the AER has not accepted the application of real cost escalation factors based on expert forecasts for materials costs. Instead, it has adopted real cost escalators of zero per cent. The AER has adopted this approach as it perceives there is 'considerable variation' between the expert forecasts submitted by the networks. However, despite these variations, there are also considerable areas of agreement in the forecasts submitted to the AER. In addition, there is no compelling evidence to support real cost escalators of zero per cent as superior to those based on expert forecasts.

Under certain economic circumstances, the application of real price escalators could be particularly material in revenue terms, either having a substantial positive or negative impact. Where this is the case, networks and/ or consumers should not be disadvantaged by the automatic application of zero real materials cost escalators.

While real cost escalators for materials have not been applied in developing this revenue proposal, AusNet Services considers there is merit in exploring this further in future revenue review processes. To this end, Frontier Economics has written a report (Appendix 4F) explaining why the use of materials escalators based on expert forecasts is preferable to the AER's recent reliance on CPI as providing an appropriate escalation for the cost of materials inputs.

## 4.4.8 Capex efficiency

AusNet Services has a strong culture of continuous improvement. In the current regulatory period, we expected that portfolio efficiencies would be delivered compared to project based planning estimates. AusNet Services has assessed whether it is appropriate to include similar projected portfolio savings in the capital expenditure forecasts for the forthcoming regulatory period.

This assessment has concluded that a top-down adjustment should be made to the capex forecast to reflect cost savings that are expected to be achieved at a portfolio level. As explained in Section 4.3.2, the magnitude of this adjustment is 0.89% and has been based on a

16 DAE's National WPI forecasts were used in the absence of DAE Victoria specific forecasts. DAE's forecast WPI growth in 2019-20 was assumed for 2020-21 and 2021-22 in the absence of forecasts for these years.

comparison of forecast and actual expenditure outcomes for recent completed transmission projects. An adjustment made on the same basis was proposed, and accepted, by the AER in its 2014-17 determination[17].

### *Interaction with the Capital Efficiency Sharing Scheme*

AusNet Services does not consider that any further top-down adjustment is warranted, as it considers that any additional capex efficiencies that it is able to achieve through continuous improvement over the 2017-22 regulatory period should be rewarded through the Capital Efficiency Sharing Scheme (CESS). As reflected in the CESS principles[18], it is appropriate for a TNSP to be rewarded for improvements (or penalised for declines) in the efficiency of capital expenditure. Moreover, this will assist in attainment of the relevant elements of the NEO.

AusNet Services has reflected the level of historical efficiencies it has achieved in the capex forecast. This includes considering synergies with other planned works as part of the project identification and costing process and through assessing the potential for portfolio level efficiencies and making a top-down adjustment for expected portfolio-level cost savings based on observed outcomes. Therefore, it is appropriate that any additional efficiencies that can be achieved, above those already factored into the forecast, are rewarded back to the relevant TNSP through the CESS.

As explained in section 4.5 below, in the AER's 2014 benchmarking report it concludes that it is 'confident we can draw conclusions on the change in transmission networks' productivity over time'[19]. At an aggregate level, the average multilateral total factor productivity (MTFP) of the NEM transmission networks has been declining since 2006.

There is no compelling evidence to demonstrate that the productivity of capital expenditure at an industry level is expected to improve over the next regulatory period. AusNet Services considers that to be consistent with its approach to assessing the opex allowance, the AER should consider historical industry average productivity trends in its assessment of the capex allowance. Any productivity improvements above this level should be captured through the CESS, as opex productivity improvements above the industry average are rewarded through the EBSS.

### 4.4.9 Capex / opex trade-offs

AusNet Services seeks to optimise the balance between operating and capital expenditure, and to balance the objectives of the NEO while also complying with the obligations imposed on it under the NER and other applicable regulatory instruments, with the aim of optimising the total costs to customers, expressed in net present value terms. This objective is embodied in AusNet Services' Asset Management Strategy. The substitution possibilities between capital and operating expenditure are considered as part of the project selection process. In particular, capital expenditure to replace an asset may reduce the need for additional operating expenditure to maintain asset condition. Conversely, capex may be unnecessary where opex solutions are effective in maintaining asset function.

Examples of where specific deferrals built into AusNet Services' capex forecast require substitution between capital and operating expenditure include:

- West Melbourne 22kV assets – the scope of the WMTS rebuild does not include replacing the 22kV assets at the site. These assets have reached end-of-life, as reflected by their condition and will no longer be required following the rebuild, following a joint planning decision by CitiPower and AusNet Services. Leasing a mobile switchboard is proposed as

---

17 The magnitude at the last review was 1.44%. The underpinning analysis has been updated to yield 0.89%.

18 NER 6A.6.5A.

19 AER, *2014 Annual Transmission Benchmarking Report*, p. 6

it is the safest and most cost-effective solution to ensure the safe operation and maintenance of the switchroom assets until they are taken out of service (see Chapter 5 – Operating Expenditure).

- Synchronous condenser refurbishments or replacement – AusNet Services has proposed to decommission three synchronous condensers which it considers have reached the end of their technical lives. The opex cost of decommissioning is included in this proposal. This avoids substantial capital expenditure to either refurbish or replace these assets, which have reached the end of their serviceable lives. As the network planner, AEMO is assessing the expected continued benefits of the synchronous condensers. To date, a firm decision has been made to retire one of the three synchronous condensers, with a decision yet to be made on the remaining two. If AEMO confirms that the services provided by these assets warrant their replacement, AusNet Services will include additional capital expenditure in its Revised Revenue Proposal. The replacement of the two remaining synchronous condensers is currently proposed as a contingent project (see section 4.8.11).
- Embedding new condition monitoring techniques for conductors (using SAIP) into existing practices has not impacted forecast capex over the forthcoming regulatory period, but is expected to affect capex requirements in future periods as we are able to inform our future tower and conductor replacements with accurate asset condition data, leading to more targeted replacements.

Non-network alternatives to major stations replacement projects have been considered in developing the capex forecast. However, these were not considered to be viable alternatives to the major stations asset replacement projects, given the supply requirements at these stations and the safety risk associated with the assets to be replaced.

More detail on the projects mentioned above is provided in Chapter 5.

Stakeholders were broadly supportive of AusNet Services adopting the lowest cost solution when assessing capex-opex trade-offs.

## 4.5 Capex benchmarking

Under NER 6A.6.7(e)(4) the AER must, when deciding whether to accept AusNet Services' capex forecast, have regard to the most recent annual benchmarking report that has been published. In relation to this requirement, the AER stated in its recent transmission determination for TransGrid:

> *"A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a service provider's efficiency with consideration given to its inputs, outputs and its operating environment. […]*
>
> *For the TNSPs we consider this economic benchmarking can give an indication of how the efficiency of each service provider has changed over time. We accept that it is not currently robust enough to draw conclusions about the relative efficiency of these service providers."*[20]

AusNet Services concurs with the AER in relation to this matter. In addition, it is difficult to compare AusNet Services with other TNSPs on a like-for-like basis given the significant differences between the TNSPs and the sensitivity of the modelling results to different specifications. Further, AEMO's planning and augmentation costs are not included in AusNet Services' data, due to the unique Victorian planning arrangements, which make direct comparisons difficult[21].

[20] AER, *Final Decision, TransGrid transmission determination, 2015−16 to 2017−18, Attachment 6 – Capital expenditure*, April 2015, pp. 6 – 31 to 6 – 32.

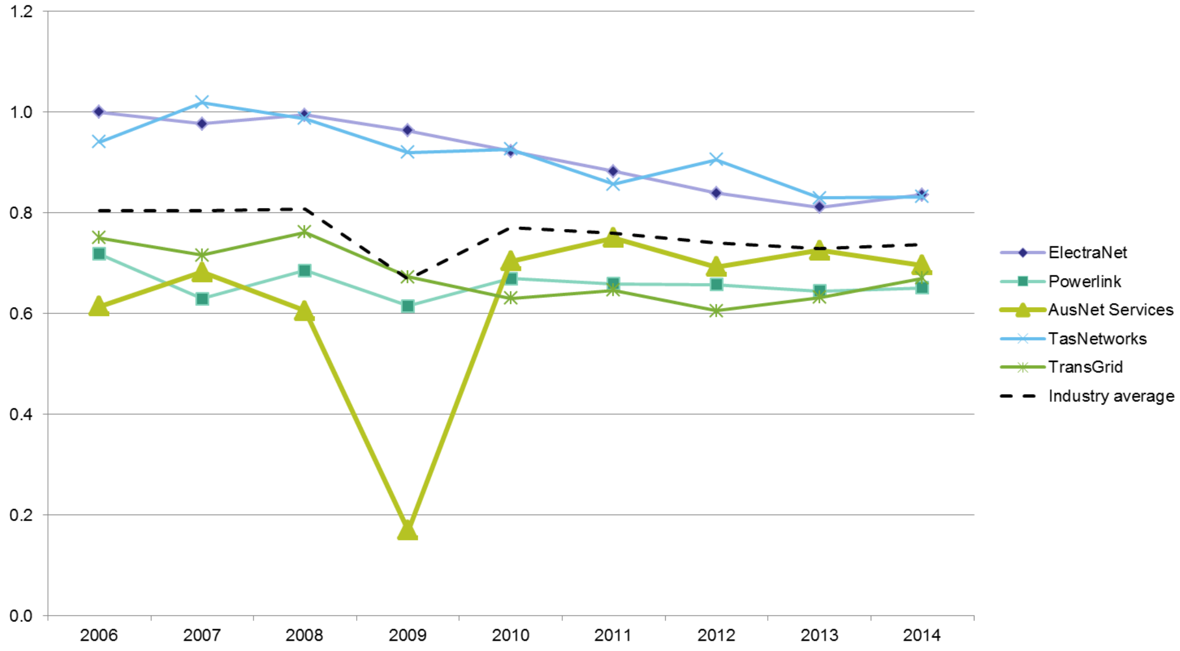
[21] This has been noted by the AER. This concern was raised by stakeholders during AusNet Services' engagement process.

That said, it is worth noting the results of benchmarking analysis commissioned by the AER as part of its recent NSW transmission determination. In its report for the AER, Economic Insights presented illustrative MTFP analysis of the transmission NSPs, and stated:

> *"Although AusNet Transmission has the lowest average MTFP level over the 8 years, this is mainly due to the one–off dip in 2009 [due to an explosive failure at South Morang Terminal Station and a conductor drop on the Bendigo to Ballarat Line]. For the second half of the period AusNet Transmission was in the middle of the MTFP range. Powerlink and TransGrid had similar MTFP levels over the 8 years. MTFP growth rates over the period have been negative for four of the five TNSPs with only AusNet Transmission displaying positive MTFP growth. As noted in section 1, however, we caution against drawing strong inferences about TNSP efficiency levels from these results given the early stage of development of productivity level measures."*[22]

The figure below (reproduced from the Economic Insights report) shows the illustrative TNSP multilateral total factor productivity indexes calculated by Economic Insights.

**Figure 4.10: Illustrative TNSP multilateral total factor productivity indexes 2006–14**




*Source: Economic Insights, benchmarking data*

As already noted, both Economic Insights and the AER have stated that caution should be exercised in drawing inferences about the TNSPs' relative efficiency from the results of this benchmarking analysis. In particular, the rankings of the TNSPs are extremely sensitive to the MTFP model specifications. The table below shows the rankings of the TNSPs under the different input and output specifications.

22 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and Tasmanian Electricity TNSPs*, Report for AER, 10 November 2014, p. 12.

**Table 4.5: Rankings of TNSPs under different MTFP model specifications**

| Model Specification Input | Model Specification Output | AusNet Services | TransGrid | Powerlink | TasNetworks | ElectraNet |
|---|---|---|---|---|---|---|
| #1 | #1 | 2 | 5 | 3 | 4 | **1** |
| #1 | #2 | **1** | 3 | 5 | 2 | 4 |
| #1 | #3 | 3 | 4 | 5 | **1** | 2 |
| #1 | #4 | 3 | 4 | 5 | 2 | **1** |

*Note – Easement Land Tax has been removed from this analysis.*

This demonstrates that the MTFP modelling has not yet been developed to a point where its results are robust, which further supports the AER's conclusion that the MTFP cannot be used to draw conclusions about the relative efficiency of the TNSPs.

However, both Economic Insights and the AER consider that more confidence can be placed in each individual TNSP's productivity growth rate results because they reflect the TNSP's performance relative to its own historical performance, and are not affected by relative rankings[23].

In this regard, it can be observed that AusNet Services' MTFP and its capital productivity have both improved steadily over the period from 2006 to 2013, after allowing for the one–off dip in 2009, which was due to an explosive failure at South Morang and a conductor drop on the Bendigo to Ballarat Line.

Stakeholders questioned whether AEMO's Victorian planning costs were captured in the AER's productivity benchmarking, to enable jurisdictions to be compared on a like-for-like basis. AusNet Services has confirmed with the AER that AEMO's costs are not included in its multilateral total factor productivity benchmarking.

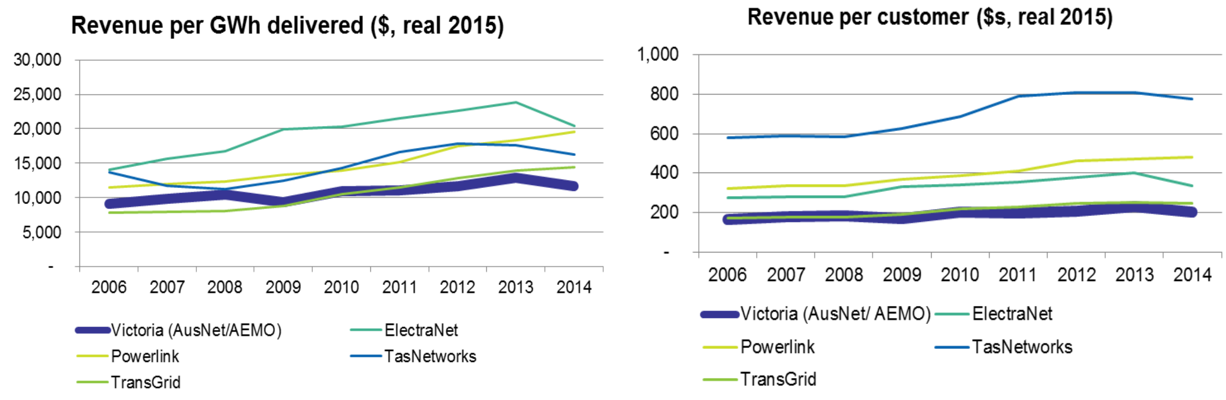
However, AusNet Services has sought to add Victorian augmentation costs into the revenue metrics presented below. The results confirm that Victorian transmission costs as a whole benchmark strongly compared with other jurisdictions.

## 4.5.1 Other benchmarking metrics

The revenue metrics presented below include the costs of AEMO, and therefore reflect the total cost of Victorian transmission services. Compared to TNSPs in other jurisdictions, AusNet Services continues to perform strongly, demonstrating that Victorian electricity consumers experience low-cost transmission services.

[23] Ibid, p. 14.

### Figure 4.11: Revenue – Key Metrics



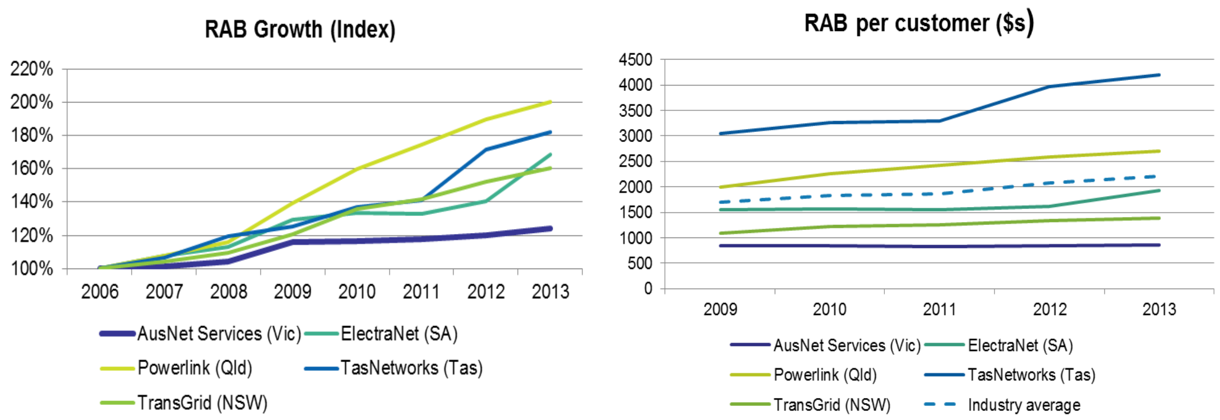

*Source: Huegin Consulting, AER RIN data, AusNet Services, AEMO*

As explained above, it is difficult to compare AusNet Services' normalised network capital expenditure requirements on a like-for-like basis with those of other TNSPs given the unique Victorian planning arrangements. While this is obvious in relation to categories which include augmentation expenditure, AusNet Services' replacement expenditure (repex) is also unlikely to be directly comparable to that of other TNSPs.

In Victoria, separate contracts are required for augmentation and replacement components of projects, so the expenditure split between the two categories is very clear. In other jurisdictions this expenditure separation may not be as distinct. It is feasible that projects driven by augmentation requirements may have been recorded as augex despite including aspects of replacement. For this reason, AusNet Services has not used capex category analysis metrics to assess its network capex forecast.

As some Victorian augmentation capex rolls into AusNet Services' RAB at each review[24], normalised RAB metrics can provide limited insights into the relative capex efficiency of the TNSPs over the long term. AusNet Services performs strongly against these measures, with the flattest RAB growth since 2006 and lowest RAB per customer of all the TNSPs. This provides a level of certainty that AusNet Services' asset management approach, on which its capex forecast is based, is likely to result in relatively efficient outcomes.

### Figure 4.12: Regulatory Asset Base (RAB) – Key Metrics

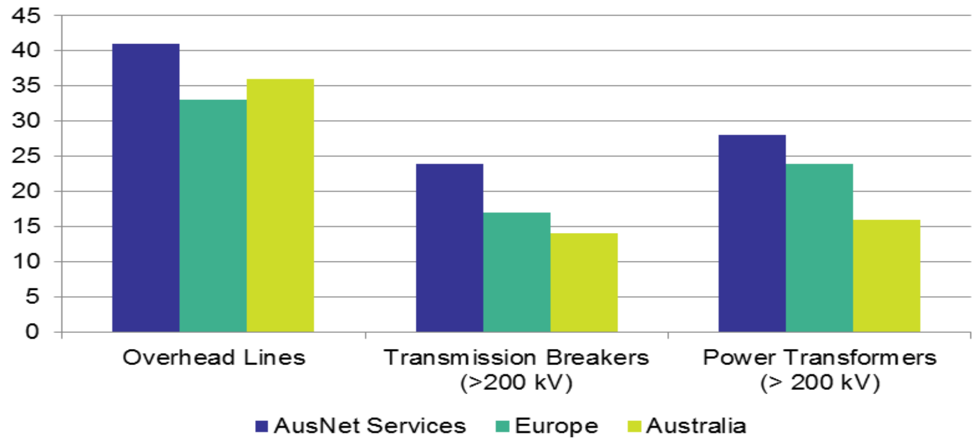



*Source: Huegin Consulting, AER RIN data*

24 Contestable capex does not roll in to the RAB.

In addition, AusNet Services' assets have lower remaining asset lives compared to other transmission companies. The figure below shows the average ages of AusNet Services' major asset groups compared with the average ages of the same assets across European and Australian TNSPs, surveyed by the most recently available ITOMS Survey 2013. This provides further evidence of the efficiency of AusNet Services' capital expenditure over successive regulatory periods.

**Figure 4.13: Average age (in years) of major network assets compared to other TNSPs**




*Source: ITOMS 2013 Survey, AusNet Services*

## 4.6 Capital Expenditure Forecast

For the purpose of presenting its capex forecast, AusNet Services has adopted the following five categories:

- CBD station rebuilds;
- Major stations replacement;
- Asset replacement programs;
- Safety, security and compliance; and
- Non-network.

An overview of AusNet Services' forecast capex is provided in the table below.

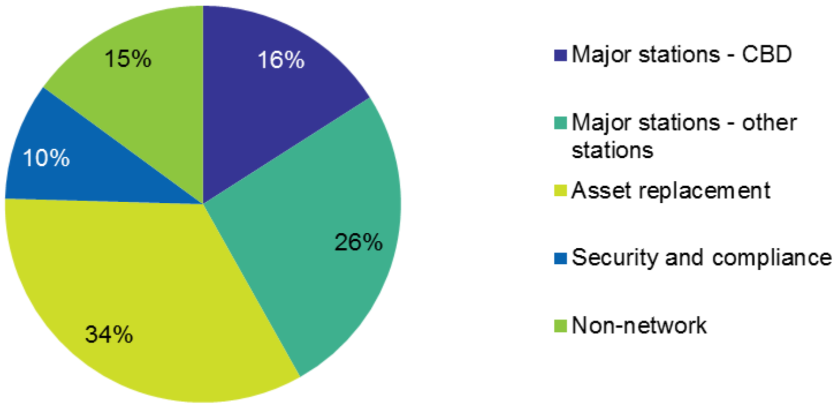
**Table 4.6: Forecast Capex 2017-22 by category ($m, real 2016-17)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total |
|---|---|---|---|---|---|---|
| **CBD station rebuilds** | 36.2 | 26.3 | 29.9 | 18.4 | 8.3 | **119.1** |
| **Major stations replacement** | 47.8 | 30.2 | 36.3 | 42.9 | 35.5 | **192.8** |
| **Asset replacement programs** | 49.5 | 56.3 | 51.1 | 49.0 | 44.7 | **250.6** |
| **Safety, security and compliance** | 14.6 | 14.0 | 14.8 | 13.3 | 14.8 | **71.6** |
| **Non-network** | 30.8 | 28.4 | 19.5 | 16.8 | 15.9 | **111.5** |
| **Total** | **178.9** | **155.3** | **151.6** | **140.5** | **119.3** | **745.6** |

*Note – totals may not sum due to rounding*

The composition of AusNet Services' forecast capex is shown diagrammatically in the figure below. Almost half of the capex (42%) is related to the rebuilding and refurbishment of terminal stations (with the CBD rebuild projects accounting for 16% of the total forecast). The next largest component is stand-alone asset replacement programs addressing specific plant items or fleet problems (34%). The remainder of the expenditure relates to safety, compliance or security obligations (10%), and non-network expenditure (15%).

**Figure 4.14: Breakdown of capex forecast into driver categories**




NER S6A.1.1(1)(v) requires the Revenue Proposal to attribute capital expenditure in relation to material assets to particular categories of prescribed transmission services. In accordance with this requirement, the proposed capital expenditure can be attributed to prescribed transmission services as follows:

- CBD Rebuilds capital expenditure will provide prescribed exit services and prescribed TUOS services;
- Major Stations Replacement capital expenditure will provide prescribed entry services; prescribed exit services; and prescribed TUOS services;
- Asset Replacement capital expenditure will provide prescribed exit services; prescribed TUOS services; and prescribed common transmission services;
- Security and compliance capital expenditure will provide prescribed entry services; prescribed exit services; prescribed TUOS services; and prescribed common transmission services; and
- Non-network capital expenditure will provide prescribed common transmission services.

## 4.7 Variations in Forecast Capex from Historic Capex

NER S6A.1.1(7) requires a Revenue Proposal to provide an explanation of any significant variations in the forecast capex from historic capex.

AusNet Services' forecast capex for the forthcoming regulatory period is, on average, 8% lower per annum than actual and expected capex in the current regulatory period. While the average age of AusNet Services' assets has continued to increase - placing upward pressure on asset replacement requirements – changes in the key planning assumptions relating to forecast demand and the VCR have led to a reduction in AusNet Services' forecast capex.

The table below shows the trend in capex by driver since 2008[25].

[25] Satisfying NER S6A.1.1

**Table 4.7: Actual and Forecast Capex for the Previous, Current and Next Regulatory Periods ($m, real 2016-17)**

| | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | *Av 2008-14* | 2014/15 | 2015/16 | 2016/17 | *Av 2014-17* | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | *Av 2017-22* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CBD station rebuilds** | 0.1 | 0.4 | 3.2 | 4.2 | 23.3 | 34.8 | *11.0* | 45.4 | 32.0 | 32.9 | *36.8* | 36.2 | 26.3 | 29.9 | 18.4 | 8.3 | *23.8* |
| **Major stations replacement** | 49.6 | 49.8 | 48.8 | 45.1 | 63.2 | 63.1 | *53.3* | 34.5 | 37.9 | 60.5 | *44.3* | 47.8 | 30.2 | 36.3 | 42.9 | 35.5 | *38.6* |
| **Asset replacement programs** | 28.5 | 43.2 | 36.1 | 50.4 | 47.0 | 19.3 | *37.4* | 46.4 | 50.4 | 46.0 | *47.6* | 49.5 | 56.3 | 51.1 | 49.0 | 44.7 | *50.1* |
| **Safety, security and compliance** | 17.7 | 22.2 | 18.9 | 33.7 | 33.7 | 11.3 | *22.9* | 8.0 | 15.4 | 15.7 | *13.1* | 14.6 | 14.0 | 14.8 | 13.3 | 14.8 | *14.3* |
| **Network - Other** | 2.0 | 3.3 | 2.4 | 1.2 | 2.8 | 2.1 | *2.3* | 1.0 | - | - | *0.3* | - | - | - | - | - | - |
| **Non-network** | 15.0 | 10.7 | 17.1 | 14.0 | 18.6 | 23.7 | *16.5* | 23.4 | 14.5 | 24.0 | *20.6* | 30.8 | 28.4 | 19.5 | 16.8 | 15.9 | *22.3* |
| **Total** | **112.9** | **129.6** | **126.5** | **148.6** | **188.6** | **154.2** | ***143.4*** | **158.7** | **150.2** | **179.1** | ***162.7*** | **178.9** | **155.3** | **151.6** | **140.5** | **119.3** | ***149.1*** |
| Related Party Margin | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | C-I-C | - | - | - | - | - | - |

*Note – no related party margins are included in the capex forecast. In this Table ABS September quarter CPI has been applied for escalation into real $2016-17 in all years.*

An explanation for the main variances over time at a category level is provided below.

### CBD Station Rebuilds

The timing of the major rebuilds at Richmond and West Melbourne Terminal Stations determine the profile of capital expenditure in this category. The Richmond Terminal Station project commenced in 2012 and will cease in 2018 and the West Melbourne Terminal Station rebuild commenced in 2013, but substantial expenditure will not be incurred on the project until 2016 as it has been deferred and re-scoped following recent changes, which will result in significant savings for consumers (see section 4.8.1).

### Major Stations Replacements

During the 2008-14 regulatory period, the major stations replacement program was focused on terminal stations in metropolitan locations, including at Keilor, Brooklyn, Rowville, Ringwood and Thomastown. Some regional terminal station rebuilds were also completed, including at Geelong, Dederang and Bendigo. In the 2014-17 regulatory period the focus of the major stations program shifted to the CBD stations, while substantial activity still occurred on metropolitan stations. During this period, significant reductions in forecast demand between 2013 and 2014, combined with the reduction in AEMO's VCR in 2014 resulted in updates to the economic timing of uncommitted major projects. This has resulted in major project deferrals, which has resulted in a decline in forecast expenditure for this category over the 2017-22 regulatory period. The timing of major stations rebuilds is shown in Figure ES4.

### Asset Replacement Programs

The focus of asset replacement programs for each period is summarised below:

- **2008-14:**
  - Replacing and preparing transformers (including at Thomastown, Morwell and Keilor);
  - Replacing 16km of the 500kV Heywood to Portland line;
  - Various secondary and protection works;
  - Replacing ageing relays and remote terminal units; and
  - Investing in digital communications including installing 400km of optical fibre ground wire (OPGW).
- **2014-17:**
  - Strengthening towers;
  - Replacing conductors, groundwires and insulators;
  - Refurbishing the synchronous condensers and replacement of their auxiliary systems to meet obligations;
  - Replacement of various secondary and protection equipment including relays;
  - Replacement of communications equipment including batteries, generators.
- **2017-22:**

  The forecast asset replacement program is explained in detail in section 4.9 below. Major components include circuit breaker replacements, groundwire replacements and tower strengthening and secondary and protection equipment replacements.

Average actual, expected and forecast annual expenditure on this category increased between the 2008-14 and 2014-17 regulatory period. A small increase is forecast between the 2014-17 and 2017-22 regulatory periods. As this category of expenditure is driven by the need to replace ageing assets that are most at risk of failure, the age profile of assets can This upwards trend can partially be explained by reducing expenditure on major stations redevelopments. The reduced number of major stations projects has led to a slightly increased need for stand-alone asset replacement programs, as fewer ageing assets will be replaced as part of major station rebuilds.

### Safety, security and compliance

This category of expenditure is generally dominated by a few larger programs. Average expenditure was higher in the 2008-14 regulatory period than it has been and is expected to be in the coming and forthcoming regulatory periods. During 2008-14 AusNet Services undertook extensive safety and compliance related capital works which targeted replacing assets presenting a risk of explosive failure. These assets included post-type instrument transformers and bulk oil circuit breakers. Over 20% of the fleet of insulators and fittings were also replaced at this time, as these posed safety risks from potentially breaking and falling over roads. The tower fall arrest program was initiated, with an average of around $6m per annum spent on this program.

In the current regulatory period, safety, security and compliance capital works largely reflected a continuation of these programs, but with reduced expenditure as the highest risk assets have already been replaced. The tower fall arrest program continued to roll-out, and accounts for the largest component of forecast safety-related expenditure in the forthcoming period, as described in section 4.10.

### Non-network

This category of expenditure is dominated by ICT. The profile of actual, expected and forecast ICT capex is explained in section 4.11.1 below.

## 4.8 Major Station Rebuilds and Major Stations Replacement Program

AusNet Services has forecast total capital expenditure of $311.9m on major station projects (including CBD rebuilds) in the forthcoming regulatory control period. The station rebuilding and refurbishment program (incorporating the CBD rebuild projects) constitutes 42% of the total capex forecast for the forthcoming period.

The CBD station rebuilds and major stations replacement program will replace selected high-risk assets in terminal stations where economic assessments have found the projects maximise net benefits. AusNet Services' plans to complete active redevelopment works at Richmond, West Melbourne, Fishermans Bend, Heatherton and South Morang terminal stations and Hazelwood Power Station. In addition, major work is planned during the forthcoming regulatory period to replace assets at Ringwood, Springvale, Heywood and Templestowe terminal stations.

These replacement projects are focussed on strengthening the resilience and reliability of the transmission system by sustaining circuit breaker and transformer failure risks within an acceptable range. The forecast works also include economic re-configuration to ensure that future needs (as defined by AEMO and the Distribution Businesses) can be met and that supply risks are minimised during the proposed brownfield rebuilds.

AusNet Services' CBD Station rebuilds and major stations replacement projects in the 2017-22 regulatory period are summarised in the table below. The committed projects are those with approved business cases and are currently underway.

**Table 4.8: Key CBD Station rebuilds and Major stations replacement projects ($m, real 2016-17)**

| Project | Description | Overall Project Timing | Expenditure over 2017-2022 period |
|---|---|---|---|
| *Committed (underway)* | | | |
| **Richmond Terminal Station (RTS) Rebuild** | Rebuild 22 kV, 66 kV and 220 kV switchyards using indoor GIS technology. Replace four 150 MVA 220/66 kV transformers with three 225 MVA transformers. Replace two 165 MVA 220/22 kV transformers with two 75 MVA 220/22 kV transformers. Includes architecturally treated buildings, buffer zones around the site and landscaping. | 2012-2018 | 14.2 |
| **West Melbourne Terminal Station (WMTS) Rebuild** | Like for like replacement of the 66 kV and 220 kV switchyards. Retire the 22 kV supply, including the 220/22 kV transformers, 22 kV switchroom and 22 kV fault limiting reactors. Replace the four 150 MVA 220/66 kV transformers with three 225 MVA 220/66 kV transformers. | 2013-2022 | 105.9 |
| **Heatherton Terminal Station (HTS) redevelopment** | Replace B1, B2 and B3 transformers with 150 MVA 220/66 kV transformers. Replace 220 kV and 66 kV switchgear. Replace associated protection and control systems. | 2014-2017 | 4.1 |
| **FBTS 220 kV and 66 kV CB Replacement stage one** | Replace one minimum oil 220 kV CB, six 66 kV bulk oil and three 66 kV minimum oil CBs. | 2014-2018 | 3.9 |
| **Hazelwood Power Station 220 kV CB Replacement – stage four** | Replace the remaining seven 220 kV bulk oil CBs and install remote operated isolators. | 2014-2018 | 12.9 |
| **South Morang 330/220 kV Transformer Replacement – Stage 1** | Replace three 330/220kV single-phase transformers with a new 700 MVA 330/220kV transformer bank and install a new 330kV switch bay for its connection. | 2014-2018 | 19.3 |
| *Planned* | | | |
| **Thomastown (TSTS) B2 Transformer and 66 kV circuit breaker Replacement** | Replace B2 220/66 kV transformer, two 66 kV minimum oil CBs and thirteen 66 kV bulk oil CBs, and install new protection and control systems. | 2019-2023 | 24.3 |
| **HYTS circuit breaker replacement** | Replace and refurbish 500 kV CBs. | 2015-2019 | 5.7 |
| **Springvale Terminal Station (SVTS) Redevelopment** | Replace B1, B2 and B3 220/66 kV transformers, five 220 kV minimum oil CBs and selected 66 kV CBs. | 2016-2022 | 75.4 |
| **FBTS B1 and B4 Transformer** | Replace B1 and B4 transformers with two 150 MVA 220/66 kV transformers. Replace | 2017-2021 | 36.9 |

| Project | Description | Overall Project Timing | Expenditure over 2017-2022 period |
|---|---|---|---|
| **Replacement** | 220 kV and 66 kV switchgear. | | |
| **RWTS B4 220/66 kV Transformer and 66 kV CB Replacement** | Replace B4 220/66 kV transformer and six 66 kV bulk oil CBs. | 2015-2019 | 11.3 |

*Note – these project costs exclude the 0.89% top-down adjustment*

These major projects are discussed in further detail below.

### 4.8.1 West Melbourne Terminal Station

#### *Background*

West Melbourne Terminal Station (WMTS) is one of three terminal stations in Melbourne supplying the CDB plus the surrounding residential, commercial and industrial western area. Much of the existing equipment was installed in 1964 and is reaching the point where replacement is required to avoid an unacceptable risk of failure. A redevelopment of WMTS is required driven by reliability risk, safety risk, load criticality and the performance of existing assets.

In the revenue proposal for the 2014-17 period, AusNet Services proposed a plan to redevelop WMTS using indoor Gas Insulated Switchgear (GIS) technologies, due to space constraints on the site.

During the course of the previous review, the Linking Melbourne Authority (LMA) notified AusNet Services that it might compulsorily acquire part of the land at the WMTS site to enable the development of the East West Link (EWL). This further constrained the space available on the site.

AusNet Services revised its proposed project to enable it to proceed regardless of whether or not the land earmarked for compulsory acquisition was subsequently acquired. This was a prudent approach as economic studies supported the project commencing in 2014 and it also recognised the significant uncertainty associated with the EWL development. An allowance of $83.4m (real 2016-17) to commence the rebuild was provided in the 2014-17 regulatory period.

At the time of the final decision it was possible that AusNet Services would have been eligible for compensation from the LMA for the higher costs of the WMTS rebuild project due to the impact of the EWL development. If this compensation had been received, it was foreseen that AusNet Services would pass this back to customers through a reduction in the RAB at the start of the upcoming regulatory period. However, the EWL did not proceed.

#### *Exogenous changes that have impacted the project's economic timing and design*

In the current period several exogenous changes have led AusNet Services to review the economic timing and design of the WTMS redevelopment. A change in key planning assumptions has enabled AusNet Services to defer the project. In addition, the easing of site space constraints have enabled the redevelopment to proceed with lower cost Air Insulated Switchgear (AIS) technology. The change in the timing and cost of the redevelopment are estimated to reduce costs to consumers by more than $1,500 per GWh of energy consumed in the 2017-22 period, compared to AusNet Services proceeding with the original solution.

The changes that have impacted the project are explained in more detail below.

### *Easing Space Constraints*

During the previous review, the space available to undertake the rebuild on the WMTS site was severely constrained, leading to the use of more compact (but more costly) GIS technology being the only feasible solution, due to the EWL development's designated freeway alignment and construction zone encroached on the WMTS site, meaning that this land would have been unavailable to AusNet Services during the WMTS redevelopment construction period. The cancellation of the EWL returned this land to AusNet Services over this time period.

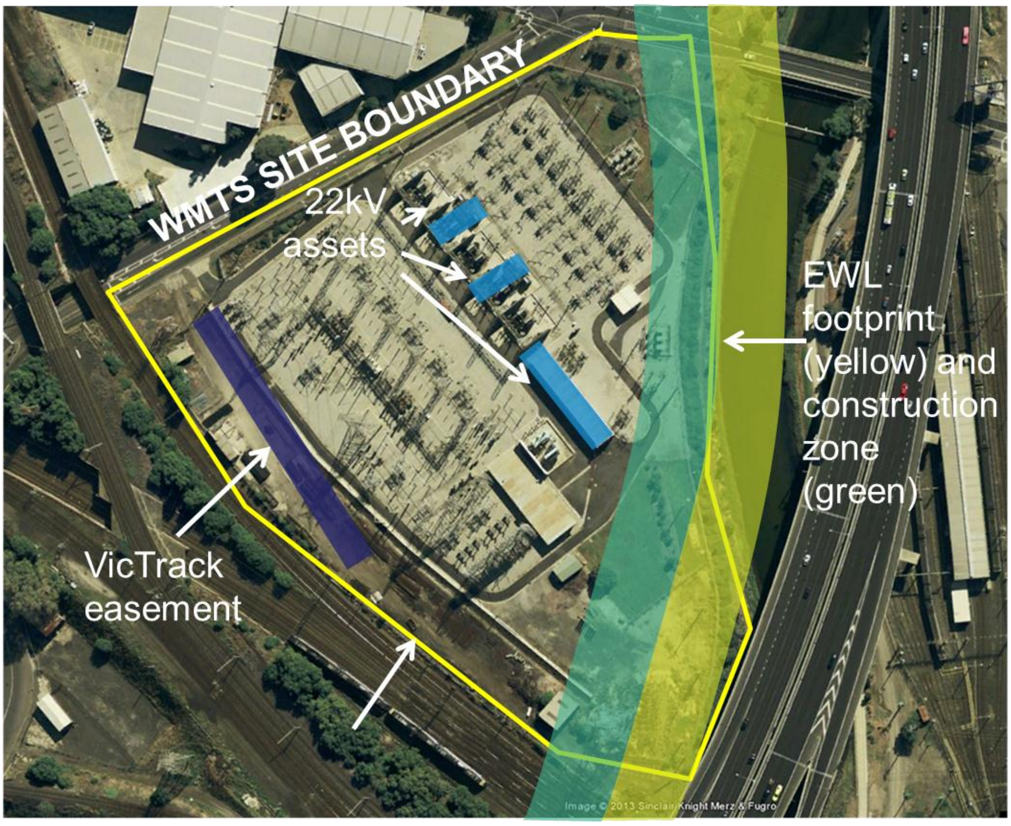
However, while AusNet Services will utilise the EWL construction zone during the WMTS project, the new solution has been designed to avoid locating assets on the footprint of the EWL. This is because the WMTS assets have 50 to 70 year lives, and it is prudent to consider the implications should the EWL proceed over this time period. This design decision has not added to the total cost of the WMTS project.

During the previous review AusNet Services sought to secure a lease from VicTrack for an unutilised easement located at the south western boundary of the WMTS site. VicTrack declined this request at the time. However, we have since continued to negotiate and have secured this lease from VicTrack. This has been critical in enabling the project to precede using AIS technology, as it provides space to work and enables assets to be replaced without impacting the reliability of the supply from this key connection station.

In addition, CitiPower has indicated that it is economic to retire the 22kV supply from WMTS, partly due to the savings consumers will realise as a result of AusNet Services no longer needing to replace the 22kV assets (which include transformers, switchroom and fault limiting reactors). This development has also contributed to the feasibility of the AIS technology as there is more space for AIS assets with the 22kV assets excluded from the design.

These changes in the land availability are illustrated in the aerial photo of the WMTS site below.

**Figure 4.15: Changes to WMTS site land availability**




*Source: Google, AusNet Services*

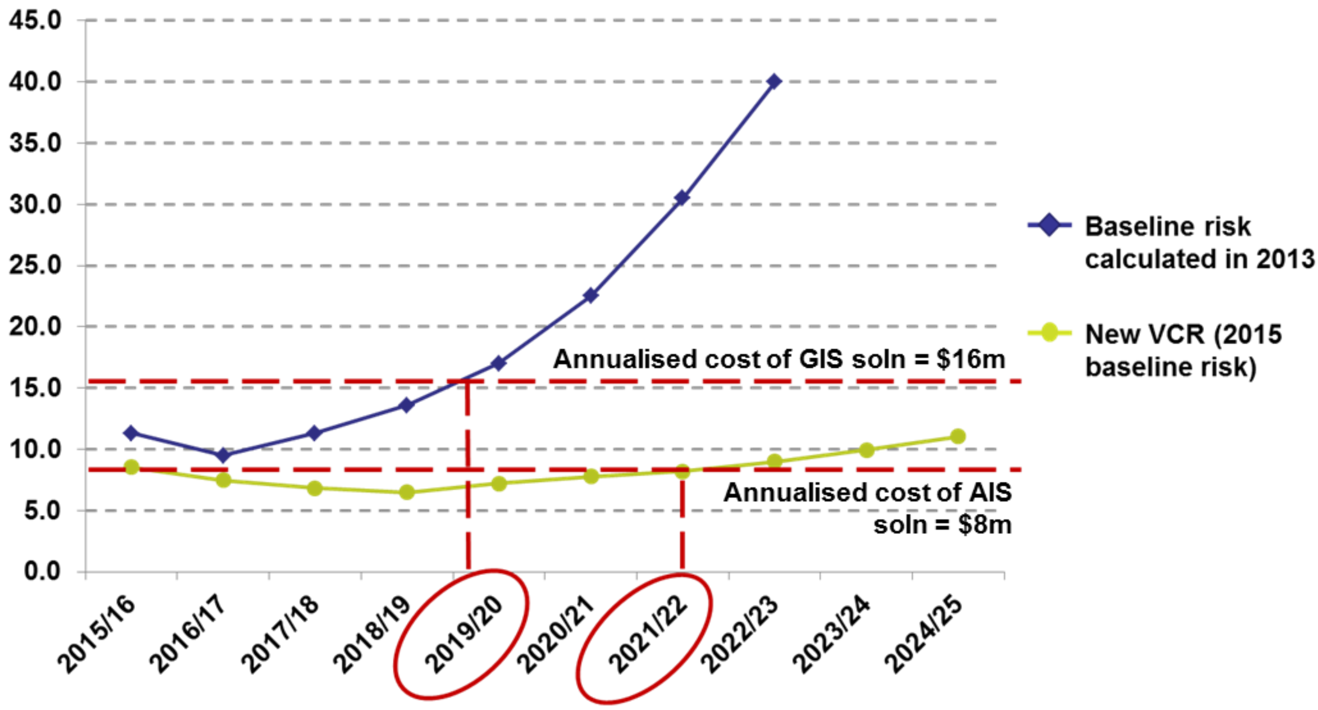
Stakeholders queried why the space constraints at WMTS eased given the rebuild will proceed on the same site. These concerns are addressed above.

***Change in Key Planning Assumptions***

As discussed earlier in the chapter, the changes in the VCR and lower demand forecasts have impacted the economic timing of major projects including WMTS.

The figure below shows the change in forecast monetised risk for WMTS as calculated in 2013 and in 2015 under new assumptions.

**Figure 4.16: Change in costed risk ($m) and economic timing of WMTS redevelopment**




*Source: AusNet Services*

A site-specific VCR is used in the economic assessment. For West Melbourne, this has reduced from $100 per kWh in 2013 to $42 per kWh in 2015.

The replacement project is assessed to be economic when the project benefits (reduction in risk and in operating costs) exceed the annualised project cost. In 2013 the GIS solution, with an annualised cost of $16.1m per annum, was the only feasible option given site space constraints. The economic analysis showed that this solution should be completed by 2019-20.

However, between 2013 and 2015 there has been a reduction in forecast risk due to lower demand forecasts and the lower VCR. It is also expected that the safety risk will reduce following the planned retirement of the 22kV assets at WMTS.

In addition, the AIS solution has become feasible due to the easing space constraints, explained above. This has reduced the annualised project cost to $8.5m per annum. The combination of these factors has pushed out the economic timing of project completion to 2021-22.

However, as noted above, the current scope and associated cost estimate of the rebuild assumes that the 22kV assets will no longer be required by Citipower. AusNet Services' notes that the AER has not approved the funding for this decommissioning in its preliminary determination for Citipower's 2016-20 regulatory period. If Citipower's plans to decommission the 22kV assets do not proceed, AusNet Services will be required to replace the existing 22kV assets. If this occurs, the project scope and cost will be updated accordingly in AusNet Services' revised revenue proposal.

### 4.8.2 Richmond Terminal Station

Richmond Terminal Station (RTS) supplies the Eastern Central Business District and inner suburban areas in the inner east and south-east of metropolitan Melbourne. Three of the four existing transformers were identified as having some of the highest risk of failure of any transformers in the AusNet Services' network. The 220 kV switchyard is situated in a very compact site which makes replacement work difficult and increases the outages required for the work.

The project is underway and is to replace the existing 220 kV switchyard with indoor GIS which provides independent switching for all circuits and joint switching of 220/66 kV and 220/22 kV transformers.

The project includes the replacement of ageing 150 MVA 220 / 66 kV transformers with larger 225 MVA units, which also helps to create more space to facilitate the redevelopment of RTS and provide for future capacity expansion. This will maintain total N-1 220/66 kV transformation capacity at current levels. The two 165 MVA 220/22 kV transformers are being replaced with two 75 MVA 220/22 kV transformers, reflecting the lower 22 kV supply capacity required to meet forecast 22 kV demand at RTS. Significant replacement of protection, control, metering and communications equipment is also required.

The redevelopment of RTS was included in the capex forecast approved by the AER in its 2014 Revenue Determination for AusNet Services with the rebuild expected to be completed by 2017-18. The project is progressing well and is forecast to achieve substantial completion by 2018.

### 4.8.3 Heatherton Terminal Station

Heatherton Terminal Station (HTS) is the main source of supply for much of bayside Melbourne, from Brighton in the north to Edithvale in the south.

HTS was commissioned in 1964, and the primary and secondary assets at the station have deteriorated. This resulted in increasing risks of failure, and inefficient operation and maintenance. Further, the security of supply risks presented by a failure of the 220/66 kV transformers, 220 kV circuit breakers or 66 kV circuit breakers are high.

The scope of the project is to:

- Replace the three 150 MVA 220/66 kV transformers;
- Replace the 220 kV switchgear and reconfigure the transformer and line connections;
- Upgrade the 66 kV and 220 kV busbars;
- Replace the 66 kV switchgear; and
- Replace secondary systems.

This project was part of the approved capex allowance for the 2014-17 regulatory period and is now underway, with the majority of the works expected to have been completed before the 2017-22 regulatory period.

### 4.8.4 Fisherman's Bend Terminal Station

Fisherman's Bend Terminal Station (FBTS) is located approximately 3 km south-west of Melbourne's CBD and is the main source of supply for Docklands, Southbank, Port Melbourne, Fisherman's Bend, Albert Park, Middle Park and St Kilda West. It will also be the primary source of supply for the Fisherman's Bend Urban Renewal Area.

Established in late 1960s, the primary and secondary assets at FBTS have deteriorated and are leading to increasing risks of failure, and inefficient operation and maintenance costs. Economic studies support their replacement in the forthcoming period taking into account the probability of failure and cost of failure risk. Two projects related to FBTS are included in the capex forecast:

- Replacement of one 220kV and seven 66kV circuit breakers. This project formed part of the capex allowance approved for the 2014-17 regulatory period. It is expected to be completed in 2017-18.
- Replacement of the B1 and B3 150 MVA transformers, other critical circuit breakers and 66kV feeder switch bays.

### 4.8.5 Hazelwood Power Station

Hazelwood Power Station is (HWPS) is a key node in the Victorian transmission system. It supplies electricity generated in the Latrobe Valley to Melbourne via the Latrobe Valley to Melbourne 220 kV transmission corridor and the Latrobe Valley to Melbourne 500 kV transmission corridor.

The bulk oil 220 kV circuit breakers installed at HWPS are the only remaining circuit breakers of this type in Victoria. The condition of these circuit breakers is poor and they present an increasing risk of failure.

The replacement of the old bulk oil 220 kV circuit breakers at HWPS has been broken into four stages, with Stage 1 and 2 now being completed. Stage 3 and 4 of the circuit breaker replacement were included in the previous submission. Delivery has commenced and both remaining stages are forecast to conclude in 2018-19.

### 4.8.6 South Morang Terminal Station

South Morang Terminal Station (SMTS) is a key switching station that forms part of the 500 kV, 330 kV and 220 kV backbone of the Victorian Transmission System. SMTS also supplies loads to northern Melbourne.

The six 330/220 kV single-phase H transformers at the station were installed in the 1960s. These transformers are in poor condition and carry a rising probability of failure with significant consequence as no spare transformer of this voltage ratio and size is available to mitigate this risk. The potential for a major failure of one of these transformers presents a significant supply risk.

This project replaces the three 330/220 kV single-phase H transformers with a new 700 MVA 330/220 kV transformer bank of three single phase units and installs a new 330 kV switch bay for the new transformer. It forms part of the approved capex allowance for the current regulatory period, but the timing has been slightly deferred due to the change in the VCR. It will now be completed in 2018-19.

Replacement of the second 330/220 kV transformer has been deferred to beyond the end of the 2017-22 regulatory control period in light of current demand projections.

### 4.8.7 Templestowe Terminal Station

Templestowe Terminal Station (TSTS) is located approximately 25km north-east from Melbourne's CBD and is the main source of supply for a major part of north-eastern metropolitan Melbourne. The TSTS supply area spans from Eltham in the north to Canterbury in the south and from Mitcham in the east to Kew in the West. TSTS is supplied from Rowville Terminal Station (ROTS) and Thomastown Terminal Station (TTS).

TSTS was established in the mid-1960s. Many of the primary and secondary assets installed at this time have deteriorated and are reaching the end of their technical lives. The risks associated with plant failure are increasing and these assets are becoming more difficult and expensive to maintain due to a lack of manufacturer support and a scarcity of spare parts.

TSTS has three 150 MVA 220/66 kV transformers, two of which were installed in the 1960s and the third was installed in the early 1980s. The high level scope of work includes:

- Replacing the B2 transformer adjacent to the existing transformers to avoid increased supply risk during the replacement of the transformer;
- 220 kV single switching for the existing B1 and B3 transformers;
- Replacing all bus tie, transformer and deteriorated feeder 66 kV switchbays;
- Installing new 66 kV bus voltage transformers;
- Replacing the station service transformers; and
- Installing new duplicate transformer protection schemes including Circuit Breaker Management schemes for the 66 kV circuit breakers.

### 4.8.8 Heywood Terminal Station

Heywood Terminal Station (HYTS) is a 500/275 kV switching station that forms part of the Victoria to South Australia interconnector. HYTS also includes the 500 kV switching of the supplies to the Portland aluminium smelter. Significant supply risk has been identified for a failure of some of the 500 kV circuit breakers at HYTS.

A contestable augmentation project is currently being delivered to install a third transformer at the site.

The HYTS circuit breaker replacement project will replace deteriorated 500 kV circuit breakers that are critical for the supply to the Portland aluminium smelter, whilst allowing for the refurbishment of the 500 kV circuit breakers that connect the Tarrone and Mortlake 500 kV lines at HYTS.

The economic completion date of this project is 2018-19.

### 4.8.9 Springvale Terminal Station

Springvale Terminal Station (SVTS) is located in south-east Melbourne. It supplies the eastern Melbourne zone substations of Clarinda, East Burwood, Glen Waverley, Notting Hill, Noble Park, Oakleigh East, Riversdale, and three Springvale stations via 66 kV feeders.

As many of the primary and secondary assets at SVTS have deteriorated, the risks associated with plant failure are increasing and assets are becoming more difficult and expensive to maintain. This is, in part, because the manufacturer no longer supports these assets and spare parts are generally unavailable.

Economic studies support the redevelopment of SVTS in the forthcoming period taking into account the probability of failure and cost of failure risk. The redevelopment with 220 kV and 66 kV AIS and 150 MVA transformers will be undertaken to address asset condition and configuration risks at SVTS. This project will:

- Replace three of the four 150 MVA 220/66 kV transformers;
- Replace 220 kV switchgear and reconfigure the transformer and line connections;
- Upgrade 66 kV and 220 kV busbars;

- Replace 66 kV switchgear; and
- Replace secondary systems.

This project was part of the previous proposal and was forecast to be economic to complete by 2019. However, due to the reduction in forecast demand and the VCR, the economic timing of the project has been re-assessed and the project has been deferred. It is now due to commence in 2016-17. This deferral will lower the opening RAB for 2017-22 which leads to lower costs to consumers.

### 4.8.10 Ringwood Terminal Station

Ringwood Terminal Station (RWTS) is located approximately 25km east from Melbourne's CBD and supplies a major part of outer-eastern metropolitan Melbourne. The supply area spans from Lilydale and Woori Yallock in the north-east, to Croydon, Bayswater and Boronia in the east and more centrally, Box Hill, Nunawading, Mitcham and Ringwood.

RWTS was commissioned in 1963. In the current regulatory period deteriorated bulk oil 220 kV circuit breakers have been replaced. Several important but deteriorated assets will remain on the site. These include a 220/66 kV B4 transformer and 66 kV circuit breakers. These assets will approach the end of their technical lives between 2014 and 2020.

This project will replace the B4 220/66 kV transformer and six 66 kV circuit breakers and change the circuit configuration to reduce the probability of multiple transformer outages arising from a single asset failure. The economic timing of this project has been re-assessed since the last review and its forecast completion date is in 2018-19.

### 4.8.11 Contingent Projects

Under NER 6A.8 AusNet Services may propose capex projects that are contingent on an identified trigger event occurring in the regulatory control period.

Pursuant to NER 6A.8.1(b), each forecast contingent project must satisfy the following criteria:

- It must be reasonably required to be undertaken in order to achieve any of the capital expenditure objectives specified in NER 6A.6.7(a);
- It must not otherwise be provided for (either in part or in whole) in the total of the forecast capital expenditure;
- It must reasonably reflect the capital expenditure criteria specified in NER 6A.6.7(c), representing efficient costs of a prudent operator; and
- It must exceed either $30m or 5% of the value of the maximum allowed revenue (MAR) for the first year of the regulatory control period (whichever is the larger amount). AusNet Services' proposed MAR for the first year of the regulatory control period is $582.3m. Five per cent of that amount is $29.1m, which makes $30m the threshold for contingent projects for the purpose of this Revenue Proposal.

In addition, under NER 6A.8.1(c) the forecast trigger event is required to:

- Be reasonably specific and capable of objective verification;
- Make the contingent project reasonably necessary to achieve any of the capital expenditure objectives if it occurs;
- Generate increased costs related to a specific location rather than the network as a whole; and
- Have a reasonable chance of occurring in the forthcoming regulatory control period, but its occurrence is not sufficiently certain that the project should be included in the total capital expenditure forecast.

AusNet Services proposes one contingent project for the 2017-22 regulatory period. The project is described in the table below, along with its estimated additional capex requirements.

**Table 4.9: Forecast Contingent Project ($m, real 2016-17)**

| Contingent Project | Trigger | Cost Estimate |
|---|---|---|
| **Replace one or both of the Brooklyn and Templestowe synchronous condensers with reactive plant providing a similar, or reduced, level of service*** | Formal confirmation from AEMO that the magnitude of expected benefits provided by the synchronous condensers justify the replacement of the Brooklyn and/or Templestowe Terminal Station syndhronous condensers with reactive plant providing a similar, or reduced, level of service. | $70m (direct cost plus overheads) |

** An opex allowance is currently proposed to decommission the synchronous condensers. See Chapter 5 for more detail on the drivers of this contingent project. Note that the synchronous condensers may not be replaced with assets located at the same sites.*

The cost estimate has been prepared consistent with AusNet Services' standard project cost estimation methodology, outlined in section 4.4.6.

More details are provided in Appendix 4G – Contingent Projects.

## 4.9 Asset Replacement Programs

AusNet Services is proposing to undertake $250.6m of expenditure on asset replacement programs over the forthcoming regulatory control period. This expenditure is necessary to maintain the resilience and reliability of the transmission system, and to address operational or asset failure risk. The reduced number of major stations projects has led to an increased need for stand-alone asset replacement programs, as fewer aging assets will be replaced as part of major station rebuilds. A number of protection, control and communication renewal projects can be categorised as modernising the network to meet operating standards.

The table below provides sets out the capex forecast for asset replacement programs, by asset category.

**Table 4.10: Asset replacement programs ($m, real 2016-17)**

| | 2014-17 Average | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total 2017-22 |
|---|---|---|---|---|---|---|---|
| **Stations** | 14.3 | 12.1 | 14.2 | 14.2 | 14.2 | 14.3 | **69.0** |
| **Lines** | 4.6 | 4.3 | 8.4 | 4.4 | 4.4 | 4.4 | **25.8** |
| **Secondary and protection** | 18.3 | 23.3 | 20.3 | 17.2 | 16.4 | 17.5 | **94.7** |
| **Communications** | 10.4 | 9.7 | 13.4 | 15.3 | 14.1 | 8.6 | **61.2** |
| **Total** | **47.6** | **49.5** | **56.3** | **51.1** | **49.0** | **44.7** | **250.6** |

These programs are discussed in further detail below.

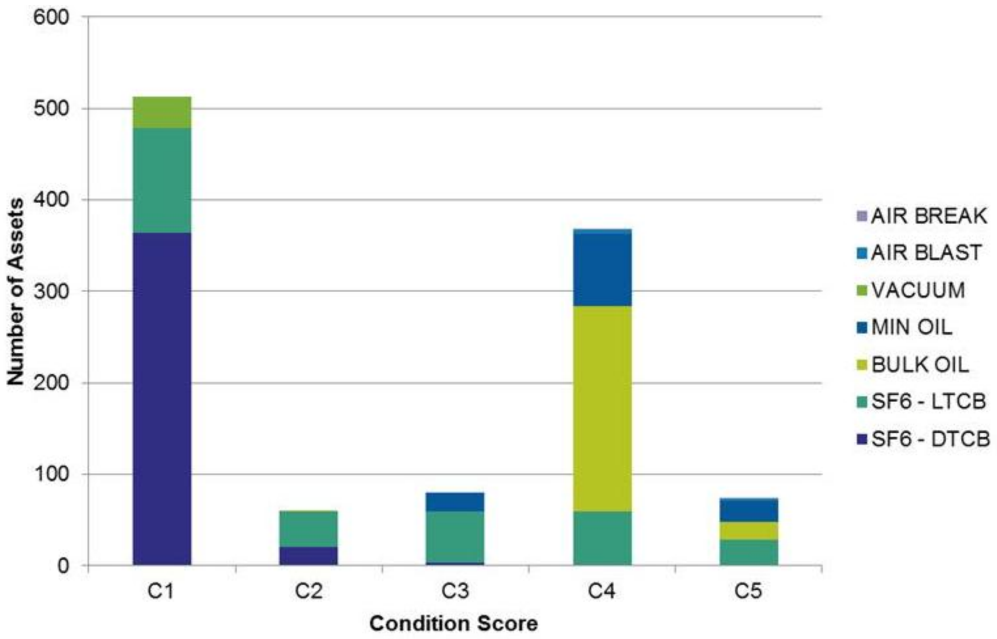
### 4.9.1 Stations

Approximately $69.0m is forecast for stations and plant, outside of the major stations projects forecast. This covers the following expenditure programs:

- Circuit breakers replacements – around 70 circuit breakers (including 500 kV, 220 kV and 66 kV) with an unacceptable risk of failure require replacement in the forecast period.

  There are a large number of circuit breakers on AusNet Services' network that are reaching the end of their useful lives. The graph below shows that there are a substantial number of circuit breakers rated as deteriorating, or advanced deterioration, condition. Circuit breakers that are currently rated condition 4 are expected to move into condition 5 over the next 5 to 10 years. Therefore, assuming that the service provided by the circuit breakers continues to be valued, there is expected to be a continuing need for expenditure on this asset class over the medium-term.

**Figure 4.17: Condition profile of circuit breakers**




*Source: AusNet Services*

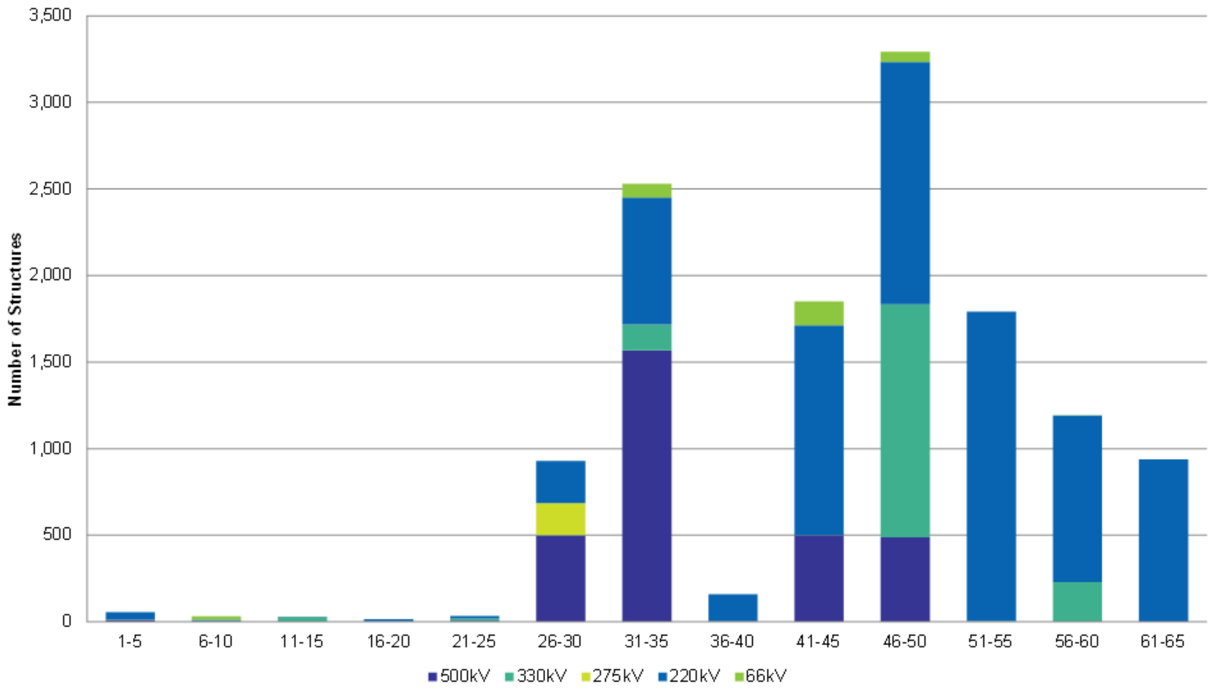
- Disconnector replacements – The program involves replacing 75 units and refurbishing 50 units. Replacements are targeted at units which have previously failed or may physically fail during operation. This poses reliability and safety risks. Refurbishment is targeted at units which have been identified to be not operating reliably.
- Life extension of power transformers – This program involves works to extend the life of ageing power transformers. While the average age of power transformers is forecast to reduce over the regulatory period due to replacements undertaken as part of rebuild projects, the proportion of the transformer fleet over 50 years increases from 14% in 2017 to 34% in 2022. Life extension works include corrosion mitigation, replacement of defective fittings, replacing seals and installing on-line gas analysers.
- Civil infrastructure – Involves the replacement or renewal of civil infrastructure and station facilities such as buildings, access roads and drainage systems, hand rails, retaining walls, station service transformers, air conditioning systems, and oil/water separating systems. The major items of expenditure are the removal of asbestos in walls, floor tiles and ceilings at fifteen sites, replacement of station service transformers and associated LV

switch/changeover boards at three stations, replacement/reinforcement of support structures, retainer walls and earth embankments at three stations, and replacement of switchyard surfaces and access roads at three stations.

### 4.9.2 Lines

Approximately $25.8m is forecast for ground wire replacements and tower strengthening. Many towers are exceeding their original expected lives, with approximately 30% of the tower fleet exceeding the age of 50 years. Of these oldest towers, approximately 94% operate on the 220kV network. This is shown in the figure below.

**Figure 4.18: Structures Age Profile**




*Source: AusNet Services*

Expenditure on lines in the forecast period is associated with the following activities:

- Ground wire replacements – a limited program of groundwire replacements is forecast to target poor condition spans. This involves the replacement of sections of deteriorated steel ground wire totalling 226 km on 14 different circuits. Visual inspection has found these conductors to be corroded. Economic risk analysis based on the probability and consequence of failure has concluded these replacements are justified. AusNet Services has trialled the use of SAIP technology to provide enhanced condition data on conductors which, if the proposed opex step change is approved, will be embedded into existing practices. This will enable future conductor replacements to be even more aligned to condition.
- Tower strengthening – a program to strengthen 48 towers on the 330 kV Murray Switching Station to Dederang Terminal Station lines; a section of the main interconnector between NSW and Victoria. The program is focused on the highest risk towers along the line and will reinforce light towers which do not meet current design standards and are susceptible to collapse in high winds.

AusNet Services has found it economically efficient to strengthen towers in key locations. Significant efficiencies in the current period have been achieved through substituting strengthening activities for replacements. This has been factored into the forecast, which does not include any replacements.

However, given the timing of the establishment of the Victorian transmission network it is likely that much more substantial tower replacement programs will be required in future regulatory periods as greater proportions of AusNet Services' fleet of 13,000 transmission towers reach the end of their useful lives.

### 4.9.3 Secondary and protection

Approximately $94.7m of expenditure is forecast for expenditure on secondary and protection replacements, outside of major projects.

This expenditure has three key drivers:

- Modernisation – Replacement of relays as a progression to a modern standardised design for station equipment using integrated functions in an intelligent device and serial communication;
- Compliance with the NER and AEMO Protection & Control Requirements (PCRs); and
- Obsolescence – Replacement of relays that are inadequate, obsolete, failing, aged and unsupported.

Protection system replacements will address reliability risks associated with slow or incorrect operation and deterioration of out-dated electro-mechanical and first generation electronic relays which do not meet current power system security requirements.

The remaining works will replace failing, non-compliant, unsupported or end of life secondary and protection assets and the continued replacement of battery chargers and DC supply packs.

### 4.9.4 Communications

Communications equipment to be replaced includes network bearers such as powerline carrier systems, network technologies such as digital multiplexers, and supporting infrastructure such as battery back-up systems.

Some powerline carrier systems have been in service for more than 25 years and are planned for replacement with either optical fibre groundwire or radio links as the existing systems can no longer be maintained and have limited capacity to enable new generator connections.

The network technologies which form the operational data network carry SCADA, protection and operational telephony communications. Planned replacements are driven by systems which are no longer supported by vendors and for which spare parts can no longer be obtained.

Two hundred battery back-up systems provide support to communications nodes. Replacements are required as 70% of battery systems that are expected to reach the end of their effective life over the next 10 years.

## 4.10 Safety, Security and Compliance

AusNet Services is proposing approximately $71.6m in capex for safety, security and compliance. The table below provides a summary of the forecast expenditure in this category of capex.

**Table 4.11: Safety, security and compliance capex ($m, real 2016-17)**

| | 2014-17 Average | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total 2017-22 |
|---|---|---|---|---|---|---|---|
| **Tower fall arrests** | **4.1** | 4.8 | 4.9 | 5.0 | 5.0 | 5.0 | **24.7** |
| **Instrument transformer replacement** | **1.6** | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | **8.5** |
| **Power transformers – improved safe access** | **0.4** | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | **2.9** |
| **Stations structure fall arrests** | **0.3** | 0.0 | 0.4 | 0.6 | 0.0 | 0.0 | **1.0** |
| **Insulator replacement** | **3.0** | 1.3 | 1.2 | 1.2 | 1.2 | 1.0 | **6.0** |
| **Fire protection and infrastructure** | **1.9** | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | **10.0** |
| **Infrastructure Security Systems** | **1.3** | 2.8 | 2.9 | 2.9 | 2.9 | 2.9 | **14.3** |
| **Communications safety and security** | **0.5** | 1.5 | 0.3 | 0.9 | 0.0 | 1.6 | **4.3** |
| **Total** | **13.1** | ***14.6*** | ***14.0*** | ***14.8*** | ***13.3*** | ***14.8*** | **71.6** |

The programs included in this category are outlined below.

### 4.10.1 Tower fall arrests

The tower structures and stations racks – fall arrest installation program is a safety initiative which is required to comply with the Occupational Health and Safety Regulations 2007, No. 54 – Part 3.3. This ongoing program will install cable-based fall arrest systems on 25% of the 47% of towers which do not currently have a fall arrest system installed to mitigate risks associated with working from heights. The targeted towers have been determined based on a risk assessment of towers without fall arrests.

### 4.10.2 Instrument transformer replacement

This program will replace seventy poor condition instrument transformers throughout the network to maintain worker safety and network reliability.

### 4.10.3 Power transformers – improved safe access

This program will fit fences, handrails, ladders and working platforms on 50 transformers manufactured since 1990 that were installed before handrails became part of the standard requirements. These maintenance access systems provide an engineering solution to working at heights exceeding four metres from the ground. Installation of these systems will enable compliance with Occupational Health and Safety Regulations 2007, No. 54 – Part 3.3 on transformers where the system is installed.

### 4.10.4 Stations structure fall arrests

This program will fit fall arrest systems on the remaining 38% of transmission rack structures that have not already had a complying fall arrest system installed. Installation of these arrests will enable compliance with Occupational Health and Safety Regulations 2007, No. 54 – Part 3.3 on station structures.

### 4.10.5 Insulator replacement

AusNet Services' insulator replacement program began in 2006. More than 24,000 insulator strings or approximately 28 per cent of the fleet has now been replaced based on condition data gathered during tower climbing inspections. In the 2014-17 regulatory period, approximately 800 insulators will be replaced. Typically, this has involved replacing insulators with corroded pins, which are at risk of mechanical failure (the pin breaking). An ongoing program at a reduced level will continue in the forthcoming period replacing 2,000 insulator strings.

### 4.10.6 Fire protection and infrastructure

Fire protection systems are needed to protect assets, personnel and help prevent bushfire ignition. This program will replace assets which are deteriorating rapidly towards unacceptable condition whilst ensuring compliance with Australian Standards.

### 4.10.7 Infrastructure Security Systems

The Infrastructure Security Systems Upgrade will increase security at sensitive sites, commensurate with the requirements of the Victorian Terrorism (Community Protection) Act 2003. AusNet Services has implemented numerous security enhancement projects since the introduction of the Act including the upgrade of security fencing at various terminal stations.

### 4.10.8 Communications safety and security

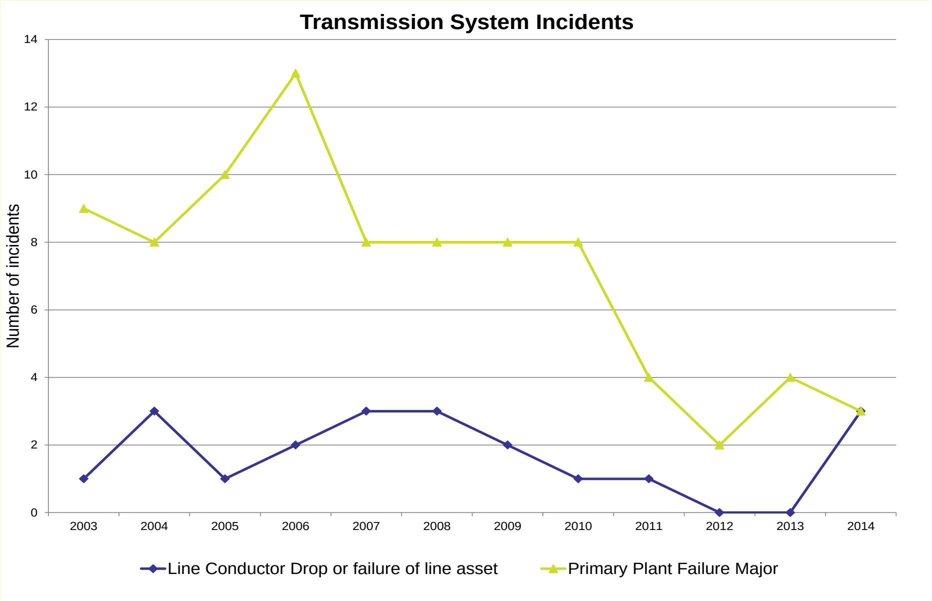
This program is aimed at improving physical and cyber security of the communication network, and ensuring Occupational Health and Safety (OH&S) requirements are satisfied at communications sites. It involves the implementation of cyber-attack detection tools and centralised management via Security Information and Event Managers. These tools provide automated threat forensics and dynamic malware protection against advanced cyber threats.

Stakeholders were interested in the magnitude of capex that is driven by safety and how the efficiency of safety capex is measured.

Over the past few years the safety program has been targeted at:

- Replacing equipment at risk of explosive failure, for example, instrument transformers and circuit breakers;
- Replacing insulators to prevent line drops; and
- Installing fall arrest systems on towers.

The number of transmission system incidents are tracked, including major plant failures and line conductor drops. The number of events in recent years are shown in the chart below. The downwards trend indicates that the safety capex program has been effective.




The installation of tower fall arrest systems is driven by a regulatory obligation. AusNet Services captures detailed data on all safety incidents, including incidents related to tower inspections.

## 4.11 Non-Network Capital Expenditure

Forecast non-network capex totals $111.5m over the next regulatory control period. The table below provides a summary of the forecast expenditure in this capex category.

**Table 4.12: Non-network capital expenditure ($m, real 2016-17)**

| | 2014-17 Average | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total 2017-22 |
|---|---|---|---|---|---|---|---|
| **IT** | 16.2 | 25.7 | 23.3 | 14.2 | 11.8 | 10.0 | **85.2** |
| **Buildings and property** | 1.1 | 0.2 | 0.6 | 0.1 | 0.2 | 1.0 | **2.2** |
| **Vehicles** | 1.0 | 1.9 | 1.5 | 2.1 | 1.8 | 1.8 | **9.2** |
| **Other** | 2.3 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | **14.9** |
| **Total** | **20.7** | **30.8** | **28.4** | **19.5** | **16.8** | **15.9** | **111.5** |

An overview of the expenditure forecast in each of these categories is provided below.

### 4.11.1 Information Technology

IT capex is required to support the business and maintain network security and reliability. AusNet Services' 2017-22 ICT Strategy (Appendix 4H) 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 $85.2m for the 2017-22 regulatory period. This is at the same level as the IT capex from the current period (averaging $17.0m per annum).

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 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 focus in the forecast period (2017-22) will be on delivering the remaining core elements of the enterprise strategy and preparing to move to more agile IT solutions. Namely, AusNet Services will:

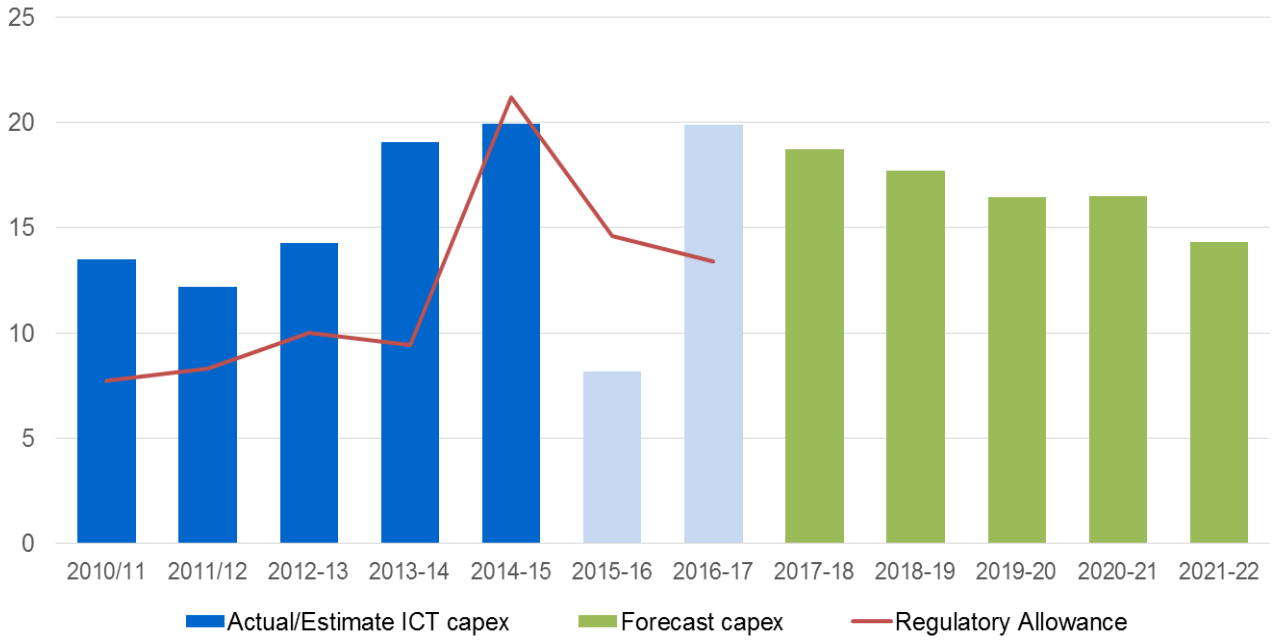
- Finish IT application modernisation;
- Begin deploying new IT capabilities across the business; and
- Retire the legacy IT environment.

The forecast IT capex has been developed in response to the following drivers:

- Simplifying the ICT landscape by proactively decommissioning aged technology and solutions and where possible enabling enhanced management of the transmission network. This encompasses enhancements to network management solutions including but not limited to alarms, limits and security management;
- Supporting enhanced business decisions through building and enhancing data analytics, reporting and data management capability. This would also allow the business to comply with industry regulations and requirements such as regulatory information notices (RINs);
- Adopting newer technology to enable greater integration and automation of processes and systems across the enterprise and modernise our system including using cloud computing and server virtualisation; and
- Protecting our customer and business information by enabling information security in response to big data, the convergence of information and operational technology and the increased and evolving threats to data, systems and assets;

The annual forecast IT capex is set out in the figure below, alongside actual and expected IT capex from 2011 onwards.

**Figure 4.19: Actual / Expected and Forecast IT Capex ($m, real 2016-17)**




*Source: AusNet Services*

*Note: Figures for 2015-16 to 16-17 are estimates.*

The investment profile in the above figure (with capex peaking in 2016/17 and falling over the forecast period) reflects the AusNet Services' completion of a number of significant IT investments and requiring less capital investment in IT over time. The drop in IT capex in 2015/16 is due to AusNet Services focusing resources on the delivery of Project Workout, the corporate wide EAM/ERP solution which is allocated to distribution more than transmission. However, following the completion of this project, investments in transmission-supporting IT capex will be ramped back up to deliver the forecast program.

The seven key programs of work in the ICT capex forecast are summarised below.

**Table 4.13: Forecast ICT Capex by Program ($m, real 2016-17)**

| Initiative | Program summary | Capex |
|---|---|---|
| **Business Programs** | | |
| **Corporate** | Leverage EAM / ERP solution including providing a secure and consistent view of data throughout the organisation. | 3.7 |
| **Customer & Metering Systems** | Implement an enterprise-wide customer information system to effectively and efficiently manage customer, regulatory and stakeholder obligations and meet the increasing information needs of customers. | 4.4 |
| **Network Management** | Increase safety, network reliability and performance by automating network monitoring and responses; data consolidation and improved visualisation of network performance. | 13.6 |
| **Works & Asset Management** | Improve network reliability and operational efficiency by leveraging the EAM / ERP investment to rationalise, consolidate and optimise business processes. | 9.7 |
| **Enterprise ICT Programs** | | |

| Initiative | Program summary | Capex |
|---|---|---|
| **Information Management** | Improve the management of networks and assets through improved data and analytics capabilities. | 18.6 |
| **Information Security** | Protect transmission network, and customer and business information through enhanced 'protect and detect' capabilities. | 6.0 |
| **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. | 29.2 |
| **Total ICT Capex** | | **85.2** |

*Note – This table shows direct costs only*

These programs of work are discussed in more detail in the ICT Strategy.

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' ICT Strategy (provided at Appendix 4H).

### 4.11.2 Buildings and Property

AusNet Services owns a number of buildings and properties which are used in the provision of prescribed transmission services and the company is responsible for the management and maintenance of these assets. Forecast capital expenditure in this area covers expenses such as office modifications including installing portable offices, and accommodation rearrangements, and purchase of office equipment such as desks and chairs. This expenditure will largely continue at historic levels.

The exception to this is a small increase associated with relocating the control centre. This is currently located on leased premises in Melbourne. AusNet Services has identified an alternative location which lowers security risk. The costs of this relocation are attributable to transmission capex totalling approximately $1m, and are embedded in the buildings and property and ICT forecasts.

### 4.11.3 Vehicles and other

AusNet Services maintains a fleet of vehicles, both owned and leased. These vehicles are used to carry out routine work on the network, to respond to network events, to travel between work sites and to travel to meet stakeholders.

Over the forthcoming regulatory control period, the existing AusNet Services-owned vehicle fleet will slightly increase compared to historic levels, reflecting the cost efficiencies associated with purchasing, rather than leasing, vehicles.

The non-network expenditure category of 'other' is comprised principally of capital expenditure on tools and measurement equipment. The forecast has been developed based on a historical average of expenditure since 2008-09 reflecting the largely recurrent nature of this category.

## 4.12 Expected Benefits of Capital Program

This section provides an overview of the key benefits of AusNet Services' forecast capital investment over the forthcoming regulatory period. The aggregate outcomes of the capital program are consistent with those identified in the detailed underlying project justifications. These individual justifications are determined through rigorous and detailed cost benefit analysis and support for a large proportion of the program is provided in the supporting documentation to this revenue proposal.

The key benefits at an aggregate level are outlined below.

### 4.12.1 Network risk

AusNet Services expects that the forecast asset replacement capex will manage the total asset failure risk within acceptable bounds. Where an asset failure poses a high risk of adverse environmental impacts, third party property damage, injury or death, replacement is prioritised. The proposed program is expected to lead to a reduction in safety and environmental risk over the period. The reliability risk will remain broadly constant in monetary terms.

This will support AusNet Services' ability to maintain the quality, reliability and security of supply of prescribed transmission services, and to maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services, in accordance with NER 6A.6.7(a)(3) and (4).

### 4.12.2 Safety and safety compliance

AusNet Services must meet legislated safety requirements to protect its employees and the community from harm. Safety remains the focus of ongoing investment by the company in equipment, training and awareness. AusNet Services expects that the forecast safety capex over the forthcoming regulatory control period will make the Victorian Transmission Network safer both for the public and employees. Many of the safety improvements delivered by the capex program will arise incidentally as a result of replacing old equipment with new, safer equipment and through the application of modern, safer station design standards. Other improvements will result directly from projects aimed at improving safety (or safety compliance). A high level summary of the safety outcomes provided by AusNet Services' forecast capital works program is shown in the table below.

**Table 4.14: Safety outcomes of capital program**

| Project or Type of Project | Outcome |
|---|---|
| **Tower reinforcement** | Reduced risk of public injury or death from a tower collapse. |
| **Cable fall arrests systems on towers & structures; power transformer safe maintenance access systems** | Reduced risk of death or injury to an employee from falling. |
| **Transformer and bushing replacement** | Reduced risk of death or injury from explosive failure of a bushing or transformer. |
| **Site security** | Improved site security reduces the risk of injury resulting from unauthorised entry to stations. |
| **Insulator replacement** | Reduced risk of death or injury from a fallen conductor. |
| **Fire protection system replacement** | Reduced risk of uncontrolled fire resulting in severe health and safety issues to public and company employee / contractor with possible bush fire initiation. |

A critical safety risk that will continue to be reduced in the forthcoming period relates to asbestos at AusNet Services properties. As part of AusNet Services on-going commitment to making its workplaces safe for all staff and the public, the company has implemented an asbestos removal program. This will continue to be delivered over the forthcoming period.

AusNet Services' capex forecast includes all capital investment required to facilitate the company's compliance with its ESV-approved Electricity Safety Management Scheme (ESMS).

### 4.12.3 Environment

Transmission equipment poses some environmental risks, particularly older assets. Typically, these risks arise from $SF_6$ gas leakage, oil leaking from transformers or pollution caused by a fire. The risk of these outcomes increases as assets degrade because there is a strong link between asset degradation and the probability of an asset failure. As part of its replacement programs, AusNet Services will be continuing to replace assets which pose a risk to the environment.

### 4.12.4 Enabling efficient future network development

As previously noted, in Victoria, AEMO is responsible for shared network planning and augmentation, while connecting parties and generators are responsible for planning and augmenting their connections to the transmission network. AusNet Services is responsible for maintaining and managing the assets that comprise the transmission system.

The two activities of augmentation planning and asset management need to be carefully coordinated to ensure the capital programs of AEMO, AusNet Services and the distributors are aligned and where possible synergies are derived. AusNet Services will continue to work closely with AEMO and the distributors to ensure that all capital works programs are coordinated, scheduled and delivered as efficiently as possible.

## 4.13 Capital works 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 works is smaller than the program in the current regulatory period but it encompasses similar activities. 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 ensuring 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.

## 4.14 Link to other building blocks

There is a strong relationship between AusNet Services' capital expenditure forecast and other aspects of its revenue proposal. Any adjustments made to related aspects of the proposal may require consequential adjustments to the capex forecast. These inter-linkages are explained below:

- Depreciation – AusNet Services has proposed to accelerate the depreciation of capex over the 2017-22 period, as an efficient response to changing network utilisation partly driven by new, emerging technologies. These emerging energy market trends have been considered in the preparation of the capex forecast and have contributed to a forecast reduction in capex compared to historical levels.
- Rate of return – the capex forecast has been developed assuming a rate of return is secured which will allow AusNet Services to finance the forecast program. If the rate of return determined is not sufficient to finance the forecast, this will present risks to AusNet Services' ability to continue to provide safe and reliable electricity services.
- Performance incentive schemes – AusNet Services has proposed adjustments to the loss of supply event frequency STPIS parameters to reflect the reduction in the VCR. As the capex forecast is developed by incorporating the updated VCR, this is expected to lead to, on average, a gradual decline in reliability over the period. NER 6A.6.7(8) requires the AER to consider whether the capex forecast is consistent with any incentive schemes that apply to AusNet Services. If the AER supports the use of the updated VCR in the forecast asset replacement plans, then the impact on reliability will need to be properly accounted for in the STPIS. This will ensure that AusNet Services is not penalised for its economic planning approach which incorporates up-to-date estimates of the value placed on reliability by customers.
- Operating expenditure – AusNet Services' opex forecast incorporates capex-opex trade-offs, whereby additional opex is proposed as a consequence of previous or expected reductions, or expected future deferrals. The revenue forecast incorporates capex-opex trade-offs to minimise total lifecycle cost.

## 4.15 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 4A – Network Capital Expenditure Overview 2017-22
- Appendix 4B – 2014 DNSP Victorian Terminal Station Demand Forecasts
- Appendix 4C – 2014 AEMO Transmission Connection Point Forecasting Report for Victoria
- Appendix 4D – Unit Rates
- Appendix 4E – Cost Estimating Methodology
- Appendix 4F – Advice on Cost Escalation Rates for Materials Inputs
- Appendix 4G – Proposed Contingent Projects
- Appendix 4H – ICT Strategy 2017-2022 Electricity Transmission Network

# 5 Operating and Maintenance Expenditure

## 5.1 Key Points

- AusNet Services is forecasting total opex requirements of $1,101.7m (real 2016-17) over the next regulatory control period. Of this total expenditure:
    - $511.8m (46%) is within AusNet Services' management control; and
    - $589.9m (54%) is non-controllable.
- AusNet Services' average annual controllable opex for prescribed transmission services in the forthcoming regulatory control period is $102.4m, approximately 13% higher than average annual controllable opex in the current period.
- The forecast increase in opex from 2014-15 levels is driven by:
    - The rising costs of inputs;
    - Increases in output growth measures used by the AER (e.g. maximum demand);
    - Growth in insurance premiums;
    - The opex associated with the roll in of Group 3 assets (which is already being charged to customers outside the revenue cap); and
    - Step changes including opex required to decommission some retired assets, roll out enhanced condition assessment technology to proactively manage capex levels (allowing the deferral of investment) and address an evolving IT security and emergency response landscape.
- These increases have been partially offset by forecast productivity improvements.

## 5.2 Introduction and Overview

### 5.2.1 Introduction

This chapter sets out AusNet Services' opex forecast for the forthcoming regulatory period. The forecasts have been prepared on the following basis:

- The forecasting methodology is consistent with the approach set out in AusNet Services' Forecasting Methodology which has been submitted to the AER;
- The forecasts are consistent with AusNet Services' approved cost allocation methodology;
- The capitalisation policy is unchanged from the current regulatory period;
- The opex forecasts exclude the operating costs associated with future augmentations of the shared network and transmission connection facilities over the period;[26] and
- The opex forecasts exclude the costs associated with the provision of negotiated or unregulated services.

As explained in this Chapter, AusNet Services considers that the total opex forecast for the forthcoming regulatory period complies with the Rules requirements because the forecast reasonably reflects:

[26] As explained in Chapter 2 these augmentations are undertaken at the direction of AEMO or the Victorian DNSPs.

- The efficient costs of achieving the *operating expenditure objectives* (which are set out in NER 6A.6.6(a));
- The costs that a prudent operator would require to achieve the *operating expenditure objectives*; and
- A realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives.*

As such, it is submitted that the AER's obligation to make decisions that are consistent with the achievement of the NEO as they pertain to a prudent TNSP are satisfied by its acceptance of the opex forecasts presented in this chapter.

### 5.2.2 Overview

AusNet Services is forecasting total opex requirements of $1,101.7m (real 2016-17) over the next regulatory control period. Of this total expenditure, $511.8m (46%) is within AusNet Services' management control, while $589.9m (54%) is non-controllable. The total annual opex forecast is set out below.

**Table 5.1: Total forecast opex ($m, real 2016-17)**

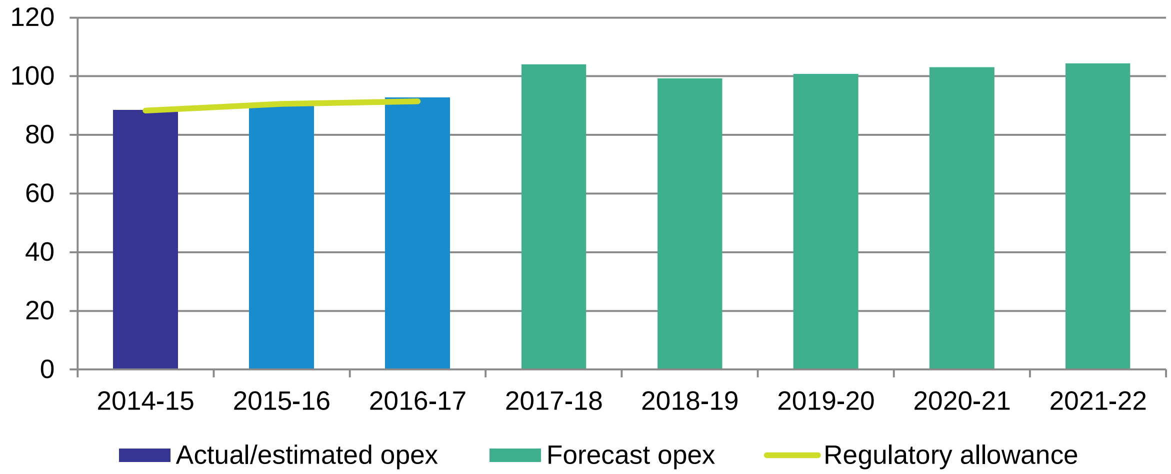
| Opex | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Controllable | 104.1 | 99.3 | 100.8 | 103.1 | 104.4 | **511.8** |
| Non-controllable | 118.0 | 118.0 | 118.0 | 118.0 | 118.0 | **589.9** |
| **Total** | **222.1** | **217.3** | **218.8** | **221.1** | **222.4** | **1,101.7** |

*Source: AusNet Services*

Of the total forecast opex, $576.4m, or around 52%, is easement land tax. Easement land tax is a levy applied by the Victorian Government, which is recovered through regulated revenues but does not represent the underlying costs of operating the network.

AusNet Services' average annual controllable opex for prescribed transmission services in the forthcoming regulatory control period is $102.4m, approximately 13% higher than average annual controllable opex in the current period. Actual, estimated and forecast controllable opex for the current and forthcoming regulatory periods is shown in the below figure.

**Figure 5.1: Actual and forecast controllable opex ($m, real 2016-17)**




*Note: Controllable opex excludes self-insurance and easement land tax; 2014-15 opex excludes movements in provisions; 2015-16 and 2016-17 values are estimates.*

The 13% increase from 2014-15 is driven by the rising costs of inputs, increases in output growth measures used by the AER (e.g. maximum demand), growth in insurance premiums, and the opex associated with the roll in of Group 3 assets (which is already being charged to customers outside the revenue cap).

A number of step changes have been included in the forecast, including opex required to decommission some retired assets, roll out enhanced condition assessment technology to proactively manage capex levels (allowing the deferral of investment) and address an evolving IT security and emergency response landscape.

These increases have been partially offset by forecast productivity improvements.

The above cost drivers are reflected in AusNet Services' average annual controllable opex forecast, which is summarised in the table below.

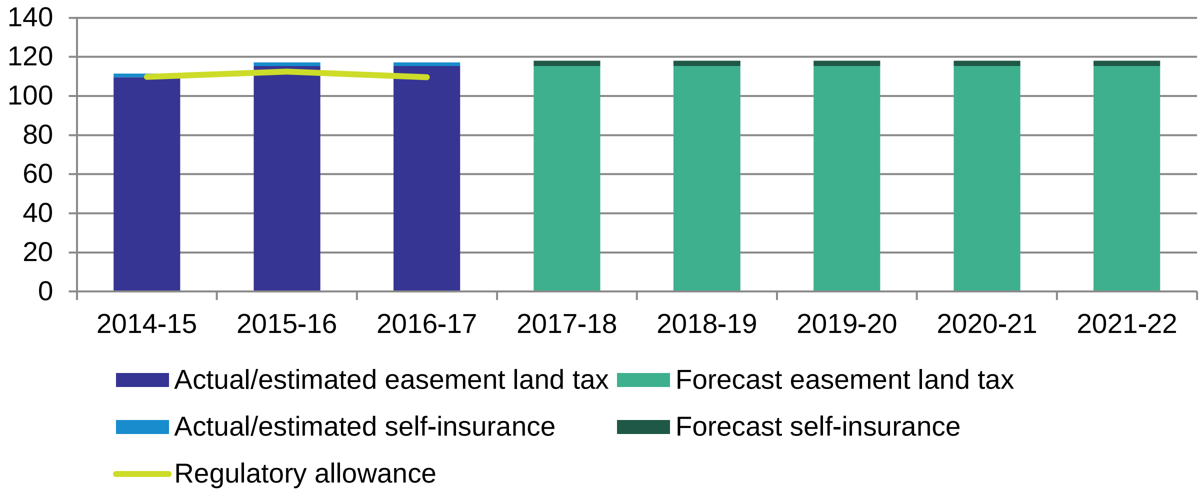
**Table 5.2: Average annual forecast controllable opex ($m, real 2016-17)**

| Opex component | Annual average opex |
|---|---:|
| Base year opex | 83.7 |
| ***Plus*** | |
| Labour escalation | 2.6 |
| Output growth | 6.7 |
| Step changes | 2.7 |
| Group 3 roll in | 2.0 |
| Insurance costs | 5.8 |
| ***Less*** | |
| Productivity improvements | -1.2 |
| **Total** | **102.4** |

*Note: Individual values may not add to total due to rounding; base year opex includes debt raising costs and excludes insurance costs and movements in provisions.*

AusNet Services has forecast non-controllable opex of $589.9m, which comprises easement land tax and self-insurance. An overview of AusNet Services' historic and forecast non-controllable opex expenditure is provided in the figure below, which illustrates that the vast majority of non-controllable opex relates to easement land tax.

**Figure 5.2: Actual / expected and forecast non-controllable opex ($m, real 2016-17)**




Note: *Pass-through arrangements prescribed in the NER ensure that over the course of a regulatory period, neither AusNet Services, nor its customers, will receive a windfall gain (or loss) due to differences between actual easement land tax payments and approved regulatory allowances.*

### 5.2.3 Structure of this chapter

The remainder of this chapter is structured as follows:

- Section 5.3 describes the forecasting methodology used to derive the opex forecast;
- Section 5.4 sets out the key assumptions and inputs that underpin the forecasts;
- Section 5.5 presents historic opex and variations in forecast opex;
- Section 5.6 sets out efficient base year opex;
- Section 5.7 presents the rate of change calculation;
- Section 5.8 sets out the insurance premium forecast;
- Section 5.9 provides the opex impact of Group 3 assets;
- Section 5.10 sets out opex step changes for the forthcoming period;
- Section 5.11 summarises the controllable opex forecast;
- Section 5.12 presents non-controllable opex forecast;
- Section 5.13 presents AusNet Services' total opex forecast;
- Section 5.14 discusses links to other building blocks; and
- Section 5.15 lists supporting documentation relevant to this Chapter.

## 5.3 Forecasting Methodology

AusNet Services has used a revealed cost base-step-trend approach to develop its proposed opex forecast.[27] To ensure this approach produces a prudent and efficient forecast of opex, it must commence with an efficient level of base year opex. 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."*[28]

For the reasons outlined in section 5.6 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 stakeholder attitudes and expectations as they relate to opex;
- Using revealed 2014-2015 expenditure to determine efficient base year costs;
- Applying a rate of change to base year costs to reflect expected changes in input costs, output growth and productivity;
- Adjusting forecast opex to account for the roll-in of Group 3 assets;
- Incorporating a number of step changes, including capex-opex trade-offs to efficiently address AusNet Services' ageing asset base, as well as to respond to developments in the emergency response and security landscape;
- Including easement land tax, which must be included in the forecast operating expenditure despite being a non-controllable cost; and
- Forecasting some 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.

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 an appropriate methodology to forecast opex requirements for an efficient TNSP.

Consistent with the 2014-17 determination where 'asset works' opex was deemed by the AER to be recurrent in nature and subject to a base-step-trend approach, AusNet Services has retained asset works in base year expenditure and forecast it using the base-step-trend approach for the forthcoming period. This approach assumes that individual items of non-recurrent expenditure will rise and fall across the forthcoming regulatory period such that total non-recurrent opex is broadly consistent from year-to-year.

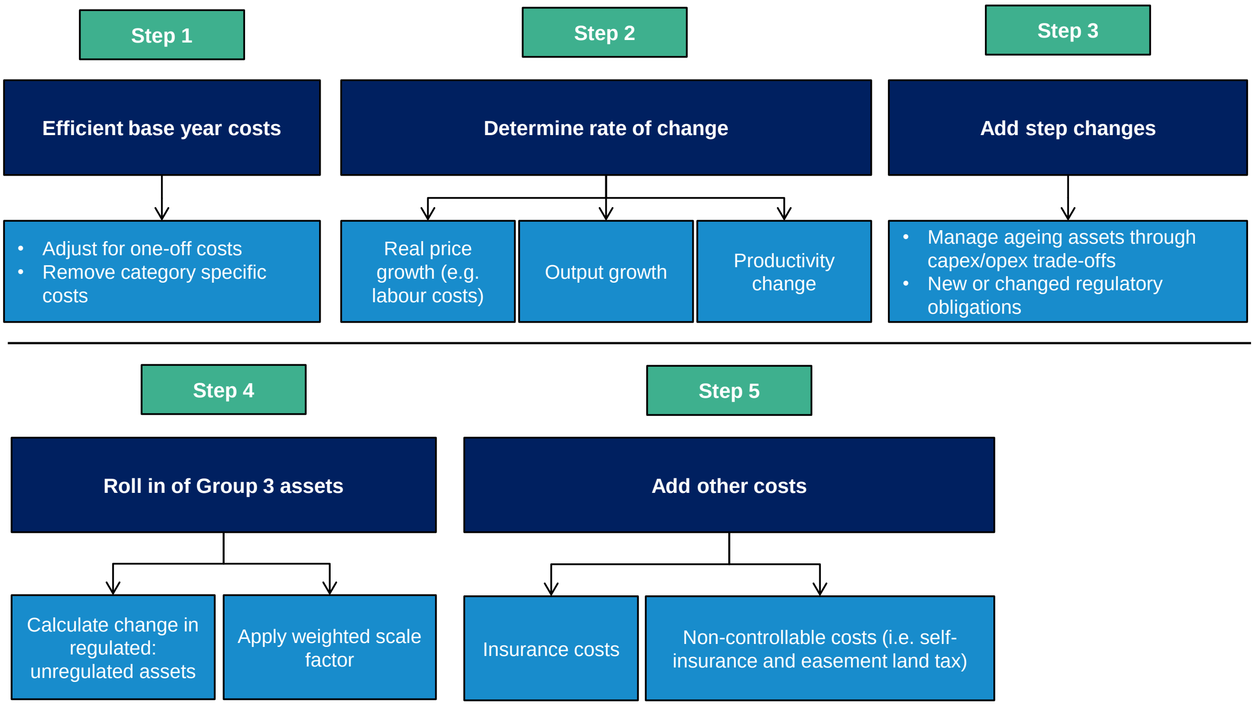
---

[27] AusNet Services' use of the base-step-trend approach is subject to some limited exceptions, which are explained later in this chapter.

[28] AER, *Explanatory Statement | Expenditure Forecast Assessment Guideline*, p. 61.

The figure below illustrates the forecasting methodology described above, which comprises five steps.

**Figure 5.3: Opex forecasting methodology**




Each step is discussed in further detail in the following sections of this chapter, commencing with an overview of the key assumptions and inputs.

## 5.4 Assumptions and Inputs

Schedules S6A.1.2(3) and S6A.1.2(5) of the NER require a Revenue Proposal to provide information on the forecasts of key variables and assumptions relied upon to derive the operating expenditure forecast. This information is set out below.

### 5.4.1 Compliance with Laws, Codes and Standards

AusNet Services must comply with all applicable regulatory and legislative requirements. This includes maintaining compliance with the following existing legislation and regulations:

- Regulations under the Occupational Health and Safety Act 2004, which drive asset works projects to undertake non-routine maintenance of facilities at Terminal Stations, including asbestos removal, building repairs, switchyard surface repairs and fire protection and security system works;
- The Environmental Protection Act 1970, which promotes sound environmental practices and procedures to ensure ecologically sustainable development. Requirements under this Act drive asset works projects including condition assessments to identify oil and gas leaks; and
- Part 6 of the Terrorism (Community Protection) Act 2003, which requires owners of declared essential services to take appropriate steps to secure their assets against foreseeable risks.

In addition, AusNet Services is required to comply with specific Victorian regulations, pursuant to its Victorian Transmission Licence.

These obligations are reflected in the forecast of recurrent opex presented in this chapter.

### 5.4.2 Stakeholder feedback

AusNet Services facilitated a number of forums to obtain the views of it stakeholders, and ensure alignment, where possible, between its Revenue Proposal and stakeholder views. In relation to opex, stakeholders were largely interested in AusNet Services' proposed step change for the deployment of Smart Aerial Image Processing (SAIP), given the AER rejected a similar proposal in its determination for the current period. Justification for the roll out of SAIP is discussed in section 5.10.

Stakeholders were also interested in further understanding the AER's economic benchmarking model (which has been used to develop the productivity forecast discussed in section 5.7.4) and its partial performance indicators. AusNet Services' performance against these benchmarking measures is discussed in section 5.6.4.

The following table sets out the feedback expressed by stakeholder with respect to operating expenditure, and AusNet Services' responses on these matters.

**Table 5.3: Stakeholder Feedback on Operating Expenditure**

| Stakeholder Feedback | Response |
|---|---|
| **Which types of customers are included in the customer numbers used in the benchmarking metrics presented?** | All end-user electricity consumers are included in the customer numbers used in the transmission benchmarking metrics. Therefore these comprise all customers of the distribution networks, plus customers directly connected to the transmission network. |
| **Are the results for the opex (partial productivity) measures affected by the different operating environments of the networks, such as the differences in terrain?** | Section 5.6.4 of this chapter compares total opex across TNSPs on a normalised basis (e.g. using customer numbers). These normalisers control for the differences between networks in relation to customer density and size of network. It is evident that AusNet Services' opex benchmarks strongly across a range of normalisers.<br><br>However, differences in the terrain of each networks' service area is a valid environmental factor which should be taken into account when in interpreting the partial factor productivity results shown in that section. |
| **Which TFP model have we used to present our results and why?** | The opex MTFP results presented in section 5.6.4 use the AER's preferred model specification. This is the model developed and applied by the AER. Under this model, the inputs and outputs of each TNSP are compared over time to assess how each networks' productivity has changed over time.<br><br>AusNet Services has experienced the strongest growth in opex productivity of all TNSPs since 2006. |
| **Why does AusNet Services perform strongly on the partial productivity measures but less well in TFP?** | AusNet Services performs strongly across a range of partial productivity measures, but ranks third out of the five transmission networks in the NEM for overall MTFP in the AER's preferred model specification. These outcomes highlight the need to continue testing the AER's preferred TFP model specification, which is in its infancy, to ensure the most appropriate inputs and outputs are being assessed. AusNet Services welcomes the opportunity to work further with the AER on this issue.<br><br>While it is difficult to draw conclusions from the networks' MTFP rankings, AusNet Services considers that the model provides useful insights into the change in networks' productivity over time. AusNet Services is the only network exhibiting an improving productivity trend over the period. |

| Stakeholder Feedback | Response |
|---|---|
| **Why does AusNet Services plan to ask the AER again for additional opex to embed the use of SAIP in its condition monitoring practices?**<br><br>**What has changed since last time?**<br><br>**Is there expected to be an offsetting reduction in other aspects of lines condition monitoring as a result of embedding SAIP?** | The AER did not accept AusNet Services' SAIP proposal at the previous review on the grounds that the overall opex allowance provided was sufficient to enable SAIP to be embedded into AusNet Services' routine maintenance.<br><br>However, AusNet Services does not agree with the AER's rationale and is therefore proposing a step change for SAIP at this review. This step change is net of forecast inspection cost savings, which will partially offset the opex required to roll out SAIP.<br><br>Section 5.10 sets out the justification for this step change, along with other information addressing stakeholder feedback on SAIP. |

### 5.4.3 Base year opex

AusNet Services' base year opex is the company's audited actual opex for the 2014-15 year ending March 2015. The efficiency of 2014-15 as a base year is addressed in more detail in section 5.6 below.

### 5.4.4 Input costs

AusNet Services has adopted cost escalators to account for the likely increase in the cost of labour and materials over the forthcoming regulatory period. In relation to labour, AusNet Services has differentiated between external and internal resources, recognising the differences in these market segments. In addition to taking account of the AER's recent approach to labour cost escalators, AusNet Services' proposed escalators are underpinned by independent expert advice.

No real increases in material costs applied to opex have been applied during the forthcoming regulatory period. Materials cost escalators are considered further in section 4.4.7.

### 5.4.5 Output growth

Output growth has been applied to AusNet Services' opex forecast using the following output measures and weights, in accordance with the AER's approach in its recent determinations for TransGrid and TasNetworks:

- Energy throughput (with a weight of 21.4%);
- Ratcheted maximum demand (22.1%);
- Voltage-weighted entry and exit points (27.8%); and
- Circuit length (28.7%).[29]

These weights have been applied to AusNet Services' forecasts of the output measures to forecast opex increases attributable to output growth.

[29] AER (2014) *Draft decision: TransGrid transmission determination 2015-18 | Attachment 7 – Operating expenditure 7*, November 2014 p. 75.

### 5.4.6 Productivity change

In line with the AER's most recent approach to forecasting productivity for transmission businesses, AusNet Services has adopted the historical average of industry-wide productivity gains in forecasting its future opex requirements. The industry average provides a reasonable estimate of the future productivity improvements an efficient TNSP would be expected to achieve.

### 5.4.7 Capex / opex trade-offs

A number of AusNet Services' proposed step changes, which are discussed in section 5.10 below, are capex / opex trade-offs.

More broadly, AusNet Services' forecast opex reflects the optimal level of expenditure (that is, the level required to minimise total capital and operating costs over the asset life cycle). The objective of minimising asset life cycle costs is explained in AusNet Services' Asset Management Strategy AMS 10-01 (Appendix 2A). The opex forecasting methodology recognises the impact on the company's operating and maintenance requirements of the proposed capital expenditure program.

As no non-network alternatives to major replacement projects have been identified, the opex forecast does not include costs associated with non-network solutions.

### 5.4.8 Cost Allocation Methodology (CAM)

The base year costs, along with all other cost data used as inputs to the opex forecast, have been allocated in accordance with AusNet Services' approved Transmission Cost Allocation Methodology (CAM). AusNet Services' application of the CAM is audited annually during the regulatory accounts approval process. AusNet Services is proposing updates to its approved CAM which do not affect the preparation of the forecast. The proposed CAM has been submitted to the AER alongside the revenue proposal.

### 5.4.9 Risk management approach

AusNet Services conducts a careful assessment of the risks faced by its transmission business and, with the assistance of experienced brokers and analysts, seeks the most cost effective range of cover available in the market and balances this with other mechanisms for insuring against loss. As a consequence of this process, AusNet Services proposes to adopt a combination of insurance policies, self-insurance and cost pass-through arrangements. This process has been conducted so as to achieve an optimal balance of risk management and cost, with the ultimate objective of minimising the overall cost to customers.

Insurance and self-insurance costs are addressed in this chapter, while cost-pass through arrangements are discussed in Chapter 12. Given the magnitude of its insurance premiums and the volatile nature of self-insurance losses, AusNet Services has forecast its insurance and self-insurance premium costs on a bottom-up basis to produce the most accurate forecast of total opex.

This approach is consistent with AusNet Services' current transmission determination, where the AER approved bottom-up forecasts of insurance and self-insurance costs developed by Aon. In making its decision on insurance, the AER found that "Aon's assumptions regarding exposure and premium rates for each category of insurance were reasonable."[30]

Forecast insurance and self-insurance costs for the forthcoming regulatory control period have again been derived from analysis conducted by Aon. This includes Aon's recommendation on

[30] AER (2014) *SP AusNet transmission determination – final decision: Part 3 – confidential appendices*, January 2014, p.3

the most appropriate insurance premium allocation methodology to ensure an appropriate amount of insurance costs are allocated to AusNet Services' transmission network business, given the fact that much of the risk faced by AusNet Services' business (e.g. bushfire risk) lies within its distribution network.

Aon's insurance and self-insurance reports can be found at Appendix 5A and 5B, respectively.

### 5.4.10 Group 3 prescribed assets

Pursuant to NER 11.6.21(c), the value of non-contestable network and connection augmentation assets that came into existence in the current regulatory control period will be rolled into AusNet Services' Regulatory Asset Base (RAB) at the commencement of the forthcoming regulatory control period. Information on these assets is derived from AusNet Services' fixed asset register and relevant connection agreements.

The opex associated with the relevant assets has been forecast in accordance with the methodology approved by the AER in its current determination. Because this opex is already being charged to customers outside the revenue cap, the inclusion of these costs in the opex forecast is equivalent to changing the categorisation of existing charges from outside to inside the revenue cap.

A full list of projects to be rolled into the RAB is provided in Appendix 5C.

### 5.4.11 Step changes

In developing a forecast of opex attributable to step changes, AusNet Services has developed bottom-up cost estimates based on actual costs incurred for similar projects or activities, or market rates where applicable. AusNet Services' proposed step changes are discussed further in section 5.10 and Attachment 5D.

### 5.4.12 Opex associated with the service target performance incentive scheme

AusNet Services' opex forecast will be sufficient to maintain – but not improve – current service performance in dollar terms. That is, the current level of reliability risk, monetised using the value of customer reliability, will be maintained over the forthcoming period. This approach is consistent with AusNet Services' network planning framework and the design of the AER's Service Target Performance Incentive Scheme (STPIS). AusNet Services' proposed application of the STPIS is set out in Chapter 7.

## 5.5 Historic Costs and Variations in Forecast Opex

### 5.5.1 Historic opex

NER S6A.1.2(8) requires a Revenue Proposal to contain actual opex for the first three regulatory years of the current regulatory control period, and expected opex for the last two regulatory years of that regulatory control period, categorised in the same way as the opex forecast.

At the time of the submission of this Revenue Proposal, actual opex is available only for the first year of the current period because of its (shorter) three-year length than the regulatory period length of five years contemplated by the Rules. Actual opex has therefore been provided for the final two years of the previous period, along with estimated opex for the last two years of the current period, categorised in the same way as the opex forecast. AusNet Services considers that this information satisfies the requirements of S6A1.2(8) given the circumstances.

The table below shows actual and estimated opex from 2012-13 to 2016-17, and forecast opex for the forthcoming period, categorised on a consistent basis.

**Table 5.4: Actual and estimated opex ($m, real 2016-17)**

| | Previous period | | Current period | | | Forthcoming period | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 |
| | A | A | A | E | E | F | F | F | F | F |
| Controllable opex | 82.3 | 85.4 | 88.5 | 90.3 | 92.7 | 104.1 | 99.3 | 100.8 | 103.1 | 104.4 |
| AIS Rebates | 2.2 | 3.4 | 2.5 | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| NCC project costs | n/a | n/a | 0.3 | n/a | 0.0 | n/a | n/a | n/a | n/a | n/a |
| Easement land tax | 109.9 | 111.9 | 109.6 | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 |
| Self-insurance | 2.7 | 2.7 | 1.8 | 1.8 | 1.8 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| Movements in provisions | 1.4 | 1.5 | -0.1 | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| **Total** | **198.5** | **204.9** | **202.6** | **207.4** | **209.8** | **222.1** | **217.3** | **218.8** | **221.1** | **222.4** |

*Notes: A = Actual, E = Estimated, F = Forecast; AIS Rebates and movements in provisions have not been forecast.*

### 5.5.2 Variations in forecast opex from historic opex

NER S6A.1.2(7) requires a Revenue Proposal to contain an explanation of any significant variations in forecast opex from historic opex. The key drivers of the forecast increase in opex for the forthcoming regulatory control period are:

- Real increases in labour costs;
- An increase in insurance costs reflecting current market conditions;
- An increase associated with the rolling-in of non-contestable prescribed service assets constructed in the current regulatory control period; and
- A number of step changes relating to opex-capex trade-offs, new or changed regulatory obligations and the decommissioning of assets.

The reasons for these variations are explained in the remainder of this chapter.

## 5.6 Efficient Base Year Opex

AusNet Services employs a base year forecasting methodology for controllable opex. Under this approach, AusNet Services uses its latest audited year of actual opex data as a base from which future recurrent opex is projected. The reasonableness of this forecasting methodology generally depends on the base year opex being efficient and the removal of costs that have been forecast separately and/or are considered one-off. This section discusses:

- The selection of the base year;
- Adjustments to the base year to establish recurrent costs;
- Treatment of debt raising costs; and
- Benchmarking that demonstrates the efficiency of AusNet Services' base year.

### 5.6.1 Selection of base year

For the purposes of this opex proposal, 2014-15 has been used as the base year. AusNet Services considers 2014-15 to be an efficient base year because:

- At the time of submission, 2014-15 is the most recent full year of available operational costs, and contains data that has been independently verified and audited;
- The operating environment conditions experienced during 2014-15 are considered representative of those prevailing in the current and forthcoming regulatory control periods (e.g. weather conditions, regulatory and legislative environment); and

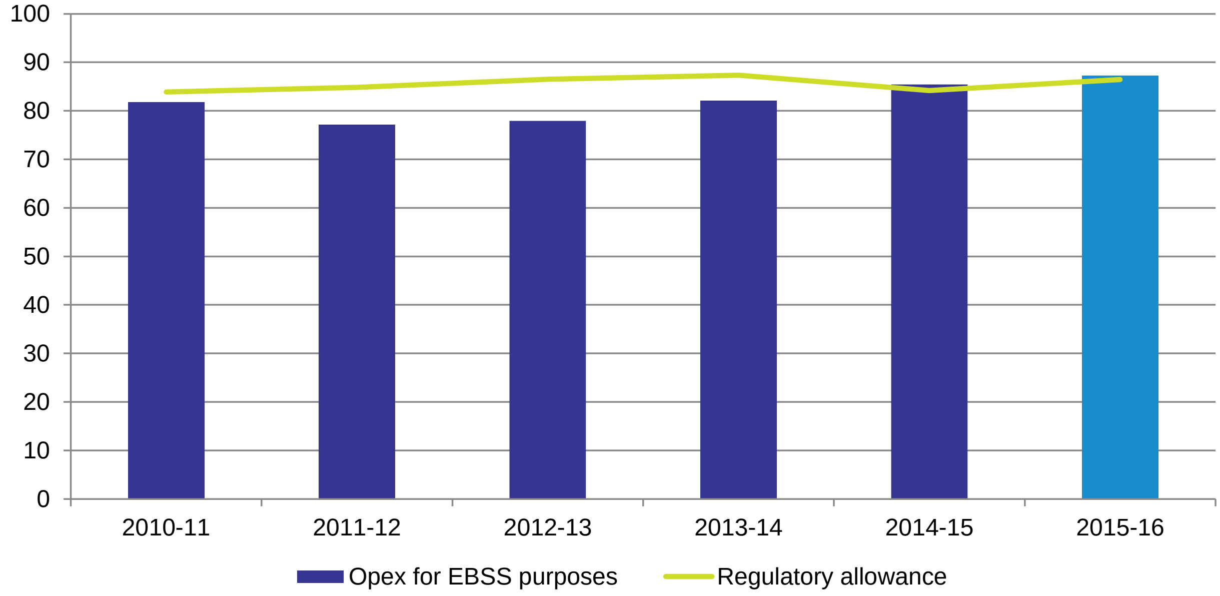
- Benchmarking results confirm that AusNet Services has achieved stronger opex productivity improvements to 2014-15 than its peers. This is discussed in further detail below.

For these reasons, AusNet Services considers that 2014-15 opex is a suitable base from which to forecast opex for the forthcoming regulatory period.

AusNet Services notes that the penultimate year of the regulatory control period is normally used as the base year for forecasting opex for the next regulatory control period. This is because the efficiency incentives provided by the regulatory framework encourage businesses to make continuous opex savings such that the most recent year of expenditure (after adjustment for one-off expenditure items) is usually taken to represent the most efficient level of expenditure.

At the time of preparing this Revenue Proposal, actual 2015-16 expenditure is not available, although forecast 2015-16 opex is expected to be similar to that incurred in 2014-15. This is demonstrated by the below figure, which shows actual opex for the purposes of the Efficiency Benefits Sharing Scheme (EBSS) from 2010-11 to 2014-15, and AusNet Services' estimated 2015-16 opex determined in accordance with the opex forecasting methodology.

**Figure 5.4: Actual and expected opex for EBSS purposes ($m, real 2016-17)**




*Note: Excludes costs determined by the AER as non-controllable for the EBSS applying during the current regulatory control period (i.e. self-insurance, easement land tax, AIS rebates, debt raising costs, NCIPAP project costs and movements in provisions).*

The figure above shows AusNet Services has consistently outperformed or met its regulatory allowances, in response to the efficiency incentives provided by the regulatory regime. The figure also demonstrates a large degree of consistency between opex in 2013-14 and 2014-15, which is prima facie evidence that 2014-15 opex is representative of efficient costs. Given there is not expected to be any material difference between opex in 2014-15 and 2015-16, AusNet Services has adopted 2014-15 as the base year.

AusNet Services will review the choice of base year following the completion of the 2015-16 year.

### 5.6.2 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 2014-15 opex. These adjustments are:

- Removal of movements in provisions to align with the AER's treatment of provisions in its recent transmission determinations;
- Removal of insurance costs, which have been forecast using a category-specific approach to improve the accuracy of the total opex forecast (discussed further in section 5.8); and
- Removal of non-controllable costs (i.e. easement land tax and self-insurance costs).

By making these adjustments, AusNet Services' forecasting approach ensures that the base year opex reflects the efficient recurrent, controllable costs, excluding those cost elements that are outside the company's control. This approach is consistent with the AER's current transmission determination for AusNet Services, and complies with the operating expenditure criteria in the NER, which require that the opex forecast reflect, among other things, the efficient costs of achieving the operating expenditure objectives.

The following table sets outs the process for adjusting 2014-15 actual opex to derive base year opex. Base year opex accounts for $418.6m, or 38%, of the total opex forecast.

**Table 5.5: Derivation of base year opex ($m, real 2016-17)**

| | |
|---|---|
| Actual 2014-15 opex | 199.8 |
| ***Less*** | |
| Easement land tax | -109.6 |
| Self-insurance costs | -1.8 |
| Movements in provisions | 0.1 |
| Insurance costs | -4.8 |
| **Total** | **83.7** |

### 5.6.3 Debt raising costs

Debt raising costs principally comprise legal fees and banking fees. AusNet Services proposes to forecast its debt raising costs by rolling forward its actual debt raising costs as part of base year opex. This approach contrasts with the current regulatory control period, where costs have been calculated in accordance with the "benchmark firm" return.

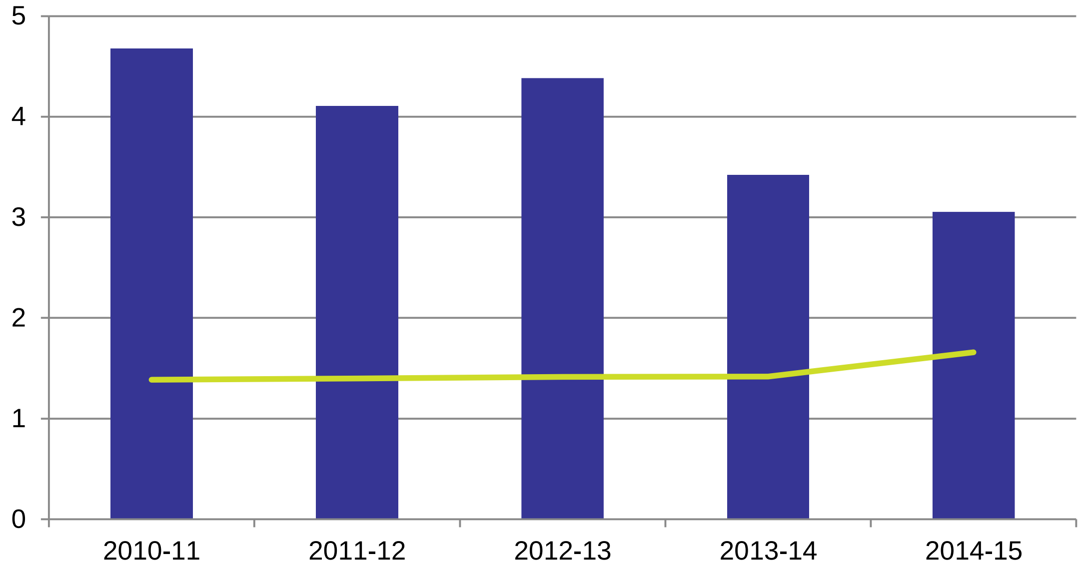
Historically, the AER has applied a benchmark approach to forecast debt raising costs due to a lack of data on businesses' actual debt raising costs. It is submitted that this is not sufficient or reasonable justification for using such an approach and would potentially undermine the attainment of the NEO for individual TNSPs with differing debt and credit rating profiles. Accordingly, AusNet Services considers that a 'revealed cost' approach is preferable because:

- AusNet Services' base year opex, which includes debt raising costs, is efficient, reflecting its response to the incentives embedded in the regulatory framework;
- Debt raising costs are relatively stable from year to year, reflecting the recurrent nature of the activities, and expenses, involved in raising debt each year (see Figure 5.5 below);
- In conjunction with an EBSS, this approach aligns with the AER's preferred approach to forecasting opex.

It is noted that debt raising costs in the base year are substantially lower than in the other years of the current period.

The figure below compares AusNet Services' actual debt raising costs from 2010-11 to 2014-15 with the allowance approved by the AER. During this period, AusNet Services' actual costs of $19.6m (real 2016-17) have significantly exceeded allowances of $7.3m.

**Figure 5.5: Actual debt raising costs against regulatory allowance ($m, real 2016-17)**




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)."*[31]

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.

31 AER, *AusGrid draft decision*, pp. 3 – 171.

This table below shows AusNet Services' forecast debt raising costs of $16.8m, which are included in the base year opex shown in Table 5.2. A detailed breakdown of these costs is available on request if required by the AER.

**Table 5.6: Forecast debt raising costs ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Debt raising costs | 3.2 | 3.3 | 3.4 | 3.4 | 3.5 | **16.8** |

### 5.6.4 Opex benchmarking

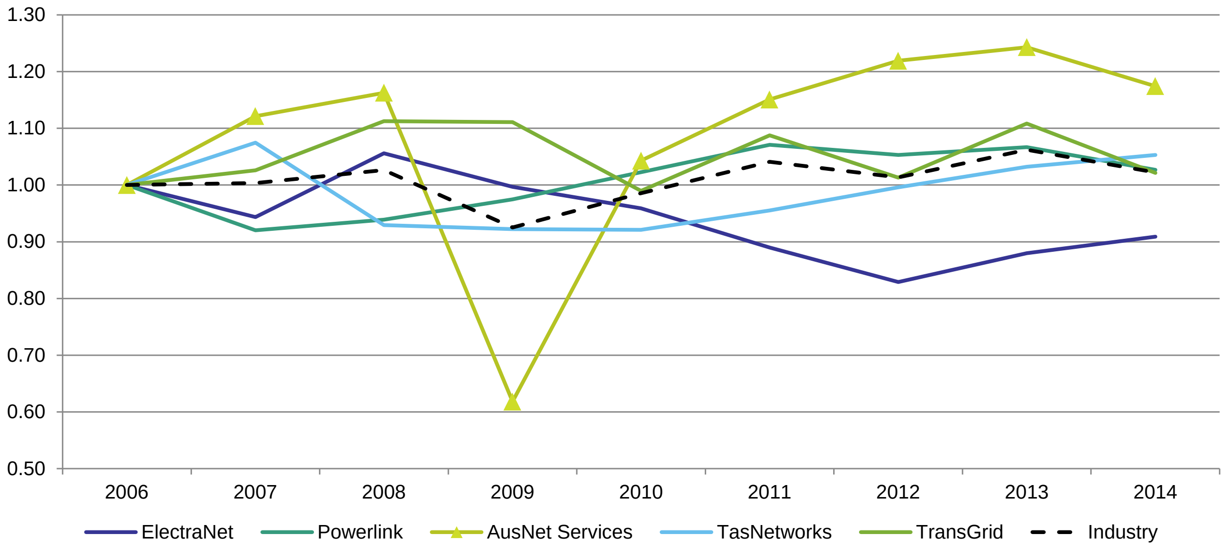
#### *Economic benchmarking*

AusNet Services' opex productivity performance in relation to the transmission services it provides compares relatively well against other TNSPs in the NEM. In particular, the analysis conducted by the AER's consultant, Economic Insights concluded that:

> *"AusNet Transmission can be seen to have had the highest opex PFP growth over the 8 year period, despite a significant drop in 2009 caused by an explosive failure at South Morang Terminal Station and a conductor drop on the Bendigo to Ballarat Line. AusNet Transmission achieved an opex PFP average annual growth rate of 3.2 per cent over the 8–year period."*[32]

AusNet Services engaged Huegin to calculate historical opex partial factor productivity (OPFP) using the same methodology in Economic Insights' report and including input and output data for 2014 (discussed further in section 5.7.4). The figure below shows the results of Huegin's analysis.

**Figure 5.6: TNSP opex partial factor productivity (OPFP) index, 2006-2013**




*Source: Huegin Consulting*

Huegin's analysis of OPFP demonstrates that AusNet Services has delivered higher rates of opex productivity growth than its peers and well above the industry average.[33] The productivity

32 Economic Insights (2014) *Economic Benchmarking Assessment of Operating Expenditure for NSW and Tasmanian Electricity TNSPs, Report for AER*, 10 November 2014, p.16.

33 The sharp drop in productivity in 2009 was caused by a number of major incidents, including an explosive failure at South Morang Terminal Station, which significantly reduced AusNet Services' output, and thus productivity, that year.

improvement achieved by AusNet Services has been despite opex increases caused by changes in regulatory obligations and an ageing asset profile.

Economic Insights explains that an adjustment for step changes further improves historic performance, with AusNet Services achieving substantially better rates of improvement than the industry average:

> *"The effect of including the two additional estimated step changes is to increase ElectraNet's average annual opex PFP growth rate from –1.8 per cent to –1.3 per cent and to increase AusNet's growth rate from 3.2 per cent to 3.6 per cent. The effect on the TNSP industry average annual opex PFP growth rate is a further increase to over 1.4 per cent."*[34]

AusNet Services' strong track record of outperforming the industry average with respect to productivity gains is prima facie evidence that its base year opex is efficient. In particular, it demonstrates that substantial historical productivity improvements are embedded in 2014-15 opex, which has been used to derive base opex.

### *Partial performance indicators*

The efficiency improvements outlined above are supported by AusNet Services' strong performance across a range of 'bottom-up' partial performance indicators (PPIs) that compare individual opex categories between TNSPs 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."*[35]

As noted by the AER, differences in cost allocation to opex categories between TNSPs can contribute to differences in category analysis metrics. However, strong performance across a range of metrics is indicative of an efficient level of total opex.

The figure below shows that since 2009, AusNet Services has consistently incurred the lowest opex per customer[36] of NEM TNSPs.

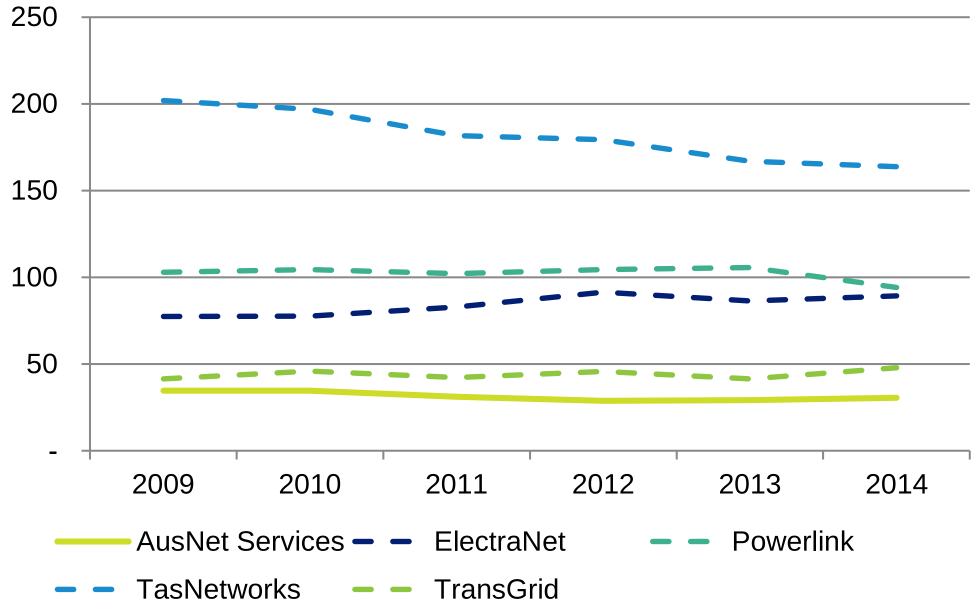
---

34 Ibid, p. 20.

35 AER (2014) *Ausgrid draft decision – Attachment 7: Operating expenditure*, November 2014, p. 77.

36 Customer numbers have been measured as the total number of customer connections for the DNSPs connected to each transmission network. While the AER's economic benchmarking model does not include customer numbers as an output measure, transmission networks are built, maintained and operated to ultimately transport electricity to end-user customers. Accordingly, the number of customers served by each network is considered a relevant driver of operating expenditure and therefore an appropriate variable to normalise total opex levels across TNSPs.

**Figure 5.7: Opex per customer (real 2016-17)**

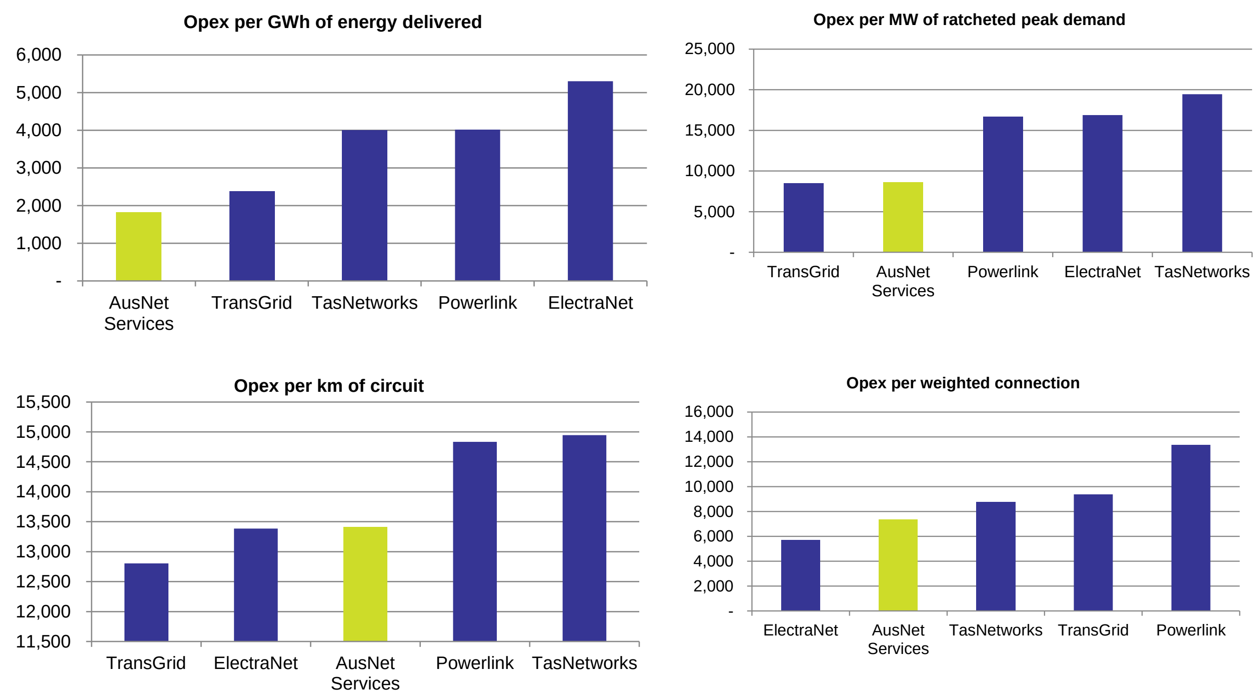



*Source: AER RIN data, Huegin Consulting, AusNet Services*

*Note: Excludes easement land tax for AusNet Services*

The figure below demonstrates that when total opex is normalised using the four output measures used in the AER's economic benchmarking model, AusNet Services benchmarks well against its peers. In particular, AusNet Services' opex is the lowest or second lowest TNSP in the NEM when normalised using energy delivered, ratcheted peak demand and weighted entry and exit connection point.

**Figure 5.8: Opex normalised using AER output growth measures (average 2009-14, real 2016-17)**

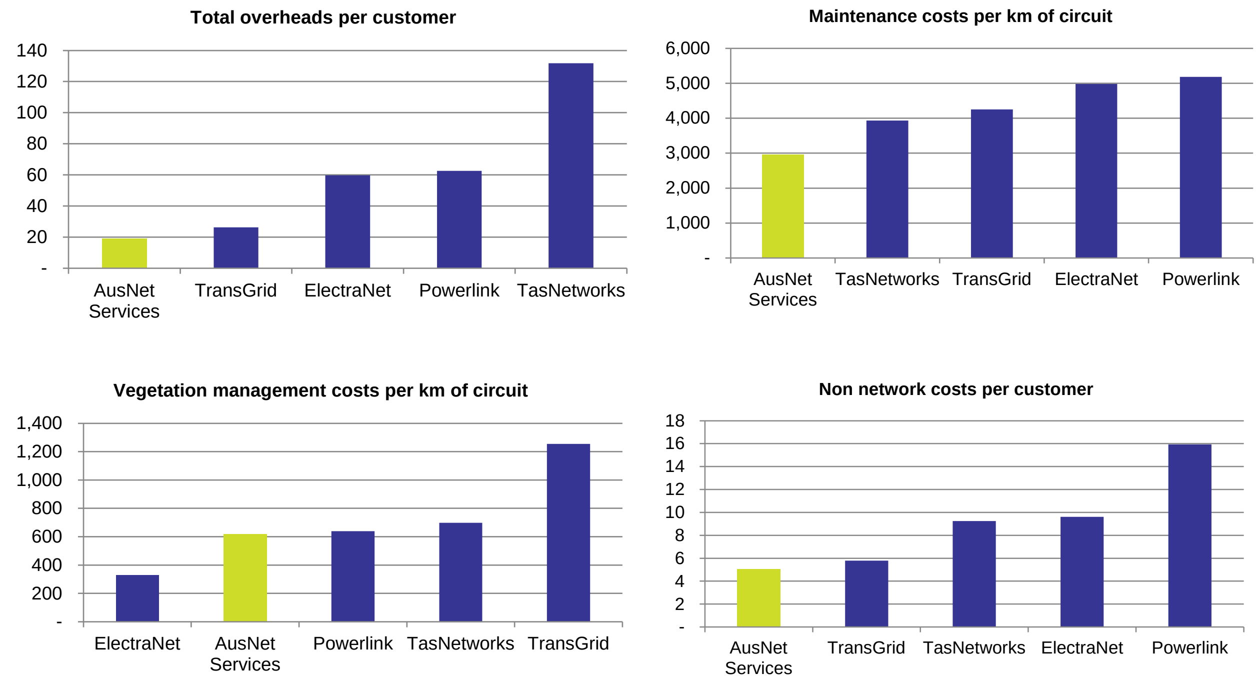



*Source: AER RIN data, Huegin Consulting, AusNet Services*

*Note: Excludes easement land tax for AusNet Services*

The efficiency of AusNet Services' opex is demonstrated further when individual opex categories are compared. The figure below shows average opex from 2009-14 for key opex categories, which have been normalised across TNSPs using what AusNet Services considers to be appropriate cost drivers for each category of opex.

**Figure 5.9: Key partial performance indicators (average 2009-14, real 2016-17)**




*Source: AER RIN data, Huegin Consulting, AusNet Services*

*Note: Excludes easement land tax for AusNet Services*

These indicators demonstrate that AusNet Services' opex benchmarks favourably across a range of measures. In particular, AusNet Services has the lowest overheads, maintenance and non-network costs of all TNSPs in the NEM on a normalised basis. Overheads and maintenance costs accounted for around 80% of AusNet Services' opex from 2009-14.

While these PPIs show relatively high opex efficiency for AusNet Services, it should be emphasised that definitional differences and differences in cost allocation between TNSPs 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.

## 5.7 Rate of Change

### 5.7.1 Overview of approach

The rate of change captures the year on year change in efficient expenditure due to forecast changes in output levels, prices and productivity (such as economies of scale or labour 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*

The table below summarises AusNet Services' proposed rate of change escalators.

**Table 5.7: Forecast rate of change ($m, real 2016-17)**

| Component | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 |
|---|---|---|---|---|---|
| Output growth | 1.78% | 1.50% | 1.50% | 1.50% | 1.50% |
| Real price growth | 0.70% | 0.71% | 0.70% | 0.76% | 0.78% |
| Productivity change | 0.28% | 0.28% | 0.28% | 0.28% | 0.28% |
| **Rate of change** | **2.21%** | **1.94%** | **1.93%** | **1.99%** | **2.01%** |

*Source: AusNet Services; Huegin Consulting*

The output growth parameters have been calculated according to the approach applied by the AER in its final decisions for TransGrid and TasNetworks. Real price growth has been forecast using an average of labour cost forecasts developed by The Centre for International Economics (CIE) and Deloitte Access Economics (DAE). The productivity forecast has been based on long-term, industry average productivity change, as determined by Huegin Consulting using data collected and published by the AER.

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. 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.[37]

The remainder of this section details each component of the rate of change.

### 5.7.2 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."*[38]

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 energy and demand from 2017-18 to 2021-22 is also a proxy for growth in network size, which drives increases in operating and maintenance costs.

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."*[39]

---

[37] NER, clause 6.5.6(c)(3).

[38] AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement*, p. 61.

[39] AER, *Expenditure Forecast Assessment Guideline – Electricity Distribution*, p. 23.

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 recent determinations for other TNSPs where it forecast output growth using an econometric model developed by Economics Insights. The report titled *Economic Benchmarking Assessment of Operating Expenditure for NSW and Tasmanian Electricity TNSPs* explains Economic Insights’ rationale for adopting these cost drivers and weightings.

The AER’s approach used the following outputs:

- Energy throughput (with a weight of 21.4%);
- Ratcheted maximum demand (22.1%);
- Voltage-weighted entry and exit points (27.8%); and
- Circuit length (28.7%).[40]

AusNet Services has adopted the AER’s forecasting method for output growth. In particular, the AER’s output measures adopted are considered reasonable drivers of opex increases over the forthcoming regulatory control period. AusNet Services has developed its forecasts of each measure as follows:

- Energy throughput and ratcheted maximum demand forecasts are based on advice from AEMO, the Victorian transmission network planner;
- The weighted entry and exit connection points forecast is based on average growth between 2006 and 2014 in the number of transmission node identifiers (TNIs), weighted by the voltage of each TNI; and
- No growth has been assumed for circuit length, with the exception of a slight increase in 2017-18 reflecting additional circuit from Ballarat to Moorabool, as advised by AEMO.[41]

When applied to AusNet Services’ forecasts of the output measures, the AER’s approach results in an output growth forecast of $33.7m over the forthcoming regulatory control period, which is equal to 3.1% of the total opex forecast.

**Table 5.8: Proposed output growth ($m, real 2016-17)**

| Output measure | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Energy throughput | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | **n/a** |
| Ratcheted maximum demand | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | **n/a** |
| Weighted entry and exit connections | 3.83% | 3.83% | 3.83% | 3.83% | 3.83% | **n/a** |
| Circuit length | 0.97% | 0.00% | 0.00% | 0.00% | 0.00% | **n/a** |
| **Output growth (%)** | **1.78%** | **1.50%** | **1.50%** | **1.50%** | **1.50%** | **n/a** |
| **Output growth ($)** | **4.1** | **5.4** | **6.7** | **8.1** | **9.4** | **33.7** |

40 AER (2014) *Draft decision: TransGrid transmission determination 2015-18 | Attachment 7 – Operating expenditure 7*, November 2014, p. 75

41 Because the additional circuit is being added to an existing transmission line, the route line length forecast for the next period (as provided in the reset RIN) is flat.

### 5.7.3 Real price growth

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."*[42]

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 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 asset maintenance, as well as consultants.

***Labour and non-labour weightings***

Internal and external labour collectively account for a significant proportion of base opex (44 per cent and 34 per cent, respectively). It is noted that in the AER's recent decisions for other NSPs, the AER assumed that total labour costs accounted for 62 per cent of each network's base year opex. The AER has explained this approach is as follows:

> *"We adopted a 62 per cent weighting for labour and 38 per cent for non-labour in forecasting price changes. The labour component is forecast based on the EGWWS industry and the non-labour component is forecast based on the consumer price index (CPI).*
>
> *These weightings are broadly consistent with Economic Insight's benchmarking analysis which applied weight of 62 per cent EGWWS wage price index (WPI) for labour and 38 per cent for five producer price indexes (PPIs) for non-labour. The five PPI's cover business, computing, secretarial, legal and accounting, and public relations services."*[43]

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, and which better achieves the NEO for each TNSP.[44] In responding to the incentives embedded in the regulatory framework, AusNet Services, as an efficient TNSP, 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 implicitly (and incorrectly) assumes that these regulatory incentives are not effective.

As demonstrated in section 5.6, 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 internal consistency with the AER's preferred base-step-trend approach using revealed costs.

***Labour cost forecasts***

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

---

42 AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement*, p. 62.

43 AER (2014) *Draft decision: TransGrid transmission determination 2015-18 | Attachment 7 – Operating expenditure 7*, November 2014, pp.70 – 71.

44 AER, *Expenditure Forecast Assessment Guideline – Explanatory Statement*, p. 61.

the cost of each type of labour reflect the market dynamics of different labour market segments and therefore require separate forecasts.

In forecasting internal and external labour costs, 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's report, which is included at Appendix 5E, sets out the assumptions underpinning its forecasts.

To derive labour escalators, CIE's forecasts were then averaged with the real EGWWS and Construction WPI forecasts presented in Deloitte Access Economics' (DAE) report for the AER, entitled *Forecast growth in labour costs in NEM regions of Australia*.[45] This methodology, which recognises that the average of two forecasts is likely to be more accurate than an individual forecast, aligns with the AER's approach in its recent reviews for other NSPs.

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. Labour productivity has instead been captured in AusNet Services' proposed productivity change parameter (discussed further in section 5.7.4). This approach aligns with the AER's preferred approach to forecasting productivity in the rate of change.

The following table sets out AusNet Services' proposed real labour escalators and cost increases for the forthcoming regulatory control period. AusNet Services' forecast labour cost increases account for $13m over the forthcoming regulatory control period, which is equal to 1.2% of the total opex forecast.

**Table 5.9: Forecast labour escalators and cost increases ($m, real 2016-17)**

| Labour category | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Internal labour (%) | 0.81% | 0.81% | 0.83% | 0.90% | 0.91% | **n/a** |
| External labour (%) | 1.04% | 1.04% | 1.01% | 1.09% | 1.12% | **n/a** |
| Internal labour ($) | 0.8 | 1.1 | 1.4 | 1.8 | 2.2 | **7.3** |
| External labour ($) | 0.6 | 0.9 | 1.1 | 1.4 | 1.7 | **5.7** |
| **Total labour ($)** | **1.4** | **2.0** | **2.6** | **3.2** | **3.9** | **13.0** |

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."*[46]

---

45 DAE's National WPI forecasts were used in the absence of DAE Victoria specific forecasts. DAE's forecast WPI growth in 2019-20 was assumed for 2020-21 and 2021-22 in the absence of forecasts for these years.

46 BIS Shrapnel, *Real Labour Forecasts to 2016/17 – Australia and Victoria*, November 2012, p. 23.

However, AusNet Services acknowledges that adjusting EGWWS forecasts to remove this bias is difficult in practice and in its recent determinations for other NSPs the AER has continued to use EGWWS. Despite the shortcomings of the EGWWS measure, AusNet Services accepts EGWWS as a proxy for the composition of its internal labour for 2017-22.

AusNet Services' external labour costs have been escalated using the Construction WPI index because most contractor labour in transmission undertakes construction-like work which is more suitably classified to the construction sector. This is particularly the case in major terminal station rebuilds which often involve significant general labour, project management and civil engineering resources, drawing upon labour from the construction market. The Construction WPI therefore 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.

The AER has previously rejected the use of the Construction index for external labour costs. In its draft decision for the NSW DNSPs, 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."*[47]

The AER's position does not accurately reflect the views of the ABS as set out below:

> *"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]."*[48]

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.

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 it is appropriate that the AER accepts this approach.

### *Non-labour costs*

The non-labour component of AusNet Services' operating expenditure includes a wide range of costs and materials ranging from field costs (protective clothing, minor tools, fuel and oil, fees and tolls, etc) to back-office costs (building leases, marketing costs, postage, freight and transport, cleaning, hospitality, office supplies, etc). These costs account for 22% of base opex.

Given the general nature of its non-labour costs, AusNet Services considers it is appropriate to assume that these costs will increase at the same rate as CPI and has therefore not applied a real escalator to non-labour components in forecasting opex.

---

47 AER, *AusGrid draft decision – Attachment 7: Operating Expenditure*, p. 147.

48 http://www.abs.gov.au/ausstats/abs@.nsf/0/00C5F12D56E7B1B0CA25711F00146DA8?opendocument.

### 5.7.4 Productivity change

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 TNSP. This level of productivity may differ from the productivity improvements that individual TNSPs may be able to achieve through implementing efficiency saving initiatives, which the EBSS is intended to encourage.

AusNet Services understands that the AER's intent is to account for any 'catch up' efficiency required by an individual TNSP through a base year adjustment, and to account for forecast shift in the 'efficiency frontier' through the productivity assumption in the rate of change.

Having established in section 5.6 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.

AusNet Services notes that the AER has included a productivity factor in its recent transmission decision for TransGrid, as explained below:

> *"We consider using the average industry productivity from 2006–13 reflects the forecast productivity an efficient transmission service provider would be expected to achieve. As noted in our draft decision our forecast productivity assumes a business as usual scenario and there will be no significant structural change in the electricity transmission industry for the 2014–18 period relative to 2006–13."*[49]

AusNet Services considers that a historical average of industry-wide productivity gains represents a reasonable proxy for the future productivity improvements an efficient TNSP would be expected to achieve in the future. Because of the time elapsed since the AER's TransGrid decision, and the potential for changes during that time to impact historical productivity improvements, AusNet Services engaged Huegin Consulting to calculate average industry productivity using the most up to date information available. This approach is consistent with the AER's preference for using up to date information where possible in making regulatory decisions, as expressed in its recent Ergon Energy determination:

> *"We have indicated in previous decisions and in defending those decisions our preference to use up to date information where possible. The Tribunal has endorsed this approach and indicated a similar preference".*[50]

Huegin's analysis of historical industry productivity shows that over the period 2006 to 2014, average annual industry productivity change was 0.28%. This is lower than the industry average of 0.86% used by the AER in its determinations for TransGrid and TasNetworks because it has been updated to include inputs and outputs from 2014. According to Huegin:

> *"We note that this growth rate (0.28%) is below the opex partial factor productivity growth rate used by the AER for TransGrid's Revenue Determination (0.86%) in 2014. This reduction is the result of industry output growth in 2014 being relatively flat whilst industry opex has increased (industry opex increased from $391.7M in 2013 to $425.6M in 2014). In order to provide the best indication of current opex productivity performance we believe it is necessary to include the most recent data available."*[51]

Huegin's analysis has been provided at Appendix 5F.

---

[49] AER, *TransGrid transmission determination 2015−16 to 2017−18, Final Decision, Attachment 7*, pp. 7 – 89.

[50] AER (2015) *Ergon Energy preliminary determination 2015–20 | Attachment 7 – Operating expenditure*, April 2015, p. 85.

[51] Huegin (2015) *AusNet Services opex productivity growth (2006-14)*, July 2015, p. 5.

The following table sets out AusNet Services' forecast productivity change for the forthcoming regulatory control period. These productivity improvements reduce forecast opex by $5.8m over the forthcoming regulatory control period, a reduction equal to 0.5% of the total opex forecast.

**Table 5.10: Forecast productivity change ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Productivity change (%) | 0.28% | 0.28% | 0.28% | 0.28% | 0.28% | |
| Productivity change ($) | -0.7 | -0.9 | -1.2 | -1.4 | -1.6 | **-5.8** |

## 5.8 Insurance Costs

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 an opportunity to mitigate low likelihood and high severity risks (discussed in Chapter 12). However, for some risks, self-insurance is the most appropriate risk mitigation mechanism (discussed in section 5.12.1).

Self-insurance, coupled with reasonable traditional insurance and the use of a captive insurer, demonstrate that an NSP has taken as many reasonable measures as possible to address and mitigate risk. This means that only in extremely rare circumstances in which the NSP's assets cause loss and damage to an extent that exceeds both insurance and self-insurance would an NSP contemplate applying to the AER for pass-through of those excess costs to customers. A balance of risk and cost demonstrates that this is a more cost-effective approach from the consumer's view, when compared with under-insurance (which may lead to payment of significant costs as a result of an insurance event) on the one hand, and the payment of excessive premiums, on the other hand.

To develop forecasts of its insurance costs, AusNet Services engaged Aon, an appropriately qualified actuarial consultancy. Aon has extensive experience forecasting insurance costs for electricity transmission businesses.

Aon, whose report can be found at Appendix 5A, provided insurance forecasts for:

- Liability;
- Property;
- Motor vehicles;
- Minor risk classes (e.g. Directors & Officers insurance); and
- A new cyber liability policy.

Aon's approach to forecasting the costs of these policies involves the following steps:

- Forecasting insurance premiums for the entire AusNet Services business, which comprises its electricity distribution and transmission networks, its gas distribution network and its unregulated business;
- Allocating a portion of total insurance costs to the unregulated business based on the ratio of regulated-to-unregulated assets; and
- Allocating a portion of the remaining regulated premiums to the transmission network based on the most appropriate allocator for each policy (e.g. asset values for the property policy) to ensure the costs funded by transmission network users are commensurate with the risk profile of the transmission network.

In developing its forecasts of liability and property insurance costs (which account for 87% of forecast insurance premiums) Aon has assumed:

- 10% (nominal) increases in 2017 and 2018 for liability followed by 5% annual increases, based on a prudent estimate of possible premium increases (which Aon estimated at up to 20%) driven by a number of factors, including the uncompetitive market for Bushfire Liability insurance and resultant lack of available cost-effective capacity; and[52]
- 4% annual increases for property, based on forecast increases in exposure (as measured by asset values). Aon considered that "growth of between 4.0% and 10% per annum would not be unreasonable".[53]

It is noted that the liability insurance premium includes a portion underwritten by AusNet Services' captive insurance company, AusNet Services Insurance Limited.[54] 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.[55]

The following table sets out AusNet Services' proposed insurance costs, which reflects the current allocation of insurance costs between AusNet Services' distribution and transmission networks. AusNet Services' forecast insurance costs account for $28.9m over the forthcoming regulatory control period, which is equal to 2.6% of total opex.

**Table 5.11: Forecast insurance premium costs ($m, real 2016-17)**

| Insurance class | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Liability | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 | **9.0** |
| Property | 3.2 | 3.3 | 3.3 | 3.4 | 3.4 | **16.6** |
| Motor | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | **1.0** |
| Other | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | **2.1** |
| New Policies | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.3** |
| **Total** | **5.5** | **5.7** | **5.8** | **5.9** | **6.0** | **28.9** |

*Source: Aon, Insurance Premium Forecast – AusNet Services Transmission, October 2015*

The Aon forecasts represent category specific forecasts of 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.

However, the AER has changed its approach to forecasting insurance costs (and self-insurance costs, as discussed in section 5.12.1 of this chapter) in its recent determinations for other NSPs:

> *"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."*[56]

---

52 Aon, *AusNet Services Transmission Insurance Premium Forecast*, p. 10.

53 Aon, *AusNet Services Transmission Insurance Premium Forecast*, p. 14.

54 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.

55 Aon, *Insurance Premium Forecast – AusNet Services Transmission*, April 2015, p. 9.

56 AER, *draft decision: TransGrid transmission determination 2015-18 – Attachment 7 – Operating expenditure*, p. 26.

In light of Aon's projections of future cost increases, AusNet Services is of the view that the AER's approach of rolling forward base year insurance premiums at the rate of change should not be applied to AusNet Services.

Insurance costs are a significant component of opex, accounting for approximately $29m, or around 6% of AusNet Services' controllable opex forecast over the 2017-22 regulatory period. The AER's approach implies that a similarly large amount of opex is rising slowly or declining at a rate that sufficiently offsets insurance cost increases. Given the quantum of its insurance premiums relative to other costs, 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 TNSP is constrained in its ability to insure for events that may affect the safety and security of consumers, and of its network.

In relation to the liability premium forecast, it is notable that Aon's forecast assumes a modest annual increase in the premium rate (the midpoint of the range of possible increases) given the factors that are expected to drive premium increases in the forthcoming period.

With respect to the AER's concerns with the use of bottom-up approaches 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. The use of revealed costs as a starting point for forecast insurance costs is expected to provide a level of certainty that AusNet Services' insurance forecasts reasonably reflect a realistic expectation of its future input costs. Furthermore, in its determination for the current regulatory period, the AER approved a bottom-up forecast of insurance developed by Aon using the same methodology.

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."[57] By doing so, the AER used a category specific method for these costs, but a revealed-cost approach for other opex categories. 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 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 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.

## 5.9 Roll in of Group 3 Assets

The regulatory framework provides for the RAB to be increased by the value of constructed assets during the previous regulatory control period used to provide prescribed transmission services, adjusted for outturn inflation and depreciation. Accordingly, at each regulatory review, AusNet Services' RAB is increased by the value of prescribed transmission assets constructed during the previous regulatory control period. The periodic inclusion of newly constructed assets is consistent with previous regulatory determinations.

The newly constructed assets are AEMO / DNSP-directed network augmentations and connection works (also known as Group 3, or excluded prescribed assets). A full list of projects to be included in the RAB for this determination is provided in Appendix 5C. The value of the

57 Ibid, p. 28.

assets being rolled into the RAB on 1 April 2017 in accordance with NER 11.6.21(c) is $99m (real 2016-17).[58]

The periodic inclusion of Group 3 assets in the RAB requires that an appropriate opex allowance must be provided in the building block calculation. To account for the increase in assets, it is appropriate to increase opex to reflect the additional assets that must be operated, maintained, monitored and condition assessed.

To ensure the opex forecast reflects efficient costs, scale factors are required to take economies of scale into account, which reflect the relationship between an increase in the asset base and the impact on different categories of opex. In forecasting additional opex required to service these assets, AusNet Services has applied the approach set out in the table below, which is consistent with the AER's determination for the current regulatory control period.

**Table 5.12: Opex scale factors applied for Group 3 roll in ($m, nominal)**

| Cost category | Scale factor | Opex ($) | Opex (%) |
|---|---|---|---|
| Routine maintenance | 95.00% | 34.4 | 41.85% |
| Routine maintenance support | 25.00% | 7.4 | 8.97% |
| Corporate support | 10.00% | 29.0 | 35.26% |
| Taxes and leases | 100.00% | 5.2 | 6.34% |
| Insurance & self-insurance | 100.00% | 6.2 | 7.58% |
| **Weighted scale factor / total** | **59.45%** | **82.2** | **100.00%** |

The weighted scale factor of 59.45% has been multiplied by the net change in the ratio of regulated to unregulated assets between 1 April 2014 and 1 April 2017 – a 4.03% increase – to determine the opex impact of the roll in of Group 3 assets – a 2.39% increase per annum. This is consistent with the opex adjustment for Group 3 assets approved by the AER for the current transmission determination.

The table below shows AusNet Services' forecast opex of $10m to account for the roll in of Group 3 assets, which accounts for 0.9% of the total opex forecast.

**Table 5.13: Forecast opex impact of Group 3 assets ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Weighted scale factor | 59.45% | 59.45% | 59.45% | 59.45% | 59.45% | **n/a** |
| Opex impact (%) | 2.39% | 2.39% | 2.39% | 2.39% | 2.39% | **n/a** |
| Opex impact ($) | **2.0** | **2.0** | **2.0** | **2.0** | **2.0** | **10.0** |

## 5.10 Step Changes

The Explanatory Statement to the Expenditure Forecasting Assessment Guideline sets out the AER's approach to assessing step changes. The AER's approach is summarised as follows:

> *"We are required to determine capex and opex forecasts that reasonably reflect the efficient costs a prudent operator would require to achieve the expenditure objectives. The expenditure objectives include compliance with regulatory obligations or requirements.*

58 Includes projects completed and in service before December 2014. AusNet Services may update the project list for more recent projects in a supplementary submission at the time of the Draft Decision.

*Regulatory obligations or requirements may change over time, so a NSP may face a step up or down in the expenditure it requires to comply with its obligations.*

*Another important consideration is the impact of the forecast capital program on opex (and vice versa), since there is a degree of substitutability between capex and opex. A NSP may choose to bring forward the replacement of certain assets (compared to its previous practice) and avoid maintenance expenditure, for example. Such an approach may be prudent and efficient.*

*Our likely approach is to separately identify and assess the prudence and efficiency of any forecast cost increases associated with new regulatory obligations and capex/opex trade-offs. We may use several techniques to do this, including examining the economic justification for the investment or expenditure decisions and technical expert review of the inputs into this analysis."*[59]

Consistent with the AER's approach to assessing opex step changes, which provides opex additional to base costs for (1) new or changed regulatory obligations that must be met and (2) capex / opex trade-offs, AusNet Services is forecasting step changes in relation to:

- New or changed regulatory obligations, including:
  - Establishment of IT security team;
  - New emergency response arrangements;
- Capex / opex trade-offs, including:
  - Smart Aerial Image Processing (SAIP) roll out; and
  - WMTS mobile switchboard.

AusNet Services also intends to remove from service a number of transmission assets during the forthcoming regulatory control period. Because carrying out substantial decommissioning works is not reflected in AusNet Services base costs, one-off, non-recurrent step change opex has been forecast to fund the decommissioning of:

- Synchronous condensers (SCOs) at the Fishermans Bend (FBTS), Brooklyn (BLTS) and Templestowe Terminal Stations (TSTS), which AusNet Services is proposing to retire subject to advice from AEMO; and
- Transmission assets at Morwell Power Station (MPS) that will be decommissioned due to the closure of MPS.

The table below shows forecast opex for the above step changes. Step change opex of $13.5m accounts for 1.2% of the total opex forecast.

**Table 5.14: Forecast opex attributable to step changes ($m, real 2016-17)**

| Step change | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Establishment of IT security team | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | **3.3** |
| New emergency response arrangements | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | **1.0** |
| SAIP roll out | 0.3 | 0.3 | 0.1 | 0.1 | 0.1 | **0.9** |
| WMTS mobile switchboard | 0.7 | 0.3 | 0.3 | 0.7 | 0.1 | **2.0** |
| Synchronous condenser decommissioning | 4.3 | 0.0 | 0.0 | 0.0 | 0.0 | **4.3** |

59 AER (2013) *EFA Guideline Explanatory Statement*, November 2013, p. 51.

| Step change | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Morwell Power Station decommissioning | 1.9 | 0.0 | 0.0 | 0.0 | 0.0 | **1.9** |
| **Total** | **8.2** | **1.5** | **1.2** | **1.6** | **1.0** | **13.5** |

In identifying step changes for the forthcoming regulatory control period, AusNet Services has taken the opex criteria into account. 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.

The remainder of this section sets out AusNet Services' justification for each of the above step changes. Additional information and analysis on the proposed step changes, including a description of how they comply with the opex criteria, is contained in Appendix 5D.

### 5.10.1 New or changed regulatory obligations

The AER has recognised that where new or changed regulatory obligations result in additional opex requirements that are not reflected in base opex, or in historical productivity change where this is used to forecast productivity, step changes may be required. However, the AER has acknowledged that it is difficult to determine the impact of past regulatory change on historical expenditure. This information would be required to assess the extent to which future opex increases caused by regulatory change are compensated by the productivity forecast (where this is based on historical productivity). Accordingly, the AER has stated:

> *"Where a service provider can demonstrate that its proposed forecast includes efficient costs due to a changed regulatory obligation we will consider whether the additional costs are accounted for in the productivity growth on a case by case basis."*[60]

AusNet Services has identified a number of step changes in response to regulatory change that it considers are not reflected in the historical productivity growth discussed in section 5.7.4. This is because the proposed step changes are driven by changes in regulatory obligations or requirements in excess of the historic trend in cost increases caused by such changes.

#### *Establishment of IT security team*

The risk of cyber-security attacks has been steadily growing in recent years on a global scale. The consequences of these threats are especially severe for critical infrastructure providers, such as electricity distribution and transmission networks. AusNet Services transmission network has been identified as national critical infrastructure by the Australian Attorney General's department.

A recent PricewaterhouseCooper survey on cyber risks that involved more than 9,700 security, IT, and business executives found that:

> *"The total number of security incidents detected by respondents climbed to 42.8 million this year, an increase of 48% over 2013. That's the equivalent of 117,339 incoming attacks per day, every day. Taking a longer view, our survey data shows that the compound annual growth rate (CAGR) of detected security incidents has increased 66% year-over-year since 2009."*[61]

60 AER (2015) *TransGrid transmission determination 2015–18, Final decision: Attachment 7 – Operating expenditure*, April 2015, p. 47.

61 PwC (2014) *Managing cyber risks in an interconnected world – Key findings from The Global State of Information Security Survey 2015*, September 2014, p. 7.

In March 2015, the Australian Securities and Investments Commission's (ASIC) published its Cyber resilience: Health Check report, recommending a cyber-security framework for ASX-listed organisations. This framework is the U.S. National Institute of Standards and Technology Cyber Security Framework for Critical Infrastructure (NIST-CSFCI). Accordingly, AusNet Services is proposing expenditure to establish a dedicated security monitoring and response team to align its IT security program with NIST-CSFCI.

ASIC notes that the "NIST Cybersecurity Framework is being adopted by critical infrastructure providers in the United States, including those operating in financial services and markets." Accordingly, while not a regulatory obligation per se, adopting NIST would align AusNet Services' IT security program with global industry best practice.

Given the potential consequences of a successful cyber-security attack on its network and the expectations of ASIC, AusNet Services considers that its proposed expenditure to adopt NICF-CSFCI reflects expenditure that a prudent and efficient network operator would incur.

Specifically, AusNet Services has interpreted ASIC's expectations on IT security for ASX-listed entities as a change in its operating environment that is equivalent to a new compliance obligation. In light of ASIC's explicit recommendation, AusNet Services could suffer considerable reputational damage were a successful cyber-attack to take place on its network that could have been prevented by the implementation of NIST-CSFCI. Accordingly, the proposed expenditure is consistent with the AER's step change assessment criteria.

The following table sets out AusNet Services' forecast expenditure for the establishment of an IT security team.

**Table 5.15: Forecast opex for establishment of IT security team ($m, real 2016-17)**

| Establishment of IT security team | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| 24/7 operations team | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | **2.4** |
| Operating systems & network device patching analyst | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.5** |
| Software maintenance cost | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.4** |
| **Total** | **0.7** | **0.7** | **0.7** | **0.7** | **0.7** | **3.3** |

### *New emergency response arrangements*

AusNet Services is proposing expenditure to comply with the greater emergency management and response capacity required of it as a result of the recently established Emergency Management Victoria (EMV) and The Office of The Inspector General of Emergency Management. These organisations were established through an amendment to the Emergency Management Act 2013.

As a result of these changes, which came into effect 1 July 2015, EMV will have capacity to activate the State Control Centre (SCC) in response to emergencies – a location at which AusNet Services will be expected to provide a proportionately increased level of assistance and liaison.

This uplift in activity will be most immediately apparent over the 2015-16 bushfire season when the potential for AusNet Services being required to deploy Emergency Management Liaison Officers (EMLOs) to the State Control Centre (SCC) is greatest. It is then planned that the degree of availability will expand from a 'fire season roster' to a 24/7 year round roster to respond to floods, storms and all other forms of disruptive emergencies. All of these requirements are in addition to, not instead of the previous counter terrorism responsibilities.

AusNet Services has forecast that to comply with the new emergency response arrangements outlined above, additional opex will be required from 2015-16 for:

- Training purposes to ensure a sufficient number of EMLOs are available for deployment during emergencies;
- Staff costs associated with on-call allowances and overtime to be paid during predicted deployments;
- Audit fees to undertake an annual (newly legislated) Risk Management Plan Audit; and
- Carrying out an annual emergency exercise that has been uplifted from a terrorism event to a more onerous “all hazards” type event.

The following table sets out AusNet Services’ forecast expenditure for compliance with the new emergency response arrangements outlined above.

**Table 5.16: Forecast opex for compliance with new emergency response arrangements ($m, real 2016-17)**

| New emergency response arrangements | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Training and staff induction | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | **0.19** |
| Attendance at State Control Centre | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | **0.54** |
| Audit of Risk Management Plan | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | **0.06** |
| Emergency exercise | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | **0.22** |
| **Total** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **1.01** |

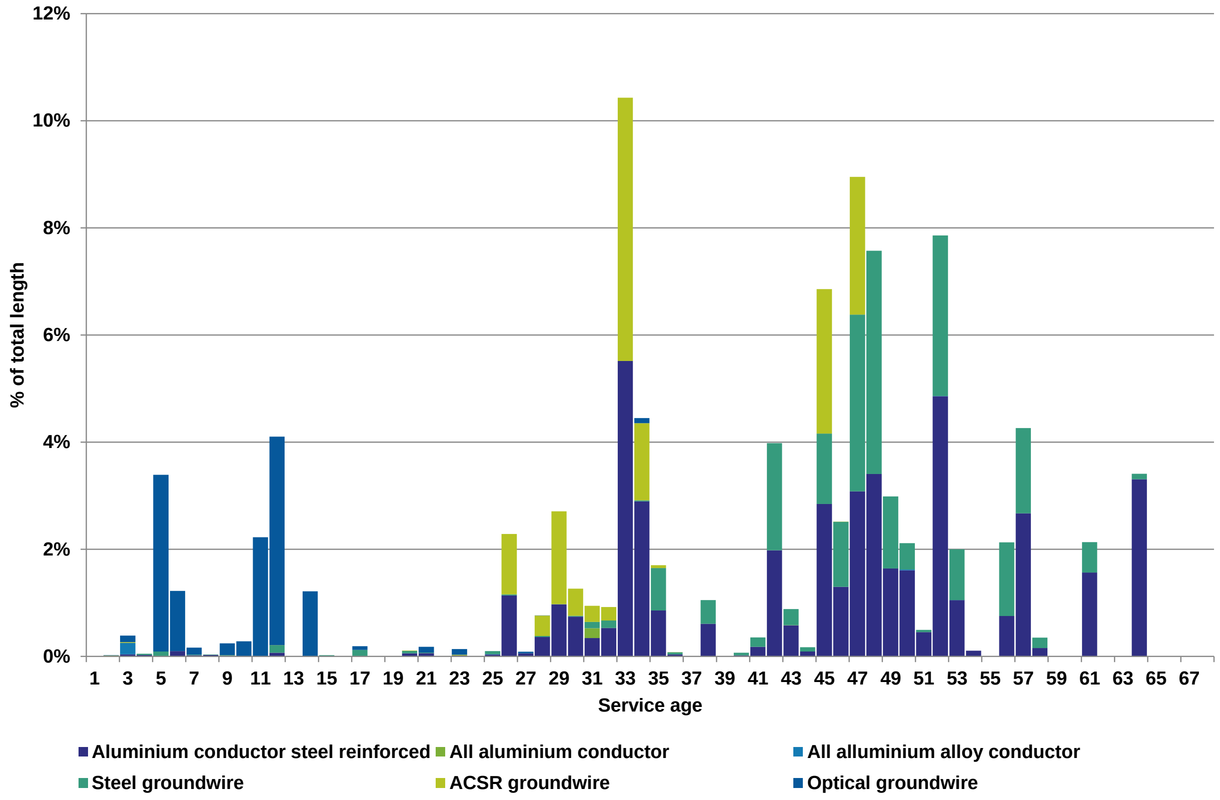
### 5.10.2 Capex / opex trade-offs

The deferral of a major terminal station rebuild in the current period and the proposed deployment enhanced condition monitoring technologies will require an increase in opex during the forthcoming period in order to meet the opex objectives. Under the NEO and the AER’s step change assessment criteria, these opex increases are justified where they result in a capex/opex trade-off.

#### *Smart Aerial Image Processing (SAIP) roll out*

AusNet Services manages an ageing transmission network, with its older assets having an increasing probability of failure due to deteriorating condition. A significant proportion of the groundwire population is now reaching the end of its original design life, and much of the conductor population will reach the end of its design life in the next 10-20 years. The average service age of AusNet Services’ transmission line conductor and groundwire population is 45 and 35 years, respectively. The figure below shows the age profile of these assets.

**Figure 5.10: Conductor and groundwire age profile by type**




*Source: AusNet Services*

Around approximately 24% of the conductor and groundwire population has been in service for more than 50 years. This will increase to 58% by 2022. AusNet Services' Asset Management Strategy AMS 10-79 (provided as a supporting document) provides further details on the age profile and condition of conductor and groundwire assets.

Existing condition monitoring techniques, which rely on the visual inspection and judgement of asset inspectors, cannot identify hidden defects and may not identify large populations of deteriorating conductor. In some cases, the time between detecting the onset of steel core corrosion and failure of the asset can be as short as three to five years.

SAIP is an enhanced condition assessment technique that uses helicopter-mounted high resolution video cameras to capture a continuous stream of digital images of overhead conductors, which are processed and analysed to detect and map defects.

Deployment of SAIP would allow AusNet Services to better predict the extent and optimal timing of future conductor replacements, and avoid initiating replacement works before they are necessary. Given the potential safety risk of delaying replacement too long, there is considerable scope for more targeted and prioritised conductor replacement, provided the requisite condition data is available. SAIP represents a low-cost, flexible method of acquiring this data. Having an awareness of this technology and acknowledging its relatively low cost, AusNet Services' potential exposure to liability increases if this technology is not deployed.

Since 2009, AusNet Services has successfully completed a number of SAIP trials on different parts of its transmission network. This includes covering approximately 500 and 1,000 kilometres of the network in 2014-15 and 2015-16, respectively, to confirm the effectiveness of SAIP with respect to identifying signs of deterioration, minor faults and defects and providing an improved mechanism for assessing condition and predicting remaining life of the asset.

To fully realise the potential benefits of SAIP, AusNet Services is proposing to conduct a full assessment of its entire network over three years to establish a condition baseline, followed by a second, targeted cycle for change monitoring.

The following table sets out AusNet Services' forecast SAIP roll out expenditure. These costs are net of SAIP expenditure incurred in AusNet Services' proposed base year of 2014-15, as well as an allowance for expected inspection cost savings.

**Table 5.17: Forecast SAIP roll out opex ($m, real 2016-17)**

| SAIP roll out | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Roll out | 0.5 | 0.5 | 0.3 | 0.3 | 0.3 | **1.8** |
| Less: costs in base year | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | **-0.7** |
| Less: saving on inspection costs | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | **-0.3** |
| **Total** | **0.3** | **0.3** | **0.1** | **0.1** | **0.1** | **0.9** |

AusNet Services has determined that deferring the replacement of 30km of 500 kV conductor (with an estimated project cost of $30m) by two years in five year' time would economically justify the proposed opex. This represents less than 1% of the length of AusNet Services' 500 kV transmission network of around 3,900km. Given the large volume of conductor and groundwire replacement expected in future periods due to the ageing profile of these assets, this is considered a conservative estimate of the potential capex deferral benefits SAIP would facilitate.

**Box 5.1: Responding to stakeholder feedback regarding SAIP**

**Stakeholders expressed interest in why AusNet Services was proposing a step change for SAIP given the AER's decision on this matter at the last Transmission Revenue Reset. Stakeholders wanted to know what had changed since last time, and whether AusNet Services' appeal the AER's previous decision on this matter. Stakeholders were also interested in whether there would be offsetting reductions in other aspects of lines condition monitoring as a result of SAIP.**

The AER did not accept AusNet Services' SAIP proposal at the previous review on the grounds that the overall opex allowance provided was sufficient to enable SAIP to be embedded into AusNet Services' routine maintenance. The AER's position assumed that that expenditure on routine and condition based maintenance on lines could be spent on SAIP instead.

However, embedding SAIP as a routine condition monitoring practice is not expected to reduce the need for routine and/or condition-based overhead lines maintenance, or tower and line inspections. SAIP is an advanced technique aimed at gathering detailed information on conductor and groundwire condition, rather than an alternative means of carrying out routine and corrective maintenance. It will also not remove the need for tower inspections because these are linked to AusNet Services' safety obligations.

Since the last review, the need for SAIP has not diminished, particularly given the continually aging conductor and groundwire population. Accordingly, AusNet Services continues to see significant economic merit in the deployment of SAIP and is proposing a step change to facilitate this. Consistent with the step change proposed at the previous review, this step change incorporates minor savings on inspection costs.

AusNet Services did not appeal the AER's last decision on SAIP.

### *WMTS mobile switchboard*

AusNet Services has determined that it is currently economic to replace the WMTS 22kV switchroom based on the safety and supply risk presented by an asset failure. The cost of replacing the switchroom, which would provide a long-term solution to address the risks outlined above, is estimated at $17.2 million.

However, joint planning by AusNet Services and CitiPower concluded the most prudent and efficient outcome for the 22kV assets is for AusNet Services to retire its 22kV WMTS switchyard, and for CitiPower to similarly retire a number of ageing 22kV zone substations by integrating the customers served by WMTS 22kV onto its 66kV zone substation network.

AusNet Services supports this proposal as its 22kV transmission assets at WMTS are in a deteriorated condition and cost savings will be realised by not replacing the 22kV assets as part of the WMTS rebuild. Refer to section 4.8.1 for more details about the WMTS rebuild.

In light of the planned retirement of the 22kV WMTS assets, it is not prudent for AusNet Services to replace these assets. As such, AusNet Services has determined that leasing a mobile switchboard is the safest and most cost-effective solution to ensure the safe operation and maintenance of the switchroom assets until the works are complete to enable them to be taken out of service

The proposed lease of a mobile switchboard would provide continual 22kV supply while the switchboard is progressively taken out of service, inspected, tested and returned to a serviceable condition. The mobile switchboard would be designed to meet the minimum installation, switching and protection requirements for short term supply continuity.

The costs of leasing and connecting the switchboard are classified as opex because they do not relate to the replacement of assets, the extension of the life of existing assets nor the enhancement of the capability of the existing assets. Instead, the costs are intended to ensure that WMTS assets remain in serviceable condition until they are retired.

This approach, which requires expenditure of $2 million over five years, does not replace the switchboard, but is required to manage the risks of failure in the short-term while awaiting the completion of the decommissioning program, and is a significantly more prudent and efficient solution than the full replacement of the switchroom. The proposed step change is also consistent with the AER's step change assessment criteria, which recognise that it may be efficient for a TNSP to increase its opex if doing so avoids capex.

AusNet Services is therefore proposing a step change for the leasing and cabling costs of a mobile switchboard, based on quotes obtained from the market and internal estimates. Due to the critical nature of this project, some project development costs have been incurred in 2015-16 to ensure the timely establishment of a lease.

The following table sets out AusNet Services' forecast WMTS mobile switchboard costs for the forthcoming period.

**Table 5.18: Forecast opex for WMTS mobile switchboard lease ($m, real 2016-17)**

| WMTS mobile switchboard | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Switchboard lease and transport costs | 0.26 | 0.25 | 0.25 | 0.25 | 0.00 | **1.00** |
| Overhaul | 0.00 | 0.05 | 0.00 | 0.00 | 0.05 | **0.10** |
| Cabling | 0.45 | 0.00 | 0.02 | 0.45 | 0.00 | **0.92** |
| **Total** | **0.71** | **0.30** | **0.27** | **0.70** | **0.05** | **2.02** |

### 5.10.3 Asset decommissioning

AusNet Services will be required to decommission and make safe a number of major assets over the forthcoming period, and is proposing opex to reflect the costs of decommissioning these assets. This approach aligns with the AER's position on forecasting opex:

> *"Any other costs base opex and the rate of change do not compensate [sic] can be added as a step change. When assessing step changes particular consideration must be given to whether the costs are already compensated for elsewhere in the opex forecast."*[62]

Because AusNet Services does not routinely decommission assets, its base year opex does not include the costs of decommissioning major assets such as synchronous condensers. Further, these costs are not captured in the elements of the rate of change discussed in section 5.7. For these reasons, and due to the quantum of these costs, AusNet Services considers that its asset decommissioning step changes are required to form a total opex forecast that reasonably reflects the efficient costs of achieving the opex objectives.

### *Synchronous condensers*

Synchronous condensers provide benefits by regulating the voltage of the network. There are three synchronous condensers on AusNet Services' transmission network. These were installed in the 1960's and 1970's and are located at Fisherman's Bend, Templestowe and Brooklyn Terminal Stations. These assets have reached the end of their economic lives and for this reason it is proposed to decommission these synchronous condensers in 2017-18.

As AEMO, not AusNet Services, is responsible for directing augmentation of the Victorian transmission network, AEMO and AusNet Services have worked together to assess whether the level of service provided by the synchronous condensers are still required. As these assets are at end of life and replacement is expensive, the benefit of continuing these services must exceed the estimated cost of replacement for a continued service to be beneficial. Continuing to refurbish the synchronous condensers is not considered to be a viable option given the high capital expenditure that would need to be incurred to extend the life of the synchronous condensers by approximately five to ten years.

AEMO has confirmed that the Fisherman's Bend synchronous condenser was providing the lowest level of market benefits and, as such, agreed to AusNet Services taking it out of service in July 2015. Additional opex is now required to decommission this asset and remove it from the site.

At the time of submission, the synchronous condensers at Templestowe and Brooklyn Terminal Stations remain in service. AusNet Services and AEMO are continuing to work together to assess whether, given the high replacement costs, it is economic to replace these synchronous condensers with reactive plant providing a similar, or reduced, level of service. This analysis will not conclude until May 2016 and their replacement is proposed as a contingent project (see section 4.8.11).

Based on the analysis done to date, AusNet Services considers that decommissioning the remaining two synchronous condensers is the most likely conclusion that will be reached. Therefore the costs of decommissioning all three synchronous condensers are forecast in this submission. However, AusNet Services continues its discussions with AEMO and will update the AER on any developments.

The following table sets out AusNet Services' forecast synchronous condenser decommissioning costs.

**Table 5.19: Forecast synchronous condenser decommissioning opex ($m, real 2016-17)**

| Synchronous condenser decommissioning | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Fisherman's Bend Terminal Station | 1.4 | 0.0 | 0.0 | 0.0 | 0.0 | **1.4** |
| Brooklyn Terminal Station | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | **1.3** |

62 AER, *EFA Guideline*, p. 61.

| Synchronous condenser decommissioning | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Templestowe Terminal Station | 1.4 | 0.0 | 0.0 | 0.0 | 0.0 | **1.4** |
| **Total** | **4.3** | **0.0** | **0.0** | **0.0** | **0.0** | **4.3** |

### *Morwell Power Station assets*

In August 2014, Energy Brix Australia Corporations' (EBAC) Morwell Power Station (MPS) shut down due to falling electricity wholesale prices and a substantial reduction in the energy needs of its briquette manufacturing facility, which is located on-site at MPS. AusNet Services currently has a connection agreement in place with EBAC for the use of AusNet Services' transmission and distribution assets to provide connection services.

In light of the closure of MPS, an interim connection agreement is currently being negotiated with EBAC to supply its load from Morwell Terminal Station using the existing electricity distribution and transmission assets at MPS. This agreement will be in place until the establishment of the Morwell zone substation on AusNet Services' distribution network in 2018, which will be used to supply EBAC's load. This will coincide with the demolition of MPS – which EBAC has advised will take place at the end of 2017 – and the cessation of the existing connection agreement in place between AusNet Services and EBAC.

Once the Morwell zone substation is established, AusNet Services' electricity distribution and transmission assets located at MPS will no longer be required. To ensure the redundant assets do not pose a safety threat, AusNet Services is required to decommission and make safe these assets. This involves identifying all live equipment in the yard and electrically isolating and disconnecting the equipment from the network in such a way that it cannot be made live by normal switching means, as well as draining and disposing of oil from transformers.

Because there is no agreement in place for AusNet Services' decommissioned assets to be located on EBAC's land, AusNet Services is proposing a step change for the costs of decommissioning its transmission assets, removing these assets from EBAC's land and restoring the site. This approach is considered the most prudent option of mitigating the risk of the 'do nothing' option, which include exposing AusNet Services to liability if its assets are not made safe and removed from EBAC's land.

The following table sets out AusNet Services' forecast opex for the decommissioning and removal of its MPS transmission assets and the associated site restoration works.

**Table 5.20: Forecast opex for MPS asset decommissioning and removal and site restoration ($m, real 2016-17)**

| Morwell Power Station decommissioning | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Decommissioning of assets | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 | **0.5** |
| Removal of assets | 0.9 | 0.0 | 0.0 | 0.0 | 0.0 | **0.9** |
| Site restoration | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 | **0.5** |
| **Total** | **1.9** | **0.0** | **0.0** | **0.0** | **0.0** | **1.9** |

## 5.11 Total Controllable Opex

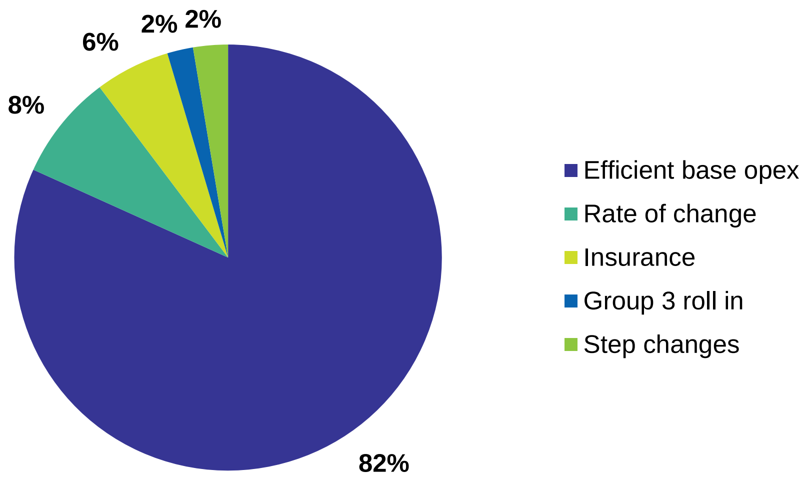
Taking into account the forecast opex outlined above, the total controllable opex forecast is $511.8m over the next regulatory control period. The annual forecast is set out below.

**Table 5.21: Total forecast controllable opex ($m, real 2016-17)**

| Controllable opex | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total ($) | Total (%) |
|---|---|---|---|---|---|---|---|
| Base opex | 83.7 | 83.7 | 83.7 | 83.7 | 83.7 | **418.6** | **81.8%** |
| Rate of change | 4.7 | 6.4 | 8.1 | 9.9 | 11.7 | **40.9** | **8.0%** |
| Insurance | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | **28.9** | **5.7%** |
| Group 3 roll in | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | **10.0** | **2.0%** |
| Step changes | 8.2 | 1.5 | 1.2 | 1.6 | 1.0 | **13.5** | **2.6%** |
| **Total** | **104.1** | **99.3** | **100.8** | **103.1** | **104.4** | **511.8** | **100.0%** |

The different components of forecast controllable opex are shown in the figure below. As noted above, efficient base year opex accounts for more than 80% of the total opex forecast.

**Figure 5.11: Components of forecast controllable opex**




*Source: AusNet Services*

## 5.12 Non-Controllable Opex

Non-controllable opex comprises easement tax and self-insurance costs. While these costs are outside AusNet Services' management control, they form part of the total operating expenditure that the network will incur to meet the operating expenditure objectives set out in NER 6A.6.6. Non-controllable costs are excluded from base year costs.

### 5.12.1 Self-insurance

As discussed in section 5.8 on insurance, for some risks, self-insurance is the most appropriate risk mitigation mechanism, rather than obtaining external insurance or seeking to utilise cost pass through provisions. These risks 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).

When choosing to self-insure, AusNet Services aims to minimise its total cost of insurable risk (TCIR) by determining an optimal balance between using insurance, self-insurance and the option of applying for a cost pass through to manage risk. This ensures that only prudent and efficient expenditure is included in forecast opex.

To develop forecasts of its self-insurance costs, AusNet Services engaged Aon, an appropriately qualified actuary. Aon has extensive experience in forecasting self-insurance costs for electricity transmission businesses.

Aon provided self-insurance forecasts for the following risk classes:

- Tower failure (uninsured);
- Machinery breakdown (insured);
- Property damage (insured); and
- Fire liability (insured).

For uninsured risks, the self-insurance costs reflect AusNet Services' unlimited exposure to these risks, while for insured risks, the costs only reflect loss amounts up to the relevant deductible level.

Self-insuring these risks is considered the most efficient approach. This is because both obtaining insurance for tower failure, or lowering AusNet Services' deductibles on its insured risks 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 self-insurance costs 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.

AusNet Services provided a significant volume of data in order to ensure Aon's analysis accurately accounted for AusNet Services' loss history and is robust. Aon's self-insurance report can be found at Appendix 5B.

The following tables set out AusNet Services' proposed self-insurance costs of $13.5m, which accounts for 1.2% of the total opex forecast. AusNet Services' Board Resolution to self-insure the following risks is provided as supporting documentation.

**Table 5.22: Forecast self-insurance costs ($m, real 2016-17)**

| Risk class | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Tower failure | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | **5.5** |
| Machinery breakdown | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | **3.6** |
| Property damage | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | **2.0** |
| Fire liability | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.3** |
| Risk margin | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | **2.1** |
| **Total** | **2.7** | **2.7** | **2.7** | **2.7** | **2.7** | **13.5** |

*Source: Aon (2015) Self-Insurance Risk Quantification – AusNet Services Transmission, April 2015.*

The Aon forecast represents a category specific forecast of self-insurance costs. There is a strong regulatory precedent for approval of this approach, with the AER approving an explicit self-insurance allowance for the risk classes shown above in its current transmission determination for AusNet Services.

However, as noted in section 5.8 of this chapter, the AER considers that self-insurance should be forecast as part of base opex.

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 likely to result in a less accurate forecast of self-insurance than such an analysis, particularly if base year opex is influenced by an abnormally high or low level of self-insurance losses.

Accordingly, AusNet Services considers that its approach to forecasting self-insurance costs – relying on an actuarial quantification of expected losses – is 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.

### 5.12.2 Easement Land Tax

In 2004, the Victorian Government extended land tax to electricity transmission easements owned by electricity transmission companies in Victoria. The new tax arrangement was designed to counter a shortfall in Government revenue as a result of the Government's abolition of the Smelter Reduction Amount levy.

This tax is recovered through regulated revenues through its inclusion in the opex forecasts used in the calculation of the revenue cap for the forthcoming regulatory control period. The forecast assumes that the tax increases at the same rate as CPI over the forthcoming regulatory period.

Over the period, any positive or negative variation between the actual tax paid and the forecast approved by the AER will be recovered from, or reimbursed to, customers via the pass-through mechanism outlined in NER 6A.7.3. This arrangement ensures AusNet Services will only recover the actual tax paid over the period.

Forecast easement land tax of $576.4m accounts for 52.4% of the total opex forecast.

**Table 5.23: Forecast easement Land Tax ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Easement land tax | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 | **576.4** |

### 5.12.3 Total non-controllable opex

Taking into account the forecast non-controllable costs outlined above, the total non-controllable opex forecast is $589.9m. The annual forecast is set out below.

**Table 5.24: Total Non-Controllable Opex ($m, real 2016-17)**

| Non-controllable opex | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total ($) | Total (%) |
|---|---|---|---|---|---|---|---|
| Self-insurance | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | **13.5** | **2.3%** |
| Easement land tax | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 | **576.4** | **97.7%** |
| **Total** | **118.0** | **118.0** | **118.0** | **118.0** | **118.0** | **589.9** | **100.0%** |

## 5.13 Total Opex Forecast

### 5.13.1 Summary of expenditure requirements

AusNet Services forecasts a total opex requirement of $1,101.7m in the 2017-22 regulatory control period. This forecast represents the necessary operating costs for the efficient operation and maintenance of AusNet Services' transmission network. The average annual forecast represents a 10% real increase on total opex in 2014-15.

A summary of the individual categories of expenditure which comprise total forecast opex are shown in the table below, as well as 2014-15 opex for comparative purposes.

**Table 5.25: Total proposed opex ($m, real 2016-17)**

| Opex component | 2014-15 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2017-22 total | | 2017-22 average ($) |
|---|---|---|---|---|---|---|---|---|---|
| | Current period | Forthcoming period | | | | | $ | % | |
| Efficient base year opex | 83.7 | 83.7 | 83.7 | 83.7 | 83.7 | 83.4 | **418.6** | **38.0%** | **83.7** |
| Rate of change | n/a | 4.7 | 6.4 | 8.1 | 9.9 | 11.7 | **40.9** | **3.7%** | **8.2** |
| Insurance costs | 4.8 | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | **28.9** | **2.6%** | **5.8** |
| Group 3 roll in | n/a | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | **10.0** | **0.9%** | **2.0** |
| Step changes | n/a | 8.2 | 1.5 | 1.2 | 1.6 | 1.0 | **13.5** | **1.2%** | **2.7** |
| **Total controllable** | **88.5** | **104.1** | **99.3** | **100.8** | **103.1** | **104.4** | **511.8** | **46.5%** | **102.4** |
| Self-insurance | 1.8 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | **13.5** | **1.2%** | **2.7** |
| Easement land tax | 109.6 | 115.3 | 115.3 | 115.3 | 115.3 | 115.3 | **576.4** | **52.3%** | **115.3** |
| **Total opex** | **199.9** | **222.1** | **217.3** | **218.8** | **221.1** | **222.4** | **1,101.7** | **100.0%** | **220.3** |

## 5.14 Link to other building blocks

In developing its opex forecast, AusNet Services has carefully considered the impact of its ageing asset base and the reduction in the VCR on its future opex requirements. AusNet Services' opex forecast incorporates capex-opex trade-offs, whereby additional opex is proposed as a consequence of previous or expected reductions, or expected future deferrals. The revenue forecast incorporates capex-opex trade-offs to minimise total lifecycle cost.

## 5.15 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 5A – Aon Insurance Report.
- Appendix 5B – Aon Self-Insurance Report.
- Appendix 5C – Group 3 Assets.

- Appendix 5D – Proposed Operating Expenditure Step Changes 2017 – 2022.
- Appendix 5E – CIE Labour Price Forecasts.
- Appendix 5F – AusNet Services Opex Productivity Growth (2006-14).

# 6 Shared Assets

## 6.1 Introduction and Overview

This Chapter sets out AusNet Services' proposed shared asset costs reductions for the 2017-22 regulatory control period. A shared asset is an asset whose costs were initially allocated to regulated services but has come to be used to provide unregulated services as well. This change from expected use means that the assets are earning both regulated and unregulated revenues.

Under NER 6.4.4, a reduction to the annual revenue requirement can be made to reflect part of the cost of assets that are used to provide both prescribed transmission services and unregulated services.

The cost reduction must be made in accordance with the shared asset principles (NER 6.4.4(c)), which are:

- The service provider should be encouraged to use assets to provide unregulated services where efficient;
- The cost reduction should not be dependent on the service provider deriving a positive commercial outcome for unregulated services provided using the shared asset;
- The cost reduction should be applied where there is material use of the asset to provide unregulated services;
- Have regard to how costs have been recovered or revenues reduced in the past with respect to the shared asset;
- The cost reduction must be compatible with the Cost Allocation Principles and the Cost Allocation Methodology; and
- Any cost reduction must be compatible with other incentives provided by the Rules.

The AER has published a Shared Asset Guideline outlining its proposed approach to making shared asset cost reductions. AusNet Services has relied on the Guideline to calculate the shared asset cost reduction.

## 6.2 Cost Reduction Methodology

The AER's Guideline sets out the following steps to establish the shared asset cost reduction:

- Determine the relevant unregulated revenues earned from shared assets;
- Determine whether shared asset unregulated revenues are material (exceed 1% of the proposed annual revenue requirement);
- If material, the cost reduction will equal 10% of total unregulated revenues from shared assets for each year of the regulatory control period, subject to:
    - The application of the control step (i.e. cap); and/or
    - Any adjustments made to account for contributed assets.

The Guideline notes that service providers may propose alternative methods to calculate a cost reduction. If it does so, it should demonstrate that customers would be no worse off than the Guideline methodology under its approach.

AusNet Services has applied the Guideline methodology. The steps it has taken are set out below.

### 6.2.1 Relevant unregulated revenues from shared assets

AusNet Services' relevant unregulated revenues from shared assets are set out in the table below. Revenues associated with these services since 2007-08 are also reported in the RIN submitted as part of this Revenue Proposal.

**Table 6.1: Shared Asset Unregulated Revenues (SAUR) ($m, 2016/17)**

| $m, real $2016/17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| HV CT & VT Testing | 1.1 | 1.1 | 1.2 | 1.2 | 1.3 | **6.0** |
| Transformer Testing (incl Condition Monitoring) | 1.5 | 1.6 | 1.6 | 1.7 | 1.8 | **8.2** |
| Chemical Testing & Analysis | 2.0 | 2.1 | 2.2 | 2.3 | 2.4 | **10.9** |
| Calibration & Electrical Testing (incl NATA accredited) | 0.9 | 0.9 | 0.9 | 1.0 | 0.9 | **4.6** |
| Fibre Optic Cable Leasing | 1.8 | 1.9 | 2.0 | 2.1 | 2.2 | **9.9** |
| Leasing Access to wireless base stations on EHV Towers | 5.6 | 5.9 | 6.1 | 6.4 | 6.7 | **30.8** |
| Leasing Access to various communication equipment on communication towers | 1.8 | 1.9 | 2.0 | 2.1 | 2.2 | **9.9** |
| Site Leasing | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | **0.4** |
| **TOTAL** | **14.9** | **15.5** | **16.1** | **16.8** | **17.5** | **80.7** |

### 6.2.2 Materiality test

The Shared Assets Guideline specifies that the unregulated use of shared assets is material when the average is expected to be greater than 1 per cent of the total smoothed revenue requirement for that regulatory year.

AusNet Services' unregulated use of shared assets is material in all years of the regulatory control period. The results of the materiality assessment are shown in the table below.

**Table 6.2: Materiality Assessment Outcome ($m, real 2016/17)**

| $m, real $2016/17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Proposed smoothed ARR | 583.2 | 586.9 | 590.7 | 594.4 | 598.2 | **2,953.4** |
| Average Annual SAUR | 16.1 | 16.1 | 16.1 | 16.1 | 16.1 | **80.7** |
| SAUR as % of ARR | 2.8% | 2.8% | 2.7% | 2.7% | 2.7% | **2.7%** |
| Material? | Y | Y | Y | Y | Y | **N/A** |

### 6.2.3 Shared Asset Cost Reduction

Consistent with the Guideline, the shared asset cost reduction has been calculated as 10% of the value of expected total relevant unregulated revenues from shared assets in that year. No further adjustments have been made in relation to contributed assets.

The proposed shared asset cost reduction for the 2017-22 period is set out in the table below:

**Table 6.3: Shared Asset Cost Reduction ($m, real 2016/17)**

| $m, real $2016/17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| **10% of relevant unregulated shared asset revenues** | 1.5 | 1.6 | 1.6 | 1.7 | 1.7 | **8.1** |

## 6.3 Summary

The impact of the shared assets cost adjustment on AusNet Services' proposed smoothed Annual Revenue Requirement is shown in the table below.

**Table 6.4: Decrement from Shared Assets ($m, real 2016/17)**

| $m, real $2016/17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| **ARR** | 583.2 | 586.9 | 590.7 | 594.4 | 598.2 | **2,953.4** |
| **Shared asset cost reduction** | (1.5) | (1.6) | (1.6) | (1.7) | (1.7) | **(8.1)** |
| **Adjusted ARR** | 581.8 | 585.4 | 589.0 | 592.7 | 596.4 | **2,945.3** |

# 7 Incentive Schemes

## 7.1 Key Points

- Incentive schemes for both operational performance and expenditure efficiency will apply to AusNet Services in the 2017-22 regulatory control period. These are:
    - Service Target Performance Incentive Scheme (STPIS), which provides incentives to maintain or improve operational performance;
    - The Efficiency Benefit Sharing Scheme (EBSS), which provides incentives to achieve and maintain operating expenditure efficiency improvements; and
    - The Capital Expenditure Sharing Scheme (CESS), which provides incentives to make capital expenditure efficiency gains.
- AusNet Service has responded to the Service Component incentives of the STPIS, recording strong performance during the last five years for the parameters applying to it during this period.
- The number of constrained dispatch intervals as measured under the Market Impact Component of the STPIS has declined sharply since 2011, demonstrating the efficacy of the performance incentive arrangements established.
- Consistent with recent AER determinations, proposed Service Component parameter targets have been set largely on the basis of average historic performance, with caps and collars set at the $5^{th}$ and $95^{th}$ percentiles of historic performance using the most appropriate statistical distribution.
- The Network Capability Incentive Parameter Action Plan (NCIPAP) proposes two priority projects to improve network capability, building on the seven projects successfully delivered to date which have created net benefits of $34m.
- The EBSS Scheme carryover amount has been calculated as $5.6m, reflecting AusNet Services' response in recent years to the cost efficiency incentives embedded in the regime.
- While AusNet Services endorses the AER's positions on the application of the new EBSS and the CESS for the forthcoming period, a number of EBSS exclusions are proposed in line with the current determination.

## 7.2 Introduction

This chapter sets out AusNet Services' proposed approach to the incentive schemes that will be applied during the forthcoming regulatory control period: These schemes are the:

- Service Target Performance Incentive Scheme (STPIS);
- Efficiency Benefit Sharing Scheme (EBSS); and
- Capital Efficiency Sharing Scheme (CESS).

AusNet Services' performance against the STPIS and EBSS during the current period is also presented.

AusNet Services strongly supports the AER's incentive regime. The framework's constituent schemes align TNSP incentives towards efficient price and performance outcomes with the long-term interests of consumers, furthering the achievement of the National Electricity Objective (NEO).

The effectiveness of incentive regulation has been practically demonstrated by AusNet Services' performance under the current period's various incentive schemes. 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's intention to apply the full suite of incentives in Victoria, including the new stronger capital efficiency incentive is fully supported.

The targets and outcomes from these incentive schemes are fundamentally interlinked to AusNet Services' expenditure proposals because both are an input to, and output from, its asset management strategies and work programs that underpin this Proposal. AusNet Services' capex and opex proposals are outlined in Chapters 4 and 5, respectively.

The remainder of this chapter is structured as follows:

- Section 7.3 presents AusNet Services' historical performance under the STPIS, and sets out proposed targets, caps and collars for the forthcoming regulatory control period;
- Section 7.4 provides the calculation of the EBSS carryover amount from the current regulatory control period, and sets out AusNet Services' proposed application of the EBSS for the forthcoming period; and
- Section 7.5 discusses the application of the CESS for the forthcoming period.

## 7.3 Service Target Performance Incentive Scheme

The Service Target Performance Incentive Scheme (STPIS) provides a financial reward (or penalty) if service performance is better (or worse) than target. As such, the STPIS acts as a counterbalance to other aspects of the regulatory framework that provide incentives for cost efficiencies. The inclusion of the STPIS in the regulatory regime recognises that economically efficient outcomes depend on the level of service as well as the cost of service.

Version 5 of the STPIS will apply to AusNet Services' 2017-22 regulatory period. This comprises the following three components:

- The Service Component;
- The Market Impact Component (MIC); and
- The Network Capability Component (NCC).

The Service Component provides incentives to reduce the occurrence of unplanned outages and to return the network to service promptly after unplanned outages. Performance targets are established for the following parameters:

- Unplanned outage circuit rate;
- Loss of supply event frequency;
- Average outage duration; and
- Proper operation of equipment.

Financial incentives apply only to the first three parameters and their various sub-components. The proper operation of equipment parameter is a reporting only parameter.

The MIC provides an incentive to minimise the impact of transmission outages at times, and on parts of the network, that are most important to influencing the spot price in the wholesale market. Performance is measured based on the number of five minute dispatch intervals (DIs) when an outage of a TNSP's network results in a network outage constraint binding with a marginal value greater than $10/MWh. This is referred to as the MIC count.

The NCC provides incentives to deliver low cost, one-off projects that increase network capability and deliver value for money to customers. Each TNSP is required to submit, as part of its revenue proposal, a NCIPAP. The TNSP must consult AEMO in developing the NCIPAP.

In Victoria, the involvement of AEMO is more substantial – as the planner of the Victorian transmission network it is responsible for identifying and scoping shared network projects and working with AusNet Services to quantify project benefits.

The AER's Framework and Approach explained that version 4.1 of the STPIS is subject to review. The AER noted its intention to apply the revised scheme (version 5) if it is published before the commencement of the forthcoming regulatory period. In September 2015, the AER published version 5 of the STPIS, which included the following key changes:

- The Service Component now differentiates between forced and fault outages by introducing non-zero weightings to the forced outage sub-parameters. The financial exposure for these sub-parameters will be 0.25%, increasing the total revenue at risk for the Service Component from ±1% to ±1.25 per cent of MAR;
- The MIC has been amended to a penalty-reward scheme with financial incentive value of ±1%. A per event cap (equal to 17% of a TNSP's target) applying to unplanned outages has also been introduced to mitigate the impact of large, unforeseen events on performance measures and targets, as well as a minimum target of 100 to avoid an excessive value per DI. Targets will be set based on the median five years of the last seven years of performance, with caps and collars set at zero and twice the target, respectively. Market impacts arising from planned third party outages have been excluded from the scheme;
- The incentive allowance for the NCC will now be adjusted on a pro-rata basis to link the incentive payment to the total expenditure of approved projects. An incentive payment of 1.5x proposed expenditure now applies, with a maximum incentive of 1.5% of approved MAR;
- The AER's ability to reduce the NCC incentive allowance has been enhanced with the introduction of an ex-post review; and
- TNSPs will have flexibility to amend their approved NCIPAP during the regulatory control period, including proposing additional priority projects.

The remainder of this section sets out:

- AusNet Services' performance against the STPIS during the 2014-17 regulatory control period measured in accordance with version 5; and
- AusNet Services' proposed targets, caps and collars for the forthcoming regulatory control period.

### 7.3.1 Current period performance

#### *Service Component*

The Service Component provides strong incentives for TNSPs to improve network reliability. The table below demonstrates that AusNet Services has responded to these incentives by making significant performance improvements during the last five years for most parameters. Targets applied to the unplanned outage circuit event rate parameter for 2014 only because this measure was first introduced in the current regulatory control period.

**Table 7.1: Historical Service Component performance**

| Parameter | Sub-parameter | Target (2010-13) | 2010 | 2011 | 2012 | 2013 | Target (2014) | 2014 | Weight (2014) |
|---|---|---|---|---|---|---|---|---|---|
| **Unplanned outage circuit event rate** | Lines event rate – fault | **n/a** | 16.81% | 24.37% | 32.50% | 20.66% | **25.90%** | 30.58% | **0.20** |
| | Transformer event rate – fault | **n/a** | 7.26% | 11.90% | 21.26% | 31.25% | **16.10%** | 22.83% | **0.20** |
| | Reactive plant event rate – fault | **n/a** | 27.14% | 34.29% | 45.71% | 47.14% | **35.10%** | 25.71% | **0.10** |
| | Lines event rate – forced | **n/a** | 14.29% | 16.81% | 14.17% | 12.40% | **14.90%** | 15.70% | **0.00** |
| | Transformer event rate – forced | **n/a** | 13.71% | 4.76% | 13.39% | 10.94% | **12.00%** | 11.81% | **0.00** |
| | Reactive plant event rate – forced | **n/a** | 14.29% | 22.86% | 22.86% | 35.71% | **15.40%** | 38.57% | **0.00** |
| **Loss of supply event frequency** | Number of events greater than 0.05 system minutes per annum | **6** | 1 | 0 | 2 | 5 | **2** | 3 | **0.15** |
| | Number of events greater than 0.30 system minutes per annum | **1** | 0 | 0 | 1 | 1 | **1** | 0 | **0.15** |
| **Average outdate duration** | Average outage duration | **n/a** | 93 | 4 | 230 | 20 | **98** | 24 | **0.20** |
| **Proper operation of equipment** | Failure of protection system | **n/a** | 14 | 23 | 33 | 41 | **n/a** | 33 | **0.00** |
| | Material failure of SCADA | **n/a** | 0 | 0 | 1 | 6 | **1** | 2 | **0.00** |
| | Incorrect operational isolation of primary or secondary equipment | **n/a** | 7 | 5 | 8 | 4 | **n/a** | 6 | **0.00** |

The frequency of unplanned outages is affected by the condition of network assets. AusNet Services' asset replacement program is driven by asset condition, and the implications of a potential failure. The reduction in the VCR in 2014 has resulted in the deferral of several major station rebuilds. This represents an efficient response to consumers placing a lower value on reliability than has been assumed in network planning to date. However, these deferrals are likely to result in a gradual decline in network reliability and therefore increased frequency of unplanned outages. This matter is discussed further in section 7.3.2.

AusNet Services' performance against each STPIS parameter is discussed below.

***Unplanned outage circuit event rate***

The unplanned outage circuit rate parameter measures outage rates for lines, transformer and reactive plant assets for both forced and fault outages. While forced outages have been a reporting only parameter during the current period, the AER has introduced a financial incentive of up to ±0.25% in version 5 of the STPIS.

The figures below show AusNet Services' performance since 2010 for the six unplanned outage circuit rate sub-parameters, as well as the targets, caps and collars that applied in 2014 when this parameter was first introduced.

**Figure 7.1: Unplanned outage circuit event rate – lines (fault outages)**

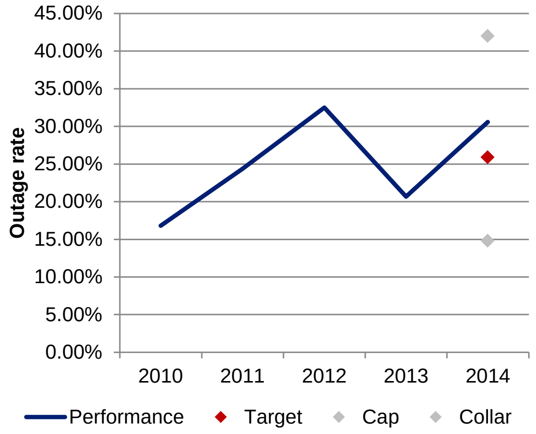



**Figure 7.2: Unplanned outage circuit event rate – lines (forced outages)**

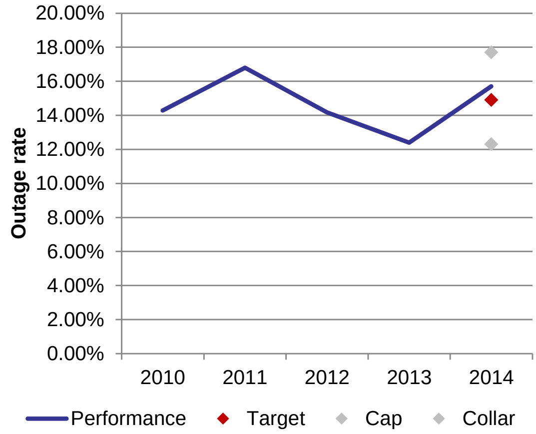



**Figure 7.3: Unplanned outage circuit event rate – transformers (fault outages)**

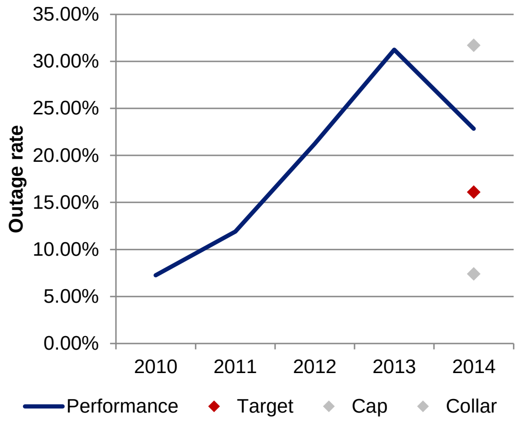



**Figure 7.4: Unplanned outage circuit event rate – transformers (forced outages)**

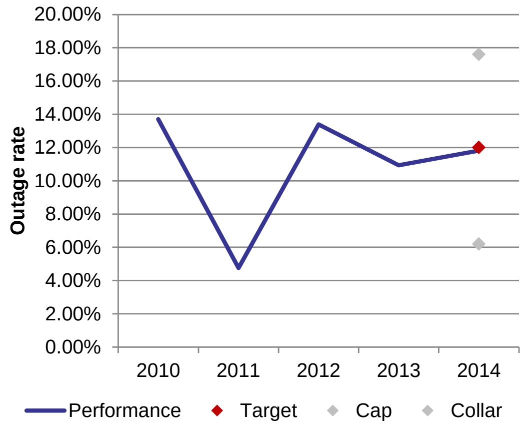



**Figure 7.5: Unplanned outage circuit event rate – reactive plant (fault outages)**

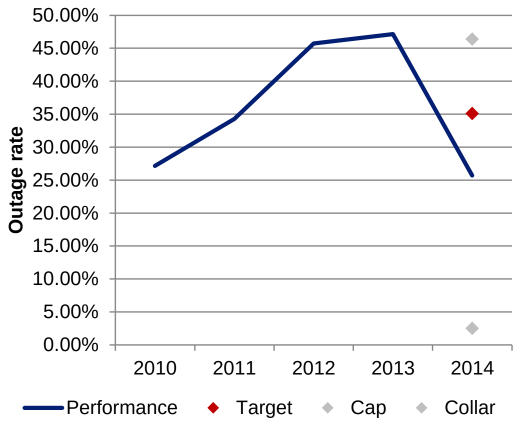
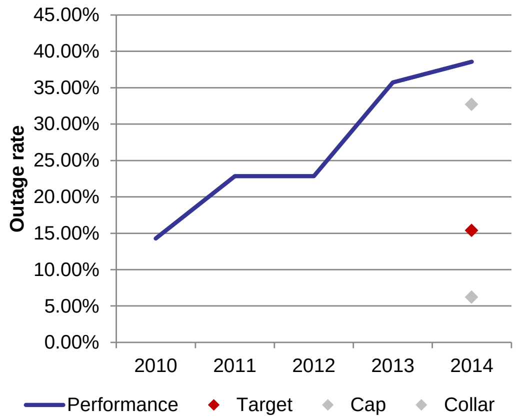



**Figure 7.6: Unplanned outage circuit event rate – reactive plant (forced outages)**



Lines' and transformers' forced outage rate has been largely steady since 2010, with 2014 performance broadly in line with targets. Reactive plant forced outage rate has increased steadily since 2010, with weak performance in 2014 against the target. For fault outages, AusNet Services' performance improved in 2014 for the transformer and reactive plant sub-parameters, but deteriorated for the lines sub-parameter. AusNet Services is working to improve its performance across both forced and fault outage measures.

***Loss of Supply Event Frequency Rate***

This parameter measures the frequency of loss of supply events exceeding thresholds of 0.30 and 0.05 system minutes. Loss of supply events are caused by unplanned outages and only a handful of events are likely to occur each year. Therefore performance against this parameter has the potential to be relatively volatile.

The figures below show AusNet Services' performance since 2010 for both parameters.

**Figure 7.7: Loss of Supply Event Frequency (>0.05 system minutes)**

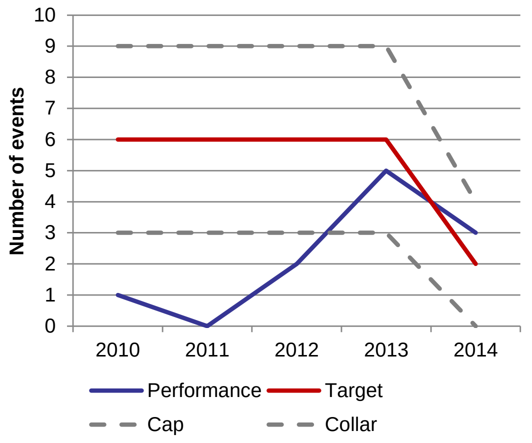
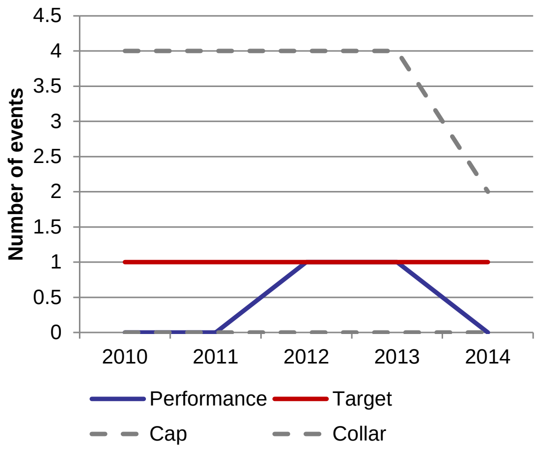



**Figure 7.8: Loss of Supply Event Frequency (>0.30 system minutes)**




Since 2010, performance against this parameter has been extremely strong, with performance measures that have largely been below or equal to targets.

AusNet Services' strong performance against this parameter has been due to the effective implementation of protection schemes, and field practices, including ensuring assets undergo vigorous testing before they are placed in service. While these steps help avoid unforeseen outages that may result in loss of supply, they have also resulted in AusNet Services approaching the performance frontier for this parameter, with further improvement beyond this point increasingly difficult to attain. Notably, for the loss of supply event frequency (>0.30 system minutes) sub-parameter, average (rounded) performance from 2010-14 was zero events, making it impossible to drive further performance improvements for this measure.

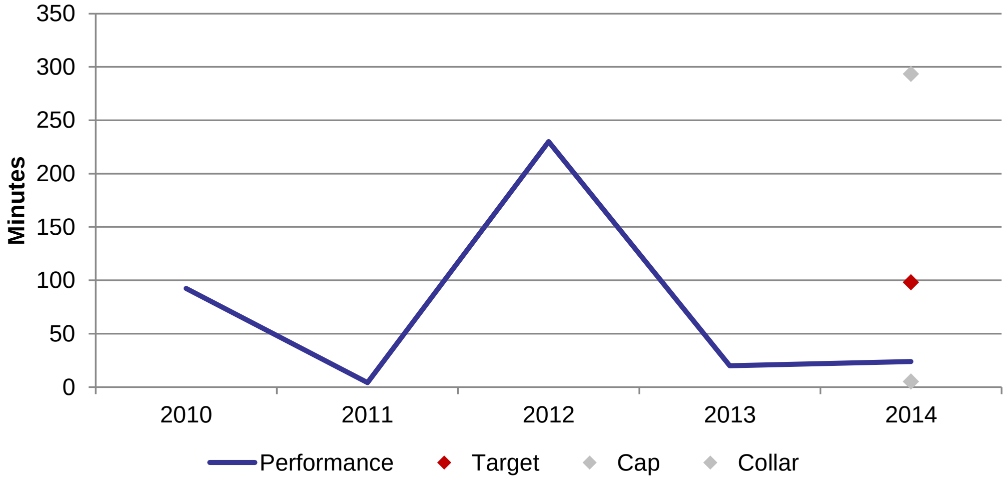
The loss of supply event frequency parameter will continue to apply to AusNet Services during the forthcoming period. However, supply interruptions are expected to increase in the forthcoming and subsequent periods consistent with the signals set by the reduction in the VCR, which is an input into AusNet Services' asset replacement plans. This should be taken into account when setting targets, caps and collars for this parameter (discussed in section 7.3.2).

***Average outage duration***

The average outage duration parameter measures AusNet Services' ability to restore service following an unplanned outage in a timely manner. Performance against this parameter can be severely affected by a small number of particularly long outages, for example outages on assets such as transformers which can take several weeks to restore.

The figure below shows AusNet Services' historical performance for this parameter. Prior to 2014, this parameter comprised two separate subparameters for the average outage duration on lines and transformer assets. Targets, caps and collars are therefore shown only for 2014.

**Figure 7.9: Average Outage Duration (minutes)**




Overall, AusNet Services' performance against the average outage duration parameter has been strong, achieving a performance measure in 2014 that was close to the cap for the maximum bonus.

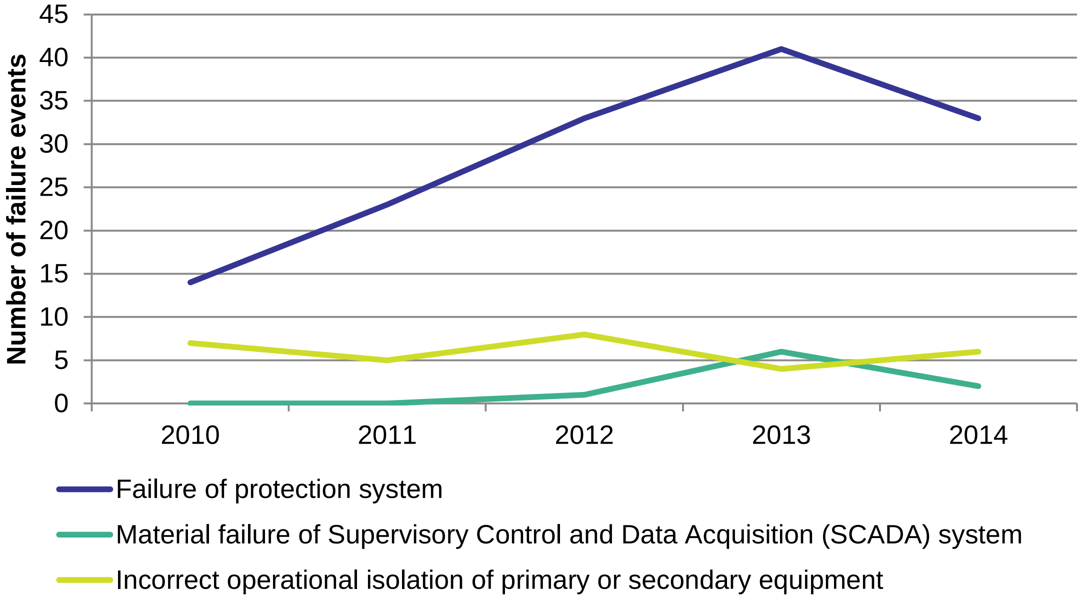
The increase in average outage duration in 2012 is largely attributable to a single outage event at Brooklyn Terminal Station, when a dedicated transformer tripped and the affected customer chose not to use an alternative supply option in accordance with AEMO operating advice. This incident also resulted in a loss of supply event greater than 0.30 system minutes, as shown in Figure 7.8.

***Proper operation of equipment***

The proper operation of equipment parameter measures the number of 'near miss' events such as failures of protection systems, material failure of the Supervisory Control and Data Acquisition (SCADA) system and incorrect operational isolation of primary and secondary equipment. As mentioned above, no financial incentive is associated with this parameter.

The figure below shows the number of events that have occurred since 2010 for each sub-parameter.

**Figure 7.10: Proper Operation of Equipment (number of failure events)**

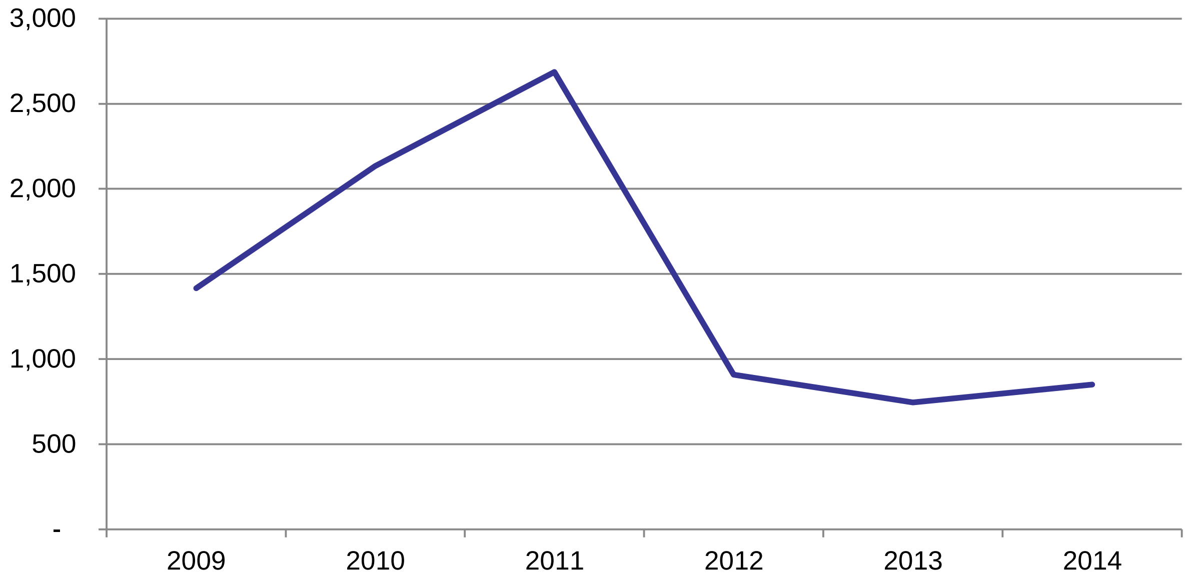



Since 2010, the number of material SCADA system failure and incorrect operational isolation of equipment events has remained largely steady. However, the number of protection system failure events has increased substantially between 2010 and 2013, before declining in 2014.

### *Market Impact Component*

In March 2011 AusNet Services requested early application of the MIC. The request was accepted by the AER, and AusNet Services began participating under the MIC from 1st August 2011. The figure below shows annual performance data since 2009 under STPIS version 5.

**Figure 7.11: Market Impact Component – number of constrained dispatch intervals with a marginal value greater than $10/MWh**




Since AusNet Services has been responding to the MIC, the number of constrained DIs has declined sharply. This performance trend suggests that the additional focus on this aspect of performance as a result of the incentive scheme has benefited customers.

While annual performance against the MIC is highly dependent on maintenance and capital works activities undertaken, enhanced outage planning activities have contributed to a reduction of the market impact of these activities. Enhanced outage planning practices involve identifying periods where network outages are likely to have a significant impact on the market, and scheduling outages to avoid these times where possible. Real time market monitoring allows scheduled works to be cancelled at short notice where they are likely to have a high market impact.

The application of the MIC in the forthcoming regulatory control period will encourage continued improvements in minimising the market impact of outages.

### *Network Capability Component*

AusNet Services was the first TNSP to have the Network Capability Component applied to it during its 2014-17 regulatory control period, and has taken steps to implement the priority projects set out in its Network Capability Incentive Parameter Action Plan. To date, seven of the fourteen priority projects contained in the endorsed NCIPAP for the 2014-17 regulatory period have been completed. The target limits have been achieved for all completed projects, creating net benefits of around $34m for customers.

## 7.3.2 Proposed application of the STPIS

This section sets out AusNet Services' proposed parameter values for the STPIS, and explains how the proposed values comply with Version 5 of the scheme. AusNet Services is the first TNSP to be subject to this version of the STPIS, following the AER's recent review of the scheme. AusNet Services is strongly committed to achieving high operational performance at all times, including when implementing capital works and undertaking maintenance programs.

Key features of AusNet Services' performance incentive scheme are:

- Service Component parameter targets are set equal to average historic performance, except for the Loss of Supply Event Frequency sub-parameters, which have been adjusted to account for the lower VCR's impact on future reliability levels;
- Service Component caps and collars are set at the 5th and 95th percentiles of historic performance using statistical distributions that best fit this performance data;
- Market Impact Component (MIC) performance data from 2009-14 is included to enable calculation of the target for 2017; and
- The NCIPAP proposes a range of priority projects to improve network capability.

### *Service Component*

#### *Methodology for setting targets*

AusNet Services' proposed performance targets, caps, collars and weightings for the parameters in accordance with version 5 of the STPIS are set out in the table below. In calculating the proposed values for these parameters, AusNet Services has complied with the requirements of clause 3.2 of version 5 of the STPIS.

Clause 3.2(g) of the STPIS specifies that, subject to some exceptions, proposed performance targets must be equal to the TNSP's average performance history over the most recent five years. To meet this requirement, proposed performance targets equal average performance history over the most recent five years (2010-14). The data used to calculate the performance target must be consistently recorded based on the parameter definitions that apply to the TNSP under the scheme.

AusNet Services is not proposing any adjustments to the targets, with the exception of the Loss of Supply Event Frequency sub-parameters, the targets for which have been adjusted in accordance with clauses 3.2 (j) and k). This adjustment, which reflects an expected decline in reliability due to the recent reduction in the Value of Customer Reliability (VCR), is explained further below.

**Table 7.2: Proposed Service Component targets**

| Parameter | Sub-parameter | 2010 | 2011 | 2012 | 2013 | 2014 | 2010-14 Average | Proposed Target | Weight |
|---|---|---|---|---|---|---|---|---|---|
| **Unplanned outage circuit event rate** | Lines event rate – fault | 16.81% | 24.37% | 32.50% | 20.66% | 30.58% | **24.98%** | 24.98% | **0.20** |
| | Transformer event rate – fault | 7.26% | 11.90% | 21.26% | 31.25% | 22.83% | **18.90%** | 18.90% | **0.20** |
| | Reactive plant event rate – fault | 27.14% | 34.29% | 45.71% | 47.14% | 25.71% | **36.00%** | 36.00% | **0.10** |
| | Lines event rate – forced | 14.29% | 16.81% | 14.17% | 12.40% | 15.70% | **14.67%** | 14.67% | **0.10** |
| | Transformer event rate – forced | 13.71% | 4.76% | 13.39% | 10.94% | 11.81% | **10.92%** | 10.92% | **0.10** |
| | Reactive plant event rate – forced | 14.29% | 22.86% | 22.86% | 35.71% | 38.57% | **26.86%** | 26.86% | **0.05** |
| **Loss of supply event frequency** | Number of events greater than 0.05 system minutes per annum | 1 | 0 | 2 | 5 | 3 | **2.2*** | 3 | **0.15** |
| | Number of events greater than 0.30 system minutes per annum | 0 | 0 | 1 | 1 | 0 | **0.4*** | 1 | **0.15** |
| **Average outage duration** | Average outage duration | 92.5 | 4.0 | 230.0 | 19.9 | 24.0 | **74.1** | 74.1 | **0.20** |
| **Proper operation of equipment** | Failure of protection system | 14 | 23 | 33 | 41 | 33 | **28.8** | 28.8 | **0.00** |
| | Material failure of SCADA | 0 | 0 | 1 | 6 | 2 | **1.8** | 1.8 | **0.00** |
| | Incorrect operational isolation of primary or secondary equipment | 7 | 5 | 8 | 4 | 6 | **6** | 6 | **0.00** |

** Note these averages are unadjusted (see discussion below for details of the adjustment applied)*

The proposed targets have been calculated as discussed below. The targets, caps and collars are then summarised in the next section.

*Unplanned outage circuit event rate*

The proposed target is equal to average annual performance for the years 2010 to 2014. For the first time, non-zero weightings will apply to the forced outage sub-parameters.

*Loss of supply event frequency*

Proposed targets for each Loss of Supply Event Frequency sub-parameter in the forthcoming regulatory control period have been calculated using the following methodology:

1. Calculate average annual performance from 2010-14;
2. Apply an adjustment to reflect the reduction in the VCR; and

3. Round the adjusted average performance data to the closest integer, consistent with clause 3.2 (l) of the STPIS.

In September 2014, AEMO published new VCR values following an extensive review which used choice modelling and a large-scale customer survey. Different VCR values were published for different business sectors and for customers directly connected to the transmission network. Compared to the previous VCR values (set by VENCorp in 2008), these were much lower.

The VCR is used to quantify the level of risk associated with key plant and lines assets and is a key input into AusNet Services' economic planning framework. A reduction in the VCR means consumers place a lower value on reliability than has been assumed in network planning to date. Consumers would prefer to pay lower prices for a lower level of reliability than has been supplied in the past. To efficiently respond to this change, AusNet Services expects its reliability to gradually decline over the forthcoming and subsequent periods as it defers asset replacements and passes on consequential cost savings to consumers through lower prices.

The reduction in reliability resulting from the decrease in the VCR is expected to be gradual at a whole of network level and, because of the long-lived nature of transmission assets, persist over the long-term. Consequently, setting targets based solely on historical performance will unfairly penalise AusNet Services for efficiently responding to changes in consumer preferences.

In particular, historical performance from 2010-14 is a function of network planning decisions underpinned by the previous VCR values, whereas performance over the forthcoming and subsequent periods will be a function of planning decisions made using the new, lower VCR. Furthermore, because targets are set using a recent five-year average of historical performance, the target setting process will not address a gradual decline in reliability. In these circumstances, AusNet Services would be faced with a perpetual penalty for efficiently providing its customers with their preferred level of reliability.

To determine an appropriate adjustment to its targets to reflect the reduced VCR, AusNet Services has used its Transformer Dependability Model (TDM) to assess how the reliability of its fleet of transformers will be impacted by the reduced VCR. Using the VCR (among other things) as an input, the TDM calculates the probability weighted costs associated with the transformers installed on the Victorian electricity transmission network by quantifying the effect of transformer failures. The total effect of transformer failures comprises:

- Expected unserved energy;
- Environmental damage;
- Safety risk; and
- Collateral damage.

By comparing the probability weighted cost of transformer failure with the cost of transformer replacement, the TDM is used to determine how many transformer replacements are economically justified over a 10 year outlook period.

AusNet Services compared the output of the TDM (i.e. the total effects of transformer failure) under two scenarios; one using the previous (higher) VCR and one using the September 2014 VCR value, holding all other inputs constant. Under the lower VCR scenario, the model shows that the total effects of transformer failure over the next 10 years are around 39% higher.

Accordingly, the model shows that by economically deferring transformer replacements, the lower VCR will result in deterioration in the condition of the transformer fleet such that the probability of failure, and therefore the cost of failure, increases by 39%.

The expected cost of transformer failure is a function of the number and duration of outage events. Changing the VCR in the TDM does not affect the duration of outage events because the duration is a model input that is held constant. Accordingly, the increase in the expected cost of transformer failure is directly related to the number of outage events.

This increase can be used as a proxy for the expected increase in the number of outage events across AusNet Services' other transmission assets, including circuit breakers and lines assets. This is because the relationship between VCR and expected cost of failure demonstrated by the TDM applies equally to other types of assets.

To develop targets for the forthcoming regulatory period, AusNet Services therefore applied a 39% increase to its average 2010-2014 performance, and rounded this number to the closest integer. This adjustment results in targets of 3 and 1 for the number of events greater than 0.05 and 0.30 system minutes sub-parameters, respectively. Adjusting targets in this manner aligns with the AER's preferred approach to accounting for the reduced VCR during the forthcoming regulatory control period:

> *"Rather than changing the parameter weighting, we have chosen to adjust the performance targets. This adjustment may either be made through clause 3.2(i) or (j). However, before such an adjustment in targets can be made, it is important that any link between the reduction in VCR and loss of reliability be demonstrated."*[63]

The adjustment methodology is consistent with clause 3.2(j), which allows the AER to approve targets based on an alternative methodology provided it is satisfied that:

- The methodology is reasonable;
- Performance has been consistently very high over the previous five years;
- It is unlikely performance can be improved further without compromising other regulatory obligations;
- The proposed targets are not a lower threshold than the targets applying in the current period; and
- The proposed methodology is consistent with the STPIS objectives.

The proposed adjustment is also in accordance with clause 3.2(k), which allows targets to be adjusted for, among other things, the expected material effects of performance from any changes to the age of assets compared to the period used to calculate targets.

As demonstrated in section 7.3.1, AusNet Services' performance under the Loss of Supply Event Frequency parameter has been consistently very strong from 2010-14, with further improvements beyond this level increasingly difficult to make.

While the adjustment has resulted in a lower threshold for one of the sub-parameters (the number of events greater than 0.05 system minutes) than that applied in the current period, AusNet Services considers that the adjusted target (3) is warranted in light of the magnitude of the expected decline in reliability as a result of the VCR reduction.

Further, without the adjustment outlined above, AusNet Services' strong historical performance would result in a target of zero for the number of loss of supply events greater than 0.30 system minutes sub-parameter. This target would result in a scenario where AusNet Services would receive no bonus for recording no outages. AusNet Services considers that, under a bonus-penalty incentive scheme, failing to reward a TNSP for achieving the strongest possible performance outcome is inconsistent with the objectives of the scheme.

Finally, given average performance from 2010-14, achieving zero outages during the forthcoming period is equivalent to maintaining current levels of reliability. Applying unadjusted targets would therefore effectively be penalising AusNet Services for reaching the performance frontier and then maintaining this performance level over the forthcoming period. This is inconsistent with NER 6A7.4 (b), which states that the STPIS should:

[63] AER (2015) *Electricity transmission network service providers service target performance incentive scheme: Final Decision*, September 2015, p.12

> *"Provide incentives for each Transmission Network Service Provider to:*
>
> *… (ii) improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices"*

Indeed, the application of unadjusted targets would mean that over time, maintained, or small improvements in, performance would yield no penalty or bonus. This conflicts with NER 6A.7.4 as there would be no incentive to 'maintain', but only to (substantially) 'improve' performance. This also conflicts with the NEO as investment in improving reliability when performance is approaching the performance frontier is not necessarily efficient, particularly as improvements are very difficult to make when a TNSP is performing at this level. This approach would be particularly concerning in light of the expected reliability impacts of the VCR outlined above.

*Average outage duration*

The proposed target is equal to average annual performance for the years 2010 to 2014.

*Proper operation of equipment*

AusNet Services has reliable historic data on the number of events that have occurred for each of the three sub-parameters. According, targets based on 2010-14 performance are proposed to apply to these sub-parameters in the forthcoming period.

***Methodology for setting caps and collars***

Clause 3.2(e) of the STPIS specifies that the proposed caps and collars must be calculated by reference to the proposed performance targets and using a sound methodology. These may result in symmetric or asymmetric incentives for the TNSP.

The proposed collars and caps have been developed using the same methodology as that adopted by the AER in the current determination and in recent determinations for TransGrid and TasNetworks. This approach reflected advice from EMCa that collars and caps should provide an equal number of probable outcomes on either side of the target. For asymmetrical distributions, this outcome is achieved by setting collars and caps at the 5th and 95th percentile.

These percentiles have been calculated using the distribution which best fits the 2010-14 performance data, as determined by statistical analysis using the @RISK software. Appendix 7A sets out this analysis.

For two sub-parameters (loss of supply event frequency (>0.30 system minutes) and incorrect operational isolation of primary or secondary equipment), the IntUniform distribution was found to be the best fit. However, to align with the AER's approach for the current determination[64], the Poisson distribution has instead been used to set caps and collars for these sub-parameters.

The table below shows the assumed probability distribution for each sub-parameter that has been used to set caps and collars to apply for the forthcoming regulatory period.

**Table 7.3: Probability distribution used to set Service Component caps and collars**

| Parameter | Sub-parameter | Distribution |
|---|---|---|
| **Average Circuit Outage Rate** | Lines event rate – fault | Erlang |
| | Transformer event rate – fault | Rayleigh |
| | Reactive plant event rate – fault | LogLogistic |

[64] AER (2013) *AER Draft decision* | *SP AusNet 2014–15 to 2016–17* | *Service target performance incentive scheme*, August 2013, p.185.

| Parameter | Sub-parameter | Distribution |
|---|---|---|
| | Lines event rate – forced | Lognorm |
| | Transformer event rate – forced | Weibull |
| | Reactive plant event rate – forced | Erlang |
| **Loss of Supply Event Frequency** | Number of events greater than 0.05 system minutes per annum | Hypergeometric |
| | Number of events greater than 0.30 system minutes per annum | Poisson |
| **Average Outage Duration** | Average outage duration | Weibull |
| **Proper Operation of Equipment** | Failure of protection system | Poisson |
| | Material failure of SCADA | Geometric |
| | Incorrect operational isolation of primary or secondary equipment | Poisson |

The table below presents the proposed targets, collars and caps for each of the service component parameters, using the methodology described above.

**Table 7.4: Proposed Service Component targets, collars and caps**

| Parameter | Sub-parameter | Cap | Target | Collar |
|---|---|---|---|---|
| **Average Circuit Outage Rate** | Lines event rate – fault | 15.9% | **25.0%** | 35.7% |
| | Transformer event rate – fault | 4.7% | **18.9%** | 35.8% |
| | Reactive plant event rate – fault | 21.7% | **36.0%** | 55.7% |
| | Lines event rate – forced | 12.3% | **14.7%** | 17.3% |
| | Transformer event rate – forced | 6.2% | **10.9%** | 15.4% |
| | Reactive plant event rate – forced | 13.4% | **26.9%** | 44.1% |
| **Loss of Supply Event Frequency** | Number of events greater than 0.05 system minutes per annum | 0 | **3** | 5 |
| | Number of events greater than 0.30 system minutes per annum | 0 | **1** | 2 |

| Parameter | Sub-parameter | Cap | Target | Collar |
|---|---|---|---|---|
| **Average Outage Duration** | Average outage duration | 1.7 | **74.1** | 253.8 |
| **Proper Operation of Equipment** | Failure of protection system | 20 | **28.8** | 38.0 |
| | Material failure of SCADA | 0.0 | **1.8** | 6.0 |
| | Incorrect operational isolation of primary or secondary equipment | 2.0 | **6.0** | 10.0 |

### *Market Impact Component*

As already noted, the MIC has been amended in version 5 of the STPIS so that it provides a bonus or penalty of up to 1 per cent of MAR each year.

In accordance with Appendix F of the STPIS, the key parameters for the MIC to apply to AusNet Services for the forthcoming period will be calculated as follows:

- Performance is measured as the number of dispatch intervals during a calendar year where an outage on the TNSP's network results in a network constraint with a marginal value greater than $10/MWh;
- The performance target for the MIC is set equal to the average of the median five years from the last seven years of actual performance;
- Caps and collars are set equal to zero and twice the performance target, respectively.

For AusNet Services, the performance target to apply from April 2017 will be based on average performance of the median five years from 2009-16. Accordingly, targets, caps and collars will be determined once these data are available. The below shows AusNet Services historical MIC performance calculated in accordance with Version 5 of the STPIS.

**Table 7.5: MIC performance, 2009-14**

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| **Dispatch intervals** | 1,417 | 2,134 | 2,687 | 909 | 745 | 852 |

The STPIS also requires each TNSP's revenue proposal to provide data in accordance with Appendix C. The appendix also sets out a number of exclusions including, for example, any outages shown to be primarily caused or initiated by a fault or other event on a third party system. Where the number of counts for a given outage exceeds 17 per cent of the annual performance target, the number of counts for that constraint set will be capped at 17 per cent of the annual performance target. The data supplied in the reset RIN complies with these requirements.

### *Network Capability Component*

As already noted, the Network Capability Component provides an incentive of up to 1.5 per cent of maximum allowable revenue each year, prorated to proposed expenditure and subject to completion of projects that improve the capability of the transmission network at times when it is most needed. The scheme is initiated by the TNSP submitting a Network Capability Incentive Parameter Action Plan (NCIPAP) which contains:

- A list of every transmission circuit and injection point on the network, and the reason for the limit for each; and
- A list of priority projects to be undertaken during the forthcoming regulatory control period to improve the limit of the transmission circuits and injection points listed above.

AEMO plans the transmission network in Victoria. Therefore the NCIPAP has been prepared jointly with AEMO. Clauses 5.4(e) and (g) of the STPIS require the TNSP to consult with AEMO about the NCIPAP proposal, and to record any disagreements in the proposal. There were no such disagreements during the development of the NCIPAP.

The full NCIPAP is attached (Appendix 7B). The projects identified and total expenditure are provided in the table below.

**Table 7.6: Proposed NCIPAP Projects ($'000s, real 2016-17)**

| Project number | Project category | Description | Proposed Project Circuit / Injection Point | Total cost |
|---|---|---|---|---|
| **1** | Terminal Station upgrade | Hazelwood to Jeeralang No. 4 line limiting elements upgrade | Hazelwood to Jeeralang 220 kV No. 4 line | 107 |
| **2** | Transmission line upgrade | South East to Heywood 275 kV lines upgrade | South East to Heywood 275 kV No.1 and No. 2 lines | 18 |
| | | | **Total Expenditure** | **125** |

AusNet Services' transmission licence specifies that AusNet Services must not augment the transmission system except:

- In accordance with ESC guidelines; or
- Pursuant to a network agreement with AEMO, or a connection agreement with a distributor, generator or customer.

Therefore, full approval of the NCIPAP requires approval from AEMO for AusNet Services to undertake the projects. This approval has been obtained in the form of a letter of endorsement from AEMO (Appendix 7C).

## 7.4 Efficiency Benefit Sharing Scheme

The EBSS provides continuous incentives for opex efficiency gains to be achieved by the TNSP. It also provides for a fair sharing between the TNSP and network users of opex efficiency gains and losses.

This section 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.

### 7.4.1 The current period carryover 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 2014-15 to 2016-17 period.

This calculation involved the following steps:

- Determining opex for EBSS purposes for 2014-15, which is equal to total opex (including debt raising costs) less costs considered uncontrollable by the AER:
  - Self-insurance;
  - Easement land tax;
  - Rebates under the Availability Incentive Scheme (AIS);
  - Debt raising costs;
  - The costs of priority projects approved under the network capability component of STPIS; and
  - Movements in provisions allocated to opex.
- Forecasting opex for EBSS purposes for 2015-16 by applying AusNet Services' opex forecasting methodology. AusNet Services will replace this forecast with actual 2015-16 opex in its Revised Revenue Proposal.
- Determining opex for EBSS purposes for 2016-17 by adding the efficient benchmark increase approved by the AER to 2015-16 opex; and
- Calculating the efficiency carryover amount by comparing opex for EBSS purposes with the approved regulatory allowances.

Note that the 2014-15 incremental efficiency gain/loss has been calculated using the approach set out in the AER's draft decision for the 2014-15 to 2016-17 period, in accordance with the AER's final decision for that period. The AER described the rationale for this approach as follows:

> *"For calculating efficiency gains, and to provide AusNet Services with a continuous incentive to reduce opex, we will treat 2014–15 as year 7 of the EBSS, not as year 1 of version one of the EBSS for electricity TNSPs. Because we will finalise this determination before the completion of 2013–14, we need to use an estimate of 'actual' opex to calculate the efficiency gains or losses for that year. If differences arise between this estimate and the actual expenditure of 2013–14, we will account for this difference when we calculate the efficiency gain for 2014–15."*[65]

This approach uses the following formula, which has been applied within the Reset RIN:

$$E_7 = (F_7 - A_7) - (F_6 - A_6) + (F_3 - A_3)$$

where $F_7$ is the forecast opex we approved for year 7, and $A_7$ is the actual opex incurred for year 7, and so on.[549] The formula references year 3 because it is the base year used to forecast opex.

AusNet Services has applied the approach outlined above to calculate the efficiency gain in 2014-15. However, AusNet Services considers that this formula incorrectly references year 3 as the base year of the previous regulatory control period (2008-09 to 2013-14). The base year used to forecast opex for the current regulatory control period was in fact 2011-12, which is year 4 of the previous period. Accordingly, AusNet Services' calculation of the efficiency gain in 2014-15 uses the formulae above but substitutes "$(F_3 – A_3)$" with "$(F_4 – A_4)$".

---

65 AER, *SP AusNet transmission determination – draft decision*, August 2013, p. 197.

In calculating the EBSS carryover amount, AusNet Services' has also diverged from the Reset RIN by:

- Applying a different half year inflation adjustment approach, which aligns with other aspects of this Revenue Proposal which also use a half year adjustment (e.g. opex);
- Converting nominal values to real 2016-17 dollars using the CPI index (i.e. September or December quarter CPI) set out in the regulatory determination applying to each year. This contrasts with the Reset RIN's exclusive use of December quarter CPI; and
- Correcting for a calculation error in cells L35:37 of the Reset RIN.

The following table sets out the calculation of AusNet Services' incremental efficiency gains and losses in the current period.

**Table 7.7: Calculation of incremental efficiency gains / losses ($m, real 2016-17)**

| | 2010-11 | 2011-12 | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 |
|---|---|---|---|---|---|---|---|
| | Actual | Actual | Actual | Actual | Actual | Estimate | Estimate |
| **Total opex (incl. debt raising costs)** | **201.8** | **200.3** | **198.5** | **204.9** | **202.6** | **207.4** | n/a |
| Less: Self-insurance | 2.7 | 2.7 | 2.7 | 2.7 | 1.8 | 1.8 | n/a |
| Less: Easement land tax | 109.2 | 113.3 | 109.9 | 111.9 | 109.6 | 115.3 | n/a |
| Less: Rebates under the AIS | 3.1 | 2.5 | 2.2 | 3.4 | 2.5 | 0.0 | n/a |
| Less: Debt raising costs | 4.7 | 4.1 | 4.4 | 3.4 | 3.1 | 3.1 | n/a |
| Less: Network Capability Component project costs | n/a | n/a | n/a | n/a | 0.3 | 0.0 | n/a |
| Less: Movements in provisions | 0.4 | 0.7 | 1.4 | 1.5 | -0.1 | 0.0 | n/a |
| **Actual opex for EBSS purposes** | **81.8** | **77.1** | **77.9** | **82.0** | **85.4** | **87.2** | **88.1** |
| **Forecast opex for EBSS** | **83.9** | **84.9** | **86.5** | **87.4** | **84.2** | **86.5** | **87.3** |
| **Incremental efficiency gain/loss** | **n/a** | **n/a** | **n/a** | **n/a** | **1.2** | **0.5** | **0.0** |

The following table shows how the above incremental efficiency savings have been used to determine the proposed carryover amount of $5.6m (real 2016-17).

**Table 7.8: Calculation of incremental efficiency gains / losses ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| Carryover of efficiency gain/loss made in: | | | | | | |
| 2014-15 | 1.2 | 1.2 | 1.2 | n/a | n/a | **3.5** |
| 2015-16 | 0.5 | 0.5 | 0.5 | 0.5 | n/a | **2.0** |
| 2016-17 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| Efficiency carryover amount | **1.7** | **1.7** | **1.7** | **0.5** | **0.0** | **5.6** |

### 7.4.2 Proposed application of the EBSS

In its Framework and Approach, the AER proposes to apply its new EBSS to AusNet Services for the forthcoming regulatory control period. This version of the EBSS is largely unchanged from the scheme that applied during the current regulatory period. However, in contrast to that scheme, 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 following exclusions for the EBSS in the forthcoming regulatory control period are proposed:

- Self-insurance;
- Easement land tax; and
- The cost of priority projects approved under the network capability component of the STPIS.

This is consistent with the AER's treatment of these costs during the current period.

### *Treatment of debt raising costs*

AusNet Services has proposed a debt raising cost opex allowance which is forecast on a revealed cost basis. Given this, AusNet Services is not seeking to exclude debt raising costs from the EBSS going forward.

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 perpetual penalty that would clearly be inconsistent with both the requirements of NER 6A.6.5 and the NEO. It would also mean that differences between actual and benchmark costs would not flow through to future opex allowances, affecting the sharing ratio of the EBSS.

## 7.5 Capital Expenditure Sharing Scheme

The CESS provides financial rewards for TNSPs that deliver capex efficiencies and financial penalties if capex becomes less efficient. Consumers benefit from improved efficiency through lower prices in the future. The CESS must be consistent with the capex incentive objective[66], which is to ensure that only capex that meets the capex criteria[67] enters the RAB used to set revenues and prices. The intention of these arrangements is to ensure that consumers only fund capex that is efficient and prudent.

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between TNSPs and network users.

In its Framework and Approach, the AER stated that it will apply the CESS in the forthcoming regulatory control period. AusNet Services endorses the AER's position.

## 7.6 Link to Other Building Blocks

As discussed in Chapter 4, AusNet Services' capex proposal is underpinned by, among other things, the revised VCR values published by AEMO in September 2014. This change has had a material impact on the economic assessment of the asset replacement program and has resulted in the economic deferral of several major station rebuilds, benefiting customers through lower prices over the long-term.

As detailed in section 7.3.2, AusNet Services has reflected the change in VCR by adjusting its proposed loss of supply event frequency targets. If the AER supports the use of the updated VCR in the development of AusNet Services' forecast asset replacement plans, then to ensure consistency across its determination, the VCR's impact on reliability should also be properly accounted for in the STPIS. This will ensure that AusNet Services is not penalised for its

---

66 As set out in NER 6A.5A(a).

67 Set out in NER 6A.6.7(c)(1) to (3).

economic planning approach, which incorporates up-to-date estimates of the value placed on reliability by customers.

## 7.7 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 7A – Fitting Probability Distributions for Service Component Data
- Appendix 7B – Network Capability Parameter Action Plan (NCIPAP)
- Appendix 7C – AEMO's NCIPAP Endorsement Letter

# 8 Regulatory Asset Base

## 8.1 Introduction

This chapter presents information on AusNet Services' regulatory asset base (RAB) for the forthcoming regulatory period. The RAB calculation is particularly relevant to the calculation of the return on capital and depreciation elements of the building block proposal. The RAB has been calculated in accordance with NER S6A.1.3(5) and Schedule 6A.2, and the requirements of the AER's proposed amended transmission RAB roll forward model (RFM)[68].

This chapter is structured as follows:

- Section 8.2 sets out AusNet Services' calculation of the opening RAB at the start of the forthcoming regulatory control period, 1 April 2017, and
- Section 8.3 sets out AusNet Services' proposed RAB roll forward into the forthcoming regulatory control period, which reflects AusNet Services' forecast capital expenditure and depreciation.

## 8.2 Roll Forward of 2014 Regulatory Asset Base to 1 April 2017

To establish the opening RAB as at 1 April 2017, it is necessary to roll forward the AER's approved RAB value as at 1 April 2014 for capital additions, disposals, revaluations and deductions of actual depreciation. In the final decision for the previous control period (2014-17), the AER determined AusNet Services' closing RAB (Partially As Incurred) as at 1 April 2014 to be $2,876.0m (nominal). The arrangements for rolling forward the RAB value from 1 April 2014 are set out in NER S6A.2.1(f). In effect, the roll forward of the RAB value from 1 April 2014 to 1 April 2017 is undertaken through the following steps:

- Commence with the nominal RAB value determined by the AER as at 1 April 2014; add
- An inflation adjustment to the opening RAB in each regulatory year of the current regulatory control period; add
- Actual and estimated nominal capital expenditure for each year of the current regulatory control period, being 1 April 2014 to 31 March 2017; deduct
- Actual and estimated nominal depreciation during the current regulatory control period; add
- Group 3 assets which were completed during the current regulatory control period up to 31 December 2014[69], rolling into RAB as at 31 March 2017 at their depreciated values; deduct
- Any inefficient capital expenditure incurred in 2014/15, subject to specific conditions having been satisfied; deduct
- Any difference between AusNet Services' forecast and actual nominal capital expenditure and forecast and actual nominal depreciation in establishing the RAB as at 1 April 2014, in accordance with NER S6A.2.1(c)(2).

It is worth noting the following points in relation to the steps described above, and the calculations shown in the table below:

68 At the time of writing this proposal the AER's proposed amended roll forward model for transmission is in draft stage only.

69 Arrangements relating to roll-in of Group 3 assets are explained in section 1.3.3 of this proposal.

- There is no need to revisit the AER's opening RAB as at 1 April 2014, apart from making an adjustment to address any capex forecasting discrepancies in relation to the 2013-14 regulatory year (final year of previous control period).
- Under NER S6A.2.2A, the conditions that would allow the AER to reduce the RAB as a result of identified inefficiency in AusNet Services' capital expenditure in 2014/15 do not apply, and therefore no reduction is warranted.
- The AER's Final Decision for the 2014-17 period mandates the deduction of actual depreciation from the RAB, rather than forecast depreciation[70].
- The inclusion of Group 3 prescribed assets is the process by which certain transmission system augmentations undertaken during a regulatory control period are rolled into the RAB. The augmentations are used to provide prescribed transmission services. The inclusion of these assets in AusNet Services' RAB is in accordance with the provisions set out in NER 11.6.21(c). Further information on the Group 3 capex to be included in the opening RAB is set out in section 8.3 below. Section 1.3.3 of this proposal provides further information on the arrangements for Group 3 augmentations.
- The AER's determination of the opening RAB as at 1 April 2014 contained an estimate of the Group 3 capital expenditure undertaken during the 2008/09 to 2013/14 regulatory period. An adjustment to account for both the difference and the compounded return on the difference between estimated and actual value of Group 3 assets is therefore included in the calculation of the opening RAB as at 1 April 2017.

The table below shows the calculation of AusNet Services' opening RAB value as at 1 April 2017.

**Table 8.1: Estimation of opening RAB value (As Incurred) as at 1 April 2017 ($m, nominal)**

| Regulatory year (commencing 1 April) | 2014/15 | 2015/16 | 2016/17 |
|---|---|---|---|
| Opening RAB | **$2,876.0** | **$2,949.4** | **$3,015.5** |
| Net Capital expenditure excluding Group 3 | $156.8 | $150.6 | $183.8 |
| Opening RAB inflation addition | $62.1 | $68.1 | $70.9 |
| Nominal Straight line depreciation | -$145.6 | -$152.5 | -$165.1 |
| Interim Closing RAB - excluding final year adjustments | **$2,949.4** | **$3,015.5** | **$3,105.0** |
| Difference Between Forecast and Actual Net Capex for the 2013/14 regulatory year | | | $19.6 |
| Return on 2013/14 Net Capex difference | | | $4.9 |
| Difference Between Actual and Forecast Group 3 Asset Roll in at 1 April 2014 | | | $0.2 |
| Return on Difference – Group 3 Asset Roll in | | | $0.0 |
| **Opening RAB at 1 April 2017** (prior to roll-in of Group 3 assets) | | | **$3,129.7** |

70 AER, *Final Decision, SP AusNet Transmission Determination 2014-17*, January 2014, footnote 49, p. 20.

As shown in the table above, the RAB value as at 1 April 2017 (prior to roll-in of Group 3 assets) in nominal dollars is $3,129.7m. It is noted that the capital expenditure values for 2015/16 and 2016/17 are forecast and therefore the opening RAB as at 1 April 2017 may be subject to change during the AER's review process as new information on AusNet Services' actual capital expenditure becomes available.

An adjustment will be made at the next revenue review for any differences between forecast capital expenditure and the outturn amount, similar to the adjustment described earlier in relation to the 2013-14 financial year. We also note and accept the AER's intention to use the forecast depreciation approach to establish the RAB at the commencement of the 2022–27 regulatory control period[71].

The calculations set out above are consistent with the AER's proposed roll forward model Version 3, which the AER issued in July 2015. The completed model is included as part of this Revenue Proposal.

## 8.3 Forecast of Regulatory Asset Base over the Forthcoming Regulatory Control Period

The table below presents a summary of the amounts, values and inputs used by AusNet Services to derive its forecast RAB value for each year of the forthcoming regulatory control period. In accordance with NER S6A.2.1(f)(4), only actual and estimated capital expenditure properly allocated to the provision of prescribed transmission services in accordance with AusNet Services' Cost Allocation Methodology has been included in the RAB.

In accordance with the approach explained in section 8.2 above, Group 3 assets are rolled into the RAB at their actual depreciated values to derive an adjusted opening RAB as at 1 April 2017. The roll in of Group 3 capex is the total actual Group 3 expenditure over the period from 1 July 2012 to 31 December 2014. This period commences immediately after the cut-off date (of 30 June 2012) for the roll-in of Group 3 assets in the current transmission determination. A list of the assets and their values is provided at Appendix 5C.

**Table 8.2: Regulatory asset base roll forward (As Incurred) 1 April 2017 to 31 March 2022 ($m nominal)**

| Regulatory Year | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Opening RAB | $3,129.7 | $3,312.7 | $3,362.2 | $3,398.7 | $3,422.8 |
| Group 3 Assets roll in | $99.0 | - | - | - | - |
| **Adjusted Opening RAB** | **$3,228.7** | **$3,312.7** | **$3,362.2** | **$3,398.7** | **$3,422.8** |
| Net Capital expenditure | $187.4 | $166.5 | $166.4 | $157.8 | $137.1 |
| Opening RAB inflation addition | $75.9 | $77.8 | $79.0 | $79.8 | $80.4 |
| Nominal depreciation | -$179.4 | -$194.8 | -$208.9 | -$213.5 | -$199.1 |
| **Closing RAB** | **$3,312.7** | **$3,362.2** | **$3,398.7** | **$3,422.8** | **$3,441.2** |

*Source: AusNet Services PTRM*

71 AER, Final Decision - Framework and approach for AusNet Services Regulatory control period commencing 1 April 2017 April 2015, p. 27.

# 9 Depreciation

## 9.1 Key Points

- AusNet Services is forecasting total depreciation costs of $561.4m (real 2016-17) for the forthcoming regulatory control period.
- AusNet Services is proposing to:
  - Continue to apply straight-line depreciation to assets in the existing RAB, in line with the approach approved by the AER for the current regulatory control period;
  - Introduce declining balance depreciation to accelerate the return of assets commissioned from 1 April 2017; and
  - Fully depreciate assets that are to be decommissioned in the current or forthcoming regulatory control periods.
- This approach will better align cost recovery with expected network utilisation to encourage more efficient pricing signals in future periods.

## 9.2 Introduction and Overview

### 9.2.1 Introduction

This chapter sets out AusNet Services' forecast depreciation for the forthcoming regulatory control period. Forecast depreciation relates to assets that are included in the RAB for the forthcoming period, as discussed in the previous chapter. The chapter is structured as follows:

- Section 9.3 describes AusNet Services' proposed depreciation approach;
- Section 9.4 presents AusNet Services' forecast depreciation costs for the forthcoming regulatory control period; and
- Section 9.5 sets out AusNet Services' justification for its proposed approach.

### 9.2.2 Overview

AusNet Services is forecasting total depreciation costs of $561.4m (real 2016-17) for the forthcoming regulatory control period. In developing this forecast, AusNet Services is proposing to:

- Continue to apply straight-line depreciation to assets in the existing RAB, in line with the approach approved by the AER for the current regulatory control period;
- Introduce declining balance depreciation to accelerate the return of new assets from 1 April 2017; and
- Fully depreciate assets that are to be decommissioned in the current or forthcoming regulatory control periods.

The AER has recognised that accelerated depreciation may be an appropriate mechanism to mitigate the risk presented by disruptive technologies (e.g. solar PV and battery storage) to the Australian energy sector:

> *"Further, we recognise the development of disruptive technologies in the Australian energy sector may create some non-systematic risk to the cash flows of energy network businesses. We consider these can be more appropriately compensated through regulated cash flows (such as accelerated depreciation of assets)."*[72]

AusNet Services agrees with the AER that altering the timing of the recovery of depreciation charges is an appropriate regulatory response to addressing utilisation risk because it better matches cash flows with expected network use.

Accordingly, in light of recent and expected developments in disruptive technologies, the proposed depreciation forecast will better align cost recovery with expected network utilisation, encourage more efficient pricing signals in future periods and limit the extent to which capital is exposed to utilisation risk.

Forecast depreciation for existing, new and decommissioned assets is presented in the table below.

**Table 9.1: Forecast depreciation ($m, real 2016-17)**

| Depreciation | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| **Existing assets** | 173.0 | 159.9 | 154.2 | 145.6 | 121.2 | **753.9** |
| **New assets** | - | 23.8 | 38.3 | 46.6 | 53.7 | **162.5** |
| **Decommissioned assets** | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | **11.6** |
| **Less: indexation on opening RAB** | -74.1 | -74.3 | -73.7 | -72.8 | -71.6 | **-366.5** |
| **Total** | **101.1** | **111.7** | **121.2** | **121.8** | **105.7** | **561.4** |

## 9.3 Proposed Depreciation Approach

AusNet Services' proposed depreciation approach involves:

- Continuing to apply straight-line depreciation to assets in the existing RAB, in line with the approach approved by the AER for the current regulatory control period;
- Introducing declining balance depreciation to new assets from 1 April 2017; and
- Fully depreciate assets that are to be decommissioned in the current or forthcoming regulatory control periods.

This approach will better align cost recovery with the expected network utilisation, encouraging more efficient pricing signals in future periods and limiting the extent to which capital is exposed to utilisation risk.

[72] AER, *SA Power Networks preliminary decision – Attachment 3: Rate of Return*, April 2015, p. 376.

### 9.3.1 Existing assets

AusNet Services proposes to depreciate its existing RAB (i.e. all assets in existence as at 31 March 2017) using the methodology approved by the AER for the current regulatory control period. This methodology applies straight-line depreciation using standard asset lives for each regulatory asset class. Straight-line depreciation is a well-established method used to reflect the decline in the service potential of an asset over its economic life.

Straight-line depreciation is calculated using a disaggregated approach. This involves disaggregating the existing RAB into asset groups based on when the assets were added to the RAB (i.e. at the start of each regulatory control period). Each individual asset group has its own opening asset value and remaining lives, which are used to calculate separate depreciation charges for each group.

To determine annual depreciation charges for existing assets, AusNet Services applied its own model, which uses the disaggregated approach to calculate depreciation charges for the forthcoming regulatory control period. This model, which is included in the PTRM provided with this Revenue Proposal, sets out the values, inputs and calculations used to determine forecast depreciation.

AusNet Services' proposed standard asset lives for the forthcoming regulatory control period are unchanged from the current period, and are presented in the table below. Proposed remaining lives for existing assets, which are based on the approved standard lives below, will continue unchanged from the current period. Consistent with the AER's previous determinations, equity raising costs from the 2003-08 regulatory control period have been amortised using a 28 year life.[73]

**Table 9.2: Proposed standard asset lives**

| Asset class | Standard life |
|---|---|
| **System assets** | |
| **Secondary** | 15 years |
| **Switchgear** | 45 years |
| **Transformers** | 45 years |
| **Reactive plant** | 40 years |
| **Lines** | 60 years |
| **Establishment** | 45 years |
| **Communications equipment** | 15 years |
| **Business support** | |
| **Buildings** | 45 years |
| **Vehicles** | 7 years |
| **Other business support** | 10 years |
| **IT** | 5 years |
| **Land** | Not depreciated |
| **Easements** | Not depreciated |
| **Equity raising costs (2003-08)** | 28 years |

[73] AER (2014) Final Decision, SP AusNet transmission determination, January 2014, p. 19

### 9.3.2 New assets

AusNet Services proposes to apply declining balance depreciation to new assets (i.e. capex commissioned from 1 April 2017) during the forthcoming regulatory control period. This approach accelerates depreciation of new investments compared to the straight line approach. AusNet Services considers that its proposed approach is justified due to the potential impact of disruptive technologies on the future utilisation of its network. Importantly, applying declining balance depreciation to new assets does not impact the total amount of depreciation recovered from customers, just the timing of this recovery. AusNet Services' justification for adopting this approach is discussed further in section 9.5 below.

The following formula was applied to determine declining balance depreciation rates to apply to new assets:

*Depreciation rate = (1 / standard asset life) * 2*

The above method of calculating depreciation rates is consistent with the methodology applied under Australian Taxation Law. These laws require that, for assets purchased on or after 10 May 2006, a rate of 200% must be applied if the declining balance method is used to depreciate the relevant asset.

### 9.3.3 Decommissioned assets

Following third party advice, AusNet Services intends to remove from service a number of transmission assets prior to, or during, the forthcoming regulatory control period. These assets, which are part of the shared network, are:

- Transmission assets at Morwell Power Station (MPS) that will be decommissioned due to the closure of MPS; and
- Synchronous condensers (SCOs) at the Fishermans Bend (FBTS), Brooklyn (BLTS) and Templestowe Terminal Stations (TSTS) that AusNet Services is proposing to retire, subject to further advice from AEMO.

AusNet Services proposes that these assets are fully depreciated over the forthcoming period.

The opening RAB value of these assets has been calculated to be $11.6m (real 2016-17), of which the SCOs account for $11.3m. This translates to less than 1% of the total opening RAB value at 1 April 2017. While the SCOs were commissioned over 40 years ago, additional capex since that time has resulted in substantial remaining asset values.

Section 9.5.2 provides further information to justify the full depreciation of these assets. The opening RAB values for these assets and the methodology used to derive them are provided as supporting documentation.

## 9.4 Forecast Depreciation Allowance

Based on the depreciation methodology described above, AusNet Services' total forecast depreciation for the forthcoming regulatory control period is $561.4m (real 2016-17). Depreciation amounts for existing, new and decommissioned assets are presented in the table below.

**Table 9.3: Forecast depreciation ($m, real 2016-17)**

| Depreciation | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| **Existing assets** | 173.0 | 159.9 | 154.2 | 145.6 | 121.2 | **753.9** |
| **New assets** | - | 23.8 | 38.3 | 46.6 | 53.7 | **162.5** |
| **Decommissioned assets** | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | **11.6** |
| **Less: indexation on opening RAB** | -74.1 | -74.3 | -73.7 | -72.8 | -71.6 | **-366.5** |
| **Total** | **101.1** | **111.7** | **121.2** | **121.8** | **105.7** | **561.4** |

## 9.5 Justification for Accelerated Deprecation

AusNet Services' proposed approach to depreciating existing assets aligns with the methodology approved by the AER for the current regulatory control period. Accordingly, this section sets out AusNet Services' justification for the application of accelerated depreciation to:

- New assets; and
- Decommissioned assets.

### 9.5.1 New assets

***Changing circumstances***

AusNet Services' current depreciation methodology allows for an asset's costs to be recovered evenly over the period of its service. While this approach allows the depreciation building block to be largely constant over time, RAB indexation results in depreciation charges that increase over time because they are based on an ever-increasing RAB value, back-ending depreciation charges. The economic and equity merits of this approach are predicated on the assumption that transmission assets will continue to be used at high utilisation rates for their forecast lives.

However, the National Electricity Market is undergoing substantial changes that will impact the transmission sector during the lifetime of new assets that will be built in the forthcoming regulatory control period. These changes primarily relate to a general reduction in energy sourced from traditional, centralised network sources, as well as a change in the generation mix. They involve:

- An increased consumer focus on meeting their energy needs from their own sources (e.g. rooftop PV);
- The introduction of disruptive technologies, principally battery storage, at prices competitive with electricity network services;
- A focus on more distributed electricity generation sources that may reduce the utilisation of transmission network assets;
- Structural and policy-driven changes in Victoria and Australia that may lead to location specific reductions in network utilisation (see Box 9.1); and
- Continuing uncertainty in future environmental policies and standards, which is influencing the manner in which future electricity generation and use is evolving.

**Box 9.1: Case study: Closure of Point Henry smelter**

In August 2014, Alcoa's Point Henry aluminum smelter closed due to financial viability and competiveness issues driven by excess capacity in the Asian markets served by the smelter.[74] The smelter's energy needs have historically been met through a combination of Alcoa's Anglesea Power Station (APS) and AusNet Services' Geelong Terminal Station to Point Henry (GTS-PTH) transmission line, which connects directly to the smelter. In May 2015, Alcoa announced that it will permanently close APS on August 31, 2015.

These closures mean that AusNet Services' GTS-PTH line is no longer being utilised to supply power to the smelter, or export energy from APS into the NEM. While a decision as to the future need for the GTS-PTH line has not yet been made, AusNet Services understands that the majority of the line will be required to connect a future Geelong East Terminal Station. The future of the remaining part of the line is unclear; however AusNet Services considers it unlikely that this section will be retired due to the high costs involved.

The closure of Alcoa's assets, while not driven by the uptake of disruptive technologies, highlights the exposure of AusNet Services' transmission assets to stranding risk and the decoupling of economic growth from electricity demand growth in parts of Australia. Future structural change in the Victorian and Australian economies, including changes brought about by increasing competition from Asia and domestic energy policy developments, may result in location-specific reductions in the utilisation of these assets. This risk is expected to be greatest where the location-specific reductions occur in circumstances where future network planning does not create a continued need for the asset(s) in question.

Together, the developments outlined above are creating continuing uncertainty about the future utilisation of electricity networks. Whether utilisation risk is best managed through changes to the cost of capital or the timing of the recovery of depreciation costs is also a current area of debate. This is because the potential changing circumstances may significantly alter the economics of investment in long lived transmission assets. By reducing the confidence around the time period over which a transmission investment may provide the services intended at the time of its deployment, thus increasing stranding risk, these changes may have implications for the cost of capital in the event that investors reassess the risk of funding investment in transmission assets. This would increase the return on capital networks must recover from customers.

The AER has recognised that accelerated depreciation – rather than an adjustment to the cost of capital – may be a more appropriate mechanism to mitigate the risk presented by disruptive technologies (e.g. solar PV and battery storage) to the Australian energy sector:

> *"Further, we recognise the development of disruptive technologies in the Australian energy sector may create some non-systematic risk to the cash flows of energy network businesses. We consider these can be more appropriately compensated through regulated cash flows (such as accelerated depreciation of assets)."*[75]

AusNet Services agrees with the AER that altering the timing of the recovery of depreciation charges is an appropriate regulatory response to addressing utilisation risk because it better matches cash flows with network use.

In April 2015, Tesla announced a range of battery storage products known as Tesla Powerwall, including both home-storage devices and larger devices for industrial consumers. It is reported that the Powerwall has been sold out through to the middle of 2016.[76]

---

74 https://www.alcoa.com/australia/en/news/releases/PTH.asp

75 AER, *SA Power Networks preliminary decision – Attachment 3: Rate of Return*, April 2015, p. 376.

76 http://www.engadget.com/2015/05/06/tesla-powerwall-earnings/

According to UBS analysts, the Powerwall will have a payback period of six years in Australia.[77] While the Powerwall will not be available in Australia until 2016, Tesla's competitors (e.g. Mercedes Benz and Daimler AG) may release products prior to this to capture early market share.

In June 2015, AEMO released its inaugural *Emerging Technologies Information Paper*, which forecasts the potential long-term impacts of battery storage, electric vehicles and fuel switching on consumers in the residential sector in the NEM. In developing this paper, AEMO has recognised that "large scale penetration of new technologies can occur over a short period of time."[78]

AEMO has forecast that the uptake of battery storage in Victoria will result in a 2.7% reduction to its maximum demand forecasts by 2024-25, increasing to 6.2% by 2034-35.[79] According to AEMO:

> *"Victoria currently has a time-of-use tariff structure that incentivises the uptake of battery storage, as households are able to use electricity from the battery during peak times. Victoria has the highest installed battery capacity (2,774 MWh) by the end of the forecast period, and this results in a sizeable reduction in the 10% POE summer and winter maximum demand forecasts."*[80]

Due to data limitations on the economics of retrofitting battery storage to existing rooftop PV systems, the forecasts include only the uptake of batteries that form part of a new installation of rooftop PV. Therefore, this conservative forecasting approach does not include uptake from a segment of electricity consumers that is likely to install battery storage technology during the outlook period. This is because households with existing rooftop PV are likely to:

- Be early adopters of disruptive technologies; and
- Consider the installed cost of a rooftop PV / battery storage system more financially attractive than households without rooftop PV.

Including retrofits in the forecast may therefore materially increase the impact of battery storage on demand.

While the uptake rate of battery storage will be driven by a range of factors, future trends in battery prices is foremost among these. The figure below, which shows long-term projections of battery prices, demonstrates that battery prices are forecast to decline sharply in the USA over the years to 2030 before flattening. Within AusNet Services' forthcoming regulatory period (shaded green), substantial price reductions have been forecast.

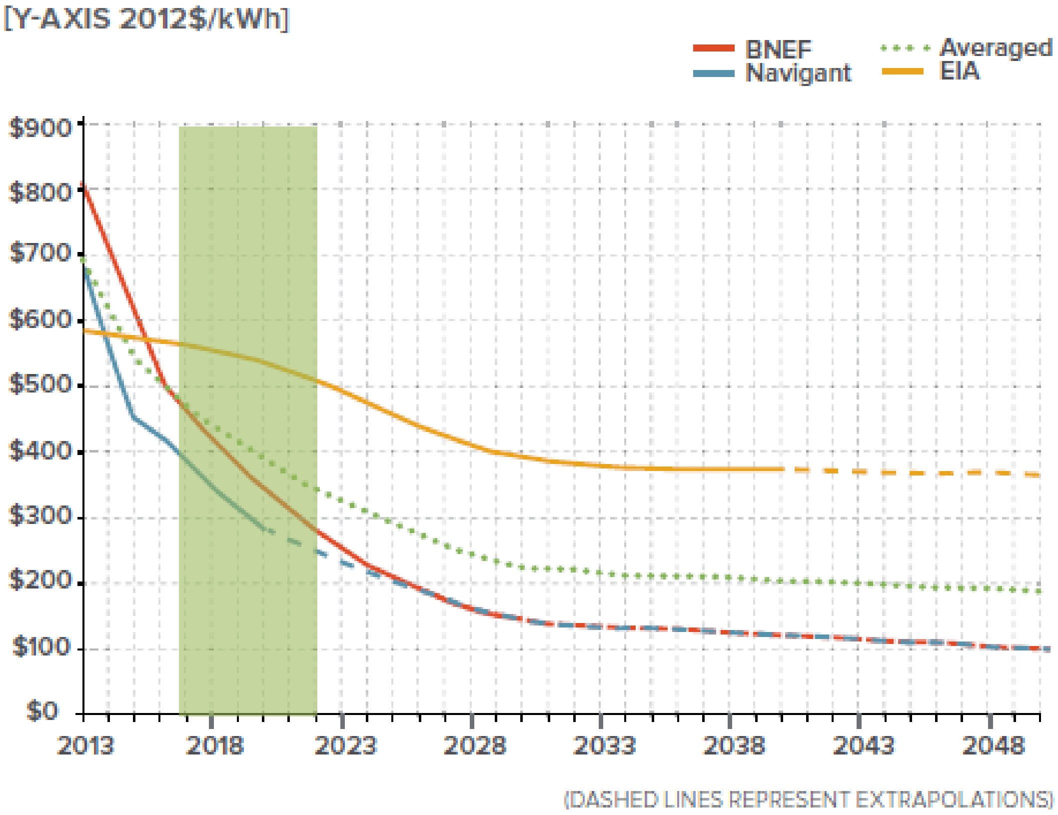
77 http://reneweconomy.com.au/2015/ubs-tesla-powerwall-can-deliver-6-year-payback-in-australia-63386

78 AEMO (2015) *Emerging Technologies Information Paper*, June 2015, p. 3.

79 AEMO (2015) *Emerging Technologies Information Paper*, June 2015, p. 5.

80 AEMO (2015) *Emerging Technologies Information Paper*, June 2015, p. 5.

**Figure 9.1: Battery price projections**




Source: *Rocky Mountain Institute (2015) The economics of grid defection – when and where distributed solar generation plus storage competes with traditional utility service, February 2014, p. 24.*

Note: *Battery price projections are based on data from Bloomberg New Energy Finance (BNEF), Navigant Research and the U.S. Energy Information Administration (EIA).*

Since the above projections were published in 2014, recent developments in the disruptive technologies space, namely Tesla's Powerwall, suggest that these projections may now be considered conservative estimates of the future reductions in battery prices that will take place.

A dramatic reduction in battery prices is expected to drive significant uptake of storage over the long-term. Indeed, the Rocky Mountain Institute considers that:

> *"Notably, the point at which solar-plus-battery systems reach grid parity—already here in some areas and imminent in many others for millions of U.S. customers—is well within the 30-year planned economic life of central power plants and transmission infrastructure."*[81]

The above analysis is based on selected geographies in the US that were chosen because they cover a representative range of conditions that influence grid parity, including annual solar resource potential, retail electricity prices, and currently installed distributed PV. Nevertheless, it is a useful indicator of potential developments in Australia, in part because of its high degree of solar penetration.

A number of prominent industry experts and analysts consider that uptake of battery storage will have a significant impact on the energy sector.

According to Bloomberg New Energy Finance's (BNEF) *New Energy Outlook 2015,* more than 50% of Australia's generating capacity will be located "behind the meter" by 2040, with more than 37GW of small-scale solar PV and 33GW of battery storage installed by then. [82]

---

81 Rocky Mountain Institute (2015) *The economics of grid defection – when and where distributed solar generation plus storage competes with traditional utility service*, February 2014, p. 6.

BNEF also predict that the payback period for an average 5kWh storage system coupled with 4KW of PV for a residential consumer will decline from 18 years currently to eight years by 2040 in Australia, and that this type of system will be able to supply residential customers with electricity cheaper than the grid by 2020 in most Australian states.[83]

This analysis highlights the potential for disruptive technologies to present credible competition to traditional network solutions well within the timeframes of new assets commissioned during the forthcoming period. Further, new assets have lives that extend decades beyond the outlook of currently available projections (such as BNEF's), increasing the level of uncertainty with respect to the continued utilisation of these assets across their full lives relative to existing assets.

### *Efficient pricing signals*

#### *The challenge*

The above changing circumstances with respect to electricity consumption and demand trends have significant potential impacts on the future utilisation of electricity networks and importantly, on the efficiency of transmission pricing in future periods.

Because of the capital intensive nature of electricity transmission networks, a large proportion of revenue recovered by these networks relates to the cost of historic investment decisions. Transmission prices, therefore, do not reflect the marginal costs of providing electricity transmission services. While this is partially addressed by two-part tariffs, it has been widely recognised that current pricing signals are substantively affected by the recovery of sunk asset costs. In fact, depreciation and return on capital on sunk investments collectively account for over half of AusNet Services' revenue requirement for the current regulatory control period.

Where the uptake of low-cost, alternative energy solutions leads to a reduction in the number of transmission network and end-user customers, future revenue requirements will not reduce commensurately because historic costs will continue to be recovered. Under this scenario, price increases are borne by the remaining customers as the costs of historic investments are recovered through a shrinking customer base, encouraging further exit from the grid to the point that networks are unable to recover their efficient costs. This extreme case is often referred to as an 'electricity death spiral' scenario.

Accordingly, should the economics of disruptive technologies improve and present a cost-effective alternative to electricity networks in future regulatory periods – which is a possible outcome based on the available analysis and projections – higher network prices that do not reflect efficient marginal costs may lead to inefficient underutilisation of networks as more customers reduce their reliance on the grid.

While the current regulatory regime ensures TNSPs can recover the costs of prudent and efficient investment – which contributes to lower price outcomes by reducing the risk attached to investment in networks and consequently the cost of capital – the scenario outlined above presents a real and significant risk to cost recovery in spite of this protection.

#### *The opportunity*

While non-network solutions are still maturing, the forthcoming regulatory control period presents an opportunity to improve the efficiency of transmission price signals in the future. Accelerating depreciation once these alternatives have become accessible at cost effective prices is likely to exacerbate the inefficiency of pricing signals and encourage inefficient reduction in utilisation of, and exit from, the grid.

---

82 Bloomberg New Energy Finance (2015) *New Energy Outlook 2015 Asia Pacific*, June 2015, p. 42.

83 Bloomberg New Energy Finance (2015) *New Energy Outlook 2015 Asia Pacific*, June 2015, p. 47.

Because new transmission assets will be most exposed to utilisation risk, it is appropriate to accelerate the depreciation of these assets rather than the entire RAB, which would include the value of assets that are approaching the end of their lives. Further, accelerating the depreciation of assets commissioned prior to 1 April 2017 would involve the arbitrary selection of a subset of assets that are deemed to be exposed to a greater degree of utilisation risk than assets commissioned in prior years. Applying accelerated depreciation to new capex only is also considered a more conservative approach, which balances mitigating potential utilisation risk with addressing the concerns of AusNet Services' stakeholders.

Implementing accelerated depreciation of new capex will reduce the extent to which the long term recovery of sunk asset costs affects prices, helping mitigate the risk of increasingly inefficient pricing signals in future periods which could inefficiently encourage uptake of alternative solutions. In contrast, efficient marginal price signals in future periods will encourage customers to use the more efficient network services when deciding how to meet their energy needs. In these circumstances, customer decisions to bypass the electricity network in favour of non-network alternatives would be based on efficient price signals, thereby maximising the productive efficiency of the network

AusNet Services recognises that considerable uncertainty exists with respect to the impact of disruptive technologies on the future utilisation of its electricity network assets. However, to not recover a higher proportion of depreciation costs from today's customers would likely require significantly higher electricity prices in the future to enable sufficient recovery of revenue from a potentially smaller customer base.

This is particularly the case because straight line depreciation charges increase over time due to the indexation of the RAB, exacerbating the potential intergenerational inequities under the current approach. Accelerated depreciation will reduce the cost burden on the future customer base and contribute to more equitable access to electricity across generations.

Against a backdrop of historically low interest rates that have reduced AusNet Services' cost of capital relative to previous regulatory control periods, the forthcoming period presents an opportune time to reduce the value of the asset base through accelerated depreciation. Furthermore, as explained in Chapter 4, the reduction in the Value of Customer Reliability (VCR) measured by the AEMO and in forecast demand has led to the deferral of major replacement projects and reduced the need for future expansion of the network. Both of these factors mitigate the short-term price impact of accelerated depreciation by reducing the capital costs that networks need to recover from customers.

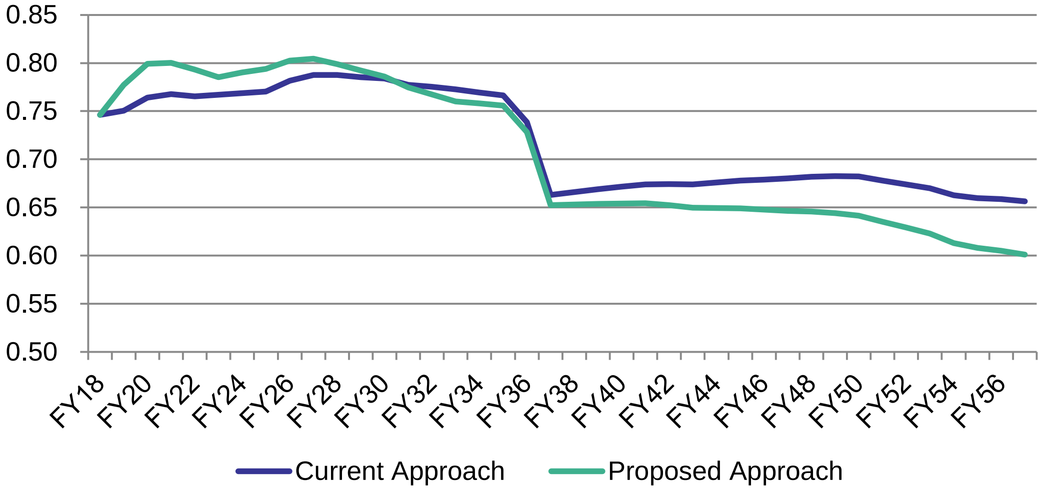
### *Long-term price outcomes*

To illustrate the impact of accelerated depreciation on future price signals, AusNet Services has undertaken indicative modelling of long-term price trends under two scenarios: one where the current depreciation approach is maintained, and one where accelerated (declining balance) depreciation is applied to new assets. Both of these scenarios assume that:

- Electricity consumption remains unchanged from current levels; and
- The cost of capital increases from 2022-23, reflecting a return towards long-run average market interest rates.

To simplify the analysis and isolate the price impacts of the alternative depreciation approaches, the modelling only includes the depreciation and return on capital building blocks.

**Figure 9.2: Indicative long-term price trends with accelerated depreciation (cents per kWh)**



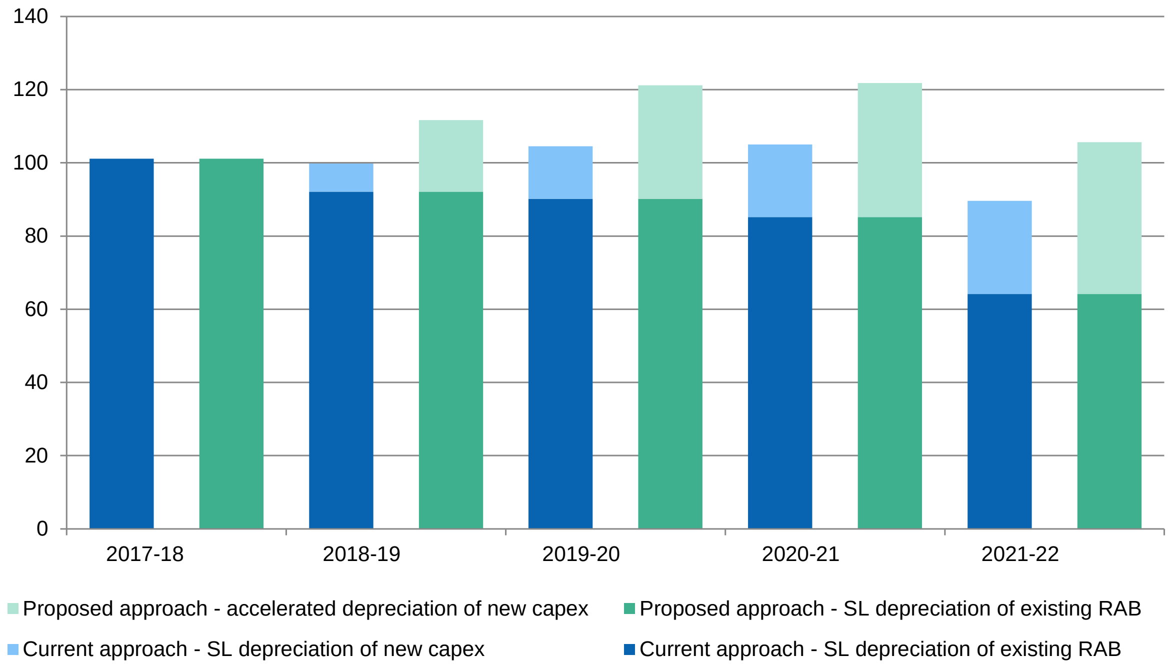

*Source: AusNet Services analysis*

*Note: The sharp reduction in prices in FY37 is a result of the full depreciation of a large segment of network assets in the RAB, based on the indicative, long-term capex forecast AusNet Services has modelled for the years following the 2017-22 period. Actual prices over the outlook period will depend on the actual capex program carried out.*

Figure 9.2 shows that an accelerated depreciation allowance may be able to facilitate improved intergenerational equity outcomes by aligning price trends with potential network utilisation per customer trends, as well as improving the efficiency of the price signals offered by networks in future periods.

AusNet Services has also considered the risk that accelerated depreciation represents to asset stranding from increasing near-term prices. The figure below compares total forecast depreciation under the current and proposed approaches.

**Figure 9.3: Depreciation forecast, current and proposed approaches ($m, real 2016-17)**




*Source: AusNet Services analysis*

Under the current approach, depreciation of new assets would account for $67.4m of the total depreciation forecast. Applying accelerated depreciation to new assets increases this amount to $128.8m, an increment of $61.4m that is equal to around 11% of total forecast depreciation, or around 2% of the total forecast revenue requirement. This increase translates into an average annual price impact of 0.00033 cents per KWh, which is not considered likely to encourage customers to disconnect from, or reduce usage of, the network.

### *Interlinkages with other building blocks*

AusNet Services is proposing range of complementary measures that both:

- Ensures customers have access to a safe, reliable and secure supply of electricity; and
- Limits the extent to which the network is exposed to utilisation risk.

These measures include:

- Shorter term or operational measures to defer asset replacement, such as increased maintenance activities to extend the life of assets in poor condition and the use of advanced condition monitoring techniques to prioritise asset replacement;
- Minimising investment in the parts of the network most at risk of future stranding (such as the Latrobe Valley), with over 95% of the major stations replacement projects being located in either wider metropolitan Melbourne or being linked to the interconnectors into NSW and South Australia. These assets are amongst the assets least at risk from future stranding, even under assumptions of extreme reductions in consumption;
- Deferring key replacement projects in response to the recent reduction in the VCR and demand forecasts, which are key inputs into AusNet Services' asset replacement planning framework; and
- Retiring assets that are no longer utilised, therefore reducing the size of the RAB.

AusNet Services has adopted a holistic approach to managing the uncertainty around the future utilisation of its network, rather than relying solely on accelerated depreciation. However, accelerating the depreciation of new assets is considered the key lever by which utilisation risk may be managed because there are likely to be many circumstances where a long life investment may be required even where its longer term utilisation is highly uncertain. The specialised nature of transmission assets, the safety obligations TNSPs must comply with and the very high costs imposed on customers for failure means that in many cases there is no practical alternative to capital investment.

The proposed WACC does not contain any provision for future utilisation risk.

### *Meeting the requirements of the regulatory framework*

The regulatory framework requires that assets be depreciated "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."[84]

While the NER do not prescribe meaning to the "nature" of assets, the characteristics of the market served by AusNet Services' transmission assets, including the utilisation of these assets, is considered part of the nature of these assets. That is, clause 6A6.3(b)(1) should be interpreted as implying that if the 'nature' of the assets is such that they are more heavily utilised now than they are likely to be in the future due to emerging competition from disruptive technologies, then a depreciation schedule that addressed this risk is justified.

Accordingly, in the context of the potential impacts of disruptive technologies that have been outlined in this chapter, AusNet Services' proposed depreciation profile aligns with the NER and

---

84 NER, Clause 6A6.3(b)(1).

the achievement of the NEO because it delivers an outcome which best serves the long-term interest of customers. Should the AER consider that new capex is of the same nature as existing assets, AusNet Services would consider the application of accelerated depreciation to its entire RAB using a rate that manages price impacts to the levels set out in this Revenue Proposal.

### *Stakeholder views*

AusNet Services facilitated a number of forums to obtain stakeholder views on, among other things, applying accelerated depreciation to address uncertainty about future network utilisation. To provide stakeholders with further opportunity to provide feedback on accelerated depreciation, a stakeholder consultation paper was also developed and published on AusNet Services' website. This paper can be found at Appendix 3B.

ElectraNet provided a submission in response to the stakeholder consultation paper. ElectraNet was of the view that uncertainty around future asset utilisation warranted further consideration of accelerated depreciation, and that "an accelerated depreciation approach in uncertain circumstances given the rapidly changing market conditions may provide more accurate pricing signals and drive more efficient consumer outcomes."[85] ElectraNet also suggested that the removal of RAB indexation, which effectively acts to defer depreciation, may be considered as an alternative means of changing the profile of depreciation cost recovery. While this alternative approach has merit, its implementation is likely to require changes to the NER as the current provisions mandate RAB indexation.

AusNet Services' stakeholders were not in favour of accelerated depreciation, largely due to its short-term impact on prices. While accelerated depreciation does increase price pressure in the short-term relative to straight-line depreciation, there are strong efficiency and equity grounds to accelerate the depreciation of AusNet Services' new capex in the context of expected trends in the utilisation of these assets.

Applying accelerated depreciation to new capex only is a relatively conservative approach compared to other possible modes of accelerated depreciation. This approach, which increases the total depreciation forecast by 12% compared to straight line, has been adopted in order to balance mitigating potential utilisation risk with addressing the concerns of AusNet Services' stakeholders regarding price.

AusNet Service also has an obligation to act in the interest of future consumers who would bear the potentially significant price increases caused by declining utilisation. The NEO specifies that the **long-term** interests of electricity consumers should be promoted. AusNet Services has developed a depreciation methodology that is consistent with the promotion of this objective. The proposed methodology is also consistent with the NER provisions regarding depreciation profiles.

However, AusNet Service acknowledges the concerns of its stakeholders, and is cognisant of the need to clearly demonstrate the advantages and disadvantages of its proposed depreciation approach. The following table sets out the key concerns and questions expressed by stakeholders with respect to accelerated depreciation, and AusNet Services' responses. The consultation paper noted above provides additional information on AusNet Services' interaction with its stakeholders.

[85] ElectraNet submission dated 12 June 2015.

**Table 9.4: Stakeholder concerns and questions regarding accelerated depreciation**

| Stakeholder concern / question | AusNet Services' response |
|---|---|
| **Customers should not pay for the depreciation of existing assets** | While the current regulatory regime ensures TNSPs can recover the costs of prudent and efficient investment, this protection contributes to lower price outcomes by reducing the risk attached to investment in networks and consequently the cost of capital. If a degree of utilisation risk was to be borne by networks, a commensurate adjustment to the WACC would be required to reflect this. |
| **Accelerated depreciation is equivalent to making customers pay for historic overinvestment by networks** | AusNet Services' investment decisions are made within a probabilistic planning framework, which compares estimated project costs with customer benefits. Under this framework, network investments are only made where customer benefits exceed project costs. |
| **There a risk that businesses will be incentivised to replace assets more quickly if accelerated depreciation is applied** | AusNet Services has also proposed accelerated depreciation using the declining balance method, which does not change asset lives, rather than by reducing asset lives.<br><br>As noted above, the prudency and efficiency of asset replacement projects is determined by evaluating the net economic benefits offered by the project. Projects are only justified if they will yield positive net economic benefits. As the depreciated value of assets is not an input into this analysis, the suggested incentive would not exist. |
| **Price increases caused by accelerated depreciation may be "sticky" over the long-run to the extent that other costs replace declining depreciation charges** | The regulatory framework provides a suite of incentives for AusNet Services to continuously drive efficiencies with respect to both operating and capital expenditure. These efficiency savings directly reduce long-term price pressure faced by customers.<br><br>Further, AusNet Services has developed its approach to accelerated depreciation in the context of its price impact, with lower capex and relatively low financing costs reducing the broader revenue requirement. AusNet Services is therefore cognisant of the price impact accelerated depreciation will have on customers.<br><br>For this reason, AusNet Services has applied accelerated depreciation to new capex only, rather than new and sunk assets. |
| **Proposing accelerated depreciation to address utilisation asset risk may not be consistent with proposing opex step changes to extend the life of existing assets** | AusNet Services recognises the importance of being consistent in its approach to addressing utilisation risk and is proposing a range of complimentary measures to manage the size of its RAB and the uncertainty around the future utilisation of its network. These include increased opex to extend the life of assets, rather than replacing assets. |
| **Does accelerated depreciation increases the amount of depreciation recovered by networks?** | Applying declining balance depreciation to new assets does not impact the total amount of depreciation (in present value terms) that is recovered from customers, just the timing of this recovery. |

| Stakeholder concern / question | AusNet Services' response |
|---|---|
| | |
| **Are other electricity networks proposing accelerated depreciation?** | No other networks have explicitly proposed declining balance depreciation as a means of addressing utilisation risk. |
| **Have AusNet Services' investors have expressed concerns with respect to utilisation risk?** | While investors acknowledge that the current regulatory framework protects networks from utilisation risk, recent analyst reports have highlighted the potential impact of disruptive technologies on the future recovery of investments made by Australian electricity networks.<br>In a recent note, Citi Research considered that "the risk of stranded assets and a death spiral as customers disconnect from the grid in favour of distributed generation is well publicised. We see limited near term risks however, because networks revenues are moving from a price cap to a revenue cap that protects against volume risk. But longer term we see significant potential risks."[86]<br>In February 2015, Morgan Stanley reduced its valuation of Spark Infrastructure, the part-owner of SA Power Networks, CitiPower and Powercor, to reflect its "higher longer run stranding risk relative to peers."[87] |
| **Can accelerated depreciation rates be adjusted if other cost pressures (e.g. the cost of capital) change?** | Any future change in AusNet Services proposed depreciation approach would only be made if there are compelling reasons for making such a change (e.g. due to changes in other cost pressures or the development path of disruptive technologies).<br>It is important to note that, under the regulatory framework, the present value of the depreciation charges for each asset is equal over the long term, regardless of changes that are made to the approach. |

### 9.5.2 Decommissioned assets

Not accelerating the depreciation of decommissioned assets would result in customers funding the return of capital over the remaining lives of the assets in question. Under this approach, future generations would continue to pay for assets that are no longer providing transmission services. AusNet Services does not consider that this contributes to the achievement of the NEO and is therefore proposing to fully depreciate these assets over the forthcoming period.

The proposed approach aligns with the regulatory framework. Specifically, NER 6A6.3 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 identified in section 9.3.3 is such they have been or will be retired in the current or forthcoming periods. AusNet Services' proposal to apply accelerated depreciation to these assets accurately reflects change in the remaining economic lives of those assets.

86 Citi Research (2015) *Regulated Utilities Initiation – A Focus on Dividends*, May 2015, p. 12.

87 Morgan Stanley Research (2015) *Regulatory Utilities – RAB Season*, February 2015, p. 17.

NER 6A.6.3 also requires that, to the extent that assets in the RAB are dedicated to a single customer or group of customers and the indexed value of these assets at the start of the current regulatory control period is greater than $20m, these assets must be depreciated on a straight line basis. Because the value of the assets identified in section 9.3.3 is less than $20m, the proposed full depreciation of these assets is consistent with NER 6A.6.3.

For the above reasons, AusNet Services' proposal conforms to the requirement of the NER. It also has the effect of allocating the costs associated with those assets equitably to those customers more likely to utilise the assets in the earlier parts of their useful lives.

# 10 Rate of Return

## 10.1 Key Points

- AusNet Services' proposed rate of return is 7.22%. This comprises:
  - 10.0% return on equity;
  - 5.37% return on debt; and
  - 60% gearing.
- The cost of equity has been estimated based on the multi-model approach as AusNet Services considers that this methodology is the most appropriate and consistent with the requirements of the NER. Extensive research has shown that there is no single financial model which can accurately estimate the return on equity in all economic circumstances. Therefore combining several different models, each with particular strengths, provides a more robust estimate in different economic conditions.
- The estimated cost of debt is based on a benchmark credit rating of BBB and 10 year term to maturity. Given current material discrepancies between the (recently developed) Bloomberg 10 year BVAL data series and actual debt issuances, AusNet Services proposes that the RBA data series should be solely relied upon at this time. This revenue proposal applies the AER's Guideline transition.
- AusNet Services is proposing a return to the use of a market-based approach to forecasting inflation, which yields an inflation forecast of 2.35%. This approach was applied by the AER prior to 2008. A return to this approach is considered to be appropriate under current circumstances, given:
  - Actual outturn inflation has been significantly lower than inflation forecast of 2.45%, which indicates that the AER's current methodology may not be appropriate in current market conditions;
  - RBA's acknowledgement that monetary policy is a less effective tool to influence inflation outcomes compared to the past; and
  - A return to liquidity in the market for indexed-linked Commonwealth Government Securities, demonstrated by higher traded volumes.

## 10.2 Overview

### 10.2.1 Introduction

Electricity transmission networks must invest in long-lived assets and therefore a key aspect of the Australian Energy Regulator's (**AER**) transmission determination is the allowed rate of return on the capital invested in AusNet Services' transmission network. Clause 6A.14.1 of the National Electricity Rules (**NER**)[88] provides that AER must make a decision on:

- The allowed rate of return for each regulatory year of the regulatory control period in accordance with NER 6A.6.2;[89] and

---

88 AEMC; *National Electricity Rules Version 74*, Rule 6A.14.1(5B), p. 837.

89 AEMC; *National Electricity Rules Version 74*, Rule 6A.6.2, pp. 784 – 786.

- 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 NER 6A.6.2(i).[90]

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.[91]

An efficient allowed rate of return is particularly important. If the rate of return is higher than is efficient, 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 NER 6A.6.2 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 Transmission 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 Transmission Network Service Provider …."*[92]

The new rules require the AER to have regard to all the relevant models and other available inputs,[93] not just the sub-set of material that the Rules previously required. With respect to equity, the new Rules require[94] 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.[95] 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.

The new NER do not alter the requirements the National Electricity Law (**NEL**)[96] that provide that in making the determination in accordance with the NER the AER must exercise its network regulatory functions:

- In a manner that contributes to the achievement of the NEO which promotes 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.

---

90 AEMC; *National Electricity Rules Version 74*, Rule6A.14.1(5B), page 837 and Rule 6A.6.2(i), p. 785.

91 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.

92 AEMC; *National Electricity Rules Version 74*, Rule 6A.14.1(5B), p. 837 and Rule 6A.6.2(c), p. 784.

93 AEMC; *National Electricity Rules Version 74*, Rule 6A.14.1(5B), p. 837 and Rule 6A.6.2(e)(1), p. 784.

94 AEMC; *National Electricity Rules Version 74*, Rule 6A.14.1(5B), p. 837 and Rule 6A.6.2(g), p. 785.

95 AEMC; *National Electricity Rules Version 74*, Rule 6A.14.1(5B), page 837 and Rule 6A.62(i), p. 785.

96 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.

The same reforms 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 driver of the recent 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.

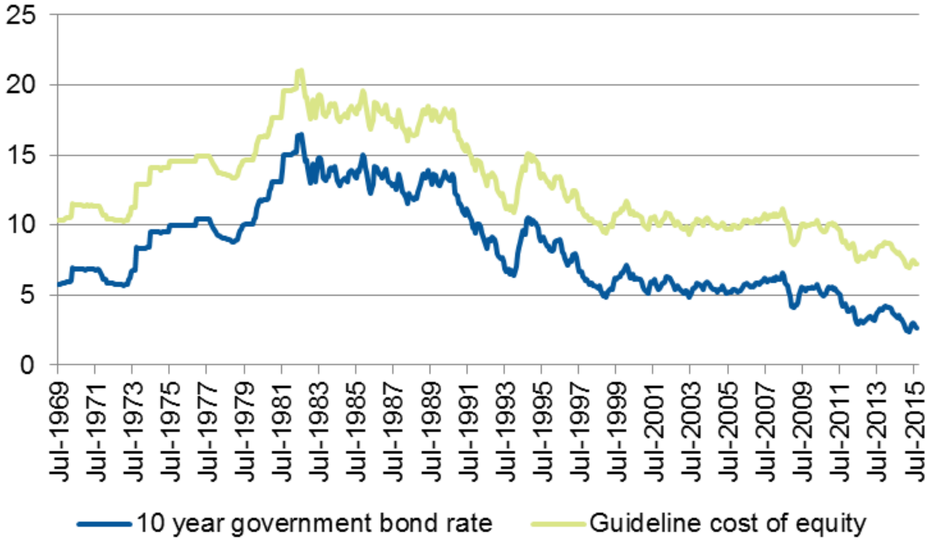
As required by the NER, the AER has issued Rate of Return Guideline[97] (the Guideline) outlining its intended approach to applying the new rules. The AER has issued final decisions for the NSW and ACT electricity distribution network businesses, the NSW and Tasmanian electricity transmission network businesses, and concurrently issued preliminary decisions relating to the South Australian and Queensland electricity distribution network businesses.

With respect to equity, AusNet Services is concerned that the AER’s approach set out in the Guideline and its recent determinations referred to above neither conforms to the new rules, nor provides a market reflective allowed rate of return. 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 AER’s 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. This 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 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 does 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.

97 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).

**Figure 10.1: Impact of changes in CGS yields on the AER's application of the SL-CAPM**




*Source: RBA, AusNet Services' analysis*

There are a number of ways in which the AER's regulatory determinations concerning the equity allowance have changed over the last five years.[98] Nevertheless, when assessing whether the current approach is sensible and robust, it is informative to consider what allowed rates of return the method would have delivered if the approach in the AER's Guideline 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.[99] The fundamental problem with this approach is that there is no reason to suppose that investors' required rates of return have varied perfectly 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, it is clear that the AER must broaden the estimation methods it takes into account and give them real weight.

In the words of the Governor of the Reserve Bank of Australia, Mr Glenn Stevens, equity rates have not in reality followed the unprecedented downward movement in base rates:

> *"[A key] feature that catches one's eye is that, postcrisis, the earnings yield on listed companies seems to have* ***remained where it has historically been for a long time, even as the return on safe assets has collapsed to be close to zero*** *[emphasis added]."*[100]

In fact, the drop in permitted returns when compared with equity market 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:

98 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.

99 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.

100 Reserve Bank of Australia; the World Economy and Australia Address to the American Australian Association luncheon hosted by Goldman Sachs, New York, USA (**RBA Speech**); 21 April 2015.

**Table 10.1: Historical and current regulatory rates of return for equity**

| | Old Rules: Victorian Transmission | | | New Rules: NSW Transmission April 2015 |
|---|---|---|---|---|
| | December 2002 | January 2008 | January 2014 | |
| **Risk free rate** | 5.12% (Nominal) | 6.09% (Nominal) | 4.31% (Nominal) | 2.55% (Nominal) |
| **Beta** | 1.0 | 1.0 | 0.8 | 0.7 |
| **MRP** | 6.0% | 6.0% | 6.5% | 6.5% |
| ***Nominal return on equity*** | 11.09% | 12.09% | 9.51% | 7.1% |
| ***Real return on equity*** | **8.87%** | **9.26%** | **6.89%** | **4.61%** |

*Source: AER website*

As discussed in this chapter, AusNet Services' principal objections to the way in which the AER's Guidelines and the AER's recent 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 four of the relevant models should be used as the NER require;
- The SL-CAPM relies on just three inputs (the risk free rate, a beta value and a value for the market risk premium). The AER has made significant errors in relation to two of these and, as such, the rate of return objective cannot be met and the outcome is contrary to the revenue and pricing principles;
- Further, there is substantial evidence[101] that the SL-CAPM model is significantly downwardly biased when estimating returns for stocks assigned a beta of less than 1.0. There is no sound basis to conclude that the AER's approach of selecting beta and MRP from the upper ends of its ranges will numerically 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 MRP (a key parameter) are equally valid and each should be used when the SL-CAPM estimate is derived. 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 both absolute terms, and also in differences between the regulatory allowance and the actual costs of debt, should be substantially reduced.

101 Handley, J., Report prepared for the Australian Energy Regulator: Advice on the return on equity, University of Melbourne, October 2014, page 5; NERA, Empirical Performance of Sharpe-Lintner and Black CAPMs, February 2015, pages 42, 51 and 52; NERA, Empirical Performance of Relevant Models for Estimating the Return on Equity, February 2015.

Under its transitional arrangements, the AER proposes to continue to predominantly use the "on-the-day" approach that applied under the previous regulatory regime. AusNet Services does not object to the concept of ultimately adopting a trailing average approach, or to an appropriately designed transition. The transition should enable a benchmark efficient firm to recover an appropriate allowance for the return on debt, while it transitions its financing practices to reflect the new trailing average approach.

The AER's adoption of a BBB+ credit rating for a 60% leveraged benchmark firm, if a BBB+ curve became available, depresses the permitted rates of return below a truly market reflective return which should be based on a BBB credit rating.

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 forecast since 2008 when in a final determination for AusNet Services' transmission network the AER determined to discontinue using the Fischer equation and, instead, adopt the RBA's forecasts and targets. At the time, the AER undertook to keep this issue under review.

There are now indications that the factual circumstances upon which the current approach is based have changed. On the one hand, the RBA has stated that there are significant deflationary forces in the economy and the RBA is finding it difficult to achieve inflation results within its target range, yet the AER's inflation assumption is that the RBA will on average achieve its targets. On the other hand, with substantial additional issues of indexed CGS, the concerns that existed in 2008 with using the Fischer equation have now gone. Therefore, it is necessary to revert to the pre-2008 Fischer equation method of determining the inflation rate rather than the AER's current combination of RBA forecasts and targets.

### 10.2.2 Summary table: Departures of this Regulatory Proposal from the Guideline

The Rules require that AusNet Services' revenue proposal identifies proposed departures from the Guideline. The following table summarises these.

**Table 10.2: Departures of this regulatory proposal from the Guideline: Equity**

| Guideline | Regulatory Proposal | Rationale |
|---|---|---|
| ***Which models should be used in setting the allowance:***<br>**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 model (see section 10.4.5(d)). |
| ***How the information gleaned from the models should be synthesised:***<br>**The SL-CAPM, implemented in the way the AER has in the past, should (continue) to play the central role.** | 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 | 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 |

| Guideline | Regulatory Proposal | Rationale |
|---|---|---|
| **Any other information should take a secondary role, at most being used to inform the estimate of one of the SL-CAPM parameters.**<br><br>**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.** | contributions each model can make. | (see section 10.4.4). |
| ***Implementing the SL-CAPM:***<br><br>**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.<br><br>When implementing the Ibbotson approach, the market risk premium should be the arithmetic average for the longest available series – that is 6.56%.<br><br>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.<br><br>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.<br><br>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 (section 10.4.4). |

The table presented below provides a summary of departures from the Guideline on the proposed approach to estimating the cost of debt, but does not seek to discuss components of the cost of debt that were omitted from the Guideline altogether. By way of example, the choice of third party data source was not considered in substance by the AER when it prepared the Guideline. There is no reference to these components in the table below, however, the choice of third party data source that is the most appropriate for reflecting the cost of debt faced by the benchmark efficient entity is discussed and evaluated in the regulatory proposal, and supporting documents.

**Table 10.3: Departures of this regulatory proposal from the Guideline: Debt**

| Guideline | Regulatory Proposal | Rationale |
|---|---|---|
| ***Credit rating from Standard and Poor's:***<br>**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 has substantial government ownership (see section 10.5.4). |
| ***Nomination of averaging periods for the cost of debt.***<br>**The AER requires averaging periods to be nominated for each of the constituent years of the regulatory period. Specifically, the averaging period should be as close as practical to the commencement of each regulatory year in a regulatory control period.**<br>**A period needs to be specified for each regulatory year within a regulatory control period.** | Averaging periods will be nominated in advance.<br>Some averaging periods occur in different parts 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 section 10.5.5). |

### 10.2.3 Chapter outline

This chapter is structured as follows:

- **Treatment of risk:** AusNet Services is concerned that the AER's approach does not adequately address the issue of risk (section 10.3). This issue affects a range of parts of this regulatory proposal including the regulatory depreciation proposal (discussed in Chapter 9 of this regulatory proposal) and the beta chosen when capital asset pricing models are implemented discussed in further in section 10.4;
- **Allowed rate of return for equity:** establishing the allowance for the return on equity (section 10.4);
- **Allowed rate of return for debt:** establishing the allowance for the return on debt (section 10.5);
- **Inflation expectations:** the forecast inflation rate (section 10.6); and
- **Conclusion:** an illustrative calculation establishing a rate of return using data from the period 22 June to 17 July 2015 (section 10.7).

## 10.3 General Assessment of Risk

AusNet Services is concerned that two aspects of the AER's recent determinations do not adequately address the issue of the risks now facing the notional benchmark energy network business.

Firstly, the AER has based its 0.7 beta for a 60:40 leveraged energy network business upon a report by Frontier Economics that it procured as part of the rate of return guideline process in 2013. At that time, Frontier Economics considered that energy network businesses had lower than average systematic risk (implying an asset beta of less than 1.0), but its report did not support the notion that a business carrying 60% debt would have a beta of less than 1.0. However, the AER has misinterpreted that report and erroneously concluded that leveraged energy businesses would have a beta of less than 1.0.

Since the 2013 rate of return guideline review, Frontier Economics has prepared an additional report (Appendix 10A – Frontier Economics, *"Review of the AER's conceptual analysis for equity beta"* 2015) explaining that the AER has misunderstood and misapplied the analysis it undertook in 2013.

The most significant misconception in the way that the AER uses Frontier Economics' work is that it has wrongly equated the issue of how leveraging affects risk with the discussion by Frontier Economics of "financial risks" and, more generally, the AER has not adequately accounted for the effect of leverage on risk. As the Frontier Report summarises:

> *"The fact that the precise relationship between leverage and equity beta is not known with certainty does not mean that the effect of leverage on beta should be disregarded when making comparisons between estimated equity betas. Such an approach would be at odds with accepted finance and regulatory practice.*
>
> *The "financial risks" that we considered in our 2013 report for the AER are not the same as financial leverage and do not substitute for the leverage component of equity beta. The AER appears to have misunderstood this point in our 2013 report.*
>
> *The evidence that the AER presents in relation to US utility betas supports a re-levered equity beta estimate of close to 1."*[102]

The fundamental point is a simple one. If a business takes on substantial debt (which takes a fixed return and ranks higher than equity in priority upon liquidation), the risk for equity holders will rise significantly.

Using the language of the SL-CAPM model, *even if* the underlying business itself has less systematic risk than the average investment, once the additional risk of leveraging is taken into account, there is no concrete basis to conclude that the appropriate equity beta is below 1.0. Some alternative models for estimating the return on equity (such as the Dividend Growth Model ("DGM")) do not explicitly contain a "beta" measure of risk. Nevertheless, the DGM accounts for risk another way in the process of selecting the relevant comparables for establishing the estimates. The fact that correctly specified DGM estimates currently deliver estimates for the return on equity that are materially higher than using a beta of 0.7 in the AER's SL-CAPM Foundation Model, corroborates the primary evidence we have provided on risk that an equity of beta of 0.7 is too low.

Secondly, the AER has not adequately addressed the issue of risk arising from the disruptive technologies that, as the AER acknowledged in the preliminary SA Power Networks decision, has significantly increased in recent times. Despite that recognition, the AER has not adjusted any of its figures to account for that risk.

Frontier Economics' 2015 report acknowledges the significance of the issue of disruptive technologies:

> *"There have been developments in the roll-out and adoption of disruptive technologies since our 2013 report. There is more uncertainty about the future of the industry now than there was even two years ago, and it is not unreasonable to think that investors would take this into account when allocating scarce capital to this industry."*[103]

---

[102] Frontier; *Review of the AER's conceptual analysis for equity beta*; June 2015, paragraph [10]; p. 2 (attached as Appendix 10A).

[103] *Ibid*; p. 3.

The Frontier Economics report also notes that:

> *"The AER suggests that to the extent that the risks are non-systematic in nature, those risks would more appropriately be compensated through regulated cash flows (such as accelerated depreciation of assets). However, notwithstanding that the AER recognises that disruptive technologies may increase the risks faced by NSPs, the AER has made no allowances for these risks either through the rate of return or through regulated cash flows."*[104]

Future changes to networks arising from disruptive technologies could be substantial. AusNet Services considers that the new risks associated with disruptive technologies are best reflected in the regulatory determination as an accelerated depreciation allowance for new investment. This is consistent with our view that in the short run our assets are likely to be more heavily utilised than in future – as such, it is both more efficient and equitable to recover a higher proportion of investment from current consumers, and a lower proportion from future consumers. Accelerating the depreciation in this way will also enable prices in the future to be lower which will facilitate keeping customers connected when the price of disruptive technologies is likely to be lower.

If the AER was not to accept our proposed regulatory depreciation approach our investors would be carrying additional risk and this would need to be reflected in the return on equity calculation.

This issue is discussed in more detail in Chapter 2 – Operating Environment and Asset Management Approach and Chapter 9 – Depreciation.

Stakeholders asked whether the regulated rate of return compensated regulated entities for the risks associated with disruptive technologies.

The AER has explained in its Preliminary Decision for SA Power Networks, it does not consider that the risk is not systematic (or non-diversifiable) (see page 3-376). As the rate of return only compensates investors for systematic risk, it does not compensate investors for this risk.

The AER further considers that even if the risk were systematic, its approach to setting the equity beta would capture this. However, this risk has become particularly pronounced over the past 1 to 2 years, particularly with battery storage being marketed as a consumer product. The AER considers estimates of equity beta over a five year period. As this risk has increased substantially over this time period, and the NER require the AER to have regard to **prevailing** market conditions, it cannot be argued that this risk is addressed.

## 10.4 Allowed Rate of Return on Equity

Since it is assumed that a benchmark efficient firm in AusNet Services' position would be 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.

As noted in the introduction to this chapter, the NER 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, AusNet Services is concerned that the

104 *Ibid*; [11]; p. 3.

AER's approach as set out in its Guideline and the AER's recent 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 transmission 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. [105] 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 efficient 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.

However, the AER's approach deviates from the requirements of the new NER that regard be had to a broader range of inputs in reaching a decision that is in line with the prevailing cost of equity faced by a benchmark efficient entity. It continues to give primary weight to the SL-CAPM. 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) at centre stage by employing it as the foundation model;
- Using the SL-CAPM as a filter through which all other information must first pass before it can have any bearing on the allowed rate of return. This approach significantly curtails the manner and degree to which the other information can contribute to the allowed rate of return;
- Making errors in applying the SL-CAPM; and
- Having insufficient regard to much of the material presented by:
  - In some cases expressly assigning zero weight to the material (i.e. the Fama-French Three Factor Model); and
  - 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).

This section explores these issues in detail as follows:

- Section 10.4.1 sets out the requirements of the Chapter 6A of the rules with respect to determining the allowed rate of return for equity;
- Section 10.4.2 summarises the approach in the Guideline;

[105] NERA, *The Cost of Equity: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks* A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy June 2015 (attached as Appendix 10B).

- Section 10.4.3 identifies the reasons why the foundation model concept is at odds with the requirements of the rules;
- Section 10.4.4 provides 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 NER; and
- Section 10.4.5 sets out AusNet Services' proposed approach to the return on equity.

### 10.4.1 Requirements of Chapter 6A of the Rules

Under the old NER 6A.6.2, the AER was required to implement the SL-CAPM in a narrowly defined way. The AEMC recognised that this approach was too limited and instead provided that the AER should:

- Have regard to the full range of available models and data when setting the allowed rate of return for equity; and
- Set the allowed rate of return such that it is achieves the rate of return objective – that the allowed rate of return for equity should be commensurate with the prevailing market returns on equity for a benchmark efficient network service provider adopting efficient financing practices.

In understanding how the new Chapter 6A rules are intended to work, it is significant to note the following points in the AEMC's explanatory statement accompanying the new rules:

- The AEMC was of the view that no single model was capable of delivering an optimal allowed rate of return for equity;
- The AEMC intended that the new rules depart from the previous position that had prevailed in the gas rules by which the AER was required to use a "well accepted" model. This had led to a considerable conservative inertia preventing any move away from the SL-CAPM and had resulted in the use of a single model to the exclusion of multi-model approaches.

### 10.4.2 The approach in the Guideline

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:*
>
> *(1) As the foundation model:*
>
> *(2) To inform the estimation of parameters within the foundation model.*
>
> *(3) To inform where within the return on equity range (set by the foundation model) our 'final' return on equity point estimate should fall:*
>
> *(4) 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. …*

*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. …"* [106]

### 10.4.3 The foundation model approach cannot meet the requirements of the rules

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[107], and, consequently the AEMC decided that NER 6A.6.2(e) should require the AER to have regard to all the relevant models, financial methods, market data and other evidence available.

The foundation model is a variation of implementing a "primary model" approach. In relation to primary model approaches, the AER's states in its rate of return guideline explanatory statement that:

*"The key benefit of using a primary model is that it provides greater predictability of outcomes."*[108]

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."*[109]

This claim of predictability is not supported with any evidence, empirical or otherwise, that investors would regard a primary model as providing greater predictability. As a business that raises equity capital in traded capital markets, AusNet Services can affirmatively state that, in its own direct knowledge, current and potential investors prefer the stability that comes from using the broadest range of relevant models directly to estimate the allowed rate

106 AER, *Guideline*; pp.13 – 15

107 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**).

108 AER; *Better Regulation | Explanatory Statement | Rate of Return Guideline* (**Explanatory Statement**); December 2013 (pdf version)*;* p. 54.

109 AER; *Explanatory Statement*; p. 102.

of return so that any short run idiosyncrasies of any particular model due to its particular weaknesses are muted by the influence of the other models.

The AER identified the secondary considerations identified in Table 10.4 below, in support of its decision to adopt the foundation approach.

**Table 10.4: AusNet Services' comments on the AER's foundation approach**

| AER comment | 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. |
| **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. Compared with all three of the other models, the model that produces an outlying result is the SL-CAPM. This is the model chosen by the AER to be the foundation model. |
| **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 multi-model averaging approach. For example, the latter approach can be distilled to a simple mathematic or logical formula whereas most aspects of the foundation model are incapable of expression in that form.<br><br>The way in which the information is categorised and combined is extremely complex and often not transparent.<br><br>Notwithstanding this, simplicity and familiarity are not relevant requirements of the NER. |
| **Using a foundation model approach may allow stakeholders to make reasonable estimates of the returns expected to be determined in advance of a determination. As noted in stakeholder submissions, the guideline should provide certainty and predictability to assist investors in making their investment decisions.** | While adopting the AER's implementation of the S-L CAPM as the foundation model makes the mechanics of how the parameters are combined to yield a final rate of return relative predictable, the outcome is highly sensitive to changes in the risk free rate, so that the outcome is much more unpredictable than the multi-model approach, which 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. That is, the approach has not proven to be flexible to changing market conditions. 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 of instances |

| AER comment | AusNet Services' comment |
|---|---|
| | in which "regulatory judgement" is exercised without an explanation of how the "judgement" has led to the adoption of a particular value. |
| **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 all of the AER's criteria are relevant and/or have been correctly applied. The SL-CAPM is not superior to the other identified models 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.** | While there was an extensive opportunity for stakeholders to provide submissions, few of the concerns raised have been taken into account in the foundation model approach. |

Of more considerable concern, the AER's foundation model is contrary to the requirements of the NER and is flawed 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 maintained one model as preeminent. Consequently, this has improperly prevented other models from contributing to the allowed rate of return according to the merits of what they can bring; and
- The particular formulation of the foundation model – which combines a very short term base rate with a very long run MRP – results in a rate of return that oscillates in volatile cycles that are contrary to the relative stability sought by equity market investors.

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 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 models;
- 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.

The AER and its consultants give very favourable descriptions of the SL-CAPM, despite its known flaws. For instance, the AER states:

*"We consider there is overwhelming evidence that the SL-CAPM is the current standard bearer for estimating expected equity returns."*[110]

McKenzie and Partington, the AER's consultant, 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."*[111]

On the other hand, there is extensive evidence (discussed below) concerning the theoretical and empirical weaknesses of the SL-CAPM.

Even the AER's peer regulators are considerably more sanguine about the merits or otherwise of the SL-CAPM. 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."*[112]

Despite the superior empirical performance of the Black CAPM discussed above,[113] 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."*[114]

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 criticism that:

> *"We consider SFG's latest estimate of the zero beta premium appears more plausible. However, we remain of the view that the large range of zero beta estimates by*

110 AER; SA Power Networks Preliminary Determination Attachment 3, April 2015, at page [3-122].

111 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.

112 (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.

113 See *National Electricity Law*, section 10.4.2

114 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.

> *consultants indicates that the model is unsuitable for estimating the return on equity for the benchmark efficient entity."* [115]

However, 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 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."* [116]

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."* [117]

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.*[118] *Further, the time series for when these estimates are available are both variable and short.*[119]*"*

However, these concerns also apply to the estimation of equity beta. These five companies are also 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:

> *"The sensitivity of DGMs to input assumptions limits the ability to use DGMs as the foundation model."*[120]

---

115 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return;* June 2015, page 3-274 (pdf version).

116 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. 21.

117 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015.

118 The relevant businesses are the APA Group, DUET, Envestra, Spark Infrastructure and AusNet Services.

119 For example, dividend yield estimates for Envestra are available from 2001, and from 2006 for Spark Infrastructure.

120 AER; *Better Regulation | Explanatory Statement (appendices) | Rate of Return guideline* (**Explanatory Statement (appendices)**); December 2013, p. 15 (pdf version).

However, the AER does not acknowledge that 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."*[121]

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."*[122]

The AER also suggests that the perpetual time-frame[123] over which the DGM is specified is inappropriate for regulatory purposes but SFG Consulting 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."*[124]

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*

---

121 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015 p. 3.

122 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015 p. 3.

123 AER; *Final Decision, Jemena Gas Networks, 2015-20, Attachment 3: Rate of Return,* June 2015, page 3-295 (pdf version).

124 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.

*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)."*[125]

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."*[126]

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.*

*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.*

125 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 5.

126 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 2.

*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."*[127]

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."*[128]

### *Extra-legislative criteria distort the evaluation of the merits of the available inputs*

Instead of directly applying the rate of return objective, the NEO and the Revenue and Pricing Principles (RPP), the Guideline applies a set of extra-legislative criteria[129] 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 financial models are required to be consistent with "well accepted economic and finance principles" and promote "simple over complex approaches"[130].

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

---

127 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.

128 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, pp. 22 – 23.

129 AER; *Explanatory Statement*; p. 24.

130 AER; *Explanatory Statement*; pp. 24 – 28.

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)."*[131]

> *"[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."*[132]

> *"The rate of return estimation should not be formulaic and be driven by a single financial model or estimation method."*[133]

> *"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."*[134]

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.[135] 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 **compelling reason to depart from the core framework** [emphasis added] underpinning the foundation model approach as outlined in Figure 5.1 on page 12 of the Guideline?."*[136]

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

131 AEMC; *Draft Rule Determination;* p. 42.

132 AEMC; *Draft Rule Determination;* p. 42.

133 AEMC; *Draft Rule Determination;* p. 47.

134 AEMC; *Draft Rule Determination;* p. 47.

135 Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, pp. 3 & 6.

136 Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, p. 6.

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."*[137]

> *"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."*[138]

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."*[139]

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 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."*[140]

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*[141] *and The Commission considered that no one method can be*

---

137 AEMC; *Economic Regulation of Network Service Providers Rule Change Final Determination* (**AEMC Rule Determination**); November 2012, p. 41.

138 AEMC; *Rule Determination;* p. 46.

139 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.

140 AEMC; *Draft Rule Determination*; p. 46.

141 AEMC; *Rule Determination*; p. 48.

> *relied upon in isolation to estimate an allowed return on capital that best reflects benchmark efficient financing costs."*[142]

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"[143] also leads the decision making process astray. The explicit requirement in NER 6A.6.2(e) 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"[144]. There is no logical basis to apply this constraint upon the use of the models.

The AER has also adopted the criterion for consideration: "where applicable, reflective of economic and finance principles and market information". The AER reveals its intent

142 AEMC; *Rule Determination*; p. 49.

143 AER; *Better Regulation | Rate of Return Guideline*; December 2013, p. 6.

144 AER; *Explanatory Statement*; p. 24.

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:

> *"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."*[145]

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."*[146]

In fact, the model's theoretical underpinning is strong[147,148] 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 hinder the achievement of the rate of return objective.

### *The foundation model imposes improper constraints that prevent real weight being given to all the relevant inputs as required by the rules*

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 NER 6A.6.2(b) 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." [149] [150] And in the absence of a definition of relevant, it is to be given its ordinary meaning in the context.[151] In this regard, it was noted by the AEMC in its draft rule determination[152] and final rule determination:

---

145 AER; *Explanatory Statement*; p. 27.

146 AER; *Explanatory Statement (appendices)*; p. 21.

147 NERA Economic Consulting; *The Fama-French Three-Factor Model, A report for the Energy Networks Association*; October 2013, pp. 8 – 10.

148 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, pp. 17 – 21.

149 *Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231, paragraph 55.

150 *Project Blue Sky v Australian Broadcasting Authority* (1998) 194 CLR 355.

151 *Project Blue Sky v Australian Broadcasting Authority* (1998) 194 CLR 355.

152 AEMC; *Draft Rule Determination*; pp. 9 – 10.

*"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*** *[emphasis added]."*[153]

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; …"*[154]

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;…"*[155]

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 service 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"[156] 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.

153 AEMC; *Rule Determination*; p. 8.

154 AEMC; *National Electricity Rules Version* 74; Rule 6A.6.2(e), p. 784.

155 AEMC; *National Gas Rules Version 25, Part 9 Price and Revenue Regulations*; Rule 87(5), p. 61.

156 *RE Dr Ken Michael AM; ExParte Epic Energy (WA) Nominees Pty Ltd & Anor* [2002] WASCA 231 at [54 – 6].

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)[157] in the establishment of the return on equity; and
- Although some limited role[158] 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 S-L CAPM. Even when used to inform a parameter of the S-L CAPM, they are used as secondary evidence that is disregarded to the extent that it is inconsistent with the primary range that is established using a different subset of the available evidence. Limiting their use this way severely constrains their ability to improve the quality of the return on equity estimate. 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 10.4.3 above).

The Explanatory Statement of the Guideline 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*** *[emphasis added] (informative use of primary model)."*[159]

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 above 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 AER's recent decisions[160] 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

---

157 AER; *Guideline*; p. 13.

158 AER; *Guideline*; p. 13.

159 AER; *Explanatory Statement*; p. 54.

160 For example AER; *Final Decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview;* June 2015, page 32 (pdf version).

consistent with the NER which require reasons to be given at both the draft determination stage[161] and the final determination stage.[162]

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 AER's recent 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."*[163]

And:

> *"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** [emphasis added] on empirical evidence from the Black CAPM, Fama French three factor model (FFM) or SFG's construction of the dividend growth model (DGM) (see appendix A–equity models and appendix B–DGM ). **We do not consider** [emphasis added] 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 section A.3.1 of appendix A- equity models). [emphasis added]*
>
> *Our equity beta point estimate provides a balanced outcome, given the submissions by stakeholders and services providers. Figure 3.28 shows our point estimate and range in comparison with other reports and submissions. **We are satisfied** [emphasis added] 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. "*[164]

And finally:

> *"We apply an equity beta of 0.7, which is above many of the equity beta estimates in Henry's 2014 report. We recognise McKenzie and Partington indicated the Black CAPM*

[161] AEMC; *National Electricity Rules Version* 74; Rule 6A.12.2, pp. 830 – 831.

[162] AEMC; *National Electricity Rules Version* 74; Rule 6A.14.2, p. 836.

[163] AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; April 2015, page [insert] (pdf version).

[164] AER; *Final Decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview;* June 2015, p. 3 – 254 (pdf version).

> *(of itself) does not justify any uplift to the estimated equity beta to be used in the SLCAPM. Nevertheless, we consider this model does theoretically demonstrates that market imperfections **could cause the SLCAPM to generate return on equity estimates that are too high or too low. Therefore, we have taken this into account in exercising our regulatory judgment** [emphasis added] to use an equity beta of 0.7 in the SLCAPM. This is the equity beta set out in the Guideline.*[165]

While the decision discloses a series of matters that were not 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"[166].

Both of these problems are illustrated in the AER's recent decisions. 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[167]. 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."*[168]

[165] AER; *Final Decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview;* June 2015, p. 3 – 254 (pdf version).

[166] 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.

[167] 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.

[168] 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 NER, 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."*[169]

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.*** *[emphasis added] 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*** *[emphasis added]."*[170]

SFG states:

[169] AEMC; *Draft Rule Determination*; p. 47.

[170] AEMC; *Draft Rule Determination*; pp. 47 – 48.

*"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."*[171]

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."*[172]

*"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."*[173]

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[174].

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

171 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.

172 Handley J.; *Advice on the Return on Equity, Report prepared for the Australian Energy Regulator*; 16 October 2014, p. 5.

173 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.

174 (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.

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[175] 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:

> *"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."*[176]

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[177] 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.

---

175 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.

176 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, p. 54. Similar results arise from out-of-sample tests.

177 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.

### *Summary*

AusNet Services cannot accept that the approach in the AER's rate of return guideline can (best) achieve the requirements of the new Chapter 6A of the NER that require the AER to have regard to all the relevant inputs. Instead, the next section explains how and why a multi-model approach should be adopted instead of the foundation model approach.

### 10.4.4 Flaws in the AER's implementation of the SL-CAPM

As well as the problems explained above concerning the notion of a foundation model, there are significant problems in the way that the AER has estimated its version of the SL-CAPM as that foundation model. This section discusses these flaws as follows:

- The AER's foundation model has structural downward biases and is unduly influenced by cyclical interest rate movements;
- The AER's chosen beta of 0.7 is far too low; and
- The AER's approach to selecting the market risk premium gives too low a figure.

### *AER's foundation model has structural downward biases and is unduly influenced by cyclical interest rate movements*

The AER's foundation model delivers acutely downwardly biased results in the current economic conditions. There are two aspects to this concern:

- There are features of the AER's SL-CAPM based foundation model that will systematically give downwardly biased results over the whole interest rate cycle.
- When interest rates are cyclically low, and the current cyclical low has reached unprecedented lows, the downward bias of the foundation model is very significantly accentuated.

The foundation model is structurally biased to give inadequate returns across the interest rate cycle because:

- The level of risk has been under-estimated (this issue is discussed above);
- The SL-CAPM has a low beta bias (this issue is very fully addressed in the submissions of the SA/Queensland businesses and there is no basis to conclude that a sufficient adjustment has been made by the AER – that being the 'rough and ready' selection of an SL-CAPM beta at the upper end of an overly constrained range inspired by the conceptual underpinnings of the Black CAPM); and
- It is quite apparent that there are significant problems with the way the AER selects its market risk premium which is explained in the next section of this submission.

Turning to the particular problems that arise with the foundation model implemented at a time of record low interest rates, these arise because the foundation model relies on implementing the SL-CAPM by combining an immediate contemporaneous measure of the risk free rate with a market risk premium derived from more than 100 years' worth of data. In times of unprecedented low interest rates, this approach delivers values that are necessarily materially lower than prevailing market returns.

As the Governor of the Reserve Bank of Australia, Mr Glenn Stevens has explained, in reality equity rates have not followed the unprecedented downward movement in base rates:

> *"[A key] feature that catches one's eye is that, postcrisis, the earnings yield on listed companies seems to have* ***remained where it has historically been for a long time, even as the return on safe assets has collapsed to be close to zero*** *[emphasis added]."*[178]

This is a point that Gray and Hall have made in the various reports submitted to the AER by the businesses for quite some time.[179]

This means that adding a long run average market risk premium to an immediately observed risk free rate will deliver downwardly biased results when risk free rates are low and upwardly biased results when risk free rates are high. In the current environment of record low risk free rates, a simple addition of a very long term market risk premium with an instantaneous risk free rate is almost bound to significantly under compensate equity investors.

It is notable that the AER's U.S. counterpart, the Federal Energy Regulatory Commission has recognised and addressed this issue. In its 28 January 2014 decision concerning the New York Independent System Operator FERC stated:

> *"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*** *[emphasis added]. 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*** *[emphasis added]."*[180]

In a further, landmark case determined at about the same time FERC stated:

> *"[W]hile U.S. Treasury bond yields are an important indicator of capital market conditions and therefore inform our determination of an appropriate base ROE, the capital market conditions since the 2008 market collapse and the record in this proceeding have shown that* ***there is not a direct correlation between changes in U.S. Treasury bond yields and changes in ROE*** *[emphasis added].*
>
> *…*
>
> *In Southern California Edison Company, a 2008 case in which the post-hearing adjustment was at issue, expert testimony indicated that,* ***as U.S. Treasury bond yields decreased DCF results instead went up, indicating an inverse relationship between U.S. Treasury bond yields and utility ROE*** *[emphasis added]. The record in this proceeding also shows an inverse relationship, but with rates moving in opposite directions:* ***U.S. Treasury bond yields have increased while DCF results for the NETOs have gone down*** *[emphasis added].*

---

178 RBA Speech.

179 See for example, SFG Consulting, "The required return on equity for regulated gas and electricity network businesses" 6 June 2014, pp. 51 – 53

180 Federal Energy Regulatory Commission (28 January 2014): "*Order accepting tariff filing subject to condition and denying waiver",* Docket No. ER14-500-000, p. 36.

> *The record in this proceeding also casts doubt on the magnitude, not just the direction, of the relationship between U.S. Treasury bond yields and utility ROE. The Commission's practice traditionally has been to adjust the ROE using a 1:1 correspondence between the ROE and the change in U.S. Treasury bond yields—i.e., for every basis point change in the U.S. Treasury bond yield the Commission would adjust the ROE by one basis point. However,* ***the record in this proceeding indicates that the 1:1 correspondence may not be accurate under current financial conditions, and that a significantly different ratio might be more appropriate—i.e., for every basis point the U.S. Treasury bond yields change, the Commission should adjust the ROE by a fraction of that amount****.* ***Thus, the record evidence indicates that, currently, adjusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate*** *[emphasis added].*
>
> *Upon consideration of the record evidence in this proceeding, and in light of the economic conditions since the 2008 market collapse more generally,* ***U.S. Treasury bond yields do not provide a reliable and consistent metric for tracking changes in ROE*** *[emphasis added] after the close of the record in a case."*[181]

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[182]:

- 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 its major peers.

With respect to the market risk premium, the fact that the MRP estimates the AER has considered vary so widely and do not over-lap with each other should sound an alarm. The starting point and the input given the most weight are a whole series of divergent historic averages. It is quite remarkable that these figures diverge so significantly given that they are all averages drawn from the same data series – using two different averaging techniques and overlapping time based 'panels' of data from the over-all series. The principle problems here are that the AER:

- Has failed to recognise that only arithmetic averages are appropriate to use because the AER's regulatory model does not compound. Geometric averages would only be relevant if compounding was present; and
- Continues to adhere to the so called "Brailsford adjustment" on the basis of a misconception that it is an adjustment that was carefully considered and endorsed by the Australian Stock Exchange when in fact the ASX did not have the benefit of the subsequent work by NERA and the Brailsford authors have never provided an adequate response to the additional discoveries that NERA has made. NERA has provided a

[181] Federal Energy Regulatory Commission, Opinion No. 531 at paragraphs 158 to 160.

[182] NERA; *European Regulators' WACC Decisions Risk Undermining Investment Decisions*; 2015, p. 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.

further report that addresses this issue and which now reconciles a small number of previously unexplained numerical differences between estimates prepared using Brailsford's data series and NERA's data series.[183]

The above issues are explained in a submission by United Energy to the NSW/ACT distribution determinations dated 26 March 2015 which also explains why these issues are important within the over-all AER approach to building up an estimate for the market risk premium. The three exhibits to that submission provide copies of the source material that unequivocally establishes that attributing any form of endorsement by the Australian Stock Exchange to the Brailsford adjustment is incorrect and this is significant because it is the primary basis stated for the AER's preference for the Brailsford work over that of NERA.

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 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."*[184]

In the current economic environment, this requires a significant change by the way in which it traditionally combines 'on the day' base rates with an extremely long run average market risk premium. Using an approach in which the regulatory return on equity moves in a 1:1 relationship with base interest rates is contrary to the observed movements in the prevailing cost of equity. On the other hand, we would not assert that the ratio is 0:1. For this reason:

- In implementing the SL-CAPM, we follow Gray and Hall's advice that the Ibbotson and Wright approaches to implementing the SL-CAPM are opposite ends of a spectrum and the moderate and reasonable approach is to take the mid-point of the estimates those two approaches produce. This is an approach supported by a recent Frontier Economics report[185] which provides equity allowances that would have applied using the AER's approach at different points. The stark conclusions are that the cost of equity is both lower than alternative measures and volatile moving in lock step with movements in the prevailing yields on Commonwealth Government Securities; and

183 NERA; Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, A report for United Energy, June 2015 (attached as Appendix 10C).

184 AEMC; *Rule Determination*; p. 44.

185 Frontier Economics; *Cost of equity estimates over time*; June 2015 (attached as Appendix 10D).

- We consider it all the more important to blend the results of the capital asset pricing models which use the base interest rate as a key input with the DGM.

### *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[186] 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[187]. 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. This is also confirmed by the authors of this Frontier report in a response to the AER's conceptual analysis for equity beta.[188]

Further, the AER 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, there is significant evidence to conclude that electricity network businesses are experiencing significant increases in risk. While AusNet Services proposes to manage these risks through cash flows (i.e. the application of accelerated depreciation) at this time, in the alternative these risks could be addressed through the beta.

When it comes to making a quantitative estimate of equity beta, it would be surprising if all parties did not agree with the following proposition:

> *"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."*[189]

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*

186 Note that in South Australia the figure was 0.9.

187 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.

188 Frontier Economics; *Review of the AER's conceptual analysis for equity beta, Report prepared for ActewAGL distribution, AGN, AusNet Services, Citipower, Ergon, Energex, Jemena Electricity Networks, Powercor Australia, SA Power Networks and United Energy;* June 2015;

189 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.

*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."*[190]

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 NER 6A.6.2(g). 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."*[191]

In the Guideline process,[192] 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,[193] 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*)[194]" 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.

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."*

---

190 Federal Energy Regulatory Commission of the United States of America, Statement of Chairman Joseph T. Kelliher, 17 April 2008.

191 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.

192 AER; *Explanatory Statement (appendices)*; Appendix C, pp. 53 – 55.

193 Henry O, University of Liverpool Management School; ***Estimating β: An update***; April 2014.

194 Henry O, University of Liverpool Management School; ***Estimating β: An update***; April 2014, p. 4.

> *"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** [emphasis added]."*[195]

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."*[196]

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 AER's recent decisions 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 AER's recent decisions. 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."*[197]

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.'*

---

195 Henry O, University of Liverpool Management School; *Estimating β: An update*; April 2014, p. 63.

196 Henry O, University of Liverpool Management School; *Estimating β: An update*; April 2014, p. 17.

197 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 (to 60% debt)* |
|---|---|---|---|
| *Contact* | *0.9* | *0.27* | *1.64* |
| ***Horizon*** | ***0.5*** | ***0.31*** | ***0.86*** |
| *NZ Windfarms* | *0.5* | *0.33* | *0.84* |
| *NZ Refining* | *0.8* | *0.17* | *1.66* |
| *TrustPower* | *0.5* | *0.36* | *0.80* |
| ***Vector*** | ***0.7*** | ***0.50*** | ***0.88*** |

*The AER's estimate of 0.6 is the average of the raw beta estimates for Horizon and Vector, which are considered to be the firms most comparable to the benchmark efficient entity. The average of the regeared estimates for these two firms is 0.87."*[198]

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."*[199]

*"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."*[200]

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

[198] 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.

[199] 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, p. 76.

[200] 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, pp. 76 – 77.

range is an adequate correction for the downward biases. Appendix C of the Guideline[201] 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.

### *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).

The AER has not explicitly explained how its 6.5 point estimate is drawn from the range.[202]

> *"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."*

As well as the historical means and DGM analysis, the AER considers certain other information as set out below.

The information considered by the AER is as follows:[203]

- Historical 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 historical long run average MRP. Specifically, the AER Guideline Explanatory Statement states:

> *"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*** *[emphasis added]."*[204]

The low point of the range is established as follows. In the Guideline process the AER states:

---

[201] 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, pp. 69 – 73.

[202] AER; *Explanatory Statement*; p. 90.

[203] AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, pp. 3 – 358 – 3 - 371 (pdf version).

[204] AER; *Explanatory Statement (appendices)*; p. 83.

> *"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."*[205]

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 AER's recent decisions[206] the above figure of 4.8 is updated and is now 4.9 using the additional data available for 2014. The data that was current as at the time of the AER's recent decisions[207] is as follows:

**Table 10.5: Historical excess returns assuming a theta of 0.6 (per cent)**

| Sampling period | Arithmetic mean | Geometric mean |
|---|---|---|
| **1883 – 2014** | 6.2 | 4.9 |
| **1937 – 2014** | 5.9 | 4.0 |
| **1958 – 2014** | 6.4 | 4.0 |
| **1980 – 2014** | 6.3 | 3.9 |
| **1988 – 2014** | 5.8 | 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

205 AER; *Explanatory Statement*; p. 93.

206 For example, AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, p. 3-331 footnote (pdf version).

207 For example, AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, p. 3 – 331 (pdf version).

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.[208]

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.[209] However, both the AER's own consultant, Lally,[210] 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]e agree with the Company that it is improper to use a geometric mean in the CAPM model…"*[211]

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).[212,213] The AER continues to take this approach despite the reliability of the data underlying the article 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."[214]

The original source of the adjusted data is identified in the footnote 13 and 16 in *Brailsford et al*[215] 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.*[216]"

---

208 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.

209 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, p. 12.

210 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, pp.12 – 13.

211 *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].

212 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, pages 3–338 – 3-344 (pdf version).

213 AER; *Explanatory Statement (appendices)*; pp. 84 & 103.

214 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, page 3-339 (pdf version).

215 Brailsford, T., J Handley and K. Maheswaren; *Re-examination of the historical equity risk premium in Australia;* Accounting and Finance 48, 2008.

216 Brailsford, T., J Handley and K. Maheswaren; *Re-examination of the historical equity risk premium in Australia;* Accounting and Finance 48, 2008, p. 80.

By the time the process of "Chinese whispers" was complete, the AER had effectively (falsely) invested the adjustment with the ASX's 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[217] 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.

### *(b) Dividend Growth Models*

Although it is the historical 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 10.6: MRP Estimates under Dividend Growth Models, 0.6 theta (per cent)**

| Growth rate | 2-stage model | 3-stage model |
|---|---|---|
| **4.0** | 7.4 | 7.8 |
| **4.6** | 8.0 | 8.2 |
| **5.1** | 8.4 | 8.6 |

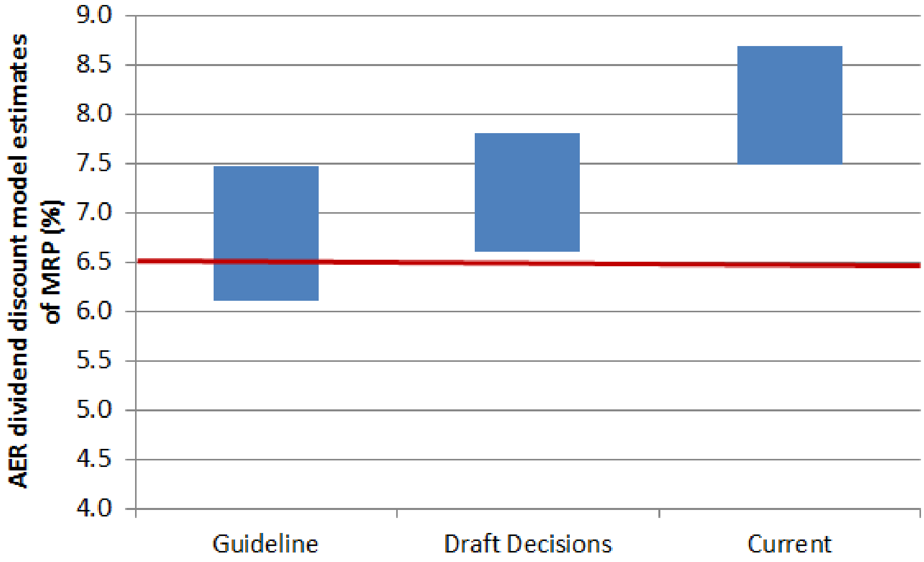
*Source: AER, Jemena FinalDecision, Attachment 3 – Rate of Return Table 3-45, pp. 3 – 3-345 (pdf version)*

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 AER's recent 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."[218]

217 Brailsford, T., J Handley and K. Maheswaren; *Re-examination of the historical equity risk premium in Australia;* Accounting and Finance 48, 2008.

218 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.

**Figure 10.2: Range of AER dividend discount model estimates of MRP**




*Source: AER*

### *(c) Survey evidence*

The AER also has regard in the Explanatory Statement accompanying its Guideline to the following Dividend Growth Model data:

**Table 10.7: Key findings from recent MRP surveys**

| Survey[219] | 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.

219 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015 table 3.46, pp. 3 – 347 (pdf version).

### *(d) Other Regulators*

**Table 10.8: 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 |
| **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."*[220]

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.

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%)."*[221]

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."*[222]

The AER asserts that:

---

220 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.

221 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, pp. 4 – 5.

222 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 6.

> *"[[R]eturn on equity and equity risk premium estimates contained in Table 3.39 include the final values used in the independent valuation report and reflect any uplifts applied."*[223]

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."*[224]

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"*[225]

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."* [226]

### *Inconsistent treatment of the imputation adjustment*

In the next 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.

---

223 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, p. 3 -477 (pdf version).

224 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, pp. 6 – 7.

225 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015, p. 7.

226 Incenta, *Further update on the required return on equity from Independent expert reports,* February 2015, pp1 – 2.

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 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 flawed. As a result of these flaws, it is not surprising that the AER's foundation model produces results that are outliers compared to all the other relevant models. While the AER's foundation model is delivering allowed rates of return of approximately 7.1%, all the other models deliver results in the vicinity of 9.93 to 10.32%.[227]

Consequently in relation to equity, 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.

### 10.4.5 Structuring a best practice multi-model approach

The concept of selecting a primary model implicitly assumes that one of the available models must be superior to all the other models and introduces a hierarchy. This assumption is without any support and appears contrary to the views of AEMC when the new rules were adopted.

Where all measures are imperfect, the benefits of diversity are strong. This is the basis for the multi-model approach adopted by AusNet Services.

The most straightforward approach for the AER to have regard to all the relevant models as required by the rules would have been to use each of them and then determine what weight each should be given in contributing to an over-all rate of return.[228] This was essentially Option 3 considered by the AER as part of the Guideline development process:

---

227 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.

228 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)."*[229]

AusNet Services has received extensive expert advice supporting a multi-model approach. Gray and Hall state:

*"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."*[230]

The Brattle Group internationally and in Australia also supports the use of multiple models:

*"All models have relative strengths and weaknesses, with the result that there is no one model that is the most suitable for estimating the cost of equity at any given time or for any given company. As our colleague and MIT professor Stewart Myers has put it eloquently — Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information."*[231]

Further, as explained below, some models are better able to address certain market circumstances and in particular, CEG notes that in the highly unusual prevailing circumstances of negative betas for CGS, the DGM model is better able to cope.

In the U.S., regulators have long had the discretion to use a range of models and the views of experts from that jurisdiction are therefore persuasive. As Malko explains:[232]

***"Which models are useful for economic regulatory purposes?***

*In my opinion, all of the models discussed above are useful in the determination of allowed return on equity, but each model has both strengths and drawbacks and should not be used alone, nor is any model superior so as to warrant its use as a primary or sole principal model.*

*In particular, the models can be grouped into two 'families': the DGM on the one hand and all the capital asset pricing models or interest rate sensitive models on the other based on how they explain and predict returns. Both major groupings, and all the variants discussed above, provide useful insights into what returns that risks-adverse investors expect to receive when making investments.*[233]

***Multiple Model Approaches are Preferable***

*In my opinion, no one single financial model is sufficient to estimate the rate of return in every economic circumstance. All models suffer a range of theoretical and/or empirical weaknesses of different kinds. If only one model is used, or if one model is given excessive pre-eminent weight, investors' returns will be highly dependent on the extent to which that model's particular weaknesses lead to over- or under-returns. If multiple models are used, then the returns will vary in response to all the weaknesses but to a smaller extent than if one model is used. It also stands to reason that where the weaknesses of different approaches are directionally different, they will to some degree*

---

229 AER; *Explanatory Statement* p. 54.

230 SFG Consulting; *The foundation model approach of the Australian Energy Regulator to re-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; paragraph 107; p. 22.

231 Brattle Group 2013, "Estimating the Cost of Equity for Regulated Companies" p. 1.

232 Malko, JR; Statement; 16 June 2015 (**Malko**); paragraphs [8.1-8.2]; pp. 9 –10 (attached as Appendix 10E).

233 *Ibid*; paragraphs [8.1-8.2]; pp. 9 – 10.

*cancel each other out. Additionally, where only one model is used there is insufficient corroborating evidence or ability to cross-check the results. By contrast, the consideration of multiple models enables the decision maker to either become comfortable that different methodologies are corroborative or, where they are not, to question why it is that one or more models may be delivering significant different results at a particular time or in particular economic circumstances. This, in turn, can give an insight into whether results should be adjusted or altering the weighting or influence accorded to particular models and their results.*

*In my opinion, to ensure the most appropriate decision, it is important to consider the results of several models. In my opinion, using several models helps compensate for the drawbacks in any single model and increases the probability that the appropriate and reasonable range is identified.*[234]

*I have observed that in the United States regulators and expert financial witnesses generally use multiple methods, at least two, when determining a reasonable range and reasonable point estimate for the cost of common equity for a regulated energy utility."*[235]

Knecht agrees that capital asset pricing models should be used together with the DGM:

*"Long-term market trends will tend to drive the estimates of one model higher than another for some years and then lower for another stretch of time. This fact justifies both the use of a wide range of models and also the continuation of the same set of models through these variations.*

*Using a number of different models is superior to relying on a more limited selection of models. This is because the CAPM, ECAPM, FF3F, and CA+I estimates use basic cost of capital data in a different manner to the DCF models. The CAPM, ECAPM, FF3F and CA+I models extract information from the Cost of Capital data that the DCF models miss – and vice versa. Using multiple models provides additional perspectives and information, yielding a more accurate, reliable, and robust estimate."*[236]

Nevertheless, the AER has rejected the notion of a multi-model approach. The reasons why the AER rejects a multi-model approach are:

*"[The multi-model approach] 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"*[237]

The AER's considerations in rejecting a multi-model approach are, in fact, misplaced:

- The criterion of "complexity" is irrelevant to the rate of return objective, NEO and revenue and pricing principles but, in any event, it is not apparent that the approach of specifying each of the models and taking a weighted average is 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

234 *Ibid*; paragraphs [9.1]-[9.2]; p. 10.

235 *Ibid*; paragraph [9.5]; p. 10.

236 Knecht, RL; *Statement*; 19 June 2015 (**Knecht**); paragraphs [4.4-4.5]; p. 3 (attached as Appendix 10F).

237 AER; *Explanatory Statement* p. 54.

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.

For all the reasons discussed above, AusNet Services is firmly of the view that a multi-model approach is needed. Consistent with the advice of Gray and Hall, Malko and Knecht (quoted in the previous section), all the relevant models should be used to develop estimates for the return on equity and the results should be used:

- To identify when particular model specifications appear to be providing anomalous or "outlier" results that warrant closer scrutiny; and
- Once any anomalous results are scrutinised and, if necessary, corrected, all the relevant models should contribute to a mean over-all allowed rate of return for equity.

It is particularly important that the multi-model approach adopted draws from both principal "families" of model which approach the task of estimating the required return on equity: the DGM or DCF family; and the family of capital asset pricing models. Each of these two families bring very different approaches to establishing what is a fair return on equity and, to a considerable degree, each family addresses the weaknesses of the other family. This is important both to assist in identifying when model is delivering anomalous results and warrants scrutiny and it is also important when establishing the mean over-all return because any sub-optimal rate of return estimation that results from a weakness of one of the models is muted when averaged with other models that are not susceptible to the same weakness.

Gray and Hall's work identifies the following four of the models that the AER has accepted in the rate of return guideline process are the relevant models:

- The Dividend Growth Model (DGM) or Discounted Cash Flow (DCF) model;
- The SL-CAPM;
- The Black CAPM; and
- The Fama French Three Factor 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:

> *"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."*[238]

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[239] addresses the issues raised in connection with the equity beta in the context of the SL-CAPM. Another three reports[240,241,242] focus on the issues raised in relation to each of the other financial models and a fifth report[243] 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.[244,245,246]

---

238 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.

239 SFG Consulting; *Equity beta, Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014.

240 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.

241 SFG Consulting; *The Fama-French model; Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid, and SA PowerNetworks*; 13 May 2014.

242 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.

243 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.

244 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.

245 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,*

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[247] and into historical estimates of the market risk premium.[248]

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.[249]

The material relevant to each model is discussed in detail below.

### *(a) The DGM or DCF model*

The Dividend Discount Model is also referred to as the Discounted Cash Flow (**DCF**) Model.

The DCF model or DGM approaches the task of estimating the required rate of return in a different way from the AER's favoured SL-CAPM:

> *"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."*[250]

Yet, the AER has declined to give the DGM or DCF any direct weight in estimating the allowed rate of return for equity. Instead, the only role given to this model is indirectly as one of a number of factors contributing to the AER's considerations on where to set the MRP. Even in that regard, it is not clear whether the AER might have set the MRP at 6.5 even absent the analysis from the DGM. In other words, it is not clear whether this model is contributing in any tangible way to the AER's foundation model approach.

The reasons why the AER excludes using the DGM or DCF to estimate the allowed rate of return on equity must be closely scrutinised. Handley's most recent advice to the AER states the following in relation to the DGM or DCF:

---

*Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks and United Energy*; 13 February 2015.

[246] 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.

[247] 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.

[248] 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.

[249] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12 January 2015.

[250] 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.

*"the regulatory environment involving an aggregate regulatory asset base measured in the tens of billions of dollars is not an appropriate setting to trial a new model whose widespread use and acceptance is yet to be established."*[251]

Even if Handley was correct, this statement effectively advances the highly conservative proposition that Australia's national energy regulator should never move away from the sum total of its own specific experience. If that approach were accepted, there could never be improvements in economic regulatory practice and this form of entrenched conservatism must be contrary to the rules requiring that regard be had to all the relevant information in seeking to set an allowance that is commensurate with the efficient costs that a benchmark business would face.

In any event, Handley's assertion that the model is not in widespread use is simply wrong. As Malko explains:

*"The Dividend Growth Model (DGM), also the DCF, is based upon the works of Irving Fisher and John Williams in the 1930s. The DGM or DCF was introduced for estimating the cost of common equity for regulated energy utilities by state regulatory authorities during the 1960s and early 1970s. Professor Myron J. Gordon is frequently recognized to be the "pioneer" or "father" of the DCF model for application in estimating the cost of common equity for a regulated energy utility. See the following: Myron J Gordon; The Cost of Capital to a Public Utility; Michigan State University Public Utilities Studies, East Lansing, Michigan, 1974.*

*....*

*The adoption of the DGM or DCF constituted a significant advance in the science of what constitutes a fair market reflective rate of return.* ***This model is still considered and almost universally used, alone or in a multi-model approach (as I discuss further below), by almost all energy regulators in the United States*** *[emphasis added]."*[252]

It is relevant to observe that the allowed rate of return objective now used in Australia's National Electricity Rules and National Gas Rules effectively codifies long-standing U.S. Federal case law:

*"[T]he return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks."*[253]

In doing so, the same U.S. case law also includes the requirement in the Australian revenue and pricing principles concerning the necessity for the business to have a reasonable opportunity to recover its efficient costs:

*"That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."*[254]

The main difference is that there is no explicit requirement upon FERC to have regard to all the available inputs.

The above case was decided in 1944 and in the U.S. there is a history of applying the standards articulated above. At the federal level in the United States, the Federal Energy Regulatory Commission (FERC) describes its use of the DGM *grosso modo* as its "standard

---

251 Handley J; *Advice on the Rate of Return for the 2015 AER Energy Network Determination for Jemena Gas Networks, Report prepared for the Australian Energy Regulator*; 20 May 2015.

252 Malko; paragraphs [3.1] to [3.2]; p. 4.

253 *Federal Power Commission v Hope Gas Co* 320 US 591 (1944) at 603.

254 *Ibid*.

bearer" when undertaking economic regulatory work. 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)"*[255]

> 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*** *[emphasis added]." Quoting J. Bonbright et al., Principles of Public Utility Regulation 318 (2d. ed. 1988).*[256]

> *"For over 30 years, the Commission has based ROEs on the rate of return required by investors to invest in a company – otherwise known as the capital attraction rate of return, or the market cost of equity capital. Over this period,* ***the Commission has relied primarily on the DCF model to provide an estimate of the investors' required rate of return*** *[emphasis added]."*[257]

There are two settled sources of a growth rate for dividends that produce high and low estimates. Even though there is no explicit requirement to consider a range of models, FERC does indeed consider the rates of return that other models produce and these estimates are employed in determining what final Rate of Return to apply in setting regulated returns. In the leading case, the use of three other models led the Commission to depart from the midpoint of the DCF analysis and instead adopt a figure three quarters of the way up its DCF range:

> *"The NETOs presented five alternative benchmark methodologies in this proceeding: risk premium analysis, the CAPM, comparison of electric ROEs with natural gas pipeline ROEs, comparison of electric utility DCF results with non-utility DCF results, and expected earnings analysis. Of those five, we find the risk premium analysis, the CAPM, and expected earnings analyses informative,* ***and each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here*** *[emphasis added]. In considering these other methodologies, we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology.*

> *…*

> *The NETOs' risk premium analysis indicates that the NETOs cost of equity is between 10.7 percent and 10.8 percent,* ***which is higher than the 9.39 percent midpoint produced by our DCF analysis*** *[emphasis added]. Similar to the risk premium analysis, the NETOs' CAPM uses interest rates as the input for the risk-free rate, which makes it useful in determining how the interest rate environment has impacted investors' required returns on equity. Further, CAPM is utilized by investors as a measure of the cost of equity relative to its risk. Using the same proxy companies from our DCF analysis, before screening for low-end outliers, the NETOs'* ***CAPM analysis produces an ROE range of 7.4 percent to 13.3 percent, with a midpoint value of 10.4 percent and a***

---

255 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].

256 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 footnote 65.

257 See Federal Energy Regulatory Commission, Opinion No. 531 (2014) at paragraph 14. This case was the landmark case in which the Commission determined to harmonise the approach in electricity and gas in which it had previously used two different forms of the DCF. The approach was to apply the "two stage" methodology previously used in gas to apply to both energy types. Still relevant, therefore, is FERC June 1999, Cost-of-Service Rates Manual for gas pipelines, page 16 of which clearly identifies the DCF as the dominant US model.

> ***median value of 10.9 percent*** *[emphasis added]. Finally, the NETOs' expected earnings analysis, given its close relationship to the comparable earnings standard that originated in Hope, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation. Once again using the same proxy group that we used in our DCF analysis,* ***the expected earnings analysis has an ROE range of 8.1 percent to 16.1 percent, with a midpoint value of 12.1 percent and a median value of 10.2 percent*** *[emphasis added]. The record evidence from each of these models affirms our setting the ROE at* ***a point above the midpoint*** *[emphasis added] under these circumstances."*[258]

In dismissing the DGM or DCF for use in directly estimating the cost of equity for benchmark businesses in this country, the AER has also stated that:

> *"We also considered that the sensitivity of DGMs to input assumptions would limit our ability to use a DGM as the foundation model. For example, estimates of simple DGMs (such as those previously proposed by CEG) have provided implausible estimates of the return on equity for the benchmark efficient entity. For example, in the Guideline we found that simple DGMs generated average returns on equity for energy infrastructure businesses over an extended period that significantly exceeded the average return on equity for the market. This did not make sense as the systematic risk of network businesses is less than the overall market.'*[259]

However, Malko advises that these potential difficulties are much exaggerated. Having reviewed the above statement by the AER he responds as follows:

> *"In response, I would make the following observations:*
>
> *Certainly the DGM is sensitive to its input assumptions and if it would be inappropriately implemented, it could deliver implausible results. In this regard, I see no difference between this and other models. If inappropriate inputs are used, any of the models can produce implausible results.*
>
> *It is common in United States regulatory determination processes for there to be debate between businesses, customers and the regulators concerning which inputs to use but these debates occur with a context in which expert testimony has regard to whether the inputs used deliver plausible results and decision making is guided by a body of court and regulatory precedent.*
>
> *Over-all, the wide acceptance and use of the DGM in the United States demonstrates that this model is sufficiently robust for it to be useful in economic regulatory decision making."*[260]

The AER also asserts that there may be issues that are specific to Australia as to why the DGM or DCF is inappropriate and in that regard it is appropriate to consider the views of Australian experts. In its previous papers rejecting the use of the DGM or DCF the AER asserted that a Grant Samuel report, which valued Envestra, provided support for several key features of the AER's approach. However, Grant Samuel has reacted with a vigorous rebuttal of the AER's use of its work and a more general explanation of its disagreement with almost every aspect of the AER's equity analysis. In particular, before turning specifically to the merits of using the DGM or DCF, Grant Samuel explains why it is important in their work to look beyond the SL-CAPM:

258 Federal Energy Regulatory Commission, Opinion No. 531 at paragraph 147.

259 AER; *Final Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of Return*; June 2015, p. 3 -379 (pdf version).

260 Malko; paragraph [3.7]; p. 5.

*"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."*[261]

Grant Samuel expresses a considerable degree of frustration that the AER applies 'double standards' when rejecting the use of the DGM to directly estimate the cost of equity and concurrently resolving to adhere primarily to the SL-CAPM. Grant Samuel states:

*"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."*[262]

Grant Samuel 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."*[263]

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*

---

261 Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12th January 2015 (**Grant Samuel Letter**); p. 2.

262 *Ibid*; p. 3.

263 *Ibid*; p. 2.

*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)."*[264]

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."*[265]

Gray and Hall state:

*"The AER applies different standards to its assessment of the SL CAPM relative to other models. By way of some examples:*

*i. The AER rejects other models on the basis that the outputs are potentially sensitive to different estimation methods, when the same is true of the SL CAPM. In its recent final decisions, the AER's own range for the allowed return on equity from the Sharpe-Lintner CAPM is 4.6% to 8.6%.*

*ii. The AER cites certain empirical studies to support its rejection of other models. However, the only reasonable interpretation is that the body of available evidence supports the empirical performance of other models over the Sharpe-Lintner CAPM. In some case, papers that the AER cites as supporting the Sharpe-Lintner CAPM actually do the opposite.*

*iii. The AER rejects all estimates for other models on the basis that it finds some of them to be implausible."*[266]

Lane and Rosewall of the RBA state:

*"DCF analysis is a standard method recommended by finance theory to evaluate investment opportunities.*[267]

*…*

*Because it provides a natural threshold to accept or reject investment decisions, the discount rate used in DCF analysis is often called the 'hurdle rate'.*[268]

*…*

*A typical firm in the Bank's liaison program evaluates discretionary capital expenditure by using DCF analysis, and also by considering the payback period as a supporting consideration. This is in line with the evidence from other advanced economies such as the United States and the United Kingdom (see below) and is also in line with earlier survey evidence for Australia.*[269]

*…*

264 *Ibid*; p. 5.

265 *Ibid*; p. 2.

266 Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity*; June 2015; paragraph 17; p. 7 (attached as Appendix 10G).

267 Kevin Lane and Tom Rosewall; 'Firms' Investment Decisions and Interest Rates' (2015) June Quarter *Bulletin*; p. 2.

268 *Ibid*.

269 *Ibid*; p. 3.

> *The available evidence suggests that firms in other advanced economies undertake investment decisions using similar criteria employed by Australian firms. Surveys have found that firms in the United States and Europe tend to evaluate proposed investments using discounted cash flow techniques, which have become more popular over the past few decades, and the payback period."*[270]

In summary, the DGM or DCF could be regarded as the safest, most tried and true model of all. That said, for the reasons articulated by Malko (ie that it is only very minimally sensitive to interest rate changes), it is important to blend the DGM or DCF in a multi-model approach that also includes at least one or more capital asset pricing models together with the DGM or DCF model.

### *(b) The 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. The model is also in long standing use in Europe and, in that sense, it holds a similar position in those countries to the position that the DCF has in the U.S.

The SL-CAPM 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.

AusNet Services supports the inclusion of the SL-CAPM for setting the allowed rate of return for equity provided it is appropriately implemented, account is taken of its low beta bias, account is taken of CEG's advice concerning the negative beta of CGS yields and provided that the SL-CAPM results are blended with the other relevant equity models.

However, AusNet Services opposes the following aspects of the AER's current approach:

- Elevating the SL-CAPM to being the "foundation model" that materially constrains the contribution other models can make (discussed above);
- Giving over-whelming weight to the Ibbotson approach to specifying the SL-CAPM and only minimal weight to the equally valid Wright approach (discussed below); and
- Failing to adequately address the low beta bias (also discussed below).

With this proposal, AusNet Services is providing expert reports from Gray and Hall, Wheatley, Grant Samuel, CEG and Malko all of which express very strong reservations about using the SL-CAPM as the primary model and particularly the AER's particular application of the SL-CAPM.

The principal issues are:

- As Gray and Hall, Wheatley and Malko all explain, the SL-CAPM is burdened by an unrealistic assumption that investors can borrow and lend at the risk free rate and this results in a constraint when the model is implemented setting the returns on a zero beta portfolio of investments as being equal to the risk free rate and this causes there to be a downward bias for all investments with a beta of less than one. There is no basis for the AER to conclude that setting the beta at the high end of its range would (adequately) address this issue.

---

270 *Ibid*; p. 5.

- As Gray and Hall explain, giving over-whelming weight to the Ibbotson approach causes the estimates to be volatile and overly sensitive to the prevailing base interest rate. They also explain that given that there are currently unprecedented low base interest rates, the approach of giving the Ibbotson predominant weight results in a significantly below-market return in the current economic conditions.
- As Hird of CEG reports, there is a particular problem using unadjusted CGS yields as the proxy for the risk free rate where it is apparent that CGS yields have a significant negative beta.
- Given the above points, it is hardly surprising that a number of suite of reports by Wheatley of NERA that are provided with this regulatory proposal thoroughly demonstrate that the SL-CAPM performs very poorly in empirical tests when compared with the alternative models. Gray and Hall and Malko both corroborate this work. These reports set out Mr Wheatley's own empirical tests[271] and a literature review[272] of a broad range of other parties' work in this regard.

Below we develop each of these points.

CEG, Gray and Hall,[273] and NERA, have consistently explained that the SL-CAPM has a low beta bias.[274] This is not surprising because the model relies on a wholly unrealistic assumption that investors can borrow and lend at the risk free rate. 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). Second, the common measurement of systematic risk – the regression coefficient of excess stock returns on market returns – is an imprecise measure of risk."*[275 276]
>
> *And*
>
> *"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*

---

271 See for example, SFG Consulting, "The required return on equity for regulated gas and electricity network businesses" 6 June 2014, pp. 51 – 53

272 NERA, Empirical Performance of Sharpe-Lintner and Black CAPMs, February 2015, pages 42, 51 and 52; NERA, Empirical Performance of Relevant Models for Estimating the Return on Equity, February 2015.

273 For example see Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity, a report prepared for ACTEWAGL Distribution, AGN, AusNet Services, CitiPower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA Power Networks and Untied Energy*; June 2015 and SFG Consulting; *The required return on equity for regulated gas and electricity network businesses*; May 2014.

274 CEG Consulting; *Estimation of, and correction for, biases inherent in the Sharpe CAPM formula, A report for the Energy Networks Association Grid Australia and APIA*; September 2008; p. 21.

275 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.

276 Also SFG Consulting; *Equity Beta; Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, pp. 6 – 7.

*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."*[277]

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:

*"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]."*[278]

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.

NERA states that:

*"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*

[277] 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, p. 9.

[278] 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.

> *that the SL CAPM underestimates the return to the portfolio by 4.90 per cent per annum."*[279]

Corroborating all the above concerns with the use of the SL-CAPM approach as implemented by the AER as the foundation model, Grant Samuel explains that real world valuations need to be informed by a range of additional material to over-come the significant limitations of solely relying on a plain or "SL-CAPM":

> *"[O]ur approach … is to form an overall judgment 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%)."*[280]

It is informative to consider how the U.S. regulatory system has engaged with the SL-CAPM. First, Malko explains why the SL-CAPM was introduced to supplement the DGM or DCF:

> *"In particular, when base interest rates were high, there was a concern (legitimate in my view) that the DGM or DCF did not, at the time, adequately reflect the increased returns that equity investors expected to receive and this led some regulators to start to have regard to the capital asset pricing models concurrently with the DGM or DCF."*[281]

Malko certainly acknowledges that the SL-CAPM has some attributes:

> *"In my opinion:*
>
> *The Sharpe CAPM has important strengths, including:*
>
> *It incorporates a first principles concept of risk and return.*
>
> *It is an interest-rate sensitive model that complements a stock price sensitive model.*
>
> *It is simple."*

However, importantly, he also notes:

> *"The Sharpe CAPM model has important limitations, including:*
>
> *It is a single factor (beta (β)) model and it does not incorporate other factors that finance literature demonstrates are known to affect equity returns.*
>
> *The model suffers from a theoretical limitation in that it assumes that investors can borrow and lend at the risk free rate which is not the case. Due to the simple mathematical specification of the model, the effect of this implausible assumption is that it under-estimates the returns for investments of below average risk and over-estimates the returns for investments of above average risk.*
>
> *Empirical work shows that there are limitations associated with its ability to explain past stock price movements and equally its predictive capabilities both associated with the theoretical limitations mentioned above and more generally."*[282]

---

279 NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM*; February 2015.

280 Grant Samuel Letter; pp. 4 – 5.

281 Malko; paragraph [3.8]; p. 6.

282 *Ibid*; paragraphs [4.3] to [4.4]; pp. 5 – 6.

Reflecting these weaknesses, Malko notes that even when the SL-CAPM is used in conjunction with the traditional DGM method, the contemporary approach is to make adjustments to account for the significant limitations of the SL-CAPM:

> *"I have observed that during the recent past (10 years or less), financial analysts have attempted to address some of the shortcomings of the Sharpe CAPM by:*
>
> - *Using the Empirical CAPM (ECPAM) (discussed below).*
> - *Making an adjustment by adding the small size risk premium. This premium reflects that small companies have higher returns on average than larger companies (which is also relevant to the discussion of the FFM below).*
> - *Applying the Hamada adjustment for a leveraged beta. This adjustment reflects a changing capital structure. For example, if a utility's current or planned capital structure reflects an increased debt level and debt percentage, then the leveraged beta is increased to reflect the increased financial risk. To make the Hamada adjustment, a comparison of the capital structure of a specific utility to a comparable group is undertaken and appropriate mathematical models are applied."*[283]

The sections below concerning the Black CAPM and Fama French Three Factor Model further develop these important observations of Malko.

However, before concluding the discussion of the SL-CAPM a further important consideration is how to implement the SL-CAPM and in particular whether to use the Ibbotson approach, the Wright approach or a combination of the two. As Gray and Hall explain, each of the Ibbotson and Wright approaches takes an extreme position on a continuum of how movements in the market risk premium may be related to movements in the base interest rate. The Ibbotson approach takes the position that the market risk premium remains wholly unchanged as interest rates vary while the Wright approach takes the position that movements in the market risk premium are exactly offset by equal movements in the risk free rate.

In fact, both of these extreme positions are unrealistic. In fact, equity returns are observed to vary when the base rate varies but the movements in equity returns are smaller than the movements in base rates. In other words the market risk premium is observed to counteract or "cushion" movements in the base rate.

A flaw of the AER's foundation model is that, like the Ibbotson approach, it takes the extreme position that market risk premiums is an unmoving constant in the face of changes in the base rate. By contrast, our approach (consistent with the expert advice of Gray and Hall) is to equally weight these two ends of the spectrum and in this regard the proposal is both much more moderate than the extreme position implicit in the AER foundation model and the result is better reflective of the way markets actually behave.

Finally, as CEG has explained, even using the Ibbotson approach there is a significant problem with using an un-adjusted CGS return as the proxy for a risk free rate in the current highly unusual prevailing market conditions. Dr Hird states:

> *"The first critical point to note is that the fall in CGS yields cannot be mechanically assumed to have been associated with a fall in the cost of equity. Instead, the cost of equity must be estimated directly and not assumed to fall/rise with CGS yields.*
>
> *The pattern of beta for CGS and other government bonds internationally gives rise to two critical implications for the use of CGS yields as the proxy for the risk free rate in CAPM. That is, two adjustments to regulatory practice are required to account for the pattern of observed betas on CGS through time:*

[283] *Ibid*; paragraph [4.5]; p. 6.

- *The prevailing risk free rate must be adjusted upwards from the prevailing nominal CGS yield by around 1.0% to account for the fact that that the best estimate of the prevailing nominal CGS beta is materially negative;*
- *The historical average excess returns needs to be adjusted upwards by around 0.7% to account for the fact that historical average betas for CGS (against which excess returns have been measured) were above zero."*[284]

However, this issue can be addressed with an adjustment:

> *"Consequently, if the best estimate of the historical average MRP relative to CGS is 6.0% (AER) or 6.5% (NERA) then the best estimate of the MRP relative to the true (unobservable) zero beta asset is 6.7% to 7.2%. If the historical average asset beta on nominal 10 year CGS is higher than 0.1, then these estimates will in turn be larger as well."*[285]

CEG's concern with the use of CGS yields as the source of the risk free rate is also a further reason to use the multi-model approach. The DGM is better able to cope with this issue and using that model concurrently with the SL-CAPM in a multi-model approach would significantly ameliorate the situation:

> *"If the cost of equity is being estimated using a prevailing estimate derived from the dividend growth model (DGM) then a much smaller, or even a zero, adjustment is required to the CGS yield. This is because the DGM will automatically 'pick up' any downward bias in CGS yields in the form of a higher estimated MRP relative to CGS yields."*[286]

In summary, while the SL-CAPM can be used:

- There needs to be a midpoint approach to implementation between the Ibbotson and Wright approaches to estimating the MRP to avoid significant unwarranted cyclical under (over) estimates in times of unusually low (or high) base interest rates;
- When using CGS yields as the proxy for the risk free rate, it is necessary to use an adjustment; and
- For a host of reasons all the experts who have considered the issue for AusNet Services concur that the SL-CAPM must be supplemented with estimates from other capital asset pricing models that are free of the low beta bias in the SL-CAPM and which account for other factors that are known to influence returns together with the DGM.

### *(c) Addressing the SL-CAPM's downward bias for low beta stocks – the Black CAPM or the ECAPM*

As noted above, 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[287]:

---

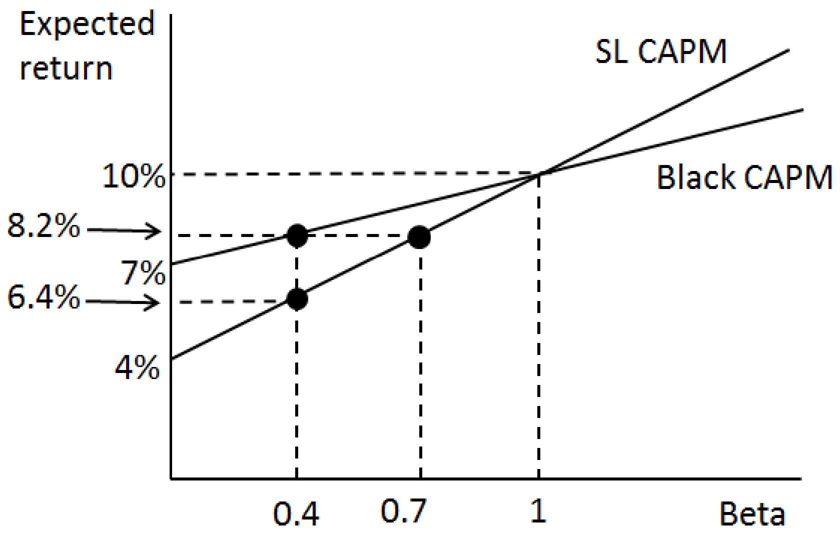
[284] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraphs [75-76]; p. 24.

[285] *Ibid*; paragraph [81]; p. 25.

[286] *Ibid*; paragraph [82]; p. 25.

[287] 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.

**Figure 10.3: SL and Black CAPM**




*Source: SFG Consulting*

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.

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:

> *"[T]he Sharpe-Lintner CAPM remains a specific application of the more general model, the Black CAPM."*[288]

> *"The Black CAPM does not rely upon the assumption that all investors can borrow at the risk-free rate of interest."*[289]

Further, even if the Black CAPM does not perfectly model the relationships in question SFG Consulting notes that:

> *"[B]ecause 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."*[290]

Indeed, 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:*

288 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.

289 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.

290 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.

*…*

*little evidence of bias in the Black CAPM"*[291]

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 consistent with what Black had in mind when he developed the model nor the way in which the Black CAPM is usually used by practitioners. Rather the Black CAPM should be used directly to estimate the cost of equity.

However, the AER has asserted that the model is unusable for directly estimating a return on capital for inclusion in the allowed rate of return for equity because a zero beta portfolio is allegedly hard to estimate but SFG has produced suitable estimates for that purpose. AusNet Services does not accept that contention by the AER because Gray and Hall have provided a robust and suitable estimate of the return for a zero beta portfolio of stocks.

The AER has also claimed that the Black CAPM is not yet used by other infrastructure regulators. This assertion warrants further scrutiny. The AER has stated in the rate of return guideline process that it is more concerned with a model's theoretical credentials. My contrast, U.S. regulators tend to be more concerned with the empirical performance of the models presented to them and consistent with that administrative approach, the Empirical CAPM is commonly advanced and the use of this model is to the same effect as using the Black CAPM.

Malko explains that:

> *"I have been asked to comment on the correctness or otherwise of the statement in the Australian Energy Regulator's (AER) Final Decision, ActewAGL distribution determination 2015-16 to 2018 -19 - Attachment 3 - Rate of Return document:*
>
> > *There is little evidence that other regulators, academics or market practitioners use the Black CAPM to estimate the return on equity. In particular, regulators rarely have recourse to the Black CAPM" at page 3-256.*
>
> *As I have explained above, although there is little explicit reference to the Black CAPM, in practice the use in the U.S. of the Empirical CAPM by financial analysts both within and outside energy regulatory processes is essentially to the same effect."*[292]

Malko explains how the regulators give effect to the Empirical CAPM as follows:

> *"The regulators who have been presented with ECAPM evidence have considered it along with evidence from the DGM or DCF and Sharpe CAPM. The results from all these approaches have been recorded in the decisions and the selection of a particular figure has been made following that consideration."*[293]

The following are examples of regulatory processes in which models with a higher intercept and flatter curve have been considered:

---

291 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.

292 Malko; paragraphs [6.4] and [6.5]; p. 8.

293 *Ibid*; paragraph [5.5]; p. 7.

### Table 10.9: Use made by regulators of the Zero-Beta and Empirical CAPM

| Regulator | Industry | Application | Citation |
|---|---|---|---|
| **New York Public Service Commission, 2009** | Electricity distribution | 50/50 weighting. "Traditional" CAPM/zero-beta CAPM paragraph 56. | Proceeding on Motion of the 2009 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.[294] |
| **New York Public Service Commission, 2007** | Gas distribution | 50/50 weighting. Average of traditional CAPM results 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 Service 2007 N.Y. PUC LEXIS 449; 262 P.U.R. 4th 233.[295] |
| **New York Public Service Commission, 2006** | Gas and electricity distribution | 50/50 weighting. Average of traditional CAPM result and zero beta CAPM result paragraph 19.<br>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.[296] |
| **Oregon Public Utility Commission, 2001** | Electricity distribution | Zero-beta is used to contrast with S-L CAPM "as beta decreases, the cost of equity decreases by less than the Sharpe-Lintner | In the matter of PacifiCorp's Proposal to Restructure and Reprise its Services in Accordance with the provisions of |

294 *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.

295 *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.

296 *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.

| Regulator | Industry | Application | Citation |
|---|---|---|---|
| | | CAPM model suggests. | SB 1149. 2001 Ore. PUC LEXIS 418; 212 P.U.R. 4th 379.[297] |
| | | 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<br>"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 equity." Paragraph 23.<br>CAPM given no weight, DCF preferred. | |

In summary, whether the Black-CAPM or an Empirical CAPM nomenclature is used, the estimated return on equity for our business should give weight to a capital asset pricing model that raises the intercept and flattens the risk-return curve relative to the SL-CAPM. By including the Black CAPM, Gray and Hall's multi-model approach does this appropriately and we continue to consider that to be the appropriate approach to take.

### *(d) Fama French Three Factor Model and Continuous Improvement in CAPM methods*

While empirical studies have consistently found that the Black CAPM performs better than the SL-CAPM, the Black CAPM is still 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."*[298]

297 *In the matter of PacifiCorp's Proposal to Restructure and Re-price its Services in Accordance with the provisions of SB 1149.* 2001 Ore. PUC LEXIS 418; 212 P.U.R. 4th 379.

298 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.

If the Fama French Three Factor model is wholly excluded from the analysis, then there will be 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, then 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."*[299]

This model provides separately for an additional return on value stocks. 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."*[300]

This model in relation to which a Nobel prize[301] 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. The Nevada State Controller, Ronald L. Knecht is an experienced former energy regulator who has consistently used the Fama French model in his work. He states:

> *"[W]hile there is still some apprehension about the use of the FF3F Model it has been recognised in at least three states, Massachusetts, Delaware and Nevada, when used in conjunction with other models to produce an arithmetic mean as an estimate. This approach ensures that factors that are ignored by one model are adequately addressed. Because the FF3F model is fairly new relative to other models I am not aware of any jurisdiction that has endorsed it exclusively or adopted allowed rates of return based expressly on it. Instead, the tradition in the United States is for regulatory decisions to review (or even just list) all the evidence in the record and then, subjectively balancing the merits and results of all of it, to arrive at a final conclusion as either a range of reasonableness or a point estimate."*[302]

Mr Knecht[303] has used the model in the following regulatory processes:

1. He 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

---

299 SFG Consulting; *The Fama-French Model; Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid and SA Power Networks*; 13 May 2014; p. 3.

300 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.

301 "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>

302 Knecht; paragraph [4.6]; p. 3.

303 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].

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.

2. On a separate occasion, in July 2007, Mr Knecht acted on behalf of the Nevada Public Utilities Commission[304] 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.[305]

3. 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,[306] the Commission recognised that the Fama-French model has "gained great currency in investment practice".[307]

More broadly, the model has been presented to U.S. public utilities regulators as follows:

1. Before the Massachusetts Department of Telecommunications,[308] 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,[309] 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 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,[310] Artesian Water Company led evidence that included Fama-French data.[311] The Commission accepted that evidence without reservation.

---

304 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.).*

305 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].

306 *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].

307 *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].

308 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.

309 *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 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.

310 *In the matter of the application of Artesian Water Company, Inc., for an increase in water rates* 2003 Del. PSC LEXIS 51.

4. 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[312]. Hayes calculated a return on 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."*[313]

However, the AER's recent determinations for the NSW and ACT electricity transmission and distribution businesses give no weight at all to the Fama French model. Handley justifies the AER's approach by asserting that the rate of return is concerned only with variables that are unequivocally proved to be ways to quantify risk and not with a more general search for a commensurate return:

> *"[E]mpirical evidence of a value effect is not sufficient on its own to justify a claim for additional compensation relative to the Sharpe-CAPM.*
>
> *The key point is that we do not have a clear understanding of what the value effect represents. This uncertainty is critically important in the current context because it means that the value effect does not necessarily reflect risk, whereas the allowed rate of return objective is clear that risk is the key determinant of the rate of return."*[314]

Handley's approach construes the rate of return objective too narrowly and a model that behaves strongly in quantifying the market rate of return is ideal for setting a commensurate rate of return and should not be excluded on the basis that there is some argument as to whether or not its parameters are solely a measure of risk.

---

311 *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].

312 Testimony of Gary G Hayes on behalf of San Diego Gas and Electric before the California Public Utilities Commission 2007, p. 19.

313 Testimony of Gary G Hayes on behalf of San Diego Gas and Electric before the California Public Utilities Commission 2007, pp. 12 – 15.

314 Handley, JC; *Advice on the Rate of Return for the 2015 AER Energy Network Determination for Jemena Gas Networks, a report prepared for the Australian Energy Regulator*; 20 May 2015; p. 6.

Finally, we note that the AER's consultants have sought to suggest that because Fama and French continue to build on their previous work[315] by seeking further refinements the three factor model should be rejected in favour of the original SL-CAPM. Maintenance of this position is illogical.

### *(e) Implementation*

The multi-model approach requires:

- An estimate of the market risk premium and beta for use in the capital asset pricing models;
- A zero beta return for use in the Black CAPM;
- The three factors for use in the Fama French Three Factor Model; and
- A growth rate for the DGM.

AusNet Services supports Gray and Hall's sourcing of these inputs. Their view as to the appropriate manner in which the AER should exercise judgment establishing the MRP relies on similar information to the AER, 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 in the AER's approach that are identified above. Gray and Hall note:

> *"[Gray and Hall 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%."*[316]

Gray and Hall's report for the 22 June to 17 July 2015 averaging period[317] 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., 3.02%) to deliver an estimate of 9.58%;
- 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 9.99%.

315 Eugene F. Fama and Kenneth R. French; 'A five-factor asset pricing model' (2015) 116 *Journal of Financial Economics*.

316 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 340, p. 82.

317 Frontier Economics; *An Updated Estimate of the Required Return on Equity – Report prepared for AusNet Services;* August 2015 (attached as Appendix 10H).

This information is synthesised to provide a single point estimate of 10.93%. This report for AusNet Services' placeholder averaging period is an update of the analysis (alongside relevant discussion) contained in previous Gray and Hall reports.

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.

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 Gray and Hall:

*"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 … ."*[318]

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.

In Gray and Hall's expert opinion[319] the most appropriate estimate for the equity beta is 0.82 on the following basis:

---

318 SFG Consulting; *Equity beta*, *Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, paragraph 10, pp. 3 – 4.

319 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. 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."*[320]

Gray and Hall have estimated the return on a zero beta asset by adding a 3.34% zero beta premium to the risk free rate of 3.02% to give an estimated return on a zero beta asset of 6.36%.

This is within the reasonable range in the Guideline[321] and for that reason this issue does not warrant a detailed treatment in this document.

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:[322]

- Market exposure: 6.17%;
- Size exposure: -0.19%; and
- Book to market exposure: 1.15%.

Using the above parameter estimates, SFG Consulting[323] estimates for the four models using an indicative averaging period spanning the 20 days to 17 July 2015:

- SL-CAPM: 9.48%;
- Black-CAPM: 10.09%;[324]
- Fama-French Three Factor model: 10.10%; and
- DDM: 10.45%.

On the basis of an equal weighting of the above estimates, the return on equity for AusNet Services is 10.00%.

On the other hand, if the SL-CAPM were to be the only model used, it would be necessary to address the two most significant flaws, being that it is downwardly biased for both low beta

320 SFG Consulting; *Equity beta*, *Report for Jemena Gas Networks, ActewAGL and Networks NSW*; 12 May 2014, paragraph 195, p. 42.

321 AER; *Explanatory Statement*; p. 15.

322 Frontier Economics; *An updated estimate of the required return on equity, Report prepared for AusNet Services;* August 2015; 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.

323 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.

324 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%.

assets and value assets. SFG Consulting has separately estimated three CAPM[325] equity betas using each of the other models to correct for these biases. If the employment of the SL-CAPM as a primary or foundation model is pursued, the correct parameters over the 22nd June to 17th July 2015 averaging period are:

- Equity beta of 0.886;[326] and
- The required return on the market to be 10.93%.

Accordingly, for a risk-free rate of 3.02%, an asset with a beta of 0.886, and an over-all required rate of return for the market of 10.93%, the required return on equity within the SL-CAPM model is 10.00%.

## 10.5 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. This puts 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 10.5.1);
- Establish, in section 10.5.2, 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 10.5.3);
- Set out the proposed estimation procedure (section 10.5.4);
- Select averaging periods (section 10.5.5);
- Assess debt raising costs (section 10.5.6);

325 (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.

326 Calculated as the average of the risk premia in each of the four models divided by the current market risk premium of 7.91% as estimated by SFG Consulting.

- Assess the cost of the new issue premium (section 10.5.7);
- Set out the proposed annual update formula (section 10.5.8); and
- Set out the proposed return on debt (section 10.5.9).

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. [327]

### 10.5.1 Tenor of the benchmark debt instrument

The Guideline[328] 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. This approach is accepted by AusNet Services.

However, in the AER's recent decisions[329] it states that "*if anything, this assumption is more likely to overstate than understate the debt term of a benchmark efficient entity*". [330] The AER's recent 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.

AusNet Services does 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. [331, 332, 333, 334]

---

327 (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.

(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.

328 AER; *Better Regulation | Rate of Return Guideline*; December 2013, section 6.3.1 p. 19.

329 For example, AER; *Decision for Jemena Gas Networks (NSW) Ltd Access Arrangements 2015-20, Overview*; April 2015 (pdf version).

330 For example AER; *Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; June 2015, page 3-193 (pdf version).

331 Witness statement of Gregory Damien Meredith; 31 January 2009.

332 Witness statement of Sim Buek Khim; undated.

333 Witness statement of Alistair Watson; 30 January 2009.

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. [335]

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).

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. As this is as close to the 10 year benchmark as is practicable given it is based on a small sample with lumpy debt raising requirements and face a range of practical constraints[336, 337, 338, 339] on when debt can be issued.

### 10.5.2. 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 transmission 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 final transmission and distribution decisions, that a benchmark efficient entity would hold an evenly staggered

---

334 Witness statement of Andrew Noble; undated.

335 Letter from Dr Tom Hird (Director of CEG) to Mr Warwick Anderson (GM Network Regulation Branch of the AER) dated 11 November 2013.

336 Witness statement of Gregory Damien Meredith; 31 January 2009.

337 Witness statement of Sim Buek Khim; undated.

338 Witness statement of Alistair Watson; 30 January 2009.

339 Witness statement of Andrew Noble; undated.

portfolio of long-term (10 year) debt where exactly 10 per cent of the debt is refinanced each year.[340] 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 more closely aligns 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.

### 10.5.3 Transitional Arrangements

AusNet Services notes that the AER has rejected a range of alternative proposed transitional arrangements for the debt allowance proposed in recent determinations and consequently it has adopted the AER's Guideline transition in this revenue proposal. It is also noted that an Australian Competition Tribunal decision on the appropriate form of transitional arrangements is shortly to be made. AusNet Services will consider the decision of the Tribunal when it is handed down.

The Guideline proposes that the new trailing average method be introduced gradually.[341] In the first year, the rate for debt would be set in the manner that applied in the previous determination for AusNet Services in 2014 (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.[342] 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.

### 10.5.4 Estimation Procedure

#### *Benchmark credit rating*

The Guideline considers that the benchmark credit rating should be BBB+.[343] Further, the AER has rejected CEG's position with respect to the appropriate credit rating for a benchmark efficient entity in the AER's recent decisions.[344] CEG found that each year from

---

340 See AER; *Decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; June 2015, p. 3 - 511 (pdf version).

341 AER; *Better Regulation | Rate of Return Guideline*; December 2013, section 6.3.2, pp. 19 – 20.

342 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.

343 AER; *Better Regulation | Rate of Return Guideline*; December 2013, Section 6.3.3, pp. 21 – 22.

344 For example: AER; *Final Determination decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; June 2015, p. 3 - 524 (pdf version).

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 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 the ownership by the Singaporean Government and later by the Chinese Government in these businesses has significant effect on the consideration of their credit ratings by credit rating agencies.

In the Jemena draft decision[345], the AER took the view that even if it were to consider government ownership in AusNet Service and SGSP, some time had 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. This interpretation misunderstands the issue that the continuing effect of 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. [346]

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.[347] 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. [348]

345 AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; June 2014, p. 296 (pdf version).

346 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014, (pdf version).

347 AER; *Final decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; June 2014, p. 3-534(pdf version).

348 For example: AER; *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 3: Rate of return*; November 2014 (pdf version).

Over a five year period the data for the corrected comparators is as follows:

### Table 10.10: Credit Ratings of Corrected Comparator Firms

| End of year | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MEDIAN over all years | Median over last 5 years |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **APT Pipelines** | | | | | | | | BBB | BBB | BBB | BBB | BBB | BBB | BBB | **BBB** | **BBB** |
| **ATCO Gas Australian LP** | | | | | | | | | | BBB | BBB | A- | A- | A- | **BBB** | **BBB+** |
| **DBNGP Trust** | | | BBB | 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+** | **BBB** |
| **Energy Partnership (Gas) Pty Ltd** | | BBB | 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-** | **BBB-** |
| **ETSA Utilities** | A- | 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+ | BBB+ | **A-** | **A-** |
| **AusNet Services** | A | 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+ | BBB+ | **A-** | **A-** |
| **The CitiPower Trust** | A- | A- | A- | A- | A- | A- | A- | A- | A- | A- | A- | BBB+ | BBB+ | BBB+ | **A-** | **A-** |
| **United Energy Distrib. Pty Ltd** | A- | BBB | 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** | **BBB** |

*Source:* AER, *SA Power Networks preliminary decision,* p. 3-488

It can be seen that, with the exception of 2015, 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 2015 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. AusNet Services (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.

Separately, ActewAGL presented analysis by CEG to the effect that applying Moody's approach to rating entities, a hypothetical benchmark entity operating ActewAGL's business would have a BBB or BBB- credit rating (depending on what assumption is made concerning its debt financing). If that expert finding were taken into account as an additional data-point in the above table, it would also reaffirm the correctness of the BBB rating.[349]

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. [350]

Until recently the two available measures of the cost of debt were published by Bloomberg and the RBA. The former was publishing an estimate with a seven year tenor and the RBA was publishing one labelled a 10 year tenor but which in reality is an estimate for a marginally shorter term.

The AER tested these two options, scoring them on a range of considerations and ultimately reaching the conclusion that each performed better in some respects and not in others and on that basis the appropriate course would be to take a 50:50 average.

Recently, AusNet Services has observed that Bloomberg's new 10 year BVAL curve has significantly understated the yields of recent debt issuances. In fact, correspondence between AusNet Services and Bloomberg has confirmed that Bloomberg made adjustments to its extrapolation methodology, following the observed discrepancies between Asciano (which issued a 10 year bond at 2.15% over swap on 12 May 2015) and the BVAL 10 year implied margin (1.7% on 20 May 2015). This discrepancy cannot be entirely explained by a 'New Issuance Premium' because:

[349] CEG, Hird, T; *Efficient debt financing costs - A report for ActewAGL*; 19 January 2015.

[350] AER; *Explanatory Statement*; p. 127.

- The discrepancy between the relevant RBA BBB curve observation (which also reflects secondary market bond yields) and the Asciano issuance was not as stark; and
- Bloomberg itself confirmed adjustments to its BVAL curves following this observed discrepancy. This indicates that the issue was methodological.

In addition, the issuance of debt by DBNGP – one of the AER's benchmark comparator firms – of an 8 year floating rate note (FRNs) at 200bp over swap on 17 July 2015 was also materially above the BVAL 10 year yields reported at the time, despite its lower term to maturity. The BVAL index does not include FRNs so this issuance was not included in the sample underpinning the curve. This further highlights limitations with the BVAL series as the sample of bonds underpinning the curve is restrictive, and accordingly, the curve does not reflect all available information on the cost of debt for a benchmark efficient network business.

Given these recent developments, AusNet Services no longer considers that the Bloomberg BVAL curve is fit for purpose at the current time.

CEG has commenced the process of scrutinising the appropriateness of using Bloomberg's 10 year curve and this has already revealed significant issues that suggest the curve is, on what has been unearthed so far, inappropriate for use.

In particular, there is a key difference between Bloomberg's 10 year curve and the RBA's 10 year curve that arises because of the bond selection criteria. Bloomberg uses a more restrictive bond sample than the RBA curve and this results in Bloomberg excluding all the available data with a term to maturity exceeding approximately 6.9 years. By contrast, the RBA uses a broader set of bonds and its data points do include longer term bonds.

Bloomberg's 10 year figures are, in fact, derived from extrapolating from its shorter term data. CEG asked Bloomberg what approach it used to derive the long end of its curve and it uses neither the "SAPN method" nor the "RBA method" of extrapolation. Rather, Bloomberg simply takes the shape of the long end of the curve for Commonwealth Government Securities and applies this to the corporate bond data.

> *"When queried by CEG on how Bloomberg could construct a BBB yield curve out beyond the available BBB bond data Bloomberg responded as follows:*
>
> *On April 14, 2015, BVAL curve methodology has introduced enhancements to curve construction to enable curve derivation for tenors three months to 30 years. Curve derivation is now using the respective government benchmark as the underlying reference curve to enable curve construction over the full maturity spectrum, in the absence of data constituents. That's the reason why you noticed AUD Corporated BBB BVAL curve has suddenly been extended from 7 to 30 years starting from April 14, 2015."*[351]

As CEG points out, that approach will underestimate the required returns for corporate debt because it wrongly assumes that lenders will be content with locking away funds in the hands of corporate borrowers for an additional three years on the same basis that lenders to the AAA rated Commonwealth Government would.

CEG concludes:

> *"Bloomberg appears to be basing its BBB BVAL yield curve shape on the shape of the government bond yield curve beyond around 5 years;*
>
> *As a matter of theory, this is likely to understate the increase in yields on BBB (as opposed to risk free) debt;*

[351] CEG; *Extrapolation of the Bloomberg curve to 10 years*; 19 June 2015; pp. 5 – 6.

> *This is borne out when the BBB BVAL curve is tested against the observed yields on longer dated BBB bonds issued by Australian corporates (both in the BVAL constituents and wider samples of bonds)."*[352]

The Bloomberg 10 year curve should not, therefore, be used at this time. It has not been subjected to the AER's testing process nor the scrutiny of stakeholders and a preliminary scrutiny of the curve already reveals a significant flaw preventing it from being suitable when establishing a measure of debt that is commensurate with the costs of a benchmark efficient entity with a comparable level of risk.

AusNet Services notes that in the matter of *Re Application by ACTEWAGL Distribution* [2010] ACompT 5; (2010) ATPR 42-324 the Tribunal noted that *"…if a representative set of bonds sufficient to determine a fair value curve cannot be ascertained, or if later checks throw doubt on the chosen fair value curve, then this method of distinguishing between the curves cannot be used."* AusNet Services is of the view that the 10 year RBA better meets the appropriate criteria such that a 50:50 average would be inappropriate. Consequently, AusNet Services' revenue proposal retains the use of the RBA 10 year curve.

### 10.5.5 Averaging period

Accompanying this revenue proposal and forming part of it is a confidential letter proposing details of the averaging periods for each year of the regulatory period (Appendix 10I – Averaging Period Letter).

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*."[353] 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 a close to "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."*[354]

As it was not necessarily efficient to issue debt in the mid- to late part 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 at this time going forward.

352 *Ibid*; p. 14.

353 AER; *Guideline*; section 6.3.1, p. 15.

354 AER; *Explanatory Statement*; pp. 108 – 109.

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.

There is no conceptual reason why it should be presumed that raising debt at a particular time of year is preferable. 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 a year.

To allow time to incorporate the updated cost of debt in prices, the averaging period cannot occur during the latter two to three months of each regulatory year. It is feasible that the benchmark efficient entity would need to issue new debt during these months, to replace debt reaching maturity. Where this is the case, an averaging period has been selected which takes place in the latter months of the regulatory year two years before the prevailing rates are reflected in the revenue allowance.

While AusNet Services recognises that it may be desirable to reduce the lag between prevailing rates and their application to setting revenues, the new approach which allows annual updating gives effect to this much more closely than under the previous approach. In addition, the NER specify that the AER must have regard to:

- The desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity (NER 6A.2.2(k)(1)). As outlined above, there is no basis for concluding that the benchmark efficient entity would have raised debt during a particular part of the regulatory years.
- Any impacts (including in relation to the cost of servicing debt across regulatory control period) on a benchmark efficient entity … that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory period to the next (NER 6A.2.2(k)(4)). As the AER has acknowledged in its recent determinations, the benchmark efficient entity seeks to effectively manage interest rate risk. Under the new trailing average approach, matching the timing of averaging periods to the timing of actual debt issuances is an efficient way to minimise interest rate risk. However, this can only be achieve by chance if the timing of averaging periods is restricted to a certain portion of the regulatory year.

### 10.5.6 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.

### 10.5.7 New issue premium

The proposed source of debt data (i.e. the RBA series) is based on 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. 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 and asymmetric information held between borrowers and lenders.

CEG has prepared a report detailing its views on the extent of the new issue premium[355]. The new issue premium is measured as the change in yields from issue relative to changes in yields of a bond market index. The RBA BBB fair value curve is 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 NER supports this conclusion. The allowed rate of return objective states:

"The allowed rate of return objective is that the rate of return for a Transmission 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 Transmission Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).[356]"

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.[357]

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's all the more important that the AER approves other aspects of our regulatory proposal in full.

### 10.5.8 Annual Update Formula

NER 6A.6.2(l) requires that if the debt allowance is to differ within the revenue period from one year to the next:

> *"… then a resulting change to the Transmission Network Service Provider's annual revenue requirement must be effected through the automatic application of a formula that is specified in the transmission determination."*[358]

For each of the four years 2018-2022, 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 x of the proposal relative to the cost of debt for that year applied by the AER in making its transmission determination; and

oRABt is the opening RAB in year t set out in the transmission determination.

*Note: The 60% represents the gearing ratio assumed for the benchmark firm.*

For clarity, in addition to the formula required under NER 6A.6.2(l) of the Rules, we have also included other formulae to describe other aspects of our proposal.

355 CEG Competition Economists Group, Hird, T; *New Issue Premium*; October 2014.

356 AEMC; *National Electricity Rules Version 74*, Rule 6A.6.2(c), p. 784

357 CEG Competition Economists Group, Hird, T; *New Issue Premium;* October 2014, p. 54.

358 AEMC; *National Electricity Rules Version 74*, Rule 6A.6.2(l), p. 786.

For Regulatory Year 2017-2018: $kd_{2017\text{-}18} = T_{2017\text{-}18;}$

For Regulatory Year 2018-2019: $kd_{2018\text{-}19} = (0.9 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19})$;

For Regulatory Year 2019-2020: $kd_{2018} = (0.8 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20})$;

For Regulatory Year 2020-21: $kd_{2019} = (0.7 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20}) + (0.1 \times T_{2020\text{-}21})$;

For Regulatory Year 2021-2020: $kd_{2020} = (0.6 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20}) + (0.1 \times T_{2020\text{-}21}) + (0.1 \times T_{2021\text{-}22})$,

where:

- In each case a Regulatory Year runs from 1 April until 30 May.
- $k_{dt}$ is the return on debt for Regulatory Year t of the Regulatory Period; and
- $T_{20XX\text{-}YY}$ is the cost of BBB 10 year debt drawn from the Reserve Bank series for the year 20XX-20YY.

The return on debt for each Regulatory Year of the Revenue Period is to be calculated as follows:

For Regulatory Year 2017-2018: $kd_{2017\text{-}18} = T_{2017\text{-}18;}$

For Regulatory Year 2018-2019: $kd_{2018\text{-}19} = (0.9 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19})$;

For Regulatory Year 2019-2020: $kd_{2018} = (0.8 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20})$;

For Regulatory Year 2020-21: $kd_{2019} = (0.7 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20}) + (0.1 \times T_{2020\text{-}21})$;

For Regulatory Year 2021-2020: $kd_{2020} = (0.6 \times T_{2017\text{-}18}) + (0.1 \times T_{2018\text{-}19}) + (0.1 \times T_{2019\text{-}20}) + (0.1 \times T_{2020\text{-}21}) + (0.1 \times T_{2021\text{-}22})$,

where:

- In each case a Regulatory Year runs from 1 April until 30 May.
- $k_{dt}$ is the return on debt for Regulatory Year t of the Regulatory Period;
- $T_{20XX\text{-}YY}$ is the cost of debt for the year 20XX-20YY;

### 10.5.9 Proposed Return on Debt

Applying AusNet Services' proposed approach to estimating the return on debt over the placeholder averaging period of 22 June to 17 July 2015 yields 5.37%.

The detail underpinning this calculation is set out in the attached model (Appendix 10J – Cost of Debt Estimate).

## 10.6 Inflation

The Rate of Return Guideline does not address the issue of what is the best estimate for inflation and instead leaves it to be decided as part of individual networks' determinations:

> *"As discussed with stakeholders, the final guideline does not cover our position on transactions costs or forecast inflation. These issues will need to be considered in upcoming determinations."*[359]

Until the AER's 2008 determination for AusNet Services' transmission business, the AER had established its inflation estimate from market data concerning the trade in indexed and nominal CGS yields.

359 AER, *Explanatory Statement*; p. 28.

The current method that the AER uses to estimate inflation was introduced in 2008 due to concerns that the then market trading conditions were significantly influenced by a scarcity of indexed bonds delivering skewed estimates of inflation.

The AER noted that:[360]

> *"In the absence of a robust market based estimate, the AER agrees with SP AusNet's emphasis on independent forecasts in its revised proposal. However, the AER considers that more regard should be given to inflation forecasts from the RBA than those available from the various forecasters cited by SP AusNet and NERA, as the RBA is responsible for monetary policy in Australia, and its control of official interest rates and commentary has a significant impact on both outturn inflation and inflation expectations. In its latest Statement on Monetary Policy the RBA forecast inflation to be 3% in the 12 months to December 2008, and 2.75-3% in the 12 months to December 2009. The AER considers the RBA's forecasts represent the best estimates of forecast inflation for these two years. The RBA does not release inflation forecasts beyond a two year period."*

And:

> *"In the absence of a reliable market based estimate, and acknowledging the difficulty of forecasting inflation beyond the short term, the AER considers 2.5% to be a reasonable estimate of inflation beyond the RBA's forecast period. Averaging the RBA's forecasts for 2008 and 2009 with 2.5% for the remaining 8 years produces a 10 year inflation forecast of 2.59%....."*

The current approach is partly based on RBA forecasts but the forecasts generally only extend out for one or two years. For the rest of the years the RBA's target inflation level is used as if it is an estimate of the inflation that is likely to occur. That approach would be appropriate if the RBA's use of its monetary policy instruments were effective in, on average, meeting the targets.

However, there is now extensive evidence that the RBA and other international central banks are struggling with the available monetary policy instruments to bring about the desired movements towards their targets in the face of strong deflationary market forces. As CEG notes that the RBA's senior staff and the Board itself have acknowledged this publicly:

> *"Overall, looking at this experience, I find it difficult to escape the conclusion that changes in interest rates are not affecting decisions about spending and saving in the way they might once have done."*[361]

> *"The Board is also very conscious of the possibility that monetary policy's power to summon up additional growth in demand could, at these levels of interest rates, be less than it was in the past. A decade ago, when there was, it seems, an underlying latent desire among households to borrow and spend, it was perhaps easier for a reduction in interest rates to spark additional demand in the economy. Today, such a channel may be less effective. Nonetheless we do not think that monetary policy has reached the point where it has no ability at all to give additional support to demand. Our judgement is that it still has some ability to assist the transition the economy is making, and we regarded it as appropriate to provide that support."*[362]

More broadly, CEG notes that it is not only RBA who is concerned about the impotence of its traditional instruments in the current circumstances:

> *"global inflation rates have been persistently below target, with instances of deflation in the US, Japan, the UK and the Eurozone;*
>
> *the ability of monetary policy to provide economic stimulus is limited, given the proximity of official interest rates to the 'zero lower bound', coupled with the fact that, at current low*

---

[360] AER (2008); *Final Decision, SP AusNet transmission determination, 2008-09 to 2013-14*; January 2008; pp. 103 – 104.

[361] RBA Deputy Governor Lowe; *Speech to the Goldman Sachs Annual Global Macro Economic Conference, Sydney*; 5 March 2015.

[362] RBA Speech.

> *interest rates, further rate reductions are of uncertain value in terms of providing economic stimulus; and*
>
> *the IMF's April 2015 World Economic Outlook publication specifically mentions Australia as being at risk of falling into a low inflation trap."*[363]

Meanwhile market participants form views about the level of inflation. As CEG states:[364]

> *"In this context, it is reasonable to expect that investors perceive an asymmetry in the probability that inflation will be above/below the RBA's target, at least in the medium term.*
>
> *This means that, even if the 'most likely' estimate is for expected inflation to average 2.5% in the medium to long term, this is not the mean (probability weighted) estimate. That is, there is more downside than upside risk to inflation. Indeed, this is precisely what market-based estimates of expected inflation are predicting – as I discuss in the subsequent sections."*[365]

Importantly, this is not an issue of whether the RBA is right or the market participants are wrong. Rather all parties, the RBA included, are concerned that the tools available to central banks are such that the actual inflation is not expected to conform to the mid-point of the target range agreed between the Governor of the Reserve Bank and the Treasurer of between 2% and 3% on average in the medium term.[366]

The AER approach to preparing inflation forecasts makes use of the following steps:[367]

- Draw upon the near term projections for inflation from the latest available version of the RBA Statement on Monetary Policy. Use the results from the Statement for underlying inflation to produce inflation forecasts for the next two years.
- For year three to year 10, insert a value of 2.5 per cent in the corresponding cells of the AER's inflation forecasting template. The value of 2.5 per cent is the mid-point of the range for inflation targeting that is used by the RBA.
- The values of the inflation forecasts for the individual years are transformed into an index, with a value of 100 being assigned to the year preceding the current year.
- A geometric mean is then fitted to the entire series, making use of the ultimate value of the index in the final year out of ten years (or 11 years, if the immediately preceding year is also counted).

Given that actual inflation has been significantly below the forecast produced from the AER's approach in recent years, it is now clear that the above method is not producing an optimal and reliable forecast for inflation at the present time. In particular, the latest annual inflation outturn which will be applied to derive allowed revenue for 2016-17 following the ABS's publication of September 2015 quarter CPI is 1.50%, which is far below the forecast for the 2014-17 period of 2.45%.

The AER's assessment of other revenue inputs, including labour and materials price escalators, includes a comparison between prior forecasts and actual outturns to assess their accuracy. AusNet Services submits that this should be a relevant factor for the AER in considering whether the continued approach of its current inflation forecasting methodology is warranted.

Recent developments in financial markets suggest that a re-appraisal of the AER's approach to developing inflation forecasts is now appropriate. In principle, the most direct and accurate way to set a rate of return allowance that is commensurate with the prevailing costs of a benchmark entity is to use market prices that are either directly observed from financial markets, or else can

---

363 CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [13]; p. 3.

364 *Ibid*.

365 CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [33]; p. 10.

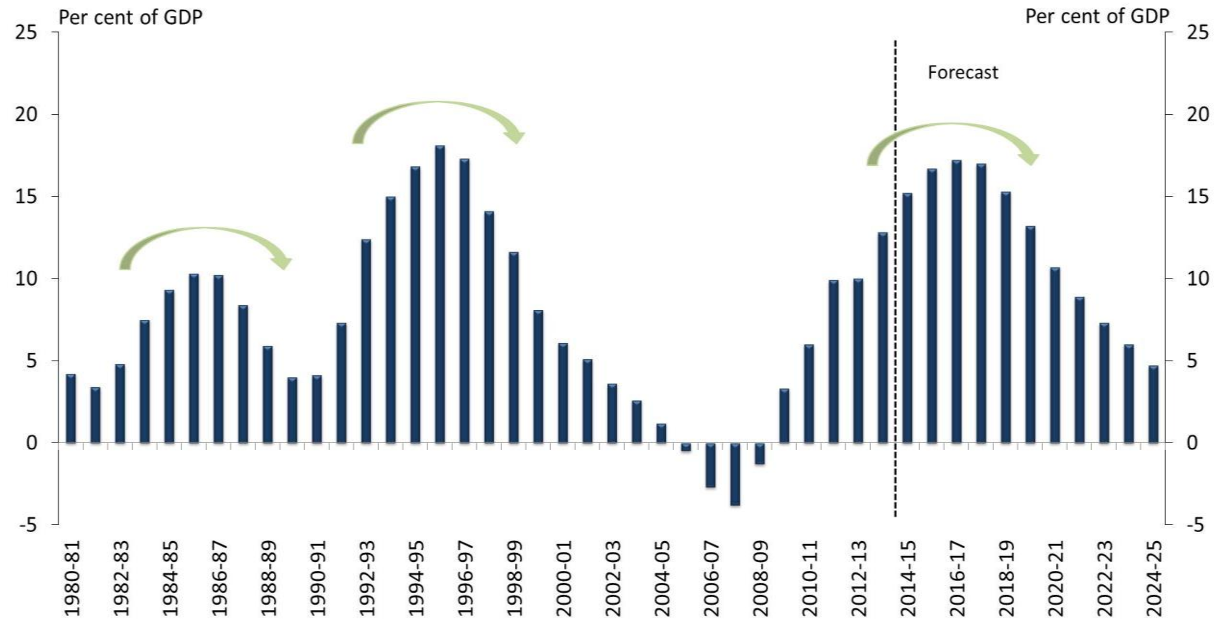
366 RBA Speech.

367 See, for instance: AER; *Final Distribution Determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17*; April 2012.

be inferred from financial markets. Prior to 2008, the inflation figure used to adjust the regulatory asset base (and, thereby, indirectly to apply a real rate of return in place of a nominal rate of return) was indeed drawn from financial markets. The Fisher equation was used to compare the yields on Treasury fixed rate bonds with the yields on Treasury indexed bonds, and to thereby infer an inflation rate which was consistent with market expectations.

However, between 1995 and 2008, there was a marked reduction in the volume of all CGS on issue. There are some investor classes for which adequate substitutes for CGS were not available, and there was a belief in the market that observed yields on CGS might have been affected by that scarcity. However, since 2008, the volumes of CGS on issue have increased significantly, both in dollar terms and as a proportion of GDP.[368] Figure 11.4: Australia's net debt position and Figure 11.5: Australian Government Bonds on issue provide a perspective on Australian Commonwealth Government debt, with the figures, and, indeed, the charts, having been sourced from the Australian Office of Financial Management.

**Figure 10.4: Australia's net debt position**




*Source:* Australian Office of Financial Management, *Investor Handout* (December 2014), slide 14 <http://aofm.gov.au/files/2015/01/AOFM-Dec-2014-Chart-Pack1.pptx, accessed 23 March 2015

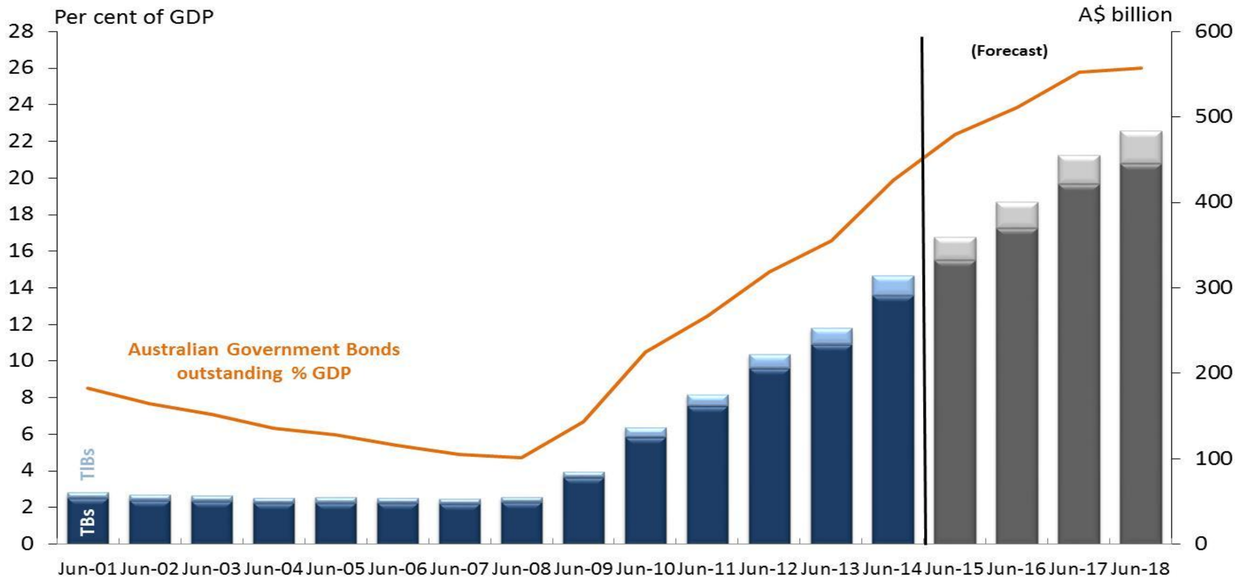
The value of indexed CGS on issue has increased from approximately $6 billion in 2009 to $18 billion in 2013.[369] Furthermore, the outstanding stock of CGS is not expected to diminish at all over the regulatory period.[370]

368 Australian Office of Financial Management; *Investor Handout*; December 2014; p. 14.

369 Ibid.

370 Ibid; p. 16.

**Figure 10.5: Australian Government Bonds on issue**




*Source:* Australian Office of Financial Management, *Investor Handout* (December 2014), slide 14 <http://aofm.gov.au/files/2015/01/AOFM-Dec-2014-Chart-Pack1.pptx, accessed 23 March 2015

Consequently, there is no longer a presumption in favour of the use of third party forecasts of inflation in place of the implied inflation measure that is provided by financial markets.

CEG agrees and consequently our revised proposal adopts CEG's recommendation that:

> *"Adopting breakeven inflation, unlike adopting the midpoint of the RBA's inflation target, can be viewed as the probability weighted forecast of inflation in all possible circumstances that market participants perceive."*[371]

We also note that CEG has used inflation swap trading data to check the usefulness of the estimate drawn from the break-even method and that check corroborates the use of the break-even method.

AusNet Services' proposal adopts an inflation estimate of 2.35% derived from market sources rather than the AER's current method of adopting the RBA's forecasts and targets. The calculation is provided as a supporting document.

AusNet Services considers that, given this revenue determination process lasts for 15 months and involves a significant amount of consultation with stakeholders there will be ample opportunity for stakeholder input on this potential change in methodology.

## 10.7 Conclusion

Using the indicative averaging period spanning the 20 days to 17 July 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:

371 CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [36]; p. 10.

**Table 10.11: 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** | 3.02% | 6.46% | 25% | **9.48%** |
| **Black Capital Asset Pricing Model** | 3.02% | 7.07% | 25% | **10.09%** |
| **Fama and French Model** | 3.02% | 7.08% | 25% | **10.10%** |
| **Dividend discount model** | 3.02% | 7.43% | 25% | **10.45%** |
| **Overall return on equity** | **3.02%** | **7.01%** | **100.00%** | **10.03%** |

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 0.89.

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, it should be populated as per SFG Consulting's advice, as outlined in section 10.4.5(e).

Combined with the proposed return on debt outlined in section 10.5 and the value of imputation credits (gamma) proposed in Chapter 11, AusNet Services' proposed rate of return for each regulatory year of the regulatory period is shown in the table below. The cost of debt will be updated on an annual basis as per the Rate of Return Guideline.

**Table 10.12: Proposed rate of return based on indicative averaging period**

| Input | Rate |
|---|---|
| **Overall return on equity** | 10.0% |
| **Overall return on debt** | 5.37% |
| **Gamma** | 0.25 |
| **Rate of Return** | **7.22%** |

*Note – the return on equity has been rounded to one decimal place, in accordance with the Guideline*

## 10.8 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 10A – Review of the AER's Conceptual Analysis for Equity Beta – Frontier Economics
- Appendix 10B – The Cost of Equity: Response to the AER's Final Decisions – NERA Economic Consulting
- Appendix 10C – Further Assessment of the Historical MRP: Response to the AER's Final Decisions – NERA Economic Consulting
- Appendix 10D – Cost of Equity Estimates Over Time – Frontier Economics
- Appendix 10E = Statement of Dr J Robert Malko – Malko Energy Consulting
- Appendix 10F – Statement of Ronald L Knecht – Ronald Knecht
- Appendix 10G – Key Issues in Estimating the Return on Equity for the Benchmark Efficient Entity – Frontier Economics
- Appendix 10H – An Updated Estimate of the Required Return on Equity – Frontier Economics
- Appendix 10I – Averaging period letter
- Appendix 10J – Cost of Debt Estimate (MS Excel file)

In addition, documents footnoted in this chapter will be submitted to the AER's Melbourne office in person on a USB on Friday 30 October 2015.

# 11 Tax and the Value of Imputation Credits

## 11.1 Key Points

- The regulatory allowance for tax is set using two inputs: the corporate tax rate and the estimated value of imputation credits (also known as gamma).
- AusNet Services is proposing a total net taxation allowance of $156.6m (real 2016-17) over the 2017-22 period; an annual average of $31.3m.
- The proposal is based on adopting:
  - The current corporate tax rate of 30%; and
  - A gamma value of 0.25.
- A different value of gamma is proposed than has previously been adopted by the AER, including in its 2013 Rate of Return Guideline. This is because AusNet Services does not agree with the ‘conceptual framework’ adopted by the AER for estimating the value of distributed imputation credits to the investors that receive them. Market value studies are the only source of evidence that capable of producing an accurate point estimate of this value.

## 11.2 Introduction and Overview

The NER 6A.6.4 provides that the estimated cost of corporate tax ($ETC_t$) for each regulatory year (t) must be calculated in accordance with the following formula:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

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 *prescribed transmission services* if such an entity, rather than the *Transmission Network Service Provider*, operated the business of the *Transmission 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

$\gamma$ is the value of imputation credits.

The proposed value of gamma is the subject of the remainder of the chapter. In order to promote the NEO[372], 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 transmission for the long term interests of consumers.

The value set for gamma is closely related to the return on equity because it adjusts permitted revenues in recognition that the benchmark entity would distribute imputation credits to its

[372] NEL, Schedule 2, Part 3, section 8.

shareholder base. The continued equity allowance and gamma determination together determine the permitted returns that investors can earn in the regulated network business.

AusNet Services' forecast tax allowance is shown in the table below.

**Table 11.1: Proposed Tax Allowance ($m, real 2016-17)**

| | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | Total |
|---|---|---|---|---|---|---|
| **Tax allowance** | 30.5 | 30.3 | 33.4 | 34.4 | 28.0 | **156.6** |

This is comprised of the following components:

- Corporate tax rate (30%)
- Value of Imputation Credits of 0.25

The current corporate tax rate has been applied – this is non-contentious. The remainder of the chapter outlines AusNet Services' position on the value of imputation credits and describes the basis of its proposed value of 0.25.

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[373], 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)[374] and previous findings of the Australian Competition Tribunal (the **Tribunal**)[375]. AusNet Services proposes that the distribution rate is combined with the best estimate of theta from market value studies (0.35), drawn from an updated dividend drop off study technique that has been honed and tested in multiple previous determinations, which leads to an estimate for gamma of *at most* 0.25. AusNet Services' proposal is consistent with the expert advice of Professor Stephen Gray and Dr Jason Hall at SFG Consulting (who have now joined with Frontier Economics[376]) and Simon Wheatley (of NERA).[377]

373 Monkhouse, P. H.L. (1996), 'The valuation of projects under the dividend imputation tax system', *Accounting & Finance*, 36: pp. 185 – 212.

374 AER, Guideline Appendices, pp. 136 – 180 (pdf version).

375 Australian Competition Tribunal, *Application by Energex Limited (Distribution Ratio (Gamma))* (No 3)(2010)ATPR 42-333; [2010] ACompt9.

376. 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, 6 February 2015, paragraph 22, p. 4 and SFG Consulting; *An appropriate regulatory estimate of gamma*; May 2014; *Reconciliation of dividend discount model estimates with those compiled by the AER*; October 2013; *Updated estimate of theta for the ENA*; June 2013; *Dividend drop-off estimate of theta, final report, Re Application by Energex Limited* (No 2) [2010] ACompT 7; 21 March 2011.

377 NERA; *The Payout Ratio, A report for the Energy Networks Association*; June 2013; and 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 En*ergy, March 2015.

AusNet Services considers that the AER's recent decisions[378] fail to estimate gamma to reflect the value equity-holders place on imputation credit as the AER:

- Proposes to revise the definition of theta to exclude the effect of certain factors on the value of imputation credits. AusNet Services consider that this is conceptually incorrect and inconsistent with the requirements of the NEO;
- 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;
- 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;
- 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, which is 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.[379] 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 that is inconsistent with evidence:
  - Of the returns that investors can obtain in equity markets at large; and
  - The AER's own analysis of the equity ownership rate and redemption rate.

### 11.2.1 Structure of Chapter

This Chapter is structured as follows:

- Section 11.2 describes the requirements of the NER and the NEL;
- Section 11.3 sets out AusNet Services' proposal, and explains the reasons why AusNet Services is proposing to depart from the Guideline value of gamma; and
- Section 11.4 describes AusNet Services' proposed approach to estimating gamma.

---

[378] For example, AER, *Final Decision Jemena Gas Networks (NSW) – Access arrangement 1 July 2015 – 30 June 2020– Overview* – June 2015.

[379] AER, *Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 105.

## 11.3 Requirements of the NER and the NEL

The key aspects of the NER and the NEL relating to gamma are:

- Clause 6A.6.4.3 of the NER required an estimate of $\gamma$ (gamma), being "*the value of imputation credits*";
- Clause 6A.6.5 of the NER, which related 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.[380] 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 AER's task set by the NER to determine total revenue by reference to the various specified building blocks. It is also consistent with past regulatory practice and previous Tribunal decisions;
- 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.

## 11.4 Proposal

AusNet Services proposes a gamma of *at most* 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[381,382] and Dr Jason Hall at SFG Consulting (who have now joined Frontier Economics)[383], Dr Simon Wheatley of NERA[384] and previous Tribunal findings.

The correct approach to estimating gamma, which is the approach adopted by AusNet Services in this proposal, is as follows:

380 NEL s 16(2)(a)(i).

381 SFG, *Estimating gamma for regulatory purposes*, February 2015, paragraph 22, p. 4.

382 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.

383 Frontier Economics, *An appropriate regulatory estimate of gamma*, *A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA PowerNetworks and United Energy* June 2015 (attached as Appendix 11A).

384 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 and NERA, *The Payout Ratio: A report for the Energy Networks Association*, June 2013 and NERA*; Do imputation credits lower the cost of equity*? Cross-sectional tests, A Report for United Energy; April 2015.

- 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, drawn from an updated dividend drop off study technique that has been honed and tested in multiple previous regulatory determinations;[385]
- 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 reasons 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))[386] is not an empirical study at all (because the data was not available), but merely

---

[385] For example AER , Access arrangement final decision – Multinet Gas (DB No. 1) Pty Ltd and Multinet Gas (DB No. 2) Pty Ltd 2013 – 17, March 2013.

[386] 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.

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.

When the AER sets gamma at a significantly higher level than the network business proposes, as it has done in recent decisions, the effect is to substantially lower the effective permitted returns below the level proposed because it leads to an assumption in the post tax revenue model that the investors are obtaining more substantial value from the imputation credits they receive and consequently that lower revenues will be sufficient to recompense existing investments and maintain the attractiveness of further investments required in the network.

## 11.5 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 by NERA[387], in his 1994 paper, Officer [388] 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.[389]

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 matters above was that Officer was preferring the second definition (i.e. 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 appropriate approach should take full account of the extensive expert material that has since been prepared. 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.

387 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.

388 Drawing on work in Officer R; *The Australian Imputation System for Company Tax and Its Likely Effect on Shareholders, Financing and Investment*; 7 Austl. Tax F. 353 1990.

389 Today we know the reasons and these are summarised in the diagrams in Figures 11.1 and 11.2 below.

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, in the absence of an energy network specific metric, AusNet Services considers the 0.7 value to be appropriate. NERA explains[390] 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.

### 11.5.1 Estimating the Distribution Rate

The AER's own Guideline states that it would apply a distribution rate (or payout ratio) of 0.7.[391] Recent empirical evidence also continues to support a distribution rate of 0.7.[392] Further the Tribunal has recently adopted a distribution rate of 0.7.[393]

Recently the AER has referred to two estimates of the distribution rate:[394]

- A market-wide distribution rate (including listed and unlisted equity) of 0.7; and
- A distribution rate for listed equity only of 0.77.

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:

> *"The distribution rate…is a firm specific parameter. One firm, after weighing up the costs and benefits of distributing credits, may decide to distribute all of the credits that have been created over some period. A second firm may rationally decide to distribute no credits – perhaps because it wishes to use internally generated funds to finance new projects."*[395]

Gray and Hall's studies take a whole-of-stock-market dividend drop off analysis to ensure that there is a wealth of data contributing to a robust valuation of theta but there is no reason to suppose that a benchmark efficient entities optimal distribution rate would match that of, for example, a company running a television station. Putting it differently, investors can trade their holdings in both power companies and television stations to effectively purchase or divest imputation tax credits but the companies concerned will logically determine their distribution rates according to their capital investment needs.

[390] 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.

[391] 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).

[392] NERA, *The payout ratio*, June 2013.

[393] Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

[394] See for example, AER, *Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, April 2015, pp. 17 – 18 (pdf version).

[395] NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks*; 22 June 2015; p. iii (attached as Appendix 11B).

At the very least, there is broad support for the notion that the distribution rate should be firm specific (even if there is debate about where to draw the theta value from). This is supported by the AER,[396] NERA,[397] Gray and Hall's report[398] and he also cites support from Lally[399].

The more important question, therefore, is what is the correct distribution rate to adopt in the context where it is acknowledged that the distribution rate is a firm specific parameter. The AER[400] has rejected the notion that the distribution rate should actually be determined by looking at energy network company stocks because the data set is small and it is alleged that doing so might create an incentive to manipulate the distribution rate. While concerns about the size of the dataset are justified, changes to the distribution rate can send strong signals to investors about the future expected earnings of a company, which in turn can influence share price. It is unlikely that influencing the value of gamma would be a strong consideration to a firm in setting its distribution rate. However, given the AER's position, the question becomes what is the next best source for a suitable distribution rate.

What would be unacceptable (as explained by NERA[401]), 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[402], 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"[403].

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.[404]

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.[405]

396 AER; *TransGrid Final Decision*, Attachment 4; page 20.

397 NERA; *Estimating Distribution and Redemption Rates from Tax Statistics,* A Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks and United Energy; March 2015; table 3.4; page 12.

398 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [99-101]; page 26.

399 Lally; *The estimation of gamma*, Report for the AER; November 2013.

400 AER; *Explanatory Statement*, page 164.

401 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.

402 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 – 13.

403 AER, *Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameter*, May 2009, p. 105.

404 M Lally, *Review of submissions to the QCA on the MRP, risk-free rate and gamma*, 12 March 2014, p. 34.

405 M Lally, *Review of submissions to the QCA on the MRP, risk-free rate and gamma*, 12 March 2014, p. 34.

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.[406]

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".[407] Therefore there is no conceptual basis to confine the dataset for estimating the distribution rate to listed equity.

As Gray and Hall's report[408] and NERA's work[409] explain, the top 20 Australian listed companies are predominantly multinational companies who are able to use dividends paid out of foreign profits to distribute a greater proportion of the imputation credits created from their domestic operations. It is not surprising that these firms have an imputation credit distribution rate exceeding 80% while the rate for other stocks is considerably lower. These top 20, predominantly multinational, listed entities are inappropriate comparators (at least unless their data is averaged with small firms in the economy who have low distribution rates). This list, for example, includes businesses with well-known international profiles such as BHP Billiton, the ANZ Bank, Macquarie Group, Rio and Westfield Corporation, all of whom self-evidently have significant foreign earnings. When the top 20 firms are "backed out" of the over-all data concerning listed equity the figure is close to 70%:

> *"The point is that any firm with foreign profits will be able to distribute more imputation credits than they would otherwise have been able to. The 20 largest multinational companies obviously have material foreign income and they would obviously be able to distribute fewer imputation credits without that foreign income."*[410]

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.[411] 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.

---

406 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.

407 AER, *Better Regulation: Rate of Return Guideline*, December 2013, p.7.

408 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraphs [111-118]; pp. 28-29.

409 NERA; *Estimating Distribution and Redemption Rates from Tax Statistics, A Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks and United Energy*; March 2015; Table 3.4; pp. 13 & 23; and NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks*; p. vii – "We believe that the AER's 2009 statement that a benchmark network service provider need be neither large and publicly listed nor publicly listed is correct. Thus we believe that Handley is wrong to advocate the use of a distribution rate that places a large weight on large publicly listed firms and no weight on private firms. It is difficult to see that there is a case for setting the distribution rate to be any different than the value accepted by the Australian Competition Tribunal in its 2010 decision and the market-wide value chosen in the AER's Rate of Return Guideline of 0.70. This value is based on a cumulative distribution rate computed using tax statistics aggregated across all companies – both private and public."

410 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [109]; p. 29.

411 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.

### 11.5.2 Value of Distributed Credits (theta)

#### *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."*[412]

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 is 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 utilization value to investors in the market per dollar of imputation credits distributed."*[413]

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."*[414]

Handley also observes that:

> *"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."*[415]

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.[416] 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.[417] 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.

412 AER, *Better Regulation: Explanatory Statement Rate of Return Guidelines*, December 2013, p. 159 (pdf version).

413 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).

414 John C Handley, *Advice on the Value of Imputation Credits*, 29 September 2014, p.17.

415 John C Handley, *Advice on the Value of Imputation Credits*, 29 September 2014, p.9.

416 See for example, AER, Final decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 44. (pdf version).

417 AER, Final decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 44. (pdf version).

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.

Indeed if the gamma is determined not from market data but from a "conceptual analysis" that causes the regulator to diverge from the actual market based valuation a mismatch will necessarily arise between regulatory allowances and investors' investment return requirements and this will necessarily distort investment decisions positively or negatively, either way to the long term detriment of consumers.

As stated in the expert report of Professor Gray and Hall, 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 and Hall:

> *"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."*[418]

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.

As Gray and Hall's report explains:

> *"In the regulatory setting, the regulator first estimates the return that shareholders' require and then reduces that according to the estimate of gamma. For example, suppose the regulator determines that shareholders require a return of $100 and that those shareholders will receive imputation credits that are worth $20 to them. The regulator would then allow the firm to charge prices so that it can pay a return of $80 to the shareholders. That is, the regulator's estimate of gamma determines the quantum of the reduction in the return that the firm is able to provide its shareholders by other means (dividends and capital gains).*
>
> *If, for example, the regulator's assessment of the value of imputation credits is greater than the true value of imputation credits to shareholders, the shareholders will be under-compensated. In this case, the reduction in other forms of return (dividends and capital gains) will exceed the true value of the imputation credits.*

[418] 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.

*Thus, when estimating gamma, the appropriate question to consider is this: What is the quantum of dividends and capital gains that shareholders would be prepared to give up in order to receive imputation credits? It is precisely this question that is addressed by market value studies that seek to quantify the relative value (to investors in the market for equity funds) of dividends, capital gains, and imputation credits.*

*The alternative is to reduce the regulatory allowance for returns from dividends and capital gains according to the proportion of investors who may be eligible to redeem credits, rather than according to the value of those credits. This approach will inevitably result in investors being mis-compensated because there is no attempt to consider whether the value of what investors are required to give up (dividends and capital gains) is equivalent to the value of what they receive in its place (imputation credits).*

*…*

*In my view it is abundantly clear that there are three components to the return on equity – dividends, capital gains, and imputation credits – and that a greater assumed value of imputation credits will result in a reduction in the regulatory allowance that generates dividends and capital gains. This is precisely what occurs in Row 35 of the PTRM – the return that could otherwise be provided to equity holders is reduced by the regulator's assessment of the value of imputation credits. Any suggestion that the regulatory allowance that generates dividends and capital gains is independent of the regulatory assumption about imputation credits is erroneous."*[419]

It is disappointing that an economic regulator such as the AER would not have faith in the market mechanism to deliver a valuation and that it would prefer its own "conceptual" valuation.

Indeed the in amending the meaning of gamma in the National Electricity Rules and inserting the definition in the National Gas Rules, the AEMC did not raise any concerns with the regulatory approach that had developed to estimating gamma which, up to that point, had amounted to a market value. Indeed the word change was a move to bring the Rules into line with regulatory practice.

Pages 11 to 16 of Gray and Hall's report identify a series of re-formulations by the AER and its consultants over the last five years as to what the AER says gamma represents. Initially the AER's formulation appeared to overlook the express requirement in the rules that gamma be a "value".

Network businesses responded by stressing the need for the gamma to be a "value" and asserting that the plain meaning of "value" imports the use of standard market valuation techniques. This precipitated a series of "back and fill" attempts to articulate how the gap could be bridged between the word "value" which appears in the rules and the AER's preferred conceptualisation of gamma as a measure of the number of credits redeemed. This led first to several internally inconsistent semantic discussions ("we consider the word 'value' used in these contexts is being used in a generic sense to refer to the number that a particular parameter takes";[420] "utilisation value"[421] and the "pre-personal-tax and pre-personal-cost-value"[422]) and finally an assertion that the redemption rate might actually constitute a way to estimate value if that term is construed in a particular way ("the use of redemption rates as a measure of estimating the value of credits is driven by conceptual considerations and theory").

The fact that the AER has been unable to provide a consistent and coherent explanation of how its preferred redemption rate concept reconciles with the language in the rules, and more significantly the notion that investors quite clearly seek market valued returns, strongly suggests that the approach it takes is inappropriate.

419 Frontier; *An appropriate regulatory estimate for gamma*; June 2015; paragraphs [12], [16] and [18]; pp. 8 – 9.

420 AER; *TransGrid Final Decision*, Attachment 4; p. 30.

421 AER, Final decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 44. (pdf version).

422 AER; *TransGrid Final Decision*, Attachment 4; p. 47.

The simple fact is that by taking redemption rates as the measure of gamma instead of studies of the value the market places on gamma, the AER's Preliminary Determination rejects the current definition in the Rules of gamma as a value. 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.[423]

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.[424]

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**). [425]

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.[426]

The AER has sought to dismiss the impact of tax rules affecting eligibility of domestic investors to redeem imputation credits by saying that:

---

423 John C Handley, *Advice on the Value of Imputation Credits*, 29 September 2014, p. 31.

424 See for example, AER, Final Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 12 (pdf version).

425 See for example, AER, Final Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 15. (pdf version).

426 Final Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 44 (pdf version)., p. 44 (pdf version).

> *"...we do not consider that there is clear evidence as to effect that these rules have or should be expected to have"*[427]

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. These rules are in place and will affect the eligibility of certain domestic investors to redeem imputation credits, and therefore mean that theta cannot be equated to the rate of domestic ownership.

Gray and Hall's latest report[428] also illustrates that the AER's methodology contains key internal inconsistencies when it comes to actually performing a redemption rate estimate:

- There is inconsistency as to whether the relevant redemption rate is a firm specific or market-wide parameter.
- Although the AER's Preliminary Determination states that it has taken into account tax statistic studies delivering numbers of 0.43, 0.45, 0.44 and 0.58, the AER's recent final determination for TransGrid states that its estimate is based on "an imputation credit utilisation rate (theta) of 0.6". A figure as high as 0.6 is only supported by one of the AER's statistics and only if it is rounded upwards to one decimal place. The other three statistics cited in the AER's Preliminary Determination all support a substantially lower number.

Although they do not themselves estimate the size of any over-statement, because the necessary data is not available, they do note that Handley and Maheswaran provides an indication that it may be material.

In summary, if a redemption rate were used as the value of imputation credits (and we have explained above why this would be the wrong thing to do), such a redemption rate should be significantly below the 0.6 level that the AER appears to use.

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).

Investors cannot rationally value an imputation credit above its face amount – they will never realise more than 100% of its face amount. On the other hand, there may be many reasons including those identified previously by Gray and Hall as to why an imputation credit may be valued at less than 100% of the face amount. Therefore, if a robust measure of redemption rates can be calculated, it can only be of use for economic regulatory purposes as an upper bound on the estimate of theta. This is further explained by Gray and Hall's report.[429]

NERA explores why redemption rates will exceed, and markedly so, the value of those imputation credits:

---

427 Final Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 44 (pdf version)., p. 44 (pdf version).

428 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; p. 31.

429 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; pp. 23 – 24.

> *"Imputation credits are of some use to domestic investors but are of little or no use to foreign investors. So the value that the market places on imputation credits distributed will largely depend on the impact that foreign investors have on equity prices."*[430]
>
> *"[O]ne can expect the rate at which credits are redeemed to exceed, significantly, the impact of credits on the cost of equity, theta."*[431]

And further:

> *"[T]he use of a domestic pricing model by the AER does not justify a presumption that the impact of foreign investors is restricted and that theta, consequently, take on a non-negligible value – contrary to claims that Handley makes in a September 2014 report."*[432]
>
> *As noted above, Handley previously stated that he considered the redemption rate is an upper bound for gamma and he still considers that the theta "should not exceed its redemption value, since this, by definition, represents the ultimate source of value of a credit".* [433]

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 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.[434]

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.

---

430 NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks, A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Energex, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy*; 22 June 2015; p. i.

431 NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks, A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Energex, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy*; 22 June 2015; p. ii.

432 NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks, A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Energex, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy*; 22 June 2015; p. ii.

433 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; pp. 23 – 24.

434 See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, April 2015, p. 14 (pdf version).

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 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 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:[435]

- 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;

[435] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2014, p. 4-27 (pdf version).

- 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.

**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.[436] 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);

[436] As noted above, the NER requires the rate of return and the value of imputation credits to be *measured* on a consistent basis (NER, clause6A.6.2(d)(d)).

- 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 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.[437]

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:

> *"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."*[438]

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.

437 Application by *Energex Limited (Gamma)* (No 5) [2011] ACompT 9, [22].

438 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 11.1: 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.[1] 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.[1]

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.[1]

In relation to the model specification and estimation procedure, the Tribunal concluded:[1]

> *"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.[1] 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.

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[439] 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.[440] 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.441 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.[442]

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, by 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.

### 11.5.3 Estimates of theta

#### *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.

---

439 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.

440 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.

441 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.

442 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.

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
- 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:[443]

- The equity ownership rate for listed equity is currently around 0.44444, 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.[445]

**Table 11.2: 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), Tables 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

---

[443] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 77 (pdf version).

[444] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p 77, footnote 243 (pdf version).

[445] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 76 (pdf version).

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.

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 "*supported an estimate of the utilisation rate between 0.4 and 0.6*".[446]

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 as a consequence we would not expect that the AER continue to use Handley and Maheswaran for this purpose;[447]
- 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.[448]

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.

---

[446] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p. 25 (pdf version).

[447] 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.

[448] See for example, AER, Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits, June 2015, p 77 (pdf version). As noted in the AER 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.

### (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.[449]

Underpinning this position appears to be a view that all market value studies should be given equal (or similar) weight, regardless of:

- 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*". [450] 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*".[451]

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.[452]

---

449 See for example, AER, *Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, June 2015, p. 4-86 (pdf version).

450 Application by *Energex Limited (Gamma)* (No 5) [2011] ACompT 9, [29].

451 Application by *Energex Limited (Gamma)* (No 5) [2011] ACompT 9, [29].

452 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.

Unlike the Tribunal in *Energex*, the AER in its recent final decisions 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.

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.

The AER has asserted that there is "new evidence" that means that very dated valuation studies should again be considered when taking a market value even though it had previously rejected them. The claimed "new evidence" comprise just two sentences in a paper by McKenzie and Partington.[453]

By contrast, Gray and Hall[454] has provided a considerably more thoughtful analysis that explains why the newer, post 2000 based studies are strongly preferable bases to assess market value.

The Final Determination for Jemena asserts[455] that there remain empirical estimation issues with Gray and Hall's work but in our view these points have already been answered by Gray and Hall[456] and, in many cases, also by the Tribunal and we do not propose to repeat those points in this submission.

### *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 Preliminary Determination asserts that Gray and Hall's drop off studies should be 'recalibrated' by dividing them upwards by an amount of 0.05. The idea of making an adjustment arises from the possibility that investors may value not only imputation credits but also dividends at less than their "face value". Gray and Hall have provided further analysis of whether this is an appropriate adjustment to make and on page 35 of their current report they do indeed provide a further explanation reaffirming why no adjustment should be made. The challenge here is to remember that a higher theta represents a lower return to investors. To explain the effects of the AER's adjustment, Gray and Hall consider a hypothetical in which an investor values dividends at only 90% of the face value. In summary, this hypothetical illustrates that:

> *"Rather than allowing a higher return, the AER proposed adjustment would result in a lower allowed return. The AER would propose that the 0.35 estimate should be divided by 0.9 to*

[453] McKenzie and Partington; *Review of Aurizon Network's draft access undertaking*; October 2013; paragraph [134].

[454] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [134]; pages 33-34.

[455] See for example, AER, *Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, June 2015, p. 4-28 (pdf version).

[456] See for example, AER, *Decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015 – 20 Attachment 4 – Value of imputation credits*, June 2015, p. 4-28 (pdf version).

*produce an adjusted estimate of 0.39. This higher theta would then result in shareholders receiving a lower return than they otherwise would. That is, rather than compensating investors for the lower value of dividends, the effect of the AER's proposed adjustment would be to compound the problem by reducing the amount of dividends that the firm is able to distribute. Thus, such an adjustment produces a perverse outcome."*[457]

The AER's recent 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 11.3: 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** |

*Source: AER*

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.

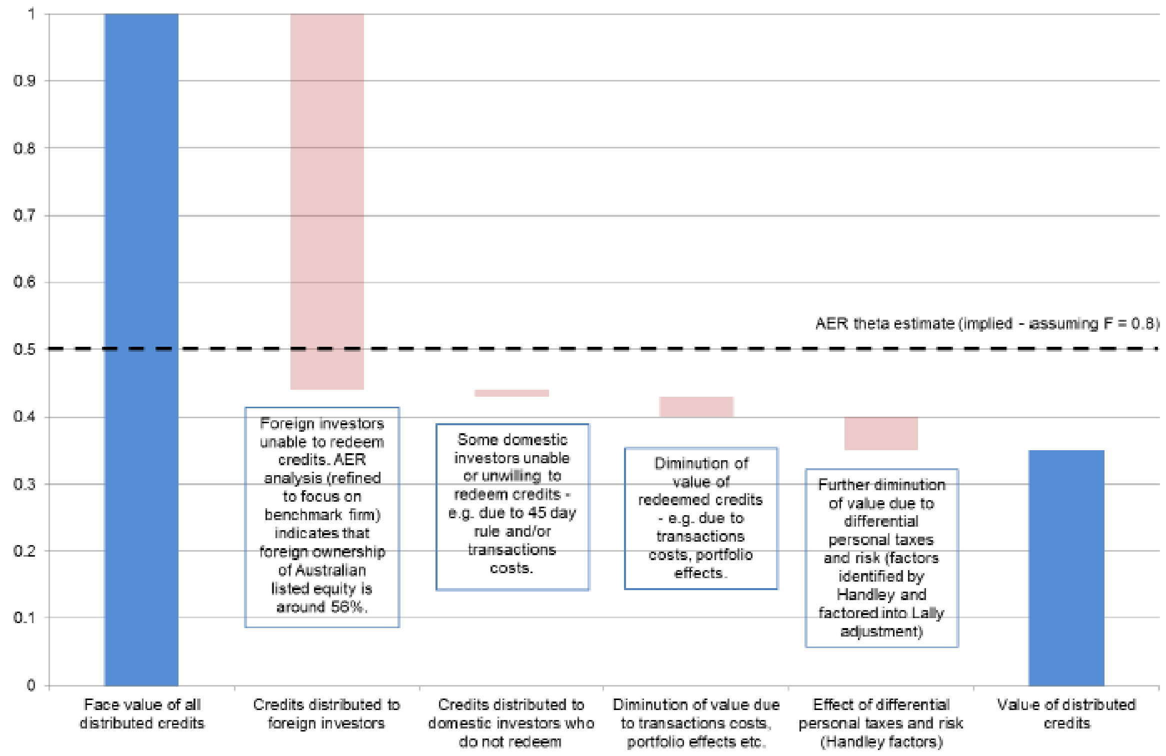
In order to illustrate the key implications of the empirical evidence, AusNet Services proposes an analysis of the data for listed equity (see figure below) reflecting the AER's updated approach. This reflects the data for listed equity, including:

- 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 11.1: Illustrative impact on value of imputation credits – listed equity**




*Source: AER*

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);

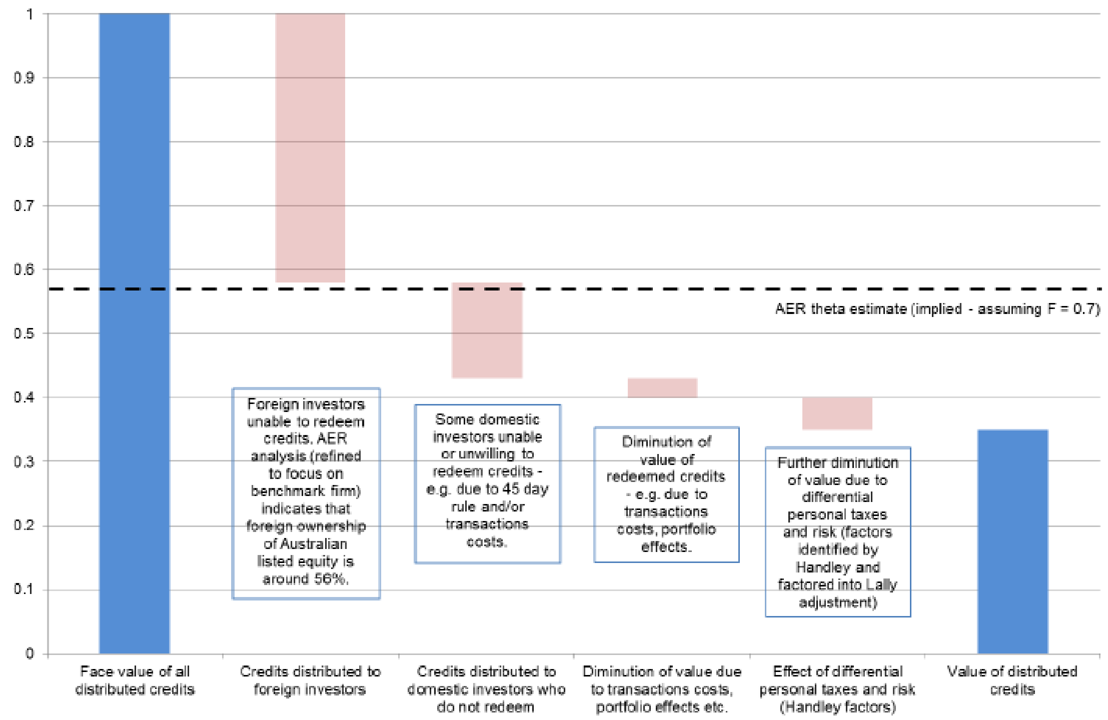
(2) the proportion of domestic investors unable or unwilling to redeem credits is set equal to the difference between the domestic equity ownership rate (0.44) and the observed redemption rate (0.43) – this is likely to be an under-estimate of the proportion of domestic investors in listed equity that 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 11.2: Illustrative impact on value of imputation credits – all equity




*Source: AER*

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.

The rules require the AER to deliver a reasoned determination. 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 its recent 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.

## 11.6 Supporting Documents

The following Appendices are relevant to this chapter:

- Appendix 11A – An Appropriate Regulatory Estimate of Gamma – Frontier Economics
- Appendix 11B – Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions – NERA Economic Consulting

In addition, documents footnoted in this chapter will be submitted to the AER on a USB with the revenue proposal.

# 12 Cost Pass Through

## 12.1 Key Points

- AusNet Services proposes six nominated cost pass through events to apply in the 2017-22 regulatory period. These are:
  - Terrorism event;
  - Insurance cap event;
  - Natural disaster event;
  - Insurer credit risk event;
  - C-I-C ; and
  - Decommissioning of the Point Henry to Geelong Terminal Station 220kV lines event.
- These nominated cost pass through events provide an efficient mechanism for managing the uncontrollable risks faced by AusNet Services within the next regulatory period.

## 12.2 Introduction

This chapter presents AusNet Services' proposed cost pass through arrangements for the forthcoming regulatory control period. Cost pass through arrangements enable adjustments (up or down) to be made to a TNSP's allowed revenue during a regulatory period if a predefined event occurs and leads to a material change in the TNSP's costs.

These arrangements provide an efficient mechanism for managing risks of material changes in costs that are beyond a TNSP's control, especially where insurance or self-insurance is either unavailable or uneconomic. It ensures consumers do not pay for uncertain but significant costs unless these events should occur.

One of the proposed nominated cost pass through events is confidential. There are sound reasons as to why the details of the proposed cost pass through event are confidential (see Confidentiality Response). However, AusNet Services is open to disclosing the details of the proposed event to stakeholders on request, subject to suitable confidentiality agreements being put in place. In addition, if the proposed event did occur during the course of the regulatory period, the reasons for claiming confidentiality over the event would no longer be relevant. Therefore it would be possible to disclose details of the event, and magnitude of the impact to consumers, in the cost pass through event application that AusNet Services would submit to the AER. The consultation process which would form part of the AER's assessment of the cost pass through event application would enable stakeholders to provide feedback on the potential cost impact of the event.

This chapter is structured as follows:

- Section 12.3 provides an overview of the cost pass through framework under the NER; and
- Section 12.4 presents AusNet Services' proposed nominated cost pass through events.

## 12.3 Overview of Cost Pass Through Framework

The arrangements for cost pass through are set out in NER 6A.6.9 and 6A.7.3.

Specifically, NER 6A.7.3(a1) prescribes the following pass through events, each of which is subject to a materiality threshold:

(1) A regulatory change event;

(2) A service standard event;

(3) A tax change event;

(4) An insurance event; and

(5) Any other event specified in a transmission determination as a pass through event for the determination.

In relation to subclause (5) above, NER 6A.6.9 provides for a TNSP to nominate pass through events, having regard to a set of considerations (termed "nominated pass through event considerations"), which include the following:

- Whether the event proposed is an event covered by a category of pass through event specified in NER 6A.7.3(a1)(1) to( 4);
- Whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;
- 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; and
- Whether the relevant service provider could reasonably insure against the event or whether the event can be self-insured.

In determining whether to accept any pass through events nominated by a TNSP in its Revenue Proposal, the AER must take into account the nominated pass through event considerations.

## 12.4 Proposed Nominated Events

Pursuant to NER 6A.6.9(a), AusNet Services proposes the following nominated cost pass through events for the forthcoming regulatory period:

- Terrorism Event;
- Insurance Cap Event;
- Natural Disaster Event;
- Insurer Credit Risk event;
- C-I-C ; and
- Decommissioning of Point Henry to Geelong Terminal Station 220kV lines event.

Having regard to the nominated pass through event considerations, the nominated events should be accepted by the AER for the following reasons:

- None of the proposed events is covered by one of the prescribed pass through events in the Rules;
- The nature and type of the each event is clearly identifiable;
- Both the occurrence of each proposed event, and the mitigation of expenditure associated with the event are outside the control of a prudent network service provider;
- None of the proposed events is insurable on reasonable commercial terms; and
- It is not possible to calculate credible self-insurance premiums for the proposed events.

The sections below provide a definition of each proposed nominated pass through event, and a more detailed explanation of the rationale for each of the proposed events.

### 12.4.1 Terrorism Event

#### *Proposed definition of event*

The proposed definition of a terrorism event is 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 section of the public, in fear) and which materially increases the costs to AusNet Services in providing prescribed transmission 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, including coverage from the Australian Reinsurance Pool;*

ii. *the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and*

iii. *whether a declaration has been made by a relevant government authority that a terrorism event has occurred."*

#### *Rationale*

AusNet Services' current transmission determination includes terrorism event as a nominated cost pass through event. The proposed definition includes an additional note, which was accepted by the AER in its April 2015 final decision for TransGrid. AusNet Services supports the inclusion of the note, which clarifies the operation of the pass through event.

Accordingly, AusNet Services expects that its proposed definition will be acceptable to the AER for the purpose of its forthcoming transmission determination.

### 12.4.2 Insurance Cap Event

#### *Proposed definition of event*

The 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*
3. *the costs beyond the relevant policy limit materially increase the costs to AusNet Services in providing prescribed transmission 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. *subject to paragraph c, 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;*
   c. *the policy limit in paragraph b will not be taken as the greater policy limit if that policy limit at the time of the event that gives rise to a claim, was not available to AusNet Services for reasons beyond its control;*

5. *a relevant insurance policy is an insurance policy held during the 2017–22 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 6A7.3, the AER will have regard to, amongst other things:*

i. *the relevant insurance policy for the event; and*

ii. *the level of insurance that an efficient and prudent TNSP would obtain in respect of the event."*

### *Rationale*

The proposed definition is consistent with the AER's April 2015 final decision for TransGrid, apart from the inclusion of the word 'relevant' in Note i, which has been included for consistency with the wording in paragraph 5.

It differs from the definition included in AusNet Services' current transmission determination, which lists the following (different) factors that the AER will have regard to when assessing an insurance cap cost event pass through application:

"i. *the insurance premium proposal submitted by SP AusNet in its revenue proposal*

ii. *the forecast operating expenditure allowance approved in the AER's final decision, and*

iii. *the reasons for that decision."*[458]

The factors included in the proposed definition are considered to be more appropriate matters for the AER to have regard to than those listed in the current transmission determination. Those factors have, therefore, been adopted in the proposed definition.

## 12.4.3 Natural Disaster Event

### *Proposed definition of event*

The proposed definition of a natural disaster event is as follows:

*"A natural disaster event occurs if:*

*Any major fire, flood, earthquake or other natural disaster occurs during the 2017-22 regulatory control period and materially increases the costs to AusNet Services in providing prescribed transmission 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 TNSP'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."*

[458] AER (2014) *AER final decision - SP AusNet Tranmission determination 2014-15 to 2016-17*, January 2014, p. 56.

### *Rationale*

The definition proposed for the forthcoming regulatory period differs from the definition included in AusNet Services' current transmission determination, which lists the following (different) factors that the AER will have regard to when assessing an insurance cap cost pass through application:

> *"i. the insurance premium proposal submitted by SP AusNet in its revenue proposal*
>
> *ii. the forecast operating expenditure allowance approved in the AER's final decision, and*
>
> *iii. the reasons for that decision."*[459]

The factors included in the proposed definition are considered to be more appropriate matters for the AER to have regard to than those listed in the current transmission determination. Accordingly, those factors have been adopted in the proposed definition.

AusNet Services' proposed definition of natural disaster event is consistent with the AER's two most recent transmission determinations (i.e., for TransGrid and TasNetworks).

## 12.4.4 Insurer credit risk event

### *Proposed definition of event*

The proposed definition of an insurer credit risk event is as follows:

> *"An insurer's credit risk event occurs if:*
>
> *A nominated insurer of AusNet Services becomes insolvent, and as a result, in respect of an existing, or potential, claim for a risk that was insured by the insolvent insurer, AusNet Services:*
>
> *1. is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*
>
> *2. incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*
>
> *Note: In assessing an insurer's credit risk event pass through application, the AER will have regard to, amongst other things:*
>
> *i. AusNet Services' attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and*
>
> *ii. in the event that a claim would have been made after the insurance provider became insolvent, whether AusNet Services had reasonable opportunity to insure the risk with a different provider."*

### *Rationale*

Although AusNet Services' current transmission determination does not include this event as a nominated pass through, its inclusion for the forthcoming regulatory period is warranted because it meets all of the requirements of the nominated pass through event considerations.

AusNet Services' proposed definition aligns with that approved by the AER in its April 2015 final decision for TransGrid.

---

[459] AER (2014) *AER final decision - SP AusNet Transmission determination 2014-15 to 2016-17*, January 2014, p. 56.

### 12.4.5 C-I-C

C-I-C

C-I-C[460].

**Figure 12.1:** C-I-C

C-I-C

C-I-C

### 12.4.6 Decommissioning of Point Henry – Geelong Terminal Station 220kV Lines Event

#### *Proposed definition of event*

The proposed definition of a PTH – GTS line decommissioning event is as follows:

> *"A PTH-GTS line decommissioning event occurs if AusNet Services is required by a relevant authority to remove all, or part of, the 220kV lines between Point Henry and Geelong Terminal Station and associated infrastructure.*
>
> *Note: In assessing a PTH-GTS line decommissioning event pass through application, the AER will have regard to, amongst other things:*
>
> *i. The origin and nature of the requirement to remove all, or part of, the lines and associated infrastructure;*
>
> *ii. Any payments received by AusNet Services for the return of the easements to the landholders; and*
>
> *iii. AusNet Services' actions in seeking to minimise the costs of the PHT-GTS line decommissioning event."*

#### *Background and rationale*

AusNet Services owns a double circuit 220kV transmission line between Geelong and Point Henry, which have primarily be used to service Alcoa's Point Henry smelter and export electricity generated at its Anglesea coal mine, via its private transmission line from the mine. The closure of Alcoa's Point Henry smelter in August 2014 results in uncertainty around the future use of these assets.

460 C-I-C

While these lines could potentially service new generation or load demand in the Point Henry area, if this does not eventuate then the lines may become either very lightly, or un-used. If this is the case there may be community pressure for these lines to be removed, due to amenity benefits and impacts on land values.

However, Powercor currently has a long-term plan to commission an East Geelong Terminal Station (EGTS) about two thirds of the way to PTH from GTS although the eventual need for this terminal station will depend on whether it is justified by future demand conditions. While long term demand projections indicate that EGTS is feasible, it is very unlikely that AusNet Services will be required to decommission the section of line between GTS and the future EGTS site. However, the section between EGTS and PTH may not be required, even if EGTS was to be established.

The figure below shows the GTS-PTH line and the position of the planned EGTS site.

**Figure 12.2: Geelong – Point Henry 220kV lines**


*Source: Google, AusNet Services*

While community pressure to remove the lines due to, for example, amenity benefits, would not justify AusNet Services undertaking additional capital expenditure for this purpose. However, if community pressure led to a formal requirement for AusNet Services to remove either all, or part of, the lines and associated assets, then a PTH-GTS line decommissioning event will have occurred. It is proposed that AusNet Services' role in minimising the cost of such an event will be taken into account by the AER when assessing any cost pass through application in relation to this event.

# 13 Maximum Allowed Revenue and Price Path

## 13.1 Key Points

- AusNet Services' revenue requirement is a total of $2,943.6m (unsmoothed, real 2016-17) over the 2017-22 regulatory period.
- The building block components comprising this requirement are set out in this chapter.

## 13.2 Introduction

AusNet Services' Revenue Proposal is based on the post-tax building block approach outlined in NER 6A.5.4, and the AER's post-tax revenue model. Information that explains and substantiates the various building block components has been set out in the preceding chapters.

The building block formula to be applied in each year of the regulatory control period is:

MAR = return on capital + return of capital + Opex + Tax

= (WACC x RAB) + D + Opex + Tax

where:

MAR = Maximum allowed revenue

WACC = Post tax nominal weighted average cost of capital

RAB = Regulatory Asset Base

D = Economic depreciation (nominal depreciation – indexation of the RAB)

Opex = Operating and maintenance expenditure

EBSS = Revenue increments or decrements arising from the operation of the Efficiency Benefit Sharing Scheme (EBSS)

Tax = Cost of corporate income tax of the regulated business

The annual revenue stream derived using the building block formula is then smoothed with an X factor in accordance with the requirements of NER 6A.6.8. The MAR is also subject to adjustments for revenue increment or decrement determined in accordance with the AER's service target performance incentive scheme (STPIS) and any approved pass through amounts.

An overview of the building blocks, the raw revenue and smoothed revenue is provided in this chapter, as follows:

- Section 13.3 provides an overview of the forecast RAB over the forthcoming regulatory control period.
- Section 13.4 provides an overview of the return on capital revenue building block.
- Section 13.5 summarises the depreciation building block.
- Section 13.6 provides a summary of the operating and maintenance expenditure building block.
- Section 13.7 sets out the revenue increments arising from the operation of the EBSS during the current regulatory period.
- Section 13.8 provides an overview of the building block relating to the estimated cost of corporate income tax.
- Section 13.9 sets out AusNet Services' annual building block revenue requirement.

- Section 13.10 details AusNet Services' proposed maximum allowed revenue, X factor and revenue cap.
- Section 13.11 provides an overview of the average price path under the proposed revenue cap.

## 13.3 Projected RAB over the forthcoming period

AusNet Services' forecast RAB for the forthcoming regulatory control period is set out in the table below. These values incorporate the capital expenditure plans set out in Chapter 4 and the forecast depreciation over the period, as described in Chapter 9.

**Table 13.1: Regulatory asset base (As Incurred) 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Opening RAB | $3,228.7 | $3,312.7 | $3,362.2 | $3,398.7 | $3,422.8 |
| Net Capital expenditure | $187.4 | $166.5 | $166.4 | $157.8 | $137.1 |
| Opening RAB inflation addition | $75.9 | $77.8 | $79.0 | $79.8 | $80.4 |
| Nominal Depreciation | -$179.4 | -$194.8 | -$208.9 | -$213.5 | -$199.1 |
| **Closing RAB** | **$3,312.7** | **$3,362.2** | **$3,398.7** | **$3,422.8** | **$3,441.2** |

*Source: AusNet Services PTRM.*

## 13.4 Return on Capital

Details of the WACC for revenue calculation purposes are set out in Chapter 10 of this proposal. The return on capital has been calculated by applying the post-tax nominal vanilla WACC to the regulatory asset base in accordance with the AER's post tax revenue model. This calculation is shown in the table below.

**Table 13.2: Return on Capital from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Opening RAB | $3,228.7 | $3,312.7 | $3,362.2 | $3,398.7 | $3,422.8 |
| WACC (percent per annum) | 7.22% | 7.22% | 7.22% | 7.22% | 7.22% |
| **Return on capital** | **$233.2** | **$239.2** | **$242.8** | **$245.4** | **$247.2** |

*Source: AusNet Services PTRM.*

## 13.5 Depreciation

The calculation of AusNet Services' proposed depreciation allowance is detailed in Chapter 9 of this proposal. The AER's post tax revenue model (PTRM) calculates economic depreciation by subtracting the indexation of the opening asset base from the nominal depreciation for each regulatory year. A summary of this calculation is shown in the table below.

**Table 13.3: Economic Depreciation from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Nominal depreciation | $179.4 | $194.8 | $208.9 | $213.5 | $199.1 |
| Less: indexation on opening RAB | -$75.9 | -$77.8 | -$79.0 | -$79.8 | -$80.4 |
| **Regulatory depreciation** | **$103.5** | **$117.0** | **$129.9** | **$133.7** | **$118.7** |

*Source: AusNet Services PTRM.*

## 13.6 Operating and Maintenance Expenditure

The derivation of AusNet Services' operating and maintenance (opex) forecasts is set out in Chapter 5 of this proposal. The total opex forecast includes controllable opex, self-insurance, and easement land tax.

**Table 13.4: Opex forecast from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Controllable Opex | $106.6 | $104.0 | $108.1 | $113.2 | $117.3 |
| Self-insurance | $2.8 | $2.8 | $2.9 | $3.0 | $3.0 |
| **Sub-total** | **$109.4** | **$106.9** | **$111.0** | **$116.1** | **$120.3** |
| Easement Land Tax | $118.0 | $120.8 | $123.6 | $126.5 | $129.5 |
| **Total** | **$227.3** | **$227.6** | **$234.6** | **$242.6** | **$249.8** |

*Source: AusNet Services PTRM.*

## 13.7 Efficiency Benefit Sharing Scheme

The table below sets out the payments arising from the operation of the EBSS revenue during the current regulatory period. The positive amounts shown indicate bonuses to be included in the building block calculation as a result of efficiency gains achieved.

**Table 13.5: Incentive scheme payments from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **EBSS** | $1.7 | $1.8 | $1.8 | $0.6 | - |

*Source: AusNet Services PTRM.*

## 13.8 Estimated Cost of Corporate Tax

The calculation of estimated corporate income tax is detailed in Chapter 11 of this proposal. The estimated tax allowance is shown in the table below.

**Table 13.6: Estimated Cost of Corporate Tax from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Tax payable | $41.6 | $42.3 | $47.7 | $50.3 | $41.9 |
| Less value of imputation credits | -$10.4 | -$10.6 | -$11.9 | -$12.6 | -$10.5 |
| **Net corporate income tax allowance** | **$31.2** | **$31.7** | **$35.8** | **$37.8** | **$31.5** |

*Source: AusNet Services PTRM.*

## 13.9 Annual Building Block Revenue Requirement

The annual building block revenue requirement for each year of the period is calculated (in accordance with NER 6A.5.4) as the sum of the building blocks – namely return on capital, regulatory depreciation, forecast opex, and net tax allowance. The table below presents a summary of the building blocks and the annual building block revenue requirement.

**Table 13.7: Annual building block revenue requirement from 1 April 2017 to 31 March 2022 ($m, nominal)**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total |
|---|---|---|---|---|---|---|
| Return on Capital | $233.2 | $239.2 | $242.8 | $245.4 | $247.2 | $1,207.8 |
| Regulatory Depreciation | $103.5 | $117.0 | $129.9 | $133.7 | $118.7 | $602.8 |
| Operating Expenditure | $227.3 | $227.6 | $234.6 | $242.6 | $249.8 | $1,182.0 |
| Revenue Adjustments* | $0.2 | $0.1 | $0.1 | -$1.3 | -$2.0 | -$2.8 |
| Net Tax Allowance | $31.2 | $31.7 | $35.8 | $37.8 | $31.5 | $167.9 |
| **Annual building block revenue requirement (unsmoothed)** | **$595.4** | **$615.7** | **$643.2** | **$658.2** | **$645.1** | **$3,157.6** |

*Source: AusNet Services PTRM.*

** This refers to adjustments for the EBSS and shared assets*

## 13.10 Maximum Allowed Revenue, X factor and Revenue Cap

Pursuant to NER 6A.5.3(c) and 6A.6.8, the annual building block revenue requirement is converted into a maximum allowed revenue in order for the revenue cap to be implemented. The revenue cap proposed by AusNet Services is:

- For the year ending 31 March 2018, $595.4m (nominal); and
- For the years ending 31 March 2019 to 2022, escalated according to a constant X factor of 0.62%.

The maximum allowed revenue for the year ending 31 March 2018, and the X factor chosen ensures a smooth transition (in terms of total revenue) from the current period, and accords with the requirements of the NER in that it meets the following criteria:

- The maximum allowed revenue in the last year (the year ending 31 March 2022) is within 3.0% per cent of the annual building block revenue requirement for that year, in accordance with NER 6A.6.8(c)(2); and
- The total building block revenue and the total maximum allowed revenue for the regulatory control period (that is, the total revenue cap) are equal in NPV terms, in accordance with NER 6A.5.3(c)(1).

The table below shows the annual building block revenue requirement, the maximum allowed revenue and the total revenue cap for the forthcoming regulatory control period.

**Table 13.8: Annual building block revenue, X factors and maximum allowed revenue from 1 April 2017 to 31 March 2022 ($m, nominal)**

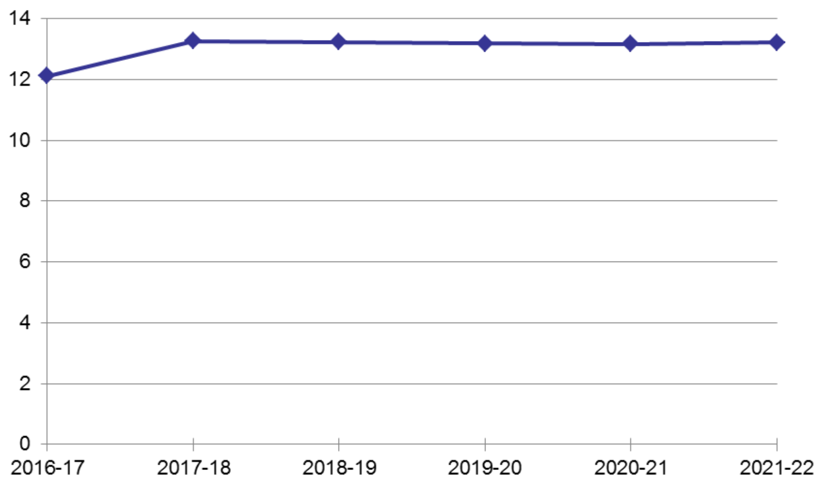
| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total |
|---|---|---|---|---|---|---|
| Annual building block revenue requirement (unsmoothed) | $595.4 | $615.7 | $643.2 | $658.2 | $645.1 | $3,157.6 |
| Annual expected MAR (smoothed) | $595.4 | $613.2 | $631.6 | $650.4 | $669.9 | $3,160.5 |
| **X factor (per cent)** | **-10.17%** | **-0.62%** | **-0.62%** | **-0.62%** | **-0.62%** | **n/a** |

*Source: AusNet Services PTRM*

## 13.11 Average Price Path under the Proposed Revenue Cap

Prices will increase in real terms by an average 1.84% each year from 1 April 2017 to the end of the regulatory period in March 2022. The figure below shows the forecast price path for the forthcoming regulatory control period.

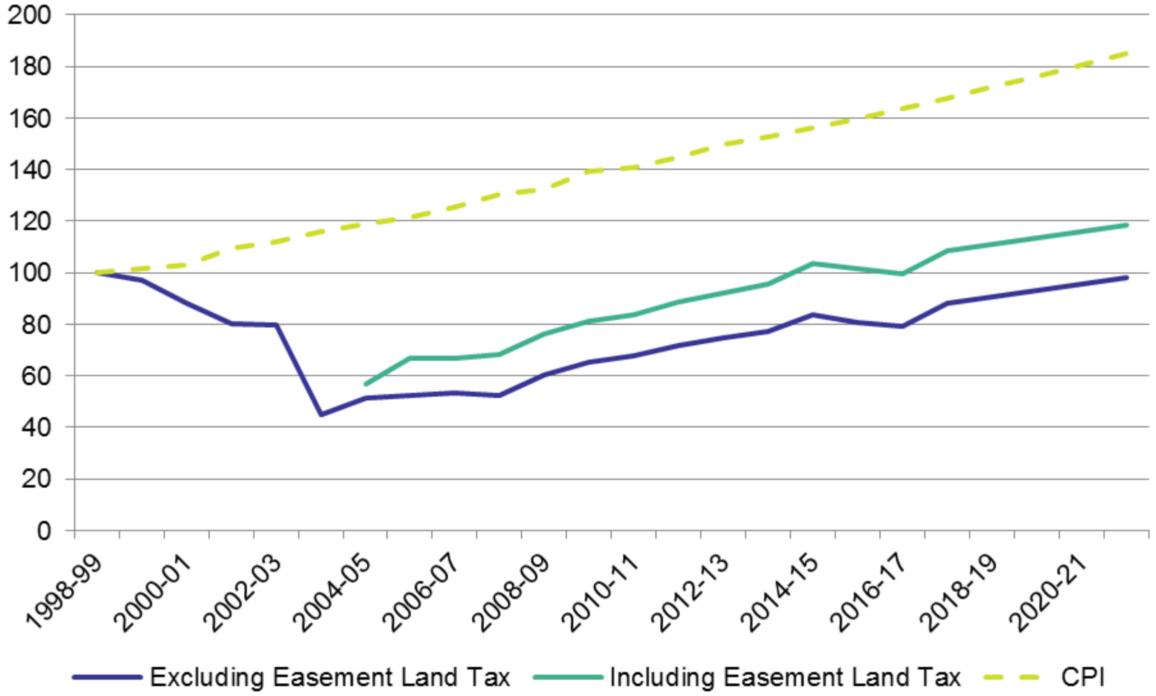
**Figure 13.1: Future Real Price Path for AusNet Services ($/MWh)**




*Source: AusNet Services PTRM*

The revenue path proposed by AusNet Services will continue to deliver low average transmission charges for Victoria, as shown in the figure below.

**Figure 13.2: Historical price path: Victorian transmission (index)**




*Source: AusNet Services analysis*

# 14 Pricing Methodology

## 14.1 Introduction

The NER requires a TNSP to submit a proposed pricing methodology relating to the prescribed transmission services that are provided by means of, or in connection with, a transmission system that is owned, controlled or operated by that TNSP.

The proposed pricing methodology must satisfy principles and guidelines established under the NER. Specifically, NER 6A.10.1(e) requires the proposed pricing methodology to:

(1) Give effect to and be consistent with the Pricing Principles for Prescribed Transmission Services (that is to say, the principles set out in NER 6A.23); and

(2) Comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose under NER 6A.25.

NER 6A.24.1(b) describes the purpose of the pricing methodology. It states that the pricing methodology is a methodology, formula, process or approach that, when applied by a TNSP:

(1) Allocates the aggregate annual revenue requirement (AARR) for prescribed transmission services provided by that provider to:

   (i) the categories of prescribed transmission services for that provider; and

   (ii) transmission network connection points of Transmission Network Users; and

(2) Determines the structure of the prices that a TNSP may charge for each of the categories of prescribed transmission services for that provider.

This chapter explains the key features of AusNet Services' proposed pricing methodology. A copy of the proposed pricing methodology is provided as Appendix 14A to this Revenue Proposal. AusNet Services is confident that the proposed pricing methodology fully complies with the NER and therefore should be approved by the AER.

The remainder of this chapter is structured as follows:

- Section 14.2 explains the relevance of the Victorian transmission arrangements to the proposed pricing methodology.
- Section 14.3 sets out the key features of AusNet Services' proposed pricing methodology.
- Section 14.4 provides concluding comments.

## 14.2 Pricing in the Context of the Victorian Transmission Arrangements

As explained in Chapter 1, the Victorian electricity transmission arrangements differ from that of other jurisdictions. In particular, AEMO and AusNet Services both have responsibilities in relation to the provision of prescribed transmission services in Victoria:

- AEMO provides shared transmission services. For those purposes, AEMO procures network capability and related services from AusNet Services and other TNSPs.
- AusNet Services provides and offers connection services.

In the context of the pricing methodology, the different responsibilities for providing prescribed transmission services are important. In relation to pricing matters, AusNet Services allocates its AARR to each of the categories of prescribed transmission services that it provides, and is also responsible for pricing connection services. AEMO is responsible for pricing prescribed TUOS services and prescribed common transmission services. AEMO is the Co-ordinating Network

Service Provider for Victoria and allocates all relevant AARR within Victoria. In light of the arrangements in Victoria, AusNet Services' proposed pricing methodology only addresses the pricing matters for which AusNet Services has responsibility.

## 14.3 Key Features of the Pricing Methodology

AusNet Services' proposed *Pricing Methodology* (Appendix 14A) has been prepared to satisfy the requirements of the pricing principles set out in Part J of Chapter 6A of the NER, including:

- Determination of the AARR requirement for prescribed transmission services provided by AusNet Services;
- Allocation of the AARR to categories of prescribed transmission services provided by AusNet Services to establish the annual service revenue requirement (ASRR) for that category of service;
- Allocation of the ASRR to each transmission network connection point;
- Price structure principles for the recovery of ASRR in accordance with the principles set out in the NER;
- Information requirements and billing process;
- Prudential requirements for prescribed transmission services; and
- Capital contributions or prepayments for a specific asset.

In addition, the proposed pricing methodology contains the information required by the AER's Pricing Methodology Guidelines, including a number of hypothetical worked examples to demonstrate how the pricing methodology works in practice.

In light of the respective roles of AEMO and TNSPs in Victoria in relation to prescribed transmission services, the proposed pricing methodology also includes a diagram illustrating the structure of transmission pricing under Part J of Chapter 6A of the NER and the respective responsibilities of AEMO and the TNSPs.

## 14.4 Concluding Comments

The NER requires each TNSP to submit a proposed pricing methodology at the same time it submits its Revenue Proposal relating to its prescribed transmission services and specifies the matters that it must address. In Victoria, the transmission arrangements differ from other jurisdictions because AusNet Services and AEMO both have responsibility for providing prescribed transmission services.

The proposed pricing methodology complies fully with the NER requirements. In addition, the proposed pricing methodology provides additional information in relation to the respective roles of AusNet Services and AEMO. AusNet Services therefore considers that the proposed pricing methodology should be approved by the AER.

## 14.5 Supporting Documents

The following Appendix is relevant to this chapter:

- Appendix 14A – Proposed Transmission Pricing Methodology

# 15 Negotiating Framework

## 15.1 Introduction

The NER requires certain transmission services (negotiated transmission services) to be provided on terms and conditions of access that are negotiated between the TNSP and the service applicant. Each TNSP is required to prepare a negotiating framework, which sets out the procedure to be followed during negotiations.

The negotiating framework must comply with the minimum requirements specified in NER 6A.9.5(c), including matters such as:

- Negotiating in good faith;
- Provision of commercial information to facilitate effective negotiation;
- Provision of information relating to the costs of service provision;
- Timeframes for commencing, progressing and finalising negotiations;
- A process for dispute resolution;
- Cost recovery arrangements for processing applications and
- A requirement to notify and consult with any affected transmission users, and to ensure that obligations to those users continue to be met.

The NER also require AusNet Services to conduct negotiations in accordance with the Negotiated Transmission Service Criteria, which will be specified in the AER's final determination. In turn, these criteria must give effect to and be consistent with the principles set out in NER 6A.9.1. In broad terms, these principles establish the acceptable upper and lower bounds for negotiated terms and conditions.

This chapter explains the key features of AusNet Services' proposed negotiating framework. A copy of the proposed negotiating framework is provided in Appendix 15A. AusNet Services is confident that the proposed negotiating framework fully complies with the NER and therefore should be approved by the AER.

The remainder of this chapter is structured as follows:

- Section 15.2 explains the relevance of the Victorian transmission arrangements to the proposed negotiating framework.
- Section 15.3 sets out the key features of AusNet Services' proposed negotiating framework
- Section 15.4 provides concluding comments.

## 15.2 Victorian Transmission Arrangements

As explained in Chapter 1, the Victorian electricity transmission arrangements differ from other jurisdictions. In particular, AEMO and AusNet Services both have responsibilities in relation to the provision of transmission services in Victoria:

- AEMO provides shared transmission services. For those purposes, AEMO procures network capability and related services from AusNet Services and other TNSPs.
- AusNet Services provides and offers connection services.

In the context of the negotiating framework, the different responsibilities for providing transmission services are important. A service applicant seeking a negotiated transmission service may need to engage with either AEMO and/or AusNet Services, depending on the type of service sought. In particular:

- A service applicant must negotiate with AEMO for the provision of shared transmission services that are defined as negotiated transmission services.
- A service applicant must negotiate with AusNet Services for the provision of connection services that are defined as negotiated transmission services.

It is also important to note that:

- AEMO has primary responsibility for assessing the impact of a proposed connection on the Victorian transmission network, including its effect on other network users.
- AusNet Services or the relevant TNSP (as applicable) has primary responsibility for assessing and advising a service applicant on the connection assets at the physical interface with its transmission network (network exit services and network entry services).
- Any application to connect to the Victorian transmission network will require the service applicant to enter into agreements with both AEMO for shared transmission services and AusNet Services or the relevant TNSP (as applicable) for connection services.

AusNet Services and AEMO recognise that a service applicant seeking a negotiated transmission service may find the Victorian arrangements complex and potentially confusing. As the principal purpose of a negotiating framework is to establish procedures to facilitate effective and fair negotiation, AusNet Services and AEMO continue to propose a joint negotiating framework to further assist service applicants. In addition to complying with the NER requirements, this joint framework explains the respective roles and responsibilities of AusNet Services and AEMO in providing negotiated transmission services.

## 15.3 Key Features of the Negotiating Framework

The joint negotiating framework established by AEMO and AusNet Services addresses all of the matters required in the NER, including:

- Application of the negotiating framework;
- Conduct of negotiations;
- Timeframe for negotiations;
- Costs of investigation and negotiation;
- Charges for negotiated transmission services;
- Provision of information;
- Confidential information;
- Dispute resolution;
- Other network users;
- Suspension of time periods; and
- Termination of negotiations.

In relation to the provision of information to facilitate the effective negotiation, the framework requires that:

- Each Negotiating Party agrees to provide to the other Negotiating Parties all such commercial information it may reasonably require to enable that other Negotiating Party to engage in effective negotiation for the provision of the relevant negotiated transmission service.

- A Negotiating Party may give notice to another Negotiating Party requesting any additional commercial information that is reasonably required by the first Negotiating Party to enable it to engage in effective negotiations in relation to the provision of a negotiated transmission service or to clarify commercial information already provided.
- A Negotiating Party who is requested to provide information under this section must use reasonable endeavours to do so within 10 Business Days of the request or as otherwise agreed by the parties.

The negotiating framework also ensures that all service applicants are treated fairly by setting out the circumstances in which negotiation may be terminated, including where:

- AEMO or AusNet Services is of the reasonable opinion that the Service Applicant will not acquire the negotiated transmission service.
- AEMO or AusNet Services believes on reasonable grounds that the Service Applicant is not conducting the negotiations in good faith.
- The Service Applicant consistently fails to comply with the obligations in this negotiating framework.

The negotiating framework also adopts a dispute resolution process in accordance with Part K of Chapter 6A of the NER, which provides for the appointment of a commercial arbitrator. These provisions are important in allowing parties access to a timely and effective dispute resolution process should negotiations lead to dispute.

The joint negotiating framework also notes that it is intended to be capable of adoption by other declared transmission system operators in respect of the connection services they provide in Victoria, subject to AER approval.

## 15.4 Concluding Comments

The NER requires each TNSP to establish a negotiating framework and specifies the matters that it must address. In Victoria, the transmission arrangements differ from other jurisdictions because AusNet Services and AEMO both have responsibility for providing negotiated transmission services. Given this observation, AusNet Services and AEMO continue to propose a joint negotiating framework.

The joint negotiating framework complies fully with the NER requirements. In addition, the framework provides additional information in relation to the respective roles of AusNet Services and AEMO. AusNet Services therefore considers that the proposed negotiating framework should be approved by the AER.

## 15.5 Supporting Documents

The following Appendix is relevant to this chapter:

- Appendix 15A – Victorian Negotiating Framework.

# List of Appendices

| Reference | Title |
|---|---|
| 1A | Cost Allocation Methodology |
| 1B | Related Parties Arrangements |
| 2A | Asset Management Strategy |
| 3A | Stakeholder Engagement Forums – Summaries |
| 3B | Consultation Paper – Accelerated Depreciation |
| 4A | Network Capital Expenditure Overview 2017-22 |
| 4B | 2014 DNSP Victorian Terminal Station Demand Forecasts |
| 4C | 2014 AEMO Transmission Connection Point Forecasting Report for Victoria |
| 4D | Unit Rates |
| 4E | Cost Estimating Methodology |
| 4F | Advice on Cost Escalation Rates for Materials Inputs |
| 4G | Proposed Contingent Projects |
| 4H | ICT Strategy 2017-2022 Electricity Transmission Network |
| 5A | Aon Insurance Report |
| 5B | Aon Self-Insurance Report |
| 5C | Group 3 Assets |
| 5D | Proposed Operating Expenditure Step Changes 2017 – 2022 |
| 5E | CIE Labour Price Forecasts |
| 5F | AusNet Services Opex Productivity Growth (2006-14) |
| 7A | Fitting Probability Distributions for Service Component Data |
| 7B | Network Capability Parameter Action Plan (NCIPAP) |
| 7C | AEMO's NCIPAP Endorsement Letter |
| 10A | Review of the AER's Conceptual Analysis for Equity Beta – Frontier Economics |

| Reference | Title |
|---|---|
| 10B | The Cost of Equity: Response to the AER's Final Decisions – NERA Economic Consulting |
| 10C | Further Assessment of the Historical MRP: Response to the AER's Final Decisions – NERA Economic Consulting |
| 10D | Cost of Equity Estimates Over Time – Frontier Economics |
| 10E | Statement of Dr J Robert Malko – Malko Energy Consulting |
| 10F | Statement of Ronald L Knecht – Ronald Knecht |
| 10G | Key Issues in Estimating the Return on Equity for the Benchmark Efficient Entity – Frontier Economics |
| 10H | An Updated Estimate of the Required Return on Equity – Frontier Economics |
| 10I | Averaging Period Letter |
| 10J | Cost of Debt Estimate |
| 11A | An Appropriate Regulatory Estimate of Gamma – Frontier Economics |
| 11B | Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions – NERA Economic Consulting |
| 14A | Proposed Transmission Pricing Methodology |
| 15A | Victorian Negotiating Framework |