Regulatory Proposal

1 July 2014 to 30 June 2019

30 May 2014

Ausgrid

Contents

About this proposal

This document is Ausgrid's substantive regulatory proposal for the period 1 July 2014 to 30 June 2019. It sets out the revenue required to manage the network in a safe, reliable and efficient manner for our customers.

The proposal should be read in conjunction with Ausgrid's transitional regulatory proposal – which covers a single year from July 2014 to June 2015 – and with the AER's determination on that transitional proposal which was made on 16 April, 2014.

We have also developed an easy to read summary of this proposal to help customers understand the key areas and how it will impact them. This customer overview accompanies this proposal.

This document differs from the regulatory proposal submitted to the AER in 2008.

One difference is that it aims to be more accessible to customers and stakeholders who seek better understanding of the complex area of electricity regulation and compliance.

Our approach conforms to the AER's consumer engagement guidelines. Although the guidelines are non-binding, we agree that they will assist customers' understanding of our regulatory proposals, our plans and the way we manage the electricity network.

By giving customers more opportunities to communicate with us, we hope we can better understand their needs and align our operation to their long-term interests.

Proposal layout

This proposal contains the following chapters:

- Summary
- Chapter 1 – About Ausgrid
- Chapter 2 – Our customers
- Chapter 3 – Framework and approach
- Chapter 4 – Building block proposal
- Chapter 5 – Forecast capital expenditure
- Chapter 6 – Forecast operating expenditure
- Chapter 7 – Allowed rate of return
- Chapter 8 – Alternative control services
- Chapter 9 – Pricing arrangements and negotiating framework

Supporting documents

We have also included a number of documents which substantiate our regulatory proposal, and address compliance obligations. They include:

- A range of attachments
- Supporting documents
- Confidentiality templates, as required under the AER's confidentiality guidelines

Feedback on this proposal

Ausgrid's customers and stakeholders can provide feedback on this proposal to:

yoursay@ausgrid.com.au

Or

Chief Operating Officer
GPO Box 4009
Sydney NSW 2001.

Customers can also provide comments on our proposal to the AER (www.aer.gov.au).

Alternatively customers may also like to make comments via Ausgrid's Facebook page at www.facebook.com/Ausgrid or via twitter.com/ausgrid.

Other ways to comment

Ausgrid, Endeavour Energy and Essential Energy have developed a Facebook page (www.facebook.com/YourPowerYourSay) to engage customers on a wide variety of topics ranging from prices and reliability to vegetation management and street lights.

Summary

This proposal outlines how Ausgrid plans to operate and maintain its electricity network in an efficient manner and keep it safe, reliable and affordable for customers. It also discusses the funding needed to deliver these objectives.

The Australian Energy Regulator (AER) administers the National Electricity Rules (NER or rules) which determine the revenue required by electricity distributors in the National Electricity Market (NEM) to recover the costs of network investments and operations. Every five years, electricity distributors must submit proposals to the AER that explain their proposed capital and operating plans and the revenue they need to fund those plans.

New South Wales (NSW) and Australian Capital Territory (ACT) electricity distribution businesses were due to submit their proposals covering the period from 1 July 2014 to 30 June 2019. However, in 2012 the Australian Energy Market Commission (AEMC) consulted the industry and wider community about major proposed alterations to the rules, and subsequently made a number of important changes. The NSW and ACT distribution network businesses are the first organisations to submit proposals under the new rules.

During the consultation period the AEMC decided that a one-year transitional proposal would help distributors make the move to the new rules, particularly given the short period available to NSW and ACT businesses to prepare their submissions after the rule change came into effect. The transitional proposal would cover the period 1 July 2014 to 30 June 2015. It is described as a "placeholder" proposal.

The full substantive regulatory proposal, covering the entire five-year period from 1 July 2014 to 30 June 2019, was to be submitted some months after the transitional regulatory proposal, and would provide full details of forecast capital and operating plans and revenue requirements.

Ausgrid presented its transitional proposal on 31 January 2014.

The AER made a determination on Ausgrid's transitional regulatory proposal on 16 April 2014. The document presented here is Ausgrid's substantive regulatory proposal.

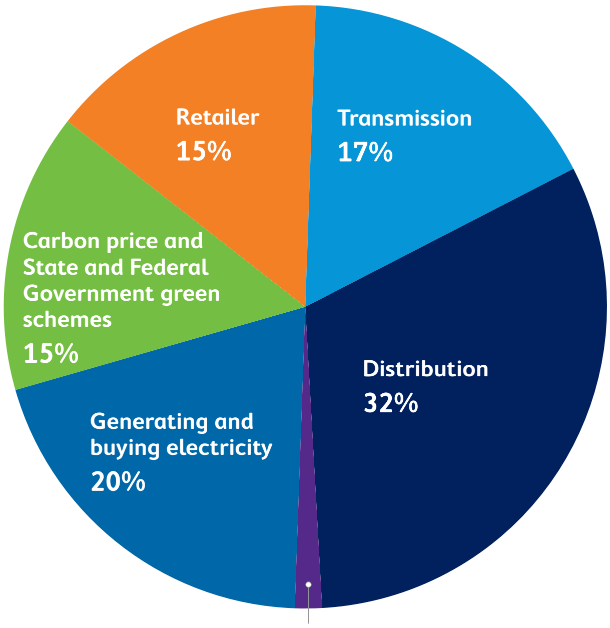
Explaining our role

Ausgrid builds, maintains and operates the electricity distribution network in Sydney, Newcastle, the Hunter Valley and Central Coast of NSW. This requires a significant financial investment each year. Our network mainly consists of distribution assets, although some parts (known as dual function assets) also support TransGrid's high-voltage transmission.

Ausgrid's charges therefore include charges for both distribution and transmission services. These make up about 40% of the average household bill. When combined with TransGrid's transmission charges, electricity network charges form around 50% of a customer's electricity bill. On average, a customer's total electricity bill breaks down into the components shown in Figure 1.

Ausgrid also plays an important role as a supply authority that ensures the safety of the electricity network. To this end we are required to establish design standards for customers' electrical installations, develop accreditation schemes for electrical service providers to ensure they are adequately trained, and create a public electrical safety awareness plan to raise community knowledge about safe practices around electricity.

Figure 1 – Components of customers electricity charges



NSW Government network reform program

In March 2012 the NSW Government announced a restructure of Ausgrid, Essential Energy and Endeavour Energy, the three state electricity distribution organisations. That restructure commenced on 1 July 2012 with three objectives:

- To continuously improve safety performance for employees, contractors and the public.
- To maintain the reliability and sustainability of the electricity distribution networks.
- To contain average increases in our share of customers' electricity bills at or below CPI (Consumer Price Index).

The network reform program has focused on applying better strategic, operational and financial discipline to both the capital and operating programs. This is projected to deliver total business savings of $5.4 billion over the five-year period commencing July 2011.

The benefits of the network reform program are included in this substantive regulatory proposal and will result in lower distribution network charges for customers. More details about the results of the reform driven initiatives in reducing business costs and increasing operational efficiencies can be found in Attachment 1.01.

Highlights of our substantive proposal

Ausgrid's substantive regulatory proposal is based on a modest increase in its revenue requirements for distribution standard control services from $2.04 billion in 2014/15 to $2.28 billion in 2018/19. This will directly translate into an average distribution price increase of 2.37% for all customers over this period – which is less than the forecast rate of inflation. The typical bill impact from this change for residential and small business customers is contained in Table 1.

The increase in our forecast revenue requirement in the next regulatory control period is driven by significantly lower capital requirements and operational efficiencies pursued by Ausgrid as a result of the network reform program.

It is also a result of lower borrowing costs which were impacted by the global financial crisis in the last determination. As a result, Ausgrid is proposing a weighted average cost of capital of 8.83% applied to the 2014-19 period.

The five-year capital program will reduce from $8.4 billion approved by the AER for the 2009-14 regulatory period to a proposed $4.9 billion[1] for the 2014-19 period – a reduction of 41% which is 47% below the forecast rate of inflation over the five year period.

Five-year operating cost will increase from $2.8 billion approved by the AER for the 2009-14 regulatory period to a proposed $3.3 billion[2] for the 2014-19 period – an increase of 18% which is 4% above the forecast rate of inflation over the five year period. This result is due to minor increases in maintenance cost, increases in demand management initiatives and one-off costs for initiatives aimed at driving longer term efficiency.

We expect, on average, our customers will continue to reduce their use of electricity by an average of 1.5% per annum over the five years commencing 1 July 2014. This expectation is a consequence of the continued take-up of domestic solar panels, the high Australian dollar's impact on Australian manufacturing and the impact of electricity price increases from July 2009 to July 2012 on customers' energy usage.

We expect that based on the proposed capital and operating program the current network reliability will be maintained or marginally improved for the regulatory period.

Engaging better with our customers

Ausgrid has traditionally engaged with customers, consumers, the community and stakeholders via face-to-face briefings, meetings, letters and presentations. In the lead up to the drafting of regulatory proposals these activities become focused on understanding our customers' needs.

New consumer engagement guidelines established by the AER gave Ausgrid the opportunity to expand and improve on this two-way communication. We have since developed a consumer engagement strategy to guide how we discuss and consult on our regulatory submission and consider the views of customers and stakeholders.

These strategies will be continually reviewed from 1 July 2014 to determine which engagement strategies the business should embrace over the long term. By giving customers more opportunities to communicate with us, we hope to learn more about what they want and align our operations to their long-term interests.

More details about our consumer engagement work can be found in chapter 2 and Attachment 2.01. To help provide greater transparency, Ausgrid has created a web page to house relevant regulatory documents and the results of our engagement efforts. Visit it at www.ausgrid.com.au/yoursay.

Table 1 – Bill impact from network charges for typical customers (including metering) (% change p.a. nominal)

Typical annual bill	2014/15	2015/16	2016/17	2017/18	2018/19	Average % change p.a.
Residential (IBT) customer	2.20%	1.84%	2.47%	2.33%	2.23%	**2.21%**
Small business (IBT) customer	2.31%	1.52%	2.46%	2.19%	2.03%	**2.10%**

Table 2 – Revenue requirement ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Annual revenue requirement	2,217.4	2,358.8	2,484.9	2,598.4	2,552.5	**12,211.9**

Table 3 – Proposed forecast expenditure for standard control services ($ million)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast capital expenditure ($ 2013/14)	1,011.5	984.9	856.8	814.0	753.8	**4,421.0**
Forecast operating expenditure ($ 2013/14)	565.1	566.2	574.2	568.9	568.4	**2,842.9**
Forecast capital expenditure ($ nominal)	1,024.2	1,020.4	907.6	884.2	838.9	**4,675.2**
Forecast operating expenditure ($ nominal)	580.8	593.5	616.6	626.2	641.3	**3,058.5**

1 This is inclusive of alternative control services
2 This is inclusive of alternative control services and emergency recoverable works

1. About Ausgrid

Ausgrid is responsible for the safe and reliable distribution of electricity across a 22,275 square kilometre area on the NSW east coast. It is a state-owned corporation that supplies electricity to almost half of the electricity customers in the state.

Our 1.65 million customers are located in some of the country's oldest and most densely populated areas, including the Sydney, North Sydney, Chatswood and Newcastle central business districts. It also supplies electricity to the major mining areas of the Hunter Valley and to fast growing residential areas on the Central Coast.

See Figure 2 for a map of Ausgrid's network.

Ausgrid's distribution network is made up of large and small substations that are connected via high and low voltage powerlines, underground cables and power poles. Our operations are governed by national and state laws and regulations, and are paid for by electricity customers via their retail electricity bill.

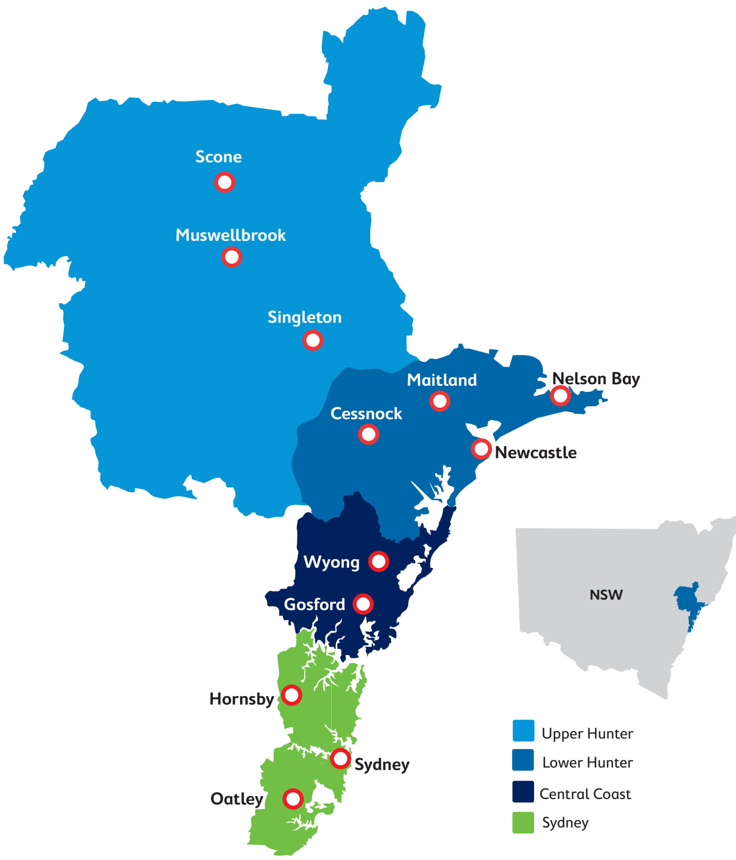
About half of a household electricity bill goes towards the cost of providing distribution and transmission networks, and for the past five years this has been the fastest growing portion of our customers' total electricity costs.

We made significant investment in the current 2009-14 period in order to maintain the safety and reliability of an aging electricity network whose capacity was being stretched.

Now, Ausgrid is increasing its focus on improving efficiency, affordability and accessibility to meet the long-term interests of the homes and businesses connected to our network.

Ausgrid has been listening to the views of its customers and increasingly engaging with them via efficient low-cost social media channels as well as by traditional face-to-face contact and correspondence. A greater emphasis on customer engagement consistent with best practice guidelines endorsed by the AER will help us to improve this conversation even further over time.

Figure 2 – Map of Ausgrid's network



About the electricity industry

Ausgrid is a key part of the chain that conveys electricity from generators to a customer's premises. In NSW, the bulk of electricity is generated in locations far away from where most people live. Power is generated and then transported as high-voltage electricity over long distances by TransGrid. Our network then transforms it at sub-transmission and zone substations, which typically service entire suburbs, into lower voltage power. Finally, electricity is again transformed at more localised distribution substations to be suitable for distribution directly to customers' premises (see Figure 3).

We manage a multi-billion dollar infrastructure portfolio, including powerlines, substations, protection equipment and ancillary equipment. There are over 200 zone substations, 30,000 distribution substations, 48,000 kilometres of powerlines and 500,000 power poles.

Our vision – Safe, sustainable and customer focused

Ausgrid's vision is to serve the community by efficiently distributing electricity to its customers in a way that is safe, reliable and affordable.

Our business plan sets the priorities and actions we must embrace to deliver this vision and to promote the long-term interests of our customers, our people and our shareholders.To this end we maintain a steady focus on delivering three key outcomes:

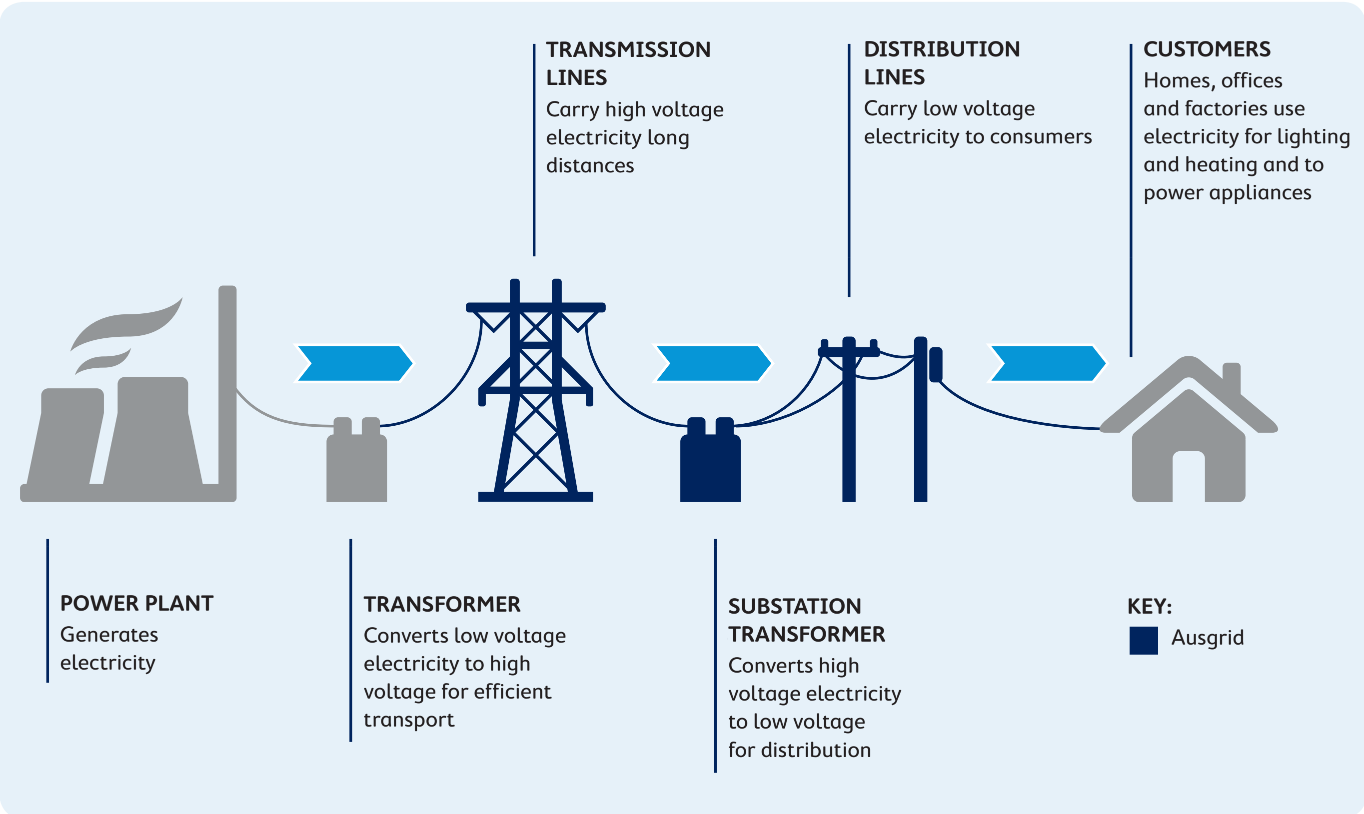
- Continuously improving safety performance.
- Maintaining the reliability and sustainability of the network.
- Containing increases to average network charges at or below CPI for our customers.

Improving safety for employees, contractors and the public will continue to be our top priority. We measure our safety performance through a range of indicators across our operations. While safety at Ausgrid has been improving, we are planning further policy and operational changes to make the network as safe as possible and to ensure that all our people are free from harm in the workplace and return home in good health.

Network reliability has improved over the most recent regulatory period. Our asset management plans now aims to leverage past investments and focus investments to maintain reliability at existing levels. We expect to achieve this while reducing capital expenditure by 41%.

Our third goal of limiting increases to average network charges to CPI for our customers is also being delivered in this substantive proposal. Average increases to our share of a customer's electricity bill were held at just 2.5% for Ausgrid's residential customers for 2013/14. Based on the forecasts included in this proposal, by July 2019 our customers will have benefited from six successive years of network price increases at or below the rate of inflation.

Figure 3 – How electricity is distributed to end customers



Our values

Ausgrid is committed to fostering a workplace culture that delivers the highest standards of safety, respect, performance and integrity for employees and the customers and the communities we serve. Our employees are required to understand and behave in a manner that supports our values as seen in Figure 4.

Figure 4 – Ausgrid's values

Safety excellence

- Put safety as your number one priority
- Do not participate in unsafe acts, and challenge unsafe behaviours
- Think before you act
- Lead by example
- Take responsibility for the health and safety of yourself and others

Respect for people

- Treat all people with respect, dignity, fairness and equity
- Demonstrate co–operation, trust and support in the workplace
- Practise open, two–way communication

Customer and community focus

- Deliver value and reliable service to our customers and communities
- Use resources responsibly and efficiently
- Be environmentally and socially responsible

Continuous improvement

- Look for safer and better ways to do your job
- Improve our financial performance
- Support innovation to add value to our business

Act with integrity

- Act honestly and ethically in everything you do
- Be accountable and own your actions
- Follow the rules and speak up

2. Our customers

Our approach to consumer engagement

Ausgrid has developed a consumer engagement strategy to guide the way we engage with our customers and community. It will create more opportunities for Ausgrid to understand the views, expectations and preferences of customers and other stakeholders. It will also give consumers an opportunity to understand and influence the operations and decision making process at Ausgrid, so that our services and operations become more customer-focused and our charges represent best value for money.

The strategy is designed to deliver these important objectives:

- Identify and monitor customers' needs, perceptions and preferences via data analysis, research and proactive communications and consultation.
- Inform and educate customers, consumers, the community and stakeholders.
- Help customers provide more effective feedback, offer ideas, raise concerns and make more informed decisions.
- Provide more frequent two-way communication to identify and respond to issues as they emerge.
- Provide accessible, comprehensive and timely information to our customers and key stakeholders using a variety of existing and new communication channels.
- To set realistic expectations for consumers on how they can influence outcomes.
- Report back to customers and stakeholders on how input has been considered and how it has or hasn't influenced outcomes.

The objectives seek to ensure Ausgrid makes sustainable decisions that are economically viable, technically feasible, acceptable to the community and compatible with the environment.

The engagement strategy has assisted in the development of this substantive regulatory submission. It has helped guide the research and consultation and ongoing business processes.

We intend to review and refine this strategy so that it remains relevant to us and to our customers, consumers, other stakeholders and the community.

Our engagement framework

Our engagement framework is built on four key pillars as shown in Table 4.

Table 4 – Ausgrid's customer engagement process

Steps	Description
Understand needs	Research and analysis to determine customers' expectations, perceptions, views and priorities. This includes qualitative and quantitative research with representation across key customer segments. Analysis includes review of existing customer communication, feedback and complaints.
Inform and build knowledge	Information provided on Ausgrid's operation and plans for the next five years, including long-term pricing strategy options. This will occur via social media channels, stakeholder presentations and forums, and written communication.
Consult and involve	Feedback provided via two-way communication with customers and stakeholders where information and advice is gathered and views are exchanged, including advice on regulatory and decision-making process. We will listen to customer feedback and ideas and take it into consideration as part of our planning and decision-making processes.
Review and report	Review engagement activity and report back to customers and stakeholders. Clearly demonstrate results of engagement and how they have influenced operations, policies and procedures. Ausgrid to make analysis and reports accessible via website and other channels.

Our engagement principles

It is also important for us to underpin our engagement process and activity with a set of principles consistently applied. These principles are shown in Table 5.

Our engagement activity will target the community we serve, our customers, electricity consumers and key stakeholders.

There are 1.65 million customers connected to Ausgrid's electricity network, across the Sydney, Central Coast and Hunter regions.

Households and small and medium businesses make up about 99% of these customers. They are mainly concentrated in densely populated urban areas with some also located in rural or semi-rural areas in the Hunter Valley and Central Coast.

There are much smaller numbers of customers from the government, commercial and industrial sectors who consume large amounts of electricity and perform an important role in the wider economy and community. They have specific requirements for the safe connection and supply of electricity and an impact on their operations can have a direct and serious impact on the wider community.

As a part of its engagement approach, Ausgrid has segmented these customers into three categories: customer type, geography and areas of interest. Ongoing engagement activity will be tailored to each group, allowing them maximum opportunity to participate. Customer segments are shown in Table 6.

Table 5 – Principles for customer engagement

Principle	Impact on our engagement activities
Transparent	We will engage in an open and honest way so that customers and stakeholders are clear about our processes and how we will consider their input in our planning and decision-making processes.
Timely	We will engage in a consistent way and allow enough time for meaningful conversations, consultation and appropriate changes to our operations or processes.
Inclusive and accessible	We will engage widely with our customers, community, consumers and stakeholders giving them the opportunity to voice their views and concerns and influence decisions. This includes overcoming barriers to participation and providing innovative ways to communicate and consult more widely. We will ensure this engagement is ongoing and genuine.
Appropriate and balanced	Engagement will be robust, cost effective and relevant. We will use methods of engagement that balance the participation and influence of all customer segments and stakeholder groups. We will offer different methods of engagement to suit the audience and the goals of engagement.
Accountable	We will provide clear actions and responses following engagement. We will monitor the effectiveness of our engagement planning and activities, implementing improvements where needed.
Clear and measurable	Information will be in a format that enables consistent and objective analysis that can be measured, assessed and improved.

Table 6 – Customer types and engagement segmentation

Group	Members	Stakeholders	Interests
Welfare and higher needs customers	• Low income customers • Housing NSW tenants • Pensioners • Disability support • Non-English speaking communities	• Welfare groups • State and federal government departments • Consumer advocacy groups	• Electricity prices • Customer support and communication • Metering • Reliability
Rural customers	• Customers situated in remote or regional areas in Ausgrid's network	• Local councils • Farming and irrigators associations • Members of Parliament	• Electricity prices • Bushfire mitigation • Private installation policy • Metering • Reliability
Residential customers	• Residential customers connected to the Ausgrid network	• Local councils • Resident groups and associations • Members of Parliament	• Electricity prices • Reliability • Metering • Customer support and communication • Capital works
Business customers	• Small businesses • Medium businesses • Large industrial users	• Chambers of commerce • Industry associations • Members of Parliament	• Electricity prices • Connection policy • Reliability • Capital works
Education groups	• Schools • Universities and TAFE	• Educational associations • Government departments	• Apprenticeships • Training • Graduates and cadetships • Community partnerships
Street lighting customers	• Local councils • Roads and Maritime Services	• Street lighting managers	• Street lighting services and maintenance • Street lighting price
Government and essential service customers	• Hospitals • Road and Transport operators • Police and emergency services • Utilities	• Government departments • Industry Associations or steering groups	• Security of supply • Incident or emergency response

More detailed information on Ausgrid's customer type and engagement segmentation can be found in our consumer engagement strategy in Attachment 2.01.

Our engagement activity

Ausgrid's engagement activity has focussed on the following key channels:

- Face to face meetings.
- Stakeholder forums.
- Letters.
- Research and surveys.
- Social media and traditional media analysis.
- Community consultation, complaint and Energy and Water Ombudsman (EWON) data analysis.
- Targeted Facebook campaign.

A full list of engagement activity is provided in Attachment 2.02.

Sharing our engagement activity

Wherever possible, Ausgrid has provided the details and results of this engagement activity on its website at **www.ausgrid.com.au/yoursay**, rather than as attachments to this submission. This is so stakeholders and members of the community can readily access this information on an ongoing basis (separate to this submission) and in accordance with the AER's Consumer Engagement Guidelines for Network Service Providers. This includes presentations, research on consumer views and trends, analysis on customer consultation and communication, findings and summaries of forums, events and campaigns.

The main findings of Ausgrid's engagement activity are presented below:

Pricing

- Customers were not supportive of further increases to their electricity bills, particularly steep or sudden increases.
- They believed the past increases had made it difficult to manage their own personal costs.
- They believed past increases should be enough to maintain supply.
- They said any increase, if justified, should be gradual.

Sources: Facebook campaign, consumer research, EWON and customer correspondence, traditional and social media analysis.

Tariffs

- New innovative tariffs have some support, however, customer's ability to respond depends upon varied factors like energy use type, income and family type.
- Some customers supported greater flexibility on time based pricing tariffs.
- Some new tariff structures such as capacity or demand charges would be difficult to understand.
- Mixed reaction to increases in fixed charges, however support increases when explained it will help keep prices fair and generally lower.

Sources: Facebook, consumer research, stakeholder forums.

Reliability and performance of the network

- There was general awareness and agreement that the performance of the electricity network had improved. When there was an unexpected electricity outage, most customers understood it was generally outside of Ausgrid's control and the organisation worked hard to get the power back on.
- There was support for maintaining current levels of reliability if it could be achieved without extra bill increases.
- There were instances where some customers expected higher reliability because they had experienced a sudden or large number of outages due to various network faults.
- It was expected these should be fixed without additional price increases.
- There was little support for reliability improvement where it involved bill increases.

Sources: Facebook, consumer research, social and traditional media analysis, customer correspondence.

Construction and design standards

- Customers ranked price as the major factor that should be taken into account by Ausgrid when making decisions around new construction/design standards.
- While price was seen as the most important factor, customers thought that safety standards should not be compromised.
- Around one quarter of customers were willing to pay more for underground cabling.
- A number of customers wanted more sympathetic tree trimming activity.
- There was support for relocation of infrastructure, where it impacted some neighbourhoods, with additional costs to be paid by everyone.

Source: Consumer research, customer correspondence, Facebook, media and social media analysis.

Safety

- Customers expected that electricity was supplied in a safe manner and believed that this should be taken into account when constructing and operating the network.

Source: Consumer research.

Communication

- Customers indicated that the level of communication that they were receiving from Ausgrid was sufficient.
- They showed a preference for communication about outages and network issues and reports at a time and via channels that conveniences them.
- They liked information about cause and restoration time of outages.

Sources: Consumer research, Facebook, social media analysis, stakeholder forums.

Street lighting

- Consumers and the community appeared generally happy with service standards.
- There is some support for better communication about fault reporting.
- Consumers and customers (local councils) showed support for new energy saving lighting technology.
- Local councils supported a simpler pricing structure and compulsory service standards for streetlight repairs.

Source: Forums, Facebook, Social media analysis.

Demand management, energy efficiency and technology

- The majority of customers indicated they had made efforts to reduce their electricity consumption as a result of higher prices.
- Most believed that Ausgrid should be working with customers to ensure they understood the impacts of changes in electricity usage.
- However, customers generally indicated they were not willing to pay for programs and expected a rebate for their participation.
- While customers indicated interest in the overall idea of new technology, such as smart meters and the opportunity to obtain further information on how they might better manage their electricity usage, few were interested in paying more for technology.

Table 7 – How we considered consumer feedback

Topic	What we did	What we didn't do
Prices	• Reduced costs to keep average increase to network charges to 2.37% at the DUOS level in 2014-19 period – below our forecast CPI of 2.5% p.a. • Stable price path	• Increase network prices above CPI • No large one-off price increases
Tariffs	• Changed TOU tariff to opt in arrangement	• Maintain TOU as default tariff
Reliability	• Network reliability management plan endorsed by Ausgrid Board in October 2013. This plan includes strategies targeting low cost initiatives to maintain or improve reliability including reductions in abnormal switching, leverage existing automation technology and establishing a metric to monitor performance of worst served customers to target potential improvements • Re-prioritised capital program and introduced wider control analysis and risk prioritisation to defer and reduce network investment • Focussed replacement program on areas of greatest risk	• Provide additional funding for network projects to improve reliability above acceptable network standards • Amend tree trimming practices to align with community expectation of greater amenity because this would create serious safety risks and significantly increase costs
Construction and design	• Align capital program to revised licence conditions	• Provide additional funding for undergrounding existing network assets
Safety	• Programs aligned to meet or improve safety standards • Black spot pole replacement program to improve public safety	• Decrease safety programs
Communication	• Develop and deliver new website to focus on customer service • Develop and deliver new online customer reporting tools • Customer outage information services	
Street lighting	• New streetlight reporting tool • LED set as default replacement	• Set service level agreement that would increase prices beyond cost reflective levels
Demand Management, energy efficiency and technology	• Network operation technology program reduced • Default meter for residential customers changed to accumulation meter • Interval meter now opt in meter • Maintained education programs	

The strong focus of feedback from consumers and stakeholders about Ausgrid's operations and plans centred around two key areas:

- Changes to network electricity prices.
- The reliability of the power supply and the impact of network improvements on network electricity prices.

Ausgrid's investment plans have been built on the objectives of maintaining average network price increases to at or below CPI, and maintaining network reliability to existing standards. These include the network reliability management plan that was endorsed by Ausgrid's Board in October 2013. The report analysed network performance and customer attitudes to reliability to determine low-cost initiatives to maintain or improve network reliability. This substantive regulatory proposal is consistent with those desired outcomes.

Although Ausgrid's third important business objective of improving safety for our customers and staff was supported via consumer research, it did not receive such broad recognition as the first two factors.

There was evidence that our customers and our community assume we will prioritise safety, even if it is not foremost in their requests. This aligns with Ausgrid's legislative and community obligations to ensure the electricity network is safe and ensure the safety of the public and people working around it.

Consumer challenge panel

The consumer challenge panel (CCP) was established by the AER to assist it in making better regulatory determinations by providing inputs on issues of importance to customers. Ausgrid has had two opportunities to meet directly with the CCP to discuss and provide clarification on our transitional regulatory proposal. This process has provided us with the following insights into issues of concerns to the CCP and these are:

- The operation of the efficiency benefits sharing scheme (EBSS) and how this scheme benefit customers in terms of prices.
- Ausgrid's proposed replacement capital expenditure.
- Make Ausgrid's public lighting service levels more transparent.

We have sought to address these matters raised by the CCP in sections 4.1, 5.2 and 8.1 of this regulatory proposal.

Ongoing engagement

Ausgrid's community engagement activity will continue as part of our business-as-usual operations, but will be reviewed to ensure it remains relevant to customers, consumers, community and stakeholders. The results of our engagement efforts will be considered as part of Ausgrid's decision making processes, and the results of that process presented to interested parties via an annual consumer engagement report. The senior leadership team will be involved in the review process.

Ausgrid's senior management team will also present the highlights of this substantive regulatory proposal at a series of stakeholder briefing sessions which will enable consumer feedback to be considered and potentially incorporated throughout the review process.

These initiatives will help ensure that consumer views are incorporated into Ausgrid's long-term decisions and that our operations are better aligned with the long-term interests of electricity consumers.

The benefits and risks to consumers about this proposal

The following is a summary of the keys benefits and risks to consumers from this proposal.

Benefits to our customers

Stable prices: We propose to keep average price increases to our share of customers' electricity bills at or below CPI for five years.

Reliability: We propose to maintain reliability or slightly improve it in some areas.

Safety: Our capital and operating plans aim to deliver programs that are safe and sustainable for the electricity network and the communities it serves.

Clarity of costs: We are giving customers greater transparency about how much they pay for metering.

Removing cost subsidies: Customers who don't use specific services (such as special meter tests and reads) will no longer subsidise those who do.

Potential risks to customers

Volatility: The AER has determined that Ausgrid's revenue collected from customers will be capped. If electricity consumption falls further than forecast, unit prices may increase but total revenue cannot increase.

Reduced reliability: If our approved capital program is not delivered on time, electricity supply may be less reliable in some areas.

New rules: Customers who request a special service may pay considerably more as the AER said they cannot continue to be subsidised by our general customer base.

Future prices: Without changes to tariff structures, customers who cannot afford to invest in solar technology will be burdened with increased network costs.

3. Framework and approach

3.1 Context and content of our substantive proposal

In our role as a Distribution Network Service Provider (DNSP) we provide a range of distribution services to our customers. This includes our core network services, connecting new customers, providing a metering service, public lighting and other non-routine services such as special meter reads.

As a regulated business, Ausgrid is subject to economic regulation by the AER under the rules. Under this process we are required to submit a regulatory proposal to the AER for a period that is usually of 5 years. The proposal covers a range of matters including revenue and prices for regulated services.

Our current regulatory period ends on 30 June 2014. Due to material changes to the rules in 2012, the AEMC considered that a one year transitional proposal would address implementation issues from transitioning to the amended rules, and as a result, a placeholder revenue determination to set prices for regulatory year 1 July 2014 to 30 June 2015 was put in place. Accordingly on 31 January 2014, Ausgrid submitted its transitional proposal to the AER for the year 1 July 2014 to 30 June 2015, and the AER has made a determination on 16 April 2014.

The rules require Ausgrid to submit a regulatory proposal and the AER to make a further determination in respect of the regulatory control period subsequent to the transitional regulatory year (substantive proposal). Ausgrid proposes this subsequent regulatory control period is to be for a term of four (4) years, commencing on 1 July 2015 and ending on 30 June 2019 (2015-19 regulatory period).[3]

However, the rules have been designed in a way that allows the AER to 'look back' in detail at its transitional determination, and make necessary adjustments if required. For this reason, the rules require Ausgrid to treat the transitional regulatory year (2014/15) as if it were the first year of the subsequent regulatory control period and as if this subsequent regulatory control period includes the transitional year. Therefore, this regulatory proposal includes all the necessary information to support our proposed expenditures for a five year period, from 1 July 2014 to 30 June 2019 (2014-19 period).

Ausgrid's substantive regulatory proposal

Ausgrid's substantive regulatory proposal addresses all matters required to be addressed by the rules in relation to a regulatory proposal.[4] Our regulatory proposal comprises of this document, attachments and all necessary supporting documents which are either required by the rules of which Ausgrid relies on to support this proposal:

- Classification proposal, showing how our distribution services should be classified.
- Building block proposal for standard control services, including indicative prices.
- Demonstration of the application of the control mechanism for alternative control services, including indicative prices.
- Proposed negotiating framework for negotiated distribution services.
- Proposed connection policy.
- Proposed pricing methodology for Ausgrid's transmission standard control services.[5]
- Proposed procedures for assigning and reassigning customers to tariffs.

It is also accompanied by:

- An overview paper which explains Ausgrid's regulatory proposal in reasonably plain language.
- Information required by the Regulatory Information Notice (RIN) issued by the AER on 7 March 2014 (reset RIN).[6]

Clause 6.8.2(c2) requires Ausgrid's regulatory proposal to be accompanied by information required by the expenditure forecast assessment guidelines as set out in the AER's framework and approach paper.

The guideline was published by the AER in November 2013 in which the AER stated that:

> *The regulatory information notice (RIN) issued in advance of a DNSP lodging its regulatory proposal will specify the exact information we require......the following sections indicate (at a high level) our likely information requirements for capex and opex.*[7]

This approach is confirmed by the AER in its stage 2 framework and approach paper (stage 2 F&A) in which the AER stated that guideline was developed to apply broadly to all electricity transmission and distribution businesses and some customisation of the data requirements contained in the guideline may be required and that these customisation issue would be addressed through the regulatory information notice (RIN) that the AER issues to the NSW distributors for the 2014-19 period.[8]

3 Clause S6.1.3(13) requires Ausgrid to specify the commencement and length of the regulatory control period. See also clause 6.3.2(4) of the rules.

4 See clause 6.8.2(c) which specifies the elements of a regulatory proposal. Ausgrid's regulatory proposal has been prepared based on Chapter 6 and Division 2 of part ZW of Chapter 11 of version 60 of the National Electricity Rules.

5 That is, standard control services provided by dual function assets.

6 With subsequent amendment from the AER on 21 March 2014.

7 AER, Better Regulation, Expenditure forecast assessment guideline for electricity distribution, November 2013, page 25.

8 AER, stage 2 framework and approach, Ausgrid, Endeavour Energy and Essential Energy, transitional regulatory control period 1 July 2014 to 30 June 2015 and subsequent regulatory control period 1 July 2015 to 30 June 2019, January 2014, p 36.

Ausgrid has undertaken a comparison of the high level requirements contained in the expenditure forecast assessment guideline against the specific requirements in the RIN. All matters covered by the guideline are addressed by the RIN requirements which have been customised to reflect Ausgrid's business. Accordingly, Ausgrid's RIN response, that accompanies this regulatory proposal, meets the requirements of the guidelines as required by the AER's framework and approach paper.

Further, Ausgrid has sought to have suppressed from publication certain parts of the regulatory proposal (including information provided in response to the RIN) on the grounds of confidentiality. This information in the main relates to market sensitive cost inputs which, if disclosed, could affect Ausgrid's ability to obtain competitive prices in future transactions. We have completed confidentiality templates in relation to this information as required by the AER's confidentiality guideline. These templates are submitted together with Ausgrid's regulatory proposal and RIN.

3.2 Our proposals in response to stage 1 of the framework and approach

In its stage 1 framework and approach paper (stage 1 F&A), the AER has already made a number of decisions and have set out its proposed approach on a number of matters affecting our regulatory determination. Our regulatory proposal considers these decisions and proposed approaches and identifies the matters that we agree with the AER's decision or approach and the matters for which we seek clarification.

The key points are:

- Our proposal adopts the AER's decisions in the F&A papers. This includes the AER's decisions on classification and control mechanisms, subject to seeking minor clarifications on definitions.
- We have suggested minor amendments and clarifications to the way incentive schemes should be applied as part of the building block determination.

In this section, we set out the decisions the AER made in stage 1 of the F&A paper. The paper was published in 25 March 2013 and sets out the AER's decisions on classification of services, control mechanisms, and pricing of dual function assets.

Proposal on classification of services

Classification of distribution services is important as it determines the extent of regulation to apply to our services. The classification of Ausgrid's distribution services in the current 2009-14 period was deemed by the rules that applied for this period.

The stage 1 F&A process was the first opportunity for the AER to consider its proposed grouping of Ausgrid's distribution services and how these services groups should be classified for the transitional regulatory control period and the 2015-19 regulatory control period. The AER proposed to group Ausgrid's distribution services as:

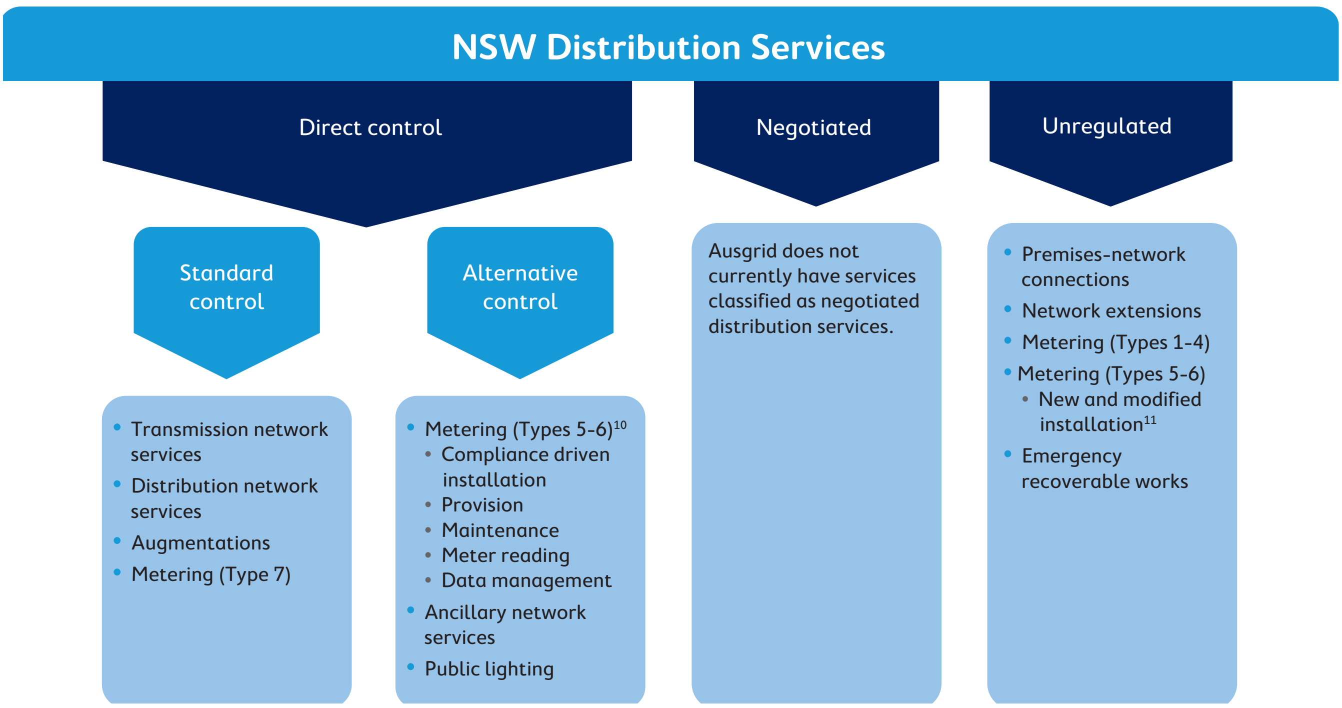
- Network services.
- Connection services.
- Metering services.
- Ancillary network services.
- Public lighting services.

For the above service groups, the AER's proposed classification is largely the same as the classification applied in the current period except for two changes which are:

- Type 5 and 6[9] metering services and ancillary network services were re-classified from standard control services to alternative control services.
- Emergency recoverable works will not be classified by the AER from 1 July 2014, meaning this service will not be regulated. It is currently deemed to be standard control services.

The AER's proposed classification of Ausgrid's distribution services is shown in Figure 5.

Figure 5 – NSW distribution services



9 Type 5 meters records energy use in 30 minute intervals. Type 6 record accumulated energy use only. Both types are manually read.

10 Includes household and small business metering.

11 Excludes CT meters due to ASP (accredited service providers) schemes.

The rules require that our regulatory proposal shows how the distribution services we provide should, in our opinion, be classified for the next regulatory period. If our proposed classification differs from the classification suggested in the relevant F&A paper, we are required to identify our reasons for the difference.[12] In relation to this rules requirement, Ausgrid's classification proposal adopts the AER's classification of services decision in stage 1 of the F&A paper.

The AER also sets out the various components of each of the above service groups and further description of each component.[13] While we propose no departure to the AER's decision on the classification of the distribution services we provide, we note that there are areas where we consider the AER's determination could provide more clarity on service description. These are:

- Specification of network augmentations as part of network services - categorising network augmentations under the broader service grouping of 'connections' is problematic. Augmentations of the network may be driven by new customers connecting to our network, but can also be driven by the need to reinforce the network as a result of increasing demand on the network from existing users[14], improving security of the network where the consequences of supply loss are high, restoring capacity lost due to de-rating of existing assets, and to address voltage or fault duty issues. We request that the AER's draft determination make clear that augmentations may also relate to these issues.
- Seeking clarity from the AER on the classification of emergency recoverable work; particularly in the case where Ausgrid is not able to identify the parties liable for the damage or is not able to recover from identified parties the costs of repairing the damages.
- Minor clarification in relation to the description of certain ancillary network services.

We set out our classification proposal, including our proposed amendment/clarification on service description in Attachment 3.01.

Further, Ausgrid agrees with the AER that none of the services provided by Ausgrid are suited to being classified as negotiated distribution services. While we do not anticipate any negotiated distribution services to arise over the 2014-19 period, we note that there is some scope for services provided by means of Ausgrid's transmission network (i.e. dual function assets) to be negotiated distribution services.[15] If Ausgrid is required to provide negotiated distribution services it will apply its negotiating framework. This is further discussed in chapter 9.

Control mechanisms

Control mechanisms provide the basis of how the AER is to regulate standard control and alternative control services. In stage 1 of the F&A paper, the AER decided that:

- The basis of control for standard control services was to be a CPI-X form consistent with the rules, and the form of control was to be a revenue cap. The AER also set out its proposed approach to the formulae that give effect to the control.[16]
- It would confirm a basis of control for alternative control services in making its determination, and that the form of control would be caps on the prices of individual services. The AER also set out its proposed approach to the formulae that give effect to the control.[17]

The rules require the AER's decision, in its distribution determination, on the form of the control mechanisms to be as set out in the relevant F&A paper.[18] However, the AER is able to amend its formulae that give effect to the control mechanisms only if the AER considers that unforeseen circumstances justify departing from the formulae. We have adopted AER's decisions on control mechanism as stated in its stage 1 F&A paper.[19] Further, we have also adopted the formula that gives effect to the control mechanism with minor clarifications including those to include adjustments needed to account for the annual update to the cost of debt[20] and the costs of repairing damage caused parties which were unrecoverable. This is further explained in Attachments 9.02.

Pricing of dual function assets

Dual function assets are high voltage transmission assets forming part of a distribution network. Where a DNSP has dual function assets, the AER is required to decide whether transmission or distribution pricing rules will apply.

In its stage 1 F&A paper, the AER considered that Ausgrid's dual function assets are a material proportion of its RAB. Based on this view, the AER decided that the standard control services provided by Ausgrid's dual function assets would be subject to transmission pricing.[21]

The AER's determination in the F&A paper is binding and therefore there is no opportunity for a DNSP to propose an amendment.

As the result of the AER's decision, Ausgrid is required to divide our total revenue for standard control services into transmission standard control services revenue and distribution standard control service revenue based on Ausgrid's approved cost allocation method (CAM).[22]

To accurately reflect the revenue associated with the transmission standard control services provided by dual function assets, Ausgrid has assessed the functionality of some existing distribution assets to determine whether these assets now need to be characterised as a transmission network asset[23] as defined in the rules; and similarly whether some existing transmission network assets continue to meet this definition. The values of Ausgrid's regulatory asset base (RAB) reflect this changed characterisation.

We provide further details of assets changing characterisation as well as the division of our total standard control services revenue in chapter 4. The approach to charging for the services provided by these assets is explained in chapter 9.

12 Clauses 6.8.2(c)(1)(i) and (ii) require Ausgrid to include a classification proposal in its regulatory proposal.
13 See Appendix D of the AER's stage 1 F&A.
14 Or combined growth related to existing and new users.
15 Clause 6.24.2(c) of the NER provides that "any service that is provided by a DNSP by means of or in connection with, the DNSP's dual function assets that, but for this Part would be a negotiated transmission service under Chapter 6A is deemed to be a negotiated distribution service." A negotiated transmission service is defined in Chapter 10 of the NER as connection services that are provided to serve transmission network users at a single connection point (excluding connection services between network service providers) as well as use of system services agreed at the time of a connection where the network service provider has augmented or extended the network. Consequently a new connection to Ausgrid's transmission network would be a negotiated transmission service which must be treated as a negotiated distribution service.
16 The AER clarified in Stage 2 Framework and Approach paper that separate revenue caps will apply (with different X factors) for the transmission and distribution portions of revenue for standard control services.
17 The AER clarified in Stage 2 of its Framework and Approach paper that it will derive the prices of quoted services from their relevant input costs (e.g. labour rate, material cost).
18 See clause 6.12.3(c) of the rules.
19 Ausgrid's position on control mechanism is therefore consistent and compliant with the AER's stage 1 F&A framework and approach paper: see paragraph 3.2(a) of the 7 March 2014 RIN.
20 Consistent with the AER's final rate of return guideline.
21 That is, under Part J of Chapter 6A of the National Electricity Rules.
22 Clause 6.26 of the rules.
23 See the definition of 'transmission network' in chapter 10 of the rules.

3.3 Our proposals in response to stage 2 of the framework and approach

In this section, we set out the decisions the AER made in stage 2 of the F&A paper. The paper was published on 31 January 2014 and set out the AER's proposed approach on the application of incentive schemes, depreciation to be applied when rolling forward the RAB and guidance on approach for true-up of alternative control services revenues earned during the transitional year.

Incentives to apply to standard control services

The regulatory framework contains a number of schemes that provide incentives to businesses to be efficient in their spending, in service standards and delivery, and in managing the network demand. These are known as incentives schemes and they form part of a building block determination. The AER has published a number of incentives guidelines and is required to set out its proposed approach in its F&A paper as to how it intends to apply these schemes to Ausgrid in the upcoming regulatory period.

The rules require Ausgrid to set out in its building block proposal to provide a description, including relevant explanatory material, of how Ausgrid proposes the incentive schemes that have been specified in the F&A paper that apply in respect of the forthcoming distribution determination should apply to Ausgrid.[24] In the sections below we set out our proposals in relation to the application of incentive schemes.

Efficiency benefits sharing scheme

The efficiency benefit sharing scheme (EBSS) provides a continuous incentive for the DNSP to achieve efficiency gains in its operating expenditure. The EBSS that applied to Ausgrid for the current 2009-14 period was recently revised by the AER (November 2013 version or version 2).[25]

For the transitional year, the AER has decided that the EBSS applicable to the current 2009-14 period, as modified to align to version 2 of the EBSS (the modified EBSS), will apply to Ausgrid for the transitional year and applies as if the transitional year was the first year of the subsequent regulatory control period.[26] For the 2015-19 regulatory period, the AER specified that version 2 of the EBSS will apply Ausgrid.[27]

As explained further in chapter 6, in developing the forecast opex for the 2014-19 period, Ausgrid has used the adjusted actual opex outcome for the 2012/13 year as the starting opex base. The adjustment relates to the actuarial assessment of long service leave obligations. This adjustment is necessary to ensure that the base opex, upon which cost escalation and change factors are applied, represents the underlying ongoing opex needed to provide standard control services.

We note that clause 6.5.8(a) of the rules states that the efficiency gains/losses are calculated as the difference between actual opex being less/more than the forecast opex accepted or substituted by the AER. The incremental efficiency gain or loss is then calculated by reference to the efficiency gain/loss of the current year and the prior year.

Consequently, to ensure comparability between the actual outturn opex and the forecast opex and to ensure that the efficiency gain/loss (and therefore the incremental efficiency gain/loss) are accurately calculated, Ausgrid considers that, in applying the modified EBSS and the version 2 EBSS for the transitional regulatory control period and the 2015-19 regulatory control period, actual outturn opex should also be adjusted for actual outturn actuarial assessment for long service leave obligations. In this way, the performance of the DNSP against the efficient opex benchmark accepted or substituted by the AER is not distorted.

Capex expenditure sharing scheme and proposed approach to depreciation

The capex expenditure sharing scheme (CESS) was recently introduced into the regulatory framework resulting from the AEMC's rule change. The CESS provides reward/penalty for efficiency gain/loss with respect to capital expenditure. The AER published its capital expenditure incentive guideline in November 2013 which sets out the CESS.[28]

In its distribution determination for the transitional year (i.e. 2014/15), the AER specified that no CESS applies.[29] This is consistent with the requirement of the transitional rules.[30]

The AER proposes to apply its CESS in the 2015-19 regulatory control period in accordance with its published guidelines. Ausgrid's proposal is to apply the CESS in the 2015-19 regulatory period, consistently with the AER's proposed approach to its application to Ausgrid as stated in the AER's Stage 2 F&A. In this respect we note that the CESS would be applied to Ausgrid by providing a reward of 30% of any underspend during the 2015-19 regulatory control period, or a 30% penalty on any overspends.

We propose that the mechanism for calculating the penalty or reward under the scheme would be calculated in accordance with the AER's guidelines. At the end of the 2015-19 period, the AER would calculate the cumulative underspend of overspend in net present terms, using an estimate in the last year of the period. The AER would apply a 30% sharing ratio to the cumulative underspend or overspend, but then adjust the final CESS payment to incorporate any financing benefit or cost incurred during the period. As required by the AER, further adjustments to the CESS payment may be made to the final CESS payment where there has been a material amount of capex deferred between regulatory control periods. The CESS payment relating to the underspend or overspend would be added to or subtracted from to Ausgrid's regulated revenue for the following regulatory control period as a separate building block.

Another key element of the overall capex incentive framework is the depreciation approach to use when a distributor's RAB is updated from forecast capex to actual capex at the end of a regulatory period. In establishing the value of the RAB as at the beginning of the period subsequent to the 2015-19 period, i.e. as at 1 July 2019, the AER can decide either to use the depreciation on actual capex (actual depreciation) or the depreciation on forecast capex (forecast depreciation). The choice of depreciation affects the power of the incentives that apply to capital expenditure.

24 See clauses S6.1.3(3),(3A),(4),(5) and (5A).
25 AER, Better Regulation, Efficiency benefit sharing scheme for electricity network service providers, November 2013.
26 AER, Ausgrid placeholder determination for the transitional regulatory control period 2014-15, p2.
27 AER, stage 2 framework and approach paper, p 20.
28 AER, Better Regulation, Capital expenditure incentive guideline for electricity network service providers, November 2013.
29 AER, Ausgrid placeholder determination for the transitional regulatory control period 2014-15, April 2014, p3
30 Clause 11.56.3(a)(3) of the rules.

The AER has proposed to use the forecast depreciation approach to establish the value of the RAB as at 1 July 2019 for NSW distributors. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capex efficiency gains over the 2014-19 period.

Our proposal is to apply the AER's approach as set out in the AER's F&A paper.

Service target performance incentive scheme

The AER proposed to not apply its national STPIS to the NSW distributors in the transitional period. It noted that under its approach the current performance reporting obligations will continue to apply with no revenue at risk.[31] Our proposal is to accept the AER's approach not to apply the STPIS to the transitional period.

The AER has proposed that the scheme will apply from the 2015/16 year onwards and has identified its proposed arrangements. Amongst other things, the AER proposed to set the revenue at risk to be within the range of +/- 5%. The AER stated:

> *In their response to the AER's 2012 preliminary framework and approach, the NSW distributors considered the ±5 per cent revenue at risk (as indicated in the national STPIS) to be excessive considering the ongoing uncertainty in the NSW electricity environment. The NSW distributors instead suggested applying a revenue at risk of ±2.5 per cent. Consistent with the objectives of the STPIS, we propose to set revenue at risk reflective of the particular circumstances of each distributor and within the range of ±5 per cent. We will determine the revenue at risk during the distribution process following receipt of the NSW distributors' regulatory proposals and submissions on those proposals.*[32]

With respect to the application of the STPIS, Ausgrid proposes a revenue at risk of ±2.5%. We note that this is within the range specified by the AER as noted above. Our proposed revenue at risk is consistent with previous representations we have made to the AER.[33] At that time, we noted that applying the maximum revenue at risk of ±5% available under the scheme would be excessive given the implementation issues with transitioning to a new scheme. We consider our proposed revenue at risk best meets the objectives of the scheme identified in section 1.5 of the STPIS, in particular the willingness of the customer or end user to pay for improved performance in the delivery of services as stipulated in 1.5(b)(6) of the scheme. Ausgrid's customer research has shown that the majority of customers are satisfied with their existing level of reliability suggesting a reluctance to pay any more for improvements.

Our complete proposal on how the STPIS will apply is set out in Attachment 3.02. This includes additional information including our assumptions, proposed targets and incentive rates. The key elements of our proposal are

- In terms of reliability parameters, we propose a revenue at risk of ±2.25%. Our proposal is to apply the SAIDI and SAIFI parameters which relate to duration and frequency of outages. We consider that measures of momentary outages should not apply due to data quality issues. We have proposed that the exclusion events identified in the AER's guidelines apply to Ausgrid when calculating reliability performance.
- For customer service parameters, we consider that only telephone response times should be included in the scheme. We propose a revenue at risk of ±0.25%. Ausgrid proposes that when an event is excluded from the calculation of reliability performance, the event should also be excluded from the calculation of our telephone service performance.

Demand management incentive scheme

The demand management incentive scheme (DMIS) that applies to Ausgrid for the current 2009-14 period comprises of two components:

- A demand management innovation allowance (DMIA) component which consists of parts A and B. Part A provides for an innovation allowance and Part B compensates for revenue forgone because of demand management initiatives.
- A D-Factor component which was established by IPART. The D-Factor also compensates for both costs and revenue forgone.

From the transitional regulatory control period onwards, the AER proposed to continue applying part A of the DMIA at the same scales as currently applied to NSW DNSPs, but to discontinue part B of the scheme as it related to compensation for foregone revenue. Our proposal is to apply the AER's approach given that we are no longer under a weighted average price control cap.

The AER also proposed to discontinue the non-compensatory incentive component of the D-Factor scheme for NSW distributors from the transitional regulatory control period onwards. However, as the D-factor operates on a two years lag, Ausgrid will be recovering the associated costs of demand management projects in the 2014-19 period.[34]

The AER has noted that the Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. The AER intend to develop and implement a new DMIS for the subsequent regulatory control period, depending on the progress of the rule change process.

31 AER, Ausgrid placeholder determination for the transitional regulatory control period 2014-15, April 2014, p3.
32 AER, stage 2 framework and approach: Ausgrid, Endeavour Energy and Essential Energy, January 2014, p16
33 NSW distributors, Response to AER preliminary F&A, Aug 2012, p. 65.
34 Stage 1 framework and approach paper, p32.

In anticipation of these changes, Ausgrid has proposed a demand management benefit sharing scheme (DMBSS) to replace and improve the incentive component of the D-factor. This is a modest scheme designed to recognise the wider benefits that can flow to consumers as a result of network initiated demand management programs or projects. The requirements of the newly introduced Regulatory Investment Test for Distribution in the rules to consider market benefits in investment decisions, the proposed scheme would remove a potential disincentive against choosing demand management alternatives. It works by sharing the market benefits that would accrue to customers with the DNSP, ensuring optimal decisions in relation to non-network alternatives. Further details of the proposal are provided in Attachment 3.03.

We note that the AER's proposed approach in its Stage 2 F&A paper in relation to the application of incentive scheme is not binding. Therefore we consider that in making a constituent decision on how any applicable incentive scheme is to apply to Ausgrid for the next period, the AER should apply a DMIS that has two components, namely:

- A DMIA component (part A of current DMIA).
- A DMBSS component as proposed by Ausgrid.

Small scale incentive scheme

Recent changes to the rules allow the AER to develop incentive schemes outside those already provided in the rules. These are small scale pilot or test incentive schemes that allow for regulatory innovation (a small-scale incentive scheme). Given that the AER has not developed this scheme and consequently has not stated a proposed approach to its application to Ausgrid for the 2015-19 regulatory control period, our proposal is not to implement such a scheme during the course of the 2015-19 regulatory control period.[35]

True-up for alternative control services

The NSW distributors requested that the AER specify in Stage 2 of the F&A how a true-up of prices will be made for alternative control services. This is to account for the fact that alternative control services prices for 2014/15 were basically set by escalating the prices of the previous year by CPI. We set out their preliminary views on how a true-up mechanism could work.

In the F&A paper the AER noted that given that it is yet to see how Ausgrid intend to treat alternative control services pricing in their transitional proposals, it preferred not to prejudice whether, and if so, how alternative control services prices are to be trued-up. For this reason, it did not specify the exact manner in which alternative control services prices may be adjusted in this F&A.

Chapter 8 of this proposal document discusses our proposed approach for the true-up of alternative control services for the transitional year. We also note that chapter 4 has been clear on our proposed method for the 'true-up' of standard control services.

[35] No small-scale incentive schemes applies to Ausgrid for the transitional regulatory control period.

4. Building block proposal

We propose total annual revenue requirements of $12.2 billion[36] ($ nominal) for the 2014-19 period. This amount is needed to recover the efficient costs we reasonably expect to incur in providing standard control services.

Ausgrid provides a range of distribution services that are classified by the AER as standard control services. These are services central to the supply of electricity and are relied on by most (if not all) of our customers.

We are required to provide the AER with a 'building block' proposal for standard control services that is used to set a revenue cap for each year of the regulatory control period. This chapter together with the relevant elements of chapter 3 and the associated attachments form Ausgrid's building block proposal.

The key points of this chapter are:

- Ausgrid is striving to contain average increases in our share of customers' electricity bills at or below CPI over the next regulatory control period.
- We have sought to minimise our revenue by reducing our costs.
- We have smoothed our revenues for 2014-19 to reduce price volatility. In smoothing our revenues, we have investigated how forecast volumes will impact the prices customers pay over the period.

4.1 Proposed building blocks

This section provides a summary of our proposed annual revenue requirements based on building block components. The building blocks refer to the efficient costs that a DNSP reasonably expects to incur in a regulatory period. We have used the building block approach required by the rules for the calculation of revenue requirements relating to standard control services.[37] These main elements are inputs into the annual revenue requirement using the AER's post tax revenue model (PTRM). These PTRMs for distribution and transmission are provided in Attachments 4.01 and 4.02 respectively.[38]

In the sections below, we have identified the building block components we have used to calculate the annual revenue requirement for each year of the regulatory control period,[39] consistent with the rules requirements. The building blocks relate to the following types of costs:

- Return of capital - We receive an allowance for a return of capital (depreciation). The calculation of the return of capital is based on key inputs such as the projected value of opening asset base as at 1 July 2014 and the remaining lives of assets and is calculated on a straight line basis. The AER offsets changes in indexation of the RAB through its depreciation calculation and refers to this as "regulatory depreciation".[40]
- Return on capital – We receive an allowance for a return on capital. This is to fund the borrowing costs of our debt and provide a reasonable return on equity. The calculation of the return on capital is based on key inputs including the value of opening asset base, the allowed rate of return and forecast capex.
- Operating and tax costs – We receive a revenue allowance to fund our operating activities, and to meet our income tax liabilities.
- Other revenue increments or decrements – We receive a revenue increase or decrease based on outstanding penalties or rewards from incentive schemes that applied in the 2009-14 period, e.g. EBSS. The rules also requires a revenue decrement arising from the use of standard control services assets, where these assets are also used to provide other services. There is no revenue decrement for the 2014-19 period as the relevant materiality threshold has not been met.

The building block components of our proposed annual revenue requirements (unsmoothed) for 2014-15 to 2018-19 are outlined in Table 8.

36 This is the 'unsmoothed' revenue

37 Our proposed building blocks and annual revenue requirement for each year of the 2014-19 period relate to standard control services only. That is, our proposal does not include amounts relating to alternative control services or unclassified services.

38 As required by clause S6.1.3(10) of the rules.

39 We note that while this proposal relates to the subsequent regulatory control period, the rules require us to treat the 2014-15 transitional year as if it were the first year of the period. See clause 11.56.4.

40 See clauses 6.4.3(a)(1) and (3) of the rules.

Table 8 - Annual revenue requirement ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Return on and return of capital						
Return on capital	1,269.2	1,348.9	1,428.6	1,494.7	1,561.9	**7,103.3**
Regulatory depreciation	135.7	159.8	184.5	166.5	182.2	**828.7**
Operating and tax costs						
Opex[41]	586.6	602.3	626.8	637.7	653.8	**3,107.2**
Income tax	120.7	132.7	153.8	150.7	154.5	**712.3**
Other revenue increments or decrements						
EBSS revenue	102.2	114.4	89.8	148.2	–	**454.7**
Proposed DMIA revenue	1.3	1.9	1.4	0.6	0.1	**5.3**
D-factor carryover	1.6	1.0	–	–	–	**2.5**
DMIA carryover	–	-2.2	–	–	–	**-2.2**
Shared asset revenue	–	–	–	–	–	**–**
Annual revenue requirement	**2,217.4**	**2,358.8**	**2,484.9**	**2,598.4**	**2,552.5**	**12,211.9**

Note: Numbers may not add due to rounding

Return on and of capital

We receive a return on the value of the RAB, determined by multiplying the value of the opening RAB by the allowed rate of return. The value of the RAB throughout the regulatory period reflects the remaining value of past capital investments and the forecast value of future capital expenditure. The allowed rate of return reflects the cost of capital for a benchmark efficient network service provider. This is discussed further in chapter 7.

We receive a return of capital or regulatory depreciation based on the age profile of the assets within the regulatory asset base and the method of calculating depreciation. The key inputs to developing our estimate of return on and return of capital are identified below.

Opening value of regulatory asset base

The estimated value of our RAB (for standard control services) as at 1 July 2014 is $14,370 million as shown in Table 9. This comprises of $12,280 million attributable to distribution standard control services and $2,091 million attributable to dual function assets. We have calculated these amounts based on clause 6.5.1 and schedule 6.2 of the rules and the AER's roll forward models. These models are provided in Attachments 4.03 and 4.04.

This RAB value of $14,370 million reflects the roll forward of actual capex for the years 2008/09 to 2012/13 and estimated capex for 2013/14. These capital expenditure amounts contain the actual and estimated capital expenditure pertaining to Type 5 and 6 metering services and ancillary services.[42]

However, as the AER has changed the classification of some services currently deemed to be standard control services for the 2009-14 period to alternative control services from 1 July 2014, adjustments to the value of the RAB as at 1 July 2014 are therefore necessary to exclude the value of assets used to provide services that are no longer classified as standard control services. This is to enable accurate calculation of the annual revenue requirements for standard control services. The adjustment is approximately $260.8 million. This calculation is provided in Attachment 4.05.

Table 9 - Opening RAB ($ million, nominal)

Calculation of RAB value as at 1 July 2014	
Opening RAB as at 1 July 2009	8,325.6
Add: Actual and estimated capex	6,720.7
Less: Regulatory depreciation	-697.4
Impact of actual capex for FY2009	282.1
Adjusted opening RAB as at 1 July 2014	14,631.1
Less: assets for reclassified services (e.g. Type 5 & 6 metering)	-260.8
Value of RAB for standard control services as at 1 July 2014	**14,370.3**
Distribution assets	12,279.8
Transmission assets	2,090.5

Note: Numbers may not add due to rounding

41 Includes debt raising cost but excludes proposed DMIA for 2014-19 which is separately disclosed.

42 These services are classified as standard control services prior to 1 July 2014.

In addition, the RAB values also reflect the change in classification of existing assets from distribution to dual function assets or of assets that no longer meet the definition of a dual function asset (and hence classify as distribution). The net value of assets changing classification from dual function assets to distribution is $3.2 million. Further details are provided in Attachment 4.06.

Forecast capex

Table 10 shows the forecast capex relating to the provision of standard control services. Details of our expenditure plan are provided in chapter 5 of this proposal.

Table 10 - Forecast capex for standard control services ($ million, 2013/14)

2014/15	2015/16	2016/17	2017/18	2018/19	Total
1,012	985	857	814	754	**4,421**

Note: Number may not add due to rounding
Exclude property remediation

Allowed rate of return

We propose a conservative estimate of the rate of return of 8.83% using a trailing average approach to the cost of debt (i.e. 10 years trailing average commencing January 2004) and a long-term average approach to the cost of equity informed by the range of relevant available evidence on the efficient cost of equity for energy networks.[43]

We propose a cost of debt of 7.98%, a cost of equity of 10.11% and a gearing level of 60%. Table 11 shows the WACC ranges we used to calculate the annual revenue requirement. Chapter 7 of this proposal and associated attachments provide further information and justification of the proposed rate of return.

Table 11 - Proposed rate of return

Rate of return parameters	Proposed WACC %	Reasonable range of estimates %
Overall WACC	8.83%	8.83% - 9.44%
Cost of equity	10.11%	10.11% - 11.50%
Cost of debt	7.98%	7.98% - 8.06%
Gearing	60%	60%
Utilisation of imputation	25%	25%

Note: Numbers exclude property remediation

Regulatory depreciation

Regulatory depreciation is the depreciation on the value of the regulatory asset base offset by the indexation on that asset base. The regulatory depreciation amount for each year of the 2014-19 period is shown in Table 8.

We have calculated the depreciation on the RAB using the straight line depreciation method which divides the opening asset values as at 1 July 2014 by the remaining lives and new assets (i.e. forecast capex for the 2014-19 period) by the standard lives.

We have adopted the AER's preferred approach to the calculation of remaining lives of assets as at 1 July 2014. This approach calculates the remaining lives as at 1 July 2014 by weighting the remaining lives of assets existing as at 1 July 2009 and the remaining lives of assets that are rolled into the RAB during the 2009-14 period (i.e. capital expenditure for the current regulatory period). The weighting used is the depreciated regulatory value. Whilst we have adopted this approach, we note that it over-estimates the remaining lives as new assets are given more weighting. We are investigating this issue further, but from preliminary analysis, the AER's preferred approach to calculating remaining asset lives significantly over-weights new assets and therefore over-estimates the remaining life of assets on our network. This is currently resulting in undercompensation for depreciation expense. One indicator of remaining asset lives is that used for accounting purposes. For depreciable assets as at 1 July 2014, Ausgrid has a weighted average remaining life of 36.6 years according to the AER's approach, but an actual weighted average remaining life for accounting purposes of 25.7 years.

Within the AER's post-tax revenue model, depreciation is calculated as straight line depreciation less the indexation of the RAB for inflation.[44] We have used a forecast inflation of 2.5% as a placeholder for this proposal and we propose that this forecast be updated using the AER's approach to calculating forecast inflation, which Ausgrid proposes to adopt. This approach uses a geometric average of the RBA's forecast of inflation for the first two years and the mid-point of the RBA's target range for inflation (2.5%) for another 8 years to provide a 10 year forecast of inflation. We note that the AER will update this forecast for the latest RBA's inflation estimates at the time of its final decision.

Indexing the RAB for inflation increases its nominal value over time and allows a return on capital to be earned on the indexed component. However, reducing depreciation allowances by the amount of indexation means that depreciation allowances are not sufficient to compensate DNSPs for actual depreciation expenses in the short to medium term. The regulatory approach to depreciation combined with the over-estimation of remaining asset lives for regulatory purposes is currently resulting in under-compensation for Ausgrid's depreciation expenses. We will be conducting further analysis on this issue and will provide any findings to the AER as they become available. As required by clause S6.1.3(12), Ausgrid's nominated depreciation schedule is provided in Attachment 4.07.

Operating and tax costs

Forecast opex

Table 12 shows the forecast opex relating to the provision of standard control services. Details of our operating expenditure plan are provided in chapter 6 of this proposal.

Estimated cost of corporate tax

The estimates of the cost of corporate income tax for each year of the 2014-19 period are shown in Table 8 and have been calculated using the AER's PTRM.

43 We refer to the return on equity and the return on debt in the NER as the cost of equity and the cost of debt.

44 Clauses 6.4.3(b)(1) and S6.2.3(c)(4) of the rules.

To estimate the cost of corporate income tax we have used the current corporate tax rate of 30% and a value for imputation credits of 0.25 per dollar of tax paid. This estimate is based on a payout ratio for imputation credits of 70% and the latest estimate of the market value of distributed imputation credits from Strategic Finance Group Consulting (SFG)of 0.35. The proposed imputation credit of 0.25 is further discussed in chapter 7. We have also provided in Attachment 4.08 an explanation of the calculation of the opening tax asset base, a relevant input into the calculation of corporate income tax.

Table 12 – Forecast opex for standard control services ($ million, 2013/14)

2014/15	2015/16	2016/17	2017/18	2018/19	Total
565.1	566.2	574.2	568.9	568.4	**2,842.9**

Note: Numbers may not add due to rounding

Other proposed revenue adjustments

The rules require that the AER allow Ausgrid to include revenue increments or decrements that relate to the operation of incentives from the 2009-14 period. The rules also require a DNSP to reduce its revenue to account for the use of shared assets if the materiality threshold is met.

Proposed EBSS revenue increment

We have applied the EBSS scheme outlined by the AER in its determination for the 2009-14 regulatory period.[45] This provides estimated carryover amounts for the 2014-15 to 2018-19 regulatory period as set out in table 7. We have provided the calculation of this EBSS carry over amount in Attachment 4.09.

During the review of Ausgrid's transitional proposal, the CCP sought clarification on the rationale for including the EBSS carryover amount in customer charges. The CCP sought to understand how customers share benefits from this scheme.

We note that the AER has implemented the EBSS under the relevant rules requirements to provide short term financial incentives for DNSPs to improve their efficiency. These financial incentives are carryover amounts for DNSPs that outperform the AER's opex allowance. These incentives put downward pressure on DNSPs' operating costs which equate to long term efficiency and, therefore, lower customer bills. The AER estimates that the short term benefit to the DNSPs is only 30% of the efficiency gains, with the remaining 70% being saved by customers through lower bills in future years.[46]

For the current 2009-14 period, the EBSS identifies that Ausgrid's actual operating expenditure outperformed the allowance determined by the AER. Consequently, the forecast opex for the 2014-19 period includes the benefit of efficiency gains achieved during the 2009-14 period, which more than offset the efficiency carry-over amounts.

Proposed DMIS revenue increment

The AER applied the DMIS to Ausgrid for the current 2009-14 period. This scheme provides incentives for the DNSP to manage demand on its network and contains two parts:

- The IPART's D-factor scheme implemented by Independent Pricing and Regulatory Tribunal (IPART) for the 2004-2009 regulatory period. This D-factor scheme was adopted by the AER to apply to Ausgrid for the 2009-14 period.
- A demand management innovation allowance (DMIA) which provide an allowance for the pursuit of innovative broad-based demand management initiatives.

The rules permit the recovery of revenue increment (or return of revenue decrement) in the 2014-19 period relating to incentive schemes that apply in the current 2009-14 period.[47]

The D-factor scheme applied by IPART provided incentives for the DNSPs to undertake projects to manage the demand on the network and thereby reduce the need for network expenditure. The D-factor that applied as part of the DMIS for the 2014-19 period was subject to a lag of 2 years between performance in a regulatory year and incorporation of the incentive payment in prices. As such, the revenue increment related to our performance under the D-factor for 2012/13 and 2013/14 has not been included in the revenue we have collected from customers in the 2009-14 period.

Accordingly, Ausgrid has included in its revenue for the 2014-19 period the actual and expected incentive payments for the years 2012/13 and 2013/14 respectively. These amounts are set out in table 7. Further details of the calculation is provided in Attachment 4.10.

Ausgrid was also provided with an annual allowance of $1 million ($2008/09) in the current regulatory period for DMIA. Any expenditure not spent or not approved by the AER will be returned to customers in 2015/16 when the results of DMIA expenditure for the 2009-14 period are known.[48]

At the time of submitting this regulatory proposal, we forecast an under-spend and consequently a negative carryover of $2.0 million ($2013/14) for the 2009-14 period. We have included this forecast revenue decrement in the annual revenue requirement for 2015/16.

It must be noted that this amount is a placeholder only as the actual expenditure for 2013/14 is not yet known and the AER's assessment of Ausgrid's DMIA expenditure for the current period has not yet been undertaken. We expect this outcome will be known at the time of the AER's final decision for the 2014-19 period and any necessary adjustments will be made accordingly.

Additionally, our proposed forecast opex for the 2014-19 period includes a proposed DMIA for this period of $5 million ($2013/14). We have shown this as a separate item in Table 8 ($5.3 million, nominal).

Proposed shared asset revenue decrement

Shared assets are those that are used to provide both regulated and unregulated services. The AER may reduce Ausgrid's annual revenue requirement for a regulatory year to reflect the costs of using shared assets that are being recovered from unregulated revenue. In making this decision, the AER must have regard to the shared asset principles and the shared asset guideline.

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline sets

45 AER, Final decision, New South Wales distribution determination 2009-10 to 3013-14, p245

46 AER, Better regulation, Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Providers, November 2013m pp5-6.

47 Clause 6.4.36(a)(5) of the rules.

48 AER, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme, November 2008, p3.

out its approach to making a reduction to a DNSP's annual revenue requirement to reflect the use of shared assets, including the definition and calculation of materiality. The use of shared asset is material when a DNSP's annual unregulated revenue from shared assets is expected to be greater than 1% of its total smoothed revenue requirement for a particular regulatory year.[49] If this material threshold is not met, no shared asset cost reduction applies.[50]

We have applied the AER's shared asset guideline and calculate the materiality of our use of shared assets to earn unregulated revenue. The calculation of materiality for each year of the 2014-19 period is shown in Table 13.

4.2 Proposed revenue requirements

Annual revenue requirements

In the previous section we set out our proposed building blocks. The building blocks are used to derive Ausgrid's total proposed annual revenue requirement (ARR), as set out in Table 14.

Given that Ausgrid has transmission standard control services, we have apportioned the revenue between our distribution and dual transmission standard control services. We have done so by allocating the building block inputs between transmission and distribution based on the cost allocation method approved by the AER on 2 May 2014. This is the same approach we used for the 2009-14 regulatory proposal.

This revenue will be recovered from our customers via network tariffs (or charges). These charges reflect the recovery of the efficient expenditure we need to invest in our network, to operate and maintain that network and comply with our regulatory obligations. They also provide a reasonable return on our investment in the network.

The AER has made a 'placeholder' determination on Ausgrid's annual revenue requirement for 2014/15. The rules require the AER to essentially re-make this decision in its determination on this proposal[51] and to account for differences in the amounts it approved under the transitional determination and the determination on this proposal in the annual revenue requirements of the period 2015-19. We address this 'true-up' of the annual revenue requirement for the transitional year below.

Adjustment to total revenue requirement for the transitional year

Ausgrid's total revenue requirement for its subsequent regulatory control period must be fully adjusted for the difference in the ARR approved for the transitional determination, and the ARR determined for 2014/15 as part of its determination for the subsequent regulatory control period, provided that the adjustment is neutral in net present value terms.[52]

Consequently, no shared asset cost reduction to the proposed annual revenue requirement for any regulatory year of the 2014-19 period is necessary.

Table 13 – Materiality of shared asset use ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast unregulated revenue from shared asset	13.0	13.2	13.5	13.8	14.0	**67.4**[53]
Smoothed revenue (prior to shared asset reduction)	2,314	2,372	2,425	2,499	2,580	**12,189**
Materiality percentage	0.6%	0.6%	0.6%	0.6%	0.6%	**0.6%**

Note: Numbers may not add due to rounding

Table 14 – Proposed 'unsmoothed' annual revenue requirements ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Distribution	1,957.1	2,079.1	2,187.1	2,293.5	2,246.4	**10,763.2**
Transmission	260.3	279.6	297.9	304.9	306.1	**1,448.7**
Total	**2,217.4**	**2,358.8**	**2,484.9**	**2,598.4**	**2,552.5**	**12,211.9**

Note: Numbers may not add due to rounding

49 AER, Better Regulation, Shared asset guideline, November 2013, p8.
50 AER, Better Regulation, Shared asset guideline, November 2013, p6.
51 Clause 11.56.4(b) & (c) of the NER.
52 Clause 11.56.4(h) of the NER.
53 See Reset RIN, regulatory template 7.4.

In our transitional proposal we outlined the amount we propose to be the annual revenue requirement for standard control services for the transitional year and the inputs used in this calculation. This was separate to the bundled revenue which included the revenues for services that had been re-classified from standard control services.[54]

For this proposal, we have only proposed building block elements and annual revenue requirements that are for the provision of standard control services. That is, any amounts in relation to alternative control or unclassified services have been excluded from our building block proposal and proposed ARR for each year of the 2014/15 to 2018/19 period (including the 2014/15 year). As noted in our transitional proposal, whilst the AER's approach to setting prices for alternative control services for 2014/15 was via general network charges[55], we consider that the demarcation between standard control services and alternative control services is essential to the AER's decision in relation to calculating the over/under recovery of standard control services revenue for the transitional year (as per clause 11.56.4(h)-(j)). In Appendix 1 of our transitional proposal we noted that the bundled revenue should not to be used in adjusting the annual revenue requirement of standard control services of the subsequent period.

Accordingly, we understand the AER's transitional determination of the annual revenue requirement for Ausgrid for the transitional year is $2,140 million (nominal). This is the 'smoothed revenue' that relates to standard control services only (as these services are classified by the AER in its Stage 1 F&A).[56] Consequently, when making the adjustment as required under the 11.56.4(h)-(j), the AER needs to use the $2,140 million smoothed revenue it determined for the transitional year in its transitional determination and the amount it will determine for the transitional year in its determination for this substantive proposal. That is, its decision on the $2,314 million smoothed annual revenue requirement 2014/15 as outlined in Table 15.

The recovery of revenue needed to cover the costs of providing reclassified alternative control services in general network charges was for the transitional year only. Separate alternative control prices will be established for the period subsequent to the transitional control period. Further we consider adjustments to alternative control services prices for the 2015-19 regulatory period should be made to account for the under recovery or over recovery of revenues for alternative control services earned during the transitional year. This is discussed further in chapter 8.

Proposed smoothed revenue and X-factors

To minimise price variations over time we need to take into account fluctuations in the annual revenue requirement over the course of the regulatory period.

As discussed in the sections below, in deciding on the proposed smoothed revenues and the resultant X-factors we have considered:

- Customers, who want prices that are stable over the period.
- The complexities that arise from the inclusion of the transitional year.
- Forecast changes in energy consumption over time.
- Though not a formal requirement, the rules requirement[57] to minimise differences between the ARR and smoothed revenue of the last year, i.e. 2018/19. This is intended to minimise the potential for price shocks between the 20014-19 period and the subsequent regulatory period.[58]

This smoothed revenue profile has been calculated using the AER's PTRM and ensures that our proposed smoothed revenues are equal to required revenues in net present value terms. This profile is shown in Table 15.

As discussed further in chapter 7, we propose a cost of debt that will be updated annually during the 2014-19 period. This means that for each year of the 2014-19 period, the allowed rate of return will be different depending on the update to the annual cost of debt. As further explained in chapter 8 and associated supporting documents, we propose to account for the revenue adjustment needed to reflect the updated annual cost of debt in the control mechanism formula.

As demonstrated in Figure 6 we have smoothed revenues such that they do not fluctuate greatly between regulatory years. In addition, we have aimed to minimise, as far as practicable, the difference between smoothed and required revenues in 2018-19.

Table 15 - Proposed 'smoothed' annual revenue requirements ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Distribution	2,039.0	2,090.5	2,135.9	2,202.8	2,276.2	**10,744.3**
Transmission	274.9	281.7	288.8	296.0	303.4	**1,444.7**
Total	**2,313.8**	**2,372.2**	**2,424.6**	**2,498.8**	**2,579.6**	**12,189.1**

Note: Numbers may not add due to rounding

54 In accordance with the approach preferred by the AER in relation to the setting of indicative prices for the transitional year, we had also aggregated the costs of providing standard control services, certain alternative control services such as metering services (but not public lighting) and unclassified services to calculate a total bundled revenue for the purpose of setting NUOS charges for the transitional year. We nominated the 'bundled revenue' to be the amount that will be recovered via NUOS charges for the 2014-15 year.

55 By 'bundling' standard control services revenue and alternative control services revenues.

56 This amount is calculated as the difference between the 'total revenue (smoothed)' of $1,958 million and the 'metering costs' of $70 million. Metering costs have been excluded as they are classified as alternative control services. This is the distribution portion to which $252 million has been added to arrive at a total of $2,140 for standard control services. See AER, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Transitional distribution decision, April 2014, tables 4.4 and 4.5, pp 23-24.

57 That would otherwise apply but for rules introduced as the result of the AEMC's rule change in 2012. See clause 11.56.4(c) of the rules.

58 For example, if revenue is smoothed over five years in such a way that smoothed revenue recovery in 2018-19 is significantly less than the level of revenues required to meet efficient costs, then in the following regulatory period prices may need to increase significantly to meet the required level of revenues.

In the sections below, we note that our smoothed revenue and resultant proposed X-factors have been influenced by 2 factors.

The X-factor represents the real percentage change in the smoothed revenue for each year of the 2014-19 regulatory period. The X-factor is important in ensuring that we comply with the control mechanism. Given that we have a separate control mechanism for the services provided by our dual function and distribution assets, this means we have 2 sets of X-factors and these are shown in Table 16.[59]

Energy consumption

Changes in energy consumption impact the prices customers pay for electricity. For example, if the required level of revenue drops in one year, but then rises again in subsequent years[60] and we do not attempt to smooth revenue recovery over the full 2014-19 period, customers could face pricing volatility over the period.[61] As such, if energy consumption falls and required revenue remains at the same level, then average unit charges would need to increase. Likewise, if energy consumption increases, the average unit charges would need to reduce to maintain the same level of required revenue.

Figure 7 depicts actual energy consumption and the AER approved energy consumption forecasts for each year of the current regulatory period. It also shows the energy forecasts for the each year of the 2014-19 period. This forecast is based on information available as at the end of November 2013 and the underlying component tariff level forecasts have been used to calculate the indicative prices. Ausgrid has no reason to believe that the underlying drivers of this forecast have materially changed since November 2013.

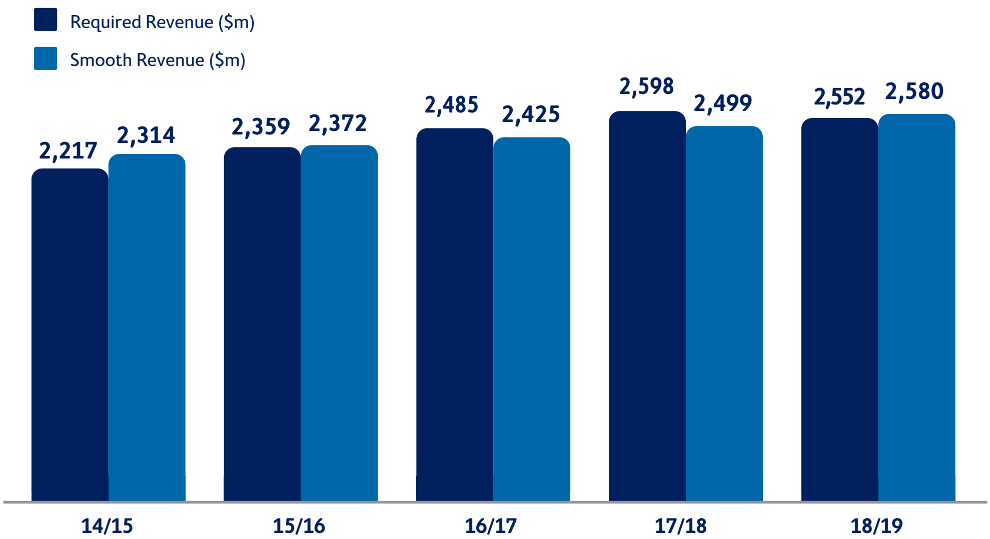
Energy consumption excluding "other loads" (that is, excluding Hydro Aluminium, OneSteel Newcastle and Essential Energy transfers) declined by an average of 1.5% per annum in the first four years of the current five-year determination period. Consumption is projected to decline by 2.1% in 2013/14 and by 2.3% in 2014/15. Thereafter the rate of annual decline in consumption is forecast to soften, before returning to positive growth in 2017/18. We project that energy consumption will decline by an average of 0.4% per annum in the five years to 2018/19. This equates to, on average, a 1.5% per annum reduction in use of electricity per customer for the five years commencing 1 July 2014. Despite the projected turnaround from consistently negative growth, forecast energy consumption excluding other loads in 2018/19 would be close to 10% lower than 2008/09 levels.

The key reason behind the expected slowdown in declining energy consumption trends is that retail electricity prices are projected to be relatively stable after 2015/16, following the high and sustained price growth which has been experienced in recent years. The projected stable electricity price path and expected moderate uptake of electric vehicle usage add positive stimulus to growth trends compared with that experienced in recent years. The forecast also includes a growth in customer connections over the period of 92,315 connections. However these positive stimuli are projected to be offset by the impacts of ongoing solar PV penetration, the wind-up of the NSW solar bonus scheme in 2016[62], the NSW Energy Savings Scheme and ongoing energy efficiency improvements. Further details are provided in Attachment 4.11.

Table 16 – Proposed X factors for distribution and transmission standard control services[63]

	2014/15	2015/16	2016/17	2017/18	2018/19
Distribution	5.66%	-0.03%	0.32%	-0.62%	-0.81%
Transmission	0.11%	0.00%	0.00%	0.00%	0.00%

Figure 6 - Forecast required revenue vs. smoothed revenue ($ million, nominal)



59 This is consistent with the AER's Stage 2 F&A, see p10.
60 Rise and fall in revenue may reflect the lumpiness of the expenditure profile.
61 Assuming energy consumption remains constant.
62 As customers on the gross scheme are likely to move to a net scheme.
63 A positive X factor denotes a price reduction.

4.3 Indicative charges and bill impact

Ausgrid is striving to contain average increases in our share of customers' electricity bills at or below CPI over the next regulatory control period. We have examined our strategies, processes and procedures to identify scope for savings. This reflects our commitment to alleviate price pressures and our ongoing effort to be effective and efficient in everything we do, without compromising on the safe, sustainable and reliable supply of electricity. In the following sections we identify:

- The forecast movement in average distribution charges, based on the proposed X-factors and energy consumption profile discussed above.
- Provide indicative NUOS prices for each year of the regulatory control period.
- Outline typical bill impacts for residential and small business customers.

Movement in average distribution charges

A useful indication of how average prices could move over the regulatory period is demonstrated in Table 17.

The average change in distribution charges shown in Table 17 is based on our latest forecast of number of customers, energy consumption, and capacity over the the 2014-19 period. Energy consumption has been falling beyond our forecast expectation over recent years and while every effort has been made to forecast accurately:

- If energy consumption falls below our forecast, average charges would need to increase more than indicated.
- If energy consumption rises above our forecast, average charges would decline below the estimates indicated.

It should be noted that Table 17 does not incorporate:

- Charges relating to transmission standard control services and alternative control services.
- Changes in the relative contribution of each tariff and/or tariff component to overall distribution revenues over the five year period. This may change based on energy consumption and pricing decisions for each year.

Indicative prices

Under clause 6.8.2(c)(4) of the rules we are required to provide indicative prices of direct control services (i.e. standard control services and alternative control services) for each year of the 2014-19 period.

Further, in Ausgrid's case, standard control services are further disaggregated between transmission standard control services (provided by dual function assets) and distribution standard control services.

Table 18 shows the indicative DUOS prices that recover the revenue associated with distribution standard control services.

Figure 7 – Actual and forecast energy consumption (GWh per annum)

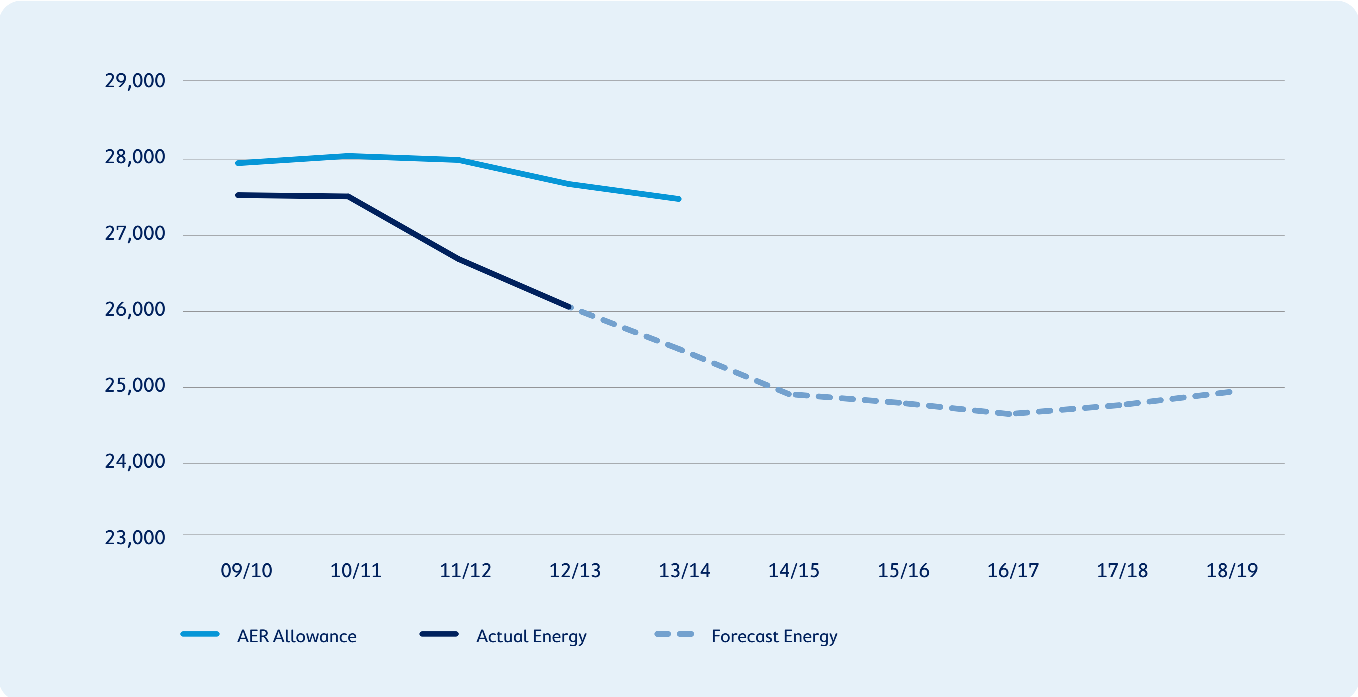


Table 17 - Change in average distribution charges (incl. metering) based on latest energy forecasts

(% change, 2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19	Average
Weighted average change in distribution charges[64]	2.06%	2.38%	2.49%	2.46%	2.46%	**2.37%**

64 Includes Type 5 and 6 metering charges.

Whilst these prices provide an early indication of our commitment to customers for the next period, they are indicative only at this stage. They are based on Ausgrid's proposed revenue for the 2014-19 period and do not reflect the placeholder revenue determined by the AER for the 2014/15 year which must be subject to a 'true-up' in the AER's further determination for the 2014-19 period. The actual prices that will be charged to customers for the 2015-19 period are dependent on:

- The AER's distribution determination for Ausgrid for the 2015-19 regulatory control period and any differences between the revenue determined for the 2014-15 year and the placeholder revenue.
- Updated energy consumption forecasts and actual consumption outcomes over the 5 years.
- Any changes in the relative portion of revenues recovered from each tariff and tariff component.

However, taking our regulatory proposal as a whole relative to 2014/15, customers would not face any increases in any year of the 2014-19 period above CPI on average, assuming volumes as forecast.

We also note that the prices outlined in Table 18 and Table 19 are only a portion of the total network use of system charge to customers. Network use of system charges also include the cost of the services provided by the NSW transmission network service provider (TransGrid) and the recovery of an amount to satisfy obligations under the NSW Climate Change Fund. These components are outside our control.

4.4 Additional pass through events

The pass through mechanism in the rules recognises that a distribution network service provider can be exposed to risk of loss beyond its control, which may have a material impact on its costs. A cost pass through enables a business to seek the AER's approval to recover (or pass through) the costs of a defined unpredictable, high cost events for which the distribution determination does not provide a regulatory allowance.

A building block proposal may include a proposal as to the events that should be defined as pass through events, in addition to the events defined under clause 6.6.1(a)(1) of the rules.

Ausgrid has undertaken a thorough risk assessment of its operations using the bow-tie risk analysis methodology.[65] We have cross-checked the results of this analysis against our historical risk register and engaged Ernst & Young (EY) to review our key risks and advise on 1) the appropriateness and prudency of Ausgrid's risk management approach (including insurance arrangements) in light of the key risks that we face; and 2) the appropriate regulatory treatment of each risk based on Ausgrid's current/and or proposed risk management approach. EY's report is provided in Attachment 4.12.

From our analysis we have identified a number of risks which we consider should be managed via a nominated cost pass through event rather than an allowance in our regulatory proposal. Whilst Ausgrid does have in place prudent risk mitigation measures, the events we are proposing are those which are beyond our control to prevent, are expected to have significant or catastrophic cost impacts and have a low likelihood of occurrence.

We propose the following events be approved as part of our regulatory determination, which are to apply as nominated pass through events during the 2015-19 regulatory control period:

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

In proposing these events, we have had regard to the nominated pass through events considerations in chapter 10 of the rules and we consider that each event meets the necessary requirements to be approved as a nominated cost pass through event. Ausgrid's proposed definition for these events and detailed assessment of how these events meet the nominated pass through event considerations is provided in Attachment 4.13.

Further, Ausgrid considers that the AER's determination should provide for the pass through provisions of the rules to apply to alternative control services. The risks faced by DNSPs in relation to these services are the same as those faced in providing standard control services and the availability of cost pass through provisions is consistent with the basis of the control mechanisms which have been developed in relation to those services. This is also addressed further in Attachment 4.13.

Table 18 - Indicative DUOS prices for published tariffs[66] for 1 July 2014 to 30 June 2019 (c/kWh, nominal)[67]

Tariff classes	2014/15	2015/16	2016/17	2017/18	2018/19
Low Voltage	9.80	10.08	10.37	10.66	10.95
High Voltage	3.66	3.76	3.85	3.94	4.04
Sub-transmission	0.68	0.70	0.71	0.73	0.75
Unmetered	6.84	7.01	7.18	7.35	7.53

Table 19 shows indicative prices for Ausgrid's transmission standard control services for 2014-19 period.

Table 19 - Indicative prices for Ausgrid's TUOS for 1 July 2014 to 30 June 2019 (c/kWh, nominal)

Tariff classes	2014/15	2015/16	2016/17	2017/18	2018/19
Low Voltage	1.20	1.20	1.24	1.26	1.29
High Voltage	1.12	1.12	1.15	1.18	1.19
Sub-transmission	1.13	1.12	1.16	1.18	1.20
Unmetered	0.98	0.98	1.01	1.03	1.04

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

66 These do not include cost reflective network prices which are customer specific tariffs calculated for very large customers.

67 These prices are calculated by reference to the forecast revenue to be recovered from each tariff class and forecasts consumption within those classes.

5. Forecast capital expenditure

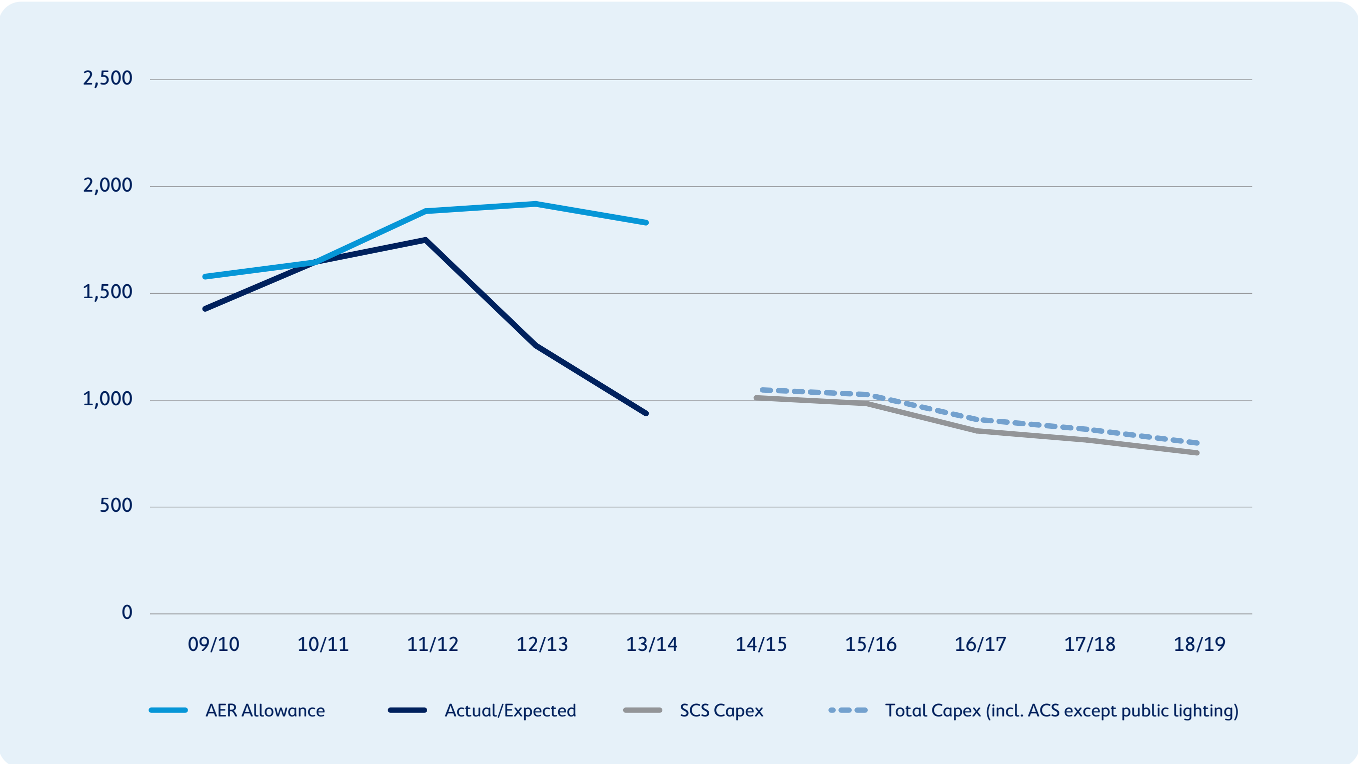
Our proposed capital program of $4.4 billion will ensure that we continue to comply with our reliability and safety obligations, while striving to contain average increases in our share of customers' electricity bills at or below CPI. Our carefully prioritised program of work will also enable us to sustain the long term health of the network.

Our proposed forecast capex for the 2014-19 regulatory control period is 37% lower than the actual capex we expect to incur for the 2009-14 period. This can be seen in Figure 8.

The forecast capital program represents a substantial reduction from the forecast in the previous submission. This reflects our expectation that the drivers and initiatives evident in the latter years of current period will continue to apply through to 2019.

Investment in the 2009-14 period has enabled Ausgrid to return the levels of network security and reliability to prudent levels, enabling us to meet the NSW Government's expectations, and to commence the long term process of renewal of the network, which had been delayed due to lack of funding in earlier periods.

Figure 8 – Comparative capex profile ($ million, 2013/14)[68]



68 It must be noted that we have included the line 'Total capex' only for comparative purpose. The 'SCS capex' reflects our proposed forecast capex for standard control services as they are defined by the AER's stage 1 F&A, applicable from 1 July 2014.

The 2009-14 period was characterised by an initial build up of capacity to deliver the much larger program that was forecast to be required. Several influences came together in the middle of the period that resulted in a rapid reduction in expenditure in the last two years. In part this was a result of delivery challenges, especially in Brownfield replacement projects that were more expensive and protracted than forecast. At the same time, better asset data collected since the forecasts of the 2008 submission progressively enabled Ausgrid to re-assess risk levels, and prioritise replacement investment requirements more effectively in light of these higher costs. The other main effect was the recognition that peak demand growth had plateaued, and improvements to demand forecasting provided the confidence to defer and avoid significant investments, in some cases indefinitely.

This lower than forecast level of investment over the 2009-14 period will be incorporated into the opening asset base for the coming period, sharing the benefits of the reduced expenditure with customers through lower prices.

The forecast 2014-19 investment program is focused on continuing the renewal of those parts of the network that represent a level of risk and cost that is best dealt with through replacement, with a continuing very low level of investment in augmentation (at around 16%). Continuing with the improved planning and investment prioritisation processes will lead to a lower, more sustainable level of capital investment in the network.

5.1 Outcomes in the 2009-14 period

The purpose of this section is to highlight the benefits we delivered our customers in the 2009-14 period. We also identify reasons for variation from the capex allowed by the AER. Together, this provides a level of assurance to the AER and our customers that:

- We have a track record in delivering promised outcomes to our customers.
- We have identified and addressed previous forecasting issues when developing our capex proposal for the 2009-14 period.

Further information on our outcomes in the 2009-14 period can be found in Attachment 5.01. We have also provided in Attachment 5.02, the network performance reports which are relevant to demonstrating the improvements we have made to network performance.

Focus of the current regulatory period

Ausgrid's investment program in the 2009-14 period improved security, reliability and safety of the network. The key drivers of investment were to replace ageing assets and to improve security and redundancy in the network, both of which had deteriorated significantly in previous regulatory periods.

Security and reliability

In the years prior to the current regulatory period, NSW DNSPs had been significantly under-investing in the network as a result of insufficient regulatory allowances. The ability to operate the network under contingency events had significantly declined, with a number of assets exceeding their rated capacity at peak times. It was recognised that good electricity industry asset management practice would require significant investment in the network, as could be seen from our experience at the time:

- In NSW we had experienced a number of significant outages and near misses.
- In Queensland, the Somerville inquiry found that excessive utilisation (loading) of assets and lack of contingency (back up) had led to large scale outages of the Queensland network in the summer of 2004.
- The ability to maintain and operate the network was being compromised by the high risk of taking assets off the network to perform required maintenance activities.

The NSW Government recognised the issue and in 2005 issued new licence conditions which were later revised and re-issued in 2007. The revised 2007 conditions required that we design the network to ensure better security of supply, and to improve reliability performance. The existence of these requirements simplified and facilitated a significant improvement over the current regulatory period.

Asset renewal

Our investment program was also aimed at replacing aged and deteriorated assets on the network, which had been subject to repeated life extension partly due to the same economic forces. We have some of the oldest network assets in Australia, with the average age increasing considerably in the 1990s and 2000s when replacement allowances had been constrained. Our focus was on replacing critical sub-transmission assets, where there were risks of large scale reliability and safety incidents.

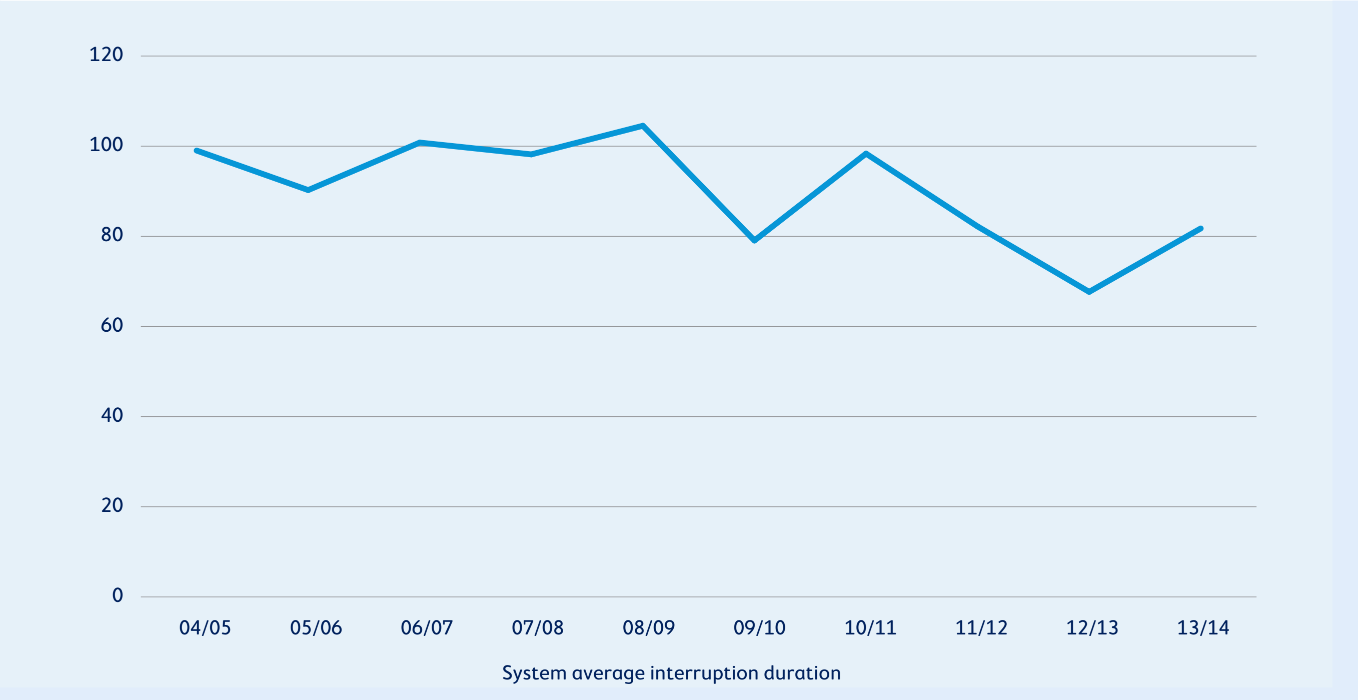
Outcomes in the current period

The sections below identify improvements we have made to reliability and safety for our customers from investment in the 2009-14 period.

Restoring supply security and delivering improved reliability

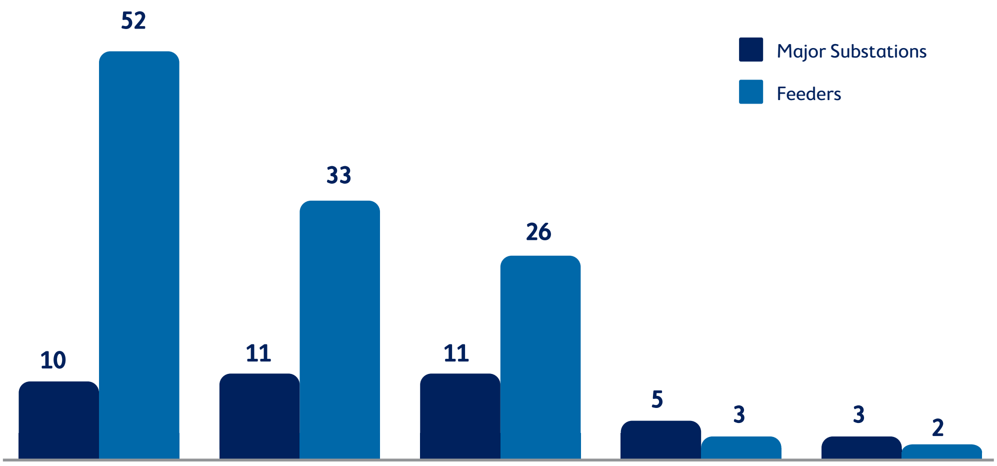
We have significantly improved our reliability performance in accordance with the increasingly stringent targets in the licence conditions that applied in the 2009-14 period. Figure 9 shows that an average customer experienced almost 22 minutes more interruption time in 2004/05, compared to average performance over the last 3 years. The frequency of interruptions has also declined by 34% over this time, from 1.29 outages per customer to 0.86 per customer per year.

Figure 9 – SAIDI performance for 2005-14 period (minutes)



Our improved reliability performance is due to significant investments related to the improvement of the security of our network. For example, Figure 10 shows that we significantly reduced the number of zone substations and subtransmission feeders that were loaded beyond prudent levels during 2009-14. The improvements in supply security were achieved primarily through restoring the level of available redundancy or 'back up' in the system. These works mean that our network is able to supply electricity when critical assets fail.

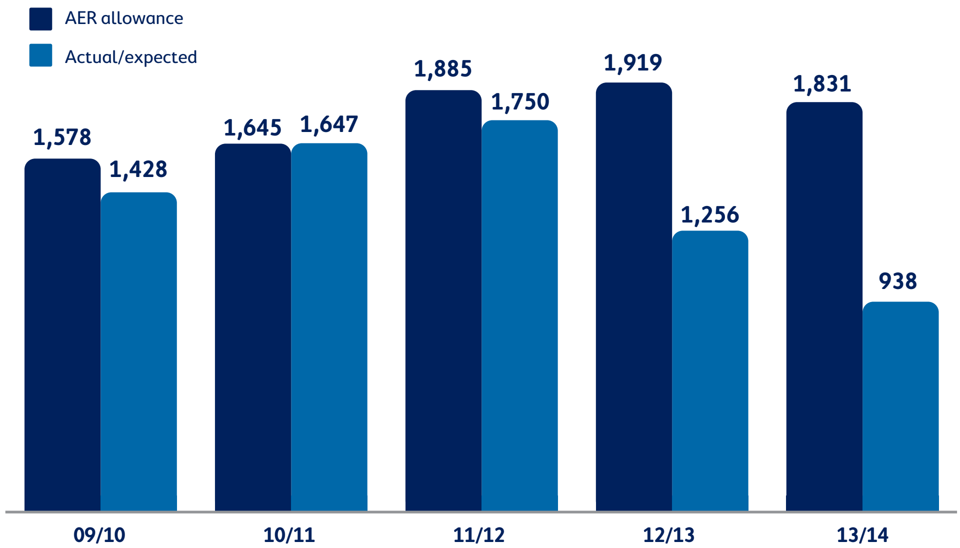
Figure 10 – Number of non-compliant major substations and feeders



How our supply security standards are applied at Green Square zone substation

At Green Square zone substation, there are three transformers. Each of them can supply about 55MVA of load. If one transformer is out of service for any reason, the substation can still supply 110MVA. With 110MVA of load connected, this substation would have a supply security level of 'n-1'. Our usual risk management practice would allow us to connect up to about 130MVA. At this level there are still enough periods of the year – where the load is under the 110 MVA – when one of the transformers can be disconnected for maintenance and the risk of a failure occurring on a day when the load is above 110MVA is acceptably small. We estimate the risk of coincident events to be less than 1%.

Figure 11 – Total capex spend relative to allowance for 2009-14 ($ million, 2013/14)



The new security standards have greatly reduced the probability of large scale outages, and allowed for improved operability of our network. For instance, the CBD subtransmission network has now been designed to supply electricity if 2 critical assets fail in service.

Replacing unsafe assets

Our replacement program has commenced removal of deteriorated assets that posed a potential safety risk to the public, workforce and customers. We also sought to replace assets that could cause serious environmental harm, or presented other risks or threatened non-compliance with legal obligations.

It is difficult to quantify the reduction in risks from the replacement program. A measure of our success is that we addressed failure rates for infrastructure that had serious safety risks. For example, we significantly reduced the uncontrolled failure rate of poles from 0.003% to 0.001% over the period.

Reasons for variation to forecast

Ausgrid spent a total of $7.0 billion ($2013/14) in the 2009-14 period, approximately 21% lower than the capex allowed by the AER for the 2009-14 determination. Figure 11 shows that we spent less than the capex allowance for most years of the regulatory period, with a significant proportion of the underspend occurring in the last 2 years of the period.

Under the incentive framework, our customers will share in the benefits of the under-spend. This is because customers pay lower prices when less capex is rolled into the regulatory asset base. Our analysis shows that a typical residential customer (5MWh pa) will benefit from electricity bills that are $51 per annum lower than they otherwise would have been had we incurred all of the allowed capex.

A relevant consideration for the AER is whether variations to forecast in the previous period have been explained and addressed in developing the forecast capex for the 2014-19 period. This is to provide assurance to the AER and our customers that there are no systematic forecasting errors underlying our proposed capex. In the sections below we identify the key reasons for variation and how these have been addressed in our forecast methodology for 2014-19.

While reductions in demand growth compared to forecasts can explain some of the reductions, we note that there have been a number of relevant factors that explain the reductions. In particular, we note that the reductions in capex are substantial in the last 2 years of the period, and this has been fundamentally driven by changes to our capital program as a result of industry reform. We also note that delivery issues also played a part in a lower capex profile to forecast, and that this was related to the significant increase in resourcing required to deliver the program.

Demand growth

Customer activity and demand growth has been lower than forecast in the 2009-14 period. A consequence was that we invested less capex to meet the lower than previously forecast increase in demand from new and existing customers. The key reasons why demand was lower than expected are:

- Lower than expected economic growth as a result of the global financial crisis (GFC). At the time of our revised proposal in 2009, we had not fully estimated the impacts of the GFC on economic confidence in NSW or the impact of the high Australian dollar on local manufacturing sector.
- Greater price sensitivity than forecast as a result of changes in network prices.
- Response to government programs and policies directed at energy efficiency including changes to appliances minimum energy performance standards (MEPS), building codes and incentive programs for products such as ceiling insulation.

In company with these underlying changes to the levels of growth in peak demand, we made substantial improvements to our demand forecasting methods. These enabled us to better predict the change in future demand and provided the confidence to make significant reductions and deferral of investment in capacity toward the end of the period.

This improved forecasting ability now considers a wider range of inputs and variables and provides a more certain basis for the low level of capacity investment we are projecting for the 2014-19 period. A comparison of the demand forecast for the last regulatory determination and our three latest forecasts is section 5.2, which demonstrates both a substantial improvement in forecast quality and the underlying moderation in growth expectations.

Anna Bay project deferred

In our original proposal for 2009-14, we expected we would need to build a new subtransmission substation at Anna Bay by 2014 to provide increased supply to the growing area of Nelson Bay. As a result of several annual reviews of our peak demand forecast, we have deferred the need for this $55m investment to at least 2023.

Efficiency from reforms

We recognise that the investment program in the 2009-14 period resulted in price shocks for our customers. In the last two years of the period, we focused on efficiencies and deferrals to reduce the price pressures faced by customers when transitioning to the 2014-19 period. A key catalyst was the NSW Government reform of the electricity distribution industry which has focused on ways of reducing the price burden of customers.

As part of this reform process, Ausgrid re-prioritised its program to respond to actual conditions experienced in the period and the ongoing development of more comprehensive asset condition data. For example, new data systems and prioritisation systems enabled us to better target our replacement program. Our forecast capex for 2014-19 has incorporated the improvements we have made over the period.

Delivery

Whilst not as significant as demand growth and efficiency from reform, delivery issues also had some impact on the variation between allowed and actual capex. The substantial investment program in the 2009-14 period placed delivery pressures on Ausgrid in the early years of the period. We responded to these pressures through outsourcing and Alliance delivery models, but in some cases our ability to plan and deliver the program fell behind due to factors such as extended community consultation, procurement lead times and complexities with Brownfield investment. Later in the program, we revised our delivery strategies to improve the cost of delivery.

We consider these delivery issues will not arise in the 2014-19 period due to developing better processes, and reduced workload from a smaller capital program.

5.2 Network strategy

The purpose of this section is to identify our network strategy that underpinned the development of our capex forecasts for the 2014-19 period. In doing so, we describe how our circumstances in the 2014-19 period have differed from our experiences in the current regulatory period, providing context for the significant variations between the forecast of required capex and actual capex in the current period, consistent with the rules requirements.[69]

Our network strategy aligns with the overarching purpose of our business, which is to be of service to our communities by efficiently distributing electricity to our customers in a way that is safe, reliable, sustainable and affordable. Affordability has been a key driver of developing our capex forecasts, with our primary objective to contain average network tariff increases to CPI. In doing so, we have responded to concerns raised by customers on the impact of rising network costs on household electricity bills.

While affordability has been a key focus, we will also be striving to provide a safe and reliable network for our customers.
In the sections below we identify the key drivers influencing the development of our capex program, and the underlying strategies that will address the drivers.

Circumstances influencing investment in 2014-19

In developing our network strategy, we have considered changes in our external and internal environment, relative to our current period. As noted at the beginning of the chapter, the proposed forecast capex is 37% lower than actual capex. The variation between actual and forecast expenditure for the 2014-19 period have been shaped by the following circumstances:

- We are proactively responding to the concerns of customers regarding electricity price pressures by identifying opportunities to defer capex and implement efficiencies. This continues the reforms introduced in the last 2 years of the current regulatory period where we tried to find efficiencies to reduce the price paid by customers in the next period. The efficiency reforms explain a significant decrease in the capex over the 2014-19 period compared to the early years of the 2009-14 period and has also explained the lower capex forecast in the 2014-19 period compared to actual capex in the current period. The efficiencies have influenced all elements of our capex programs including network and non-network assets.
- We still have a large number of old assets on our network. While we made strong inroads into removing degraded assets on the network in the 2009-14 period, it has been insufficient to arrest the deterioration of assets as a result of the continued ageing of the network. This has led to an increase in our proposed replacement over the 2014-19 period compared to the current period, and explains why our replacement accounts for a greater proportion of total capex.
- In the previous period we had to make significant investment to meet a higher security and reliability standard under our licence conditions. Having largely met this higher standard in the current period, we have more opportunity to return to lower levels of capacity investment. Further, changes in the NSW Licence conditions to apply from 1 July 2014 will also provide for greater flexibility in meeting those requirements, and we have reflected this opportunity in our expenditure forecasts. Despite this, we still need to invest in capacity to meet pockets of demand on our network, particularly from new customers. Overall, there has been a very significant decline in the need for investment in network expansion.

69 This information relates to the requirements in Schedule 6.1.1 (7) of the Rules.

Price pressures

Our method to forecast capex for the 2014-19 period has incorporated efficiencies, and prudent methods to defer capex. This has largely carried forward the reforms that we implemented in the last 2 years of the 2009-14 regulatory period. We have:

- Deferred capital works through prudent planning decisions: Deferrals and removals of our program based on better information and improved processes for managing risks. For example, we have deferred the timing of some of our proactive replacement programs by adjusting our risk parameters and refining the targeting of the programs. This reduces the level of activity in the capex program.
- Identified cost efficiencies in how we deliver our projects that have been incorporated into our final capex program. For example the Network Reform Program has focused on driving down the costs of delivering our capex programs through refinement of design standards and improvements in procurements, logistics and the cost of support activity such as fleets and IT.

Together our carefully prioritised and streamlined program has assisted us to meet our goal of striving to contain average increases in our share of customers' electricity bills at or below CPI.

Age and condition of network

While we have sought to focus and prioritise expenditure, our proposal recognises a continuing need to replace assets to avoid a decline in safety and reliability. The average age of our assets has increased despite investment in the 2009-14 period.

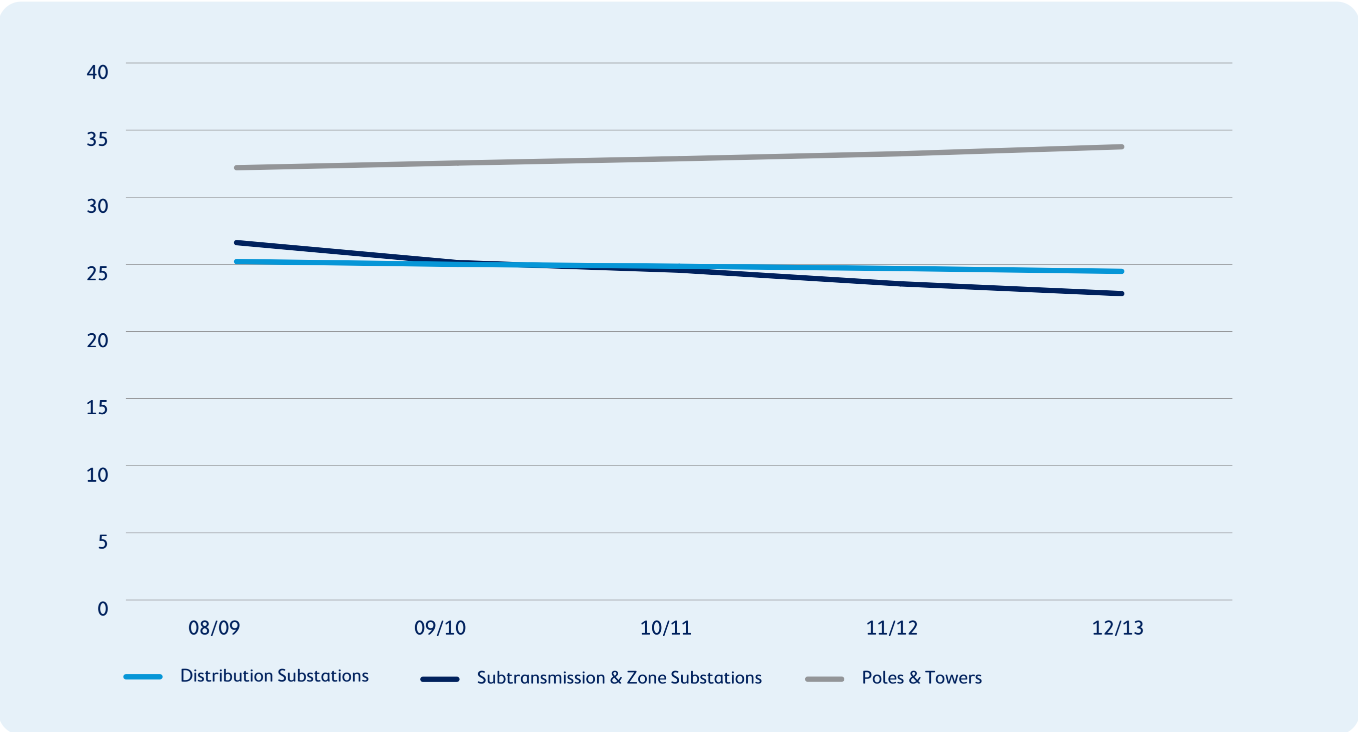
Figure 12 shows the change in the value weighted average age of several classes of our assets from 2009 to 2013. It demonstrates that the replacement investment over the period has had a significant effect on the mean age of our sub-transmission and zone substations, that the average age of distribution substations has remained effectively constant, and that the average age of poles and towers has increased.

This demonstrates the nature of our program over the period. Subtransmission and zone substations have been impacted by a proactive replacement program directed at the assets with the most significant condition issues and greatest failure consequences. The renewal effect of growth driven investments over the period has also contributed. The change in distribution substations, by contrast, is mainly a result of a small replacement program focused on the worst risks and a large impact from adding new assets – the total number of distribution centres has risen by 3-4% per year each year. In the case of poles, the replacement program is based on condition assessment of individual assets leading to replacement or life extension class. The aging profile demonstrates that this approach is enabling the risks associated with these assets to be managed while the overall profile ages.

Poles are also a good example of the potential impacts of a distorted asset age distribution. Of our almost 300,000 low voltage poles, 43% were installed before 1968 and are therefore already beyond what would normally be regarded as the 'standard age' of 45 years.

In a network with the volume of assets Ausgrid operates, and with an age profile distorted by the rapid expansion of the 1960s, renewal of large classes of assets must be addressed over time. Resource and operational constraints mean it is sometimes not feasible to replace large numbers of similarly aged assets "just in time". In these cases a renewal program must be staged over several regulatory periods. While our 2009-14 program has focused on those assets with the highest risk profiles, a large number of aged assets remain to be addressed over the next 10 to 15 years. The balance of our replacement program for the next period is weighted more towards the distribution network assets.

Figure 12 – Value weighted mean asset age by asset category (years)



Average age is a high level but relatively simplistic indicator of the health of the network. Our asset management strategy is based on in-depth condition assessment and analysis at the detailed asset class level. A more appropriate indicator of the success and drivers for our replacement program is failure statistics, and these form a key tool for developing our program. Figure 13 and Figure 14 show that overall corrective[70] and breakdown[71] failures have been stable or increased for both transmission and distribution assets types despite investment undertaken this period.

Figure 13 – Number of breakdown and corrective failures for 2009/10 - 2012/13 for distribution

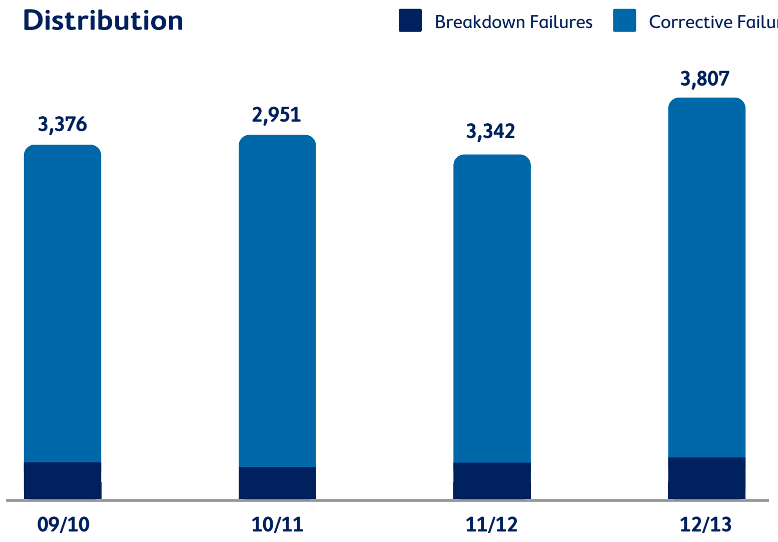
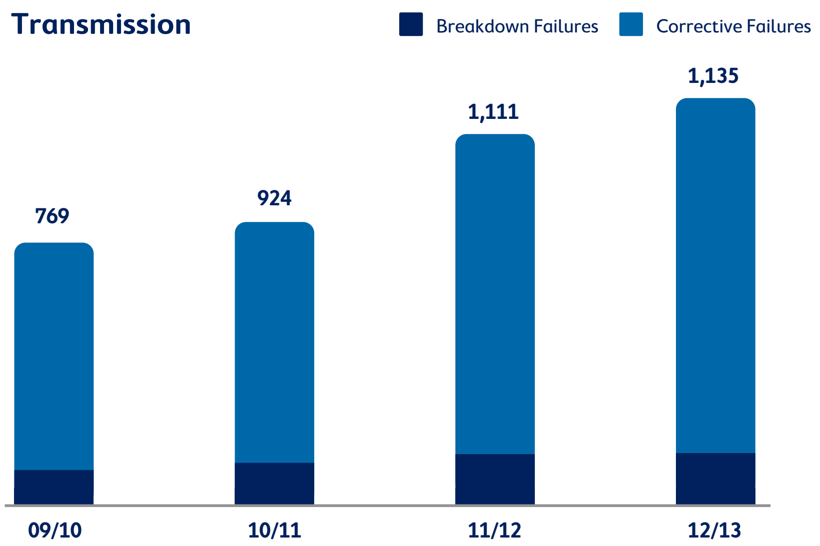


Figure 14 – Number of breakdown and corrective failures for 2009/10 - 2012/13 for transmission



The introduction of an integrated asset management system in 2009 has enabled a continuing improvement in data capture and improved analysis. Some of the upward trend in the failure data is due to this steady improvement in the recording and identification of failures. However, the underlying trend is certainly not decreasing and is at best stable. The ratio of corrective to breakdown failures suggests that our inspection and preventative maintenance programs are effective in capturing issues before they become in-service failures – effectively avoiding the higher consequences and costs.

These high level indicators of increasing asset age in most asset classes and steady or slightly increasing failure rates supports the outcome of our detailed condition based replacement planning. Our proposal is for a generally consistent overall level of replacement expenditure that represents a long term sustainable level of expenditure. Improved outcomes will come from ensuring that our maintenance and replacement planning is well targeted and prioritised to ensure that risks are managed at the most economical cost.

70 The correctives show the number of conditional issues identified during maintenance and addressed prior to failure, thus preventing a breakdown.

71 The breakdowns show the number of issues that, despite a well developed and implemented maintenance program, went through to full failure.

Pockets of demand growth and impact of changing licence conditions

We are required to invest in our network to meet increased demand for electricity from our customers. In the 2014-19 period, we will augment our network to connect new customers and to meet increased demand at peak times.

Overall, we expect only a moderate increase in customer activity and demand in the 2014-19 period. We forecast that summer system peak demand will grow at an average of 1.18% per annum and winter at 1.24% per annum for the 2014-19 period. This is historically lower than the levels experienced in the 2000s (average 3.14%), but is higher than the 2009-14 period (average 0.54%).

It is important to recognise that investment in the 2014-19 period is driven by areas of high growth on our network, rather than system wide demand. Figure 16 better illustrates that there is great diversity across Ausgrid's network with over 40 zone substations experiencing growth rates of more than 2% per annum on average. Our network strategy is focused on ensuring that there is sufficient capacity to meet the demands of new and existing customers in these areas of our network.

We note that the forecasts of load growth we have relied on are based on our spatial demand forecasts at our zone substations and sub-transmission substations, as this provides a more accurate basis for determining capacity needs on the network. Attachment 5.03 provides the forecasts we have relied on, while Attachment 5.04 provides the method used for developing those forecasts of load growth.[72]

Pockets of growth at West Menai

While we forecast average demand growth at the ten other zone substations in the Sutherland area to be only 2.5% in 2016/17, a new residential development proposed for West Menai will almost double the load on our Menai zone substation, i.e. 40 MVA.

Figure 15 – Ausgrid summer system peak demand (MW)

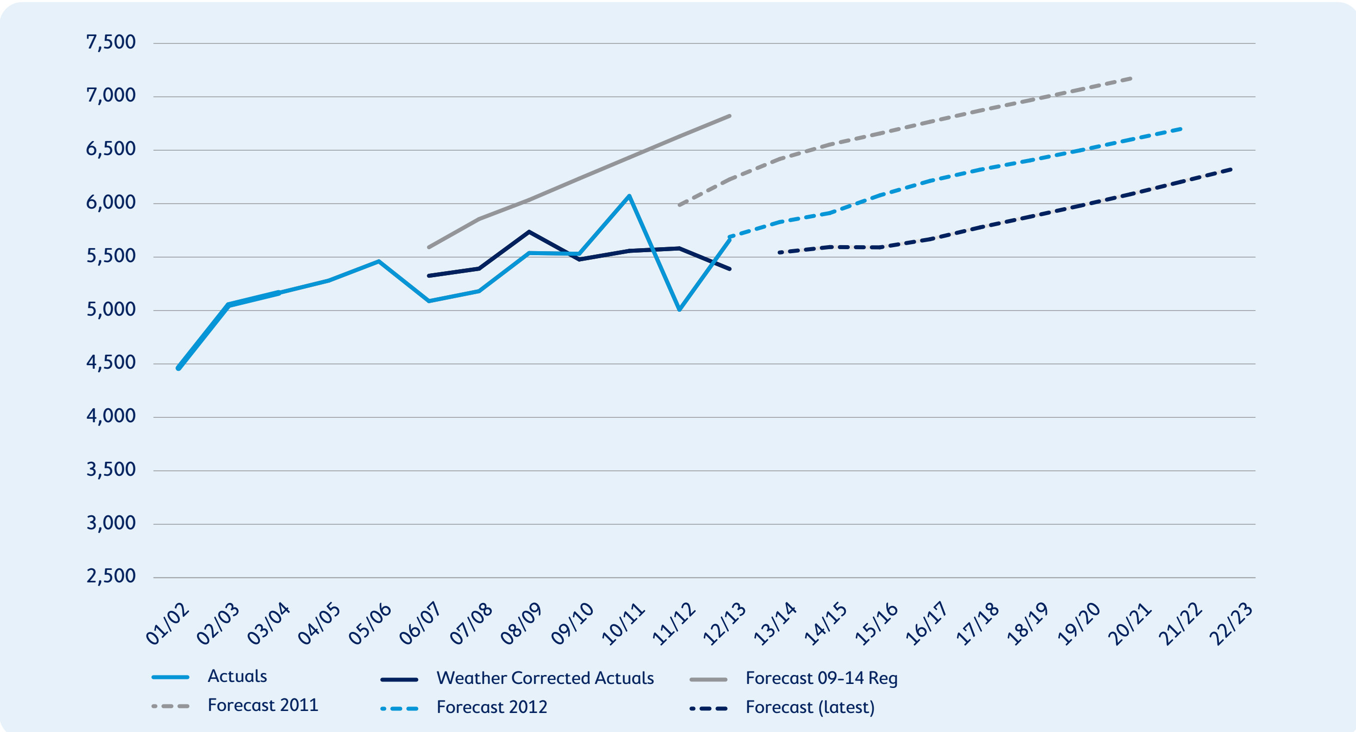
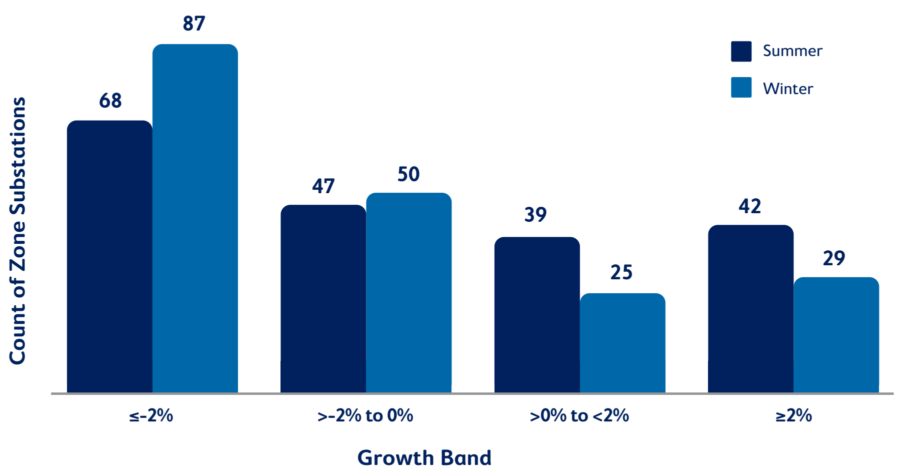


Figure 16 – Annualised growth rates for 2009/10 - 2013/14



72 This information relates to the requirements in Schedule 6.1.1 (3) of the Rules.

Growth in customer activity is a key driver of new connection expenditure, and is also a relevant factor in explaining diversity of growth rates across the network. In the next period we forecast an increase in residential housing and commercial connections. New residential connections are expected to increase in line with the projected building cycle from 8,000-10,000 per year this period to a high of almost 18,000 towards the end of the next period.

A key consideration we have taken into account is the change to the NSW Government licence conditions regarding design planning criteria, which will be effective 1 July 2014. In recognition of the likely increased flexibility this will enable, Ausgrid has adjusted the basis for its subtransmission planning and chosen more aggressive input assumptions for its modelled capacity investment programs.

Capex strategies

Our network strategy responds to our underlying drivers in the 2014-19 period to ensure that our proposed capex program is efficient and prudent in our circumstances. We have developed a number of underlying strategies to support our network objectives including customer value and engagement, asset management, demand management, and resource planning. Each of these strategies are discussed below.

Customer value and engagement

Through the reform process, we have developed a common vision for engaging with our customers. The ultimate goal is to ensure that customers receive an efficient energy distribution service that provides value for every dollar we spend.

A strategic and consistent approach to customer engagement over time will give us greater understanding of our customers' perspectives, and enable us to consider and accommodate their concerns in our planning and decision making processes where appropriate. In particular, we have responded to customers' concerns relating to high prices, and have developed our program in a way that maximises opportunities to defer investment, and leverage efficiencies.

Asset management strategy

The asset management framework adopted by Ausgrid recognises that efficient and prudent planning requires a lifecycle view of asset from needs identification, acquisition, use and maintenance and disposal of the asset.

Our asset management is broader than simply maintaining an existing asset. It extends to the identification of needs and the design and acquisition. Design standards are regularly reviewed and challenged as part of our value engineering approach. In some cases we standardise on design approach to reduce design, procurement and life cycle costs, and in some cases a more tailored bespoke design can be more efficient. For example, the design concept for one Cessnock substation was recently critically reviewed and optimised to reduce cost. Our delivery methods will continue to utilise a mix of internal and external resources with a view to achieving the most efficient outcome, provide benchmarking data and providing optimisation feedback into our standards and designs. This blend of internal and competitive external sourcing will be progressively enhanced across disciplines over the period. Equipment supply and resource intensive services such as civil construction will continue to be outsourced.

Further detail on our asset management strategy can be found on our supporting documents to our regulatory proposal.

Design optimisation at Cessnock

Our original design estimate for a replacement zone substation for Cessnock was $27m. We undertook a detailed design review and benchmarking exercise in conjunction with other NSW distributors, and identified staging options within the standard design and different construction approaches that led to a reduction in project cost to less than $19m.

Demand management

Demand management provides opportunities to cost effectively defer investment, and pass these savings onto our customers. In some cases, those benefits also extend to savings in the transmission and generation sectors, which multiply the benefits to customers. Demand management is an effective way to manage load factors and curtail investment in network capacity by reducing demand at peak times. Our demand management strategy for the 2014-19 period has focused on:

- Opportunities to defer specific projects – We have investigated ways to defer augmentation at specific sites of our network as an integral part of our capacity planning process. $2 million of operating expenditure for demand management programs is required to defer $22.8 million in growth capex investment over the period.
- Broad Based initiatives – We will also implement a number of initiatives that reduce system peak demand more generally across our network area, focused on building up impacts over time and delivering longer term benefits. The resulting reductions in demand have been incorporated into our peak demand forecast, and our capacity planning models for the distribution (11kV) system. $22.1 million of opex has been allocated for broad-based DM programs, and our analysis indicates that the program would break even after eight years taking into account only the benefits within the Ausgrid network. If the net benefits that flow to customers from reductions in the transmission and generation sector are included, the ten year NPV is estimated at $37.6m.

Further details of the demand management programs are provided in attachments and supporting documents to our proposed forecast opex, detailed in chapter 6.

Resource planning

An important aspect of the network strategy is to ensure the business has the capability to deliver the forecast capital program in an efficient and effective way. The importance of efficient program delivery is further elevated in the context of striving to contain average increases in our share of customers' electricity bills at or below CPI over the 2014-19 period.

A key feature of our delivery strategy for the next regulatory period focuses on optimising the mix of labour between internal and external resources. We will aim to utilise external resources in instances where they are able to safely deliver the desired outcomes and are more cost effective than in-house resourcing.[73]

[73] See Ausgrid Agreement 2012 clause 6.2.3

5.3 Forecast method

The rules require us to describe our method for developing the capex forecast for the 2014-19 period.[74] This provides a level of assurance to the AER and our customers that our forecast method is prudent and efficient.

Approach to capital planning

Ausgrid incurs capex to meet our regulatory obligations to provide a safe and reliable network. In the sections below we document our capital plans, drivers, and forecasting approaches at a high level. This is summarised in Table 20. Further details supporting our approach to capital planning can be found in Attachments 5.05 to 5.19.

Capital plans

The proposed method to forecast total capex for the 2014-19 period is based on the sum of eight capital plans.

Our network capital plans set capex requirements for assets used to convey electricity through the network. There are four types of capital plans relating to network assets including the area plans (covering major projects), the replacement and duty of care plan, the distribution capacity plans (including reinforcements and customer connections requiring augmentation of the network), and the reliability investment plan.

Our support (non-network) capital plans set out our capex requirements for assets that assist us to meet our network and corporate governance obligations, including underlying technology required to operate and manage the electricity network. Ausgrid has consolidated its requirements for support assets into four plans including the technology plan, the corporate property plan, the fleet plan and other support plan, which includes items such as plant and tools.

Drivers of investment

Each of our capital plans are based on meeting one or more driver of capex. Ausgrid only invests in capital when an appropriate driver exists to enable us to meet our regulatory obligations to provide an efficient, safe and reliable network.

- Asset condition and safety - Ausgrid undertakes replacement to ensure its network infrastructure is operated effectively and efficiently. There are a number of regulatory obligations that drive Ausgrid's investment including public safety, workplace safety, and environmental legislation. The key drivers of investment are:
  - Risk and cost trade-offs arising from the degradation in the condition of assets on the network.
  - Safety, environmental or other asset related risks.
- Need for increased delivery capacity[75] - The network is augmented to connect new customers, and to address imbalances in supply and demand. There are two drivers of investment. Firstly, where a new customer connection necessitates deep augmentation of the shared network. Secondly, where the aggregate demand from new and existing customers in the area is greater than the available capacity of the shared network. This may be driven by changes in either demand or capacity. As noted in our circumstances, driving investment, our decisions to augment the network have been influenced by changes in our licence conditions which provide more flexibility on when to invest in augmentation needs.
- Reliability investment - Investment is also required to comply with reliability performance targets in the NSW licence conditions. The main driver of investment is when there is forecast a gap in meeting mandated performance targets, after having taken into account the reliability benefits of other investment programs (e.g. reliability benefits of a replacement program or area plans capex).
- Network support drivers - Investment is required in support (non-network) assets to meet network and corporate functions. Support capex includes technology, corporate property and fleet, in addition to other support activities such as plant and tools. The key drivers of investment are:
  - Investment is required to support the network.
  - The condition of existing asset is forecast to be inadequate to perform its current function.
  - A new compliance obligation necessitates investment in a supporting asset.
  - A supporting asset will result in an efficiency benefit, resulting in long term benefit to customers.

Forecasting approaches

Our capital plans have been based on deriving capex related to standard control services only. In particular:

- We have applied our approved cost allocation method (CAM) to ensure our forecast capex is appropriately allocated to standard control services.[76] The approved CAM is in Attachment 5.10.
- We have applied our proposed connection policy to identify the forecast capex that relate to standard control services, in contrast to capex that customers directly fund. Our proposed connection policy is set out in Attachment 5.11. We note that the connection policy approved by the AER as part of the distribution determination for 2014-19 period will need to be revised each year to include prices for alternative control services that are approved by the AER as part of Ausgrid's annual pricing proposal.
- We have applied our capitalisation policy in Attachment 5.12 to identify the forecast expenditure that is related to capex, and which sets out the basis on which we capitalise our costs. In this respect, we note that the policy is based on appropriate accounting standards and ensures we do not capitalise operating expenditure.[77]

For the majority of plans, Ausgrid has used a 'bottom up' ('zero based') method to derive the forecast capex in its capital plans. This is consistent with a business as usual approach to developing capital forecasts. Ausgrid's method relies on the following principles for selecting efficient and prudent investment:

- Ausgrid identifies the need and required timing, in accordance with the capex drivers discussed above.
- Consideration of all feasible options to address the need, and select the option which is least cost or maximises benefits in net present terms.

In other cases, Ausgrid has used top down approaches to derive its forecasts. This generally involves a modeling approach to estimate future capex based on 'fit for purpose' considerations such as historical expenditure, and future drivers including changes in the number of connections.

74 This information relates to the requirements in Schedule 6.1.1 (2) of the rules.

75 We referred to this driver as growth in peak demand in the expenditure forecasting methods statement. The terminology changed to more accurately describe the driver.

76 To be clear, this refers to standard control services as they are classified by the AER in its Stage 1 F&A paper applicable from 1 July 2014.

77 This information relates to the requirements in schedule 6.1.1 (8) of the rules.

Table 20 – Forecasting methods and drivers for capital plans

Capital plans	Key forecasting methods		Key plan drivers			
	Bottom up	Top down	Capacity	Asset condition & safety	Reliability compliance	Network support
Area plans	✓		✓	✓		
Replacement and duty of care plans	✓			✓		
Distribution capacity plan		✓	✓			
Reliability investment plan		✓	✓		✓	
Technology plan	✓		✓	✓		✓[78]
Corporate property plan	✓					✓
Fleet plan	✓					✓[79]
Other support plan	✓					✓

Prioritisation of program

A key aspect of our forecasting method was to apply the outcomes of a prioritisation process that was centrally coordinated across the 3 NSW DNSPs. The objective of the process was to identify prudent opportunities to defer or avoid capital expenditure based on an assessment of relative risk such that we could minimise our requirement for investment funding and better meet our goal of customer affordability. The prioritisation process was conducted in parallel with Ausgrid's planning processes, and each informed the other to arrive at the resulting capital expenditure forecast. The key components of the prioritisation process were:

- At several points in the development of the expenditure plans, Ausgrid identified a full suite of projects and programs that would comprise the proposed expenditure portfolio. This was at a granular level involving between 400 and 500 individual line items.
- Each project or program was assigned a risk ranking, based on a consistent methodology for assessing risk. The consistent application of a single approach by each of the NNSW businesses allowed us to objectively rank projects across the 3 businesses in a consistent way.
- A process of feedback and iteration refined the plans and risk assessments as the expenditure forecasts were refined with multiple passes through the risk prioritisation tool.

A Board level review of the overall risk profile and the relationship between risk and different scenarios of expenditure identified the prudent level of capital investment which forms the basis of our expenditure forecast. It should be noted that the resultant expenditure level took into account the prudent risk level in Ausgrid's circumstances of Ausgrid, and was not dependent or related to overall risk across the 3 NSW DNSPs.

Costing the programs

Ausgrid has largely used historic costs to determine the expected costs of completing works, and has modified this to reflect detailed planning, and potential efficiencies and for some areas we use external independent estimating databases as the source of inputs (for example, major substation construction cost estimates). As part of our forecasting process we have proactively considered efficiencies in design scope and delivery costs. Further information on how we have cost our proposed program of works is set out in Attachment 5.15. Further detailed information on unit costs for each program is contained in our individual plans.

We have escalated our costs to reflect the expected real change in costs over the 2014-19 period. Ausgrid has developed real cost escalators by identifying the elements of costs for each of its programs, such as labour, material type and contracted labour. We have then identified the real cost escalator for each element of service using independent market data or economic analysis. As noted in the next section, the labour escalation values we have used for our forecasts are a key assumption underlying our forecast capex.

[78] The forecast includes a number of initiatives to support productivity savings in the network business.

[79] Fleet forecast capex includes the benefits from initiatives to reduce fleet cost. These initiatives involve extension of replacement cycle, fleet standardisation and improved buying power to realise maximum value.

Table 21 – Ausgrid's key assumptions

Key assumption	Activities
Legal and organisational structure	The legal entity, ownership and organisational structure are those in place at the time forecasts are finalised.
Amendments to reliability and planning licence conditions	The capital program has been prepared on the basis of amendments to the NSW design reliability and planning licence conditions that will come into effect on 1 July 2014.
Strategic management framework	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.
Forecasts of demand	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.
Labour cost escalation	Forecast labour cost escalation has been set consistent with our enterprise bargaining agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".
Customer engagement	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.
Transitional service agreement	Ausgrid has supplied transitional services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination is yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan time line is achieved.

Key forecast assumptions

The rules require us to identify the key assumptions that underlie the capex forecast. Table 21 summarises the key assumptions that underlie our forecast of required capital expenditure for the 2014-19 period, with further information on the reasonableness of each assumption provided in Attachment 5.13.[80] The rules also require a certification of the key assumptions that underlie that capex (and opex) forecast by the directors of Ausgrid. This certification is provided in Attachment 5.14.[81]

5.4 Proposed program

The purpose of this section is to:

- Identify the total forecast proposed by Ausgrid and to show how these relate to our investment plans and categories of capex.
- Provides a summary of the program including a snapshot by investment plan and capex category.
- Outline the key programs of work for our network and support capital plans respectively.

The majority of the program is to replace aged and deteriorated assets on the network. We also have proposed capex to augment the network to meet requirements from new customers and localised demand growth. In addition, we have a small program of works related to support assets such as IT and corporate property.

Attachment 5.20 sets out the forecast capex by plans. Further information on each of our investment plans is contained in the supporting documents of this proposal. For each plan, we have provided:

- An overview of the investment plans outlining actual expenditure in the current period, drivers of investment in 2014-19 relative to the current period, forecast method used, and a summary of the program.
- Additional supporting information including project justifications such as business cases or detailed reviews, and a description of our planning and costing processes.

In addition, we have provided further information on our capital program that addresses some of the requirements of schedule 6.1.1 of the rules including:

- Forecast of the required capital expenditure with reference to well accepted categories. Attachment 5.21 provides a forecast of capex by the asset classes in our post tax revenue model (PTRM) for distribution and transmission.[82]
- Capital expenditure for each of the past regulatory years, including actual capex for the previous period (2004-05 to 2008-09) and the first four years of the current period (2009-10 to 2013-14), and the expected capex for the current period inclusive of the transitional year (2013-14 to 2014-15). This has been provided by asset class consistent with the forecast of required capex above, and is also contained in Attachment 5.21. We note that capex in past regulatory years contains no margins paid or expected to be paid that do not reflect arms length terms, and therefore we consider schedule 6.1.1 (6)(i) does not apply. Similarly, we note that the reported capex in past regulatory years was properly allocated to capex based on our capitalisation policy, and does not relate to capitalising operating expenditure. For this reason schedule 6.1.1(6)(ii) does not apply.[83]
- Identification of proposed material projects including the location of the asset, the anticipated or known cost of the proposed asset, and the categories of distribution services which are to be provided by the asset. We note that the forecast of costs only relate to standard control services. This is contained in Attachment 5.22.[84]

80 This information relates to the requirements in Schedule 6.1.1 (4) of the rules.
81 This information relates to the requirements in Schedule 6.1.1 (5) of the rules.
82 This information relates to the requirements in Schedule 6.1.1 (1)(i) and (ii) of the rules.
83 This information relates to the requirements in Schedule 6.1.1 (6) of the rules.
84 This information relates to the requirements in Schedule 6.1.1 (iii),(iv) and (v) of the rules.

Summary of proposed program

The total (gross) forecast capital expenditure of $4,421 million ($2013/14) for the 2014-19 period is based on the outcomes of our investment plans. The forecast capex for each regulatory year is shown in Table 22.

Table 22 – Total capex ($ million, 2013/14)[85]

2014/15	2015/16	2016/17	2017/18	2018/19	Total
1,012	985	857	814	754	**4,421**

Note: Numbers may not add due to rounding

The forecast capex shown in Table 22 and in Figure 17 is expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the cost allocation method (CAM) approved by the AER on 2 May 2014. That is:

- Capex that is directly attributable to standard control services is allocated wholly to standard control services. This is the case for all system capex (area plans etc).
- Non system capex is allocated to standard control services, alternative control services and unregulated services based on the relevant allocators such as the number of FTEs.[86] For example, non system land and building capex is allocated to the various distribution services based on the FTEs.

Snapshot by investment plan

The majority of investment relates to network capital plans which account for over 90% of the total capex proposed. The remaining proposed capex is for support capital investment related to IT, property, fleet, plant and tools.

Figure 17 shows that our area plans and replacement and duty of care plans account for 76% of the total proposed capex. Distribution capacity plans account for 14% of total proposed capex, while reliability compliance accounts for less than 1%.

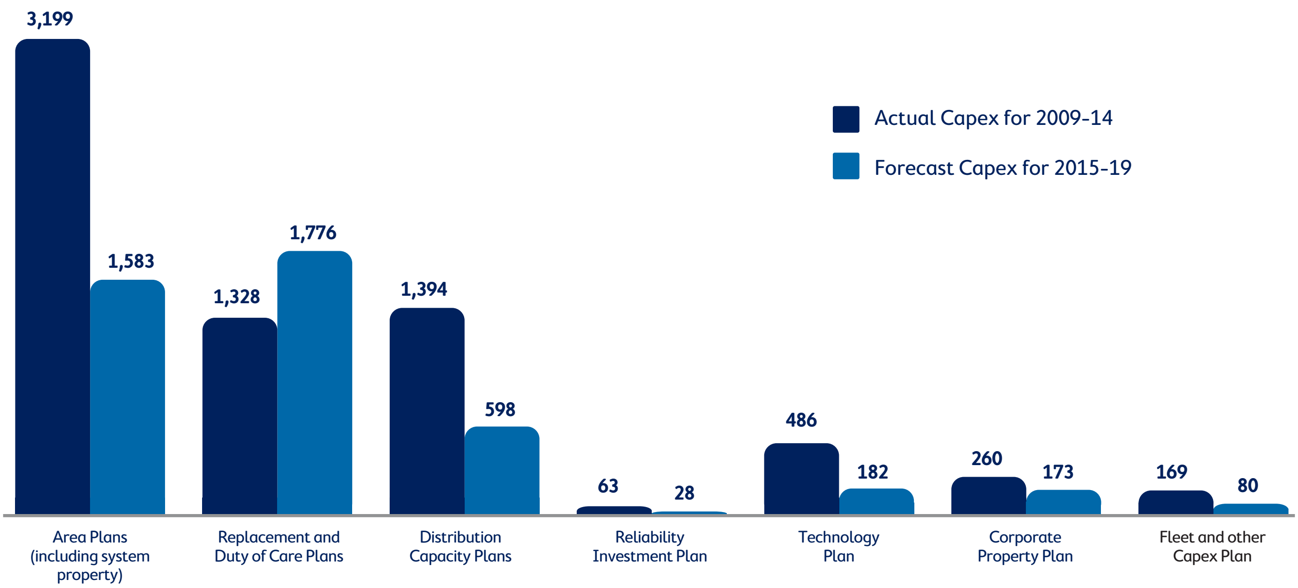
Snapshot by capex category

As required by the rules we have classified our total forecast in accordance with well accepted categories of capex, consistent with the drivers identified in our forecasting method document. The majority of capex relates to:

- Replacement to address asset condition and safety accounts for 73% of proposed capex.
- Augmentation to match capacity with peak demand and connect new customers accounts for 16% of proposed capex.
- Reliability investment to meet the performance standards in our licence conditions accounts for less than 1% of proposed capex.
- Investment in network support drivers including IT, corporate property and fleet account for approximately 10% of proposed capex.

In comparison with the previous period, the most significant change is in the capacity driven investment program. As a result of the changes in underlying growth in peak demand, the improvements in our forecasting confidence, the greater flexibility enabled by the change in licence conditions and the prioritisation process, our expenditure on capacity programs is forecast to be very significantly lower than in the previous period. This is shown in Figure 18.

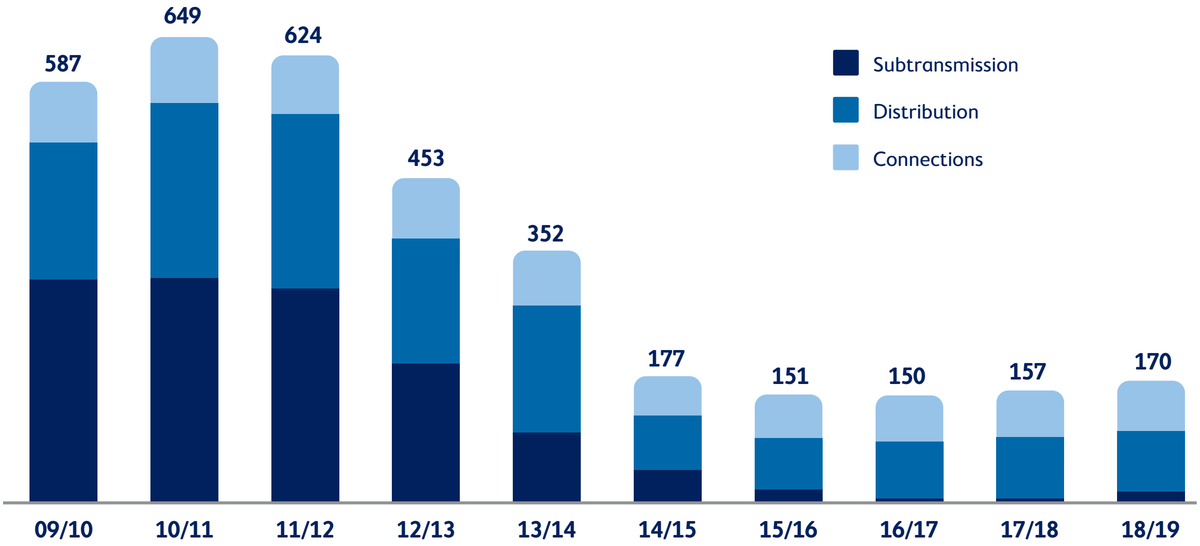
Figure 17 – Capex by plan for 2009-14 and 2014-19 periods ($ million, 2013/14)



[85] Excludes property remediation.

[86] See table 5 of the approved CAM.

Figure 18 – Change in capacity driven investment ($ million, 2013/14)[87]



This figure shows the very rapid decline in spending on augmentation of the network and the shift from investment in "backbone" elements to a proportionally greater focus in the lower voltage levels, consistent with the pockets of local growth view. Note also that the component of the capacity investment that is attributable directly to individual customer connections or developments becomes a much larger proportion when underlying growth is so low.

Network capital plans

In the section below we identify the key highlights of our programs for network capital plans. This includes a material replacement program for our oil and gas filled sub-transmission cables, and significant replacement of our aged distribution assets. Table 23 shows our total capex by program.

Area Plans

Our area plans identify augmentations and large (strategic) replacements on our sub-transmission network. We review 25 areas of our sub-transmission network and 3 transmission regions. For each area, we undertake a bottom up review of capital requirements.

We identify drivers of future investment including spatial demand, major customers and condition of large assets such as zone substations and transmission cables. A key feature of our approach is that we develop an optimal strategy that efficiently addresses the multiple drivers of investment in an area, leveraging synergies where possible.

We forecast capex of $1,582.8 million over the 2014-19 period. The majority of capex relates to replacement of large assets which is approximately 85% of the total forecast. The regions which account for the majority of our program are in the Sydney CBD, eastern suburbs, Canterbury-Bankstown area and in Sydney's Inner West. The key programs of work include the replacement of oil filled and gas filled sub-transmission cables, and 11kV switchgear replacement and retirement.

Table 23 – Total capex forecast by program ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Area plans (including system property)	485.0	427.5	268.3	225.7	176.3	**1,582.8**
Replacement and duty of care plans	313.2	334.1	365.0	373.4	390.3	**1,776.0**
Distribution capacity plans	110.9	111.1	121.6	128.8	125.3	**597.7**
Reliability investment plan	5.5	5.6	5.7	5.7	5.8	**28.3**
Technology plan	38.0	33.0	36.0	39.3	36.1	**182.3**
Corporate property plan	40.5	61.3	45.1	24.5	2.0	**173.3**
Fleet and other capex plan	18.4	12.4	15.1	16.7	17.9	**80.5**
Total capex	**1,011.5**	**984.9**	**856.8**	**814.0**	**753.8**	**4,421.0**

Note: Numbers may not add due to rounding

[87] Connection related ancillary network services are included to provide a like for like comparison between 2009-14 and 2014-19 periods.

The forecast expenditure for the area plans is $1.6 billion lower than the actual expenditure in the current period. The majority of this change is due to the significant reduction in capacity expenditure evident in Figure 18. About 25% of the reduction is due to the focus of our forward replacement expenditure being more toward the distribution level of the network.

Further explanation of the area plans is provided in the area plans overview which is included as Attachment 5.23 to this proposal. Additional details and supporting information relating to the area plans are also provided in the supporting documents.

Replacement and duty of care plans

Our replacement and duty of care plans identify all replacements of distribution network assets and smaller piecemeal replacement of sub-transmission assets that are not included in the area plans. Our method involves a bottom-up review of asset condition for different technology types on the network.

We forecast capex of $1,776.0 million over the 2014-19 period. The proposed expenditure is primarily to replace degraded assets due to condition, risk and compliance related issues. Our program of works includes replacing distribution mains and substations, and sub-transmission equipment. We are also forecasting capex for duty of care programs to meet compliance obligations and manage risks not arising necessarily from deterioration in asset condition. These programs relate to fire prevention, safety and the environment.

Further explanation of the replacement and duty of care plans is provided in the replacement and duty of care plans overview which is included as Attachment 5.24. Additional details and supporting information relating to the replacement and duty of care plans are also provided in the supporting documents.

Distribution capacity plans

Our distribution capacity plans identify forecast capex for augmentations on the distribution network. We forecast capex of $597.7 million over the 2014-19 period comprising of:

- $202.3 million for 'customer connection' capex. This is our forecast of capital works in the 2014-19 period for augmenting the shared network to enable connection of a customer. The forecast excludes the dedicated costs of connection that are funded by a customer in accordance with the connection policy.
- $202.3 million for reinforcement of the 11kV network, and $193.1 million for reinforcement of the Low Voltage network. These relate to the augmentation works to meet a combined increase in localised demand from existing and new customers. These works are not identified at the time a new customer connects to the network, but are diagnosed as part of our regular monitoring of the distribution network.

We have primarily used high level modeling to forecast capex for these plans as we do not have precise information on where new customers or localised demand will occur beyond a year or two into the future. Our models are based on analysis of expenditure in previous periods, connection policy decisions, and factors such as changes in demand and changes in customer connection activity.

Further explanation of the distribution capacity plans is provided in the distribution capacity plans overview which is included as Attachment 5.25. Additional details and supporting information relating to the distribution capacity plans are also provided in the supporting documents.

Reliability capex plans

The reliability investment plan includes any additional capex specifically required to meet reliability performance standards in the NSW reliability and performance licence conditions for electricity distributors (schedules 2 and 3) and customer expectations. These relate to average and individual reliability performance of 11kV feeders and feeder segments.

We have used a modeling approach to determine the capex required to meet our reliability standards, taking into account the reliability impact from other planned capex and opex programs. We also forecast requirements for reactive reliability improvement projects at the individual feeder and feeder segment level based on historical performance.

We forecast capex of $28.3 million over the 2014-19 period. The capex is to remediate individual feeders and feeder segments reactively that we forecast will not meet our performance standards. We have not forecast capex for the proactive increase of reliability.

Further explanation of the reliability plan is provided in the reliability plan overview which is included as Attachment 5.26. Additional details and supporting information relating to the reliability plan are also provided in the supporting documents.

Supporting investment plans

Supporting capex accounts for only 10% of the total program, compared with 13% in the 2009-14 period. IT expenditure accounts for approximately 4% of total capex with property, fleet and other capex accounting for 6% of total capex.

This reflects an underlying change in our business environment with lower system capex requirements and industry reform focused on efficiency savings. Our program has responded to the changes in the landscape by:

- Looking at ways to prioritise the program by deferring replacement of assets, or through consolidating our portfolio.
- Narrowing the suite of efficiency projects to those with short payback periods in terms of efficiency benefits in the 2014-19 period.

Technology plan

The technology plan comprises infrastructure, platforms, applications and devices required to support our network and corporate functions. This includes the operational technology required to control and manage our network.

We have used a bottom up approach to forecast capex on IT assets. This includes assessing needs with reference to key business processes such as asset management, workforce management and corporate functions. We forecast technology plan capex of $182.3 million over the 2014-19 period. The majority of capex is to maintain the currency of our existing IT services.

Further explanation of the technology plan is provided in the technology plan overview which is included as Attachment 5.27. Additional details and supporting information relating to the technology plan are also provided in the supporting documents.

Corporate property plan

The corporate property plan includes capex to support the housing of staff. It includes depots and office accommodation. We have used a bottom up approach to forecast capex for corporate property assets. This includes assessing the need with reference to the current condition of housing facilities, regulatory requirements and key changes in our business environment. We forecast capex of $173.3 million over the 2014-19 period. The majority of capex is to replace and/or upgrade nine ageing depots.

Further explanation of the corporate property plan is provided in the non-system property plan overview[88] which is included as Attachment 5.28. Additional details and supporting information relating to the corporate property plan are also provided in the supporting document.

Fleet and the other support capex plans

The fleet plan relates to vehicles and equipment used to provide our network services, and other capex such as plant and equipment. We have undertaken a 'bottom up' review of our requirements for the 2014-19 period. The majority of fleet capex is to replace heavy vehicles and plant used to maintain and construct network assets.

In addition to the fleet plan, we have also forecast our capex for other support capex such as plant and tools. Together, the fleet and other support capex plans total $80.5 million over the 2014-19 period.

Further explanation of the fleet plan is provided in the fleet plan overview which is included as Attachment 5.29 and the other supporting capex overview is in Attachment 5.30. Additional details and supporting information relating to the fleet plan are also provided in the supporting documents.

5.5 Meeting the rules

Ausgrid has proposed a total forecast capex for the 2014-19 period that Ausgrid considers is required in order to achieve each of the capital expenditure objectives (capex objectives) listed in clause 6.5.7(a) of the rules. The AER is required to make a decision on whether to accept or reject our total forecast capex. The AER must accept the total capex forecast if it is satisfied that the forecast of required capex reasonably reflects each of the capital expenditure criteria (capex criteria), having regard to the capital expenditure factors (capex factors).

To enable the AER to make its decision, the rules require Ausgrid to comply with specific information requirements in clause 6.5.7 and schedule 6.1.1 of the rules. This includes an obligation to comply with the requirements of any relevant regulatory information instrument.

In the sections below we briefly identify how we have met the capex objectives, criteria and factors. In our Attachment 5.31, we provide more detailed information.

Meeting the capex objectives

The rules states that Ausgrid's forecast opex must be the expenditure that Ausgrid considers is needed to achieve each of the outcomes listed in clause 6.5.7(a), known as the 'capital expenditure objectives' (capex objectives). These objectives are:[89]

- Meet or manage the expected demand for standard control services (objective 1).
- Comply with all applicable regulatory obligations or requirements (objective 2).
- Maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3).
- Maintain the safety of the distribution system through the supply of standard control services (objective 4).

Ausgrid's capital plans relate to one or more of the 4 capex objectives in the rules. Our network capital plans relate to investments we require to comply with our regulatory obligations as a DNSP to provide safe and reliable electricity services. For example, our jurisdictional obligations require us to meet performance standards, and to provide safe and reliable services. Our support plans set out investment needed to provide support in constructing our network in an efficient manner and to meet our general corporate obligations. In Table 24 we show how each of our capital plans relate to one or more objectives.

Table 24 – Forecast capex and the capex objectives

Capex cost group	Activities	Capex objectives achieved
Area plans	Capex on the sub-transmission network to: • Replace major assets to maintain safety of the network. • Increase capacity on the network (to meet demand and maintain security, reliability and quality of supply).	All capex objectives
Replacement and duty of care plans	Capex to replace distribution network assets and smaller piecemeal assets on the sub-transmission assets in order to maintain the safety of the network.	2 and 4
Distribution capacity plans	Capex to increase capacity on elements of the distribution network to meet demand, and to maintain security, reliability and quality of supply.	1 and 3
Reliability compliance plan	Capex that is required to meet reliability performance standards in the NSW design, reliability and planning (DRP) licence conditions.	2 and 3
Support plans	Capex on technology, corporate property and fleet to provide necessary supporting activity to undertake our network activities and fulfill our corporate obligations.	All capex objectives

88 The corporate property overview document is titled as "non-system property" to reflect internal Ausgrid terminology, and provide clarity that it excludes network related property costs.

89 See clause 6.5.6(a) for exact wording.

Meeting the capex criteria and factors

The AER must accept Ausgrid's forecast of required capex if it is satisfied that the total forecast capex reasonably reflects each of the opex criteria, being:

- The efficient costs of achieving the capex objectives.
- The costs that a prudent operator would require to achieve the capex objectives.
- A realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives.

In making this decision, the AER must have regard to the capex factors as well as the information included in or accompanying Ausgrid's regulatory proposal, written submissions and any analysis undertaken by or for the AER.[90]

At the time of our 2009-14 regulatory proposal, we engaged NERA to provide expert economic advice on the interpretation of the expenditure criteria and on how to demonstrate that our forecast expenditure reasonably reflects these criteria. In 2014, we engaged NERA to provide an updated view on its initial report in light of changes to the rules for economic regulation. NERA's advice is in Attachment 5.32.

An important element of NERA's advice was that there are no directly observable measures of efficiency. NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent. In this respect a number of the capex factors relate to the process used by the DNSP.
- Using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the capex factors represent partial checks of the forecast.

Forecast process

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. In terms of demonstrating that our forecasting process is efficient and prudent, we have provided evidence in Attachment 5.31 to show that:

- We have effective policies and procedures to inform our expenditure decisions and our planning processes.
- Our governance processes ensure that expenditure decisions are appropriately delegated and have effective financial controls.
- We have used a fit for purpose forecasting method which ensures there is no overlap or gap in our expenditure requirements, and uses appropriate methods for identifying investment on different parts of our network and network elements.
- We have a consistent and appropriate method for identifying investment need that takes into account our circumstances, and a rigorous approach for selecting of the most efficient option to address the need.

A key element of our forecasts process is the use of realistic expectation of the demand forecasts and costs inputs, consistent with the capex criteria in the rules. Ausgrid's planning process has incorporated accurate and up to date peak demand forecasts as part of the key inputs into developing capital plans. Ausgrid records peak demand at each of its 220 zone areas, and this provides an indication of trends in demand growth at different points in the network. Importantly, Ausgrid's forecast process is capable of excluding spot loads from trend growth, considering new connections in the short-term, and weather correcting.

In terms of cost estimates, we have used 'fit for purpose' methodologies to derive the costs of undertaking projects or programs of work in each capital plan. Our methodologies take into account historical experience, the specific nature of the program of work, and potential efficiencies that may arise. Our cost estimates have also taken into account expert opinion from economic forecasters on real cost escalation over the 2014-19 period.

In the Attachment 5.31, we have also addressed the capex factors in the rules that specifically relate to the forecasting process used by a DNSP. In summary:

- We have considered the substitution possibilities between operating and capital expenditure in developing our forecast capex.[91] A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions.
- Ausgrid has considered and made provision for efficient and prudent non-network alternatives.[92] We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. The savings from demand management initiatives have been incorporated into our capex forecasts.
- We have considered the relative prices of operating and capital inputs.[93] As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation.
- Our forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers.[94] We engaged customers on a range of issues including reliability, price, and demand management. The findings from our customer engagement support the basis of our proposed total capex including in relation to price affordability, and maintaining current levels of safety and reliability.
- Ausgrid's forecast method considered whether any projects or programs of expenditure should be identified as contingent projects, and therefore excluded from the total forecast capex for standard control services.[95] We found that no project met the criteria of a contingent projects set out in 6.6A.1 of the rules.
- Our forecast process identified that there have been no final project assessment reports at the time of submitting this proposal.[96]

90 Clauses 6.10.1(b) and 6.11.1(b) of the rules.
91 Capex factor 7
92 Capex factor 10
93 Capex factor 6
94 Capex factor 5A
95 Capex factor 9A
96 Capex factor 11

Indicators to assess the reasonableness of the forecast

Whilst there is no external, observable measure that can be relied upon to demonstrate that the total forecast expenditure is efficient, there are nevertheless partial indicators that assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 5.31 we have addressed the remaining capex factors that we consider may represent partial indicators of the efficient level of capex. In relation to actual and expected capital during any preceding regulatory control periods (capex factor 5), we consider there are 2 primary considerations that provide a partial check on the total forecast proposed:

- We have identified key variations to forecast capex in the 2009-14 period, and consider that these have been taken into account when developing forecasts in the next period. For example, we consider that lower demand forecasts were a key driver of reduced capex, and that our demand forecast process has improved considerably in preparing our 2014-19 forecasts.
- Our forecast capex for 2014-19 is substantially less than the 2009-14 period, and can be explained by key changes in our circumstances. In particular the lower capex has incorporated the efficiencies we have sought to achieve to make prices more affordable for our customers. While capex is lower in the 2014-19 period, we note that replacement is still required to maintain the safety of our network, and that capacity investment relates to localised spot loads on our network.

We note that previous expenditure analysis should be viewed in conjunction with whether the forecast is consistent with any incentive scheme that apply to the DNSP (capex factor 8). Under the ex-ante incentive regime applied to capex in the 2009-14 period, Ausgrid had strong incentives to prudently and efficiently reduce capex relative to the AER's allowance.

Ausgrid's actual capex in the 2009-14 period was considerably lower than forecast, particularly in the last 2 years of the period. In our view, this demonstrates that the reduction in capex was to improve affordability for customers in the next period, rather than to gain financial rewards. In this respect, customers benefited the most from reductions to the RAB which lowered prices when transitioning to the new period.[97]

The incentive regime has played a complementary role in the speed of our reform process, including re-orientation of strategies and planning processes towards meeting our goal of customer affordability. In this way, we consider that the AER can place weight on the efficiency of the forecasts for the 2014-19 period, providing a partial indication on the efficiency of our total capex.

The AER must also consider the most recent annual benchmarking report and the benchmark capital / operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (capex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data. The AER will be releasing its first benchmarking report in September 2014, and therefore we are not provided with an opportunity to demonstrate or make representations on this report at the time of submitting our regulatory proposal.

Ausgrid has developed a comprehensive benchmarking report provided in Attachment 5.33. The report examines the inherent limitations of benchmarking Australian DNSPs, and the role that benchmarking should play as a partial indicator of efficiency. Our analysis identified that benchmarking has inherent limitations such as inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We think that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. It should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool. In the report we also:

- Assessed the relative weight that should be applied to each of the benchmarking tools identified by the AER in its Forecast Expenditure Assessment Guidelines including economic analysis, aggregated category analysis, and cost category data including the augex and repex models. When deciding if a benchmark is appropriate, we have been guided by the Productivity Commission's review in 2013 which set out 6 criteria for when a benchmarking tool could be used in the process.
- Sought to understand the available data that can be used for benchmarking and reported on these outcomes. This was based on a Huegin Consulting study of 7 DNSPs in Australia. The Huegin study demonstrates that benchmarking is of limited value due to its inherent limitations, and that measures of efficiency more closely relate to the characteristics of the business rather than managerial decisions. Despite this, Huegin's report does provide some basis to show that Ausgrid is improving its efficiency over time relative to other peers in the study group.
- We have assessed the relative merits of the repex and augex model that the AER have developed. Our analysis of the models suggest that the models fail to meet the criteria of the Productivity Commission, and should be used with extreme caution. In the case of the augex model, we consider it to be highly flawed as an indicator of the efficiency of our capacity investments. The repex model should only be used for limited asset classes, where it can be demonstrated that it is fit for purpose. Even in these cases, we think the model is very limited and should only be used to assist the AER to target its detailed review of business cases.

Based on this approach, we have placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast and consider that the AER should do likewise in its assessment. Our analysis of benchmarking tools suggests that trends in a DNSP's results over time are of more value, that relative efficiencies between DNSPs at a point in time. In this respect the data provided does demonstrate that Ausgrid's growth rates in expenditure are among the lowest out of the peer group studies. Once again, however we draw caution on such results as they cannot capture the reasons for observed differences between DNSPs.

The final factor we have considered as a partial indicator of efficiency is the extent the capital expenditure forecast is referable to arrangements with another person that do not reflect arm's length terms (capex factor 9). We confirm that our forecast capex for 2014-19 does not include any arrangement with any other person that do not reflect arm's length terms.

97 The benefits of reductions in capex has been shared with the customer through a lower value in the regulatory asset base, resulting in lower prices when transitioning to the next regulatory period.

6. Forecast operating expenditure

We are proposing $2.8 billion ($ 2013/14) of operating expenditure for the 2014-19 period. This forecast includes a number of initiatives aimed to minimise the impact of necessary increases on our customers.

The purpose of this chapter is to outline our forecast opex for the 2014-19 period. We explain our performance for the current period, our circumstances for the next period and the plans we have to absorb necessary increases in our opex requirements. The key points of our proposed forecast opex are:

1. We need to keep our network safe and reliable and comply with our obligations.

Customers have indicated that they are concerned with network prices, particularly large increases in the past. But we are also obliged to meet our legislative and regulatory obligations as well as ensuring that the network is safe and reliable. Our forecast opex reflects these objectives.[98]

2. There are unavoidable upward pressures on our operating costs for the next period.

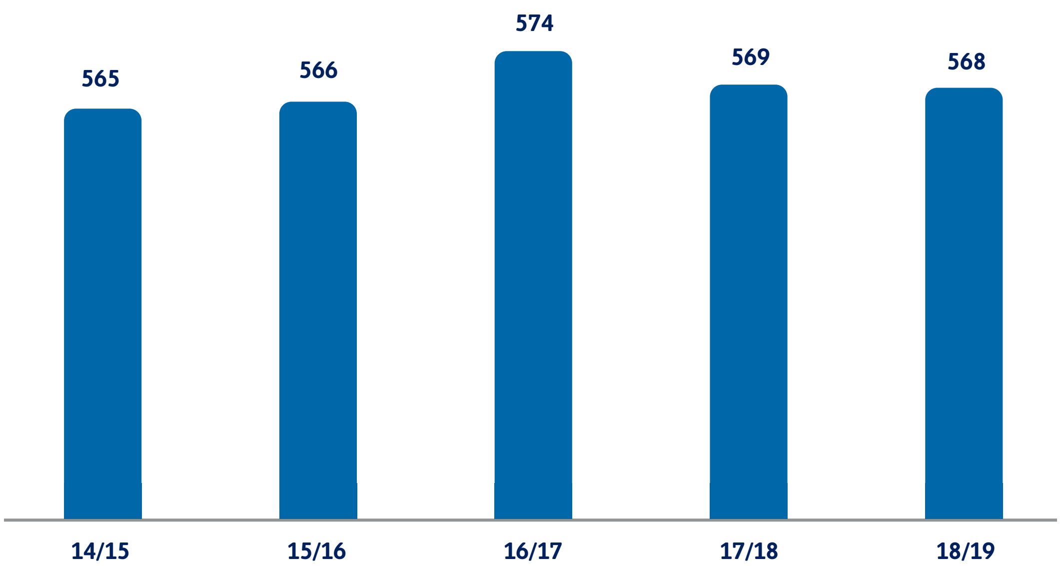
Whilst our performance during the current period has provided us with a solid platform going forward, there are however necessary increases in our opex requirements for the 2014-19 period. Nevertheless, we expect longer term benefits to result from these costs, in particular reform costs which will enable a lower opex cost requirement as we enter the 2019-2024 period.

3. We are minimising price pressures through efficiency savings.

We plan to find efficiency savings to offset these necessary opex increases so that we can strive to contain average increases in our share of customers' electricity bills at or below CPI.

Our forecast opex for the 2014-19 period is $2,843 million[99] ($ 2013/14). Figure 19 shows the forecast opex for each year of the 2014-19 period.

Figure 19 – Forecast opex for 2014-19 period ($ million, 2013/14)



98 These objectives are consistent with the operating expenditure objectives in clause 6.5.6(a) of the rules.
99 Excludes a debt raising cost total of $45.4 million ($2013/14)

This forecast represents the expenditure we consider would be required to achieve each of the operating expenditure objectives listed in clause 6.5.6(a) of the rules. It also reflects the expenditure that is properly allocated to standard control services in accordance with Ausgrid's approved CAM.

Our total forecast opex has been developed to achieve our overarching objectives for the next period, having had regard to (a) our performance during the current regulatory period and (b) our anticipated circumstances in the next period.

Our performance during the current period and our circumstances going forward then inform us on the plans we need to undertake to absorb increases in our opex requirements so as to achieve our objectives of balancing the need to ensure a safe and reliable network and supply of electricity, complying with our regulatory and legislative obligations whilst at the same time striving to contain average increases in our share of customers' electricity bills at or below CPI.

We have considered a primary concern of our customers, which is the high electricity prices to date, in approaching the forecasting of our opex requirement. In this context, Ausgrid is committed to strategies to deliver future cost savings and the proposed forecast opex includes the costs of implementing initiatives to achieve cost efficiencies. These are discussed further below.

Our proposed forecast opex therefore:

- Reasonably reflects the efficient amount that a prudent DNSP would require to achieve the opex objectives base on a realistic expectation of demand forecast and cost inputs.
- Is consistent with and gives effect to the national electricity objectives of promoting the efficient investment in, and efficient operation and use of, electricity services for the long term interest of customers with respect to price, quality, reliability and security of electricity supply and of the national electricity system.[100]

In the following sections, we explain our performance during the current period and our circumstances in the next five years.

6.1 Our performance in the current period

To appropriately forecast our operating expenditure requirement for the 2014-19 period, it is essential to understand our performance during the current period, particularly with respect to the efficient and prudent benchmark allowance approved by the AER.

Table 25 shows the comparison of Ausgrid's annual actual and expected opex against the approved allowance. It should be noted that the approved and actual/expected underlying opex includes expenditure relating to services that are classified as standard control services in the current period. This includes Type 5 and 6 metering services, ancillary services and emergency recoverable works.[101]

The total actual opex for the 2009-14 period is expected to be $2,941.2 million ($2013/14). This is $32.7 million (or 1%) below the efficient level set by the AER.

Ausgrid is subject to the EBSS for the 2009-14 period. The EBSS is a key element of incentive regulation employed by the AER to encourage the DNSP to be as efficient as possible.

Ausgrid has responded to the incentives within the regulatory framework. We have actively reviewed our strategies, policies, business processes and procedures so as to contain our total opex for the 2009-14 period within or below the efficient benchmark set by the AER. We undertook a number of cost saving initiatives to contain our outturn opex over the 2009-14 period. The Network Reform Process implemented under industry reform has enabled Ausgrid to make significant reductions in opex over the last 2 years of the period. The initiatives relate to:

- Streamlined operating model, which has led to significant reductions in FTEs by centralising and rationalising corporate and business support functions such as finance, human resources, procurement and business services.
- Reviewing our policies and procedures to eliminate any discretionary expenditure.

Table 25 - Comparison of opex ($ million, 2013/14)

	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Actual/expected[102]	598.6	584.5	645.2	520.9	592.0	**2,941.2**
Allowance	573.1	585.0	597.4	608.4	610.0	**2,973.9**
Difference	25.5	-0.5	47.8	-87.5	-18.0	**-32.7**

Note: Numbers may not add due to rounding

100 National Electricity Laws, clause 7.

101 Type 5 & 6 metering services and ancillary services are classified as alternative control services and emergency recoverable works are not classified, hence are unregulated services from 1 July 2014.

102 2013/14 amount of $592.0 million is the expected opex. It must also be noted that the approved and actual/expected opex relate to standard control services of the 2009-14 period (i.e. inclusive of Type 5-6 metering services and ancillary network services).

- Leveraging the functions of all three NSW DNSPs and by focusing our expenditure on core functions.
- Targeted capex and procurement efficiencies including a review of our fleet and procurement policies to ensure value for money. For example, we have undertaken joint consultancies with other NSW DNSPs to reduce our contracting costs.

Industry reform has been more than a set of “top down” initiatives. The reform process has elicited significant cultural change at Ausgrid. We now have more effective cost controls in place with a renewed focus on micro efficiency reforms in areas where there was room for cost savings such as:

- A review of work practices to ensure less overtime is needed to perform core functions. The total overtime expenditure for Ausgrid as a whole fell from approximately $96 million in 2011/12 to a forecast of approximately $40 million in 2013/14.
- Reductions in travel expenses by reducing flight and taxi usage.
- Reducing the number of staff who have access to fleet cars, which has led to significant reductions in fleet costs per FTE. In 2013/14 we are aiming to reduce our fleet by over 550 vehicles.

The efficiency improvements have been set out in Attachment 1.01. The attachment has been prepared by Networks NSW to identify the level of savings that have been achieved. Also in Attachment 5.01, we set out further details of our performance during the 2009-14 period with respect to capital and operating expenditure.

6.2 Drivers impacting our proposal for 2014-19

The rules require an explanation of any significant variations in the forecast opex from historical opex.[103] We address this requirement in this section by identifying the drivers impacting on our forecast opex requirement for the 2014-19 period. These factors constitute the reasons for variations between historical and forecast opex and are further explained in section 6.3.

Our concerted effort to reduce cost within the 2009-14 period, particularly in the last two years, has provided us with a solid platform so that we can meet our objective of containing average increases in our share of customers’ electricity bills at or below CPI over the forthcoming regulatory period. The underlying actual opex for 2012/13 therefore represents an efficient starting base to forecast our opex requirements for the next period as we have responded to the incentives to be efficient by containing our total opex within the allowance set by the AER for the current period.

Nevertheless, to ensure that our forecast opex reflects our expected expenditure requirements for the next period, we must consider a number of factors that would impact on this expenditure requirement. Generally, some of the factors that influence the level of opex required in the forthcoming regulatory control period are:

- Regulatory obligations and changes to these obligations or the introduction of new obligations.
- Ausgrid’s environment and changes to this operating environment since the last determination. The change in operating environment necessitates costs of implementing initiatives required to move the business to a more sustainable and efficient cost structure as a network only business.
- The current condition of our asset.
- The inherent relationship between forecast capital and operating expenditure.
- Forecast cost of inputs (i.e. labour, materials etc).
- Implementation costs supporting reform initiatives.

We have considered the impact of these factors on our operating expenditure needs for the next period. We have used the actual underlying opex of the financial year 2012/13 as the efficient starting base. To this base we incorporated the impact of the following factors to ensure that our forecast reflects our future needs. These factors, therefore, represent the reasons for the significant changes between historical opex and forecast opex.

These specific factors are:

- Additional cost of inspecting private mains to comply with our legislative and regulatory obligations.
- Additional costs associated with a more comprehensive asbestos audit and inspection programs to comply with the Work, Health and Safety Act.
- Leaseback cost of one of our corporate buildings that has been sold and the settlement of which is expected to occur in June 2014. The leaseback is for the period up to 2016/17 and the additional cost will be more than offset by the lower return on and of capital as the proceeds from the sale of this asset will be deducted from the value of the RAB.
- Demand management initiatives which will provide positive returns with the deferral of capex and reduction of peak demand.
- Forecast changes in the prices of inputs. We anticipate that rate of increases in labour costs and contracted services costs for the next period to be above expected CPI (i.e. real cost escalation based on forecast of Independent Economics).

In addition to these factors (which tend to occur frequently from regulatory period to regulatory period) Ausgrid also faces other unique factors in the 2014-19 period that will put upward pressures on our costs. These specific factors are:

- Loss of synergy costs (approximately $65 million) from the cessation of the transitional service agreement (TSA) with EnergyAustralia (formerly TRUenergy). These are fixed operating costs which are shared between distributions services and unregulated services (i.e. TSA). With the expected cessation of the TSA at the end of November 2014, we will lose this synergy of being an integrated business, resulting in increases in the operating expenditure needed to provide standard control services. Our forecast includes a number of initiatives to ensure by 2017/18 the loss of synergy costs are offset by efficiency in the network business.
- Impact of transitioning to the new cost allocation method approved by the AER. The allocators for some shared costs used in the CAM applicable to the 2009-14 period have now been rationalised under the new CAM applicable from 1 July 2014. The main change is the use of weighted average revenue as opposed weighted average operating expenditure.

The above factors are further explained in section 6.3.

Our performance in the current period and the circumstances we are expecting to face in the next period are critical factors we must take into account in developing forecast operating expenditure for the 2014-19 period. In addition to these factors, the rules also require the AER, in making its decision on whether to accept the proposed forecast opex, to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by Ausgrid in the course of its engagement with customers.[104]

One of the findings from our engagement is customers’ concern about electricity prices. Mindful of these concerns, Ausgrid’s forecast

[103] Clause S6.1.2(8)
[104] Clause 6.5.6(e)(5A)

expenditure contains savings to ensure that there is nil bill impact to customers as a result of:

- Losing the synergies of no longer being an integrated Network / Retail business after the cessation of the TSA by 2017/18.
- Transitioning to the new cost allocation method approved by the AER on 2 May 2014 by 2016/17.

Further, the forecast opex also include costs of implementing initiatives to attain a more sustainable and efficient cost structure.

We therefore have forecast a total opex requirement for the next period of $2,842.9 million ($2013/14). Having taken into account our performance in the current period, the circumstances we expect to face in the 2014-19 period as well as customers' concerns, Ausgrid considers that this total proposed forecast is the efficient amount that a prudent DNSP would require to achieve the operating expenditure objectives and reflects a realistic expectation of the demand forecasts and cost inputs. Our opex requirement also supports the necessary investment to continue to drive to an efficient cost structure.

This total forecast opex has been developed using a method that accounts for all of these factors, namely, our performance for the current period, the drivers of opex requirement for the next period and the concerns that customers have indicated through our engagement with them. We explain further below the forecasting method used and the impact of the above factors on the opex requirements for the next period.

6.3 Forecast methodology

The rules require us to provide information on the method/s used for developing the forecast opex as well the forecast of key variables and the key assumptions underlying the forecast opex. We outline this information in this section. A forecast model and explanatory statement are also provided in Attachments 6.01 and 6.02 respectively.[105] Other forecast models are also provided as part of the supporting documents to chapter 6.

Forecast methods

In the previous section we outlined our performance for the current period, our anticipated circumstances for the next period as well our strategies to achieve our overarching objectives in light of these factors. The forecast method/s we adopted embodied these factors and translates them into a forecast opex that reasonably reflects:

- The efficient costs of achieving the opex objectives.
- The costs that a prudent operator would require to achieve the opex objectives.
- A realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

We have adopted a 'fit for purpose' approach to forecasting our operating expenditure for the forthcoming regulatory control period. This approach is as follows:

- Disaggregate Ausgrid's total opex into various cost categories.[106] These cost categories represent the costs of undertaking a set of related activities to provide standard control services and to achieve the opex objectives (for example, maintenance opex, system control, finance, human resources etc).
- Assess the nature of each cost category and determine the appropriate forecasting method that would result in a forecast cost that reasonably reflects the efficient cost that a prudent operator would need to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs for that particular cost category.

We consider that this 'fit for purpose' forecasting approach ensures that the nature of each cost category and its relevant underlying drivers are appropriately accounted for, such that the resulting forecast opex is reflective of the efficient costs that a prudent operator would require to achieve the opex objectives.

Table 26 – Forecast opex requirements ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Maintenance	243.7	247.4	252.6	257.9	263.7	**1,265.2**
Operations & support	307.5	313.5	322.7	315.7	321.1	**1,580.5**
Other opex	4.2	8.6	7.3	8.2	9.0	**37.3**
Total business as usual opex	**555.4**	**569.5**	**582.5**	**581.8**	**593.7**	**2,882.9**
TSA loss of synergy costs	5.3	14.4	14.6	14.8	15.0	**64.1**
Impact of transitioning to new CAM	3.9	4.0	4.2	4.3	4.4	**20.8**
Total costs without efficiency measures	**564.6**	**587.9**	**601.3**	**600.9**	**613.1**	**2,967.8**
Efficiency initiatives implementation costs	31.8	21.3	24.5	20.0	7.8	**105.5**
Efficiency / productivity savings	-31.3	-43.0	-51.6	-52.0	-52.5	**-230.4**
TOTAL FORECAST OPEX	**565.1**	**566.2**	**574.2**	**568.9**	**568.4**	**2,842.9**

Note: Numbers may not add due to rounding

105 Clause S6.1.2(2) and (3) and RIN 10.1(a)

106 Clause S6.1.2(1) requires Ausgrid to identify the forecast opex by reference to well accepted categories.

Table 27 – Summary of forecast methods

Group	Cost category	Base year	Base year variation by volume	Base year historical averaging	Bottom up	'Top down' approach	Other
Maintenance	Inspection – vegetation management	✓					
	Inspection – all other costs		✓				
	Corrective	✓					
	Breakdown	✓					
	Nature induced breakdown			✓			
	Non-direct maintenance	✓					
	Engineering support	✓					
Operation and support		Either base year or bottom up or combination thereof					
Other opex	Cost savings / productivity improvement					✓	
	Non network alternative programs				✓[107]		
	Debt raising cost						✓ i.e. AER's method

Our total forecast opex comprises of the following broad groups with various cost categories for each group. These are:

- ***System maintenance opex.*** This cost relates to maintenance activities on Ausgrid's network. The cost categories within this group are:
  - Inspection.
  - Corrective.
  - Breakdown.
  - Nature induced breakdown.
  - Engineering and non direct maintenance.
- ***Operation and business support opex.*** This cost relates to the operation of Ausgrid's network system and the operation of Ausgrid as a business. The cost categories within this group are:
  - Network operations including engineering support, planning and project management, customer operations and system control.
  - Information, communication and technology.
  - Property management.
  - Training and development.
  - Metering.
  - Other operations and business support costs such as contact centre, finance, insurance, fleet and logistics management, human resources management, workers compensation, occupational health and safety, management and regulation.
- ***Other opex.*** This is demand management costs.

In addition to the above costs, Ausgrid has also proposed a debt raising cost $45.4 million ($2013/14).

The method/s we used to forecast each of the above cost categories are:

- Base year approach or variants thereof. These variants are:
  - Base year method – variation by volume.
  - Base year method – historical averaging.
- The bottom up method.
- In relation to debt raising cost, we have used the AER's method.

Table 27 shows the applicable forecasting method for each cost category. Each of the forecasting methods is further discussed below.

107 A small component of this cost will be forecasted using the base year approach

Base year method

The base year method is commonly used by the DNSPs and the AER to develop forecast opex. We use this method to forecast the majority of our costs because opex is largely a recurrent expenditure. The base year method is appropriate for forecasting recurrent expenditure because the base year amount encapsulates the actual annual cost currently required by Ausgrid to provide standard control services.[108]

This current actual cost is then adjusted to account for future changes in Ausgrid's circumstances, operating environment, regulatory obligations and changes in demand and cost inputs in arriving at a forecast opex. This is to ensure that all known factors affecting Ausgrid's future opex requirements are appropriately accounted for.

We have used the actual opex we incurred for the regulatory year 2012/13 to derive the efficient underlying opex base. The actual 2012/13 opex is the latest available actual opex at the time of preparing the forecast opex for the next five years. This actual opex had also been audited and provided to the AER, and was below the AER's allowance for that year.

The efficient underlying starting opex base to forecast our requirements for the next five years is $544.6 million. We consider this amount represents an efficient underlying base opex as:

- It is slightly below the average underlying actual and expected opex for the 2009-14 period, as can be seen in Table 28.
- It incorporates efficiencies from business process improvements.

This underlying opex was derived from the actual total opex for 2012/13 after excluding the actuarial component of long service leave costs to ensure that opex base amount is reflective of the underlying ongoing costs for the next 5 years. Cost escalation and change factors are then applied to this underlying opex.

The $503.6 million opex incurred in 2012/13 contains year-end adjustments to reflect actuarial gains and loss in the assessments of our long service leave obligations. Actuarial gains and losses are changes in the present value of these obligations. These gains and losses resulted from adjustments made to reflect the differences between the previous actuarial assumptions and what had actually occurred as well as the effect of changes in actuarial assumptions (e.g. model discount rates). These adjustments are included in our actual opex for 2012/13 as required by Accounting Standards; however, they have been excluded from the base opex to ensure that the base opex amount, upon which cost escalation and change factors are applied, reflects the underlying ongoing opex needed to undertake the required activities to provide standard control services. This approach is consistent with that used to forecast our current period opex allowance approved by the AER.[109]

We note that in recent decisions, the AER had reversed 'movement in provisions' from the base amount to reflect the cash payout rather than the amount accrued. The AER's approach effectively represents 'cash accounting' instead of 'accrual accounting'. Under the AER's approach, the forecast opex would reflect the estimated cash to be paid in the next five years in relation to provisions liabilities. Under the accrual approach we have adopted, the forecast opex represents the amount that accrues (e.g. long service leave, annual leave) based on actual year to date results.

We had not adopted the AER's approach of cash accounting because it has a real potential to result in price shock to customers (particularly when an organisation is undertaking significant reform) as well as imposing further costs on Ausgrid which we must recover from customers. This is in our view contrary to the national electricity objective of ensuring the long term interest of customers with respect to price.

A principle of Australian Accounting Standard '137 Provisions, Contingent Liabilities and Contingent Assets' is that a provision should be recognised when:

- An entity has a present obligation (legal or constructive) as a result of a past event.
- It is probable that an outflow of resources embodying economic benefits will be required to settle the obligations.
- A reliable estimate can be made of the amount of the obligation.

The recognition of a provision often does not coincide with the cash outlay as the provision should be recognised as soon as a present obligation exists. For example, employees are compensated for their service in the form of salary, associated annual leave, long service leave and superannuation benefits. Ausgrid recognises these liabilities and costs as soon as the employees have rendered their services; e.g. an additional year of service.

The cash outlay however is made when the employees take the leave entitled to them or upon exit from Ausgrid. This can be dependent upon employee behavior and in the case of long-term employee benefits, the cash outlay can often occurs many years after the recognition of the original liability. A large proportion of Ausgrid's workforce are long term serving employees with considerable entitlements to long term service. As such, the cash outlays associated with long service leave can be significant as it presents the settlement of a liability that has accumulated over many years. A cash payment approach therefore will introduce lumpiness in the forecast opex profile, resulting in volatility of the revenue required to recover this forecast opex and consequently subjecting customers to a variable price path.

An accrual approach on the other hand would help to alleviate lumpiness from customer pricing by ensuring that the costs are recovered at a consistent rate over time; by setting aside amounts as soon as the obligation arises. When the cash is paid, it is drawn from the provision, resulting in no impact on the opex.

Table 28 – Underlying opex ($ million, nominal)

2009/10	2010/11	2011/12	2012/13 [base]	2013/14	Average
529.9	536.1	550.3	544.6	571.3	**546.5**

Note: Numbers may not add due to rounding

108 This is consistent with the AER's view in its decision for Aurora Pty Ltd, 2012-13 to 2016-17, November 2011, pp 156 - 158.

109 EnergyAustralia, Regulatory Proposal, June 2008, section 10.1.6, page 130.

The second concern we have about the AER's cash approach is that it will result in a permanent difference between the statutory and regulatory accounts; consequently requiring the maintenance of two separate accounting systems at significant additional costs to Ausgrid (and all other DNSPs). These costs will need to be passed on to customers, causing unnecessary increases in prices.

It is because of these concerns, and the potential impact on customer pricing, that we have not adopted the AER's cash accounting approach.

In summary, the underlying opex base is $544.6 million. This is $43.7 million lower than the efficient benchmark opex of $588.2 million allowed by the AER for the 2012/13 base year. As noted in section 6.1 our performance in the current period, particularly the last two years, had set up a solid foundation for us to achieve an efficient forecast opex for the next 5 years. This is through our concerted effort to respond to the incentives in the regulatory framework to be efficient. This response has resulted in an EBSS reward for the period of $455 million.[110] Our customers will also enjoy the benefits of our effort because of a lower opex base amount has been used to derive the opex forecast as compared to the efficient benchmark set by the AER.

Table 29 shows the reconciliation between our actual opex for 2012/13 as reported in our annual RIN and the underlying opex base amount. The underlying amount of $544.6 million represents an appropriate base to develop the efficient forecast opex because it encapsulates the current efficient costs that Ausgrid incurs in achieving the opex objectives.

Table 29 – Base year underlying opex ($ million, nominal)

Derivation of underlying opex base	2012/13
Total opex for standard control service as per annual RIN	503.6
Add: actuarial adjustments	41.0
Underlying opex starting base	**544.6**

Note: Numbers may not add due to rounding

We used this underlying opex base to forecast the opex requirement for the 2014-19 period. We note however that the base year opex represents the cost of providing standard control services as they are classified in the current 2009-14 period.

However, some of these services will change classification on 1 July 2014 as per the AER's Stage 1 F&A. As such, to ensure that the proposed forecast opex for 2014-19 represents expenditure that is properly allocated to standard control services, we have removed $34.8 million ($, nominal) for alternative control services and unregulated services from the base opex of $544.6 million.

Variants of the base year method

We use variants of the base year method to forecast our requirements for maintenance opex for the next five years. A key variable in the application of these variants of the base year method are the annual actual opex we incurred in the first four years of the current period. Further details of our forecast maintenance opex are provided in Attachment 6.03.

For the costs of inspection (vegetation management), corrective, breakdown, non direct maintenance and engineering support, the base year method as described above is applied. For other maintenance costs, we apply variants of the base year method. These variants are:

Base year method – variation by volume

We used this method to forecast system maintenance inspection opex (excluding vegetation management). This method is appropriate where there is an ability to accurately predict the forecast volume of tasks that varies from the base year volume. For example, the required number of planned inspection and routine maintenance tasks is driven by the number of items of equipment and the applicable maintenance cycle and standards. Maintenance cycles are determined on the basis of failure modes effects criticality analysis (FMECA), and expenditures are determined on the basis of historical costs.

The average cost per task is comprised of two elements. These are:

- The 'base' average unit cost – this is the actual average cost per task incurred during the financial year 2012/13. It is derived by dividing the total actual opex incurred by the number of completed tasks.
- Cost escalation – cost escalation is applied to the base average unit cost to calculate the forecast average unit cost for each year of the 2014-19 period. The average cost per task is then applied to the forecast volume of tasks to derive the total system maintenance inspection forecast opex for the 2014-19 period.

Base year method – historical averaging

We used this method to forecast nature induced breakdown costs. This method is appropriate where there is significant variation in year to year expenditure and the base year is not representative of the likely future. This involves taking a historical average of the costs (in $2013/14) captured during the first four years of the current 2009-14 regulatory period and substituting the average for the base year actual opex.

This method was considered appropriate for this expense category as the underlying opex is subject to volatility of weather and climate patterns.

Bottom up method

In the instance where the future requirements of a cost category is not a function of the current base year cost, we applied a bottom up method which essentially derives the total forecast opex by taking into account all the inputs and factors relevant to the activities being performed (for example, number of tasks, the cost types required to perform each task such as labour and materials and the price of these cost inputs).

Forecast of debt raising costs

Our total forecast opex also comprise an amount for debt raising costs. We intend to adopt the method that the AER has been using to derive this cost. That is, debt raising cost is calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values. This bench market debt raising unit rate is 9.9 basis points per annum. This is further discussed in chapter 7.

110 See table 7.

Interaction between forecast capex and forecast opex

Clause S6.1.3(1) of the rules requires Ausgrid to identify and explain any significant interactions between forecast capital expenditure and forecast operating expenditure programs. In deriving the forecast opex for the 2014-19 period, we consider the consequential impact on forecast opex from capital investment. These interactions are:

- The impact of system capex on inspection maintenance costs - the cost of routine inspection is dependent on the volume of inspection. The volume of inspection tasks for the 2014-19 period is determined with reference to the number of assets which in turn are impacted by the forecast replacement and capacity investment program for the next period.[111]
- Property capital investment and statutory charges - property operating expenditure includes statutory charges such as land tax which is calculated based on forecast values of the property portfolio of the 2014-19 period. The property portfolio incorporates the values of properties expected to be acquired (i.e. capital investment in properties) and the values of properties expected to be disposed during the 2014-19 period.
- Information technology investment and consequential opex – similar to property investment, Ausgrid's forecast investment in information technology system also requires consequential incremental opex to operate and maintain these systems.
- Demand management programs - in developing the opex forecast for demand management programs, the demand forecast and maximum demand were taken into consideration when determining the appropriate broad based demand and demand management program to implement over the next regulatory period to control load and assist in deferring capex obligations into the future.

Key variables and assumptions

We outlined the forecast methods used to derive future opex requirements. The rules further require Ausgrid to include in the regulatory proposal the forecast of key variables relied upon to derive the forecast opex and the method used to develop these forecast of key variables.[112] We address this requirement in this section. As noted in section 6.2, these variables represent the reasons for significant variations between historical opex and forecast opex.

The key variables are:

- Real cost escalation.
- The interaction between forecast capex and forecast opex.
- Change factors. These comprise of:
  - Cost increases to comply with legislative obligations and due to changed circumstances.
  - Growth factors where applicable.
  - Costs of restructuring the business to ensure an efficient cost base.
  - Productivity savings to offset necessary cost increases.

Real cost escalation

The underlying base opex reflects the current prices of cost inputs. Forecast opex needs to account for changes the price of cost inputs in order to reasonably reflect a realistic expectation of cost inputs required to achieve the opex objectives in the forthcoming regulatory period.[113] These price increases may not necessarily be at the same rate as the consumer price index (CPI). They may be higher or lower than CPI due to a number of factors.[114] The need to adjust forward forecasts to take into account real cost escalation is accepted by the AER as important in reflecting the opex criteria.[115]

Ausgrid applied real cost escalation to the underlying base opex to derive a forecast opex that reasonably reflects the realistic expectation of the cost inputs required to achieve the opex objectives.

Ausgrid identified the total underlying base opex by cost categories. The total base opex of each cost category is disaggregated between different cost types. The cost types represent the costs of specific inputs (internal labour, labour hire, contracted services, materials and other costs etc) required to undertake the necessary activities to deliver standard control services and to achieve the opex objectives. For each cost category, we identify and apply the appropriate real cost escalators to each cost type to account for the change in prices of these cost types.

We engaged Independent Economics to provide forecast real cost escalators. Independent Economics prepared forecast of labour escalators for the general labour market and the utilities industry. Independent Economics' report and calculation are provided in Attachment 5.18. This attachment detailed the method/s and data used to develop these forecast labour cost real escalators.[116]

In addition, we also have an enterprise agreement (Ausgrid Agreement 2012) that provides for an annual pay rise of 2.7% (nominal) on 19 December 2012 and 18 December 2013. This agreement ends in December 2014, six months into the next 5 years period.

Table 30 and Table 31 show the cost types, their descriptions and applicable escalators.

111 See further in section 2.3 and 3.4 of the Attachment 6.03. - System maintenance operating expenditure plan.
112 Clause S6.1.2(3) of the rules.
113 Clause 6.5.7(c)(3). This is one of the opex criteria and a basis on which the AER may or may not accept the forecast opex.
114 For example labour supply and demand imbalances.
115 AER, Draft distribution determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17, p 93.
116 As required by clause S6.1.2(3) of the Rules.

Table 30 – Cost escalators applied

Cost types	Nature of the cost type	Real cost escalators applied	
		July – Dec 2014	Remainder of period
Labour	Cost of internal labour	Ausgrid Agreement 2012	NSW wage price index for the utilities industry
Labour hire	Cost of external labour	Independent Economics forecast for the general labour market[117]	
Contracted services	Cost of external contractors	CPI only (i.e. no real cost escalator)	
Materials	Cost of materials used, e.g. [tools etc]		
Other	Remaining cost types that make up the total opex for the cost category		

Table 31 – Cost escalators (%, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19
Labour - Utilities	1.25	1.56	2.07	2.06	2.04
Labour hire	0.56	1.06	1.67	1.75	1.81
Contracted services	0.56	1.06	1.67	1.75	1.81
Materials	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00

We have used the actual underlying opex of 2012/13 as the efficient starting base. To this base, in addition to real cost escalation, we have also incorporated the impact of the following change factors to ensure that our forecast is reflective of our future needs. These change specific factors are:

- Loss of synergy costs from the cessation of transitional service agreement with EnergyAustralia (formerly TRUenergy). These are fixed operating costs that are shared between regulated and unregulated services until the cessation of the TSA.
- Additional cost of inspecting private mains connected to our network to comply with our legislative obligations.
- Additional costs associated with a more comprehensive asbestos audit and inspection programs to comply with the Work, Health and Safety Act.
- Leaseback cost of one of our corporate buildings that has been sold and the settlement of which is expected to occur in June 2014. In revenue allowance terms, the leaseback is for the period up to 2016/17 and the additional cost will be more than offset by the lower return on and of capital as the proceeds from the sale of this asset will be deducted from the value of the RAB.
- Costs of demand management initiatives.
- Impact of changing our cost allocation method which was approved by the AER on 2 May 2014.

Change factors

Cessation of transitional service agreement

Prior to 1 March 2011, Ausgrid (formerly known as EnergyAustralia) was an integrated business that provided both network services (as a DNSP) and retail services. Ausgrid provided these services using integrated IT systems and business processes whilst maintaining ring fencing arrangements.

EnergyAustralia's retail business was sold to TRUenergy on 1 March 2011. This sale involved the sale of the EnergyAustralia brand, EnergyAustralia's retail customers and wholesale contracts to TRUenergy (now EnergyAustralia). Under the terms of the sale, a transitional services agreement (TSA) was agreed between Ausgrid and TRUenergy.

The TSA stipulates the provision of retail related services[118] to TRUenergy's retail customers (i.e. previously EnergyAustralia's customers) on behalf of TRUenergy by Ausgrid. Ausgrid provides these services to TRUenergy's customers using the same resources, systems and process that it employed to provide services to its own retail customers prior to the sale to TRUenergy. That is, there has been no substantial change to the way Ausgrid operates in providing retail related services to TRUenergy as opposed to its own retail customers prior to the sale.

These services are scheduled to end on a specified date unless TRUenergy chooses to terminate them early in accordance with the agreed conditions. At present, unless extended by TRUenergy, Ausgrid anticipates that these services will end in November 2014, with an option to extend to March 2015 to cater for any transition issues.

Upon termination of the TSA, Ausgrid's operational and fixed support cost of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. The cessation of the TSA has direct impact on operational areas of the NEM data operations and the emergency contact centre as well as support areas such as, finance, human resources, IT, property and management.

117 Please see Attachment 5.18.

118 Including customer service, billing, call centre, contract management and data performance management.

These 'loss of synergy' costs have been factored into the forecast opex for the 2014-19 period. The AER recognised this potential 'loss of synergy' in its distribution determination for Ausgrid for the 2009-14 period. In accepting the 'Retail project event' (i.e. sale of the retail business) as a nominated pass through event, the AER stated:

> *If the NSW electricity retail businesses are privatised the DNSP's cost of providing direct control services may increase due to loss of synergies.*[119]

Mindful of the impact of these increases on our customers, Ausgrid intends to implement strategies to ensure that, by 2017/18 there is no bill impact to customers resulting from these costs increases over the 2014-19 period. Our forecast opex includes the costs of implementing these strategies as well as the savings expected to result from these strategies. We expect all cost increases due to the loss of synergies to be fully offset in our cost structure by 1 July 2017.

Table 32 shows the impact of the cessation of the TSA on the forecast opex required to provide standard control services as well as the saving offsets (discussed further below).

Table 32 – Impact of cessation of TSA ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Cost of impact TSA cessation						
Direct operational impact on SCS[120]	2.2	9.0	9.2	9.3	9.4	**39.0**
Fixed support cost on SCS[121]	3.1	5.4	5.5	5.5	5.6	**25.1**
Initiatives to offset impact						
Cost of initiatives	4.4	4.5	4.9	0.0	0.0	**13.9**
Savings from initiatives	0.0	-7.2	-14.6	-14.8	-15.0	**-51.6**
Net impact	**9.7**	**11.7**	**4.9**	**0.0**	**0.0**	**26.4**

Note: Numbers may not add due to rounding

Compliance with our obligations

We have reviewed our obligations under the Electricity Supply (Network Safety and Management) Regulation 2008 regarding the inspection, testing and maintenance of private mains and the extent of these obligations. Currently, Ausgrid is at risk of breaching the regulatory and statutory obligations imposed under the Electricity Supply (Safety and Network Management) Regulation 2008, specifically clauses 10(2c) and 12(2e). As a result, Ausgrid considers it prudent that a regular inspection process is undertaken and where a defect is identified, the inspection results provided to the owner for rectification. It is planned to use the existing defect notification process to execute this process, with ultimate disconnection of installations with defects that present major risks that remain unrectified.

A policy for the management of private mains assets has been developed to provide a standard set of principles to be applied across Ausgrid to the delineation of ownership of private mains and the allocations of responsibility between customers and Ausgrid for private mains inspection, testing and maintenance. The requirements of this policy are consistent with the proposed expenditure forecast for the 2014-19 period.

The additional cost of complying with our obligations is factored into the total forecast system maintenance opex and is shown in Table 33. Further details of the additional cost of inspecting private mains are provided in attachment 6.03.[122]

Table 33 – Additional cost of inspecting private mains ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
GIS data capture	2.8	0.0	0.0	0.0	0.0	**2.8**
Inspection plan	2.8	2.8	2.9	2.9	3.0	**14.5**
Total private mains inspection	**5.6**	**2.8**	**2.9**	**2.9**	**3.0**	**17.3**
Asbestos inspection program	1.5	1.5	1.5	1.6	1.6	**7.7**
Total compliance obligations	**7.1**	**4.3**	**4.4**	**4.5**	**4.6**	**25.0**

Note: Numbers may not add due to rounding

119 AER, EnergyAustralia, draft distribution determination, 2009/10 to 2013/14, 21 November 2008, p280.
120 Loss of TSA contact center emergency overflow capacity, operational technology cost and stranded retail cost.
121 This relates to the portion of shared costs (such as finance, IT, management and other corporate costs) that were previously allocated to the TSA business.
122 Ausgrid seeks to have this attachment not be published on the grounds of confidentiality.

Table 34 – Leaseback cost of head office building ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Leaseback costs	7.0	7.4	7.4	0.0	0.0	**21.9**
Make good costs	0.0	0.0	1.8	0.0	0.0	**1.8**
Property costs savings	0.0	0.0	0.0	-3.7	-3.7	**-7.4**
Total leaseback costs	**7.0**	**7.4**	**9.3**	**-3.7**	**-3.7**	**16.3**

Note: Numbers may not add due to rounding

Leaseback of head office building

As an efficiency initiatives, Ausgrid has decided to sell its head office building in the Sydney CBD. The sale is expected to be finalised in June 2014 at which time Ausgrid will enter into a lease back arrangement for up to three years. This will enable Ausgrid to consolidate into one CBD based premise (which contains a CBD substation) and relocate staff to alternative non CBD sites. The cost of this leaseback must therefore be incorporated into our forecast opex as it is not currently in the base year amount. The proceeds from the sale of this asset will be deducted from the regulatory asset base and provide a long term benefit to the customer. There will also be property cost benefits from consolidating staff at the alternative sites from 2017/18 onward. Further details of this cost can be found in Attachment 6.04 and in Table 34.

Impact of complying with approved cost allocation method

For the current regulatory period, Ausgrid applied the cost allocation method (CAM) that was prepared in accordance with clause 11.15 of the rules. In its preliminary positions in the F&A paper, the AER considered that this CAM is inconsistent with the AER's cost allocation guideline which applies to Ausgrid from 1 July 2014 and requested all NSW DNSPs to submit a new CAM. Consequently, Ausgrid submitted a new CAM that complies with the AER's cost allocation guideline on 29 November 2013.

The new CAM proposed alternate allocators for a number of shared costs to better reflect the underlying cost drivers. The AER reviewed these and considered them to be appropriate. The proposed CAM was approved by the AER on 2 May 2014.

As the base year actual opex must comply with the CAM applicable to the current period and the forecast opex must comply with the new approved CAM, an adjustment is needed to cater for the impact of complying with the new approved CAM applicable from 1 July 2014. This is shown in Table 35.

However, recognising the impact on our customers, Ausgrid has offset these increases with efficiency initiatives to reduce the impact to nil by 2016/17.

Productivity savings

Ausgrid's proposed forecast opex requirement for the 2014-19 period remains relatively flat over the next regulatory period. This is the result of the strategies and initiatives that aim to:

- Eliminate the cost impact of losing the synergies of no longer being an integrated Network / Retail business after the cessation of the TSA.
- Eliminate the impact of transitioning to the CAM approved by the AER.
- Move the business towards an efficient cost base.

These objectives will drive efficiency so that we can strive to contain average increases in our share of customers' electricity bills. They will be achieved by the following initiatives:

- Management saving initiatives.
- Network reform project initiatives.

These initiatives will require initial implementation expenditure of $105.5 million ($2013/14) but will result in a total saving benefit of $230.4 million ($2013/14) in the forthcoming period. The $105.5 million comprises of implementation costs of:

- Transitioning to an efficient cost base ($53.7 million, $2013/14).
- Achieving efficiency through industry reform ($51.8 million, $2013/14).

Table 35 – Cost impact of transitioning to new CAM ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Impact on SCS of new approved CAM	3.9	4.0	4.2	4.3	4.4	**20.8**
Initiatives to offset impact	0.0	-2.0	-4.2	-4.3	-4.4	**-14.9**
Net impact of new CAM	**3.9**	**2.0**	**0.0**	**0.0**	**0.0**	**5.9**

Note: Numbers may not add due to rounding

Move towards a more efficient cost base

As stated in the previous section, Ausgrid's operating environment and circumstances will change with the cessation of the TSA. Coupled with the significant reduction in the forecast capital investment program for the 2014-19 period, Ausgrid is facing a pool of excess resources and other stranded costs, despite the prudent action we undertook in outsourcing additional required resources through the alliance partners. This prudent action has minimised the cost impacts of a reduced capital program on the operating expenditure required for the 2014-19 period but the impact is still putting upward pressure on the cost base. Whilst this may be the case, it is important to note that in this proposal Ausgrid has not sought any funding from customers for costs of stranded resources (i.e. stranded labour costs and support costs) resulting from a reduced capital investment program in the next period. This is one way Ausgrid has addressed customers' concerns on increases in electricity charges and is consistent with the expectation of customers expressed to us via the CCP regarding the funding of this cost.

Nevertheless, this is a critical issue that we have to respond to in a measured way that balances the interests of all stakeholders, i.e. our employees, our customers and shareholders. We need to undertake active measures to respond to the need of constraining the impact on our cost base and to ensure an efficient cost structure going forward. To do nothing and maintain a level of resources that is in excess of requirements would not be a prudent option and would impose a heavy burden on Ausgrid's financial resources and financial viability.

Whilst Ausgrid would have preferred to redeploy surplus labour requirements to other parts of the business, there is limited scope to do so because:

- The rationalisation of functions across the three DNSPs as part of the NSW Government's industry reform will result in additional surplus requirements rather than vacancies.
- The focus on core functions of being a DNSP means that there are limited opportunities in respect of redeployment to Ausgrid's unregulated business.

In light of the limited opportunities for redeployment, we have commenced a program to transition our labour workforce over the 2014-19 period to a sustainable level. We have begun a 'mix and match' voluntary redundancy program which has been approved by the Australian Taxation Office. Under this program we seek expression of interest from our eligible electrical trade employees who may be interested in voluntarily leaving Ausgrid. The program aims to create sufficient trade positions for graduating apprentices.

We have also reduced the number of yearly apprentice intake in anticipation of reduced capital investment. Apprentice intake is reflected in the forecast opex requirement for learning and development (included in operations & support opex).

The ramp down in investment and the cessation of the TSA give rise to an inevitable need to evolve our business and to restructure our organisation so that an efficient and sustainable level of resource is achieved such that previously shared fixed costs are now for a network only business. Cost restructuring is a legitimate option and a well accepted practice by businesses in response to changing needs and circumstances. In our case, it is a prudent course of action having regard to the interests of our customers and our long term financial viability.

Whilst it is a prudent option that ensures customers will not bear the financial burden of maintaining a workforce and other support costs (e.g. property/IT) in excess of requirements, Ausgrid nevertheless is an employer with certain legislative obligations to its employees, some of whom have been with us for a long period of time. We must meet these obligations.

We forecast the costs of implementing these initiatives as \$53.7 million[123] (\$2013/14) for the 2014-19 period. These are the costs to cover our obligations and are shown in Table 36.

Table 36 – Cost base restructure ($ million, 2013/14)

2014/15	2015/16	2016/17	2017/18	2018/19	Total
12.0	12.3	17.1	12.4	0.0	**53.7**

Note: Numbers may not add due to rounding

These implementation costs are expenditure that Ausgrid needs to recover as the efficient costs of providing standard control services. These initiatives represent a prudent option that will result in ongoing cost savings that will ultimately benefit our customers through lower charges. With the exit of these employees, Ausgrid will have a significantly lower labour cost profile as well as reduced support costs such as information technology, property, finance and human resources etc.

Efficiency program

As outlined in chapter 1 and in Attachment 1.01, the NSW government instituted network industry reforms to drive efficiency across the three NSW DNSPs in a number of key areas. This efficiency drive is achieved by removing functional duplication, streamlining corporate and support services and creating better and faster procurement and logistic processes to achieve value for money.

This efficiency drive will incur one-off implementation costs of \$13.2 million (\$2013/14) in 2014/15 and \$4.6 million (\$2013/14) in 2015/16 and ongoing investment costs (e.g. licence fees for IT system) of \$34.0 million (\$2013/14) over the 2014-19 period. The strategies will reap a forecast benefit of \$163.9 million (\$2013/14), leaving customers with a net benefit of \$112.1million (\$2013/14) over the 2014-19 period. Table 37 shows the costs by year.

123 Inclusive of TSA implementation costs of \$13.9 million as per table 32.

Table 37 – Efficiency program ($ million, 2013/14)

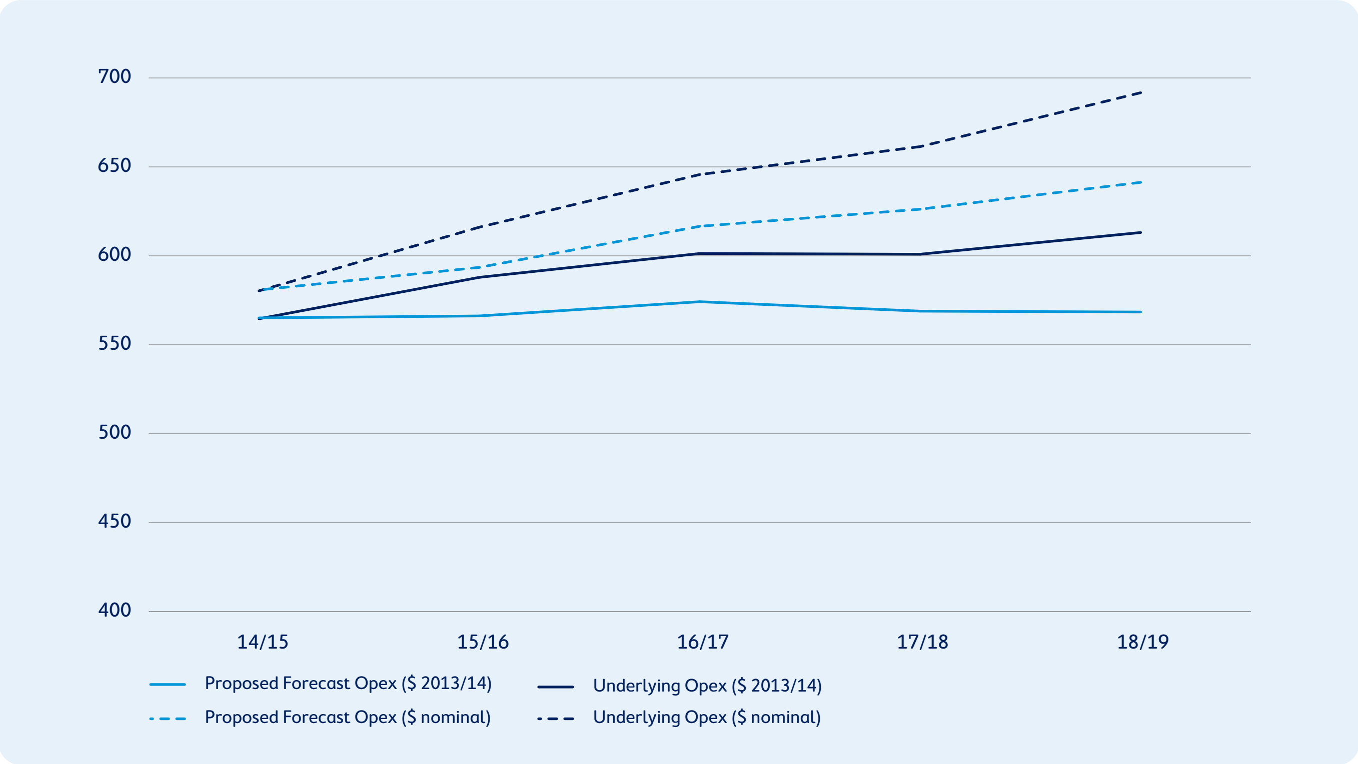
	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Implementation costs	6.6	4.5	7.5	7.6	7.8	**34.0**
Restructure costs	13.2	4.6	0.0	0.0	0.0	**17.8**
Benefits	-31.3	-33.8	-32.8	-32.9	-33.1	**-163.9**
Net savings	**-11.5**	**-24.7**	**-25.3**	**-25.3**	**-25.3**	**-112.1**

Note: Numbers may not add due to rounding

Result of our plans to be efficient

Figure 20 illustrates the results of our concerted effort to find efficiency savings for our customers. It shows that without this effort, the cost we need to deliver our services for the next five years would be much higher due to unavoidable cost increases.

Figure 20 – Forecast opex for 2014-19 ($ million)



Key forecast assumptions

The rules require Ausgrid to provide details of the key assumptions underpinning our forecast opex and a director's certification as to the reasonableness of these key assumptions.

Attachments 5.13 and 5.14 provide details of key assumptions and the directors' certification. Table 38 outlines the key assumptions underlying our forecast opex. These are assumptions relate to the facts or circumstances, the truth or correctness of which underpins or is highly material to the forecast of opex. We note that there are other key assumptions which apply solely to forecast capex and have been identified in chapter 5.

6.4 Proposed program

Our proposed forecast opex program for the next five years is to ensure that we continue to keep our network safe and reliable and complying with our legislative obligations. This proposed program of work will be delivered effectively and efficiently so that our customers will not be unduly burdened.

The purpose of this section is to identify Ausgrid's total forecast opex for the next five years by cost categories. This section also provides a high level overview of the activities underpinning each cost category and the specific change factors applicable to each cost category (if any). Further details underpinning each category are provided in attachments and supporting documents to Ausgrid's regulatory proposal.

It must be noted that our total proposed forecast opex includes the cost of a number of strategies we intend to implement to achieve costs efficiency for the 2014-19 period and the associated savings expected from these strategies.

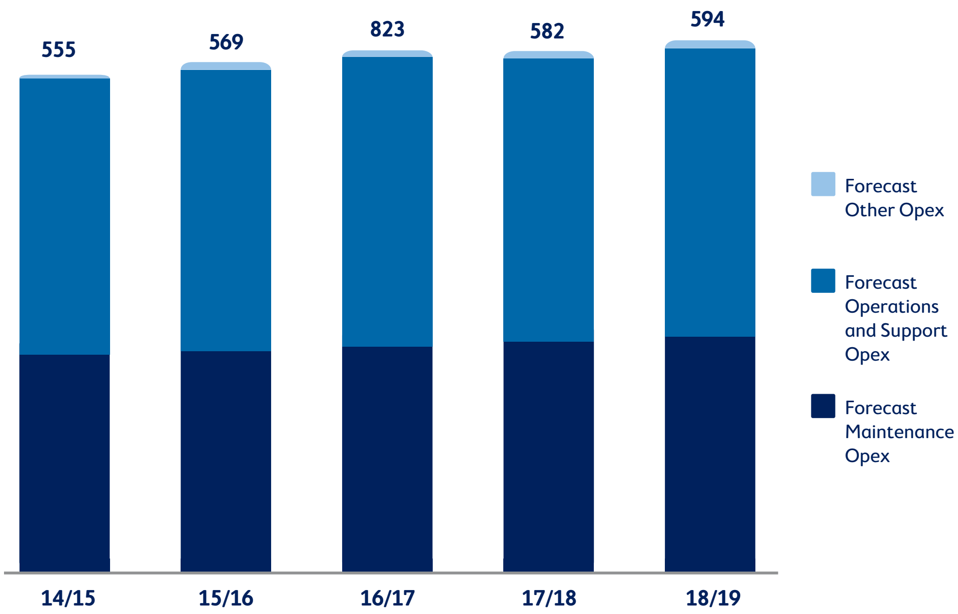
The specific programs to give effect to these strategies are in the progress of being developed and consequently, the forecast opex at the cost categories level (i.e. maintenance, operations and support etc.) presented below and in the associated attachments are exclusive of the costs to implement the initiatives and expected efficiency savings.

Throughout this section, we will provide information on our total forecast opex required by the rules so as to meet our compliance obligations. A breakdown of Ausgrid's opex forecast by program is shown in Figure 21.

Table 38 – Key assumptions

Key assumption	Description
Base opex	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.
Labour cost escalation	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".
Transitional service agreement	Ausgrid has supplied transitional services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan time line is achieved.
Legal and organisational structure	The legal entity, ownership and organisational structure are those in place at the time forecasts are finalised.
Customer engagement	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.

Figure 21 – Forecast opex by program ($ million, 2013/14)



We propose a total forecast opex for the next five year period of $2,842.9 million ($, 2013/14). Ausgrid considers this amount is needed to achieve each of the opex objectives set out in the rules.[124] In addition to this total forecast opex, Ausgrid also proposes a forecast debt raising cost of $45.4 million ($, 2013/14).

Table 39 below shows the forecast opex for each regulatory year of the next five year period, including an allocation between transmission and distribution standard control services. This forecast expenditure is for the provision of standard control services[125] and represents expenditure that had been properly allocated to standard control services in accordance with the policies and principles set out in Ausgrid's cost allocation method that was approved by the AER on 2 May 2014. That is:

- Opex that are directly attributable to standard control services are allocated wholly to standard control services, for example, forecast maintenance expenditure.
- Shared costs are allocated to standard control services, alternative services and unregulated services based on the relevant allocators such as the number of FTEs or the floor space ratio.[126] For example human resources management costs are allocated to standard control services based on FTEs.

Table 39 – Total forecast opex ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Maintenance	243.7	247.4	252.6	257.9	263.7	**1,265.2**
Operations & support	307.5	313.5	322.7	315.7	321.1	**1,580.5**
Other opex	4.2	8.6	7.3	8.2	9.0	**37.3**
Total business as usual opex	**555.4**	**569.5**	**582.5**	**581.8**	**593.7**	**2,882.9**
TSA loss of synergy costs	5.3	14.4	14.6	14.8	15.0	**64.1**
Impact of transitioning to new CAM	3.9	4.0	4.2	4.3	4.4	**20.8**
Total costs without efficiency measures	**564.6**	**587.9**	**601.3**	**600.9**	**613.1**	**2,967.8**
Efficiency initiatives implementation costs	31.8	21.3	24.5	20.0	7.8	**105.5**
Efficiency / productivity savings	-31.3	-43.0	-51.6	-52.0	-52.5	**-230.4**
TOTAL FORECAST OPEX	**565.1**	**566.2**	**574.2**	**568.9**	**568.4**	**2,842.9**
Distribution	**524.5**	**525.5**	**532.7**	**528.7**	**528.3**	**2,639.7**
Transmission	**40.6**	**40.8**	**41.5**	**40.2**	**40.1**	**203.2**

Note: Numbers may not add due to rounding

124 Clause 6.5.6(a) of the rules.
125 Clause S6.1.2 (1)(iv) requires Ausgrid to identify the categories of distribution services to which the forecast opex relates.
126 See table 3 of the approved CAM.

Table 40 – Forecast maintenance opex ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Inspection (incl. vegetation management)	104.2	106.2	109.0	111.2	115.2	**546.5**
Corrective	55.0	55.7	56.6	57.5	58.4	**283.2**
Breakdown	54.3	55.0	55.8	56.7	57.6	**279.3**
Nature induced breakdown	8.6	8.7	8.8	9.0	9.1	**44.2**
Non-direct maintenance	0.7	0.7	0.7	0.7	0.8	**3.7**
Engineering support	20.8	21.2	21.6	22.1	22.5	**108.2**
Total	**243.7**	**247.4**	**252.6**	**257.9**	**263.7**	**1,265.2**

Note: Numbers may not add due to rounding

Our total business as usual forecast opex is comprised of three cost groups. We discuss these in turn below.

System maintenance opex

We propose a total forecast opex of $1,265.2 million ($2013/14) for the next five years to maintain our electrical network. This forecast is exclusive of efficiency initiative implementation costs and resulting benefits.

Our maintenance program consists of inspection costs as well as costs of correcting faults and rectifying breakdowns. It also consists of engineering support and indirect maintenance costs. It must be noted that Ausgrid is not proposing planned maintenance programs, whose purpose is to improve the performance of the relevant distribution system for the purposes of the STPIS.[127]

In Attachment 6.03 we detail and explain the plans and strategies underpinning our forecast maintenance opex and the change factors. A limited portion of this attachment has been sought by Ausgrid to be suppressed from publication on the ground of confidentiality.

Highlights of our forecast maintenance opex for the next five years are:

- The continuation of the current business as usual maintenance program with additional opex required to comply with our obligations in relation to the inspection of private mains. To fulfil this obligation, we intend to undertake a routine program of regular inspections of privately owned mains assets. This program is forecast to cost $17.3 million ($ 2013/14).
- An additional $7.7 million ($ 2013/14) for a planned 5 year asbestos audit and inspection of sites across the network.
- A renewal of contracts with external service providers for vegetation management with cost increases expected to be above CPI.
- Increases in the costs of labour inputs as outline above.

Table 40 shows the component of forecast maintenance opex. Further details are provided in Attachment 6.03.

Operations & support

We propose a total forecast opex of $1,580.5 million ($2013/14) to operate and support our network and our business. This forecast is exclusive of efficiency initiatives implementation costs and resulting benefits. Highlights of the forecast operations and support opex for the next five years are:

- Leaseback cost of Ausgrid's head office building in the Sydney CBD.
- Increases in land tax and statutory charges of $13.3 million ($2013/14) to account for the expected increase in land values, partly offset by the sale of a number of properties.
- Increases in information, communication and technology costs to reflect costs needed to maintain system capabilities and to deliver future efficiencies.
- A reduction in apprentice intake for the next five years.

Table 41 – Forecast operations & support opex ($ million, 2013/14)[128]

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Property	64.7	64.2	66.0	53.5	53.4	**301.7**
Information, communication and technology	58.2	60.7	63.7	65.2	66.5	**314.2**
Network operations	63.4	64.9	66.8	68.1	69.0	**332.2**
Learning and development	29.7	29.7	30.1	30.8	31.6	**151.9**
Other	91.6	94.1	96.2	98.1	100.6	**480.5**
Total	**307.5**	**313.5**	**322.7**	**315.7**	**321.1**	**1,580.5**

Note: Numbers may not add due to rounding

127 Clause S6.1.2(4).

128 It must be noted that forecast opex contained in this total does not include the 'loss of synergy' cost impact and the cost impact of transitioning to the new approved CAM whereas the forecast opex in the attachments are inclusive of these cost impacts.

We have provided further details supporting our forecast operations and support opex in Attachments 6.04 to 6.11 and in Table 41.

Other opex

Other forecast opex relates to the proposed demand management innovation allowance (DMIA) of $5 million ($ 2013/14), demand management programs of $24.1 million ($ 2013/14), and demand management operation costs of $8.2 million ($ 2013/14).

Table 42 shows the costs for each year. Further details of our proposed forecast DMIA and demand management opex are provided in Attachment 6.12.

6.5 Meeting the rules

Ausgrid has proposed a total forecast opex for the 2014-19 period that Ausgrid considers is required in order to achieve each of the operating expenditure objectives (opex objectives) listed in clause 6.5.6(a) of the rules. The AER is required to make a decision on whether to accept or reject our total forecast opex. The AER must accept the total opex forecast if it is satisfied that the forecast of required opex reasonably reflects each of the operating expenditure criteria (opex criteria), having regard to the operating expenditure factors (opex factors).

To enable the AER to make its decision, the rules require Ausgrid to comply with specific information requirements in clause 6.5.6 and schedule 6.1.2 of the rules. This includes an obligation to comply with the requirements of any relevant regulatory information instrument. In Attachment 6.13 we provide opex information in compliance with Schedules 6.1.2(1) & (7).

In the sections below we briefly identify how we have met the opex objectives, criteria and factors. In our Attachment 5.31, we provide more detailed information.

Achieving the opex objectives

The rules state that Ausgrid's forecast opex must be the expenditure that Ausgrid considers is needed to achieve each of the outcomes listed in clause 6.5.6(a), known as the 'operating expenditure objectives' (opex objectives). These objectives are:[129]

- Meet or manage the expected demand for standard control services (objective 1).
- Comply with all applicable regulatory obligations or requirements (objective 2).
- Maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3).
- Maintain the safety of the distribution system through the supply of standard control services (objective 4).

In order to achieve each of the opex objectives, Ausgrid must have the necessary capabilities, personnel and systems to undertake the necessary activities to achieve these objectives. For example, one of the opex objectives is to maintain the safety of the distribution system through the supply of standard control services. In order to achieve this objective, Ausgrid must have the capabilities, personnel and systems to undertake maintenance on the electrical network. Consequently, in undertaking these activities and in operating the necessary systems, Ausgrid must incur maintenance opex.

Ausgrid's total forecast opex therefore comprises of the costs of undertaking all the related activities and to operate the necessary systems to deliver each of the opex objectives listed above. Ausgrid's total forecast opex comprises of three cost groups and Table 43 shows the opex objective/s that each cost group deliver.

Table 42 – Forecast other opex ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Proposed DMIA	1.3	1.8	1.3	0.5	0.1	**5.0**
Demand management programs						
Location specific	0.0	0.4	0.4	0.5	0.8	**2.0**
Broad based	1.4	3.0	4.0	5.6	8.1	**22.1**
Technical support & reporting	1.6	3.4	1.6	1.6	0.0	**8.2**
Total	**4.2**	**8.6**	**7.3**	**8.3**	**9.0**	**37.3**

Note: Numbers may not add due to rounding

[129] See clause 6.5.6(a) for exact wording.

Table 43 – Forecast costs and the opex objectives

Opex cost group	Activities	Opex objectives achieved
Maintenance opex	Maintenance opex is required to undertake various activities on Ausgrid's electrical network. These activities, hence associated cost, are critical to achieve all four opex objectives.	All opex objectives
Operation and support	Operation expenditure are those costs incurred in undertaking the required activities to directly support the operation of Ausgrid's network system. Support expenditure are those necessary for the normal operation of Ausgrid as a business such as management costs, financial reporting or human resources management costs. These costs would be found in any typical business. These costs are essential to the effective running and operation of the network and therefore are required to achieve all of the opex objectives.	All opex objectives
Other	Ausgrid's other opex relates to demand management. This expenditure is required to manage the demand on our network through various non network alternatives. This expenditure is to achieve the opex objective 1.	Opex objective 1

Meeting the opex criteria and factors

The AER must accept Ausgrid's forecast of required opex if it is satisfied that the total forecast opex reasonably reflects each of the opex criteria, being:

- The efficient costs of achieving the opex objectives.
- The costs that a prudent operator would require to achieve the opex objectives.
- A realistic expectation of the demand forecast and costs inputs required to achieve the opex objectives.

In making this decision, the AER must have regard to the opex factors as well as the information included in or accompanying Ausgrid's regulatory proposal, written submissions and any analysis undertaken by or for the AER.[130]

At the time of our 2009-14 regulatory proposal, we engaged NERA to provide expert economic advice on the interpretation of the opex criteria and on how to demonstrate that the forecast opex reasonably reflects these criteria. In 2014, we engaged NERA to provide an updated view on its initial report in light of changes to the rules for economic regulation.

An important element of NERA's advice is that there are no directly observable measures of efficiency. NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent. In this respect a number of the opex factors relate to the process used by the DNSP.
- Using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the opex factors represent partial checks of the forecast.

Forecast process

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. In terms of demonstrating that our forecasting process is efficient and prudent, we have provided evidence in the Attachment 5.31 to show that:

- We have effective policies and procedures to inform our expenditure decisions and our planning processes.
- Our governance processes ensure that expenditure decisions are appropriately delegated and are supported by effective financial controls.

In terms of forecasting opex for the 2014-19 period, we have adopted a 'fit for purpose' approach that comprises the following steps:

- Disaggregate Ausgrid's total opex into various cost categories. These cost categories represent the costs of undertaking a set of related activities to provide standard control services and to achieve the opex objectives (for example, maintenance opex, system control, finance, human resources etc).
- Assess the nature of each cost category and determine the appropriate forecasting method that would result in a forecast cost that reasonably reflects the efficient cost that a prudent operator would need to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs for that particular cost category.

We consider that this approach ensures that the nature of each cost category and its relevant underlying drivers are appropriately accounted for, such that the resulting forecast opex is reflective of the efficient costs that a prudent operator would require to achieve the opex objectives. This process gives us confidence that our total forecast opex would reasonably reflect the opex criteria and ensures that the national electricity objectives and the revenue and pricing principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient cost we expect to incur in the 2014-19 period.

130 Clauses 6.10.1(b) and 6.11.1(b) of the rules.

This approach to forecasting total opex that selects the most appropriate methods for the relevant cost categories would be expected to be the approach that a DNSP would undertake to ensure that the resulting forecast expenditure reasonably reflects the opex criteria. Throughout this process, as well as considering the nature and drivers of each particular cost category, likely legislative changes, changes to our operating environment as well as scope for efficiency savings, we also have had regard to the opex factors in the rules that the AER must consider in deciding whether it is satisfied that our total forecast opex reasonably reflects the opex criteria. Consideration of the above factors in forecasting future expenditure requirements is a prudent course of action and would be expected if the total forecast opex is to reasonably reflect the opex criteria.

In the Attachment 5.31 we have also addressed the opex factors in the rules that specifically relate to the forecasting process used by a DNSP. In summary:

- We have considered the substitution possibilities between operating and capital expenditure in developing our forecast opex.[131] A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions such as maintenance, which have then been factored into our opex forecasts.
- Ausgrid has considered and made provision for efficient and prudent non-network alternatives.[132] We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts, and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. These efficient costs have been incorporated into our opex forecasts.
- We have considered the relative prices of operating and capital inputs[133]. As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation.
- Our expenditure forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers.[134] We engaged customers on a range of issues including reliability, price, and demand management. The findings from our customer engagement support the basis of our proposed total capex including in relation to price affordability, and maintaining current levels of safety and reliability.
- Ausgrid's forecast method considered whether any opex should be identified as contingent projects, and therefore excluded from the total forecast capex or opex for standard control services.[135] We found that no component of our opex cost categories met the criteria of a contingent project set out in 6.6A.1 of the rules.
- Our forecast process identified that there have been no final project assessment reports at the time of submitting this proposal.[136]

Indicators to assess the reasonableness of the forecast

Whilst there is no external, observable measure that can be relied upon to demonstrate that the total forecast expenditure is efficient, there are nevertheless partial indicators that assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 5.31 we have addressed the remaining opex factors that we consider may represent partial indicators of the efficient level of opex. In this respect, the rules require the AER to give regard to actual and expected operating expenditure during any preceding regulatory control periods (opex factor 5), whether the operating expenditure forecast is consistent with any incentive scheme or schemes (opex factor 8).

Ausgrid was subject to the efficiency benefit sharing scheme (EBSS) for the current 2009-14 period. The EBSS provides incentives for business to pursue efficiency improvements in opex and to share efficiency gains with customers. This is demonstrated by the comparison of our actual opex performance against the efficient benchmark set by the AER. Ausgrid expects to spend $2,941 million ($2013/14) for the 2009-14 period compared to an allowance of $2,974 million ($2013/14) approved by the AER.

This performance was achieved by the implementation of a number of cost saving initiatives. It has set a solid platform for Ausgrid in ensuring that the forecast opex for the 2014-19 period reasonably reflects the efficient costs that a prudent operator would need to achieve the opex objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

The AER must also consider the most recent annual benchmarking report and the benchmark capital / operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (opex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data. The AER will be releasing its first benchmarking report in September 2014, and therefore we are not provided with an opportunity to demonstrate or make representations on this report at the time of submitting our regulatory proposal.

131 Opex factor 7.
132 Opex factor 10.
133 Opex factor 6.
134 Opex factor 5A.
135 Opex factor 9A.
136 Opex factor 11.

Ausgrid has developed a comprehensive benchmarking report provided in Attachment 5.33. The report examines the inherent limitations of benchmarking Australian DNSPs, and the role that benchmarking should play as a partial indicator of efficiency. Our analysis identified that benchmarking has inherent limitations such as inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We think that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. It should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool. In the report we also:

- Assessed the relative weight that should be applied to each of the benchmarking tools identified by the AER in its forecast expenditure assessment guidelines including economic analysis, aggregated category analysis, and cost category data. When deciding if a benchmark is appropriate, we have been guided by the Productivity Commission's review in 2013 which set out 6 criteria for when a benchmarking tool could be used in the process.
- Sought to understand the available data that can be used for benchmarking and reported on these outcomes. This was based on a Huegin Consulting study of 7 DNSPs in Australia. The Huegin study demonstrates that benchmarking is of limited value due to its inherent limitations, and that measures of efficiency more closely relate to the characteristics of the business rather than managerial decisions. Despite this, Huegin's report does provide some basis to show that Ausgrid is improving its efficiency over time relative to other peers in the study group.

Based on this approach, we have placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast and consider that the AER should do likewise in its assessment. Our analysis of benchmarking tools suggests that trends in a DNSP's results over time are of more value, than relative efficiencies between DNSPs at a point in time. In this respect the data provided does demonstrate that Ausgrid's growth rates in expenditure are among the lowest out of the peer group studies. Once again, however we draw caution on such results as they cannot capture the reasons for observed differences between DNSPs.

The final factor we have considered as a partial indicator of efficiency is the extent to which the operating expenditure forecast is referable to arrangements with another person that do not reflect arm's length terms (opex factor 9).

7. Allowed rate of return

We propose a rate of return on capital of 8.83 per cent that promotes long term stability for customers and equity holders, as well as debt financiers. A long term approach achieves what should be a fundamental objective of the regulatory framework – to minimise the impact of short term volatility in financial markets when calculating the allowed rate of return. This is in the interests of both consumers and regulated businesses.

In this chapter, we provide further information on the basis of our proposed rate of return on capital. Our proposed approach has considered the AER's final rate of return guideline. Where we have departed from the methods set out in the rate of return guidelines, we explain our reasons for departure.[137] Our key contentions are as follows:

- We propose a rate of return of 8.83%, which is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Ausgrid over the 2014-19 period. The proposed rate of return has been developed to promote long term stability both for customers and equity holders.
- Our proposed rate of return approach for setting both the allowed cost of debt and the allowed equity would provide return profiles commensurate with what is required to attract investment in long-lived electricity network assets. This is essential because investors want stable and predictable returns over the long term to be able to invest in such long lived infrastructure assets.
- We propose an allowed cost of debt of 7.98%, which has been calculated consistent with the 10 year trailing average approach set out in the AER's final rate of return guideline. This estimate is based on bond yield data for BBB+ and BBB rated Australian corporate bonds issued from 1 January 2004 to 31 December 2013.
- Consistent with the AER's final rate of return guideline, we agree that the cost of debt should be subject to annual updates throughout the regulatory period. Attachment 9.02 sets out our proposed method for annually updating revenue allowances for changes in the cost of debt.
- We have serious concerns with the AER's proposed ten year transition path to the trailing average. As Ausgrid has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's debt transition would significantly under compensate Ausgrid based on current forecasts of yields on 10 year BBB corporate bonds. We consider that the application of the AER's proposed debt transition would not allow us the opportunity to recover at least our efficient costs of debt finance, which is inconsistent with the revenue and pricing principles outlined in section 7A of the National Electricity Law (NEL) and should not be applied to Ausgrid.
- The AER's proposed transition path would mean that the benchmark efficient approach for setting the allowed cost of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis. If the AER applied its proposed transition to firms that issue on a staggered portfolio basis, it would be setting revenue allowances on an inefficient basis and providing incentives inconsistent with the benchmark efficient approach to debt portfolio management.
- We propose an allowed cost of equity of 10.11%, which has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity is at the lower end of a reasonable range that takes into account prevailing market conditions and evidence from relevant financial models including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM), the Fama-French 3 Factor Model (FFM).

137 As required by schedule 6.1.3(9) of the NER we note where we have departed from the AER's final rate of return guideline.

7.1 Overall rate of return

The NSW DNSPs have consistently advocated a return on capital that is based on long term observations of financial market data and that takes account of prevailing conditions in the market for funds. This approach minimises the impact of short term volatility in financial markets (that would not be expected to prevail over a regulatory period) on regulated revenues and consequently consumer prices over time. Our proposed rate of return incorporates the following:

- A 10 year trailing average approach with annual updates for setting the return on debt, which the AER has recognised is commensurate with the staggered portfolio approach that is the most efficient and stable approach in the presence of refinancing risks.[138] Annual updates also ensure that changes in debt costs can be gradually incorporated into consumer prices rather than through price shocks between regulatory periods.
- A long term approach to setting the allowed return on equity, which provides efficient and stable returns to equity holders. The long term estimate has been considered in the context of prevailing market conditions to ensure that the allowed return on equity that is commensurate with the benchmark efficient costs of raising equity finance for long-lived infrastructure assets over the 2014-19 period.

Our proposed rate of return has been developed to meet the requirements of the rules, to contribute to the achievement of the national electricity objective set out in section 7 of the National Electricity Law (NEL), and to be consistent with the Revenue and Pricing Principles set out in section 7A of NEL. In particular, clause 6.5.2(c) of the rules requires that the rate of return must achieve the allowed rate of return objective, which is that:

> *...the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).*
>
> As set out above, our proposed rate of return has been developed to be commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk as that which applies to Ausgrid in providing standard control services.

In setting the allowed rate of return, clause 6.5.2(e) of the rules also require that the AER must have regard to:

1) *relevant estimation methods, financial models, market data and other evidence;*
2) *the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and*
3) *any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.*

Consistent with the rules requirements, we propose a rate of return of 8.83%. Our proposed rate of return is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Ausgrid over the 2014-19 period.[139]

The cost of debt has been estimated using a 10 year trailing average approach that will be subject to annual updates throughout the regulatory control period. We propose an automatic approach to annually updating the cost of debt using data published by the Reserve Bank of Australia (this is outlined below). We note that we have serious concerns over the AER's proposed approach of adopting a transition to the trailing average because it varies significantly from the return on debt required by a benchmark efficient entity facing similar risks as Ausgrid. This transition exposes Ausgrid and our customers to undesirable volatility and risk. The transition would, if implemented when rates remain at current levels, significantly under-compensate Ausgrid. If the AER was to apply a transition to the trailing average for Ausgrid, we would likely be provided with an allowed return on debt lower than our efficient cost of debt. This is not consistent with the allowed rate of return objective, the Revenue and Pricing Principles or the national electricity objective, which require that a network service provider be provided with a reasonable opportunity to recover at least its efficient costs so as to promote the efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity.

The cost of equity has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity is at the lower end of reasonable ranges taking into account prevailing market conditions[140] and evidence from relevant financial models including the CAPM, the dividend growth model (DGM) and the Fama-French 3 Factor Model (FFM).[141] The breakdown of our proposed rate of return is outlined below in Table 44.

Our proposed rate of return has been informed by leading financial and economic experts and we have attached a number of expert reports in support of our position. Additional details on Ausgrid's approach to the rate of return are set out in a report from Competition Economics Group (CEG), provided as Attachment 7.01 to this regulatory proposal. We note that the CEG report references an extensive number of relevant documents and expert reports, which are also provided for completeness as attachments to this regulatory proposal.

Table 44 – Indicative range of rate of return and proposed rate of return

Rate of return parameters	Proposed WACC %	Reasonable range of estimates %
Overall WACC	8.83%	8.83% - 9.44%
Cost of equity	10.11%	10.11% - 11.5%
Cost of debt	7.98%	7.98% - 8.06%
Gearing	60%	60%
Utilisation of imputation credits	25%	25%

138 AER, Explanatory statement on the rate of return guideline, December 2013, p. 23.
139 As required by clause 6.5.2(c) of the NER.
140 As required by clause 6.5.2(g) of the NER.
141 As required by clause 6.5.2(e)(1) of the NER.

7.2 Cost of debt

Throughout the development of its rate of return guideline, the AER has recognised that in the presence of re-financing risk, the benchmark efficient practice is to issue debt on a staggered portfolio basis.[142] A trailing average estimate reflects the cost of debt for a benchmark efficient entity that has issued debt on a staggered portfolio basis. As a result, in its final rate of return guidelines the AER proposed to estimate the allowed return on debt for energy network firms using a trailing average approach.[143] We agree that the allowed return on debt should be estimated using a trailing average approach.

Ausgrid's proposed approach

Ausgrid proposes a trailing average return on debt allowance using yields on 10 year BBB+ and BBB rated Australian corporate bonds over the past 10 years. This reflects the benchmark efficient costs of debt for a firm that has issued Australian corporate debt on a staggered portfolio basis over the past 10 years. We propose a 7.98% trailing average cost of debt, which is based on the following:

- An immediate application of the 10 year trailing average approach without any transition.
- Australian corporate bond yield data from the Reserve Bank of Australia (RBA) for the nine year period from 1 January 2005 to 31 December 2013.
- Bloomberg data for the one year period from 1 January 2004 to 31 December 2004. (We have used Bloomberg data for this period because the RBA has not published corporate bond yield data prior to January 2005. Using Bloomberg data allows us to calculate a proper 10 year trailing average).
- Consistent with market data for listed energy firms, an assumption that the benchmark entity has a BBB+ rating up to 2008 and a BBB rating from 2009 onward. (The sample of energy firms used to determine this assumption is the same sample of firms used by the AER's sample to determine the benchmark efficient credit rating for energy network firms).
- An extrapolation of the RBA curve to an effective tenor of 10 years, which is necessary to achieve a 10 year trailing average, since the RBA forecast has an effective tenor shorter than 10 years (approximately 8.7 years for BBB rated debt and 8.9 years for A rated debt).

The data and calculations are outlined in further detail in Attachment 7.01 to Ausgrid's proposal. Here we note that the 2004 Bloomberg data would only be used in the calculation of the trailing average for 2014/15 as it would "roll off" and be replaced by data contained in the RBA data set from 1 January 2005 (i.e. for the calculation of the 2015/16 trailing average) onwards.

Credit rating

The AER's rate of return guideline sets a BBB+ benchmark credit rating based on the median credit rating for a sample of regulated Australian utilities over the period 2002 to 2012. The AER does not provide the basis for its calculation. However, CEG has replicated the AER's analysis and determined that up to the end of 2008 the benchmark credit rating for the AER's sample is BBB+, but from 2009 onwards there has been a sustained drop in median credit ratings for the AER's benchmark to BBB. This is illustrated in Table 45.

Table 45 – Median credit rating for AER sample by year

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A-	BBB+	BBB+	BBB+	BBB+	BBB+	A-	BBB	BBB	BBB	BBB	BBB

Source: Bloomberg, CEG analysis

142 AER, Explanatory statement, Rate of return guideline, December 2013, pp. 104-105.

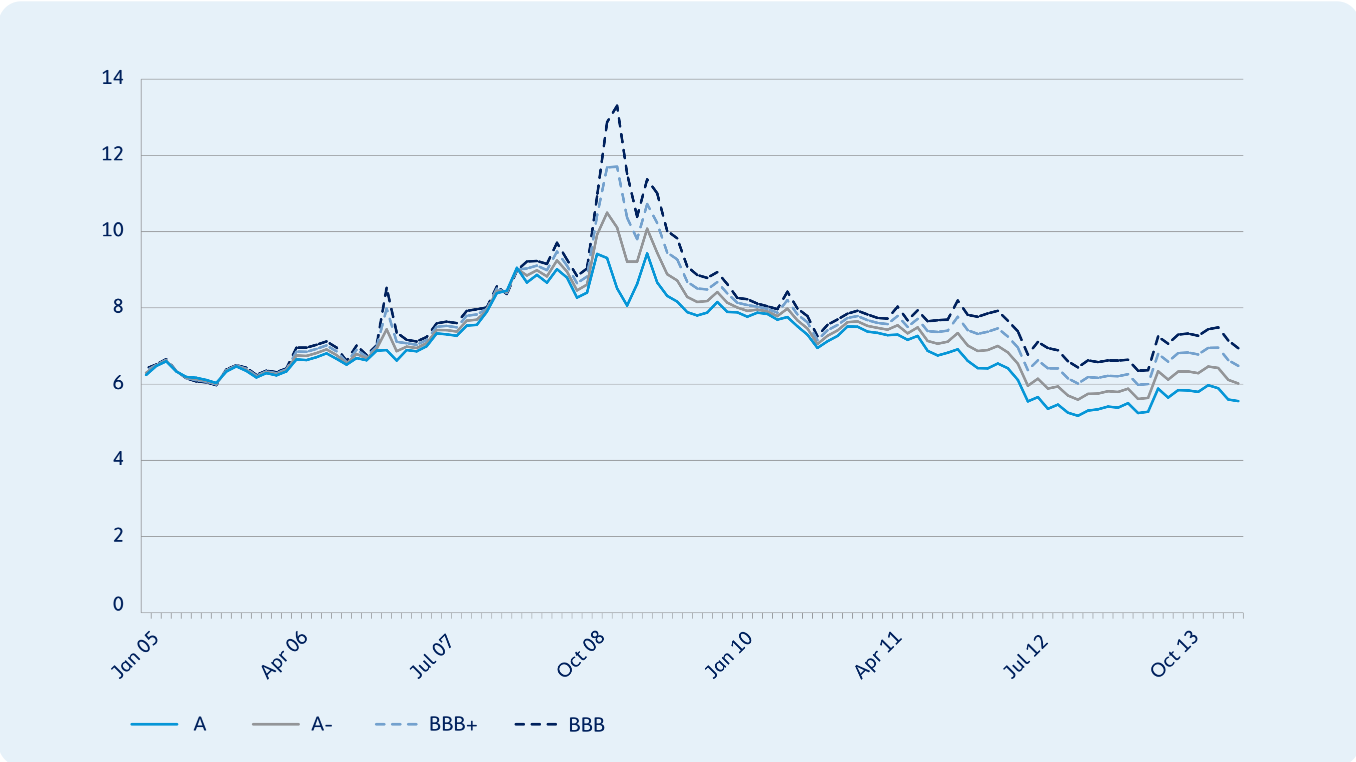
143 AER, Final rate of return guideline, December 2013, section 6.3.1, p. 19.

The impact of the credit rating assumed can have a material impact on the cost of debt as illustrated in Figure 22 , which provides the full time series of RBA data used to calculate the trailing average from 1 January 2005 to 30 December 2013.

As illustrated in Figure 22, varying the benchmark credit rating in the years 2008 and earlier does not have a material impact on estimated average yields. It is only in 2009 and onwards that there is a significant departure in the cost of debt between the different credit ratings.

Given that the median credit rating of the sample used to derive the AER's benchmark credit rating since 2009 is BBB, it is appropriate that a BBB+ credit rating is applied up to 2008, with a BBB credit rating from 2009 onwards as this represents the benchmark efficient firm. Applying the AER's BBB+ credit rating is not consistent with the available data set for determining the benchmark efficient firm and would under-compensate Ausgrid. Ausgrid considers that it is appropriate to hold this benchmark credit rating constant for the five years of this regulatory period – an approach which is consistent with the view that the benchmark only changes gradually. However, an alternative approach would be to calculate the median credit rating of the AER sample in the middle of each new averaging period (calendar year) using the methodology set out in Attachment 7.01.

Figure 22 – Time series of RBA cost of debt by credit rating (% p.a.)



Source: RBA, CEG analysis, A0/BBB+ is calculated as 2/3 weight A/BBB and 1/3 weight to BBB/A-.

The trailing average approach

A trailing average cost of debt would ensure that customer prices are not exposed to short term movements in financial markets that could significantly raise or lower the allowed cost of debt if it were set using observations of bond yields over a short 20 business day period. In addition, a trailing average cost of debt provides appropriate incentives for energy network firms to issue debt on a staggered portfolio basis, which minimises refinancing risks and allows businesses to more effectively manage the risk of mismatch between the regulated cost of debt and the actual costs of debt (interest rate mismatch risk).

The previous rules required the AER to use a short-term averaging period approach when setting the allowed cost of debt. The short term averaging period was intended to smooth out daily variability in corporate bond yields. However, the previous rules were conceived without proper regard to the efficient practices of businesses and the potential volatility in corporate debt costs over time. Following the global financial crisis corporate bond yields became much more variable over short periods as demonstrated in Figure 23 – demonstrating that a short-term averaging period cannot be presumed to be sufficient to smooth variability in corporate bond yields over time.

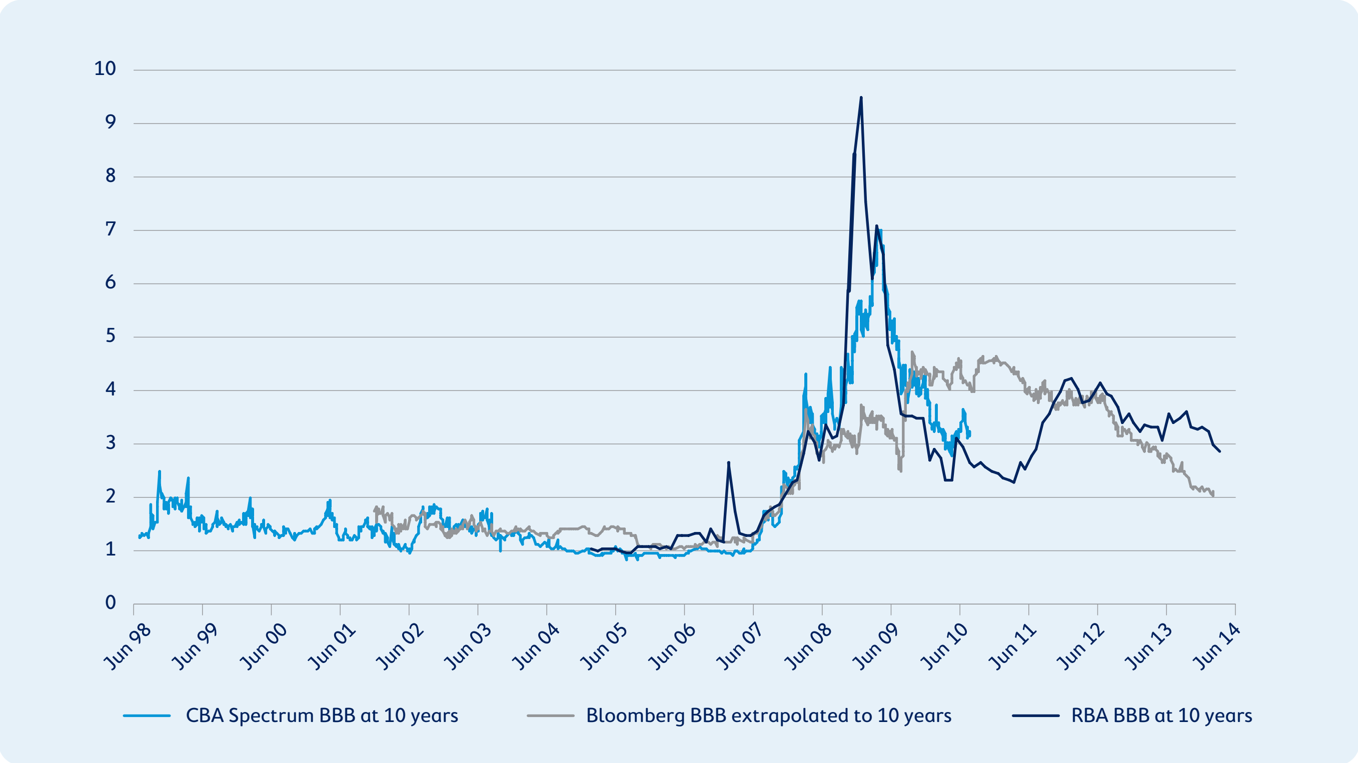
Under the previous short-term averaging period approach, some businesses may have attempted to manage interest rate mismatch risk in a number of ways, for example by issuing significant tranches of debt over their nominated[144] short-term averaging period, by issuing callable debt or by using hedging instruments to match a large component of actual interest costs to the allowed cost of debt. While these practices may have mitigated some (but not all) of the interest rate mismatch risk, each practice would expose a business to significant refinancing risks.[145] These risks included that:

- the business could be forced to access debt/hedging markets at times that were generally or specifically unfavorable for the business; and/or
- the business would have to access debt/hedging markets in such large quantities relative to demand that the proposed transactions would move market prices against the business.

This meant that the actual cost of debt incurred by a business pursuing these (partial) hedging strategies could be expected to be higher than the efficient cost of debt on average. It also meant that the regulatory allowance could be well above or below both the efficient cost of debt and any given business's actual (partially) hedged cost of debt.

A trailing average approach would have ensured more stable debt allowances (and customer prices) over time. It would also reduce the potential for measurement error to affect the regulatory allowance. The potential for measurement error is illustrated by the periods when Bloomberg and RBA/CBASpectrum estimates departed from each other significantly. Under the trailing average approach debt costs in any individual period would be given a small weight in the trailing average allowance and will tend to offset each other provided that estimation error is not systematic in one or the other direction.

Figure 23: Corporate bond spreads to 10 year CGS yields (% p.a.)



Source: CEG, Efficiency of staggered debt issuance, June 2013, p. 24

144 Nominated at the time of a regulatory decision.

145 This risk was recognised by the AER during its rate of return guidelines process. See AER, Explanatory statement, Rate of Return Guideline, December 2013, pp. 104.

Inefficiency of trying to manage debt using the previous "on the day" approach

The AER's explanatory statement to the final rate of return guideline stated that it was open to regulated energy network firms to match interest costs with the short term averaging period approach by either:

- re-issuing all debt over one short term averaging period every five years (a natural hedge); or
- using derivatives instruments to match actual debt costs with cost of corporate debt issued over a short term averaging period (a synthetic hedge).

However, given the significant size of Ausgrid's debt portfolio, it would have been costly and imprudent to have managed interest rate risk by issuing significant tranches of debt during the nominated short term averaging period. Given that Ausgrid's benchmark debt portfolio was approximately $8.3 billion in 2009, the refinancing risk would simply have been too great for Ausgrid to expose itself to in the face of short term variability in financial markets. We note that in the face of the Global Financial Crisis (GFC) Ausgrid would have been refinancing its entire debt portfolio to match the regulatory allowance. Clearly this refinancing would not have been possible at a time when the Australian corporate bond market had all but dried up.

Similarly, if attempting to use interest rate swaps, Ausgrid would have been attempting to lock in a 5 year base rate on its entire debt portfolio at a time of great dislocation in financial markets. This is illustrated by the fact that the spread between 5 year swaps and CGS was at historic high levels (around 120bp per annum compared to pre GFC levels of a little over 40bp per annum).[146] It is unclear whether large scale interest rate swap transactions at this time would have been possible let alone prudent.

Ausgrid's benchmark debt portfolio is estimated to be approximately $14.4 billion by 30 June 2014 (for SCS alone) and it remains costly and imprudent for Ausgrid to attempt to match its actual debt costs with the regulatory allowance under a short term averaging period and transition approach. Confidential advice received from UBS that is attached with this regulatory proposal (Attachment 7.05) and which has been previously provided to the AER outlined that given the depth of the interest rate derivative market there is a real risk that Ausgrid would not be able to hedge the cost of debt allowance using interest rate swaps. The UBS advice also demonstrates that even if Ausgrid was able to refinance its entire debt portfolio over a short-term averaging period or use interest rate swaps to match its actual costs to yields observed over a short term averaging period, the pricing of the debt would not be efficient and would come at a significant cost to Ausgrid.[147]

Therefore, a short-term averaging period approach reflects a clearly inefficient approach to managing debt for a benchmark efficient DNSP with a notional debt portfolio the size of Ausgrid's. Ausgrid therefore supports the adoption of the trailing average approach to estimating the return on debt.

Transitional arrangements for the cost of debt

In its final rate of return guidelines, the AER stated that the return on debt will be estimated using a 10 trailing average debt portfolio approach[148] after a transitional period. The AER's final rate of return guideline proposes to apply a transition to the trailing average approach to all service providers. We agree with the adoption of a 10 year trailing average approach, but we do not agree with the AER's proposed transition. We consider that the AER's proposed transition approach will not contribute to the achievement of the national electricity objective, is inconsistent with the revenue and pricing principles and the provisions of the NER. Moreover, we do not consider that the final rate of return guideline has properly considered joint NSW DNSP submissions on the proposed transitional approach to setting the cost of debt and its application to the NSW distribution businesses, including Ausgrid.[149]

The rate of return guideline sets out the methods the AER proposes to use in estimating the allowed rate of return for distribution determinations. The guideline is not binding on either the AER in making a distribution determination, neither is it binding on a DNSP in developing its regulatory proposal. However, schedule 6.1.3(9) of the rules requires a DNSP to explain its reasons for departing from the rate of return guideline if it chooses to do so. In this section we set our reasons for departure from the transitional approach to setting the cost of debt set out in the final rate of return guideline. Detailed reasons for our departure from the proposed transition approach outlined in the AER's final rate of guideline are elaborated by CEG in its report, consistent with the NER and NEL. This report is provided at Attachment 7.02.

Inconsistency with the revenue and pricing principles

The revenue and pricing principles set out in section 7A of the NEL provide that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services, and complying with a regulatory obligation or requirement or making a regulatory payment.[150]

Section 7A sets out the revenue and pricing principles in detail:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in —*
>
> *a) providing direct control network services; and*
>
> *b) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes —*
>
> *a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
>
> *b) the efficient provision of electricity network services; and*
>
> *c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.*
>
> *(5) 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.*
>
> *(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.*

146 CEG, WACC estimates, May 2014.
147 UBS, Advice to Networks NSW, October 2013 [Confidential].
148 That is, the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period. See AER, Explanatory Statement, Final rate of return guideline, December 2013, p. 73.
149 See NSW DNSPs, Submission on AER rate of return consultation paper, 21 June 2014 and NSW DNSPs, Submission on AER draft rate of return guideline, 11 October 2013.
150 S 7A(2) of the NEL.

The AER must take into account the revenue and pricing principles when making a distribution determination.

The AER has determined that the efficient financing practice of a benchmark efficient entity is to issue debt on a staggered basis consistent with the trailing average approach. The transitional approach of the AER proposes to preclude consideration of the individual circumstances (i.e. the current debt structure) of the service providers. This means that it is not relevant that some service providers may already structure their debt in an efficient manner consistent with the trailing average and therefore do not require transitional arrangements. Indeed, the application of the arrangements to all service providers has the effect that some service providers such as Ausgrid may be under-compensated for their costs of debt, as the formula applied to determine the cost of debt assumes that a benchmark efficient entity does not structure its debt in an efficient manner.

Under the AER's proposed transition to the trailing average, the AER would set the allowed cost of debt for the first year of the next regulatory period (2014/15) based on observations of corporate bond yields over a prospective, short term averaging period that is close to the time of a final network determination. For the second regulatory year (2015/16), 90% weight would be given to the observed cost of debt over 2014/15 and thereafter each year the initial observation would be given 10% less weight and each new year of data would be given 10% weight in the allowed cost of debt for that regulatory year. It is only in the tenth year that the transition is complete and each year has an equal 10% weighting in the trailing average calculation.

This approach exposes Ausgrid to significant risk because only a small fraction, less than 10%, of a benchmark efficient DNSP's debt portfolio (and indeed less than 10% of Ausgrid's total debt portfolio) will be refinanced between January and December 2013, in the lead up to 2014/15. Even less would be re-financed over a 20 business day period. Consequently, debt market conditions in this period would affect less than 10% of a benchmark efficient DNSP's (and in this case, Ausgrid's) debt portfolio for a period of around 10 years. By contrast, the AER's transition allowance will give this same period 100% weight in 2014/15 and 90% weight in the next year and so on until this period drops out of the AER's cost of debt allowance in 10 years. The effect of this is that over the next 10 years this period will have 55% weight in the AER's allowance. This is even more than the 50% weight that the same period would have been given under the previous approach (100% weight in the first of two averaging periods over 10 years and 0% weight in the second). In this sense, over the next 10 years, the AER transition actually compounds rather than alleviates the mismatch problems associated with the former 'on the day' approach.

This exposes Ausgrid to significant mismatch risk arising from differences in market conditions under which it has actually raised its debt and the market conditions under which the AER transition allowance assumes debt was raised. It also exposes Ausgrid to significant risk of measurement error. By giving such high weight to the short term averaging period, the AER's transitional allowance will be materially impacted by any measurement error in that period and that impact will be long lasting. By contrast, under immediate adoption of a trailing average as proposed by Ausgrid each individual month receives less than 1% weight in the cost of debt allowance – such that any unbiased measurement error will largely cancel out over the full period used to estimate the trailing average. The heightened measurement error associated with the AER's transition approach has been implicitly recognised by the AER.[151]

The AER transition approach means that service providers such as Ausgrid will be under-compensated to the extent that spot rates for the cost of debt are at levels below trailing average estimates (and vice versa). The rate of return guidelines (if adopted by the AER in making a revenue determination) may have the effect of denying Ausgrid and others a reasonable opportunity to recover their efficient financing costs, contrary to the revenue and pricing principles. We note that the opportunity to recover costs has been recognised as a crucial factor in the achievement of the national electricity objective (see reference below to the Australian Competition Tribunal's decision in Energy Australia and Others [2009]).

In addition, the transition mechanism actively encourages Ausgrid to move away from the approach to financing that the AER has concluded is efficient (the use of a trailing average). To hedge to the regulatory costs of debt under the AER's transition approach Ausgrid's would have to enter into swaps and/or hedges for its already issued debt in order to manage the interest rate risk from the on the day approach to the extent possible. In determining the efficient financing practice of the benchmark efficient entity, the AER implicitly concluded that these swap and hedge contracts were inefficient. Encouraging Ausgrid to enter into these inefficient arrangements when it is already efficient is inconsistent with section 7A(3) of the NEL.

Finally, any under-recovery of Ausgrid's efficient costs may lead to inefficient under-investment in distribution networks given that the under-recovery will be reflected in the revenue that Ausgrid may earn (and the prices that Ausgrid may charge). The potential consequence of under-investment in Ausgrid's distribution network is significant given security of supply risks and the importance of electricity supply to consumers. Having regard to these issues as required by sections 7A(6) and (7) of the NEL, emphasises the need for Ausgrid to be able to recover at least its efficient costs of providing the services, which will not be achieved if the transition is applied.

Will not, and is not likely to, contribute to the achievement of the national electricity objective

The NEL sets out that the AER must perform or exercise an AER economic regulatory function or powers in a manner that will or is likely to contribute to the achievement of the national electricity objective.[152] The national electricity objective is defined in section 7 of the NEL:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to:*
>
> *a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *b) the reliability, safety and security of the national electricity system.*

[151] AER, Explanatory statement, Final rate of return guideline, December 2013, p. 110.

[152] S 16 of the NEL.

The making of a distribution determination is an AER economic regulatory function or power conferred on the AER by the NER.

Imposing transitional arrangements which do not allow service providers the opportunity to recover their efficient costs and potentially dis-incentivises investment is contrary to the national electricity objective. The Australian Competition Tribunal (Tribunal) has considered the importance of a service provider being provided with the opportunity to recover at least their efficient costs of investment.

> *The national electricity objective provides the overarching economic objective for regulation under the NEL: the promotion of efficient investment and efficient operation and use of, electricity services for the long term interests of consumers. Consumers will benefit in the long run if resources are used efficiently, that is if resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost. As reflected in the revenue and pricing principles, this in turn requires prices to reflect the long run cost of supply and to support efficient investment, providing investors with a return which covers the opportunity cost of capital required to deliver the services.*
>
> *…*
>
> *It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterised by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, at the outset the regulator did not provide the opportunity for a DNSP to recover its efficient costs (e.g., by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*[153]

It is evident that the Tribunal considers that providing service providers with the opportunity to recover efficient costs is crucial to the functioning of the regime. The adoption of transition arrangements which substantially delay the implementation of the trailing average approach effectively defers the opportunity to recover "efficient costs" while at the same time penalising Ausgrid for being efficient and encouraging the adoption of inefficient financing practices during the short term. The transition does this because it fails to take into account the risks faced by Ausgrid. As a result the application of the transition would be contrary to the national electricity objective.

Further, we consider that the transitional approach does not encourage efficient investment practices because it prescribes a rate of return that is likely to "punish" those service providers who have already structured their debt in an efficient way by not allowing them to recover their efficient costs of debt.

Inconsistency with the provisions of the NER

Section 6.5.2(c) of the rules requires the AER to determine an allowed rate of return that achieves the allowed rate of return objective at the time of the determination. The allowed rate of return objective is:

> *…that the rate of return … is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services].*[154]

The return on debt forms part of this allowed rate of return. The AER must estimate the return on debt such that it contributes to the achievement of the allowed rate of return objective. Ausgrid does not consider that the application of the transition to it will result in an estimate of the return on debt that contributes to the achievement of the rate of return objective or complies with the provisions of the NER for the reasons discussed in this section.

Delay in achieving the allowed rate of return objective

The adoption of the AER's cost of debt transition is contrary to the rate of return objective precisely because it significantly delays the adoption of the 10 year trailing average approach to determining the cost of debt, which the AER has determined is consistent with the rate of return objective. This is clear from the AER's Explanatory Statement to the final rate of return guideline in which the AER stated:

> *Our preferred approach to estimation of allowed return on debt is the trailing average portfolio approach. ….In the presence of refinancing risk, it is efficient for a service provider to hold a portfolio of debt with staggered maturity dates. The allowed return on debt under the trailing average portfolio approach reflects the financing cost of a benchmark efficient entity with such a staggered portfolio.*[155]

We note that Clause 6.2.8(d) of the rules requires that where any guideline published by the AER indicates that there may be a change of regulatory approach in future distribution determinations, the guideline should also (if practicable) indicate how transitional issues are to be dealt with. For the cost of debt, neither Ausgrid nor its customers would be subject to adverse outcomes by moving to the 10 year trailing average approach. This has been noted in consumer advocacy group submissions to the AER.[156] For example, in response to the AER's rate of return consultation paper, the Energy Users' Association of Australia (EUAA) submitted that:

> *If the reason for changing the arrangements for the return on debt is that the current arrangement is flawed, and that a rolling average is a better solution (both propositions now widely accepted) how can any change resulting from the correction of a flawed arrangement be "undue" or "sub-optimal", and hence deserving of a transition arrangement?*[157]

153 Application by EnergyAustralia and Others [2009] ACompT 8 (12 November 2009) (EnergyAustralia and Others), [18], [81].
154 Rule 6.5.2(c).
155 AER, Explanatory statement, Final rate of return guideline, December 2013.
156 See summary of consumer group submissions in NNSW, Submission to AER draft guideline, 11 October 2013, p. 8.
157 EUAA, Submission on rate of return consultation paper, p. 15.

Throughout the rate of return guideline consultation process, we have noted in joint NSW DNSP submissions to the AER that we have prudently managed refinancing risks over the past 10 years by issuing debt on a staggered portfolio basis. Ausgrid maintained this efficient debt management approach despite the previous cost of debt rules, which mandated that the cost of debt be set based on a short term averaging period. Therefore, we do not face the transitional issues that may face network service providers that were able to re-finance large portions of their total debt portfolios (either directly or through derivative instruments) to match the allowed cost of debt under the short term averaging period approach.

The AER's Explanatory Statement to the rate of return guideline clearly demonstrates that the AER agrees that it would not be efficient to attempt to issue 100% of all debt in such a narrow window.[158] Therefore, the AER's justification for the beginning point of its transition (which is the 'on the day' approach) must rely on the belief that businesses can match their costs to the 'on the day' approach using swap contracts. Indeed, the explanatory statement explicitly states:

> *Given the observed practices of regulated network businesses and the definition of the benchmark efficient entity, we consider that the following practice is likely to constitute an efficient debt financing practice of the benchmark efficient entity under* ***[the] current 'on the day' approach:***
>
> *holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period.*[159] *[Emphasis added.]*

Definition of the benchmark efficient entity

The AER appears to be proposing a definition of the benchmark efficient entity as one who uses interest rate swaps to align the resetting of base interest rates to the beginning of the regulatory period. The benchmark efficient entity described in the allowed rate of return objective must be a:

> *benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services]*

Consistent with the advice from UBS, Ausgrid believes that any attempt to use swap contracts in the manner described would have resulted in both the risk of an inefficiently high cost of debt and a risk that Ausgrid would not be able to hedge all of its debt. The transition proposed by the AER in the rate of return guidelines is based on a benchmark efficient entity that responds in a particular way to the specific rules of the regulatory regime and fails to consider the risks faced by Ausgrid. A transition based on this benchmark efficient entity cannot result in an estimate of the return on debt when it is applied to a Ausgrid, particularly one that faces risks faced by Ausgrid.

The AER's ultimate adoption of a trailing average benchmark and not a hybrid benchmark (staggered debt issuance with an interest rate swap overlay) is tacit support for this position.

Impact from the change in methodology

When estimating a return on debt such that it contributes to the achievement of the allowed rate of return objective, section 6.5.2(k)(4) of the rules requires the AER to have regard to:

> *any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.*[160]

This indicates that the AER must consider whether changing the methodology for estimating the return on debt would have any impact on "a benchmark efficient entity". It is important to understand that this factor is directed to any potential impact on the benchmark efficient entity. Therefore it anticipates that there may be circumstances in which a change in methodology to be applied in a distribution determination (as compared to the methodology that was applied in the preceding determination) may adversely affect a benchmark efficient entity. This is consistent with the revenue and pricing principles, the application of which would require that a service provider receives "at least" its efficient costs which may include costs that would be incurred by a benchmark efficient entity as a result of a change in methodology for estimating the return on debt under the NER.

However, putting the above aside, even if the AER could reasonably characterise the current efficient benchmark debt management strategy for Ausgrid as:

> *holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period.*

Then any transition designed to start with this practice would not begin by giving 100% weight to an 'on the day' estimate of the cost of debt. Rather, it would start with the cost of debt associated with this strategy which would need to compensate for the historical average debt risk premium (DRP). This is consistent with the AER's own acceptance that:

> *For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP.*
>
> *Therefore the benchmark efficient entity would not [be] able to alleviate all potential mismatch in relation to the debt margin component of the return on debt, unless it issues the entirety of its debt during the averaging period. To this extent, under the 'on the day' approach the benchmark efficient entity faces a potential trade–off between the need to manage its refinancing and interest rate risk.*[161]

Therefore, even if one did accept that the AER's proposition that "and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period" was efficient under the previous 'on the day approach this does not provide a justification for the AER adopting the 'on the day' approach as the starting point for its transition.

Moreover, the starting point for the transition would need to include transaction costs associated with operating in swap markets – including the costs associated with (hypothetical) large transactions for NSW DNSPs moving the observed market prices. Such costs were not included in Ausgrid's efficient financing costs in its last distribution determination. Ausgrid does not consider that these costs can now be assumed to have been borne by the benchmark efficient entity because the impacts which must be considered under

158 This is, of course, borne out by the fact that the AER moved away from an allowance that was based on 100% debt refinancing at the beginning of the regulatory period. It is also consistent with other statements made in the December explanatory statement to the final rate of return guideline such as "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" (p. 109). For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP. (p 105)

159 AER, Explanatory Statement, Rate of Return guideline, Dec 2013, p. 107.

160 Rule 6.5.2(k)(1) and (4).

161 AER, Explanatory Statement, Rate of Return guideline, Dec 2013, p. 105. This first sentence in this extract is a quote from the AER's adviser, Chairmont consulting.

this clause are the impacts from changing from the methodology applied at Ausgrid's previous distribution determination and the AER's definition of the benchmark efficient practice at that determination. It is clear from the AER's 2009-14 final decision for the NSW DNSPs that the costs of engaging in interest rate swap transactions were not taken into account when setting benchmark efficient debt costs.[162]

In any event, the risks that are faced by Ausgrid mean that the benchmark efficient entity is not able to enter into hedging arrangements to manage its interest risk under the on the day approach. It is therefore an inappropriate starting point for the transition and would result in an estimate of the return on debt that does not contribute to the achievement of the allowed rate of return objective.

Potential under-compensation with a debt transition

Based on current forecasts of yields on 10 year BBB corporate bonds (extrapolated to 10 years and annualised), the AER's transitional approach to setting the cost of debt would significantly under compensate Ausgrid relative to its stand-alone benchmark efficient costs of debt as illustrated in Table 46 and Table 47. The application of the AER's proposed debt transition would not allow us the opportunity to recover at least our efficient costs of debt finance which is inconsistent with the revenue and pricing principles outlined in section 7A of the National Electricity Law.

Table 46 – Ausgrid's benchmark efficient debt cost v AER transitional cost of debt (% per annum)

	2014/15	2015/16	2016/17	2017/18	2018/19	Average
Benchmark efficient cost of debt	7.98%	7.88%	7.77%	7.67%	7.56%	**7.77%**
AER transition cost of debt	6.93%	6.93%	6.93%	6.93%	6.93%	**6.93%**
Difference	-1.05%	-0.95%	-0.84%	-0.74%	-0.63%	**-0.84%**

Note: Assuming the AER adopts the RBA's estimated BBB cost of debt in April 2014 (extrapolating to 10 years effective term to maturity and annualizing) and that rates continue to remain at current levels.

Table 47 – Ausgrid's potential under-compensation ($ millions, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Benchmark debt portfolio	8,622	9,163	9,705	10,154	10,611	**n/a**
Under-compensation	91	97	103	108	113	**510**

Note: Benchmark debt portfolio assumes 60% gearing on Ausgrid's forecast RAB over the 2014-19 period.

Minimising the difference between the allowed return on debt and that of an efficient entity

As demonstrated above, the AER's transitional approach would mean that Ausgrid would not be provided sufficient regulatory revenues to compensate for the efficient staggered portfolio cost of debt based on current short term observations of corporate bond yields. Under the AER's transition approach, the return on debt allowance would not match the efficient cost of debt until 2024/25 - three regulatory periods. This is clearly inappropriate for a business that already issues debt on a staggered portfolio basis. An immediate application of the trailing average should be preferred because it provides longer term stability.

Clause 6.5.2(k)(1) and (4) of the rules require that in estimating the allowed return on debt, regard must be had to:

> *the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*

The benchmark efficient entity would issue debt on a staggered portfolio basis and would need to be provided with a return on debt consistent with the 10 year trailing average estimate. The trailing average approach to estimating the return on debt would minimise the difference between the allowed return on debt and the benchmark efficient return on debt. Therefore, where possible, and in any case for the NSW DNSPs, the AER should apply an immediate transition to a trailing average approach to setting the cost of debt, which it has recognised reflects the benchmark efficient cost of debt. Using the transition approach would not achieve this outcome.

Interrelationship between the return on equity and the return on debt

Finally, the AER must have regard to "the interrelationship between the return on equity and the return on debt"; when estimating the return on debt such that it contributes to the achievement of the allowed rate of return objective under clause 6.5.2(k)(2) of the rules.

The cost of equity is, by necessity, based on estimates of the risk adjusted return for businesses facing a similar nature and degree of risk as that faced by Ausgrid. None of the privately owned and publicly listed energy network businesses regulated by the AER finance themselves in the manner implied by the AER's transition calculation – with all having an element of a stagger to their debt portfolio. If they did finance debt in the manner implied by the AER's transition then equity in those businesses would be materially higher risk due to the refinancing risk equity investors would have to bear. Consequently, the AER's approach results in an internally inconsistent estimate of the cost of equity and debt – with the former based on real world debt financing strategies and the latter based on a hypothetical strategy which the AER acknowledges

[162] AER, NSW DNSPs final decision, 2009-14 distribution determinations, May 2014, p. 232.

would raise the risk and cost of equity if actually implemented. This emphasises the fact that the benchmark efficient entity that the AER has determined for the purposes of the transition is incorrect, particularly when taking into account the risks of Ausgrid.

Conclusion on cost of debt transition

Ausgrid has consistently raised debt on a staggered portfolio basis over the past 10 years, which has allowed us to efficiently manage refinancing risk on our sizeable debt portfolio. Therefore, an immediate transition to a trailing average cost of debt allowance would allow Ausgrid to more closely match the efficient costs of servicing debt that we have raised over previous regulatory control periods. Ausgrid would not be advantaged nor disadvantaged by an immediate transition to a trailing average cost of debt allowance. The allowance would simply more closely match Ausgrid's existing and future efficient debt costs. By contrast, the AER's proposed transitional approach would negatively impact our ability to service our existing efficient costs of debt.

For the reasons outlined above, we consider that applying the AER's proposed transitional approach to setting the cost of debt for Ausgrid is inconsistent with the rules and the NEL. We submit that only the 10 year trailing average approach, with no transition, meets the rate of return objective and other requirements of the rules. It is also the only approach that allows Ausgrid to recover at least its efficient costs of debt incurred in providing standard control services.

Ausgrid's detailed methodology and calculations for the cost of debt are outlined in Attachment 7.01.

Automatic update of the cost of debt

Clause 6.5.2(i)(2) of the rules allow the return on debt to be the same for each regulatory year or different across regulatory years within a regulatory control period. The AER's final rate of guideline stated that the AER intends to annually update the cost of debt within a regulatory control period. Ausgrid agrees with annually updating the allowed return on debt.

Clause 6.5.2(l) of rules requires that, where the allowed return on debt is different across regulatory years within a regulatory control period is, that this be effected through an automatic update. In Attachment 9.02 we set out our proposed approach to adjusting the maximum allowed revenue within the regulatory control period to take into account an annual update the cost of debt. Below we outline how the allowed return on debt itself is estimated for each regulatory year over the 2014-19 period.

Ausgrid considers that the historical corporate bond yield series recently introduced by the RBA provides a robust source of estimates for the BBB cost of debt for Australian corporate entities. In its report to the NSW DNSPs, CEG advised that the methodology used by the RBA is robust and reliable.[163] In its report, CEG also outlines how the RBA BBB forecast of the cost of debt using a 10 year target tenor can be annualised and converted to an effective tenor of 10 years.[164] This is what is required to obtain an estimate of the 10 year cost of the BBB cost of debt for a benchmark efficient energy network firm for each year within the trailing average sample.

Ausgrid considers that the averaging period for each annual observation in the 10 year trailing average should use as many data points as possible to minimise the potential for any single estimate to bias the estimated cost of debt in any particular year. As outlined in a joint NSW DNSP letter to the AER, we outlined that the averaging period for each annual observation of the cost of debt should be 1 January to 31 December.[165] Based on the RBA's current corporate bond yield series this would provide 12 monthly data points of the BBB cost of debt for each year in the 10 year trailing average. By using data up to 31 December each year, the annually updated cost of debt would be available in advance of annual pricing proposals and would also coincide with the cut-off date for annual updates to CPI that are also incorporated as part of annual pricing proposals.

Debt raising costs

The process of raising debt finance incurs significant transaction costs that should be recognised in regulated revenue allowances over the 2014-19 period. The AER's standard practice has been to recognise these costs as benchmark efficient operating expenditure and this is reflected in the AER's PTRM. The AER's PTRM requires input of benchmark efficient debt raising costs in basis points per annum (bppa) that is applied to the regulatory asset base.[166]

Incenta has researched market data on debt raising transaction costs and has found that the benchmark efficient debt raising costs for Australian corporate entities incorporate the following:

- costs of issuing bonds – this includes arrangement fees, bond master program costs, legal fees, credit rating fees, issuance fees etc.
- costs of establishing and maintaining bank facilities required to meet S&P liquidity requirements and maintain an investment grade credit rating – bank facilities are required in the event that bond markets suddenly lose liquidity and funds are still required for operations as was the case during the global financial crisis, European sovereign debt crisis and the US government debt ceiling crisis.
- costs of refinancing debt 3 months ahead of refinancing date, which is required by S&P as a condition of maintaining investment grade credit rating.[167]

Overall Incenta found that the benchmark efficient debt raising costs for Ausgrid would be approximately 9.9 bppa on a levelised basis over the 2014-19 period. The components of these total debt raising costs are outlined in Table 48.

Table 48 – Ausgrid's benchmark efficient debt raising costs

Debt raising cost component	Levelised cost over 2014-19
Debt raising transaction costs	9.9 bppa
Liquidity – commitment fee	7.0 bppa
3 month ahead financing	5.1 bppa
Total debt raising transaction costs	22.0 bppa

Note: Benchmark debt portfolio assumes 60% gearing on Ausgrid's forecast RAB over the 2014-19 period.

Of these benchmark efficient debt raising costs, Ausgrid propose only to include the debt raising transaction cost component, which is approximately 9.9 bppa.

163 CEG, WACC estimates, a report for NSW DNSPs, May 2014.
164 CEG, WACC estimates, a report for NSW DNSPs, May 2014.
165 NSW DNSPs, Letter to the AER on cost of debt averaging periods, 25 February 2014.
166 AER, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008, pp. 8-9.
167 Incenta, Debt raising transaction costs – Ausgrid, May 2014.

7.3 Cost of equity

The AER's final rate of return guideline sets out the AER's intended approach to estimating the return on equity using a "foundation model" approach. The guideline outlines that the foundation model is to be the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM), with:

- evidence from the 'Black CAP' framework informing the estimate of equity beta in the SL CAPM.
- evidence from the Dividend Growth Model framework informing the estimate of market risk premium in the SL CAPM.
- no evidence to be considered from the Fama-French 3 Factor model.

The guidelines also outline a range of evidence that the AER intends to consider when setting the allowed return on equity. In particular when estimating parameters for input to the SL CAPM, the AER has determined that it will estimate:

- the risk free rate using yields on 10 year Commonwealth government bond securities (10 year CGS) observed over a 20 business day period as close as practically possible to the commencement of the regulatory control period.
- the equity beta based on empirical analysis of Australian energy utility firms the AER considers reasonable comparable to the benchmark efficient (which it states provides an equity beta estimate range of 0.4 to 0.7).
- other information on equity betas for overseas firms and the theoretical underpinnings of the Black CAPM to inform the final equity beta estimate.
- the market risk premium (MRP) using historical excess returns, dividend growth model estimates, survey evidence and "conditioning" variables.

Following this, other evidence would be considered, including the "Wright approach" to estimating the SL CAPM return on equity, other regulators' return on equity estimates, brokers' return on equity estimates and takeover/valuation reports and comparisons with the return on debt.[168]

We agree that the SL CAPM can be used as a base model for estimating the allowed return on equity. We also agree that the following sources of information should be taken into account when estimating the allowed return on equity:

- evidence from the 'Black CAPM' (where we use the term "Black CAPM" to signify the body of theoretical and empirical literature that suggests that equity with a zero measured regression beta will earn a return significantly above the government bond rate. Black (1972)[169] is one important, but far from the only, contribution to this literature)
- evidence from the Dividend Growth Model (DGM estimates of the benchmark return on equity and the return on the market)
- using yields on 10 year CGS as a proxy for the risk free rate (although not restricted to short term observations)
- empirical estimates of the equity beta from both domestic and overseas firms
- estimates of the MRP using historical excess returns

The AER's consideration of relevant evidence is too narrow and does not give proper weight to each source of evidence that should be considered when estimating the cost of equity. The proposed approach in the rate of return guideline disregards empirical estimates of the cost of equity from the Black CAPM, the DGM applied to specific utility firms (as opposed to the market portfolio in aggregate) and completely disregards evidence from the Fama-French 3 Factor Model. For this reason, the approach specified in the rate or return guideline has not had regard to all relevant estimation methods, financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the rules.

The term 'relevant' used in clause 6.5.2(1)(e) is not defined in the rules. In the absence of a definition, it is to be given its ordinary meaning in context.[170]

In the context of rule 6.5.2 which sets out the information that the AER must take into account in determining the allowed rate of return, the ordinary meaning of the term 'relevant' means any estimation methods, financial models, market data or other evidence which could rationally affect the AER's assessment of the allowed rate of return under Chapter 6 of the rules.

The AER has formulated assessment criteria outlined in the AER's Explanatory Statement on the rate of return guideline published in December 2013 (AER ROR Explanatory Statement) to determine what evidence it will take into account in determining the allowed rate of return.[171] While the AER may use the assessment criteria in forming a view as to whether or not particular evidence is relevant, it is not able to substitute those criteria for the express wording of clause 6.5.2(e)(1) of the rules. Specifically, Ausgrid notes that some of the criteria such as the simplicity or complexity of the information do not go to the question of whether the evidence is able to rationally affect the AER's assessment of the allowed rate of return, and as a consequence cannot determine the relevance of the evidence for the purposes of clause 6.5.2(e)(1) of the rules.

We also note that the guideline approach for estimating the risk free rate and the MRP is likely to lead to inconsistent parameter estimates within the SL CAPM. The final rate of return guideline identified that there is a requirement for internal consistency in the application of the SL CAPM estimates for the risk free rate and the MRP/expected return on the market.[172] However the final approach outlined in the guideline does not lead to internally consistent estimates of the risk free rate and the MRP being applied and therefore the approach does not take into account interrelationships between estimates of financial parameters (the risk free rate and the MRP in the SL CAPM) that are relevant to the estimate of the return on equity, which is required by clause 6.5.2(e)(3) of the rules.

We propose to depart from the AER's approach as to the estimation methods, financial models, market data and other evidence to be taken into account when setting the allowed return on equity in the following areas, as we believe they are inconsistent with the requirements of the rules:

- estimation of the risk free rate;
- using the Black CAPM cost of equity estimate to inform the choice of point for the allowed return on equity;
- using empirical estimates of the benchmark efficient cost of equity using the Black CAPM to inform estimates of the equity beta when the applying the SL CAPM to set the allowed return on equity;
- using the FFM cost of equity estimate to determine whether estimates from the base model are reasonable; and
- using the DGM estimate of the required return on equity to inform the allowed return on equity.

In the following sections we set out our proposed return on equity and in accordance with schedule 6.1.3 of the NER, we explain our reasons for departing from particular aspects of the AER's method for setting the allowed return on equity.

168 AER, Final rate of return guideline, December 2013, pp. 11-17.
169 Black, Fischer, Capital market equilibrium with restricted borrowing, Journal of Business 45, 1972, pages 444-454.
170 Project Blue Sky CLR.
171 See AER, Explanatory Statement to final rate of return guideline, December 2013, pp 23-24.
172 AER, Explanatory Statement to final rate of return guideline, December 2013, Appendices, p. 108

In contrast, the AER's proposed approach is unlikely to achieve the rate of return objective and may not allow Ausgrid to recover at least its efficient costs of equity finance.

Ausgrid's proposed approach to the cost of equity

Ausgrid has assessed all relevant financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the rules to determine that the benchmark efficient cost of equity is in the range 10.11% to 11.5%. This range incorporates cost of equity estimates using long term and short term financial market data. It also incorporates estimates of the required return on equity/equity related parameters using different financial models including the SL CAPM, the Black CAPM, the Fama French 3 Factor Model (FFM) and the Dividend Growth Model (DGM). We set out below why these estimates are relevant evidence that the AER must consider in determining the allowed rate of return pursuant to clause 6.5.2(e)(1), and the weight that they AER should attribute to them in determining the cost of equity.

Within the range of estimates, Ausgrid proposes a 10.11% cost of equity, which is commensurate with the minimum efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Ausgrid.[173] Specifically, our approach to estimating the required cost of equity, combined with our proposed approach to estimating the cost of debt is consistent with providing returns on equity that ensure long term stability and predictability of returns to equity holders. This is the profile of returns that is commensurate with the returns required by investors in benchmark efficient entities with a similar degree of risk as that which applies to Ausgrid in the provision of standard control services.

This cost of equity is based on long term data and internally consistent parameter estimates within the SL CAPM framework. In arriving at parameter estimates for input to the SL CAPM, we have had regard to all relevant estimation methods, financial model, market data and other evidence as required by clause 6.5.2(e)(1) of the NER. The parameter estimates we have used to estimate the 10.11% minimum required return on equity within the SL CAPM framework are outlined below:

- Rfr – a nominal risk free rate of 4.78% based on historic yields on 10 year Commonwealth Government bonds using data from 1883 to 2011, consistent with the dataset underpinning the calculation of the market risk premium;[174]
- MRP – a market risk premium of 6.5%, based on long term historic data (1883 to 2011)[175] and consistent with the recommended position contained in the AER rate of return guideline; and
- βe – an equity beta of 0.82, consistent with the best empirical estimate from Strategic Financial Group Consulting (SFG), which incorporates data from Australian listed energy network firms and US comparator firms,[176] drawing on evidence from CEG.[177] This estimate is informed by the empirical approaches suggested by a number of Australian academics.[178]

Our proposed SL CAPM point estimate for the allowed return on equity is summarized in the Table 50.

Table 49 – Reasonable range for the cost of equity

Cost of equity model	Parameter approach	Estimated cost of equity
Models that do not account for 'low beta bias' *(a)*		
SL CAPM	Long term – MRP and rfr estimated over a consistent time period	10.1%
SL CAPM	Long term (Wright approach) – Rm estimated over a historical time period.	10.2%
SL CAPM	Short term – MRP and rfr estimated over a consistent time period	10.1%
Models that do account for 'low beta bias'		
Black CAPM	E(rm) and zero beta premium estimated over a long term period.	10.7%
FFM	Contemporaneous rfr, Equity Beta, MRP, SMB and HML factors	10.9 – 11.5 %
CAPM (informed by DGM)	0.94 beta (based on DGM estimates of relative risk), DGM for E(Rm) and prevailing CGS for risk free rate	11.0% *(b)*
Overall Range		**10.1 – 11.5%**

Source: CEG, WACC estimates, a report for NSW DNSPs, May 2014.
(a) "low beta bias" is the bias associated with using government bonds as the proxy risk free rate proxy and using regression estimates of betas.
(b) Average of CEG and SFG based estimates. All estimates are based on a gamma of 0.25 and would be higher with the AER's proposed gamma of 0.5.

173 As required by NER, clause 6.5.2(c).
174 CEG, WACC estimates, A report for NSW DNSPs, May 2014,
175 NERA "The market, size and value premiums", June 2013, p. 17.
176 SFG, Equity beta, May 2014, p. 41 and SFG, Regression based estimates of risk parameters for the benchmark firm, p. 16.
177 CEG, Information on equity beta from US companies, June 2013 and CEG, AER equity beta issues paper: International comparators, October 2013.
178 Gray et. al., Comparison of OLS and LAD regression techniques for estimating beta, June 2013; Gray et. al., The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model, June 2013; Grey et. al., Assessing the reliability of regression-based estimates of risk, June 2013.

Table 50: Proposed cost of equity using CAPM point estimate

Parameter	Basis of estimate	Estimate
Risk free rate, rfr	Long term data 1883-2012	4.78%
Equity beta, ßе	Data from small sample of Australian listed energy network firms and large sample of US comparator firms	0.82
Market risk premium, MRP	Long term data 1883-2012	6.50%
Overall cost of equity estimate		10.11%

Source: See summary provided in CEG, WACC estimates, a report for NSW DNSPs, May 2014.

A detailed description of the approach and calculations of Ausgrid's proposed return on equity is provided in Attachment 7.01.

In terms of equity beta, the AER's small sample of publicly listed Australian energy network firms (currently only 5 firms out of the sample remain listed) produces equity beta estimates between 0.4 – 0.7.[179] Recently, the AER has released an updated empirical report which widens the AER's range for point estimates of equity beta even further to between 0.3 and 0.8. This wide range is indicative of the difficulty in developing a robust estimate of the equity beta for application in the SL CAPM.[180] However, expanding the AER's sample to include equity beta estimates for US listed energy network firms broadens the sample to include data on over 56 US firms. Even when giving each Australian observation twice the weight of each US observation the resulting weighted average beta is 0.82. This improves the statistical robustness of the equity beta estimate[181] and produces a result that is closer to estimates of the required return on equity from other models such as the DGM and the FFM.

The AER's final rate of return guidelines proposes to estimate the risk free rate using only short term observations of the 10 year CGS,[182] but to give greatest consideration to historical averages in estimating the market risk premium.[183] This is an inconsistent approach to populating the SL CAPM to estimate a required return on equity. This is demonstrated by the SL CAPM equation itself. The SL CAPM is specified as outlined at step 1:

1. Expected return on equity for a stock = Risk free rate + ß (Expected return on the market – Risk free rate).
2. The AER estimates (Expected return on the market – Risk free rate = Market Risk Premium) having most regard to the historical average market returns in excess of historical average risk free rates.
3. The AER then implements equation in (1) by combining the Market Risk Premium estimated in step (2) with a prevailing risk free rate. This gives rise to an estimate of expected return on equity for a stock = Prevailing risk free rate + ß (Historical return on the market in excess of Historical risk free rate).

However, fundamentally, the market risk premium is defined in the CAPM as the expected return to the market portfolio less the risk free rate.[184] As a result, whatever risk free rate is used to estimate the MRP must be the same as the risk free rate separately input as the first term on the right hand side of equation (3) above. The AER's approach will result in a short term estimate of the risk free rate being used as the first term on the right hand side of equation (3) above, but a different (long term) estimate of the risk free rate being embedded within the MRP estimate. This can result in an internally inconsistent application of parameters within the allowed return on equity.

This internal inconsistency means that this approach cannot be relied on to promote the allowed rate of return objective. Moreover, clause 6.5.2(e)(3) of the NER, requires that the allowed rate of return estimate must have regard to any interrelationships between estimates of financial parameters that are relevant to estimates of the return on equity and the return on debt. This explicitly directs the AER to have regard to interrelationships within the parameters used to estimate the cost of equity.

The requirement in clause 6.5.2(e)(3) was specifically included in the rules to recognise that for a financial model to be reliable it must properly reflect any interactions between the parameters within the model. In models where two or more parameters are mathematically linked or there is an empirical relationship between them, proper implementation of the model requires that any mathematical relationship between parameters be recognised when estimating those parameters. We note that the AEMC was concerned to ensure that the rate of return framework specifically stated that such interrelationships of parameter values be recognised.[185]

The internal inconsistency is demonstrated even more clearly when the basis of the AER's historical MRP estimates is considered. In the final rate of return guideline, the AER states that it will give primary weight to historical estimates of the MRP and notes estimates in the range 5.7 – 6.4%. We note that NERA economic consulting has produced the most recent and comprehensive estimate of historical excess returns of 6.5% for the period 1883 to 2011.[186] The method used to estimate these excess returns in the historical studies is as follows:

- estimate total annual returns on equity for Australian firms (including both dividends and capital gains)
- then remove the yield on 10 year CGS for each year.

The estimate therefore starts with the actual return on the Australian market and subtracts the proxy for the risk free rate to provide a market risk premium estimate. The only way to avoid inconsistency between the risk free rate estimate used by the AER and the historically estimated market risk premium are to either:

1. Estimate the risk free rate as the average yield on 10 year CGS over the period 1883-2011 as we propose; or
2. Estimate the risk free rate using short term observations of yields on 10 year CGS and estimate the market risk premium based on short term estimates, such as DGM based forecasts of the expected return on the market over the same period as the risk free rate proxy is observed, minus this same risk free rate.

179 AER, Explanatory statement to the final rate of return guidelines, December 2013, p. 86.
180 Henry O., Estimating beta: an update, April 2014, p. 63.
181 See CEG, Information on equity beta from US companies, June 2013, SFG, Report on equity beta, May 2014, p. 15, and SFG, Regression based estimates of risk parameters for the benchmark firm, June 2013.
182 AER, Final rate of return guideline, December 2013, p. 15.
183 AER, Explanatory statement to final rate of return guideline, December 2013, p. 95.
184 CEG, Estimating the return on the Market, June 2013, p. 4.
185 AEMC, Draft Rule Determinations Draft National Electricity Amendment (Economic Regulation of Network Providers) 2012, 23 August 2013, p. 50.
186 NERA "The market, size and value premiums", June 2013, p. 17.

We propose option 1 because a long term approach using the SL CAPM is likely to deliver the most stable cost of equity allowances over time. This approach is consistent with the trailing average approach that we adopt for estimating the cost of debt and is likely to ensure more stable price outcomes for electricity customers between regulatory periods and provides for stable, predictable outcomes for investors over the long term. The estimated cost of equity using option 1 is currently 10.11%. We also note that as shown above, option 2 gives very similar estimates – also centered on 10.1% (CEG has estimated 10.1% and SFG based estimates are 10.2%).

SFG has estimated that the prevailing expected return on the market is around 10.32% excluding any value for imputation credits.[187] SFG has estimated a risk free rate of 4.12% over the 20 days ending on 14 February 2014. This implies a market risk premium excluding the value of imputation credits of 6.2%. Applying an equity beta of 0.82 gives DGM estimate of the required return on equity before imputation credits of 9.2% (= 4.1%+0.82*(10.3%-4.1%)). However, the cost of equity that is entered into the PTRM is inclusive of imputation credits and SFG advises that, for a gamma of 0.25, the pre-imputation credit must be divided by 0.9032 which gives a cost of equity inclusive of the value of imputation credits of 10.20%.

CEG has similarly estimated that the prevailing expected return on the market is around 11.4% including the value for imputation credits. CEG has estimated a risk free rate of 4.0% over the 20 days ending on 13 May 2014. This implies a market risk premium including the value of imputation credits of 7.41%. Applying an equity beta of 0.82 gives DGM estimate of the required return on equity inclusive of the value of imputation credits of 10.0% (=4.0%+0.82*(11.4%-4.0%)).

The Wright approach

The AER's final rate of return guideline states that, towards the end of its estimation process for the cost of equity, the AER would take into account evidence from the "Wright" approach. The "Wright" approach simply involves estimating the required return on the market based on the historical average market return on equity (rather than estimating the MRP based on historical excess returns on equity)[188] As outlined above, the SL CAPM requires an estimate of the expected return on the market and then combines this with estimates of the risk free rate and the equity beta.

The historical estimates of the MRP used by the AER are estimated using annual returns on the equity market (dividends and capital gains) less the risk free rate proxy (10 year CGS yield) in the same year. Applying the "Wright" approach to this same historical data would involve estimating the expected return on the market using the annual returns on the equity market and then combining this with an appropriate estimate of the risk free rate and equity beta. CEG has constructed estimates in this manner and have found that the approach produces much more stable cost of equity forecasts over time.[189]

CEG has estimated that the historical average return on the market in Australia (normalised to a 2.5% inflation environment) is 11.56%. Over the 20 trading days ending on 13 May 2014, average yield on 10 year CGS is 4.0% - implying an MRP of around 7.4%. With an equity beta of 0.82 the Wright approach delivers an estimate of the cost of equity of 10.2% (10.2%=4.0%+0.82*(11.6%-4.0%)).[190]

Notably, this value is almost identical to the cost of equity derived when the MRP is estimated using the DGM model.

By contrast, combining a 4.0% prevailing risk free rate with a historical average MRP estimate of 6.5% and an equity beta of 0.82% will results on a cost of equity estimate of 9.3% - substantially lower than Ausgrid's proposal which is itself lower the estimates from applying the Wright approach and the DGM approach (all with the same equity beta).

We note that the "Wright" approach is not a separate model, but is in fact a way to parameterise the CAPM that should be used when distilling a cost of equity estimate from that model (which aligns closely to the approach suggested by Professor Wright himself, which is that the primary focus should be on the real cost of equity).[191] CEG has advised that the "Wright" approach should also be used to check whether combining an estimate of MRP based on one risk free rate measure with a different measure of the risk free rate produces a reasonable outcome. It is clear from CEG's work that applying the AER's approach that combines a short-term risk free rate and a long term estimate of the MRP does not produce a reasonable outcome when compared to the Wright approach using the same underlying data.[192]

This highlights the significant internal inconsistency in the AER's approach to parameterising the SL CAPM, which is discussed above

Having regard to prevailing market conditions

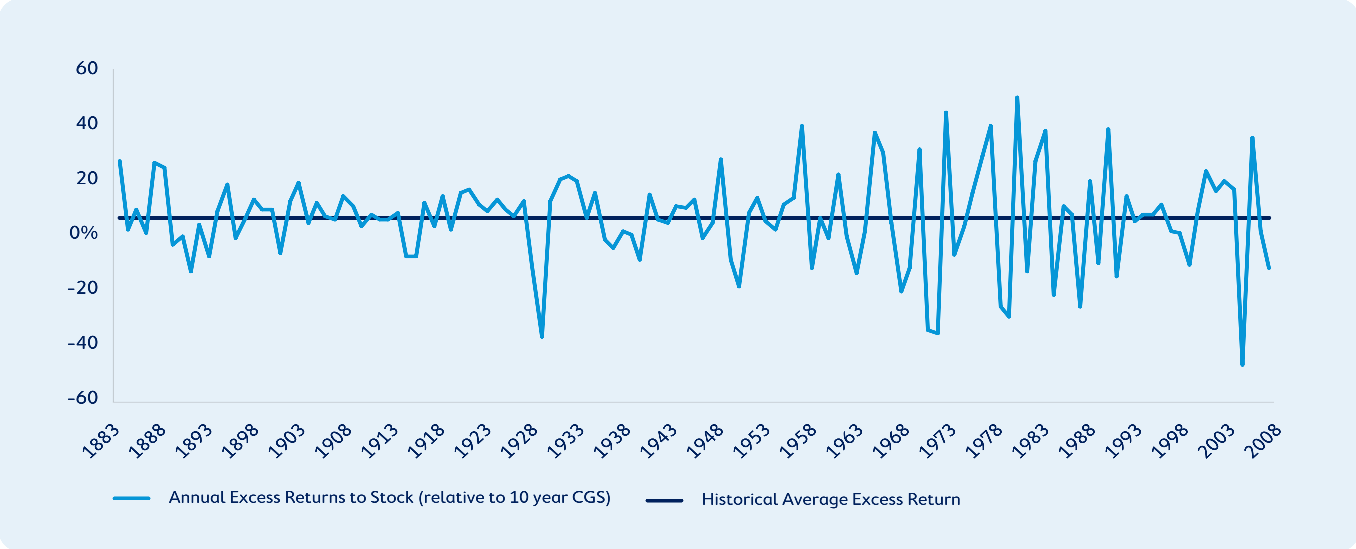
Clause 6.5.2(g) of the NER requires that in estimating the allowed return on equity, regard must be had to prevailing conditions in the market for equity funds. We have had regard to prevailing market conditions by considering short term estimates of the return on equity using the DGM to derive internally consistent SL CAPM paramaters above, this provides a cost of equity estimate of 10.1% (averaging CEG and SFG based estimates) which is very similar to our proposed 10.11% cost of equity using long term estimates. Having regard to these estimates would suggest a cost of equity higher than our proposed estimate. However, having regard to longer term stability we are proposing an allowed return on equity of 10.11%. We believe this will maintain the minimum return on equity required to attract investment into the business over the long term.

We note that estimating the allowed return on equity using historical data is not in itself inconsistent with prevailing market conditions. Historical data is likely to inform investors' expectations and requirements of equity returns over 2014-19.

There is also an advantage to using historical data – it can help to smooth out short-term volatility in financial market data. For example, when estimating historical excess returns, the data relied on by both the AER and Ausgrid, yearly data shows significant variation over the estimation period. This is illustrated in Figure 24. However, averaging this data (as per the dark blue line in the figure below) using a long term approach would promote stability in allowed equity returns across energy network determinations.

187 SFG, Cost of equity in the Black capital asset pricing model, May 2014.
188 Wright S., Response to Professor Lally's Analysis, November 2012, p. 5.
189 CEG, Estimating the return on the Market, June 2013, pp. 30-31.
190 CEG, WACC estimates, a report for NSW DNSPs, May 2014.
191 Conclusion vii in Wright S., Response to Professor Lally's Analysis, November 2012, p. 3.
192 CEG, WACC estimates, a report for NSW DNSPs, May 2014.

Figure 24: Historical realised excess returns on the market (% p.a.)



Source: CEG, WACC estimates, a report for the NSW DNSPs, May 2014.

We also note that the AEMC's final rule determination on the current NER specifically noted that the requirement to determine a rate of return that is commensurate with prevailing conditions is not meant to exclude from consideration historical or realised returns.[193] As outlined, we have had regard to prevailing market conditions and find that our proposed cost of equity is not inconsistent with prevailing market conditions as highlighted by internally consistent short term estimates of the SL CAPM return on equity.

Range of estimates for the cost of equity

There is uncertainty when estimating the benchmark efficient cost of equity because the available information on required returns for equity investments in energy networks is imperfect (indeed the available information on the required returns on equity generally is imperfect). We have been guided by the requirements of the NER when assessing the available information. In particular, the allowed return on equity must be estimated such that it is consistent with allowed rate of return objective (clause 6.5.2(f) of the NER). The allowed rate of return objective is that:

> *...the rate of return ... is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services].* [194]

To achieve this objective we have considered all relevant estimation methods, financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the NER.

The Black CAPM

The rate of return guideline approach disregards empirical estimates of the cost of equity from the Black CAPM. However, Ausgrid considers that empirical estimates of the cost of equity from the Black CAPM are relevant evidence that the AER must take into account in determining the allowed are of return pursuant to clause 6.5.2(e) of the rules. Recent analysis from CEG and SFG illustrates that the Black CAPM framework can be used to provide robust cost of equity estimates for the benchmark energy network firm.[195] Moreover, use of the Black CAPM is likely to lead to more accurate forecasts of required equity returns over the forecast period. This is because the Black CAPM framework relaxes a key assumption of the SL CAPM that all investors can borrow and lend as much as they like at the risk free rate. As noted by the AER, the Black CAPM acknowledges that investors may not be able to borrow and lend at the risk free rate (the AER states that it is in fact unlikely that investors have unlimited ability to borrow and lend at the risk free rate).[196] By relaxing the SL CAPM assumption that investors have unlimited ability to borrow and lend at the risk free rate the Black CAPM framework can more effectively explain movements in equity returns and therefore predict what equity returns would be required over the 2014-19 period.

Using this information would enable the AER to take into account market data on the required return on equity for a benchmark efficient energy network firm with a similar degree of risk as that which applies to Ausgrid in respect of the provision of standard control services. This would contribute to the achievement of the allowed rate of return objective and is therefore relevant evidence that should be considered (in accordance with clause 6.5.2(e) of the rules) when estimating the allowed return on equity for Ausgrid over the 2014-19 period.

We have used the Black CAPM cost of equity estimate to inform the range of reasonable cost of equity estimates as outlined above. Although we have not used the Black CAPM as our base model, our proposed approach uses empirical estimates of the benchmark efficient return on equity from the Black CAPM to both:

1. Inform the choice of a point estimate for the allowed return on equity, and
2. Inform estimates of the equity beta when applying the SL CAPM to set the allowed return on equity.[197]

With regard to the second point, the zero beta premium estimates from SFG [198] (and many other academic studies as listed by CEG),[199] suggest that only considering regression based estimates of equity beta to predict the required return on equity within the CAPM is likely to produce a downwardly biased estimate for low beta stocks. This is a relevant consideration when determining the equity beta estimate that is used to populate the SL CAPM under the AER's "foundation model" approach.

193 AEMC Final Rule Determinations Draft National Electricity Amendment (Economic Regulation of Network Providers) 2012, 29 November 2012, p. 66.
194 Rule 6.5.2(c).
195 SFG, Cost of equity in the Black capital asset pricing model, May 2014.
196 AER, Explanatory statement to the rate of return guideline, Appendices, p. 17.
197 The AER proposed to use only the theoretical underpinnings of the Black CAPM to inform its equity beta estimate. See AER, Explanatory statement to the final rate of return guideline, Appendices, pp. 16-18. However the recent evidence from SFG strongly suggests that empirical evidence from the Black CAPM should be taken into account both when estimating the return on equity as well as determining what estimate of equity beta should be used when setting the allowed return on equity.
198 SFG, Cost of equity in the Black capital asset pricing model, May 2014.
199 CEG, WACC estimates, a report for NSW DNSPs, May 2014.

Even though SFG/CEG's best regression based estimate of equity beta (0.82) is above the top of the AER's range (0.70), the evidence from CEG, Grundy, NERA and SFG using the Black CAPM framework suggests that the AER's implementation of the SL CAPM (using the government bond rate as the risk free rate proxy) is likely to underestimate the required return on equity for stocks with an empirical equity beta less than 1.0.[200] This means that, even with a 0.82 equity beta, required returns are likely to be underestimated using the AER's implementation of the SL CAPM.

Therefore we propose that, as a minimum, the Black CAPM evidence suggests that the more robust empirical equity beta estimate of 0.82 should be used. We note that, based on the advice of Grundy, CEG and SFG, fully adjusting for the above underestimation would require an increase in the estimated cost of equity by around (1-0.82)*0.5*MRP. This would be an increase of 59 basis points for an MRP of 6.5%.

The Fama-French three Factor Model

The AER's final rate of return guideline gives no weight to the Fama-French three Factor Model (FFM). We consider that the FFM is a relevant financial model that the AER should have regard to pursuant to clause 6.5.2(e)(1) of the rules.

Estimating the required return on equity for a benchmark efficient firm over the 2014-19 period effectively requires a prediction of what equity investors require/expect over that period. The FFM significantly improves predictability of stock returns over time compared to the SL CAPM (which, as discussed below has been recognised by the Nobel Prize Committee). Considering estimates of the return on equity for the benchmark efficient firm using the FFM model would help to develop an estimate of the return on equity that is commensurate with prevailing conditions in the market for funds over the 2014-19 period as required by clause 6.5.2(g) of the rules.

Considering estimates of the return on equity from the FFM would also assist in developing an estimated return on equity that is commensurate with the required return on equity for a benchmark efficient firm with a similar degree of risk as that which applies to Ausgrid in respect of the provision of standard control services, as required by clauses 6.5.2(f) and 6.5.2(c) of the rules.

One of the authors of the FFM, Eugene Fama, has recently won the Nobel prize in part for his work on the FFM model. The Nobel Prize Committee noted that the FFM model significantly improves predictability of stock returns over time compared to the SL CAPM. The Committee's background paper notes that:

> *...the classical Capital Asset Pricing Model (CAPM) – for which the 1990 prize was given to William Sharpe – for a long time provided a basic framework. It asserts that assets that correlate more strongly with the market as a whole carry more risk and thus require a higher return in compensation. In a large number of studies, researchers have attempted to test this proposition. Here, Fama provided seminal methodological insights and carried out a number of tests. It has been found that an extended model with three factors – adding a stock's market value and its ratio of book value to market value – greatly improves the explanatory power relative to the single-factor CAPM model.*[201]

The Committee also noted:

> *...following the work of Fama and French, it has become standard to evaluate performance relative to "size" and "value" benchmarks, rather than simply controlling for overall market returns.*[202]

These statements provide a clear indication that the Nobel Prize Committee considers the FFM model is a relevant financial model for estimating equity returns.

However, the AER's final rate of return guideline concluded that the FFM was not a relevant financial model to have regard to when setting the allowed return on equity. The AER concluded that:[203]

- the FFM model risk factors have no clear theoretical foundation
- the empirical patterns on which the FFM was developed may be variable over time, and may not apply in Australia
- the FFM is complex to implement
- to the AER's knowledge, the model is not used to estimate future returns on equity in Australia.

NERA have responded to many of these concerns in a report that was previously submitted to the AER. NERA set out, contrary to the AER's statements in the final rate of return guideline that:

- the FFM has strong theoretical foundations
- there are benefits to using the FFM to estimate the cost of equity for value stocks (which SFG has demonstrated that the benchmark energy network firm is likely to be)[204]
- the FFM is used in practice [205]

Furthermore, in response to the AER's claims that the FFM is complex to implement, estimates of the required return on equity using the FFM are readily available to the AER.[206] CEG has estimated the return on equity for the benchmark efficient energy network firm to be approximately 11.5% using long term estimates of parameters in the FFM and 10.7% using short term estimates of parameters. This analysis is based, in part on SFG's analysis referred to above.

Only using return on equity estimates produced by the SL CAPM (which is the approach outlined in the AER's final rate of return guideline) disregards relevant evidence from FFM estimates of the required return on equity, which is inconsistent with clause 6.5.2(e)(1) of the rules. Due to the FFM's greater ability to fit data on stock returns than the SL CAPM, empirical estimates of the benchmark efficient required return on equity using the FFM:

- provide relevant information on prevailing conditions in the market for funds (as required by clause 6.5.2(g) of rules) in addition to information from the empirical estimates using only the SL CAPM
- provide information on the required return on equity for a firm facing a similar nature and degree of risk as that faced by Ausgrid in addition to evidence from the empirical estimates using only the SL CAPM.

We propose that the benchmark cost of equity estimates produced by CEG using the FFM framework should be considered when setting the allowed return on equity for Ausgrid to determine whether estimates from the base model we have used are reasonable. The FFM estimates indicate that our proposed return on equity of 10.11% is reasonable and if anything is at the low end of the

200 SFG, Cost of equity in the Black capital asset pricing model, May 2014. NERA, Estimates of the zero beta premium, June 2013 and CEG, WACC estimates a report for NSW DNSPs, May 2014.

201 Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, UNDERSTANDING ASSET PRICES, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, October 2013, p. 3.

202 Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, UNDERSTANDING ASSET PRICES, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, October 2013, p.44.

203 NERA, The Fama-French Three Factor Model, October 2013.

204 SFG, Regression based estimates of risk parameters for the benchmark firm, June 2013.

205 See The Fama-French Three Factor Model, October 2013, pp. 34-42.

206 AER, Explanatory Statement to the Final rate of return guideline, December 2013, Appendices, p 23.

reasonable estimates. Considering empirical estimates of the benchmark efficient return on equity using the FFM and assessing the allowed return on equity in this manner will result in a more accurate estimate of the return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Ausgrid in providing standard control services than an approach which disregards all evidence from the FFM. Therefore considering evidence from the FFM as we propose will achieve the allowed rate of return objective and will contribute to achieving the National Electricity Objective, whereas disregarding all evidence from the FFM as proposed in the AER's final rate of return guideline will not.

The Dividend Growth Model

The AER's final rate of return guideline recognises that the DGM is a relevant financial model that should be considered when setting the allowed return on equity.[207] The guideline states that the underlying financial theory of the model (that the price of an asset should be equal to the present value of the expected future cash flows from that asset) is well accepted and sound.[208] The guideline also states that the dividend and price information needed to estimate the required return on equity using the DGM are readily observable in the market and as such the model is flexible to reflect changing market conditions.

However, the guideline states that the DGM suffers from implementation issues because the estimates are sensitive to dividend yield and growth rate assumptions. The guideline refers to estimates of the benchmark network business rate of return using the single period (constant growth rate) DGM to demonstrate this sensitivity. The guideline states that the DGM applied to overall equity market returns does not suffer the same implementation issues as the estimates for the benchmark firm. Based on these considerations, the guideline concludes that the DGM should only be used to inform the estimate of the MRP.

We agree with the AER, that the DGM should be used to inform the estimate of the MRP/Expected return on the market when applying the SL CAPM (SFG has estimated that the three stage DGM implies an MRP of 6.43% using data from July 2002 to January 2014 and 7.46% using market data from January 2010 to November 2013).[209] However, we also consider that the DGM can be used to provide an estimate of the required return on equity for a benchmark regulated firm.

DGM based estimates of the required return on equity are very useful, because the nature of estimates are quite different to the SL CAPM, Black CAPM and FFM based estimates of the return on equity. The DGM relies on dividends, earnings, share prices and forecasts of dividend/earnings growth, whereas the SL CAPM, Black CAPM and FFM based models rely on regression based estimates of risk parameters. The DGM therefore provides a largely independent estimate of the benchmark return on equity for a regulated energy network firm, which should be taken into account when assessing the range of cost of equity estimates.

In concluding that the DGM should not be used to estimate the required return on equity for the benchmark efficient firm, the AER has referred to implausible estimates of the return on equity for the benchmark efficient energy network firm produced by the single-stage (constant growth rate) DGM.[210] However, the AER's guideline has not substantively addressed DGM estimates of the return on equity that have been developed by SFG which do not impose a long run dividend growth rate [211] other than to say that SFG's DGM is complex.[212]

The DGM outlined by SFG reduces sensitivity of return on equity estimates to the perpetual growth rate assumption for dividends. This is because the model allows the dividend growth rate to transition from current levels to a reasonable long term assumption for growth in dividends.[213] SFG has recently updated its analysis of the DGM based estimates of the return on equity for firms with a similar degree of risk as that which applies to benchmark efficient regulated energy networks.[214] In its latest report on the DGM, SFG outlines the theory and application of the DGM in estimating the required return on equity and demonstrates that estimates of the required return on equity for the benchmark efficient firm can and should be used when setting the allowed return on equity in energy network determinations under the rules.

SFG's report outlines that the required return on equity for the benchmark efficient energy network firm is approximately 11.0% using a DMG based estimate of relative risk for the equity beta (as opposed to a regression based estimate of beta) in the CAPM[215] We consider this is relevant evidence within the meaning of clause 6.5.2(e)(1) of the rules because the DGM has a sound empirical basis (as acknowledged by the AER) and because SFG's DGM incorporates mean reversion of growth in dividends. By enabling mean reversion of growth in dividends. SFG's DGM approach addresses the implementation problems referred to by the AER (which exist for the constant growth versions of the DGM). In addition to this, SFG's DGM based estimate relative risk for the benchmark efficient energy network firm reflects prevailing market conditions as required by clause 6.5.2(g). This is because it uses current equity prices and dividend yields.

By reflecting prevailing conditions in the market for funds and not requiring regression based estimates of risk parameters, DGM based estimates of the required return on equity for the benchmark firm (i.e. using the DGM based relative risk estimate of the equity beta as SFG does) are likely to improve estimates of the required return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Ausgrid.

We consider that SFG's DGM based estimate of the required return on equity for the benchmark efficient energy network firm (11.0%) indicates that our proposed return on equity of 10.11% is at the low end of reasonable estimates taking into account all relevant financial models, and other evidence as required by clause 6.5.2(e)(1) of the rules. Considering estimates of the benchmark efficient return on equity as informed by a DGM based estimate of relative risk to estimate the equity beta in the CAPM will result in a more accurate estimate of the return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Ausgrid in providing standard control services than an approach which does not consider estimates of the benchmark efficient cost of equity using the DGM framework. Therefore considering evidence from the DGM as we propose will achieve the allowed rate of return objective and will contribute to achieving the National Electricity Objective, whereas the proposed approach in the AER's final rate of return guideline will not.

207 AER, Final rate of return guideline, December 2013, p.13 and AER, Explanatory statement to the final rate of return guideline, December 2013, p. 96.
208 AER, Explanatory statement to the final rate of return guideline, Appendices, December 2014, pp. 14-15.
209 SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 11.
210 AER, Final rate of return guideline, Appendices, December 2014, pp. 14-15.
211 SFG, Dividend discount model estimates of the cost of equity, June 2013.
212 AER, Final rate of return guideline, December 2014, pp. 14-15.
213 SFG, Dividend discount model estimates of the cost of equity, June 2013, pp. 11–16.
214 SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 64.
215 SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 64.

Equity raising costs

Raising equity finance incurs costs that should be recognised in regulated revenue allowances over the 2014-19 period. The AER's standard practice has been to recognise equity raising costs as capex within the PTRM and amortise these costs over the life of the assets that they are used to fund.[216] Ausgrid has applied the AER's standard cash flow analysis sheet within the PTRM to estimate the benchmark efficient equity raising costs that are estimated over the 2014-19 period. The components of these costs are outlined below.

Table 51 – Benchmark efficient equity raising costs components

	Cost over 2014-19
Seasoned equity offering (SEO)/ Subsequent equity raising costs	3.00%
Dividend re-investment plan cost	1.00%

Source: AER, Powerlink transmission determination 2012-13 to 2016-17, April 2012, p. 108.

In estimating the benchmark efficient equity raising costs we have assumed a dividend re-investment plan take-up of 30% and a dividend payout ratio of 70% (this is consistent with our assumption of the imputation credit payout ratio, which is discussed further below).

7.4 The value of imputation credits

The NER state that the estimated cost of corporate income tax should be reduced by the value of imputation credits. Within the post-tax revenue model framework, this means that the allowed revenues for tax expense will be less than the company is actually likely to incur. Most companies pay a cost of corporate income tax equal to 30% of earnings after opex, interest costs and depreciation. However, under the NER framework, the revenues allowed for cost of corporate tax is reduced by the assumed value of imputation credits as set out in clause 6.5.3 of the NER:

Estimated cost of tax = (Estimated taxable income × Corporate tax rate) (1- value of imputation credits)

This effectively reduces the post-tax return on equity provided by the company and assumes that a portion of the post-tax return on equity is achieved through the value of imputation credits. Therefore, it is absolutely essential that the estimated value of imputation credits represents the value of imputation credits to investors within the company. If the imputation credit assumption is higher than the value that investors attribute to them, then ceteris paribus, regulated revenues will not be sufficient to provide the allowed return on equity applied in the determination. This outcome would not be consistent with the section 7A of the NEL, which requires that:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in —*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

The AER's final rate of return guideline applies an approach that defines the value of imputation credits (gamma) as the product of:

- the payout ratio for imputation credits; and
- the utilisation rate (theta or Θ), which is the value of each dollar of distributed imputation credits

The AER applies an estimate of the payout ratio of 70%. The AER estimates the utilization rate as 0.7 based on excessive weighting to the "equity ownership" approach and tax statistics estimates. However, this approach does not actually estimate the value of distributed imputation credits to investors.

Ausgrid proposes to calculate gamma in accordance with the Monkhouse formula, as the product of:

- the distribution rate (i.e. the extent to which imputation credits that are created when companies pay tax, are distributed to investors); and
- the value of distributed imputation credits to investors who receive them (referred to as theta).

Ausgrid proposes a distribution rate of 0.7, which is consistent with the AER's rate of return guideline. Recent empirical evidence continues to support a distribution rate of 0.7. [217]

Ausgrid proposes a value for theta of 0.35. The reasons why Ausgrid is proposing a different value for theta to that in the rate of return guideline include:

- Ausgrid 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 National Electricity Objective (NEO). It does not measure the required return for the purposes of promoting efficient investment, and would lead to underinvestment.
- 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 are compelling reasons why the benefit of imputation credits, which is the amount by which the allowable return otherwise calculated in accordance with the NER should be reduced, is significantly less than the face value of imputation credits or the utilisation of imputation credits. However, these were not considered in the rate of return guideline.
- The value for theta proposed by Ausgrid 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 rate of return guideline does not.
- There are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the rate of return 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)) is not an empirical study at all (because the data was not available), but merely involves an

216 See for example AER, Final decision, ElectraNet 2013-14 to 2017-18 transmission determination 2013-14 to 2017-18, p. 87; AER, Final Distribution Determination Aurora Energy Pty Ltd, 2012-13 to 2016-17, April 2012, p. 78; AER, Final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012, pp. 107-108; AER, Final decision, Victorian distribution determinations 2011-2015, Appendix O, pp. 505–506; AER, Final decision, Qld Distribution determination 2010-11 to 2014-15, May 2010, p. 201;

217 NERA, The payout ratio, June 2013.

assumption of full utilisation by domestic investors; any reliance upon it involves obvious error.

- 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;
- The best estimate of investors' valuation of imputation credits from market value studies is 0.35.

Combining a distribution rate of 0.7 with a theta estimate of 0.35 produces a value for gamma of 0.25, which differs from the AER's gamma estimate as outlined in the final rate of return guideline. Ausgrid's reasons for proposing a different value for theta to that in the rate of return guidelines are outlined in Attachment 7.26 and SFG's latest report addressing the value of imputation credits.[218]

[218] SFG, An appropriate regulatory estimate of gamma, May 2014.

8. Alternative control services

The AER sets a separate price cap for some of our smaller services – public lighting, ancillary (or non-routine) services and elements of our metering services. Our proposed price reflects the efficient costs of providing these services.

The AER has classified public lighting services, ancillary network services and some metering services as 'alternative control services' and decided to set a price cap as the control mechanism.[219] We are required to submit a regulatory proposal that demonstrates the application of the AER's control mechanism for alternative control services and to provide adequate supporting information.[220] We are also required to provide indicative prices for these alternative control services each year of the 2014-19 period.[221] We address these requirements for alternative control services in this chapter.

This chapter sets out our proposed indicative prices for alternative control services. Customers buying these services will pay a specific cost reflective price for the service, rather than the costs being bundled as part of the network charge.

The main difference customers will see this regulatory period is the AER will determine a standalone price for metering effective 1 July 2015, which was previously bundled in network tariffs. We have removed our cost of providing metering services from our main network costs and therefore have ensured the new metering charges are offset by an equivalent reduction in our network tariffs.

The key points of this chapter are:

1. **We have proposed public lighting prices using a methodology similar to that developed by the AER last period. We hope to work with customers and the AER to make improvements to the public lighting pricing framework.**

Our proposed prices for public lighting have considered the capital, operating and implementation costs of providing elements of our service. We have used the AER's public lighting pricing models approved in its 2010 pubic lighting determination.

2. **Our proposed metering prices will be based on the metering service provided to the customer, which is driven by the type of meter installed on its premises.**

Customers will have a separate tariff for metering services depending on the meter installed. In developing prices, we have considered the revenue we need to fund significant investment in metering undertaken in the past. The new metering charges are offset by an equivalent reduction in our network tariffs.

3. **Our proposed prices for each ancillary service will reflect the efficient costs of providing the service.**

We have more than 52 non-routine services we provide our customer base. In the past the customers pay only a portion of the cost of providing the service, with the residual collected from the general customer base. The AER now consider that customers should face the full cost reflective charge for these services.

8.1 Public lighting

We have applied the AER's control mechanism of a cap on the prices of individual services by proposing a series of fixed charges, annual capital prices and residual capital value charges.

Our proposed approach to pricing public lighting services is consistent with the AER's 2010 determination for last period. Our public lighting customers will continue to pay a fixed charge for assets installed before July 2009 and an annual capital price for assets installed after July 2009. Customers will also continue to pay annual maintenance charge per asset. The final part of the control mechanism is a cap on the residual capital value that we can recover when customers choose to have lights replaced early.

We have undertaken considerable analysis of alternative options to replace the current complicated pricing models with models that allow Ausgrid to provide a simple price list that is transparent to customers and other stakeholders.

In this section we provide an overview of public lighting services and the indicative prices for the 2014-19 period which demonstrate the application of the control mechanism. Further details supporting our proposal on public lighting services can be found in Attachment 8.01 and other attachments and supporting documents which provide more details on our proposal. We address the application of the AER's formulae to give effect to the control mechanism in Attachment 9.02.

219 Refer to AER's framework and approach paper
220 See clause 6.8.2(c)(4) of the rules.
221 Clause 6.8.2(c)(4) of the rules.

About our public lighting services

Public lighting services encompass the provision, construction and maintenance of public lighting and emerging public lighting technology.[222] Ausgrid provides public lighting services to over 90 customers including councils, community groups and government associations. There are over 240,000 public lights in Ausgrid's network area, which are typically installed on major and minor roadways. A conventional public light comprises five (5) main components of a lamp, a luminaire, a support structure, a bracket and a connection to the low voltage electricity network. Attachment 8.02 provides an introduction into Ausgrid's public lighting services.

Under the AER's 2010 determination models that we have adopted, each lamp, luminaire, support structure, bracket and connection is treated individually from a cost build up perspective and results in two types of capital charges mentioned above. The maintenance charge per lighting structure is charged based on the lamp type but relates to the cost of maintaining all 5 components. Generally customers pay capital and maintenance charges, however some customers choose to install their own public lighting assets, which are gifted to Ausgrid and therefore they only pay Ausgrid to perform annual maintenance activities. Additionally, some customers choose to replace an existing public lighting asset before its economic end of life. In this case a residual charge is calculated which represents the remaining value of the asset.

Ausgrid has historically provided a variety of different light types including a range of lights designed for non standard or aesthetic purposes. As a result Ausgrid has quite a diverse population of light types, which is part of the complicated billing currently in place. Ausgrid will continue to maintain these legacy non standard lights until they require replacement at which time they will be decommissioned and replaced with a light from our standard list of light types. More information can be found in Attachment 8.03

Our proposal is to provide our lighting services to the standards specified in the NSW Public Lighting Code (Attachment 8.04). The main service level is to repair broken lights, on average, within eight days after we have been notified of a failure. Further details of public lighting service levels can be found in Attachment 8.05.

Objectives of public lighting

Our public lighting proposal is based on achieving a set of objectives which help to ensure the prices proposed are fair for the level of service we offer and recover our efficient costs. The objectives have been developed to provide an efficient and cost effective service to our customers while aiming to comply with the public lighting code. There are four key objectives:

Minimise total lifetime cost for Ausgrid and our customers

Ensuring that Ausgrid operates prudently and efficiently is fundamental to providing the required service at the lowest cost. This includes:

- Improving labour productivity.
- Reducing overheads through network reforms.
- Standardising our lighting population.
- Offering energy efficient lighting technology.

Maintaining network performance as described in the public lighting code

Attachment 8.04, the NSW Public lighting code is a document which describes minimum performance standards and practices for the provision of public lighting services. This document references the Australian Standard (AS1158) for public lighting. In the 2014-19 period, we will be working towards meeting the targets of the code throughout the regulatory period.

Decrease complexity and provide more transparency to the customer

Reducing complexity and providing more transparency in the pricing of public lighting services is a concern that has been conveyed to us during consultation with councils, the AER and the CCP. We have made effort to address this concern by:

- Chairing meetings with councils and the AER to outline different pricing options and seeking feedback on these.
- Made available our public lighting pricing models on Ausgrid's website.[223]

Attachment 8.06 details Ausgrid's engagement with our customers and the AER through this current period. Attachment 8.07 outlines a number of improvements to our public lighting service processes.

Currently, there are three categories of public lighting charges, capital, maintenance and residual charges:

- Fixed capital charge for assets installed prior to 2009 and annuity capital charge for assets installed post 2009.
- Maintenance charge that is applied to all assets.
- Residual charges for assets replaced before their regulatory end of life.

We have undertaken considerable analysis of other pricing options to attempt to reduce the price list from over 300 prices down to a standard list of prices for 24 services. We would like to work further with the AER and our customers to develop our alternative to the AER's 2010 models to help provide pricing transparency and a simpler customer bill.

Efficient cost reflective prices

Ausgrid's proposal to ensure cost reflective prices will help customers and Ausgrid. Efficient cost reflectivity at the highest level will ensure Ausgrid can recover the cost incurred in providing the public lighting service. It also means customers have a sound basis for decisions about technology and whether to seek an alternative third party to provide public lighting services.

222 AER, stage 1 framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy, Transitional regulatory control period 1 July 2014 to 30 June 2015 & subsequent regulatory control period 1 July 2015 to 30 June 2019.

223 (https://www.ausgrid.com.au/Common/About-us/Newsroom/News-gallery/Network-maintenance/Street-lighting.aspx)

Our costs and revenues

The basis of our public lighting proposal is to recover the efficient costs of providing the standard public lighting services. These services are underpinned by our existing capital costs plus new capex and opex. Our capex and opex forecasts include the ongoing maintenance of our lights and investment in programs to replace old lights with new technology. More detail about our proposed capex in Attachments 8.08 to 8.11 whilst details of forecast opex can be found in Attachment 8.12.

The existing capital costs have been included in the roll-forward of a public lighting asset base, which has been carried forward from the AER's 2010 public lighting determination. As this only includes assets that were installed prior to 1 July 2009, new capital has not been added. The value of the public lighting asset base has been depreciated from $140 million as at 1 July 2010 to $101 million as at 1 July 2014. Attachment 8.13 includes the calculations underlying this asset base value and details the individual customer allocations of the asset base.[224]

Our prices for assets installed after 30 June 2009 include capital costs based on the annuity model from the AER's 2010 determination model, which has been updated for the current inputs. As a result there is no forecast asset value for assets installed after 30 June 2009.[225] We have made two key changes to this model:

1. The allocation of labour to the installation of a luminaire and bracket has been split to better reflect the volumes of this work in reality. The 2010 determination split was 90% to the bracket and 10% to the luminaire. This did not allow for accurate cost reflectivity as brackets are not often replaced with luminaires and therefore only 10% of the labour is recovered in the annuity price when a luminaire is installed without a new bracket.
2. Overheads and on costs associated with capex, as well as a proportion of overtime labour has been included to better reflect the true costs associated with the installation of these assets.

Similarly our opex forecasts are based on the AER's 2010 determination opex model updated for the most recent inputs (see Attachment 8.13[226]). We have made two key changes in this model:

1. We have not assumed a flat rate of 25% overheads for each price. Instead we have adopted a percentage calculated using our approved cost allocation method. In doing this we have also removed on costs from the labour rate to ensure overhead costs are not double counted.
2. We have adopted actual asset failure rates, instead of the manufacturers' estimated lamp failure rates, to determine how much reactive maintenance will be required into the regulatory period. This change was required as Ausgrid has observed many more reactive repairs this regulatory period than was implied in the AER's 2010 determination model by using manufacturer failure rates.

Public lighting prices

These costs and revenues underlie our moderate price increases. Given the complexity of the current pricing arrangements, it is difficult to provide a single average price increase. A complete list of our proposed public lighting prices for the five years period 2014-19 is provided in Attachment 8.14.

8.2 Metering services

In the AER's framework and approach paper, the AER decided to re-classify metering services from standard control to alternative control. This has meant that metering is no longer part of the bundled charge for standard control services, but that customers pay a cost reflective charge based on the meter installed.

In this section we outline our proposed indicative prices for metering services. We identify the types of meters that are subject to pricing regulation by the AER, how we developed metering prices, and the proposed charge our customer will pay depending on the type of meter installed.

We have applied the AER's control mechanism of a cap on the prices of individual services. We have done this by proposing a series of prices caps on the services that comprise metering services, including an exit fee where a customer chooses to replace a type 5 and 6 meter with another meter such as a type 4 meter.

Attachment 8.15 provides the detailed process we have followed to develop the indicative prices for type 5 and 6 metering services.

About our metering services

Metering services is one of the terms developed by the AER to group classes of services provided by NSW distribution businesses. The AER has divided Metering Services into the following three categories:

1. **Metering installation types 1, 2, 3 and 4:**
   The rules require a type 1, 2, 3, or 4 metering installation at premises where energy consumption is greater than 160MWh per annum.[227] These types of meters record detailed energy usage and have a number of other required capabilities,[228] the most significant being the requirement to have remote communication facilities installed.

   The provision of metering services for metering installation types 1, 2, 3, and 4, is provided in a competitive market and are therefore not regulated by the AER.
2. **Metering installation types 5 and 6:**
   Type 5 metering installations record energy in 30 minute intervals, without the requirement to remotely acquire the data. Typically, these meters are read every three months, sometimes monthly.[229] Often the term MRIM (manually read interval meter) is used interchangeably for type 5 meter. A type 5 metering installation however, is not the same as a Smart Meter[230] installation.

   A type 6 metering installation is defined as a 'general purpose' meter that records accumulated energy data only.[231] The term 'BASIC meter', accumulation meter and type 6 meter can be used interchangeably.

   Currently, distribution businesses are required to provide metering services at premises with energy consumption less that 160MWh per annum where type 5 or 6 metering is installed.[232]

224 This attachment contains 4 models – see models titled 'Public lighting opening RAB value @ 1 July 2014' and 'Pre 2009 Fixed Charge Model'.
225 See model titled 'Post June 2009 annuity prices' model within the attachment 8.13 package.
226 See 'Opex cost build up model' within this attachment package.
227 An average domestic customer consumes approximately 7MWh pa.
228 Meter capabilities include the ability to record 1/2 hr energy consumption (kWh), data storage requirement >35 days, the measurement of reactive energy (kvarh) (for Type 1, 2 and 3) and the ability to access the meter data on a daily basis (i.e. remote communication facilities).
229 The time between meter reads is normally a function of the network tariff applicable to a customer's premises.
230 The National Electricity Law defines smart metering infrastructure as "infrastructure (and associated systems) associated with the installation and operation of remotely read electricity metering and communications, including interval meters designed to transmit data to, and receive data from, a remote locality.
231 Processes used to convert the accumulated metering data into trading interval metering data for settlements purposes are included in the metrology procedure.
232 For metering installation types 1, 2, 3 and 4, the customer's retailer is the responsible person and contracts an MPB and MDP.

3. **Metering installation type 7:**
   A type 7 metering installation applies to the condition where it has been determined by the Australian Energy Market Operator (AEMO) that the metering installation does not require a meter. Examples may include, street, traffic, park, and community lighting, traffic parking meters.

   The AER has decided that metering data services associated with type 7 metering installations, like network services, will continue to form part of standard control services.

Ausgrid is responsible for approximately 1.62 million national metering identifiers (NMIs) connected to its distribution network where Type 5 or type 6 meters are installed. Some NMIs have one meter, whilst others have two or more. This is why Ausgrid's total type 5 and type 6 meter population is approximately 2.4 million meters as shown in Table 52.

Table 52 - Ausgrid's Type 5 and 6 metering population for 2013/14

Meters	Type 5 meters	Type 6 meters	Total
Ausgrid NMIs	463,000	1,156,000	**1,619,000**
Ausgrid meters	658,000	1,696,000	**2,354,000**

The rules establish the role of the responsible person as the party responsible for:

- The provision, installation and maintenance of a metering installation.
- The provision of metering data services (including the collection, processing and delivery of the metering data) in accordance with the rules.
- Engaging appropriately accredited metering providers (MPBs) and meter data providers (MDP) to conduct these services on their behalf.

The local network service provider (LNSP) is mandated under the rules to perform the role of responsible person for type 5 and type 6 metering installations at premises with energy consumption less that 160 MWh per annum where type 5 or 6 metering is installed. As the designated responsible person for type 5 and 6 metering installations located in Ausgrid's network area, the rules require us to:

- Ensure that all relevant connection points are metered to the defined standard.
- Develop a metering asset management plan (MAMP) for the maintenance of metering installations and for the MAMP to be approved by the Australian Energy Market Operator (AEMO).
- Comply with the rules and the associated procedures (Metrology and MP/MDP service level procedures) in relation to the method for provision, installation, maintenance of metering installations and provision of metering data services.
- Where relevant, we also ensure that we meet the Australian Standards applicable to metering equipment. Type 5 and 6 metering equipment must also meet the requirements of the National Measurements Act and the equipment is pattern approved and verified by a National Measurements Institute approved laboratory.

Strategic objectives of metering services

In addition to complying with requirements of the responsible person role contained in the rules and any other regulatory requirements, Ausgrid's overall objective of ensuring investment is prudent and efficient for the required outcome has lead to the following business objectives governing the provision of type 5 and 6 metering services:

- Metering is safe and accurate.
- Metering equipment supports network pricing strategies.
- Compliant with the Networks NSW metering strategy.
- Able to support the network load control strategy.
- Able to support any related market or customer objectives identified as being within the network business scope.

Activities undertaken to deliver metering services

In the AER's stage 1 F&A, the AER outlines four sub-categories of metering services relating to type 5 and type 6 meters. These sub-categories are defined as:

1. Meter provision - The capital costs of purchasing the meters.
2. Meter maintenance - covers works to inspect, test, maintain, repair and replace meters.
3. Meter reading - refers to quarterly or other regular reading of a meter.
4. Metering data services – services incorporating the collection, processing, storage and delivery of metering data and the management of relevant National Meter Identifier (NMI)[233] Standing Data in accordance with the rules.

Meter provision

In NSW, Accredited Service Providers (ASPs)[234] install type 5 and type 6 whole current meters at new and upgraded connections. The costs associated with the ASP installing the meter(s) at a new or upgraded premise is paid by the customer to the ASP as part of the total costs for electrical works and does not form part of the annual metering price. Ausgrid purchases rules compliant meters and manages the logistics of issuing the meters to the ASPs.

Currently there is an exception where Ausgrid does install meters at new and upgraded connections, and this is when a current transformer (CT) connected type 5 or 6 metering is required, at approximately 900 installations per year. From 1 July 2014 NSW distribution businesses are proposing a new ancillary network service fee will apply for this installation service from and therefore these costs have been removed from the alternative control service for metering services.

233 A national meter identifier is assigned to every connection point.

234 An ASP is a suitably qualified person or company accredited (by NSW Trade & Investment) and under which individual(s) representing the ASP, are authorised by Ausgrid to work on or near Ausgrid's network, with a specific category of the accreditation required for the installation of direct connected meters.

Ausgrid also provides and installs meters in circumstances where the existing meter fails or it belongs to a group of meters identified as performing below specified standards. We refer to these activities as reactive and proactive meter replacement.

Meter maintenance

Ausgrid's Meter Asset Management Plan (MAMP), submitted and approved by the Australian Energy Market Operator (AEMO), outlines our asset management strategy for the maintenance of metering and associated equipment[235]. The activities performed include:

- Replacement of damaged or defective meters.
- Emergency maintenance of metering installations within 10 days as required by the NERs.
- Customer or retailer requested meter accuracy tests.
- In-service sample meter testing to verify that meter populations remain accurate.
- In-service sample CT testing and inspection to verify that CT populations remain accurate.
- Inspection of metering installations.
- Maintenance of Controlled Load Profile NMIs (200 remotely read interval meters registered as type 6 in the market) to allow AEMO to calculate a deemed net system load profile to enable type 6 metering installations to be settled in the NEM.

Meter reading and meter data services

The responsible person is required to engage an accredited meter data provider for the provision of metering data services. As an accredited meter data provider, Ausgrid performs these services which include:

- Meter data collection; including the manual (local) and remote collection of metering data from a metering installation.
- Forward estimation of type 5 metering data (to allow NEM settlements to occur weekly).
- Validation of type 5 and 6 metering data after collection.
- Substitution type 5 and 6 metering data where required.
- Storage of type 5 and 6 metering data in accordance with the rules.
- Forwarding of metering data to eligible market participants, for billing purposes.
- Forwarding of metering data to AEMO to allow for market settlement.

Costs to deliver metering services for type 5 and 6

The costs incurred by Ausgrid to deliver metering services for type 5 & 6 metering installations comprise of operating costs and capital costs.

Operating costs

The total operating costs for metering services are made up of the maintenance, meter reading and meter data services (outlined above) in addition to metering IT operating costs and overheads. The total forecast operating costs of providing metering services for each year of the 2014-19 period is shown in Table 53.

Table 53 – Forecast opex ($ million, 2013/14)

		2014/15	2015/16	2016/17	2017/18	2018/19	Total
Metering maintenance	Type 5	3.18	3.22	3.28	3.34	3.40	**16.42**
	Type 6	2.31	2.34	2.38	2.42	2.47	**11.92**
Meter reading	Type 5	3.25	3.30	3.36	3.42	3.49	**16.83**
	Type 6	4.75	4.82	4.91	5.00	5.10	**24.57**
Metering data services	Type 5	3.84	3.89	3.96	4.04	4.12	**19.85**
	Type 6	0.93	0.94	0.96	0.98	1.00	**4.81**
Metering ICT opex	Type 5	3.17	3.19	3.23	3.26	3.29	**16.14**
	Type 6	1.36	1.37	1.38	1.40	1.41	**6.92**
Opex overheads (indirect)	Type 5 and 6	4.28	4.41	4.49	4.58	4.66	**22.42**
Total		**27.07**	**27.47**	**27.95**	**28.44**	**28.94**	**139.87**

Note: Numbers may not add due to rounding

Further details of the forecast opex required to provide type 5-6 metering services for the 2014-19 period can be found in Attachment 8.16.

235 The obligations detailed in the MAMP encompass responsible person compliance responsibilities that span more broadly than type 5 and type 6 metering services governed by the alternative control service regulatory framework.

Figure 25 – Value of metering asset base ($ million, nominal)

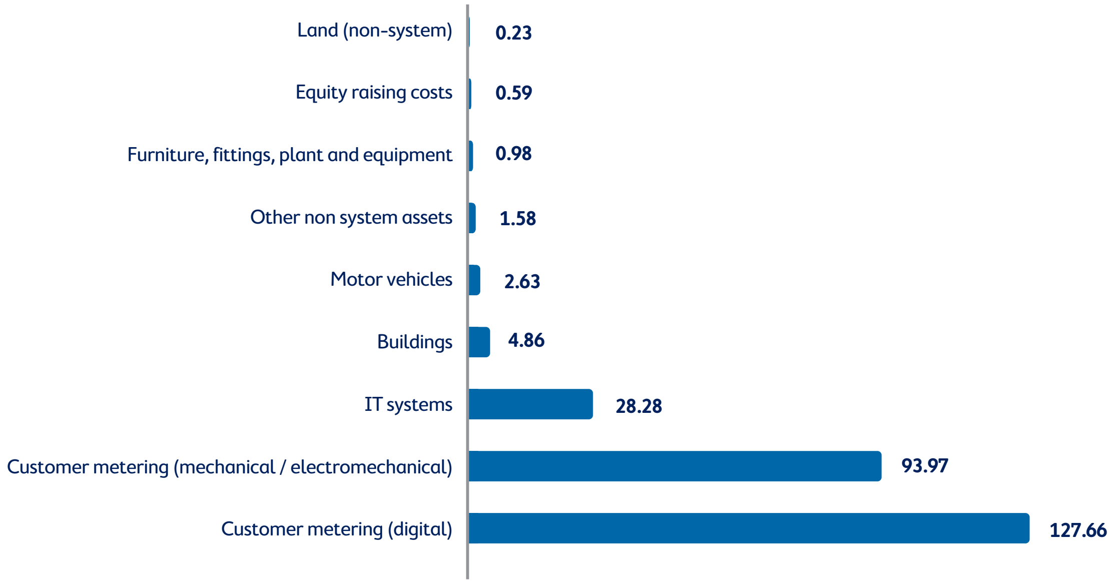


Table 54 – Forecast capex ($ million, 2013/14)

Capex Category	2014/15	2015/16	2016/17	2017/18	2018/19	Total
New and upgrade connections	4.92	5.28	8.54	8.47	5.11	**32.32**
Reactive replacement	5.16	5.16	5.05	5.04	5.08	**25.47**
Proactive replacement	4.32	7.74	13.59	13.55	13.71	**52.91**
Direct IT capex	4.09	2.58	4.86	2.03	1.91	**15.48**
Total	18.49	20.76	32.04	29.08	25.81	**126.18**

Note: Numbers may not add due to rounding

Capital costs

The capital costs represent the cost of financing the capital value of the meters installed at customer premises (the return on capital) as well as the return of this capital (regulatory depreciation). A key determinant of these costs is the value of the metering asset base which is informed by the value of existing meters and the forecast value of meters to be installed in the 2014-19 period. The process we have used to establish the value of the metering asset base and to develop the forecast capex is outlined in Attachments 8.17 and 8.18 respectively.

The value of the metering asset base and forecast capex are shown in Figure 25 and Table 54 respectively.

In addition to the forecast capex above, $11.6 million ($ 2013/14) of indirect capex is allocated to type 5 and 6 metering across 2014-19 through Ausgrid's CAM. To calculate the capital cost, we applied a rate of return of 8.83%, consistent with that used for standard control services.

Forecast revenue requirement

We have adopted the building block approach to the determination of the revenue requirements for metering type 5 and 6 services. The building block approach is the same approach used for establishing revenue requirements for standard control services and we have utilised the AER's PTRM for this calculation. This PTRM is provided in Attachment 8.19.

The section above summarised the forecast capex, operating costs and the value of the meter asset base. These are inputs into the calculation of the revenue we are proposing to recover for the 2014-19 period, which are shown in Table 55.

Table 55 – Metering building block revenue requirement ($ million, nominal)

Metering services	2014/15	2015/16	2016/17	2017/18	2018/19
Return on capital	23.03	23.18	23.01	23.42	23.96
Return of capital	20.63	23.20	25.62	20.79	21.17
Opex	27.90	29.02	30.25	31.55	32.91
Cost of corporate tax	2.48	4.32	6.50	5.50	3.97
Building block revenue requirement	**74.04**	**79.73**	**85.38**	**81.26**	**82.02**

Note: Numbers may not add due to rounding

Indicative prices

The forecast revenue required to recover the costs of providing type 5 & 6 metering services are charged to customers via a set of prices. The indicative prices for the 2014-19 period which also demonstrate application of the control mechanism is shown in in Table 56. The pricing methodology used to develop these prices is discussed in Attachment 8.15 and the pricing model is provided in Attachment 8.20. We address the application of the AER's formulae to give effect to the control mechanism in Attachment 9.02.

Table 56 – Indicative prices for metering services (c/day, nominal)

Tariff Name	2014/15[236]	2015/16	2016/17	2017/18	2018/19
Residential Inclining Block	9.23	9.51	9.84	10.16	10.49
Residential ToU	15.13	15.55	16.05	16.53	17.03
Controlled Load	3.72	3.84	3.98	4.12	4.27
Small Business Inclining Block	12.61	13.00	13.47	13.91	14.37
Small Business ToU	14.74	15.14	15.63	16.10	16.58
LV 40-160MWh ToU	23.32	23.93	24.69	25.41	26.15
Generator Tariff	4.42	4.56	4.73	4.89	5.05

We are proposing that metering hardware costs and directly associated logistics and engineering costs will be charged as an up-front fee from 1 July 2015. These are shown in Table 57.

236 The prices shown for 2014/15 represent Ausgrid's proposed cost-reflective prices, not the actual prices charged to customers for this year. The actual prices charged for 2014/15 are included in the general network charges.

Table 57 – New or upgraded meter charge ($ nominal)

Meter description	2014/15[237]	2015/16	2016/17	2017/18	2018/19
Single Phase Single Element Two Wire Direct Connected Accumulation Watt-hour Meter	47.73	49.30	51.05	52.87	54.76
Three Phase Single Element Four Wire Direct Connected Accumulation Watt-hour Meter	123.91	127.39	131.10	134.92	138.85
Single Phase Single Element Two Wire Direct Connected Interval Watt-hour Meter	116.16	119.44	122.95	126.57	130.30
Single Phase Dual Element Two Wire Direct Connected Interval Watt-hour Meter	177.29	182.10	187.18	192.40	197.77
Three Phase Single Element Four Wire Direct Connected Interval Watt-hour Meter	239.67	246.04	252.71	259.57	266.62
Three Phase Single Element CT Connected Interval Watt-hour Meter	578.64	593.48	608.84	624.60	640.78

We are also proposing an exit fee for circumstances where a customer chooses to upgrade the meter at their premises (that is currently managed and maintained by Ausgrid) to a type 1, 2, 3 or 4 meter. This fee is shown in Table 58.

This fee is to cover the 'sunk' or stranded costs associated with our past investment. In choosing to propose exit fees and in developing those prices we have noted the recommendations in the AEMC's Power of choice review (stage 3) published in November 2012 regarding exit fees.[238] Our considerations in this regard are outlined in Attachment 8.15.

NSW distribution businesses engaged Energeia to independently review our proposed approaches, methodologies and resulting proposal for Types 5 and 6 metering services. We provide a copy of Energeia's finding in Attachment 8.21.

Table 58 – Exit fee ($ nominal)

Components of meter exit fee	2014/15[239]	2015/16	2016/17	2017/18	2018/19
Administration costs	36.00	37.47	39.20	41.01	42.89
Stranded asset costs	160.64	157.76	158.68	160.48	161.78
Total exit fee (Type 5 or 6 meter)	**196.64**	**195.24**	**197.89**	**201.49**	**204.67**

237 The prices shown for 2014/15 represent Ausgrid's proposed cost-reflective prices, not the actual prices charged to customers for this year. The actual prices charged for 2014/15 are included in the general network charges.

238 FINAL REPORT Power of choice review – giving consumers options in the way they use electricity 30 November 2012, pages 79, 83, 87, 89- 90, 92- 93.

239 The prices shown for 2014/15 represent Ausgrid's proposed cost-reflective prices, not the actual prices charged to customers for this year. The actual prices charged for 2014/15 are included in the general network charges.

8.3 Ancillary network services

In this section we explain what ancillary network services are and the methodology we have used to set prices for these services. We have applied the AER's control mechanism of a cap on the prices of individual services by proposing a fee for each ancillary network service.

What are ancillary network services?

The AER has proposed to create a group of services called ancillary network services to capture non-routine services provided to customers on an 'as needs' basis. Examples of such services include providing design related information for connections to our network, special meter readings, and site establishment fees.

These services are currently called 'miscellaneous and monopoly' services and form part of standard control services provided by NSW distribution businesses. The prices for these services were first set in 1999.

From 1 July 2014, the AER has reclassified these services to alternative control services because the services are provided to a small sub-set of our customers and the costs of such services can be directly attributed to those individual customers, rather than the whole customer base.

Prices for many of the existing services were originally set by IPART in our 1999 determination. Since that time, costs have only been indexed with inflation every 5 years and not reviewed in detail. As such, many of these services have been historically under-costed and subsidised by our standard control services. This change in classification also recognises this issue, and seeks to ensure that standard control customers no longer subsidise these activities specific to a small sub-set of customers.

From 1 July 2015, some new ancillary network services will commence, such as those that are required to satisfy the national energy customer framework's requirements (NECF). Some new fees will also be set for the first time for services we already provide, but do not currently charge to the customer requesting the service.

Whilst in general, the fees associated with ancillary network services will increase from 1 July 2015 to more accurately reflect costs, the increases in prices are generally a result of removing costs that historically have been allocated to the provision of other services by Ausgrid (i.e. consistent with the AER's intention, we have sought to remove cross subsidies and achieve prices that reflect actual costs). A corresponding decrease in costs from Ausgrid's standard control services has occurred.

Note that some fees have reduced, primarily due to efficiencies in the manner in which we provide those services. Currently there are 22 service groups. From 1 July 2015, there will be 30 service groups, however within some groups there are multiple services and prices. The list of service groups and services is provided in Attachment 8.22.

Activities undertaken to deliver ancillary network services

A worksheet for each service or service group is provided in Attachments 8.23 and 8.24. The worksheet outlines the AER's current service description, any additional service related information, an outline of what is involved in providing the service and the current and proposed fee.

Method used to develop prices

The AER has stated it will set service specific prices to enable the distributor to "recover the full cost of each service from customers using that service"[240] and by doing so ensuring that standard control customers do not subsidise these activities specific to a small sub-set of customers. We have therefore sought to develop our rates based on our historic data to provide these services.

Method to determine costs

In some cases, this historic data is not available or is not at a sufficient level of detail to determine the historic costs of providing the service. As a result we have needed to use one of the three following methods to determine the costs to provide the services and establish prices:

- Historical data - For a number of existing services that have an associated fee, we are able to identify incurred costs associated with the provision of the services, the numbers of services that historically have been provided and the hours associated with provision of the services. Due to the historical data being clearly identifiable for those services, we have typically utilised 4 years of historical data to determine the cost of the service and establish the price, unless there is a compelling reason to use a subset of that period or to use the most recent (FY13) figures. This approach can be considered a 'top-down approach'.
- Operating costs and capital costs[241] - This method uses available data to establish an average cost to provide the service. In these instances, we are able to identify incurred costs associated with the provision of the services and the number of services that have historically been provided. For some services, the historic costs may not have been recorded at a service-by service level and we may need to apportion historic costs between more than one service. By way of example, the back-office costs associated with meter tests and meter investigations are not separately recorded and we have allocated these costs based on an average handling time (AHT), resulting in 60% of back office costs being allocated to meter tests and 40% to meter investigations.
- Bottom up approach - For those services where we were unable to reliably extract the data, a bottom up approach was used. In these circumstances, we may have data available on the total costs for a service group, but the data is not distinguishable between the 50 service (and chargeable) components. This method was also used for new ancillary network services. The method relies on identifying the type of employee who carried out the service, with an average hourly rate and estimating the time it took to carry out that service. We sought to utilise a limited number of labour classes, consistent with IPART's previous approach.

Indicative prices for ancillary services

Attachment 8.22 sets out our indicative prices for ancillary network services for each year of the 2014-19 period. Details of the calculation of these prices as well as further information on the activities (and associated costs) undertaken to provide each ancillary network service are provided in Attachments 8.23 and 8.24. We address the application of the AER's formulae to give effect to the control mechanism in Attachment 9.02.

240 Stage 1 F&A paper, p8

241 That is, costs that have been characterised as capex due to accounting standards.

8.4 Compliance with control mechanism and basis of control

The AER has decided to apply caps on the prices of individual services to all alternative control services for the 2014-19 period.[242] We have set out in the sections above how we consider that our application of the control mechanism is compliant with that required by the AER's framework and approach paper. The AER also set out its proposed formulae that give effect to the control mechanism.[243] As stated in chapter 3, Ausgrid adopts the AER's approach to the proposed formulae and considers that the demonstration of compliance with the control formulae for alternative control services will be done through the annual pricing proposal process, using the published price list as the vehicle to demonstrate compliance. The attachments and worksheets supporting this chapter together with Attachment 9.02 addresses the formulaic expressions for the basis on control mechanisms for alternative control services and the detailed explanation and justification for each component that makes up the formulaic expression so far as those matters are applicable to the AER proposed control mechanism.

Clause 6.2.6(b) of the rules provides that, for alternative control services, the control mechanism must have a basis stated in the distribution determination and that the basis of control may use elements of part C of the rules. Part C of the rules outlines the building block approach for standard control services.

In deriving prices for alternative control services so that we can demonstrate application of the control mechanism, Ausgrid has adopted a cost buildup approach to the setting of these prices, an approach that is analogous to the building block approach prescribed for standard control services.

As noted in chapter 4, Ausgrid considers that the pass through provision in the rules should apply to alternative control service and should form part of the basis of control to be determined by the AER. As we have utilised an approach to the setting of price that is similar to the building block approach, we consider the costs of providing alternative control services can be adjusted to account for the cost impact of pass through events that have materialised (after having been subjected to the pass through assessment process by the AER under clause 6.61 of the rules).

8.5 True-up for transitional year

The NSW distributors requested that the AER specify in stage 2 of the F&A how a true-up of prices will be made for alternative control services. In the F&A paper the AER noted that given that it is yet to see how Ausgrid intend to treat alternative control services pricing in their transitional proposals, it preferred not to prejudice whether, and if so, how alternative control services prices are to be trued-up. For this reason, it did not specify the exact manner in which alternative control services prices may be adjusted in this F&A.

Instead the AER stated that it will examine options for a true up as part of the regulatory review and provide reasons for the approach that is eventually adopted in its determination.[244]

As we have noted to the AER previously,[245] Ausgrid considers that a true up mechanism for alternative control services should be implemented so that the AER can exercise its power in accordance with the national electricity objective (NEO) and the NEL revenue and pricing principles (RPP) of ensuring the long term interest of customers in respect of prices and of ensuring the DNSPs are given a reasonable opportunity to recover their efficient costs.[246]

In particular, as previously agreed with the AER, the recovery of revenue for alternative control services that were previously classified as standard control services, was to be recovered through prices for standard control services during the transitional year but not in subsequent years. However, this amount has not been included in the proposed revenue requirements for the five year regulatory control period in this proposal as we have assumed that:

(a) A standard control services revenue should only be for standard control services, a "pure" amount should be provided for the purposes of determining the five year revenue amounts (i.e. not inclusive of revenue recovered through the transitional year for alternative control services).

(b) A the AER has previously agreed to the recovery of reclassified alternative control services revenue for the transitional year through DUOS prices, that this position is unchanged and this approach will continue to apply.

(c) A shortfall in revenue for alternative control services for the transitional year will be recovered through prices for alternative control services in the subsequent years through a true up mechanism.

We set out our view on how a true up mechanism may operate for the AER's consideration in Attachment 8.25.

242 Stage 1 F&A, p57
243 Stage 1 F&A, pp60-62
244 Stage 2 F&A paper, p40
245 See Attachment 8.25, letter of 10 January 2014 to the AER's chairman, from the Chief Executive Officer of Ausgrid, Endeavour Energy and Essential Energy
246 As per letter to the AER's chairman on 10 January 2014.

9. Pricing arrangements and negotiating framework

The purpose of this chapter is to outline our proposed approach to setting network tariffs in the 2014-19 period, and the reporting arrangements for our annual pricing proposal. We also submit our transmission pricing methodology and our negotiating framework in relation Ausgrid's dual function assets.

Ausgrid's charges include charges for both distribution and transmission services. These make up about 40% of the average household bill. When combined with TransGrid's transmission charges, electricity network charges form around 50% of a customers electricity bill.

For the 2014-19 period, our network tariffs will comprise the following:

- Distribution use of system and transmission use of system – This will enable recovery of the revenue we are permitted to collect for the standard control services provided by our distribution assets.
- Specific charges for metering – This will allow us to recover our efficient costs for the provision, maintenance, reading and data services of type 5 and 6 meters, noting that the price a customer pays will depend on the meter installed in their premise.
- Jurisdictional scheme amounts – These amounts allow us to recover our annual contribution to the NSW Climate Change Fund.
- Designated pricing proposal charges (for transmission services) – These primarily relate to payments for the use of the transmission network in NSW.[247] These payments are primarily made to TransGrid but also incorporate the maximum revenue we are permitted to collect for Ausgrid's transmission standard control services.

9.1 How we set our network tariffs

We submit an annual pricing proposal to the AER every year. This proposal outlines our proposed network tariffs for the forthcoming regulatory year and demonstrates how these tariffs comply with our obligations under the rules.

Our approach to setting network tariffs each regulatory year aims to achieve a broad range of objectives, as summarised below:

- Revenue sufficiency – This means that our network tariffs recover sufficient revenue to fund the efficient cost of owning, operating and investing in our distribution and transmission network. It also means that we pass through to our customers the full cost associated with our use of the TransGrid's transmission network and our annual contribution to the NSW Government Climate Change Fund.
- Equity – This means that customers with similar network usage characteristics pay prices that reflect their proportionate use of the network.
- Efficient use of our network – This means that customers receive price signals that reflect the economic cost of using our electricity network.

Purpose of tariff classes

We are required under the rules to assign customers to an individual tariff class. This is an important aspect to the annual pricing process because we have to demonstrate that our proposed prices are free of economic subsidy and comply with the price limit mechanism at the tariff class level. The concept of a tariff class is also relevant to the calculation of long run marginal cost to the extent that it is economically desirable to group customers with similar economic characteristics.

Ausgrid's current tariff classes are shown in Table 59. We believe that our current tariff classes are appropriate to carry forward for the 2014-19 period because they result in customers being grouped together in an economically efficient manner. Importantly our approach also has the advantage of not imposing unnecessary transaction costs on Ausgrid or our customers. Further details regarding our proposed approach to tariff classes will be provided in our annual pricing proposals published on Ausgrid's website. These tariff classes and tariffs are also those which have been used to complete regulatory template 7.7.1 in AER's reset RIN.

[247] In addition to these charges, our network tariffs need to recover payments to embedded generator for avoided Transmission costs; and payments we make to other DNSPs for the use of their network.

Table 59 - Current tariff classes for 2009-14 period

Tariff class	Tariff code	Tariff name
Low voltage	EA010	Residential Inclining Block
	EA025	Residential Time of Use
	EA030	Controlled Load 1
	EA040	Controlled Load 2
	EA050	Small Business Inclining Block
	EA225	Small Business Time of Use
	EA302	LV 40-160 MWh (System)
	EA305	LV 160-750 MWh (System)
	EA310	LV > 750 MWh (System)
	EA325	LV Connection (Standby) Closed
High voltage	EA360	High Voltage Connection (Standby) closed
	EA370	High Voltage Connection (System)
	EA380	High Voltage Connection (Substation)
Sub-transmission voltage	EA390	Sub-transmission Voltage Connection
Unmetered	EA401	Public Lighting
	EA402	Constant Unmetered
	EA403	EnergyLight
Cost reflective network price		Individually calculated - site specific

Indicative prices and tariffs

As explained above the tariffs that apply from 1 July each year are an outcome of our annual pricing proposal process. However the rules governing our regulatory proposal require us to include indicative prices in our regulatory proposal. Our indicative prices at tariff class level for the 2014-19 period are set out in chapter 4 at Table 18 and Table 19. Our indicative prices at the tariff level are set out in regulatory template 7.7.1 and are explained further in Ausgrid's Basis of Preparation prepared in relation to the AER's reset RIN.

Proposed procedures for assigning existing and new customers to tariff classes

For the 2015-19 regulatory period, we propose that our current procedures for assigning new retail customers to tariff classes, or reassigning existing retail customers from one tariff class to another be continued with some minor modifications to reflect our experience with the procedures during the 2009-14 period. We believe that our proposed procedures are consistent with the requirements set out in clause 6.18.4 of the rules because they take into account the voltage level of the connection, the type of metering installed in the premise and the level of energy consumption and maximum demand at each individual connection point.

Our proposed procedures also involves an annual review to assess whether existing connection points need to be re-assigned to new tariff class due to a recent changes in annual usage and/or their connection arrangements.

Our proposed procedures are set out in Attachment 9.01. We request that the AER determine under clause 6.12 1 (17) of the rules that these procedures apply to Ausgrid for the 2015-19 regulatory period.

New tariff designs for 2014-19 period

For the 2015-19 regulatory period, we will investigate the merit of changing our network tariff structures to ensure that our network tariffs continue to meet our objectives of revenue sufficiency, economic efficiency and equity in an environment of declining energy consumption.

9.2 Reporting arrangements for pricing proposals

The AER has a role in monitoring whether we comply with the controls it applies to our regulated services. For this reason the AER is required to make a number of upfront decisions in its regulatory determination on how a DNSP is to set network tariffs and how it reports on compliance during the course of the 2014-19 period.

For the most part, these decisions relate to the preparation of our network tariffs as part of our annual pricing proposal. In the sections below we describe why the AER has to make each of its decisions, and our proposed method or approach.

Compliance with control mechanisms

The AER is required to make a decision on how compliance with a relevant control mechanism is to be demonstrated. Our proposed approach on demonstrating compliance for each control mechanism is as follows:

- For our alternative control services, we consider that our published price lists be the vehicle to demonstrate compliance with the price cap formulae in the control mechanism.
- For our standard control distribution service, we consider that the pricing proposal would need to show that the proposed distribution prices are forecast to result in a level of revenue in year t equal to the maximum allowed revenue in year t.
- For our standard control transmission service, we consider that the pricing proposal would need to show that the level of revenue that we seek to recover via TransGrid's transmission charges in year t is equal to the maximum allowed revenue in year t.

Attachment 9.02 provides more information on our proposed arrangements to demonstrate compliance with control mechanisms.

Control mechanism for standard control services

The AER have decided to apply a revenue cap to both our distribution and transmission standard control services in the 2014-19 period. The AER's framework and approach stage 1 paper sets out the following generic formulaic expression of the revenue cap to apply to our standard control services.

$$MAR_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^{t*}$$

$$MAR_t = AR_t + I_t + T_t + B_t$$

$$AR_t = AR_{t-1}(1 + CPI)(1 - X_t)$$

Where:

MAR_t	is the maximum allowable revenue in year t.
p^t_{ij}	is the price of component i of tariff j in year t.
q^{t*}_{ij}	is the forecast quantity of component i of tariff j in year t.
AR_t	is the allowable revenue for year t.
I_t	is the sum of incentive scheme adjustments in year t.
T_t	is the sum of transitional adjustments in year t.
B_t	is the sum of annual adjustments in year t.
CPI_t	is the percentage increase in the consumer price index.
X_t	is the X-factor in year t.
AR_1	is the allowable revenue in the first year of the regulatory control period.[248]

It is clear from the above revenue cap formula shows that the AER wishes for the maximum allowable revenue for standard control services to be calculated on the basis of four key parameters - the allowable revenue (AR), annual revenue adjustments (positive or negative) relating to applicable incentive schemes (I), transitional adjustments (T) and the over or under recovery of revenue in previous years (B). We note that the issue of under and over recovery will only arises for the standard control services provided by our distribution network.[249]

248 AER 2013, Formulae for control mechanisms – revised, Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19, February, p.7

249 The arrangements for recovering our maximum allowable revenue (MAR) for transmission standard control services are complex. The arrangements require us to collect revenue for all transmission services in NSW as part of designated pricing proposal charges, and pass this through to TransGrid. TransGrid will then invoice us for only the TransGrid component of these charges, meaning there is no possibility of under or over recovery of the Ausgrid MAR for its transmission (dual function) assets.

Ausgrid notes that at this stage the AER have provided limited detail on the specific parameters set out in the generic revenue cap formula. To assist the AER to make a decision on the final specification of the revenue cap formula to apply to our standard control services, our interpretation of each specific parameter is summarised below and outlined in detail in Attachment 9.02.

- The allowable revenue (AR) parameter relates to the following:
  - The annual (smoothed) revenue requirement as per the post tax revenue model (PTRM):[250]
  - Revenue adjustment to account for the annual update to the cost of debt.
  - Revenue adjustment to account for emergency response works; that is, costs of repairing damages to Ausgrid's assets which were not recoverable from the liable party.
  - Revenue adjustments to account for the difference in revenue requirement in 2014/15 under the Transitional decision and the final determination as required by clause 11.56.4(h)-(j). In the event that the AER considers the allowed revenue is not the most appropriate part of the control mechanism formula to make the adjustment required by the rules, Ausgrid considers that the adjustment would then need to be accounted for via the T factor.
- The incentive (I) parameter relates to the annual revenue adjustments arising from the application of applicable intra-period incentive schemes.
- The transitional (T) parameter relates to residual adjustments to revenue that cannot be accounted for under the other parameters in the revenue cap formula.
- The overs and unders account (B) parameter relates to the true-up required under the revenue cap to account for differences between the actual revenue recovered and the maximum allowable revenue in previous regulatory years. To ensure stable pricing outcomes under the revenue cap, Ausgrid proposes that specific tolerance limits apply to allow the proposed prices to be set under the revenue cap on the basis a non-zero forecast closing balance under certain circumstances.
- Ausgrid also proposes to explicitly include a parameter to account for pass through amounts approved by the AER during the course of the 2014-19 period.

Transmission pricing for our dual function assets and recovery of designated pricing proposal charges

As noted in chapter 3, our dual function assets are priced separately to our distribution assets. Effectively this means that we collect the revenue portion associated with our dual function assets from all customers in NSW, rather than just Ausgrid's customers.

Transmission pricing necessitates a complex process to recover the revenue requirement for our dual function assets. TransGrid is responsible setting the charges for providing transmission services in NSW. TransGrid sets these charges to ensure that each DNSP in NSW pays their fair share of the cost of the providing transmission network services, including the costs relating to dual function assets.

250 Please note that annual update to WACC for the cost debt would also influence the calculation of WACC interest in relation to the overs and unders account for distribution standard control revenue, transmission use of system (TUOS) revenue and Climate Change Fund (CFF) revenue.

We set our designed proposed charges each year to recover the cost of using TransGrid's transmission network and to recover the maximum allowable revenue (MAR) for our dual function assets. TransGrid will only invoice us for our use of their transmission network. Given that TransGrid, rather than Ausgrid, sets transmission charges and bears the associated volume risk it is important the AER realises that there is no need for a B-parameter to be included in the revenue cap formula for our transmission standard control services.[251]

To appropriately set transmission charges in NSW, TransGrid requires financial and load information in relation to our dual function assets. To ensure that we satisfy TransGrid's information requirements and implement the rules with respect to transmission pricing we are required to submit a proposed transmission pricing methodology as part of our regulatory proposal for approval by the AER. Our proposed pricing methodology is set out in Attachment 9.03. This methodology is similar to the current methodology approved by the AER for the 2009-14 determination.

In addition to the payments we make to TransGrid for transmission services, we are also required to make payments to other DNSPs and to pay avoided TUOS to eligible embedded generators. The charges we make to TransGrid and others are termed 'designated pricing proposal charges". The rules require the AER to make a decision on how we report to the AER on our recovery of designated pricing proposal charges for each regulatory year of the 2014-19 period, and on adjustments to account for over or under recovery of those charges. We propose to continue with the existing reporting arrangements.

Attachment 9.04 provides further information on how we propose to report on these charges and make adjustments for under and over recovery of designated pricing proposal charges. We propose to use the mechanism we had in place during the 2014-19 period for recovering these types of charges.

Negotiating framework and negotiated distribution service criteria for our transmission (dual function assets) which provide negotiated distribution services

Whilst it is possible, Ausgrid does not anticipate any negotiated distribution services during the 2014-19 period. The AER in its Stage 1 F&A paper stated that none of the services provided by the NSW distributors are suited to being classified as *negotiated distribution services*[252] and consequently did not indicate that it would classify any services as *negotiated distribution services*.

There would be some scope for services provided by means of Ausgrid's transmission network to be *negotiated distribution services*. Clause 6.24.2(c) of the rules provides that "*any service that is provided by a DNSP by means of or in connection with, the DNSP's dual function assets that, but for this Part would be a negotiated transmission service under Chapter 6A is deemed to be a negotiated distribution service.*"

A *negotiated transmission* service is defined in chapter 10 of the rules and includes connection services that are provided to serve transmission network users at a single connection point, (excluding connection services between network service providers) as well as use of system services agreed at the time of a connection where the network service provider has augmented or extended the network. Consequently a new connection to Ausgrid's transmission network would be a negotiated transmission service which must be treated as a negotiated distribution service.

Negotiating framework

If Ausgrid is required to provide negotiated distribution services it will apply its negotiating framework. Ausgrid's proposed negotiating framework has been submitted to the AER as part of its regulatory proposal and is in Attachment 9.05. The negotiating framework has been prepared to comply with the requirements of part D of chapter 6 of the rules.

Proposed approach to negotiated distribution service criteria

In addition to considering the negotiating framework, clause 6.12.1(16) of the rules requires the AER to make a decision on Ausgrid's negotiated distribution service criteria as part of its distribution determination. These criteria are to be applied by Ausgrid in negotiating terms and conditions of access and by the AER is resolving any access disputes.

Clause 6.7.4 of the rules requires that the negotiated distribution service criteria must give effect to and must be consistent with the principles set out in clause 6.7.1 of the rules.

Ausgrid would support the AER adopting the negotiated distribution service principles in clause 6.7.1 and as the appropriate criteria in a similar approach to that which was adopted by the AER for the current 2009-2014 regulatory control period.

251 The tariffs relate to the following types of transmission services: prescribed exit services; prescribed common transmission services; and prescribed TUOS services.

252 AER, stage 1 framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy, Transitional regulatory control period, 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019, March 2013, p8.

Jurisdictional scheme payments – NSW Climate Change Fund

The rules allow us to recover "jurisdictional scheme payments" relating to obligations imposed by governments. The payments are not related to the network services we provide, and are separate to the maximum revenue or prices we charge customers for direct control services.

As part of its regulatory determination, the AER must make a decision on how we are to report to the AER on our recovery of jurisdictional scheme amounts for each regulatory year of the regulatory control, and on adjustments for over or under recovery of those amounts. The AER's decision only relates to jurisdictional scheme obligations we have at the time the decision is made.

For the 2014-19 period, we will have a continuing jurisdictional scheme obligation to make payments to the NSW Government for the Climate Change Fund. We propose the same mechanism for reporting on recovery of jurisdictional scheme amounts (NSW Climate Change Fund) to that which has been in place during the current regulatory control period, including the mechanism for under over recover adjustments. The current mechanism is based on the audited closing balance in year t-2, and an estimate of the closing balance in year t-1. The over or under recovery in year t-1 is recovered via an adjustment in year t. This information is reported in the annual pricing proposal. Further information is provided in Attachment 9.04.

Glossary

Abbreviation	Meaning
($ nominal) [for paragraphs]	($ nominal). This is the dollar of the day.
($ million, nominal) [for tables]	Nominal dollars for table/figure captions
($2013/14) [for paragraphs]	Real dollars. This denotes the dollar terms as at 30 June 2014.
($ million, 2013/14) [for tables]	Real dollars for table/figure captions
2014-19 period	The period that comprises both the transitional regulatory control period 1 July 2014 to 30 June 2015 and the regulatory control period 1 July 2015 to 30 June 2019 (2015-19 regulatory control period)
2015-19 regulatory period	The regulatory control period commencing 1 July 2015 to 30 June 2019
Next five years	The 5 year period between 1 July 2014 to 30 June 2019
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual revenue requirement
Augex	Augmentation expenditure model
CAM	Cost allocation method
CAPM	Capital asset pricing model
Capex	Capital Expenditure
CCF	Climate Change Fund
CESS	Capital expenditure sharing scheme
CPI	Consumer Price Index
CRNP	Cost reflective network price
Current regulatory period	Regulatory control period of 1 July 2009 to 30 June 2014
DFA	Dual function assets
DGM	Dividend growth model
DMEGCIS	Demand management embedded generation connection incentive scheme
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DMBSS	Demand management benefit sharing scheme
DNSP	Distribution network service provider
DRP	Debt risk premium
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
ERW	Emergency recoverable works

Abbreviation	Meaning
EWON	Energy & Water Ombudsman NSW
EY	Ernst & Young
F&A	Framework and approach
FEMCA	Failure modes effects criticality analysis
FFM	Fama-French 3 Factor Model
GFC	Global financial crisis
IBT	Inclining block tariff
Last regulatory period	Regulatory control period of 1 July 2004 to 30 June 2009
LNSP	Local network Service provider
MRIM	Manually read interval meter
MRP	Market risk premium
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NMI	National Meter Identifier
NUOS	Network use of system
NER or rules	National Electricity Rules
the transitional rules	The National Electricity Rules applicable to the transitional regulatory proposal.
Next regulatory period	Regulatory control period of 1 July 2015 to 30 June 2019
Opex	Operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
RIN	Regulatory information notice.
RoR	Rate of return
Repex	Replacement expenditure model
Regulatory Proposal	Ausgrid's proposal for the next regulatory period submitted under clause 6.8 of the rules.
SCS	Standard control services
SCER	Standing council on energy and resources
STPIS	Service target performance incentive scheme
TOU	Time of use
Substantive proposal	Ausgrid's proposal for the next regulatory control period 1 July 2015 to 30 June 2019 (including 2014/15 information)
Transitional period / transitional year	Regulatory control period of 1 July 2014 to 30 June 2015
transitional regulatory proposal / transitional proposal	Ausgrid's proposal for the transitional period submitted under clause 6.8.2 of the transitional rules.
TUOS	Transmission use of system
WACC	Weighted average cost of capital

Attachments

Attachments	
1.01	NNSW - Delivering efficiencies for our customers
2.01	Ausgrid's customer engagement strategy
2.02	Customer engagement survey
3.01	Ausgrid Classification proposal
3.02	Application of STPIS
3.03	DMEGIS Proposal 2014-19
4.01	PTRM – Distribution
4.02	PTRM – Transmission
4.03	RAB – Distribution
4.04	RAB – Transmission
4.05	Adjustment of RAB for Type 5 & 6 metering services
4.06	Value of asset changing function
4.07	Nominated depreciation schedules
4.08	Opening tax asset base
4.09	Calculation of EBSS carryover for the 2009-14 period
4.10	Calculation of D-factor and DMIA adjustment for 2009-14
4.11	Energy volume forecast
4.12	Ernst and Young - Regulatory treatment of risk
4.13	Ausgrid’s nominated pass through events (CONFIDENTIAL)
5.01	Arup review of outcomes for the 2009-14 regulatory period (CONFIDENTIAL)
5.02	Network Performance Reports
5.03	Spatial demand forecast by Zones and Substations
5.04	Planning Standard – Demand Forecasts and related documents
5.05	Design, Reliability and Performance Licence Conditions for DNSP, Minister for Energy, Dec 2007
5.06	Reliability and Performance Licence Conditions for DNSP, Minister for Energy, commencing 1 July 2014
5.07	Ausgrid's planning standard from 1 July 2014 (interim)
5.08	Network Management Plan
5.09	Network Asset Management Strategy
5.10	Approved cost allocation method
5.11	Proposed connection policy for 1 July 2015
5.12	Capitalisation policy
5.13	Key assumptions underlying capex and opex

Attachments	
5.14	Directors' certification of key assumptions
5.15	Unit cost methodology
5.16	Overview of the cost escalation methodology
5.17	Cost escalation inputs and model
5.18	Independent economics - Labour escalation for NSW DNSPs
5.19	CEG - Material escalation for NSW DNSPs
5.20	Total capex forecast for 2014-19
5.21	Capex by asset class for the previous, current and forecast period
5.22	Material assets
5.23	Overview of the area plans for 2014-19
5.24	Overview of the replacement and duty of care plans for 2014-19
5.25	Overview of the distribution capacity plan for 2014-19
5.26	Overview of the reliability (compliance) Plan for 2014-19
5.27	Overview of the technology plan for 2014-19 (CONFIDENTIAL)
5.28	Overview of non-system property capex and opex for 2014-19
5.29	Overview of fleet capex for 2014-19
5.30	Other capex - forecast & explanation (plant & tools)
5.31	Addressing the capex and opex objectives, criteria and factors
5.32	Economic Interpretation of clauses 6.5.6 and 6.5.7 of the NER (Meaning of prudency and efficiency)
5.33	Addressing the benchmarking factor for capex and opex (including Huegin, Evans & Peck, Repex and Augex)
6.01	Total forecast opex model (Standard control) (CONFIDENTIAL)
6.02	Forecast opex model explanatory statement
6.03	System maintenance opex plan (CONFIDENTIAL)
6.04	Property opex plan
6.05	Information, communication and technology (ICT) opex plan (CONFIDENTIAL)
6.06	System control opex plan
6.07	Engineering, Planning & Project Management opex plan
6.08	Learning & development opex plan
6.09	Customer operations opex plan
6.10	Metering opex plan
6.11	Other operations and business support opex plan
6.12	Demand management opex plan

Attachments	
6.13	Forecast opex by cost categories from 2004 to 2019
7.01	CEG, WACC estimates, a report for NSW DNSPs
7.02	CEG, Debt transition consistent with the NER and NEL
7.03	CEG, Efficiency of staggered debt issuance
7.04	CEG, Transition to a trailing average approach
7.05	UBS, Advice to Networks NSW (CONFIDENTIAL)
7.06	Kanangra , Credit ratings for Regulated Energy Network Services Businesses
7.07	Incenta, Debt raising costs for NSW DNSPs - Individual reports for Ausgrid, Endeavour and Essential
7.08	Nobel Prize Committee, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, UNDERSTANDING ASSET PRICES
7.09	NER, The Fama-French Three-Factor Model
7.10	SFG, Alternative versions of the dividend discount model and the implied cost of equity
7.11	SFG, Dividend discount model estimates of the cost of equity
7.12	NERA, The market, size and value premiums
7.13	NERA, MRP, analysis in response to the AER's draft rate of return guideline
7.14	CEG, Estimating the return on the market
7.15	CEG, Estimating the E[Rm] in the context of recent regulatory debate
7.16	SFG, Cost of equity in the Black Capital Asset Pricing Model
7.17	NERA, Estimates of the zero beta premium
7.18	SFG, Equity beta
7.19	SFG, Regression-based estimates of risk parameters for the benchmark firm
7.20	CEG, Information on equity beta from US companies
7.21	CEG, Equity beta issues paper: International comparators
7.22	Grey et. al., Comparison of OLS and LAD regression techniquest for estimating beta
7.23	Grey et. al., The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model
7.24	Grey et. al., Assessing the reliability of regression-based estimates of risk
7.25	SFG, Water utility beta estimation
7.26	Ausgrid’s Gamma Proposal
7.27	SFG, An appropriate regulatory estimate of gamma
7.28	NERA, Imputation credits and equity prices and returns
7.29	SFG, Updated dividend drop-off estimate of theta
7.30	NERA, The payout ratio
7.31	Hathaway, Imputation Credit Redemption ATO data 1988-2011
7.32	NSW DNSPs,Submission on the rate of return consultation paper

Attachments	
7.33	NSW DNSPs, Submission on the draft rate of return guideline
7.34	NSW DNSPs, NNSW response to AER letter on cost of debt averaging periods
8.01	Public lighting overview
8.02	Introduction to Ausgrid's public lighting business
8.03	Policy for non standard lighting
8.04	Public lighting code
8.05	Public lighting management plan
8.06	Stakeholder engagement / customer consultation for public lighting
8.07	Public lighting process improvements
8.08	Public lighting capex investment plan summary
8.09	Public lighting investment plan - active reactors (CONFIDENTIAL)
8.10	Public lighting investment plan - Replacement of twin 20 luminaires (CONFIDENTIAL)
8.11	Public lighting investment plan - Replacement of 42W CFL with LED (CONFIDENTIAL)
8.12	Public lighting opex forecast
8.13	Public lighting models (4 models) (CONFIDENTIAL)
8.14	Public lighting price list (CONFIDENTIAL)
8.15	Type 5 and 6 metering services proposal
8.16	Forecast opex for type 5-6 metering
8.17	Type 5 and 6 metering RAB
8.18	Forecast capex for type 5-6 metering
8.19	Type 5 and 6 metering services PTRM
8.20	Type 5 and 6 metering pricing model
8.21	Energeia review of Ausgrid's metering tariffs
8.22	Ancillary network services proposal
8.23	Metering related ancillary network services models
8.24	Connection related ancillary network services models
8.25	Options for alternative control services true up mechanism
9.01	Procedure for assigning customers to tariff class
9.02	Application and demonstration of compliance with control mechanism for standard control Services
9.03	Transmission pricing methodology (CONFIDENTIAL)
9.04	Reporting on recovery of designated pricing proposal charges and jurisdictional scheme amounts (climate change fund)
9.05	Proposed negotiating framework