Transitional Regulatory Proposal

for 1 July 2014 to 30 June 2015

January 2014

Ausgrid

Contents

Summary

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

The Australian Energy Regulator (AER) administers the National Electricity Rules (NER or rules) that 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 what they believe the revenue requirements are to fund those plans.

A new regulatory proposal was due to be submitted by the NSW and ACT electricity distribution businesses for the period of 2014 to 2019. In 2012 the Australian Energy Market Commission (AEMC) consulted on major rule change proposals covering the rules and subsequently made a number of important changes. The NSW and ACT distribution network businesses were to be the first organisations to submit proposals under these new rules.

During this rule change consultation, it was agreed by all parties that a one-year transitional proposal would help smooth the implementation of the new rules given the short implementation period available to the NSW and ACT businesses after the rule change came into effect.

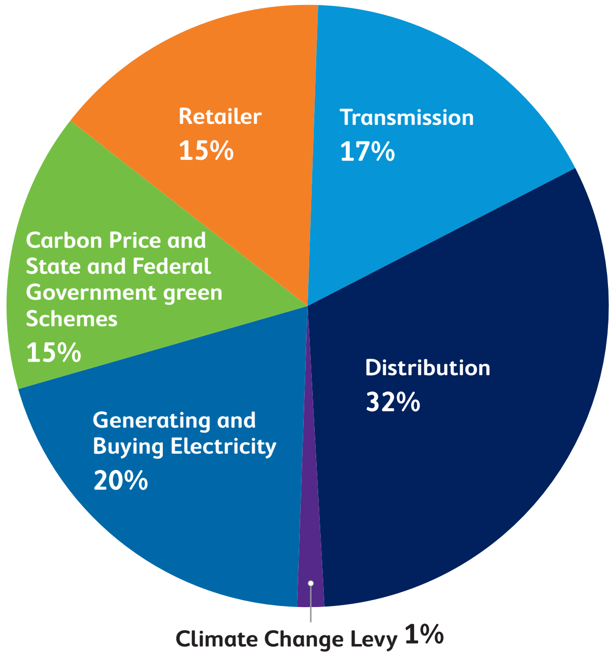
This transitional proposal covers just the 2014-15 financial year, the first year of the five year regulatory period and provides context by setting out indicative forecast expenditure and revenue for the total five-year period. The requirements to deliver Ausgrid's capital and operating plans for the remaining four years of the regulatory period will be covered in a substantive proposal to be submitted to the AER on 31 May 2014.

Ausgrid's transitional proposal has been prepared in accordance with the requirements of the transitional chapter 6 and Division 2 of part ZW of Chapter 11 of the rules.

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 the investment of billions of dollars each year. Our charges are provided to electricity retailers and, when combined with TransGrid's transmission charges, represent about half of customers' electricity bills. On average, customers' total electricity charges break down into the components shown in figure 1.

Figure 1 – Components of your electricity charges[1]



NSW Government network reform program

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

1. To continuously improve safety performance for employees, contractors and the public.
2. To maintain the reliability and sustainability of the electricity distribution networks.
3. To strive 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 rigorous strategic, operational and financial discipline to both the capital and operating programs. This has delivered total savings of $1.1 billion across the three NSW electricity distribution organisations in the 2012–13 financial year with current projected savings of $4.3 billion over the five–year period commencing July 2011.

The benefits of the network reform program are included in this transitional regulatory proposal and will result in lower distribution network charges for customers.

[1] The transmission component represents Ausgrid and TransGrid Transmission Use of System charges (TUOS).

Transitional proposal highlights

Compared to the current 2013-14 year, Ausgrid's share of an average household electricity bill will increase in 2014-15 by 1.12%, which is 1.34%[2] below the forecast rate of inflation. The typical bill impact for residential and small business customers is contained in table 1.

Table 1 – Bill impact from network charges for typical residential and small business customers (including metering) ($ p.a; nominal)

Typical annual bill	2013-14	2014-15	Change	Change
Residential (IBT) customer	812.52	821.65	9.13	1.12%
Small business (IBT) customer	2,612.73	2,656.34	43.61	1.67%

The key drivers of this outcome are:

- 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[3] for the 2014-19 period – a reduction of 41% which is 48% below the forecast rate of inflation over the five year period.
- The five year operating program will increase from $2.8 billion approved by the AER for the 2009-14 regulatory period to a proposed $3.2 billion for the 2014-19 period[4] – an increase of 16% which is 2% above the forecast rate of inflation over the five year period.
- 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 continuing take-up of domestic solar panels, the high Australian dollar's impact on Australian manufacturing and the continuing impact of double digit electricity price increases from July 2009 to July 2012.
- 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.

Better customer engagement

We have used a variety of channels to reach out and listen to our customers on the operations of Ausgrid and most importantly how these operations impact our customers' lives. These channels include qualitative and quantitative customer research, targeted stakeholder meetings and presentations, social media and customer correspondence. These opportunities for communication have varied depending on the type of customers, their communication preferences and availability of open two-way channels of communication.

New customer engagement guidelines established by the AER give Ausgrid the opportunity to significantly expand and improve on this two-way communication. To this end, Ausgrid has partnered with Endeavour Energy and Essential Energy to launch an innovative, low cost, social media campaign which is proving to be a highly successful engagement channel.

Ausgrid has developed a framework for the way it will engage with its customers. The framework and the initial engagement activities have assisted in the development of this transitional proposal. Further and more detailed activity will increase over time and will be explained in more depth in Ausgrid's substantive proposal.

Ausgrid expects that the engagement framework will help ensure its operations and services become better aligned with the long-term interests of electricity customers. It expects that clear and accurate communication will be delivered at the appropriate time and give the consumer a greater understanding of its operations and how and why they are funded.

This proposal will also outline how Ausgrid will embed better customer engagement into its business practices and how it will continuously assess and measure those engagement actions to ensure they remain effective, open and transparent to all its customers.

[2] 1.34% was calculated using the Fisher Equation using a CPI assumption of 2.5%. See glossary.
[3] For comparison, this proposed expenditure is inclusive of ancillary network services and Type 5 and 6 metering services. To give effect to the AER's 2014-19 classification of services, amounts in the remainder of this document will be exclusive of ancillary network services and Type 5 and 6 metering services unless otherwise stated.
[4] See above.

About this proposal

This document is Ausgrid's transitional regulatory proposal for the period 1 July 2014 to 30 June 2015[4]. It sets out the revenue requirements needed to manage the network in a safe, reliable and efficient manner for our customers. It differs in a few key respects from previous regulatory proposals submitted to the AER.

Our proposal covers only a single year as part of the arrangements to transition to the new rules that became effective in November 2012.

It also attempts to be more accessible to our customers and stakeholders, who may not be used to the complex area of electricity regulation and compliance.

This approach is consistent with the wishes of the AER and its new customer 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 greater opportunities to communicate with us, we hope that we can learn more about their views and better align our operation to their long term interests.

Proposal layout

This proposal contains the following chapters:

- **Chapter 1** – Ausgrid and our customers. This is an overview of our network, the results of our engagement with customers thus far; and the plans we intend to implement to relieve price pressures on our customers.
- **Chapter 2** – Regulatory matters. This chapter provides the context and content of our transitional proposal.
- **Chapter 3** – Network charges and revenue. This chapter summarises how much revenue we need to cover our forecast costs and how that will flow through to customers' bills.
- **Chapter 4** – Forecast network expenditure. This is a summary of our capital and operating expenditure forecasts required to provide reliable and safe supply to all of our customers.
- **Chapter 5** – Alternative control services. This chapter outlines relevant information about other services we provide.
- **Chapter 6** – Other compliance matters. This chapter provides an overview of some of the other rules requirements that we need to address.

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 report 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.

Other ways to comment

Ausgrid, Endeavour Energy and Essential Energy have also jointly launched 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. We are also now seeking customer feedback about our regulatory proposals on the joint Facebook page.

Ausgrid is seeking feedback with Endeavour Energy and Essential Energy on their joint facebook page at www.facebook.com/YourPowerYourSay

[5] In this document, we refer to this period either as the transitional year or 2014-15 or FY15. These terms are taken to be reference to the regulatory control period 1 July 2014 to 30 June 2015

1. Ausgrid and our customers

In 2012, the NSW Government announced the reform of the electricity distribution industry in response to the price pressures on our customers. So far, the reforms have made significant inroads in delivering efficiencies and driving down our costs to provide services.

1.1 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.

Its 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 as well as major mining areas of the Hunter Valley and 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 costs required to provide for the distribution and transmission networks and for the past five years it has been the fastest growing portion of our customers' total electricity costs.

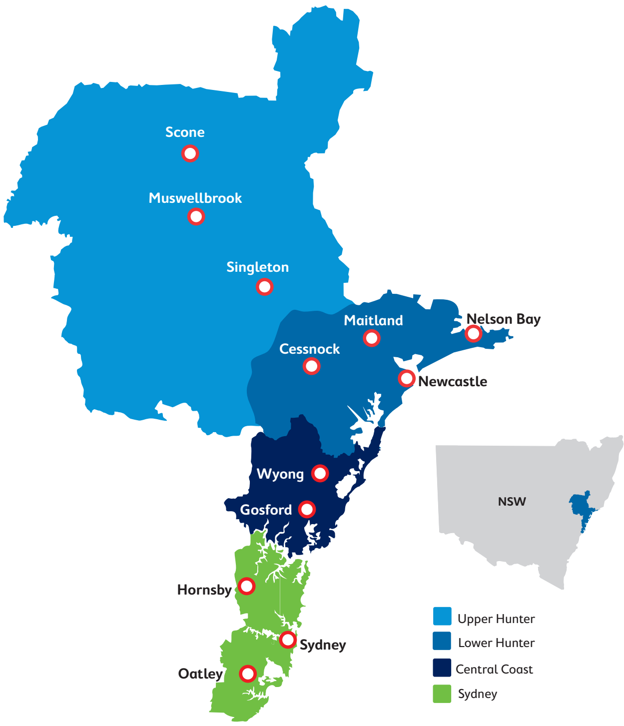
We made significant investment in the current 2009-14 period in order to maintain the safety and reliability of an aging electricity network whose capacity was being stretched.

Now, Ausgrid is increasing its focus on improving efficiency, affordability and accessibility in order to meet the long-term interest of the homes and businesses that are 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 traditional face-to-face contact and correspondence.

A greater emphasis on customer engagement consistent with best practice guidelines endorsed by the AER will assist Ausgrid in improving this conversation with its customers.

Figure 2 – Map of Ausgrid's network

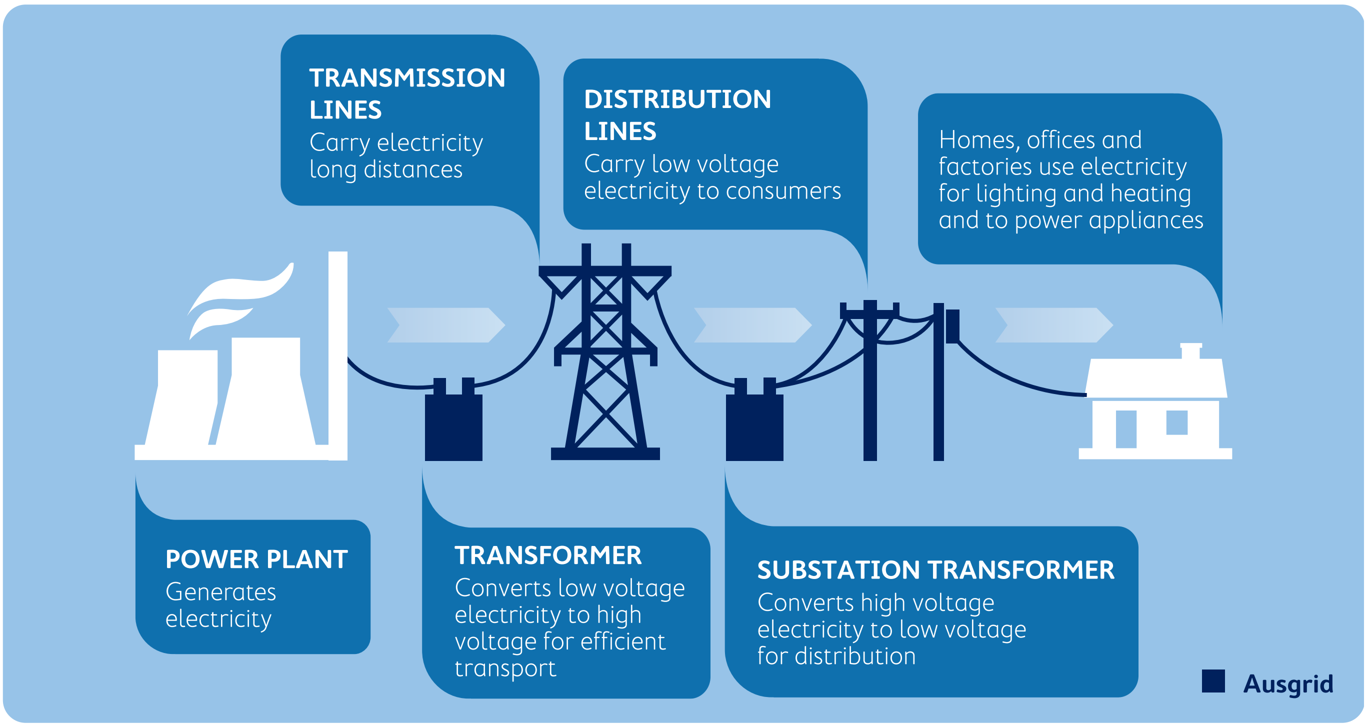


1.2 About the electricity industry

Ausgrid is a key part of the transport 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 customers live. Power is generated then transported as high-voltage electricity over long distances by TransGrid. Our network then transforms it at subtransmission and zone substations, which typically service entire suburbs, into lower voltage electricity. Electricity is again transformed at more localised distribution substations to be suitable for distribution directly to our 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 zones substations, 30,000 distribution substations, 48,000km of powerlines and 500,000 power poles.

Figure 3 – How electricity is distributed to end customers



1.3 Delivering for our customers

Ausgrid aims to be of service to the community by efficiently distributing electricity to customers in a way that is safe, reliable and sustainable.

This transitional proposal reflects our vision. It sets out our commitment to our customers - a commitment to a safe and reliable network; but most of all a commitment to do everything we can to alleviate the pressures that rising electricity charges have placed on our customers for the last few years.

Customers can be assured that we are striving to contain average increases in our share of customers' electricity bills at or below CPI and at the same time continuing to maintain a safe, reliable and sustainable network.

Our proposal, if accepted by the AER, will see customers enjoy real reductions in distribution charges over the next period. These indicative reductions in distribution charges are highlighted in table 2.

Table 2 – Change in average distribution and transmission charges based on latest energy forecasts

	FY15	FY16	FY17	FY18	FY19	Total
Distribution (real)[6]	-2.13%	-0.40%	-0.07%	-1.43%	-1.22%	-5.15%
Transmission (real)[7]	1.91%	-3.68%	0.16%	-0.63%	-1.15%	-3.43%

Our indicative forecast of a reduction in average distribution charges will contribute towards alleviating network price pressures on customers. An estimate of a typical customer network bill is shown in table 3.

Table 3 - Typical customer network use of system bill ($p.a., nominal)

	2013–14	2014–15	Change
Residential (IBT) customer	813	822	1.12%
Small business (IBT) customer	2,613	2,656	1.67%

Our vision and commitment to customers are underpinned by our values which govern everything we do. Findings from our engagement with customers have also played an important role in our vision for the future. The following sections outline our values and discuss the results of customer engagement activities.

[6] These prices have been converted to 2013-14 dollar terms. That is, the impact of expected inflation is not included.
[7] Includes the recovery of Ausgrid and TransGrid TUOS charges, with TransGrid's revenue assumed to increase by 2.5% each year.

1.4 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

1.5 Better customer engagement

Ausgrid's customers have numerous ways to have their say on the organisation's operations and how those day-to-day operations impact their lives. These take into account the type of customer, their communication preferences and the availability of open two-way channels of communication.

The new customer engagement guidelines established by the AER have provided Ausgrid with the opportunity to significantly expand and improve two-way communication with customers.

Ausgrid has developed an engagement program that will help create more opportunities for Ausgrid to better understand the views, expectations and preferences of our customers and stakeholders. It will also enable our customers to better understand our business and have a say in how we operate.

This program has assisted in the development of our transitional proposal and this activity will increase over time and will be further explained in Ausgrid's substantive proposal.

Importantly, it is expected that Ausgrid's engagement framework will enable our operations and services to become better aligned with the long-term interests of electricity customers. By providing clear and accurate communication at the appropriate time, we expect to give customers a better understanding of our operations, as well as how and why they are funded.

The program will also guide how Ausgrid embeds better customer engagement practices into its normal practice. It will continuously assess and measure its engagement actions to ensure they remain effective, open and transparent to all its customers. Ausgrid's engagement process will follow four broad areas which is shown in figure 5 and described in table 4.

Figure 5 – Customer engagement process

Table 4 - Description of 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.

Table 5 shows the activities undertaken to date and for the future.

Table 5 - Ausgrid's customer engagement framework activities

Pre-October 2013	Nov 2013 – June 2014	May 2014	June 2014 – ongoing
Existing engagement activities	**New engagement activities**	**Review and evaluation of engagement activities**	**Embed activities and report**
1. Analysis of customer views from existing channels: • Two years of social media and traditional media interaction. • 12 months community consultation. • 12-18 months of customer correspondence, EWON[8] reports. 2. Qualitative and quantitative customer research over multiple customer segments. 3. Targeted stakeholder meetings, forums and presentations.	1. Social media campaign to provide new channel for open and two-way dialogue on business-as-usual operations and new proposals. 2. New website page for customers' access to information and feedback. 3. Joint presentations[9] to common NSW stakeholders. 4. Presentations to unique Ausgrid stakeholders. 5. Report how success of engagement will be measured.	1. Presentation of engagement activity reports via: • Letters. • Presentations/forums. • Website page. • Social media channels. 2. Report on how engagement results have/have not been adopted or influenced activities.	1. Comprehensive review of all engagement activities. 2. Publish reports via: • Website. • Social media. • Stakeholder contact. 3. Embed engagement activities. 4. Follow up forums.

Customer feedback

Ausgrid has conducted research with residential and business customers. This included a dedicated research project to gain feedback from our customers on the areas listed below. It involved more than 900 telephone and online surveys with both residential and business customers and detailed discussions via focus groups and one-on-one interviews with around 80 customers. The research included a wide representative sample of our customers from a geographic perspective and included feedback from families, retirees, vulnerable customers, students, renters, owner-occupiers, businesses and industry.

The research explored customers' willingness to pay across seven main areas:

1. ***Reliability*** – customers' perceptions and experiences regarding power interruptions, their frequency and duration, customers' expectations regarding communication during power outages and customers' views regarding the links between reliability and price and their willingness to pay more to increase reliability.
2. ***Price*** – customers' perceptions surrounding prices and recent increases and the way this has impacted their behaviour in relation to electricity use and appliance purchases.
3. ***Construction and design standards*** – customers' views regarding construction and the aesthetic impact of the electricity network, connections costs and perceptions around environmental and safety considerations.
4. ***Metering technology*** – customers' attitudes towards advanced metering, the perceived value of the features and potential benefits of new technology and their willingness to pay for metering programs.
5. ***Demand management and energy efficiency*** – customers' views on a range of energy efficiency initiatives and their willingness to pay for these programs.
6. ***Support for vulnerable households*** – customers' views about the level of support for vulnerable customers, which segments of the community should receive support and the willingness for customers to pay to ensure this support can be provided.
7. ***Communication and engagement*** – investigation of customer needs and wants with regard to the information provided by Ausgrid and the level of engagement they want to have with us.

Research findings

Overall there is limited understanding among customers regarding the role of retailers and distributors. There is also customer confusion about whether Ausgrid is privately or publicly owned. Customers had some understanding of Ausgrid's role in the community. This was based on customers observing Ausgrid staff in the street working on power poles, etc. However, there is limited detailed understanding about the organisation.

1. ***Reliability*** – customers were generally satisfied with the reliability of their service, in fact, many felt it had improved over recent years. There was little willingness to pay more for a higher level of reliability.

   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. Most customers indicated that they want to know when power would be back on; a minority wanted further information regarding the reason for the outage.

[8] Energy & Water Ombudsman NSW
[9] With Endeavour Energy and Essential Energy

2. ***Pricing*** – a significant number of our customers had seen increases in their electricity bills over the past few years. Our customers were upset by these increases with few having a clear understanding of the reasons for the steep increases. Customers understood the need to spend money to maintain the electricity network. However, there was a clear preference that if prices needed to increase, they should do so in a steady manner over a number of years rather than a one-off "bill shock".
3. ***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, customers thought that safety standards should not be compromised. Around one quarter of customers were willing to pay more for underground cabling.
4. ***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.
5. ***Demand management and energy efficiency*** – 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.
6. ***Support for vulnerable customers*** – there was a mixed response from customers to this issue. Nearly half of the customers indicated that they thought the retailer or "someone else" was better placed to support vulnerable customers. However, 40% believed that Ausgrid also had a role to play in supporting vulnerable customers.
7. ***Communication and engagement*** – customers indicated that the level of communication that they were receiving from Ausgrid and their retailer was sufficient and that overall they don't expect a great deal of communication.

These key findings from our engagement with customers form the basis of Ausgrid's transitional proposal. Ausgrid's objectives for the upcoming period are:

- **Safety** by continuously improving our safety performance for employees, contractors and the public.
- **Affordability** by striving to contain average increases in our share of customers' electricity bills at or below CPI.
- **Reliability** by ensuring the ongoing reliability, security and sustainability of the network.

Figure 6 - Customer feedback

1.6 Summary of our 2009-14 program

The current 2009-14 regulatory period has been characterised by high levels of investment in the electricity network, and the systems and people needed to support it. This occurred after a period of under investment in the electricity network, and in parallel with increasing energy demand and use.

A high level of network investment was needed to address under investment in previous regulatory periods, and the need to replace ageing electrical infrastructure that was increasingly at risk of failure. The investment was also required because of increasing demand, particularly at peak periods, as well as the need to meet government reliability standards that covered the performance of the electricity networks in different parts of the state.

Ausgrid set out to deliver $8.4 billion ($nominal) of system and non-system capital investment and $2.8 billion ($nominal) in operational expenditure during this period.

The AER allowed $9.6 billion ($nominal) of revenue to be recovered from Ausgrid's network customers. As a result approved network charges increased by an average of 16.3% per annum from 2009-14 for most of our customers.

Other concurrent factors magnified the level of charges experienced by Ausgrid's customers.

Ausgrid was borrowing money to fund its network investment at a time when the world was in the midst of a financial crisis. In common with the rest of the business community, our cost of borrowing rose. This, too, led to higher electricity charges for customers.

Table 6 – Annual indicative network use of system charge for typical residential and small business customers ($nominal)[10]

	FY10	FY11	FY12	FY13	FY14
Residential	444	530	634	793	813
Change		19.3%	19.8%	25.0%	2.5%
Small business	1,330	1,605	1,953	2,549	2,613
Change		20.6%	21.7%	30.5%	2.5%

1.7 Changes as we lead in to the 2014-19 period

An analysis of customer feedback via traditional and social media, customer and EWON correspondence and complaints showed that customers do not support a continuance of this rate of network electricity price increases and that there is a need to better communicate the drivers behind electricity charges.

Qualitative and quantitative research commissioned in June 2013 also supports this view.

Ausgrid's significant investment program has delivered positive and long lasting results for the security and reliability of customers' power supply. This now allows us to return to more sustainable levels of investment, while retaining our focus on those parts of the network that require investment to alleviate significant risk of failure. Conditions in the financial markets have also stabilised. That will also help to take the pressure off future network charges.

In April 2012, the NSW Government commenced an electricity network reform project aimed at cutting costs, reducing duplication between network businesses in NSW and increasing and driving efficiencies across its operations.

The aim was to reduce capital and operating costs so that we can strive to contain average increases in our share of customers' electricity bills at or below CPI.

Network reform program

On 1 July 2012, the Networks NSW (NNSW) operating model commenced with Endeavour Energy, Ausgrid and Essential Energy having a joint Board and Chairman and a common Chief Executive Officer. A Group Management structure has been implemented to assist the Board and the Chief Executive Officer in undertaking reform of the industry consistent with the objectives of the NSW Government policy.

NNSW has a direct focus on identifying and driving efficiencies in the operations of the network businesses. The key focus areas of Networks NSW generated reform include:

- ***New operating model initiatives.*** These relate to streamlining both corporate and support services, removing functional duplication within, and sharing better practices between the three companies.
- ***Capital expenditure efficiency initiatives.*** These relate to improved capital management across the three distributors in relation to expenditure on the network, as well as on fleet, property, and technology.
- ***Strategy and policy initiatives***. These relate to policy changes for consistent better practice across the three distributors, particularly in network areas such as reliability planning, maintenance and renewal policies, fleet strategy and property portfolio management. In each case, significant operational business change will be required to achieve both operational and capital expenditure benefits.
- ***Procurement and logistic initiatives.*** These will create repeatable, auditable, controlled and faster sourcing processes that will drive significant procurement savings across a number of product and service categories.

Since 2012, the industry reform has significantly changed Ausgrid's operational focus. We have reviewed our strategies and policies, reprioritised our capital programs and reduced operational spending through management of overheads and tightening of Enterprise Bargain Agreement negotiations. The aim is to find cost efficiencies and expenditure deferrals to minimise price impacts, whilst not impacting on the safety of our people and customers and the overall reliability of the electricity network.

Ausgrid is in the process of introducing tighter controls on the approval of capital and operating expenditure including a strong focus on reducing the costs of delivery at the project design stage for capital works.

It has also introduced wider analysis and risk prioritisation in parallel with the planning stage to further develop opportunities to defer the need for expenditure and develop more efficient investment options.

Total expected operating expenditure for the 2009-14 period is forecast to be below the efficient allowance set by the AER. This is the result of ongoing management initiatives as well as network reform initiatives driven by NNSW.

We are also implementing management-led initiatives including tightening overtime and discretionary spend as well as a number of efficiency programs. These will operate in conjunction with the network reform projects.

These initiatives demonstrate ongoing effort by Ausgrid to be efficient in our operations. These significant savings are providing the foundation for Ausgrid to contain average increases in our share of customers' electricity bills at or below CPI for the next five year period and provides for an even more efficient expenditure profile as we enter into the 2019-24 period.

[10] The network bill comprises of Ausgrid's DUOS and share of TUOS, TransGrid's TUOS, and climate change fund obligations. Ausgrid therefore can only influence its DUOS and share of TUOS. The indicative network bills are for a typical residential customer consuming 5MWh per annum and a typical small business customer consuming 15MWh per annum on inclining block tariff (IBT).

2. Regulatory matters

We are commencing a 5 year regulatory determination process under the new National Electricity Rules. This is a transitional proposal for revenue and charges in 2014-15. We will submit a complete substantive proposal on 31 May 2014 that covers the entire 2014-19 period.

2.1 Context and content of transitional proposal

The AER administers the rules that the electricity distributors such as Ausgrid comply with and operate under. Every five years, electricity distributors must submit proposals to the AER that explain their efficient capital and operating costs and what they consider the revenue requirements are to fund them.

A new regulatory proposal was due to be submitted by the NSW and ACT distribution businesses by May 2013 for the period of 1 July 2014 to 30 June 2019. During 2012 the AEMC consulted on a number of major rule change proposals covering the NER and subsequently made a number of important changes. The NSW and ACT distribution network businesses will be the first organisations to submit proposals under these new rules.

During the rule change consultation, all parties agreed that a one year transitional proposal would help bridge the gap that would have occurred due to the short implementation period after the rule changes came into effect.

In making the rules to apply to the transitional year, the AEMC identified certain principles which should apply to the transitional arrangements[11]. These principles were:

a) The transitional arrangements should provide service providers with reasonable opportunity to recover at least the efficient costs they incur in the provision of regulated services.

b) Any transitional arrangements should be practicable having regard to the regulator's resourcing constraints, as well as the resourcing capacity of stakeholders.

c) Any arrangements put in place to facilitate the transition to the new rule should minimise the potential for one-off price shocks.

Whilst Ausgrid's transitional proposal covers just the 2014-15 regulatory year – the first year of the five year regulatory period, it also sets the context by providing an indication of key requirements for the subsequent four years. Full details will be covered in a substantive proposal to be submitted to the AER on 31 May 2014.

The matters that Ausgrid must address in the transitional proposal are set out in transitional Chapter 6 and Division 2 of Part ZW of Chapter 11 of the rules.

These matters focus mainly on:

- The amount Ausgrid proposes to be the annual revenue requirement for standard control services (SCS) for the transitional year, the indicative range of revenue requirements for the five year period 2014 to 2019 and the inputs into the calculation of these revenue requirements.
- A summary of Ausgrid's plan for expenditure for the transitional period and subsequent period.
- The indicative prices of direct control services.
- A proposed connection policy and other compliance matters.

The AER has indicated its preferred approach to the above requirements and Ausgrid has implemented the substance of this approach with a few refinements in preparing this transitional proposal. This is discussed further below.

Ausgrid's transitional proposal comprises this document and the information contained in the appendix and attachments. These are listed at the end of this document.

Ausgrid has sought to have suppressed from publication attachment H and appendix B of attachment K on the ground of confidentiality.

No regulatory information instrument was issued by the AER in respect of Ausgrid's transitional proposal. Consequently, this proposal does not need to comply with this particular requirement of the rules.

[11] AEMC Final Determination for the National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 at pp 215-216.

2.2 AER's framework and approach papers

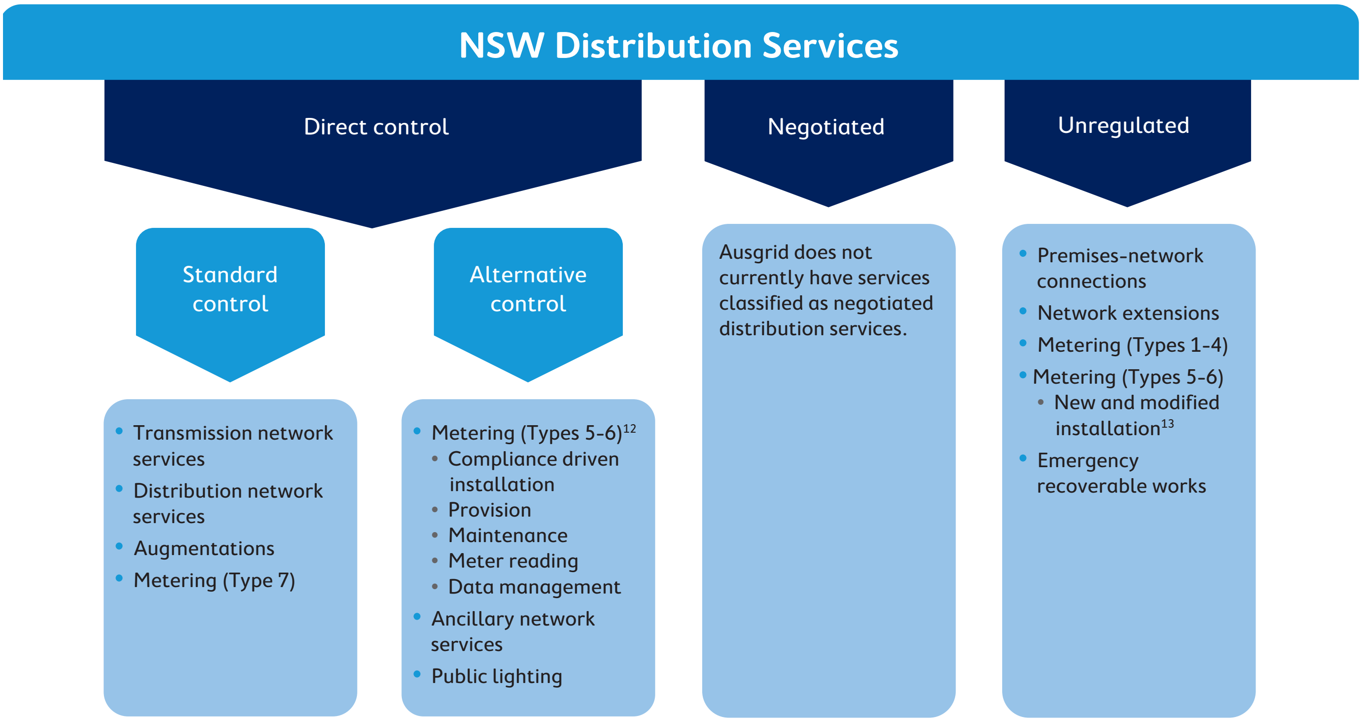
The framework and approach (F&A) paper is the first step in the regulatory process that determines our revenue and charges for the upcoming regulatory period. In this paper, the AER set out its decisions and approach on a number of matters relevant to an upcoming distribution determination. One of the matters, for which the AER must set out its proposed approach, is the classification of distribution services. Figure 7 summarises the AER's proposed classification of the distribution services provided by Ausgrid.

The AER may classify a ***distribution service*** provided by Ausgrid as:

- a direct control service, being services that are directly regulated by the AER; or
- a negotiated distribution service, being services that are not directly regulated by the AER and are provided on terms negotiated between the distribution network services provider (DNSP) and the customers subject to AER's oversight.

Direct control services are to be further classified as standard control services and alternative control services. In essence, standard control services comprise of distribution services that are integral to electricity supply and are relied upon by the majority of our customers, essentially the delivery of electricity. Alternative control services are customer specific or customer requested services. These services are provided to a particular group of customers or customers who request the service.

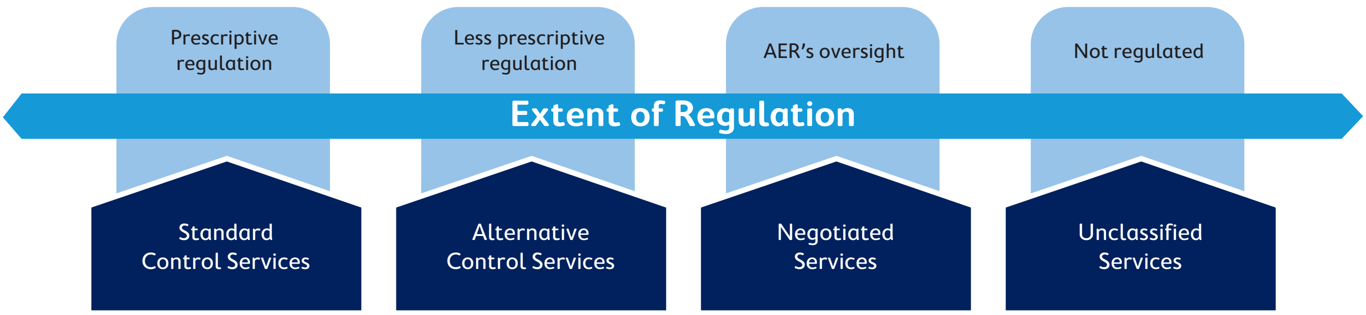
Figure 7 – NSW Distribution Services



Negotiated services are those that the AER considers that all relevant parties have sufficient market power to negotiate the provision of those services. For the 2014-19 period, the AER determined that none of the distribution services provided by Ausgrid are suited to be classified as negotiated distribution services. For the services that the AER decided to classify as direct control services, the AER changed the classification of some of these services from their current classification of standard control services to alternative control services. In the case of emergency recoverable works, the AER decided not to classify it for the next period.

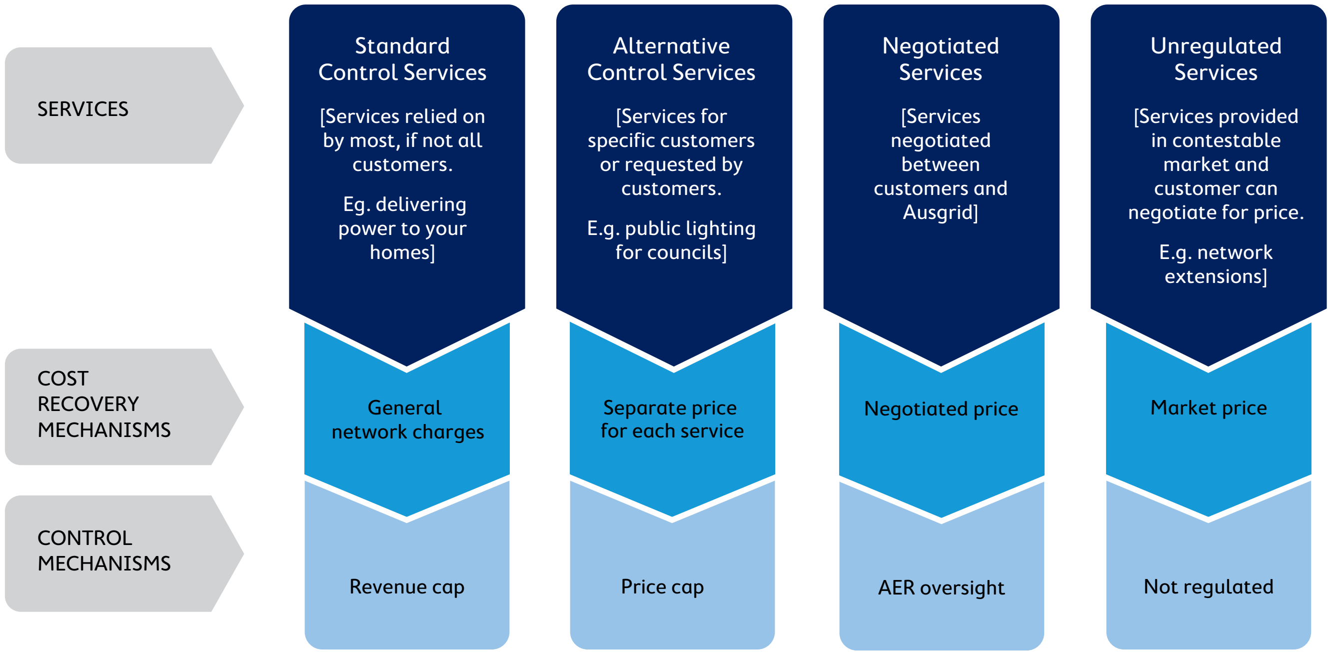
Classification of distribution services is important as it determines the level of regulation to apply. In the case of a service being unclassified, it is not subject to economic regulation by the AER. Figures 8 and 9 illustrate the level of regulation and how services are regulated.

Figure 8 – Extent of Regulation



[12] Includes household and small business metering.
[13] Excludes CT meters due to ASP (accredited service providers) schemes.

Figure 9 – Cost recovery mechanisms and AER's imposed control mechanisms



The AER's proposed approach to classification of services in the F&A paper is relevant for Ausgrid's transitional proposal. This is because the rules require the AER's distribution determination for the transitional period to specify the same classification of services as that which applied to the current 2009-2014 regulatory period except to the extent the AER's F&A paper for the subsequent period provides for a change in classification of services, in which case that change of classification will also apply to the transitional year. This means that the changes in classification determined by the AER should apply to the transitional year.

Transitioning to the new rules has necessitated this F&A process to be divided into two (2) stages. Stage 1 F&A paper was published by the AER on 25 March 2013[14]. It sets out the AER's approach to the classification of distribution services and decisions on the form of control mechanisms and dual function assets for both the transitional regulatory period and subsequent regulatory period.

The AER decided in the stage 1 F&A paper:

- To change the classification of Type 5 and 6 metering services and ancillary network services (i.e. customer specific or customer requested services) from standard control services to alternative control services from 1 July 2014.
- To not classify emergency recoverable works from 1 July 2014, meaning this service will not be regulated by the AER. It is currently deemed to be standard control services.
- That the forms of control mechanisms for standard control services and alternative control services are revenue cap and caps on the prices of individual services respectively.
- That the pricing in respect of services provided by Ausgrid's dual function assets are to be regulated under Part J of Chapter 6A of the rules, i.e. transmission pricing.

For the stage 2 F&A paper the AER may deal with:

- Modifications to be made to the incentives schemes.
- The adjustments to the 2014-15 revenue approved under determination for the transitional period and the notional revenue for subsequent regulatory control period.
- The manner in which prices that may be charged for alternative control services in the subsequent regulatory period is to account for any under or over recovery of revenue during the transitional period.

Stage 2 of the framework and approach is required by the rules to be published by the AER by 31 January 2014, the same day we are due to lodge this transitional proposal to the AER[15]. At the time of preparing and lodging this proposal, the AER had not published its stage 2 F&A paper and consequently Ausgrid is unable to consider these matters in this transitional proposal.

Nevertheless, there has been engagement between Ausgrid and the AER. Our proposal assumes the following:

- The AER plans to apply the service target performance incentive scheme with revenue at risk from 2015-16 onwards. For the transitional year, the current approach of collecting data via an annual regulatory information notice would continue.
- The new Efficiency Benefits Sharing Scheme (EBSS) to apply from the transitional year.
- Forecast depreciation would be used to establish the value of the regulatory asset base at the commencement of the next regulatory period.
- The Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) will carry over the existing arrangements of the current regulatory period although the d-factor will be removed.

[14] 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.
[15] Clause 11.56.4(o) and 11.55.2(b)(a) of the Rules.

Giving proper effect to the AER's classification of services

The rules require Ausgrid to propose an annual revenue requirement for standard control services for the transitional year. In addition, Ausgrid is also required to provide indicative prices for direct control services, i.e. standard control services and alternative control services (as classified by the AER in its stage 1 F&A paper).

As noted, the AER has re-classified some of our services from standard control to alternative control including Type 5 and 6 metering services and ancillary network services. In addition, the AER has re-classified emergency recoverable works from standard control to unclassified services. To give effect to the AER's re-classification, we need to allocate the costs of providing these services to the correct class of services in order to develop indicative prices for the transitional year.

However, an anomaly in the transitional rules means that we are prevented from allocating costs to these services for the transitional year. The rules state that costs which have been allocated to a particular service cannot be reallocated to another service during the course of a regulatory control period. Complying with this requirement of the rules however means that proper effect cannot be given to the AER's classification of services for the transitional year.

The NSW DNSPs have had discussions with the AER on the approach to fulfilling the rules requirements for the transitional proposal, particularly the provision of indicative prices. On 11 December 2013, the AER wrote to Networks NSW outlining their view of a preferred approach to setting indicative prices for the transitional year[16]. Essentially this approach is to allocate costs for all services which are changing classification to standard control services and include those costs in a bundled price for standard control services, Type 5 and 6 metering services and certain ancillary network services. We have largely adopted the AER's preferred approach so as to fulfil the AER's wish of minimising changes during the transitional year.

As explained in more detail in appendix 1, the AER's preferred view has impacted the way we have developed our proposal. While we have been clear that the AER's classification of services is applicable for the transitional year, we have included the costs of providing these re-classified services in the standard control services cost pool, where the costs will be recouped through prices for standard control services (i.e. DUOS prices)[17]. We have made clear however that the annual revenue requirement only relates to standard control services as defined by the AER in stage 1 of its framework and approach paper.

Importantly, the AER's preferred approach has impacted the way we have presented indicative prices for these services:

- Metering services Type 5 and 6: the AER considers that new prices should not be established for the transitional year as the transitional rules prevent the re-allocation of costs from standard control service to alternative control service for the transitional year. Instead we understand that the AER prefers to leave the costs of providing Type 5 and 6 metering services within the standard control services cost pool and these costs are to be recouped through DUOS prices. This approach is the same as how Type 5 and 6 metering services costs are being recovered in the current period (because they are classified as standard control services for the current period).
- For those ancillary network services currently being provided and have existing prices, the AER prefers to apply CPI to these prices, as required by clause 11.56.3(j) of the rules.
- For those ancillary network services currently being provided but there are no existing prices and the costs are currently captured as part of the standard control service cost pool (because these services are classified as standard control services for the current period), the AER prefers to leave the costs of providing these services in the standard control services cost and recovered through DUOS prices for the transitional year.

Table 7 illustrates the recovery of costs of the various services in the transitional year and in the subsequent years.

Table 7 – Revenue recovery mechanism

Service classification	Revenue recovery mechanism	
	Transitional year (FY15)	Remaining years (FY16 – FY19)
Standard control services	General network charges	General network charges
Alternative control services		
• Metering	General network charges	Specific metering charges
• Ancillary network services	General network & customer specific charges	Customer specific charges
• Public lighting services	Street lighting charges	Street lighting charges
Unclassified services	General network charges	Unregulated charges

Ausgrid considers that further clarification from the AER would assist in the effective implementation of the AER's preferred approach for the transitional period. Clarification would ensure a seamless transition from the transitional period to the subsequent period and preserve the integrity of the AER's classification of services for the transitional year. Of significance is the clarity around the revenue amount that will be used for adjustments to the annual revenue requirement of the subsequent period and to demonstrate compliance with the control mechanism. This is set out in detail in appendix 1.

[16] Letter from the General Manager, Network Regulation, AER
[17] Distribution Use of System

3. Network charges & revenue

We propose an amount of $2,274 million ($nominal) to be the annual revenue requirement for standard control services for the 2014-15 transitional year. This amount is needed to recover the efficient costs we reasonably expect to incur in providing those services.

Ausgrid provides a range of distribution services some of which are classified by the AER as standard control services. Standard control services are those central to the supply of electricity and are relied on by most (if not all) of our customers; essentially the delivery of electricity to customers.

As part of our transitional proposal we are required to propose an amount to be the annual revenue requirement for the 2014-15 year to recover the costs of providing standard control services[18]. 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 may only approve the amount we propose to be the annual revenue requirement for 2014-15 if it is satisfied that the recovery of the proposed amount by Ausgrid is likely to minimise variations in prices between the years from 2013-14 to 2018-19[19]. In making this decision, the AER must also take into account the national electricity objective and the revenue and pricing principles.

We also provide other accompanying information that assists the AER in making its decision on the amount we proposed as the annual revenue requirement for standard control services. This includes a range of revenue requirements for the five year period 2014-19, and other inputs such as the opening regulatory asset base and rate of return.

In addition, Ausgrid has adopted the AER's approach to the setting of indicative prices for some alternative control services.

In this chapter we outline the amount we propose to be the annual revenue requirement for 2014-15 including:

- The approach we took in determining this amount.
- The inputs used to determine this proposed annual revenue requirement amount.

To give effect to the AER's approach, this chapter also includes:

- The total bundled revenue we nominate to be recovered through NUOS charges for the transitional year.
- The indicative NUOS prices to recover the total bundled revenue nominated by Ausgrid.

3.1 Our proposed revenue – standard control services

We propose the amount of $2,274 million ($nominal) as the annual revenue requirement for the transitional regulatory control period 2014-15.

The rules do not require us to calculate this amount in accordance with the provisions that would otherwise apply[20]. It is therefore essentially a placeholder amount, giving an indication of the annual revenue requirement for 2014-15.

Recognising this, the AER is required to make a final decision on Ausgrid's annual revenue requirement for 2014-15 in its final determination for the 2014-19 regulatory period, with a 'true up' for the difference in the annual revenue requirement for 2014-15 that the AER determined under the transitional proposal and the 2014-19 proposal.

Nevertheless, we have taken an approach that mirrors the rules requirements as much as possible. In determining the amount we propose as the annual revenue requirement for 2014-15 and indicative range of annual revenue requirement for subsequent years, we have used the main elements of the building block approach prescribed in the rules for the calculation of revenue requirements relating to standard control services. These main elements are:

- Indicative forecast capital and operating expenditure.
- Indicative estimate of the value of the regulatory asset base.
- Indicative rate of return.

These main elements are inputs into the annual revenue requirement using the AER's post tax revenue model. Details of these elements are provided in this chapter and in chapter 4.

We have adopted this approach to ensure that:

- We adhere as close as possible to the rules requirements that would otherwise apply so as to minimise the adjustments needed when the 'true up' is performed.

[18] As they are defined in the AER's stage 1 F&A paper.
[19] Clauses 11.56.3(b).
[20] As acknowledged under clause 11.55.2(b) of the Rules.

- The amount we propose as the annual revenue requirement for the transitional year has been derived using the indicative forecast capital and operating expenditure for that year. That is, the annual revenue requirement we propose for the transitional year is consistent with the indicative expenditure we expect to incur in providing standard control services for that year. Moreover, in calculating the indicative range of revenue requirement for the subsequent four years, we have also used the indicative estimate of forecast capital and operating expenditure for these years. As such, there is consistency between the indicative forecast expenditure we expect to incur and the revenue we propose to recover from customers.

Further, to minimise potential price variations we have used our best forecasts of required capex and opex (for standard control services) over the full 2014-19 period and smoothed the resulting revenue requirements over a 5 year horizon. Tables 8-10 show the result of the above approach with $2,274 million ($nominal) being proposed to be Ausgrid's annual revenue requirement for 2014-15.

Table 8 also shows the indicative range of revenue requirements[21] for the five year period 2014-19 based on a rate of return or weighted average cost of capital (WACC) range of 8.52% to 9.11%[22]. The rate of return was used as the variable in deriving the indicative range of revenue requirements; all other inputs such as forecast capex and opex remain constant. From the range of 8.52% to 9.11%, we had used a conservative rate of return of 8.52% to calculate the amount we proposed to be the annual revenue requirement for 2014-15.

Table 8 – Proposed annual revenue requirement for transitional year and indicative range of revenue requirement ($ million, nominal)

	FY13	FY14	FY15	FY16	FY17	FY18	FY19	Total
Actual/estimate revenue	2,410	2,377						
Lower Case (8.52% WACC)			2,274	2,320	2,366	2,412	2,463	11,835
High Case (9.11% WACC)			2,384	2,431	2,479	2,529	2,582	12,405

Numbers may not add due to rounding

In relation to the AER's decision to apply the transmission pricing rules to services provided by Ausgrid's dual function assets, we gave effect to this decision by dividing Ausgrid's proposed annual revenue requirement for the transitional period into transmission standard control service revenue and distribution standard control service revenue. We have done so by allocating the building block inputs between transmission and distribution. This is the same approach we used for the 2009-14 determination.

Table 9 – Proposed 'smooth' annual revenue requirement for transitional year and subsequent years ($ million, nominal)

	FY15	FY16	FY17	FY18	FY19	Total
Distribution	2,004	2,044	2,085	2,126	2,171	10,430
Transmission	270	275	281	286	292	1,404
Total	**2,274**	**2,320**	**2,366**	**2,412**	**2,463**	**11,835**

Numbers may not add due to rounding

Minimising price variations

To minimise price variations over time we need to take into account changes in the level of revenues required to meet efficient costs, as well as forecast changes in energy consumption over time. For example, if the required level of revenue drops in the transitional year but then rises again in subsequent years[23] and we do not attempt to smooth revenue recovery over the full 2014-19 period, customers could face a price shock downwards then another price shock upwards[24]. Alternatively, if energy consumption falls and required revenue remains at the same level, then average charges will need to increase.

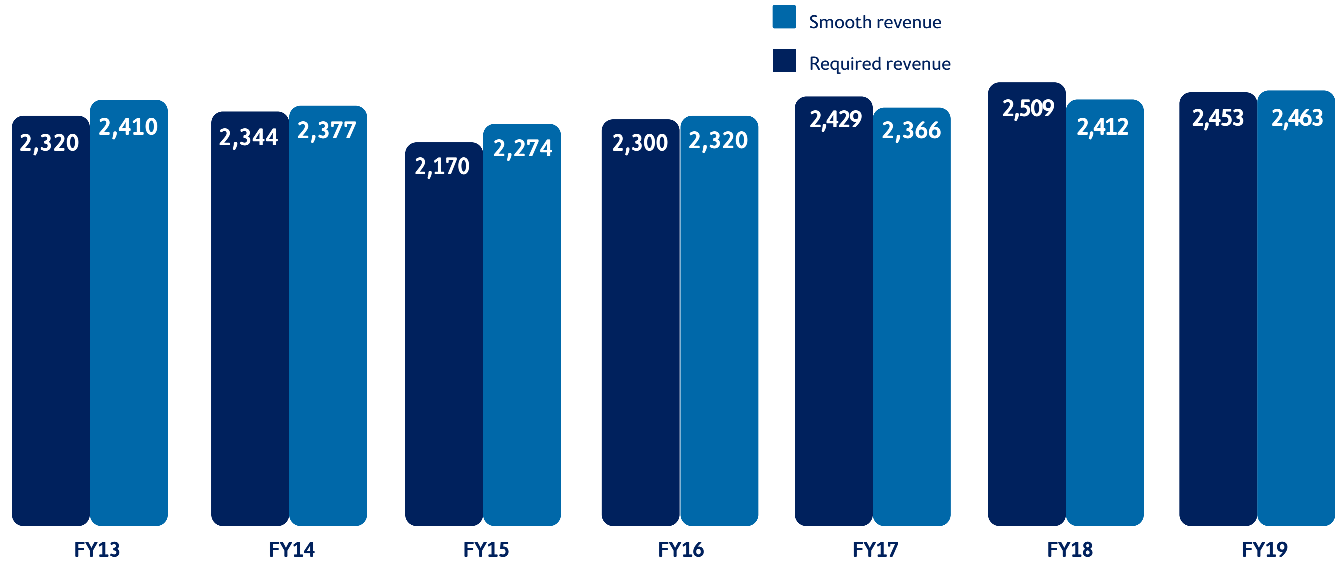
In addition to this, the rules require that revenues be smoothed such that it minimises the difference between required revenues and expected revenue recovery in the final year of the regulatory period (i.e. 2018-19)[25]. This is intended to minimise the potential for price shocks between the the 2014-19 period and the subsequent regulatory period[26].

We have taken these factors into account in developing the amount we propose to be the annual revenue requirement for 2014-15 (to which we added the revenues needed to recover the costs of providing certain alternative services and unclassified services to arrive at the total bundled revenue). Figure 10 shows our best estimate of required revenues (prior to smoothing) for the five years 2014 to 2019. The figure also illustrates the revenue smoothing profile we have adopted to minimise price variations between years. This smoothing profile determines the revenue we propose to be our annual revenue requirement for the transitional year as well as the indicative revenues for the subsequent four years.

This smoothed revenue profile has been calculated using the AER's post tax revenue model and ensures that our proposed revenues are equal to required revenues in net present value terms. These models are provided in attachments A and B.

21 Clause 11.56.2(b)(5).
22 Nominal Vanilla WACC is the weighted average of the cost of equity and cost of debt multiplied by the proportion of equity and debt in the firm. The cost of equity is assumed to be post-tax and the cost of debt is pre-tax.
23 Rise and fall in revenue may reflect the lumpiness of the expenditure profile.
24 Assuming energy consumption remains constant.
25 NER, cl. 6.5.9(b)(1)
26 For example, if revenues are 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.

Figure 10 – Forecast required revenue vs. smoothed revenue ($ million, nominal)



3.2 Supporting inputs

The previous sections provided the proposed annual revenue requirement for standard control services for the transitional year and an indication of the likely revenue required in the subsequent four years. These revenues have been calculated using the building blocks approach and the AER's PTRM. The building block components we have used to calculate the annual revenue requirement for the transitional year and indicative revenue requirements for the subsequent four years are:

- A return on the value of the regulatory asset base (RAB), determined by multiplying the value of the RAB by our proposed rate of return. The value of the RAB reflects the remaining value of past capital investments and the forecast value of future capital expenditure. The proposed rate of return reflects the cost of capital for a benchmark efficient network service provider.
- A return of capital or regulatory depreciation.
- Forecast operating expenditure.
- An estimate of the cost of corporate income tax for the transitional year.
- An indicative revenue carry over amount from the application of the EBSS and the demand management innovation allowance (DMIA) in the current regulatory control period.

The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2014-15 to 2018-19 are outlined in table 10.

Table 10 – Building block components of required revenue ($ million, nominal)

	FY15	FY16	FY17	FY18	FY19	Total
Return on capital (RAB)	1,226	1,298	1,376	1,439	1,503	6,843
Return of capital	131	157	182	166	181	817
Opex[27]	593	593	636	613	621	3,056
EBSS carry over	102	125	90	148	-	465
Income tax	118	127	145	143	149	682
Alternative control services (excluding public lighting) and emergency recoverable works	90					90
Required revenue[28]	**2,260**	**2,300**	**2,429**	**2,509**	**2,453**	**11,952**
Distribution portion	1,916	2,028	2,138	2,213	2,157	10,453
Transmission portion	254	272	290	296	296	1,409
Alternative control services (excluding public lighting) and emergency recoverable works	90					90

Numbers may not add due to rounding

[27] Inclusive of debt raising cost for all years and a DMIA adjustment of $1.5 million ($,2013-14) in FY16.
[28] That is, unsmoothed revenue

Indicative estimate of value of regulatory asset base

The indicative estimate of the value of our RAB (for standard control services) as at 1 July 2014 is $14,390 million as shown in table 11. This comprises of $12,281 million attributable to distribution standard control services and $2,109 million attributable to transmission standard control services (e.g. services provided by Ausgrid's dual function assets). We have calculated these amounts based on clause 6.5.1 and schedule 6.2 of the rules (noting that schedule 6.2.1 is not applicable to the transitional regulatory control period) and the AER's roll forward models. These models are provided at attachment C and D. This RAB value of $14,390 million reflects the roll forward of actual capex for FY2009-13 and estimated capex for FY14.

These capital expenditure amounts contain the actual and estimated capital expenditure pertaining to Type 5 and 6 metering services and ancillary network services[29].

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. The adjustment is approximately $256 million ($nominal).

Table 11 – Opening RAB ($million, nominal)

Calculation of RAB value as at 1 July 2014	
Opening RAB as at 1 July 2009	8,325
Add: Actual and estimated capex	6,731
Less: Regulatory depreciation	-692
Impact of actual capex for FY2009	282
Adjusted opening RAB as at 1 July 2014	14,646
Less: assets for reclassified services (eg Metering)	-256
Value of RAB for standard control services as at 1 July 2014	14,390

Numbers may not add due to rounding

Allowed rate of return

We propose a conservative estimate of the rate of return of 8.52% using a trailing average approach to the cost of debt 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[30]. We consider that a long term average approach is reflective of both the efficient costs of debt and equity for regulated energy networks. As the AER recognised in its final rate of return guideline, in the presence of re-financing risk, the benchmark efficient practice is to issue debt on a staggered portfolio basis[31].

We also consider that investors in regulated utility firms are likely to invest over a long term horizon and it is reasonable to use long term historical data to set the efficient cost of equity over a five year regulatory period. This approach smooths out short term volatility in data used to estimate the cost of equity. We have also had regard to prevailing conditions in the market for equity funds when developing our indicative rate of return for this transitional proposal. In addition, stable returns are an important driver in providing stable prices to customers over the long term.

We propose a cost of debt of 7.55%, a cost of equity of 9.98% and a gearing level of 60%.

Our proposed cost of equity has been informed by the opinion of expert economic consultants Competition Economics Group (CEG). Additional details on Ausgrid's approach to the rate of return are outlined in a report from CEG titled 'WACC Estimates' provided as attachment E.

Table 12 shows the WACC ranges we used to calculate the indicative revenue requirements described in section 3.1.

[29] These services are classified as standard control services prior to 1 July 2014.
[30] 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.
[31] AER, Final rate of return guideline, December 2013, pp. 104-105.

Table 12 – Indicative range of rate of return and proposed rate of return

Rate of return parameters	Low case (proposed) WACC %	High Case WACC %
Overall WACC	8.52%	9.11%
Cost of equity	9.98%	11.02%
Cost of debt	7.55%	7.84%
Gearing	60%	60%
Nominal risk-free rate	4.78%	5.17%
Inflation rate	2.50%	2.50%
Debt risk premium	2.77%	2.67%
Market risk premium	6.50%	6.50%
Utilisation of imputation	25%	25%

Cost of debt – 7.55%

For the cost of debt, we propose a trailing average cost of debt using yields over the past 10 years on Australian BBB+ corporate bonds with a term to maturity at issuance of 10 years. We have used a conservative cost of debt estimate of 7.55%, which is based on the average of the long run estimate of the cost of A and BBB rated debt as estimated by the Reserve Bank of Australia (RBA)[32].

For the upper end of our WACC range we have used a cost of debt estimate of 7.84%, which has been estimated by CEG as the trailing average 10 year cost of debt using only Bloomberg data for yields on 7 year corporate bonds and regulatory precedent for the method of extrapolating the yield from a 7 year yield to an implied ten year yield.

To the extent possible we have had regard to the AER's final rate of return guideline to estimate our indicative rate of return. The AER's final rate of return guideline stated that a trailing average cost of debt is commensurate with the benchmark efficient practice, which is to issue debt on a staggered portfolio basis to manage refinancing risks. We have adopted a trailing average estimate and we consider that this approach is commensurate with the rules as it reflects the benchmark efficient cost of debt for network businesses.

However, the final rate of return guideline also stated that the AER intends to apply transitional arrangements that move all businesses from the current approach of estimating the cost of debt over a short observation period close to the final decision for a network determination over 10 years. Based on current forecasts of yields on 10 year BBB corporate bonds, this would significantly under compensate Ausgrid relative to its stand-alone benchmark efficient costs of debt finance.

As we have noted in submissions to the AER throughout the rate of return guideline consultation process, Ausgrid has consistently issued debt on a staggered portfolio basis and prudently managed refinancing risks over the past 10 years. The AER's introduction of a 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.

We consider that the proposed transitional arrangements for moving to a trailing average cost of debt set out in the AER's final rate of return guideline are inconsistent with the National Electricity Law and the rules.

We also note that based on advice received from UBS and provided on a confidential basis to the AER in combined NSW DNSPs submissions to the AER's draft rate of return guideline, it would not have been, nor would it now be possible to efficiently re-finance the debt portfolios of the NSW distributors on the basis implied by the AER's transition approach to setting the cost of debt.

The UBS advice suggests that it would be difficult and costly for the NSW DNSPs to refinance their debt portfolios over a 10-40 day period close to the start of the next regulatory period. UBS suggested:

- If the NSW DNSPs attempted to hedge their debt portfolios (approximately $17 billion in notional debt) over a 10-40 day period, it is questionable whether the Australian swap market would be sufficiently liquid to accept this level of swap contracts.
- Even if the NSW DNSPs were able to hedge their full debt portfolios using interest rate swaps over a longer period (e.g. 3 months), the transaction would need to be performed behind information barriers to avoid speculators taking advantage of the hedging requirement. However, this would also limit the ability to gain a competitive rate through competition across market participants.
- The costs involved in executing such a large hedging transaction would be significant and the market risk that the NSW DNSPs would have to take on during the execution period would be extraordinarily high. It may be possible for the NSW DNSPs to issue their debt offshore in the US market and then enter into swaps to fix the USD/AUD exchange rate. However, the transactions cost of doing this (information requirements, credit rating reports, advertising etc.) would be high.
- Moreover, even though the US bond market is much more deep and liquid than the Australian market a new issuance of $17 billion or greater would attract a significant new issuance premium. For example, the recent debt issuance by Verizon (approx $US 49 billion) attracted a 100 basis point new issue premium. There would also be significant lead time (up to 3 months) before such a transaction could be completed.
- In addition to this, there is insufficient liquidity in the Australian cross currency basis swap market to hedge the exchange rate risk for such

[32] See attachment E, page 27

a large debt issuance in the US market immediately following such an issuance. Therefore the NSW DNSPs would be exposed to an extraordinarily high level of currency risk over the 3 month period before the debt issuance could be completed. 1 standard deviation in the AUD/USD rate over this period could increase the combined debt obligation of the NSW DNSPs (based on a notional debt portfolio of 60% of forecast RABs) by close to $1 billion. The maximum shift over a 3 month period is likely to be 2 standard deviations leading to a potential increase in the combined debt obligation of the NSW DNSPs of close to $2 billion.

- In both the domestic and offshore scenarios, it is unlikely that Ausgrid, Endeavour Energy and Essential Energy or bank counterparties to swap transactions would be able to engage in swap contracts without a Credit Support Annex (CSA) in place. This would expose the NSW DNSPs to even greater funding risks in the event that collateral is called in accordance with a CSA.

The advice from UBS supports the view that the costs of moving away from the Ausgrid's existing portfolio approach to debt management would have been, and continue to be prohibitively high for the NSW DNSPs, and therefore would result in inefficiently high debt costs.

Cost of equity – 9.98%

In determining our proposed cost of equity of 9.98% we have had regard to relevant estimation methods, financial models, market data and other evidence[33]. We have also used an approach that leads to a consistent application of financial parameters within the return on equity[34].

The Sharpe-Lintner CAPM estimates the cost of equity as follows:

Cost of equity = risk free rate + ße × [E(rm) – risk free rate]

One approach is to populate the CAPM using an estimate of the forward looking required return on the market based on the historical average realised real return on the market. The AER has termed this approach the "Wright approach".

CEG has applied this approach estimating the required return on the market consistent with NERA's update to the Brailsford et. al. data[35]. NERA estimated the average real realised return on the market, inclusive of the value of imputation credits, from 1,883 to 2011 is 8.84%. Adding currently expected inflation of around 2.50% to the historical average results in a realised real return on the market of 11.56%. Given prevailing interest rates in December 2013 (4.34%) this implies a market risk premium of 7.22%. CEG has applied this approach and estimate a cost of equity for a benchmark DNSP of 10.3% to 11.3% (depending on whether an equity beta of 0.8 or 1.0 is used).

Another approach that relies on the historical average realised return on the market is to assume that the market risk premium is constant over time and to use the historical average realised excess return on the market (i.e., in excess of the 10 year risk fee rate) as a proxy for the prevailing market risk premium.

CEG has estimated the cost of capital using this approach. For our proposed cost of equity we use:

- A long term average of yields on 10 year Commonwealth Government Bonds of 4.78% to proxy the risk free rate. This is a nominal risk free rate estimate using data from 1883 to 2011 to be consistent with the period over which they calculate our proposed estimate of historical excess returns and an implied market risk premium[36]. (For the high case we have estimated the risk free rate over a 10 year period consistent with the benchmark efficient approach to estimating the cost of debt. This provides a risk free rate estimate of 5.17%.)
- An equity beta of 0.8 based on long term empirical estimates prepared by Strategic Finance Group Consulting (SFG) and CEG[37]. We note that empirical evidence from NERA consulting using the Black CAPM framework suggests that empirical estimates of the equity beta within the Sharpe-Lintner CAPM framework are likely to understate the return on low beta stocks (i.e. stocks with an equity beta estimate of less than 1). NERA's analysis suggests that the best estimate of the cost of equity for a benchmark efficient energy network firm within the Sharpe-Lintner CAPM framework is given by using an equity beta of one (equivalent to assuming the expected return on the market portfolio is the best predictor of the efficient benchmark cost of equity)[38].
- An excess return to the market portfolio of stocks relative to the risk free rate (often referred to as the market risk premium) based on historical excess returns to stocks above the risk free rate of 6.5% over the period 1883 to 2011[39].

This approach provides a cost of equity of 9.98% using the CAPM framework. This is very similar to the estimate arrived at following the Wright approach (10.26%). For the purpose of this transitional proposal we have adopted the lower of the two.

We have also had regard to other estimates by CEG of the cost of equity not based on historical averages. These include:

- Using the Dividend Growth Model (DGM) to estimate the MRP in order to estimate the capital asset pricing model (CAPM) cost of equity (9.70% to 12.06%)[40].
- Using the DGM to directly estimate the cost of equity for the benchmark firm (11.18%).
- Using the Fama French model to estimate the cost of equity for the benchmark firm (11.61%).

We note that most of these estimates fall above the top end of the range used in this submission. Therefore, we consider our cost of equity of 9.98% to be a conservative estimate in the context of all the relevant estimation methods, financial models, market data and other available evidence.

Indicative estimate of forecast capex and opex

Table 13 shows the indicative estimate of our forecast capex and opex relating to the provision of standard control services. These estimates were used in calculating the annual revenue requirements for the transitional year and the subsequent four years. Details of our expenditure plan are provided in Chapter 4 of this proposal.

33 NER, cl. 6.5.2 (e)(1)
34 NER, cl. 6.5.2 (e)(3)
35 See attachment E - CEG "WACC estimates", Page 8.
36 CEG-WACC estimates, pp. 11-12.
37 CEG-WACC estimates, p. 11.
38 NERA, Estimates of the zero-beta premium, June 2013, p. 39.
39 NERA, The market, size and value premiums, June 2013, p. 17.
40 Associated with a theta of 0.35.

Table 13 – Indicative estimate of forecast capex and opex for standard control services ($ million, 2013-14)

	FY15	FY16	FY17	FY18	FY19	Total
Capex	1,020	991	853	801	741	4,406
Opex	571	557	582	547	540	2,797[41]

Numbers may not add due to rounding

Estimated cost of corporate tax

To estimate the cost of corporate income tax we have used the current corporate tax rate of 30% and assumed 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%[42] and the latest estimate of the market value of distributed imputation credits from SFG[43] of 0.35[44]. The estimated cost of corporate income tax has been calculated using the AER's PTRM and is outlined in table 10.

Regulatory depreciation

We have estimated revenue allowances for regulatory depreciation based on the AER's preferred approach to calculating regulatory depreciation. This estimates straight line depreciation that divides asset values by the remaining life for each asset. Remaining lives for each class of asset have been estimated as a weighted average of the remaining life of existing assets and depreciation of new assets by the standard life for that asset. This average is weighted by the value of assets as at 30 June 2014.

Straight line depreciation is offset by indexation of the RAB within the building blocks framework set out in the NER. This is reflected in the revenue allowances for regulatory depreciation outlined in table 10.

Proposed EBSS carryover amount

We have applied the EBSS scheme outlined by the AER in its determination for the 2009-10 to 2013-14 regulatory period. This provides estimated carryover amounts for the 2014-15 to 2018-19 regulatory period as set out in Table 10 above. We have provided the calculation of this EBSS carry over amount in attachment F.

3.3 Total revenue for NUOS pricing

In sections 3.1 and 3.2 and in table 8 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.

In accordance with the approach preferred by the AER in relation to the setting of indicative prices for the transitional year, we have 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[45] for the purpose of setting NUOS charges for the transitional year.

This 'bundled revenue' is shown in table 14. Ausgrid nominates this 'bundled revenue' to be the amount that will be recovered via NUOS charges for the 2014-15 year. The AER will effectively make a decision, either to accept or otherwise amend this nominated amount in its determination for the transitional control period.

Table 14 – Total bundled revenue for NOUS pricing ($ million, nominal)

Breakdown of 'bundled revenue' for 2014-15	
Annual revenue requirement for standard control services (excl. metering)	2,274
Net alternative control services revenue (excluding public lighting)	70[46]
Net emergency recoverable works revenue	1
Total bundled revenue	**2,345**

Numbers may not add due to rounding

3.4 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. Our proposed annual revenue requirement for 2014-15 and the subsequent four years to 2018-19 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:

- Demonstrate how the total 'bundled revenue' for 2014-15 is reasonably likely to minimise variations in network prices between the current regulatory control period: the transitional regulatory control period and the subsequent regulatory control period and between the regulatory years of the subsequent regulatory control period.

  Strictly speaking, this is a criterion in the rules for the AER's approval of Ausgrid's proposed annual revenue requirement for the provision of standard control services. However for practical purposes and because of the AER's preferred approach to the setting of indicative prices for the transitional year, the total 'bundled revenue' for 2014-15 has been used in this demonstration[47].

[41] Excludes debt raising costs
[42] NERA, The payout ratio, June 2013, p. 13.
[43] SFG was engaged by the Energy Networks Association (ENA) of which Ausgrid is a member, to advise on the AER Rate of Return guideline consultation process.
[44] SFG, Updated dividend drop-off estimate of theta, June 2013, p. 31.
[45] Net of revenues expected from separate miscellaneous and monopoly prices and from third party damage recovery
[46] The revenue requirement for ACS (excluding public lighting) is $90m, however only $70m is recovered within NUOS charges

- Provide indicative NUOS prices for the transitional year. These prices reflect the recovery of the total bundled revenue outlined in table 14.
- Outline typical bill impacts for residential and small business customers.

In smoothing the required revenue over the five year period, we need to consider the expected revenue for 2013-14 (last year of the current regulatory period) as well as the energy consumption forecast.

The expected revenue for the last year of the current regulatory period is shown in table 15[48].

Table 15 – Revenue forecast for 2013– 14 ($ million, nominal)

Component	Revenue
DUOS	2,108.6[49]
TUOS	268.4
Total	**2,377.0**

Numbers may not add due to rounding

Table 16 – Change in average distribution charges based on latest energy forecasts (% change, 2013-14)

	FY15	FY16	FY17	FY18	FY19	Total
Weighted average change in distribution charges	-2.13%	-0.40%	-0.07%	-1.43%	-1.22%	-5.15%

The expected revenues include revenues related to metering and ancillary network services. These services will change classification from standard control to alternative control from 1 July 2014.

However, as noted in chapter 2, the AER indicated its preferred approach for the transitional year is to include the revenues associated with these services to be recovered via the DUOS charges. This has been reflected in our total nominated 'bundled revenue' for 2014-15 as shown in table 14. This total 'bundled revenue' has been used in this smoothing process to minimise price variations between years.

However the revenue for the years 2015-16 onwards relates solely to the provision of standard control services. Therefore the drop in revenues from 2014-15 to 2015-16 incorporates the removal of metering and ancillary network services related revenues from standard control service revenues.

When estimating charges for customers we have added back the expected metering service charges that customers will face over the 2014-19 period. Overall we have aimed to minimise the prospect of price shocks between 2013-14 and 2014-15 using the smoothing profile outlined in section 3.1.

As demonstrated in figure 10, we have smoothed revenues such that they do not fluctuate greatly between regulatory years. In addition to this we have aimed to minimise, as far as practically possible, the difference between smoothed and required revenues in 2018-19. This is consistent with clause 6.5.9(b)(1) of the rules[50].

We have also considered the impact of energy consumption trends when developing the smoothing profile outlined in section 3.1. To minimise price variations from the current regulatory period to the transitional year and across the regulatory period we need to take into account changes in energy consumption over the 2014-19 period.

Indicative prices for 2014-15 based on the nominated total 'bundled revenue' for 2014-15 and our latest forecast of energy consumption is outlined in the next section. However, a useful indication of how average prices could move over the regulatory period is demonstrated in table 16.

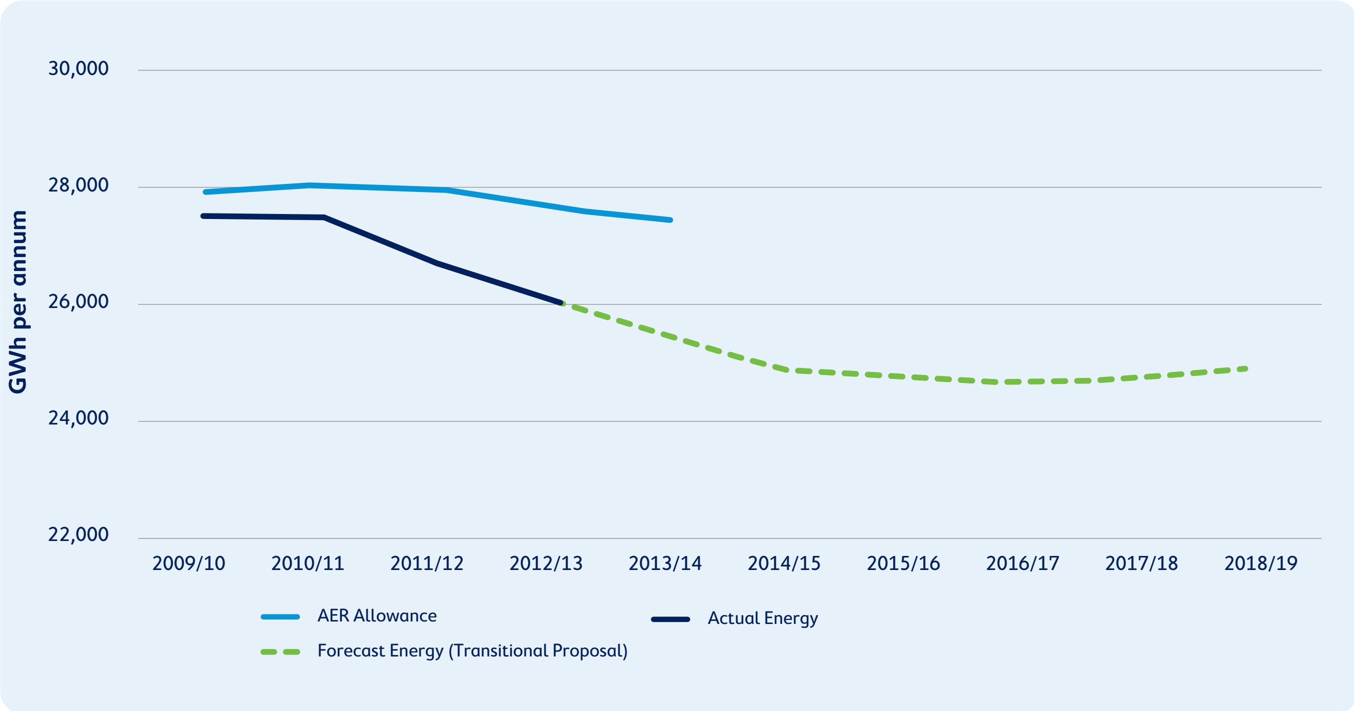
This average change in charges is based on our latest forecast of energy consumption over the 2014-19 period. Energy consumption is difficult to forecast and is likely to change over the regulatory period relative to the forecast:

- If energy consumption falls below our forecast, average charges would need to increase more than indicated in table 16;
- If energy consumption rises above our forecast, average charges would decline below the estimates in table 16.

It should be noted that this forecast does not incorporate 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.

[47] As set out in the AEMC's final rule determination, see AEMC, Final rule determination: Economic regulation of Network Service Providers and Price and Revenue Regulation of Gas Services, November 2012, p. 238.
[48] Clause 11.56.2(b)(8)
[49] Excludes forecast revenues for miscellaneous and monopoly and emergency recoverable works
[50] Despite the fact that this requirement does not apply to the transitional proposal.

Figure 11 – Forecast energy consumption



Consumption

Figure 11 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 transitional regulatory year and each year of the 2015-2019 period. This forecast is based on information available as at the end of November 2013 and has been used to calculate the indicative prices for the transitional year.

The forecast will be updated when calculating the indicative prices required to be included in Ausgrid's regulatory proposal for the subsequent regulatory control period.

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. 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, the NSW Energy Savings Scheme and ongoing energy efficiency improvements. The forecast also includes a growth in customer connections over the period of 92,315 connections.

Indicative prices

Under Clause 11.55.2 (b)(b)(2) we are required to provide indicative prices of direct control services (i.e. standard control services and alternative control services) for the transitional regulatory control period, that is, for 2014-15.

The indicative prices for 2014-15 also include a component required to recover the revenue associated with the provision of alternative control services (other than public lighting) and unclassified services. In effect, the indicative prices shown in this section relate to the nominated total 'bundled revenue' for 2014-15.

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 17 shows the indicative DUOS prices that recover the revenue associated with distribution standard control services, certain alternative control services and unclassified services.

Table 17 – Indicative DUOS prices for published tariffs[48] for 1 July 2014 to 30 June 2015 (c/kWh, nominal)[51]

Tariff classes	FY14	FY15	% Change
Low Voltage	9.92	9.99	0.68%
High Voltage	3.59	3.61	0.67%
Sub-transmission	0.68	0.67	-1.78%
Unmetered	6.73	6.75	0.32%

Table 18 shows indicative prices for Ausgrid's transmission standard control services for 2014-15.

Included in these prices is the recovery of forecast under recovery of TUOS revenue for the 2013-14 year of $19.8 million ($nominal).

Despite the increase in Ausgrid's TUOS tariffs for FY15, we expect a 3.43% real reduction in overall TUOS charges over the 2014-19 period, as shown in table 2.

Table 18 – Indicative charges for Ausgrid's TUOS for 1 July 2014 to 30 June 2015 (c/kWh, nominal)[52]

Tariff classes	FY14	FY15	% Change
Low Voltage	1.12	1.20	7.84%
High Voltage	1.08	1.13	4.46%
Sub-transmission	1.09	1.13	3.99%
Unmetered	0.94	0.98	4.46%
CRNP	0.85	0.92	9.21%

Whilst these prices provide an early indication of our commitment to customers for the next period, they are indicative only at this stage. The actual prices that will be charged to customers for the 2014-15 year are dependent on:

- The AER's distribution determination for Ausgrid for the transitional control period.
- Updated energy consumption forecasts.
- Any changes in the relative portion of revenues recovered from each tariff and tariff component.

We also note that the prices outlined in tables 17 and 18 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.

Total bills

Table 19 illustrates charges for a typical residential customer and a typical small business customer on the inclining block tariff (IBT) structure. This assumes that energy consumption is constant for the customer between 2013-14 and 2014-15.

Table 19 – Typical customer NUOS outcome ($nominal)

Typical annual bill	2013–14	2014–15	% Change
Residential (IBT) customer[53]	813	822	1.12%
Small business (IBT) customer[54]	2,613	2,656	1.67%

[51] These do not include cost reflective network prices which are customer specific tariffs calculated for very large customers.
[52] The increase in indicative TUOS prices in FY15 will not translate to an equivalent increase at the NUOS level because Ausgrid's annual transmission revenue requirement accounts for only around 10% of the total NUOS revenue requirement
[53] Consuming 5 MWH per annum.
[54] Consuming 15 MWH per annum.

4. Forecast network expenditure

Ausgrid's indicative forecast expenditure for standard control services reflects its commitment to be as efficient as possible while maintaining a safe, reliable and sustainable electricity supply.

In the previous sections, we have provided our proposed annual revenue requirement for the transitional regulatory year and indicative prices for standard control services for 2014-15. We also give an indicative range of the likely revenue we will need in the subsequent four years. These revenues are for the recovery of our forecast capital (via the return on capital and regulatory depreciation) and operating expenditure.

In the following sections:

- We provide an overview of the capital and operating expenditure forecasts that we have used in calculating the proposed annual revenue requirement for 2014-15 and the subsequent four years. This information is required under the rules to be included in our transitional proposal.
- Though not formally required for this transitional proposal, we have also outlined the forecast expenditure of the 2014-19 inclusive of expenditure relating to the reclassified alternative control services[55] and unclassified services. This is only for ease of comparison to the previous regulatory period during which certain alternative control services and unclassified services were deemed to be standard control services.

4.1 Expenditure summary

Our indicative estimate of capital expenditure and operating expenditure for standard control services[56] for the five year period from 1 July 2014 to 30 June 2019 is $4,406 million ($2013-14) and $2,797 million ($2013-14) respectively. There is also a debt raising cost of $42 million ($2013-14).

Table 20 shows the annual indicative expenditure in dollar terms as at 30 June 2014 (i.e. $2013-14). Our forecast expenditure profile highlights a reduction in our indicative capital and operating expenditure requirements over the next period, reflecting our commitment to be effective and efficient in our investment and in our operation. Consequentially this concerted effort will greatly assist us in striving to contain average increases in our share of customers' electricity bills at or below CPI.

It must be noted that these expenditure forecasts for the four years from 2015 to 2019 are indicative estimates only at this stage. Greater detail of Ausgrid's proposed expenditure for the period will be contained in our substantive regulatory proposal, due to be lodged with the AER by 31 May 2014.

Table 20 – Indicative expenditure ($ million, 2013-14)

	FY15	FY16	FY17	FY18	FY19	Total
Capital expenditure	1,020	991	853	801	741	4,406
Operating expenditure	571	557	582	547	540	2,797[57]

Numbers may not add due to rounding

4.2 Capital expenditure summary

Ausgrid's indicative estimate of total forecast capex is $4,406 million ($2013-14). This includes $1,020 million for the 2014-15 transitional regulatory control period and $3,386 million for the subsequent four regulatory years. We have used $1,020 million ($2013-14) in calculating the proposed annual revenue requirement of $2,274 million.

Our indicative total capex is approximately 37% lower ($2013-14) than our expected[58] total capex for the 2009-14 period. When compared to the total capex allowed for the 2009-14 period, it is 48% lower ($2013-14)[59].

The lower capex is reflective of the lower demand forecast as well as the initiatives we have implemented to actively reduce the need for capex and contain average increases in our share of customers' electricity bills at or below CPI. We have reduced our volume of works through enhanced risk management requirements for planning and reduced costs through a stronger focus at both design and delivery stages.

The need for network augmentation has lessened significantly due to improvements in the accuracy of our demand forecasts and a lower demand forecast than approved by the AER for the 2009-14 period. It is also lower because we have incorporated an expected reduction in the stringency of our licence conditions in the planning standards used for this review.

[55] Except public lighting.
[56] As they are defined in the AER's stage 1 framework and approach paper.
[57] Excluding debt raising costs
[58] That is, actual capex for the first four years and expected capex for the last year.
[59] This comparison includes the alternative control services (except public lighting) and unclassified services.

The overall investment portfolio has been refined using an investment prioritisation model that produces an assessed risk ranking for all proposed capex projects and programs. This has been used in parallel with our planning processes to produce the final capital works program for the regulatory period based on an acceptable level of risk. Reflecting our commitment to offset labour cost increases through efficiency improvements, a zero real cost escalator has been applied to to internal labour costs.

While we have sought to minimise expenditure, we still need to incur capex to maintain the reliability and safety of the network. The majority of our proposed investment is to replace existing network assets that are reaching the end of life and exhibiting increasing risk of failure. In the last period, we made significant inroads into addressing condition issues. Despite this, the average age of our distribution network has continued to increase, and an ongoing investment program is needed to limit maintenance and breakdown costs and manage safety (including public safety), environmental and other risks.

We are also investing a modest amount to meet pockets of high demand on our network, including augmentations of the network to meet the needs of new customers. While forecast growth in overall system peak demand is lower than in the past, there is significant diversity between local network areas. This means that the majority of our capacity investment is in small areas of growing demand or to meet the needs of new customers. Despite the relatively smaller level of investment in capacity, we have taken full advantage of demand management to defer capex in a prudent manner wherever possible, and included this in our investment plans.

We have forecast our capex requirements for the 2014-19 period based on seven capital plans, similar to those provided for the 2009-14 determination, based on Ausgrid's business as usual processes. In the following sections, we describe the methodology and key focus of investment for each plan.

Table 21 – Forecast gross capex for transitional and subsequent regulatory period ($ million, 2013-14)

	FY15	FY16	FY17	FY18	FY19	Total
Area plans (including system property)	484.3	425.1	266.7	222.5	173.8	1,572.5
Replacement and Duty of Care Plans	314.4	333.3	361.1	365.8	377.9	1,752.5
Distribution capacity plans	113.0	111.3	118.7	126.3	124.5	593.9
Reliability investment plan	5.5	5.5	5.5	5.5	5.6	27.6
Technology Plan	39.4	36.3	36.2	37.1	38.5	187.4
Corporate Property Plan	44.4	66.1	49.0	26.6	2.2	188.4
Fleet and other capex plan	19.3	12.9	15.7	17.4	18.7	84.0
Total Gross capex[60]	1,020.3	990.5	852.9	801.3	741.3	4,406.2
Equity raising costs[61]	-	-	-	-	-	-
Total capex	1,020.3	990.5	852.9	801.3	741.3	4,406.2

Numbers may not add due to rounding

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 $1,572.5 million over the the 2014-19 period. The majority of capex relates to replacement of large assets which is approximately 89% 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 22 – Forecast area plans capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
484.3	425.1	266.7	222.5	173.8	1,572.5

Numbers may not add due to rounding

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.

[60] Gross capex does not reflect property remediation costs or disposals such as sale of corporate property.
[61] Equity raising costs, if any, would be determined using the AER's formula on benchmark costs.

We forecast capex of $1,752.5 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.

Table 23 – Forecast replacement and duty of care capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
314.4	333.3	361.1	365.8	377.9	1,752.5

Numbers may not add due to rounding

Distribution capacity plans

Our distribution capacity plans identify forecast capex for augmentations on the distribution network. We forecast capex of $593.9 million over the 2014-19 period comprising of:

- $207 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.
- $203 million for reinforcement of the 11kV network, and $184 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 modelling 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.

Table 24 – Forecast distribution capacity capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
113.0	111.3	118.7	126.3	124.5	593.9

Numbers may not add due to rounding

Reliability plan

The reliability investment plan includes any additional capex specifically required to meet reliability performance standards in the NSW Design, Reliability and Planning (DRP) licence conditions (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 modelling 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 $27.6 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.

Table 25 – Forecast reliability capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
5.5	5.5	5.5	5.5	5.6	27.6

Numbers may not add due to rounding

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 $187.4 million over the 2014-19 period. The majority of capex is to maintain the currency of our existing IT services.

Table 26 – Forecast technology plan capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
39.4	36.3	36.2	37.1	38.5	187.4

Numbers may not add due to rounding

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 $188.4 million over the 2014-19 period. The majority of capex is to replace and/or upgrade nine ageing depots, which no longer meet modern day compliance standards.

Table 27 – Forecast corporate property plan capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
44.4	66.1	49.0	26.6	2.2	188.4

Numbers may not add due to rounding

Fleet and other capex plan

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. We forecast capex of $84.0 million over the 2014-19 period. The majority of fleet capex is to replace heavy vehicles and plant used to maintain and construct network assets.

Table 28 – Forecast fleet and other capex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
19.3	12.9	15.7	17.4	18.7	84.0

Numbers may not add due to rounding

4.3 Operating expenditure summary

Ausgrid's total forecast opex comprises the following broad groups. These are:

- System maintenance opex.
- Operation and business support opex.
- Other opex.

System maintenance opex - This cost relates to maintenance activities on Ausgrid's network such as inspection, corrective work, breakdown (including nature induced breakdown), engineering support 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. Examples include property management costs, information technology, human resources, finance and senior management.

Other opex - These are operating expenditure relating to non network alternatives (i.e. demand management), self insurance and debt raising costs.

Our indicative estimate of forecast operating expenditure for the transitional year and the subsequent four regulatory years is $2,797.2 million ($2013-14)[62]. This is the indicative estimate of forecast opex we would need to provide standard control services for the transitional year and subsequent four years.

We have used the forecast amount of $570.9 million ($2013-14) in the calculation of our proposed annual revenue requirement for the transitional year of $2,274 million.

The indicative forecast opex for the transitional year and subsequent four years represents the expenditure we consider would be required to achieve the operating expenditure objectives and to deliver standard control services in the forthcoming regulatory control period. 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 unavoidable 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.

The result of this approach is an operating expenditure profile that shows a decline in expenditure (in real dollar terms) over the 2014-19 period- particularly in the last 2 years when the continuing benefits of initiatives to transition the business to a lower cost base are realised. It must be noted that the indicative forecast opex for FY2015 and FY2017 reflects the anticipated impact of the reduced capital program as well as implementation costs of efficiency initiatives. This is shown in table 29.

Table 29 – Indicative forecast opex ($ million, 2013-14)

FY15	FY16	FY17	FY18	FY19	Total
570.9	557.4	581.9	546.8	540.2	2,797.2

Numbers may not add due to rounding

Our performance in the current period

A key challenge of Ausgrid's 2009-14 regulatory proposal was the need to address the legacy of previous regulatory decisions that resulted in chronic under-investment in the network. We needed to make significant investments to reduce safety risks and ensure our system was operating to the standard required under licence conditions. In recognition of this need, an appropriate capital expenditure and operating expenditure program was approved by the AER which consequently translated into higher charges for our customers.

[62] Excluding debt raising costs.

Table 30 – Comparison of opex ($ million, 2013-14)

	FY10	FY11	FY12	FY13	FY14	Total
Actual/expected[63]	598.6	584.5	645.2	520.9	599.4	2,948.6
Allowance	573.1	585.0	597.4	608.4	610.0	2,973.9
Difference	25.5	-0.5	47.8	-87.5	-10.6	-25.3

Numbers may not add due to rounding

The total actual opex for the 2009-14 period is expected to be $2,949 million ($2013-14). This is $25.3 million (or 0.85%) below the efficient level set by the AER.

Table 30 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 network services and emergency recoverable works[64].

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 with the main features of the cost reduction initiatives including:

- A review of work practices to ensure less overtime is needed to perform core network functions.
- Rationalisation and centralisation of finance, human resources, procurement and business services functions.
- Review of our fleet and procurement policies, processes and procedures to ensure value for money, including joint procurement initiatives with Networks NSW.
- Review of our policies and procedures to eliminate any discretionary expenditure; i.e. spending that is not essential to the running of our business.

Our circumstances in the 2014–19 period

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 strive to contain average increases in our share of customers' electricity bills at or below CPI over the forthcoming regulatory period. The actual outturn 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.
- The particular environment of the DNSP and changes to this operating environment since the last determination.
- The current condition of our asset and the inherent relationship between forecast capital and operating expenditure and the consequential impact on opex from future capital investments.
- 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 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 specific factors are:

- Additional cost of inspecting private mains to comply with our legislative and regulatory obligations.
- Leaseback cost of one of our corporate buildings that is forecast to be sold by 30 June 2014. The leaseback is for the period up to 2016-17 and the additional cost will be 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.
- 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).

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 from the cessation of the transitional service agreement (TSA) with EnergyAustralia (formerly TRUenergy).
- The impact of the forecast capex on opex requirements including the impact of a reduced capital program on our cost structures.

Ausgrid intends to implement efficiency initiatives to minimise the costs impact of these factors. The implementation costs of these initiatives have also been taken into account in the forecast opex of

[63] FY14 amount of $599.4 million is the expected opex.
[64] Type 5 & 6 metering services and ancillary network services are classified as alternative control services and emergency recoverable works are not classified, hence are unregulated services from 1 July 2014.

the next period. These factors are explained in the following sections.

Compliance with our obligations

We have reviewed our obligation under the Electricity Supply (Network Safety and Management) Regulation 2008 regarding the inspection of private installations and the extent of that obligation. We are currently developing processes consistent with that obligation which includes a rigorous inspection process. Where a defect is identified, we will provide the inspection results to the owner for rectification. We anticipate that the existing defect notification process will be used to execute this process. Installations with defects that present major risks and that remain unrectified will face disconnection.

Leaseback of head office building

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.

Real cost escalation

The base opex reflects current costs and the current prices of cost inputs. Forecast opex needs to account for changes to 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[65]. These price increases may not necessarily be at the same rate as the CPI. They may be higher or lower than CPI due to a number of factors[66]. Ausgrid has applied the following changes in costs to the adjusted base year opex to derive a forecast opex that reasonably reflects the realistic expectation of cost inputs required to achieve the opex objectives:

- Wage increases contained in Ausgrid's enterprise agreement (Ausgrid Agreement 2012) for the duration of its term which ends in December 2014. The agreement allow for an annual wage increase of 2.7% (nominal) offset by savings in other labour costs to achieve an outcome aligned to CPI of 2.5%. This is consistent with the NSW Government Wage Policy and is a good outcome for Ausgrid and for customers, particularly given that the new agreement now enables improved flexibility to outsource some work where this is the most cost effective option, when judged against safety, quality and cost criteria.
- Forecast real cost escalation for external labour derived by Independent Economics - an external consultant engaged by Ausgrid.

Any increases in excess of CPI will however be offset by management initiatives to improve the productivity of Ausgrid's workforce such that we can strive to contain average increases in our share of customers' electricity bills at or below CPI.

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 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's brand, EnergyAustralia's retail customers and wholesale contracts to TRUenergy (now EnergyAustralia). Under the terms of the sale, a Transitional Service Agreements (TSA) was agreed between Ausgrid and TRUenergy.

The TSA stipulates the provision of retail related services 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 on 27 November 2014[67].

Upon termination of the TSA, Ausgrid's cost of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. 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[68].

Mindful of the impact of these increases on our customers, Ausgrid intends to implement strategies to eliminate 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.

[65] This is one of the opex criteria and a basis on which the AER may or may not accept the forecast opex.
[66] For example labour supply and demand imbalances.
[67] This is a key assumption underpinning our forecast opex.
[68] AER, EnergyAustralia, draft distribution determination, 2009-10 to 2013-14, 21 November 2008, p280.

Impact of forecast capex

Our forecast opex also accounts for the consequential impact from efficient and prudent capital investment over the 2014- 19 period, as well as the impact of a lower capital expenditure requirement on support costs and maintenance costs.

For the 2009-14 period the AER approved a significant capital investment program, amongst other things, to comply with licence conditions mandated by the NSW Government. These licence conditions were needed to address the potential adverse issues arising from under investment in the past with respect to security and reliability of supply. Our capex program was also aimed at replacing the aged and deteriorated assets on our network which, if not addressed, could have resulted in large scale reliability and safety incidents.

The approved capex program for the current period was Ausgrid's biggest ever investment. It equalled a doubling of Ausgrid's previous works program and was required to be delivered in addition to our regular maintenance and other works programs.

The delivery of this much needed investment in a short span of time was beyond Ausgrid's internal capacity to deliver. For this reason, we outsourced part of the work and entered into alliance contracts with three partners, Transmission Cable Alliance, Energised Alliance and Energy2U Alliance. These alliance partnerships were a prudent course of action that allowed Ausgrid to deliver the capital investment needed to keep the network safe and reliable whilst not committing to an unsustainable level of long-term resources.

Looking forward to the next five years, we still have a need to invest to maintain the safety and reliability of our network, but the need for capacity capex has subsided. Furthermore, recognising the pricing pressures customers are facing and the reduced forecast demand, we have actively reviewed our strategies, policies and planning processes to find efficiencies in our capital works program. As a result, our forecast capex is about 37% ($2013-14) lower than that required for the current period.

The lower forecast capex program will not require as many resources as were needed to deliver the approved capex program of the current period. These resources were previously tasked with the delivery of the capital program and therefore their costs were fully funded by the capex allowed by the AER for the current period. These stranded costs are a legitimate cost to be recovered as part of Ausgrid's operating costs. However, as noted in the following sections, we have initiatives in place to deal with these stranded costs over the 2014-19 period.

Table 31 – Impact of efficiency drive ($ million, 2013-14)

2014–19 indicative forecast opex	FY15	FY16	FY17	FY18	FY19	Total
Maintenance	243.2	250.2	255.6	259.1	264.5	1,272.6
Operations & Support	300.9	295.9	302.4	296.9	300.9	1,497.0
Other Opex	10.9	15.2	14.0	15.4	16.7	72.2
Total business as usual opex	**555.0**	**561.3**	**572.0**	**571.4**	**582.1**	**2841.9**
TSA loss of synergy costs	13.4	23.0	23.0	23.0	23.0	105.5
Change in operating environment	13.2	10.1	38.9	24.6	24.2	111.1
Total costs without efficiency measures	**581.6**	**594.4**	**633.9**	**619.0**	**629.3**	**3058.5**
Efficiency initiatives implementation costs	31.4	20.8	23.4	18.7	7.1	101.3
Efficiency / productivity savings	-42.0	-57.8	-75.5	-91.0	-96.3	-362.6
TOTAL FORECAST OPEX	**570.9**	**557.4**	**581.9**	**546.8**	**540.2**	**2,797.2**

Numbers may not add due to rounding

Our plans to be cost efficient

Table 31 shows a declining opex profile in real dollar terms over the next regulatory period. This is the result of the strategies and initiatives that aim to:

- Fully 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 cost impact of excess resources from a reduced capital investment over the 2014-19 period.
- Absorb the increases in cost inputs (e.g. employee wages, contracted services, labour hire etc) that are above CPI (estimated to be 2.5%).

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

- Management saving initiatives.
- Network reform project initiatives.

These initiatives will require initial implementation expenditure of $101.3 million ($, 2013-14) but will result in a total saving benefit of $362.6 million ($2013-14) in the forthcoming period.

The $101.3 million comprises of implementation costs of:

- Transitioning to an efficient cost base ($51.6 million, $2013-14).
- Achieving efficiency through industry reform ($49.8 million, $2013-14).

Move to 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. While this prudent action has minimised the cost impacts of a reduced capital program on the 2014-19 forecast opex, the impact is still putting upward pressure on the cost base.

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. 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 customers through charges higher than otherwise should be.

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 businesses and to restructure our organisation so that an efficient and sustainable level of resource is achieved. Cost restructuring is a legitimate option and a well accepted practice by business 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 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 $11.8 million ($2013-14) for the transitional year and $39.8 million ($2013-14) for the subsequent four years. These costs cover our policy obligations.

These implementation costs are legitimate 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 significant lower labour cost profile as well as reduced support costs such as information technology, property, finance and human resources etc.

These strategies will eliminate the cost impact of anticipated change in our operating environment by 2018-19. By then, we expect the TSA loss of synergy costs and labour costs associated with surplus resources from a reduced capital program will be fully eliminated; meaning that our customers will enjoy a permanent step down in costs from 2019-2020 onwards.

Efficiency drive

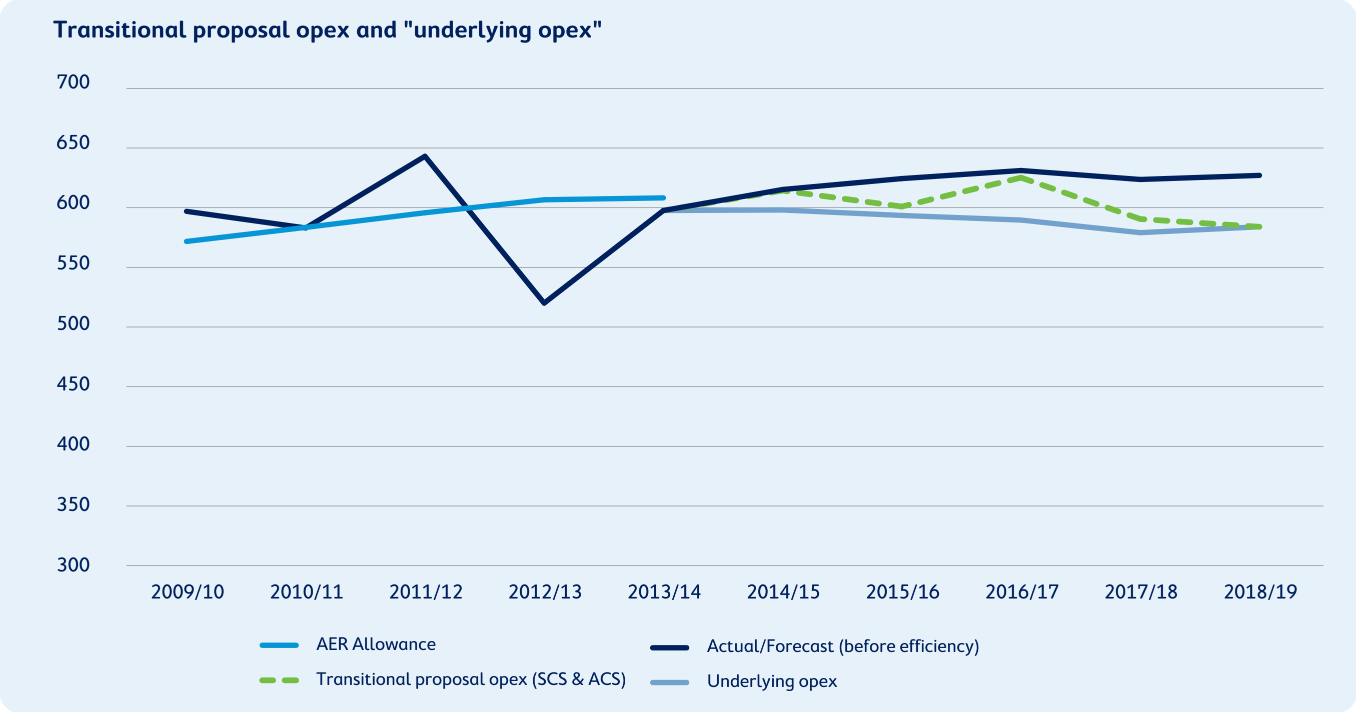
As outlined in Chapter 1, the NSW government instituted network industry reform to drive efficiency across the three NSW DNSPs in a number of key areas. This efficiency drive is achieved by removing functional duplication, streamlining corporate and support services and creating better and faster procurement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

These initiatives will incur one-off implementation costs of $17.5 million ($2013-14) over the 2014-19 period, outsourced and technology investment costs (e.g. licence fees for IT system) of $32.3 million ($2013-14). The strategies will reap a forecast benefit of $140.2 million ($2013-14), leaving customers with a net benefit of $90.4 million ($2013-14) over the 2014-19 period.

Result of our plans to be efficient

Figure 12 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.

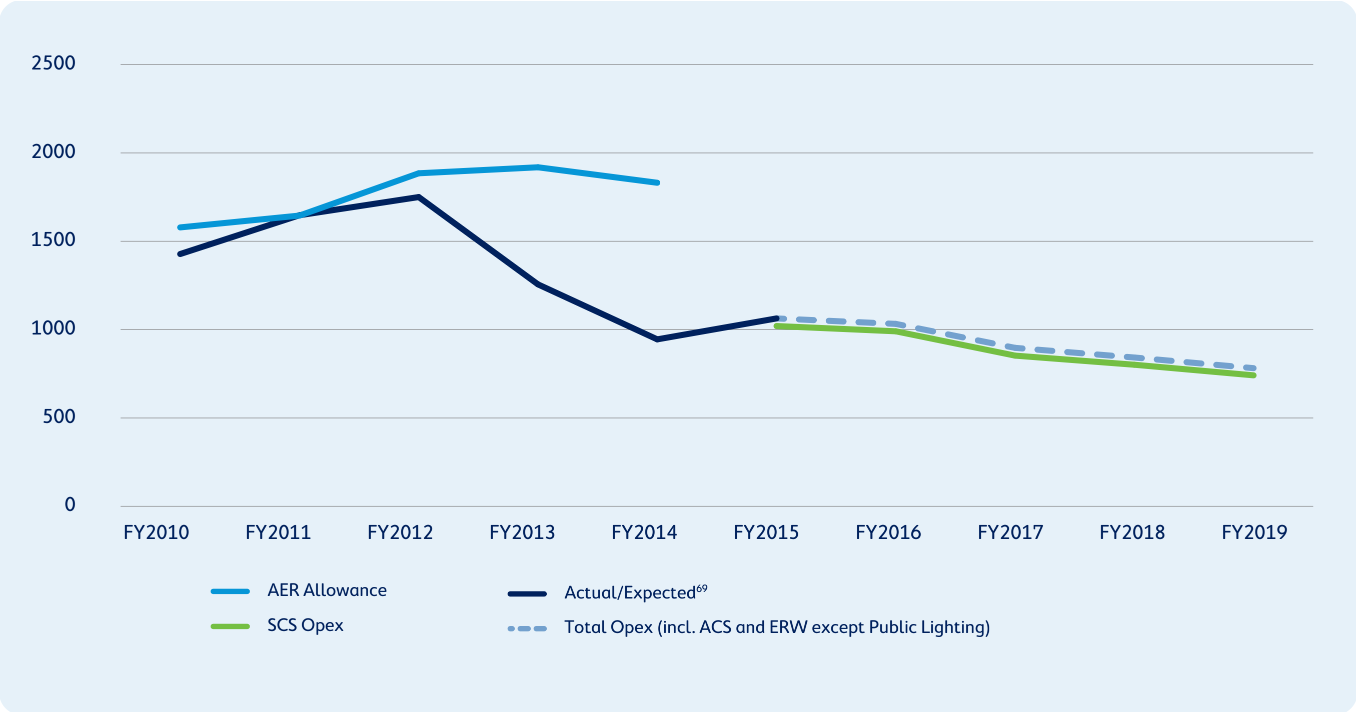
Figure 12 - Underlying and proposed forecast opex ($ million, 2013-14)



4.4 Expenditure comparison

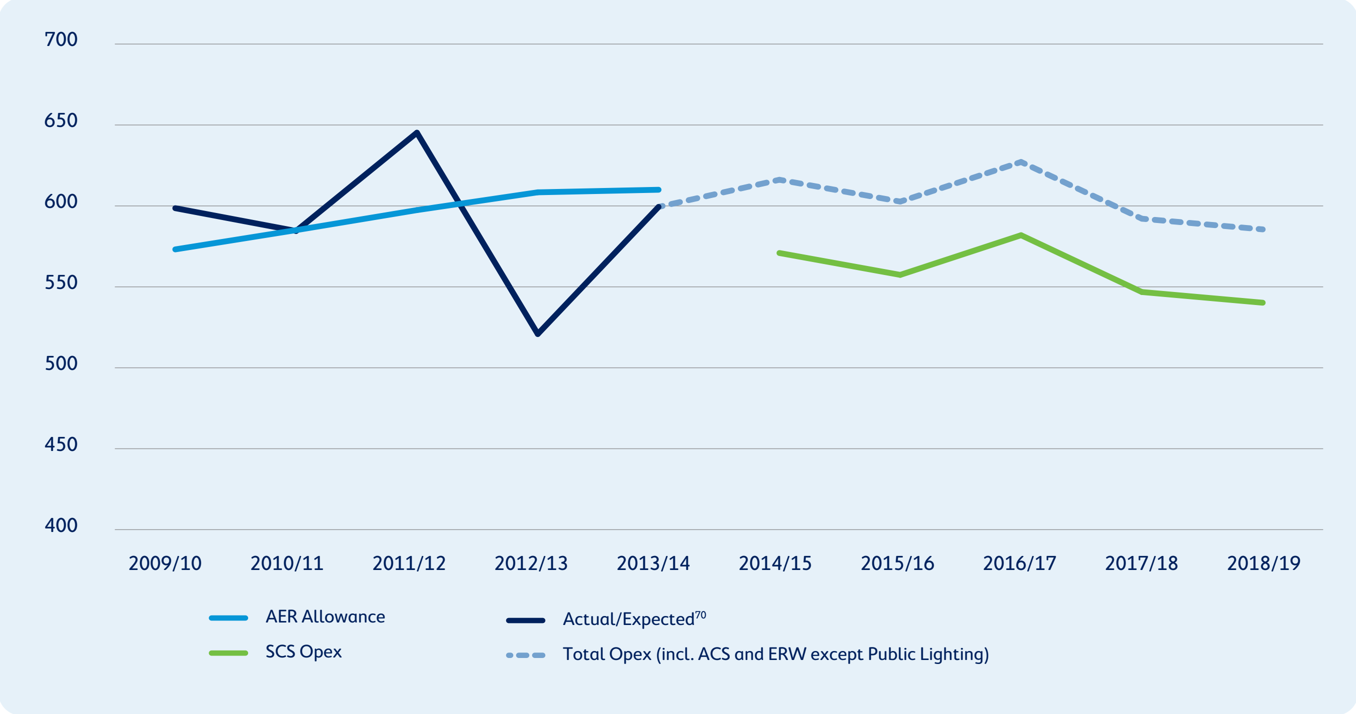
In the 2009-14 period, the reclassified alternative control services (i.e. Type 5 and 6 metering services and ancillary network services) and unclassified services were deemed to be standard control services. Whilst not a formal requirement for this transitional proposal, Ausgrid has provided a comparison of the expenditure profile over the ten years period from 2009-10 to 2018-19 which may be of interest to stakeholders. The capital and operating expenditure profiles are shown in figures 13 and 14.

Figure 13 – Comparative capex profile ($ million, 2013-14)



[69] The actual/expected numbers include fair value adjustments on employee provisions.

Figure 14 – Comparative opex profile ($million, 2013-14)



[70] The actual/expected numbers include fair value adjustments on employee provisions.

5. Alternative control services

As required by the rules, the prices for public lighting services and some ancillary network services increase by CPI only.

In the previous chapters, Ausgrid outlined the information relevant to standard control services. In this chapter we set out some relevant information for the services classified as alternative control services from 1 July 2014. These services are:

1. Type 5 and 6 metering services.
2. Public lighting services.
3. Ancillary network services.

Whilst these services have changed classification from 1 July 2014, the revenues needed to recover the costs of providing some of these services in the transitional year are aggregated with the revenue for standard control services. This is in accordance with the AER's preferred approach which is outlined in chapter 2 and appendix 1. It must be noted that this aggregation does not include the revenue relating to public lighting services.

5.1 Type 5 and 6 metering services

Metering services is one of the terms developed by the AER to group classes of services provided by NSW distribution businesses. 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[71]. 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*[72] installation. A Type 6 metering installation is defined as a 'general purpose' meter that records *accumulated energy data only*[73]. The term 'BASIC meter', accumulation meter and Type 6 meter can be used interchangeably.

Customers currently pay for their metering service in the bundled charges they pay for standard control services. The AER has reclassified metering services associated with Type 5 and 6 metering installations provided by NSW distribution businesses from 1 July 2014, with the intention of establishing separate prices for these services.

However, the AER's preferred approach for the transitional year is to maintain existing cost allocations; that is, to continue to recover the costs of providing these services through the bundled charges they currently pay. As a result, we have delayed proposing separate prices to apply from 1 July 2015 until our substantive proposal.

The revenue amount for Type 5 and 6 metering services for the transitional year that we have nominated to be recovered through the bundled revenue is $72 million (nominal). This revenue is to recover the following costs needed to provide Type 5 and 6 metering services:

- The value of the Type 5 and 6 metering regulatory asset base (metering RAB).
- Forecasting opex.
- Forecasting capex.

We provide a summary of these inputs in the following sections.

Activities undertaken to deliver metering services

In the AER's stage 1 F&A paper published in March 2013, 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)[74] Standing Data in accordance with the rules.

Establishing a separate metering RAB.

Currently, all metering assets form part of Ausgrid's total RAB for standard control services. The standard control services RAB represents the 'regulatory' value of all the assets purchased and installed by Ausgrid to provide network-related services to customers[75]. We have identified an opening RAB value metering assets (as of 1 July 2014 for Type 5 & 6) of approximately $256.15 million as shown in table 32.

[71] The time between meter reads is normally a function of the network tariff applicable to a customer's premises.
[72] 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.
[73] Processes used to convert the accumulated metering data into trading interval metering data for settlements purposes are included in the metrology procedure.
[74] A national meter identifier is assigned to every connection point.
[75] The RAB value is not necessarily the same as the 'accounting' value

Table 32 – Indicative Opening Value of Metering Services RAB at 1 July 2014 ($ million, nominal)

Asset class name	Opening asset value	Remaining life (years)	Asset life (years)
Type 5-6 customer metering	127.59	14.45	25
Type 5-6 customer metering (digital)	87.29	12.62	15
Type 5-6 furniture, fittings, plant and equipment	0.97	12.36	17.44
Type 5-6 land (non-system)	1.45	n/a	n/a
Type 5-6 other non system assets	1.56	7.47	29.44
Type 5-6 IT systems	28.13	3.19	5
Type 5-6 motor vehicles	2.60	6.42	10.24
Type 5-6 buildings	5.99	15	15
Type 5-6 equity raising costs	0.56	15	15
Total metering services RAB value	**256.15**	**-**	**-**

Indicative forecast opex

The AER has identified three components of metering services opex:

- *Meter maintenance* – covers works to inspect, test, maintain, repair meters.
- *Meter reading* – refers to quarterly or other regular reading of a meter.
- *Meter data services* – the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the rules.

In addition to these operating cost components, there are also IT costs associated with providing meter services and an allocation of shared operating expenditure (related to general information technology, furniture, plant, other and non-system assets). Table 33 details the indicative forecast operating costs required to provide Type 5 and 6 metering services. It must be noted that the forecast operating costs are indicative only and will be finalised in our substantive proposal.

Table 33 – Indicative operating costs for 2014-19 for Type 5 and Type 6 metering services ($ million, 2013-14)

AER service category	FY15	FY16	FY17	FY18	FY19	Total
Meter maintenance	7.50	7.50	7.50	7.50	7.50	37.50
Meter reading	7.90	7.90	7.90	7.90	7.90	39.50
Meter data services	5.09	5.09	5.09	5.09	5.09	25.45
IT opex[76]	4.57	4.57	4.57	4.57	4.57	22.85
Corporate overheads	2.64	2.64	2.64	2.64	2.64	13.2
TOTAL[77]	**27.70**	**27.70**	**27.70**	**27.70**	**27.70**	**138.5**

Indicative forecast capex

Metering capex can be grouped into two categories: a) expenditure for assets wholly attributable to the provision of Type 5 and 6 metering services and b) expenditure for assets which are partially attributable to Type 5 and 6 metering services such as furniture, IT, and fleet etc. For the next five years, we forecast a total capex of $136.93 million for Type 5-6 Metering. The annual forecast capex is shown in table 34.

[76] Allocated of IT operating costs between Type 5 and Type 6 is based on the unit cost ratio of meter maintenance, meter reading and meter data processing (70/30%).

[77] Our indicative metering opex for the 2014-19 period has been held constant at the FY2014 level. Cost reflective opex will be forecast for our substantive proposal.

Table 34 – Indicative forecast capex for 2014 – 2019 for Type 5 and 6 metering services ($ million, 2013-14).

Metering services	FY15	FY16	FY17	FY18	FY19	Total
Type 5-6 Metering capex	23.08	23.08	23.08	23.08	23.08	115.39
Type 5-6 Metering IT systems	3.75	2.36	4.42	1.83	1.71	14.07
Furniture, plant, fleet, other, Shared IT	1.63	1.88	1.67	1.31	0.97	7.47
Total indicative forecast capex	**28.46**	**27.32**	**29.17**	**26.22**	**25.76**	**136.93**

Forecast volumes

The rules require us to provide an indicative estimate of demand (including customer numbers, energy demand and maximum demand) for Type 5 and 6 metering services. The two factors that provides the best indicative estimate of demand for metering services is the number of existing connections, and the number of new connections that occur during the period, rather than demand. This is because the forecast number of connections provides the indication of revenue that will be recovered from providing Type 5 and 6 metering services. Table 35 provides Ausgrid's existing Type 5 and 6 metering population and table 36 includes forecast new connections for 2014-19.

It should be noted that modified connections (table 37), reactive meter replacements (table 38), and proactive meter replacements (table 39) are relevant as they affect forecast capital expenditure, however they do not impact on total number of connections.

Table 35 – Ausgrid's Type 5 and 6 metering population for 2013-14

Ausgrid's Type 5 and 6 metering population	Type 5	Type 6	Total
Ausgrid NMIs (i.e. connection points)	455,000	1,165,000	1,620,000
Ausgrid meters	625,000	1,775,000	2,400,000

Table 36 – New connection numbers for 2014 – 2019

	Type 5/6 new CT connected customers	Type 5/6 new direct connected customers	Type 5 new NET solar installations	Total
NMIs	4,310	92,315	30,000	126,625

Table 37 – Modified connection numbers for 2014 – 2019

	Type 5/6 upgrade direct connected customers	Type 6 SBS gross to net solar installations	Total
NMIs	99,400	50,000	149,400

Table 38 – Reactive meter replacement numbers for 2014 – 2019

Reactive replacement	FY15	FY16	FY17	FY18	FY19
Faulty MRIM[78] meters	11,156	11,156	11,156	11,156	11,156
Faulty BASIC[79] meters	3,860	3,860	3,860	3,860	3,860

[78] i.e. type 5 meters
[79] i.e. type 6 meters.

Table 39 – Proactive meter replacement numbers for 2014 – 2019

Proactive Replacement	FY15	FY16	FY17	FY18	FY19	Total
NMI's targeted for replacement with BASIC meters	39,911	39,911	39,911	39,911	39,911	199,557

5.2 Public lighting services

Public lighting services encompass the provision, construction and maintenance of public lighting and emerging public lighting technology[79]. Ausgrid provides public lighting services to over 100 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 four (4) main components of a lamp, a luminaire, a support structure, and a connection to the low voltage electricity network. Each component is treated individually from a charging perspective and each attracts a capital charge and a maintenance charge. Generally customers pay both charges, however some customers choose to purchase public lighting assets outright and only pay Ausgrid to perform 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.

Public lighting prices for transitional year

There are four categories of public lighting charges:

- Fixed capital charge for assets installed prior to 2009.
- 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.

Attachment G and confidential attachment H contain the indicative maintenance and/or capital prices for the transitional year. Ausgrid has sought to have suppressed from publication attachment H on the ground of confidentiality. We have completed a confidentiality template in relation to this information as requested by the AER's Confidentiality Guidelines.

In accordance with the requirements of the rules, we have applied a CPI of 2.5%[80] to each published capital and maintenance public lighting price using the following formula:

$$Price_{FY15} = Price_{FY14}(1+CPI)$$

Attention needs to be paid to the application of the rules to the residual charge. The residual charge is not published per year and is calculated based on depreciated asset value of the specific assets being replaced. This depreciated value changes as the asset get older. Ausgrid proposes the formula to calculate the residual values should remain unchanged for the transitional period as it already incorporates a CPI adjustment. The formula[81] is:

$$Residual\ value = AD.RL.N.CPI_{t-1}^{actual}(1 + \Delta CPI^{forecast})$$

Where

AD	is the annual depreciation in 2008-09
RL	is the remaining life of the asset
N	is the number of assets
t	is the year the residual value is calculated
CPI_{t-1}^{actual}	is the cumulative CPI index
$\Delta CPI^{forecast}$	is the annual % change

Carry over issues from 2009–14 period

The rules require public lighting prices for 2014-15 to be set by increasing the 2013-14 prices by CPI only. There could be however an issue with a strict application of clause 11.56.3 (j) of the rules. This is because there was an error in the allowed public lighting revenue requirement for 2009-10 and it was corrected by increasing the pre 2009 capital charges for the remaining years of the 2009-14 period. This means that the public lighting prices for 2013-14 contains a one-off $6 million adjustment to account for this error. See figure 15 for a representation of this issue.

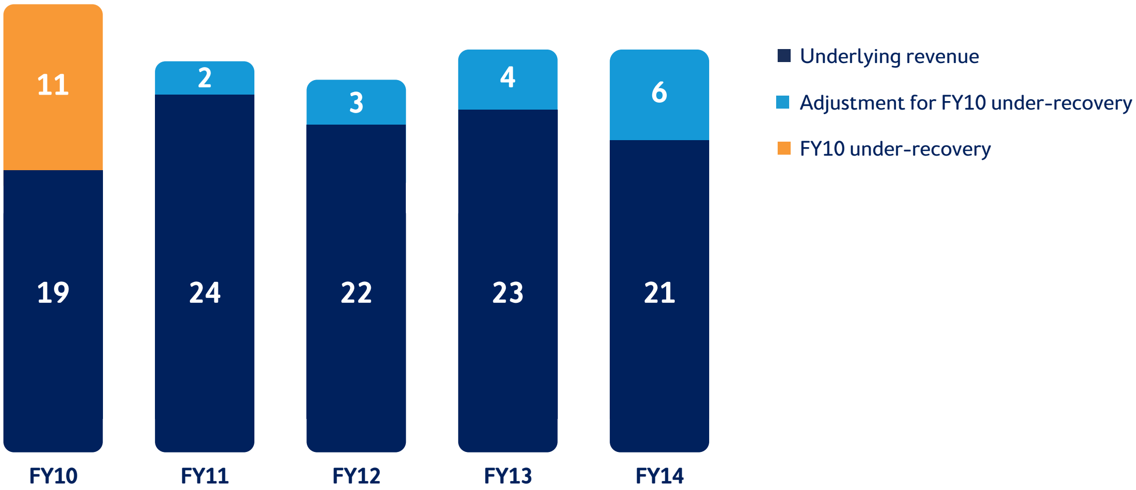
A strict application of clause 11.56.3(j) of the rules without excluding this one off adjustment would carry it forward. To avoid this unintended effect, Ausgrid proposes that the pre 2009 asset charges for 14-19 be based on the underlying revenue requirement in 2013-14. That is, remove the correction amount in 2013-14 and then escalate the charges by CPI to derive 2014-15 public lighting prices.

[80] 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.

[81] Ausgrid has used a CPI of 2.5% as a placeholder. This is to be updated when the data is available to calculate the actual CPI in accordance with chapter 10 of the Rules.

[82] This formula can be found in "Final decision EnergyAustralia distribution determination 2009–10 to 2013–14 Alternative control (public lighting) services", pg 48, AER, 13 April 2010.

Figure 15 – Under-recovery and smoothed allowance in the 09-14 period ($ million, nominal)[82]



Forecast volumes

We are required by the rules[83] to provide an indicative estimate of demand for public lighting services. The variable that provides the best indicative estimate of demand for public lighting services is the number of connections rather than energy demand, number of customers or maximum demand. This is because the number of connections rather than the number of customers provides an indication of public lighting revenue. Similarly, revenue is not determined by an application of the price cap to demand as revenue is not directly based on the flow of electricity through the connection. We have therefore provided an indicative estimate of the number of connections for the transitional year and the subsequent four years in table 40.

Table 40 - Number of public lighting connections

FY15	FY16	FY17	FY18	FY19
248,456	249,698	250,947	252,202	253,463

5.3 Ancillary network services

The list of non-routine services that the AER has categorized as Ancillary Network Services are comprised of the following:

- Non-routine services provided by Ausgrid for which there is currently an applicable regulated price (called miscellaneous and monopoly price) [84].
- Non-routine services currently provided by Ausgrid for which there is currently no applicable price[85].
- New non-routine services that have recently commenced for which there is no applicable price[86].

The AER's preferred approach for setting the indicative prices for the transitional year is to:

- Adjust the 2013-14 miscellaneous and monopoly fees by CPI.
- Only set new cost-reflective prices for the recently commenced services.
- Retain existing cost allocations, that is, the total cost of providing existing ancillary network services less the amount forecast to be recovered through miscellaneous and monopoly fees, is recovered through DUOS charges.

This approach is applied for the transitional year only with a minor modification in relation to new services as outlined in the next section. From 1 July 2015 separate prices for all ancillary network services will be set to recover the efficient costs of providing the service from the customer using that service.

Method used to establish prices

i. Existing miscellaneous and monopoly fees

In accordance with AER's preferred approach and clause 11.56.3(j) of the rules, we have applied a CPI of 2.5%[87] to each existing fee as at 2013-14 using the following formula:

$$Price_{FY15} = Price_{FY14}(1{+}CPI)$$

The resulting 2013–15 prices for miscellaneous services are shown in attachment I, table 1. The resulting 2014–15 prices for monopoly services are shown in attachment I, table 2 and table 2 notes.

ii. Prices for services that have recently commenced

With the commencement of the new National Energy Customer Framework in NSW on 1 July 2013, NSW distribution businesses are required to modify the services they provide in relation to processing connection applications and making a corresponding connection offer to our customers. These are not entirely new services however there are elements of the services that have changed and will result in additional costs for NSW distribution businesses. In the interests of reducing complexity in the transitional year and to enable better engagement with affected stakeholders prior to the commencement of the new charges, we are deferring proposing cost reflective prices for these services until the substantive proposal.

Forecast volumes

We are required by the rules[88] to provide an indicative estimate of demand (including customer numbers, energy demand and maximum demand) for ancillary network services. The variable that provides the best indicative estimate of demand for ancillary network services is the number of services that are forecast to be provided. This is because the forecast number of services provides an indication of revenue recovered from providing ancillary network services. Similarly, the revenue is not determined by an application of the price cap to demand as revenue has no correlation to demand but instead is determined by the number of services requested by customers (or their agent). The forecast volumes for these services in 2014-15 is based on volumes of services charged in 2012-13 and this is shown in attachment I, table 4.

[83] Clause 11.56.2(b)(7).
[84] For example, meter test
[85] For example, disconnection of vacant premises
[86] For example, services relating to the National Energy Customer Framework
[87] Ausgrid has used a CPI of 2.5% as a placeholder. This is to be updated when the data is available to calculate the actual CPI in accordance with chapter 10 of the rules.
[88] Clause 11.56.2(b)(7).

6. Other compliance matters

Ausgrid's transitional proposal puts forward our views on various compliance matters to assist the AER in making a determination.

In this chapter, we submit our proposed connection policy and proposed pricing for transmission standard control services. We also put forward our views on:

- Reporting on recovery of designated pricing proposal charges.
- Reporting on jurisdictional schemes amounts.
- Demonstration of compliance with the control mechanisms for standard control services.

Details of these matters can be found in attachments L.

6.1 Proposed Connection Policy

We are required to include a proposed connection policy in the transitional proposal. Our proposed connection policy that is to apply from 1 July 2014 is provided at attachment J.

Customer connections in NSW operate under a contestability framework governed by the provisions in the Electricity Supply Act 1995. Under this framework , connection services are supplied in a contestable market and are not regulated monopoly services. Consequently, customers pay an accredited service provider of their choice to undertake the connection service rather than paying a capital contribution to the DNSP. In other states connection services are still regulated and provided by the local DNSP. Because these services are contestable in NSW, capital contributions payable by a customer are not covered by our proposed Connection Policy.

The AER Connection Charge Guideline does not explicitly anticipate how it applies to services offered under the NSW contestability framework. In some areas, this makes unambiguous interpretation in a contestable environment difficult, for example in relation to prepayment of Design Information fees. Ausgrid would welcome further engagement to clarify these requirements should the AER have any concerns about the proposed Connection Policy.

6.2 Pricing methodology for transmission standard control services

Section 2.2 outlines the outcomes of the AER's F&A stage 1 and its relevance for Ausgrid's transitional proposal. The AER decided to apply Part J of chapter 6A of the rules to the services provided by Ausgrid's dual function assets. Rule 11.56.3(a)(12) requires that this methodology be the same as that approved by the AER for the 2009-14 regulatory control period. Consequently, we have submitted the transmission pricing methodology approved by the AER for that period. This methodology is provided at attachment K, which includes a confidential appendix B. Ausgrid has sought to have suppressed from publication this appendix B on the grounds of confidentiality. We have completed a confidential template in relation to this information as required by the AER's confidential Guidelines.

6.3 Reporting on recovery of Designated Pricing Proposal charges

Designated Pricing Proposal Charges include the transmission related charges payable to TransGrid, avoided TUOS charges payable to certain generators as well as inter distributor payments. The rules require the AER to specify the manner in which Ausgrid is to report to the AER on its recovery of designated pricing proposal charges. In attachment L, we set out the details of this requirement and our proposal for the AER's consideration.

6.4 Reporting on jurisdictional scheme amounts (Climate Change Fund)

Jurisdictional schemes amounts are amounts which DNSPs are required to pay under jurisdictional requirements which have been recognised by the rules or the AER as amounts which may be recovered under the rules as part of the DNSP's pricing proposal. There are currently two jurisdictional schemes relevant to the NSW DNSPs which are recognised by the rules. The first is the NSW Solar Bonus Scheme, the second is the NSW Climate Change Fund, each of which are recognised under Rule 6.18.7A(e)(2) and (3) respectively. The rules require the AER to specify the manner in which Ausgrid is to report to the AER on its recovery of jurisdictional schemes amounts. In attachment L, we set out the details of this requirement and our proposal for the AER's consideration.

6.5 Demonstration of compliance with control mechanism for standard control services

Clause 11.56.3(5) requires the AER to specify the same control mechanism for standard control services as those which were decided for the 2009-14 period except to the extent to which the framework and approach paper in respect of the subsequent period provides otherwise in accordance with clause 11.56.3(h)(2).

In its F&A stage 1 paper, the AER decided to apply the revenue cap form of control to standard control services[86] and also set out its proposed approach to the formulae that give effect to the control mechanisms for standard control services[87].

In attachment L, Ausgrid set out our proposed approach to demonstrating compliance with the control mechanism for distribution standard control services. This attachment also provides the AER with:

- Our consideration of how the over/under recovery of revenue should be calculated for the transitional year.
- An understanding of some of the key outstanding issues in relation to the control mechanism.

[89] AER's framework and approach paper, stage 1, March 2013, p43.
[90] AER's framework and approach paper, stage 1, March 2013, p56

Appendix 1 - Clarification of AER's approach

Constraints imposed by the transitional rules

Ausgrid's transitional regulatory proposal must comply with the requirements of the transitional rules[88]. Two provisions of these rules however constrained Ausgrid in giving full effect to the AER's classification of services applicable from 1 July 2014. The relevant provisions are:

- For the purpose of the application of clause 6.15.2(7) of the transitional chapter 6, the transitional regulatory control period must be treated as if it were the last regulatory year of the current regulatory control period, and not as a separate regulatory control period[89].
- Clause 6.15.2(7) states that costs which have been allocated to a particular service cannot be reallocated to another service during the course of a regulatory control period.

The combined effect of the above clauses mean that the way costs are allocated in the current 2009-14 period must be maintained for the transitional year. In other words, costs cannot be reallocated between standard control services and newly classified alternative control services in the transitional year. Complying with the above requirements of the rules however means that full effect cannot be given to the AER's classification of services for the transitional year.

AER's preferred approach

Ausgrid, through Networks NSW, have had discussions with the AER on the approach to fulfilling the rules requirements for the transitional proposal, particularly the provision of indicative prices. On 11 December 2013, the AER wrote to Networks NSW outlining their view of a preferred approach to setting indicative prices for the transitional year[90]. The AER's letter stated that:

This letter sets out the views of the AER staff on this topic (i.e. how alternative control services prices should be set for the transitional regulatory year). These views have not been endorsed by the AER and are provided by staff to assist you in formulating your views. (However) our preferred approach.... seeks to comply with the rules and minimise significant changes that would impact on customers in the transitional year. In practical terms it makes sense for as few changes as possible to be made in the transitional year. This is because there will be limited or no opportunity to consult with the stakeholders on any potential changes[91].

We understand the approach preferred by the AER's staff is:

- Public lighting services: prices for the transitional year are the 2013-14 prices escalated by CPI as at the end of the current regulatory period. This is to comply with clause 11.56.3(j) of the rules. Ausgrid's transitional proposal was already being prepared on this basis as the rules are clear for these services which are currently classified as alternative control during the current regulatory control period.
- Metering Type 5 and 6: the AER considers that new prices should not be established for the transitional year as the transitional rules prevent the re-allocation of costs from standard control service to alternative control service for the transitional year. Instead we understand that the AER prefers to leave the costs of providing Type 5 and 6 metering services within the standard control services cost pool and these costs are to be recouped through prices for standard control services (i.e. DUOS prices). This approach is the same as how metering Type 5 and 6 metering services costs are being recovered in the current period (because they are classified as standard control services for the current period).
- For those ancillary network services currently being provided and have existing prices, the AER prefers to apply CPI to these prices, as required by clause 11.56.3(j) of the rules.
- For those ancillary network services currently being provided but there are no existing prices and the costs are currently captured as part of the standard control service cost pool (because these services are classified as standard control services for the current period), the AER prefers to leave the costs of providing these services in the standard control services cost and recovered through DUOS prices for the transitional year.
- For new ancillary network services (i.e. those not being provided for the current period) new cost reflective prices should be established.

Ausgrid's consideration

We agree with the AER that the transitional rules are complex and contain an anomaly that renders the preparation of the transitional proposal more complicated than initially envisaged. In the interest of minimising changes in the transitional year, Ausgrid has adopted the substance of the AER's approach. Of significance, we note the AER's view that its preferred approach complies with the rules and on this basis we consider that Ausgrid's compliance with the rules will not be jeopardised in implementing the substance of the approach preferred by the AER.

However to avoid any unintended consequences of this approach and to provide clarity for the regulatory proposals of the subsequent regulatory period (and the AER's determination thereof) Ausgrid considers the following clarification must be made to the scope of this approach. These clarifications are necessary because the AER's approach effectively seeks to maintain the status quo despite the reclassification of some services from 1 July 2014. The clarifications needed are:

a) The AER's classification of services applicable from 1 July 2014 (as per the F&A stage 1) remains applicable.

b) Ausgrid will propose an amount to be the annual revenue requirement for standard control services for the transitional year (as required by 6.8.2 and amended by 11.55.2(b)). The AER will make a constituent decision on this amount as required under 11.56.1(b) and in accordance with 11.56.3(b) to (f).

[91] Clause 11.56.2(a) of the rules.
[92] Clause 11.56.3(i)
[93] Letter from the General Manager, Network Regulation, AER.
[94] AER's letter of 11 December 2013, pp1-2.

c) For the purpose of complying with clause 11.56.2(b)(6), Ausgrid will provide a summary of the plans for expenditure for standard control services only, as they are defined in the AER's stage 1 F&A.

d) This amount (as accepted or determined by the AER) will be the amount used for:

   i. Adjusting the annual revenue requirement of the subsequent period as set out in 11.56.4(h). To avoid doubt, this amount will be the amount for the purpose of clause 11.56.4(i)(1).

   ii. Calculating the over/under recovery of revenue (as compared to actual revenue) in the transitional year in demonstrating compliance with the control mechanism for standard control services applicable from 1 July 2014.

Ausgrid considers the above clarifications are consistent with the AER's view as outlined in its letter of 11 December 2013, the AER contemplated the clear delineation of revenues associated with the provision of standard control services and alternative control services. The AER stated that:

A reconciliation of the costs of these services (i.e. Type 5 and 6 metering services) will be required to the extent that the standard control building blocks require an adjustment as part of the AER's final distribution determination for the subsequent regulatory control period.

We set out further details and examples of how the adjustment and calculation of over and under recovery would operate in attachment L.

e) Ausgrid will add to the revenue amount proposed to be the annual revenue requirement for standard control services for the transitional year, the revenue needed to recover the costs of providing reclassified alternative control services and unclassified services (as they are defined in the AER's F&A stage 1 paper). For clarity, public lighting revenues will not be 'bundled'.

   This 'bundled' revenue[90] will be nominated as the total revenue to be recovered through DUOS charges for the transitional year. This amount will effectively be accepted or otherwise amended by the AER in its transitional determination.

   For avoidance of doubt, the total bundled amount only has the effect of setting DUOS charges for the transitional year and nothing else.

We note that this bundled revenue includes the costs of emergency recoverable works for transitional year (net of any revenue expected to be recovered through third parties). This inclusion was not raised by the AER in its letter of 11 December 2103. The AER's approach rests on the fact that the rules prevent the re-allocation of costs between services in the transitional year. For this same reason, we consider that costs relating to emergency recoverable works, which are classified as standard control services in the current period but unclassified by the AER from 1 July 2014 should also be left in the standard control services costs pool in the transitional year and recovered through the bundled DUOS charges for the transitional year.

Further, in relation to this 'aggregation' of revenue in the transitional year, it must be noted that:

i. The fact that revenues needed to recover costs relating to alternative control services (e.g. Type 5 and 6 metering services) and unclassified services) does not render ineffective the AER's classification of these services from 1 July 2014 onwards.

ii. The bundled revenue[91] will not to be used in adjusting the annual revenue requirement of standard control services of the subsequent period (as per clause 11.56.4(h)-(j)) or in calculating the over/under of standard control services.

iii. The aggregation of revenues is for the transitional year only and only for the purpose of setting the DUOS prices of this year. In relation to the requirements of clause 11.56.2(b)(5), the indicative revenue requirements for the transitional year and the subsequent four years will be the revenue relating to the provision of standard control services (as they are defined in the AER's stage 1 F&A).

iv. The recovery of revenue needed to cover the costs of providing reclassified alternative control services in DUOS prices is for the transitional year only and that an adjustment will be made to the prices for alternative control services in the subsequent period for under/over recovery of alternative control services in the transitional year. Separate alternative control prices will be established for the period subsequent to the transitional control period.

[95] Net of revenues expected from separate miscellaneous and monopoly prices and from third party damage recovery.
[96] i.e. the total revenue aggregated from the annual revenue requirement for standard control services and the revenues needed to recover the costs of alternative control services and unclassified services.

Glossary

Abbreviation	Meaning
($nominal) [for paragraphs]	$XXXXX million ($nominal). This is the dollar of the day.
($ million, nominal) [for tables]	Nominal dollars for table/figure captions
($2013-14) [for paragraphs]	$XXXXX ($2013-14), Real dollars. This denotes the dollar terms as at 30 June 2014.
($ million, 2013-14) [for tables]	Real dollars for table/figure captions
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.
DMEGCIS	Demand Management Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DMIA	Demand management innovation allowance
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
ERW	Emergency recoverable works
EWON	Energy & Water Ombudsman NSW
F&A	Framework and approach
Fisher equation	= 1+ real rate of change) x (1+ rate of inflation) = (1+ nominal rate of change). For example 1.34% =[(1+1.12%)/(1+2.5%) -1]%
IBT	Inclining block tariff

Abbreviation	Meaning
Last regulatory period	Regulatory control period of 1 July 2004 to 30 June 2009
LNSP	Local Network Service Provider
MRIM	Manual read interval meter
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
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
STPIS	Service Target Performance Incentive Scheme
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

Attachment A	Post tax revenue model – distribution and metering (excel models)
Attachment B	Post tax revenue model – transmission (excel model)
Attachment C	Roll forward model – distribution (excel model)
Attachment D	Roll forward model – transmission (excel model)
Attachment E	CEG-WACC estimates
Attachment F	EBSS calculation (excel model)
Attachment G	Indicative price list for public lighting services (maintenance charges and post-2009 capital charges)
Attachment H	Indicative price list for public lighting service – (pre-2009 capital charges) (CONFIDENTIAL)
Attachment I	Indicative prices and volumes forecasts for ancillary network services (miscellaneous and monopoly services)
Attachment J	Proposed connection policy
Attachment K	Pricing methodology for transmission standard control services (CONFIDENTIAL)
Attachment L	Other compliance matters